Energy Research and Development Division

FINAL PROJECT REPORT

Groundwater Bank Energy Storage Systems

A Feasibility Study for Willow Springs Water Bank

California Energy Commission

Edmund G. Brown Jr., Governor

July 2017 | CEC-XXX-2017-XXX

PREPARED BY: Antelope Valley Water Storage, LLC

Primary Author(s):
Mark Beuhler
Naheed Iqbal
Zachary Ahinga

Contributor(s):
Lon W. House

Antelope Valley Water Storage, LLC
1672 W Avenue J Suite 207
Lancaster, CA 93534
Phone: 323-860-4824 | Fax: 661-945-4554

Contract Number: EPC-15-049

PREPARED FOR:
California Energy Commission

Yu Hou
Project Manager

Aleecia Gutierrez
Office Manager
ENERGY GENERATION RESEARCH OFFICE

Laurie ten Hope
Deputy Director
ENERGY RESEARCH AND DEVELOPMENT DIVISION

Robert P. Oglesby
Executive Director

ACKNOWLEDGEMENTS

The authors wish to thank the following individuals and organizations for their support towards the completion of this study:

Technical Advisory Committee members: Angelina Galiteva (California ISO Board of Governors), Adam Hutchinson (Orange County Water District (OCWD)), Ted Johnson (Water Replenishment District of Southern California (WRD)), Garry Maurath (California Energy Commission), and Robert Wilkinson (University of California, Santa Barbara)

Yu Hou (California Energy Commission)

Tommy Ta (Antelope Valley Water Storage, LLC)

Will Boschman of the Semitropic-Rosamond Water Bank Authority for selected photographs

Subcontractor firm: HDR Engineering, Inc. (HDR)

The agencies that responded to the survey: Castaic Lake Water Agency (CLWA); City of Bakersfield, Water Resources Department; Elsinore Valley Municipal Water District; Foothill Municipal Water District; James Irrigation District; Mojave Water Agency; Monterey Peninsula Water Management District; Orange County Water District; Root Creek Water District; Rosedale-Rio Bravo Water Storage District; San Bernardino Valley Water Conservation District; Three Valleys Municipal Water District; United Water Conservation District; and Western Municipal Water District

PREFACE

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

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

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

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

Groundwater Bank Energy Storage Systems: A Feasibility Study for Willow Springs Water Bank is the final report for the Electricity Pumped Storage Systems using Underground Reservoirs: A Feasibility Study for the Antelope Valley Water Storage System project (Contract Number EPC-15-049, Grant Number GFO-15-309) conducted by Antelope Valley Water Storage, LLC. The information from this project contributes to Energy Research and Development Division's EPIC Program.

All figures and tables are the work of the author(s) for this project unless otherwise cited or credited.

For more information about the Energy Research and Development Division, please visit the Energy Commission's website at www.energy.ca.gov/research/ or contact the Energy Commission at 916-327-1551.

ABSTRACT

Increased renewable generation in California has resulted in an excess of electricity supply during certain periods of the day. Energy storage systems make it possible to repurpose the supply glut to meet grid needs during peak hours and thereby, help with integration of renewable energy into the electric grid. Pumped storage is a well-established type of energy storage which uses water to store energy during the off-peak (low demand) hours. The stored energy is released during the peak hours when there is a spike in electricity demand. Integrating pumped storage with groundwater banking operations has the potential to increase the number and type of areas where pumped storage can be implemented. The objective of this study is to address the knowledge gaps associated with having onsite pumped storage at groundwater banks. The study evaluated two pumped storage systems: Peak Hour Pumped Storage (PHPS), that has all the components aboveground, and Aquifer Pumped Hydro (APH), that uses the aquifer as the lower reservoir. Besides pumped storage, hydropower generation and demand response potential of groundwater banking projects were also assessed. The hydrologic year type will determine which of the three configurations is used in a particular year. These configurations and their corresponding economic values were analyzed for an existing groundwater banking project, Willow Springs Water Bank (WSWB) which served as a case study for this project. The WSWB specific findings were used to evaluate the potential of statewide implementation of PHPS and APH. The analysis shows that the demand response during a dry hydrologic year has the highest value. To enhance the economic viability of energy storage systems as well as to address the grid needs, a groundwater bank should be configured to provide demand response during a dry year as well as hydropower generation, demand response, and pumped storage benefits in other hydrologic year types.

Keywords: California Energy Commission, pumped storage, groundwater banks, energy storage systems, demand response, hydropower generation, renewable energy

Please use the following citation for this report:

Beuhler, Mark, Naheed Iqbal, Zachary Ahinga, and Lon W. House. Antelope Valley Water Storage, LLC. 2017. *Groundwater Bank Energy Storage Systems: A Feasibility Study for Willow Springs Water Bank*. California Energy Commission. Publication Number: CEC-XXX-2017-XXX.

TABLE OF CONTENTS

LIST OF FIGURES

Page

LIST OF TABLES

Page

EXECUTIVE SUMMARY

Introduction

California is experiencing a surge in renewable generation that has resulted in operational challenges for the grid. Solar generators comprise majority of the renewable energy and their output varies throughout the day. This is causing a mismatch between energy supply and demand, with a glut of supply in the afternoon hours (when the solar generation peaks) and a shortage of supply in the evening hours (when the renewable generation ceases for the day). This mismatch is represented by a daily electric demand curve ("duck curve") that dips in afternoon and rises sharply in evening and resembles the profile of a duck. To address this mismatch and move the excess energy from periods of low demand to periods of high demand, the electric grid must have energy storage systems.

Pumped storage is an established energy storage technology and has been deployed nationwide. It works by pumping water from a lower reservoir to a higher one. Energy is stored in the form of gravitational potential energy of water. Electricity is generated when the stored water at the higher elevation returns to the lower reservoir through a turbine generator.

Project Purpose and Description

The purpose of this project is to evaluate the feasibility of using the conventional pumped storage concept in a novel way to provide cost-effective and reliable energy storage. The State is home to a number of groundwater banking facilities that safeguard against potential water shortages (such as the ones occurring during the recent 2013—2015 drought). The project examines the applicability of implementing pumping storage at these groundwater banks. The banks store water in the natural underground reservoirs (aquifers) in wet years and pump it out for use in dry years via groundwater wells. The primary function of these banks is water storage and there is no precedent for evaluating these banks for pumped storage. These sites present an opportunity for pumped storage systems because they have water supplies and an existing infrastructure (including wells and pipelines) to cycle the water for energy storage. Therefore, pumped storage implementation at these sites requires minimal additional facilities and has a smaller environmental footprint than that of conventional pumped storage.

The project evaluates two pumped storage technologies: Peak Hour Pumped Storage (PHPS) and Aquifer Pumped Hydro (APH) for their applicability at groundwater banks. Conceptually, PHPS operates like the conventional pumped storage – water is cycled between two surface reservoirs through a connecting pipe to store and release energy. However, PHPS is much smaller in scale and can be implemented in areas that would normally be precluded from consideration for conventional pumped storage. An APH unit uses the aquifer as a lower reservoir in conjunction with a surface (upper) reservoir. A groundwater well cycles the water between the two reservoirs. It is a novel form of pumped storage and has been the subject of only a few studies.

Project Process

A two-fold approach was adopted for the analysis. The PHPS and APH potential was first determined for an existing groundwater banking project, Willow Springs Water Bank (variously referred to as "the Bank" or WSWB in this report). The WSWB specific analysis yielded criteria which the project team used to evaluate other sites and develop an estimate of cumulative pumped storage capacity (MW) available at statewide groundwater banks.

WSWB has a 5.2 MW capacity for PHPS. The PHPS facility at WSWB can generate energy up to 12 hours daily depending on the size of the upper reservoir. During the remaining hours, water is pumped to the upper reservoir to refill it. Statewide, the cumulative PHPS potential is estimated to be 44 MW. APH is infeasible at WSWB because of low round-trip efficiency. Preliminary screening of other sites indicates that the APH has limited statewide potential.

Economics Evaluation

Just as water storage infrastructure at groundwater banks can be used for energy storage, the pumped storage facilities at groundwater banks can be used to provide energy benefits other than energy storage. These benefits include hydropower generation (water passing through the turbines to generate energy without first being pumped to an upper reservoir) and demand response (changing load or demand based on grid requirements). Which of the energy benefits occur at any one time is determined by the hydrologic year type which in turn determines the operating mode for the groundwater banking facilities (including any installed pumped storage facilities). These additional benefits were taken into consideration when evaluating the economic feasibility of pumped storage at groundwater banks.

The operations of a typical groundwater banking project such as WSWB vary based on the hydrological year type. This study evaluates groundwater banking operations in three hydrological year types: a wet year, a dry year, and a neutral or idle year. In contrast, California Department of Water Resources (DWR) classifies a water year (Oct 1 – Sep 30) into five types: as a wet year, an above normal year, a below normal year, a dry year and a critical year (DWR, 2017). In this report, the term "wet" indicates a wet year as defined by DWR, "neutral" is used for above normal and below normal year types, and "dry" represents the DWR defined dry and critical hydrologic year types.

During neutral or idle year type the water bank is neither recharging nor extracting water. During a wet year type the water bank is continuously recharging water. During dry years the water bank is continuously extracting water.

For economic evaluation, an operating mode configuration was assigned to each of these year types:

In a neutral year, the Bank was assessed as a pumped storage facility which uses APH or PHPS technology to generate when electricity prices are high, and refill storage when prices are low. Because of the slow response time (the time required for the aquifer to reestablish equilibrium as the operations are switched from pumping to generating and vice versa) and low round-trip efficiency, APH at WSWB was found to be suited for only one electricity market, Day-Ahead

Energy Market. The Day-Ahead market is a type of energy market that matches electricity sellers and buyers and closes the day prior to the day the energy will be used.

In a wet year, the Bank was assessed as a generator which uses turbines (same turbines as used for PHPS in a neutral year) to generate 5.2 MW constantly over the year. The APH units which have reversible pump/turbines cannot similarly be used for generating year-round hydropower in a wet year. This is because to generate hydropower recharge water has to be injected into the ground instead of percolated. Injecting recharge water will incur additional compliance costs which makes well field dependent hydropower generation impractical.

In a dry year the Bank pumps the stored water and has pumping demand from groundwater wells (17.2 MW) and the pump station (10.1 MW). In this year, the Bank acts as a continuous load and can be configured for demand response that is the wells and pump station can be turned off during the on-peak (high electricity demand) periods.

The table below summarizes the operational configurations for WSWB that use existing water banking facilities in conjunction with additional facilities installed for PHPS and APH to provide pumped storage, demand response and hydropower generation.

WSWB PHPS and APH Operating Scenarios

Hydrologic Year Type	Probability of Occurrence	WSWB Operation Type	Electricity Demand Potential	Electricity Generation Potential	Evaluated As
APH					
Wet	32%	Recharge	0	0	
Neutral	33%	Idle	17.2 MW	3.7 MW for 5 hours daily	Pumped Storage
Dry	35%	Extraction	17.2 MW groundwater pumping + 10.1 MW pump station use	0	Demand Response
PHPS					
Wet	32%	Recharge	0	5.2 MW 24 hours daily	Generator
Neutral	33%	Idle	10.1 MW pump station use	5.2 MW for 5 hours daily	Pumped Storage
Dry	35%	Extraction	17.2 MW groundwater pumping + 10.1 MW pump station use	0	Demand Response (demand reduction)

Source: (House L. W., 2017 a)

The estimated statewide pumped storage and demand response potential was used in conjunction with the operating configurations developed for WSWB to evaluate the value of pumped storage and associated benefits at other groundwater banks. This approach assumes that WSWB operations are representative of typical groundwater banking projects. Therefore, all the groundwater banking projects in the State (including WSWB) have an estimated 44 MW of cumulative PHPS potential (in a neutral year), 44 MW of cumulative hydropower generation potential (in a wet year), limited cumulative APH potential (in a neutral year), and 220 MW of cumulative demand response potential (in a dry year).

Project Results

PHPS facilities, if configured appropriately, can be potentially economically viable but it will be more challenging for an APH setup to be so at typical groundwater banking projects. The net present value (NPV) method was used to evaluate costs and revenues for PHPS and APH. A positive NPV indicates that a project is financially viable. Projects with negative NPV should generally be avoided. The results show that adding dry year demand response to a PHPS facility's wet and neutral year operations makes it cost effective but adding dry year demand response to APH is not enough to make APH cost effective. The table below summarizes these findings:

Comparison of WSWB APH and PHPS Operational Analysis

	Aquifer Pumped Hydro (APH)	Peak Hour Pumped Storage (PHPS)	Demand Response
Components needed	Reversible pump-turbines, surface storage reservoir, aquifer lower reservoir	Hydroelectric generator, upper and lower surface reservoirs	Additional groundwater wells for 320 hours curtailment
Capital Cost	$18.6M	$7.9M	$2.1M
Net Present Value (NPV)	-$18.2M (generator operating in neutral years)	-$0.9M (generator operating during wet and neutral years)	$9.1M (dry years)
Capital Cost with Dry Year Demand Response	$20.3M	$10M	-
Net Present Value (NPV) with Dry Year Demand response	-$9.1M	$8.1M	-

Source: (House L. W., 2017 a)

44 MW of statewide PHPS potential (with PHPS facility used for both pumped storage and hydropower generation and evaluated with dry year demand response) has an annual net benefit of $5.9 M and the 220 MW of statewide load used for demand response purposes has an annual net benefit of $6.3 M.

Benefits to California

Energy storage is one of the solutions being explored to address the "duck curve" problem. This problem is projected to worsen as more renewables come online and is characterized by an excess of generation during the afternoon hours (when solar generation peaks), a very steep ramp in generation requirement during the late afternoon (as solar generation ends), followed by a peak generation requirement during the evening. The analysis shows that the PHPS facilities at groundwater banks can be economically viable if appropriately configured and have the potential to mitigate the duck curve problem by:

- Curtailing hydropower generation during afternoon (renewable overproduction period) in a wet hydrologic year.
- Generating hydropower during the morning and evening ramp periods, and increasing demand (pumping load) to refill reservoirs during the afternoon (renewable overproduction period) in a neutral hydrologic year.
- Curtailing pumping load during the late afternoon ramping period and evening peak in a dry hydrologic year.

Besides enabling renewable integration, implementing pumped storage facilities at groundwater banks also benefits California by adding to the renewable generation capacity, and providing demand response benefits that can help out the grid in the event of unplanned outages. Pumped storage facilities at groundwater banks can also enable participation in additional electricity markets to provide more services provided the facilities are configured properly and the water banks are willing to turn over operational control of the facilities to the California Independent System Operator (an entity that manages the electricity flow and operates the electric grid in California). Using small scale pumped storage also decreases the need for large, environmentally invasive new reservoirs thus reducing the risk of catastrophic floods after an earthquake. The statewide PHPS potential of 44 MW is expected to address up to 1% of the State's storage needs and results in an annual greenhouse gas emissions reduction of 44,000 metric tons of carbon dioxide equivalent (CO_2e) GHG reductions on average. An extensive database of statewide groundwater banking facilities was compiled for this project. The project team has also developed PHPS and APH templates which together with the database can be used to identify potential sites for testing the pumped storage concepts in a next-step pilot project. Particularly favorable sites include groundwater banks in the Tulare Basin and in the Southern California coastal plain, where both the pumped storage and the demand response aspects can be exploited.

CHAPTER 1: Introduction

Groundwater banks are underground storage facilities that are used for banking or storing water. Stored water can be recycled water, imported water from other areas (typically Northern California) or local surface water. The underground saturated, permeable, water-bearing rock that transmits groundwater is called an aquifer. Water is stored in an aquifer through artificial recharge in years of water surplus and recovered during years when there is a water shortage. Groundwater wells are typically used to recover water from an aquifer.

In addition to their primary function of water storage, groundwater banks also provide an opportunity to store energy. Harnessing the potential of water for energy storage purposes is not new. Conventional water storage or pumped storage is a well-established technology with multiple projects in California. In contrast, pumped storage using a groundwater bank and the aquifer is far from established. This Electric Program Investment Charge (EPIC) funded project assesses the statewide pumped storage potential of groundwater banks and provides a framework to utilize groundwater banks for cost-effective and efficient distributed energy storage. The study investigates two different kinds of pumped storage. The first one called Peak Hour Pumped Storage (PHPS) is similar to the conventional pumped storage with the difference being that instead of building new dedicated facilities including large surface reservoirs, existing groundwater banking facilities can be modified and enhanced with hydroelectric generators and surface storage reservoirs to cycle water with a much smaller environmental footprint. The second one called Aquifer Pumped Hydro (APH) uses the aquifer below a groundwater bank as the lower reservoir, a small earthen reservoir as the upper reservoir and reversible pump turbine groundwater wells (instead of a pipeline) to cycle the water.

1.1 Background

The increased renewable generation in California has made integrating renewables into the grid a top priority. Energy storage systems are necessary to allow for smooth integration of renewables such as wind and solar and to overcome the "duck curve" problem. The duck curve problem is an imbalance in supply and demand at various times of the day resulting from the nature of the renewables (particularly solar). Since renewables are generating energy mostly during the afternoon hours, there is overgeneration during the day. By evening as solar generation peters out, the demand ramps up. Consequently, the daily net electric demand (total demand for electricity net the renewable generation) change considerably throughout the course of a day. This is reflected in a duck shaped profile (duck curve) for the net electric demand with the belly of the duck representing the glut of energy (low net demand) and the head representing the shortage (high net demand). For additional information on duck curve, see Section 6.1.

Without adequate storage, the duck curve problem is projected to be exacerbated as more renewable sources come online to meet the State of California's target of 50% renewable electricity by 2030 and the potential goal of 100% by 2045 (Senate Bill 100). The capability to provide peak electricity during the early evening as solar generation ramps down will become increasingly important. Consequently, various storage technologies are being explored and developed to provide reliable and cost-effective storage. Conventional pumped hydroelectric storage has been the dominant energy storage technology in the United States and has been widely deployed all over the country and globally to provide peak hour energy and to increase grid reliability and flexibility. The conventional form of pumped storage uses two reservoirs (usually a dam and an aqueduct) situated at different elevations to cycle the water. Water is pumped to the higher elevation reservoir during off-peak hours to store energy. During on-peak hours, water flows by gravity to the lower reservoir generating energy in the process. This technology is limited by topography, environmental concerns, high cost, and the large size requirements needed to make it practical. Most of the best sites for surface reservoirs have already been taken limiting the wider use of pumped storage.

Groundwater banks (Figure 1) offer an opportunity to expand the geographic scope of pumped storage. As traditional pumped storage, pumped storage at groundwater banks has the potential to store excess energy during non-peak hours for release during the dusk (peak) hours when the grid needs it the most. Using groundwater banks for pumped storage operations will also have fewer environmental impacts including reduced risk of catastrophic flooding.

Figure 1: Recharge Basins at a Typical Groundwater Banking Project

Figure 1 shows recharge activities via spreading at Semitropic Groundwater Storage Bank in Central Valley, California. Although groundwater banks have traditionally been used only for water storage, they may have potential as energy storage systems as well.

Source: (Semitropic Water Storage District, 2017)

Unlike traditional pumped storage, the use of pumped storage in conjunction with a groundwater bank remains largely unexplored. This study is the first of its kind to put forward a conceptual framework to assess the potential of pumped storage at groundwater banks in California. It identifies and analyzes current policy, regulatory, economic and technical parameters pertinent to the implementation of pumped storage operations at existing and planned groundwater banks to determine value of the PHPS and APH energy storage system technologies. The value of these technologies lies in their role as 'transition' energy storage systems – they will start up when the quick response (seconds) but low capacity energy storage (battery/flywheels) runs out and before slow response (minutes or hours) but high capacity storage (large pumped hydro facilities) engages. Statewide application of pumped storage at groundwater banks has the potential to enhance grid reliability by enabling greater integration of solar and wind energy and providing power during unplanned outages.

The study establishes the potential of pumped storage at an existing large groundwater bank in the Antelope Valley, Willow Springs Water Bank (variously referred to as "the Bank" or WSWB in this report) and identifies criteria thresholds that must be met for the successful deployment of the two ESSs at other groundwater banks. This information is then used to provide estimates of statewide potential, taking into consideration specific characteristics of other regions and other groundwater banking projects. The statewide potential is evaluated in context of the State's storage needs with description of major limitations and anticipated costs and benefits.

1.2 Objectives

The study evaluates the energy storage potential of groundwater banks, specifically (1) potential of Peak Hour Pumped Storage (PHPS) technology which uses surface reservoirs at groundwater banks; and (2) potential of Aquifer Pumped Hydro (APH) technology which uses the aquifer at groundwater banks (APH). The study has three objectives:

- Feasibility analysis of PHPS and APH technologies at WSWB including development of optimized facilities layout for the two energy storage systems (ESSs)
- Assessment of statewide potential of the pumped storage at groundwater banks including identification of criteria and specific groundwater banking sites or regions where the two technologies are likely to be successful
- Estimation of the value of energy storage and other grid benefits provided by the two technologies.

The key features of the study include (1) analyzing the impact of various storage capacities on the duration of energy release, (2) developing an optimized layout containing specifications for reservoirs, generators, and locations along with the corresponding peak power generation potential in MW, (3) creating a template that can be used to determine the groundwater banking areas where energy storage and peak power generation is practical, and (4) providing initial estimates of peak energy generation and associated grid support benefits resulting from pumped storage at groundwater banks. Ultimately, the goal of the study is to provide a preliminary assessment of the statewide potential for pumped storage systems at groundwater banking projects.

1.3 Energy Storage Systems at Groundwater Banks

Groundwater banks have not traditionally been targeted to provide peak energy. Currently, there are more than 90 groundwater banking projects spread across California (Antelope Valley Water Storage (AVWS), 2016). Many new groundwater banking operations and recycled water programs are planned to be implemented as a result of the Water Quality, Supply, and Infrastructure Improvement Act of 2014 (Proposition 1) and Sustainable Groundwater Management Act (SGMA). This study evaluates the potential of two as yet untested pumped storage technologies at groundwater banks. The PHPS technology uses a combined pump/generator pumping station in conjunction with an upstream surface reservoir and a downstream surface reservoir. PHPS is best suited for groundwater banks that have elevational differences within their groundwater bank and suitable surface area to construct additional surface storage reservoirs. The elevation difference between the reservoirs provides the pumping lift and the reservoirs are connected by a pipe. Energy is generated when the water flows to the lower reservoir during peak hours when the electricity demand is high. During non-peak hours energy is stored by transporting water to the upper reservoir. Depending on the size of the reservoirs and the pumping lift involved, a PHPS project can discharge energy over a long duration or during the peak hours and allows rapid demand management. Although relatively proven, PHPS is a novel concept in the context of being implemented at a groundwater bank for daily peaking.

APH is an underground pumped hydroelectric energy storage method that uses aquifer as the lower reservoir of a pumped hydro system. An APH unit consists of a reversible pump/turbine, a well, and related equipment. The pump/turbine generates electricity from water flowing down the well hole. It stores electricity at other times by pumping water up the well to a surface reservoir using electric power. APH is best suited for groundwater banks that have aquifers with high groundwater transmissivity, deep water levels, and surplus well capacity. APH can be implemented as a modular array to capture electrical oversupply, store electrical energy and provide distributed generation and demand response. Most of the studies of underground pumped hydro concept date back to 1970's and 1980's[1] and focus on using a large underground cavern, either available from abandoned mines or excavated, as the lower reservoir. Energy storage needs has caused a resurgence of interest in the underground pumped hydroelectric energy storage method and largescale utility sized projects (1,000-3,000 MW) using underground caverns have been evaluated in recent years (Fairley, 2015; Madlener, 2013; Uddin & Asce, 2003; Tam, Blomquist, & Kartsounes, 2007; Pickard, 2012). While none of these largescale projects have been built, there are existing permits at the Federal Energy Regulatory Commission for some of these projects[2]. The concept of using the aquifer, rather than an underground cavity, as the lower reservoir has been explored by very few studies

1 (Allen, Doherty, & Kannberg, 1984; Blomquist C. , Frigo, Tam, & Clinch, 1979; Braat, van Lohuizen, & de Haan, 1985; Chang, Thompson, Allen, Ferreira, & Blomquist, 1980; Doherty, 1982; Farquhar, 1982; Frigo, Blomquist, & Degnan, 1979; Blomquist, Frigo, & Degnan, 1979; Frigo & Pistner, 1980; Ridgway, Dooley, & Hammond, 1979) (Rogers & Larson, 1974) (Rogers F. C., 1975) (Scott, 2007) (Willett & Warnock, 1983)

2 For example, FERC Project No. 14612-000, New Summit Hydro LLC, is for 1,500 MW pumped hydro storage project in Ohio using an abandoned underground limestone mine as the lower reservoir.

(Martin, 2007; S.Y. & I.E., 2017; Budris, 2014) and these evaluations have been of a preliminary nature.

This study uses data from an operating groundwater bank to study the APH in more depth and provides valuable information about the efficiency, costs and value estimates for the APH form of pumped storage. The study also assesses potential use of recycled water for APH to eliminate ½ of the round trip and improve the overall efficiency of peak hour power generation.

1.3.1 Willow Springs Water Bank

Willow Springs Water Bank (WSWB) is a groundwater banking project located in Antelope Valley, California on approximately 1,838 acres of agricultural land. The Bank has 500,000 acre-feet (AF) of approved storage capacity. Recent groundwater modeling results indicate that the Bank's capacity can be increased to 1,000,000 AF. Additional details about WSWB are provided in the WSWB Fact Sheet (Attachment I).

At WSWB, the pumping lifts are 350' to 450' for the PHPS and APH energy storage systems. The Bank's build out plan also includes a big pipe, a pump station/turbine, and potential sites for large upstream and downstream reservoirs. Therefore, WSWB provides a good opportunity for preliminary assessment of pumped storage potential at groundwater banks.

The study uses design information for the Bank's facilities, water quality and aquifer data, and well drawdown results to provide conclusions about the economic and technical feasibility of the two pumped storage technologies at WSWB. The optimized facility layout for PHPS technology was developed as part of the study. This layout balances various parameters such as size of the generating equipment, discharge duration and reservoir capacity to achieve a PHPS configuration that integrates well with the WSWB operations and maximizes the benefits to the grid in a cost-effective way. Existing wells at WSWB were used for field evaluation of the startup and shutdown times.

The findings from the WSWB site specific analysis were used to develop criteria to evaluate pumped storage potential at other groundwater banks. Figure 2 shows the general conceptual facility layout for implementing both PHPS and APH systems at a groundwater bank.

Figure 2: Facility Layout for Pumped Storage at a Groundwater Bank

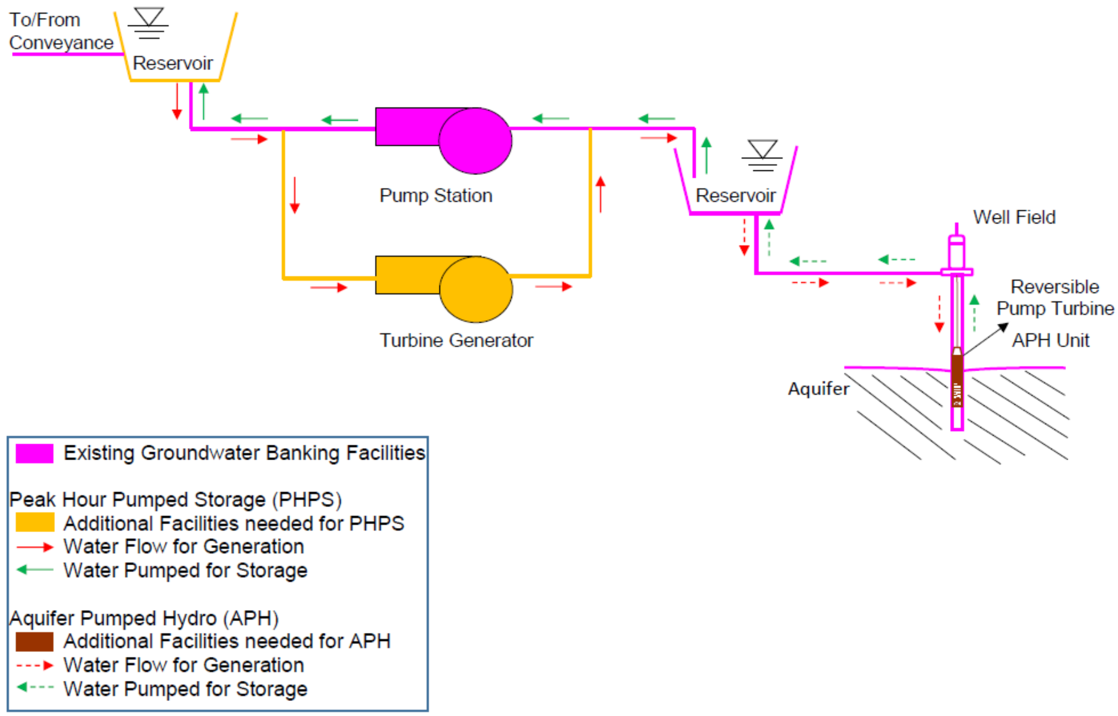


Figure 2 illustrates a simplified conceptual layout for the PHPS and APH systems at a groundwater bank. Many groundwater banks get water from and send water to a conveyance (for example California Aqueduct) during recharge and recovery operations respectively. The onsite surface reservoir helps with flow regulation during recovery. PHPS and APH primarily use existing groundwater banking infrastructure but also require additional facilities. During off-peak periods, both the systems pump water from a lower reservoir to a higher reservoir for storage (green arrows). During the on-peak periods, the stored water is released from the higher reservoir to the lower reservoir (red arrows). The released water passes through the turbines which convert the kinetic energy of moving water into electrical power. In this way, the water can be cycled repeatedly between the higher and lower reservoirs to generate energy.

CHAPTER 2: Aquifer Pumped Hydro at Willow Springs Water Bank

This chapter describes the technical feasibility of Aquifer Pumped Hydro (APH) at Willow Springs Water Bank (WSWB). APH uses the existing groundwater aquifer as a lower reservoir and a surface reservoir as the upper reservoir. The existing electric grid provides the energy source and sink. The system operates on a cycle that has two stages – storage and generation. During the storage stage water is pumped out of the groundwater aquifer into the upper reservoir, and during the generation stage, water is injected back into the groundwater aquifer via the pump/turbine generator and well shaft piping. APH has to be installed so as not to interfere with the primary operations of a groundwater bank and uses wells that are part of the groundwater bank.

The study examined the potential of Aquifer Pumped Hydro (APH) to produce hydropower during the 5 peak hours of the day. An APH unit consists of an existing WSWB well, piping, and reservoir facilities. A typical well at WSWB includes a 300 HP 480 Vac (Volts, alternating current) 3-wire electric pump motor, standard centrifugal vertical-turbine pump, motor control panels, electrical panels, circuit breakers and transformer unit. The vertical-turbine pump is operated in the forward direction using electric power to pump water and would be operated in the reverse direction, “Pump As Turbine” to generate electric power.

To enable the pump to operate in the reverse direction to generate electric power, required modifications to the system may include:

1. Pump shaft modification to enable the shaft to turn in the reverse direction.
2. Addition of pressure control valve on pump shaft and electronic valve control unit.
3. Addition of Power Electronics Controller to excite the motor-generator and rectify the output to enable motor to operate efficiently as a generator.
4. Addition of a grid-tie inverter/rectifier.
5. Addition of System Control and Monitoring for overall control and protection of all the elements of the electrical system, with primary job to route power to and from the energy storage system, local power sources and the loads.
6. Modification of electric system to interface with energy sources, user loads, and utility grid.

Providing detailed designs of these modifications is not part of this study and should be part of a next-step pilot-program to confirm the appropriate component size/capacity and effectiveness of the system.

Figure 3 through Figure 6 depict the conceptual components of the Aquifer Pumped Hydro system. A large array of standardized modules enables precise ramp up and ramp down capability. For example, an array of 100 equally sized modules can quickly go from 1% to 100% capacity by activating from 1 module to 100 modules in the power generation mode based on the needs of the grid. Similarly, 100 modules in the power storage mode can decrease demand rapidly and/or incrementally from 1% to 100% within seconds by shutting off 1 module to 100 modules. The modular pumped hydroelectric system can therefore provide both power generation and demand response rapidly[3] and in any increment desired and is more flexible than a conventional large pumped hydroelectric project.

Figure 3: An individual unit of the APH pumped hydroelectric system

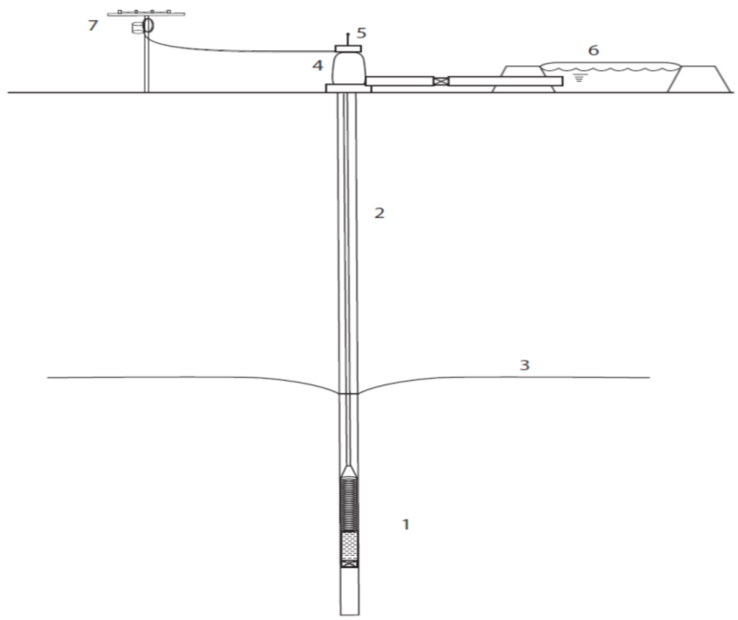


Figure 3 shows an individual unit of the APH modular pumped hydroelectric system. It consists of a reversible pump/turbine unit at the bottom of a well shaft with a control valve 1, the well itself 2, the natural water table of the aquifer which serves as the lower reservoir 3, the electric variable frequency motor/generator for the module 4, the remote control and command of the valves and motor/generator of the module 5, the surface reservoir, combined inlet/outlet pipe and flow control valve which constitutes the upper reservoir 6, and the alternating current transformers that connect the module to the electric grid 7.

3 The term, 'demand response' used in the context of APH is different from the demand response potential realized by shifting the groundwater recovery operations out of peak summer hours discussed elsewhere in this report. While APH pumped storage and associated demand response capability of a multi-modular APH array can potentially occur in all hydrological year types, the latter is largely limited to dry years which is typically when groundwater is extracted for deliveries.

Figure 4: An APH unit in generating and storing modes

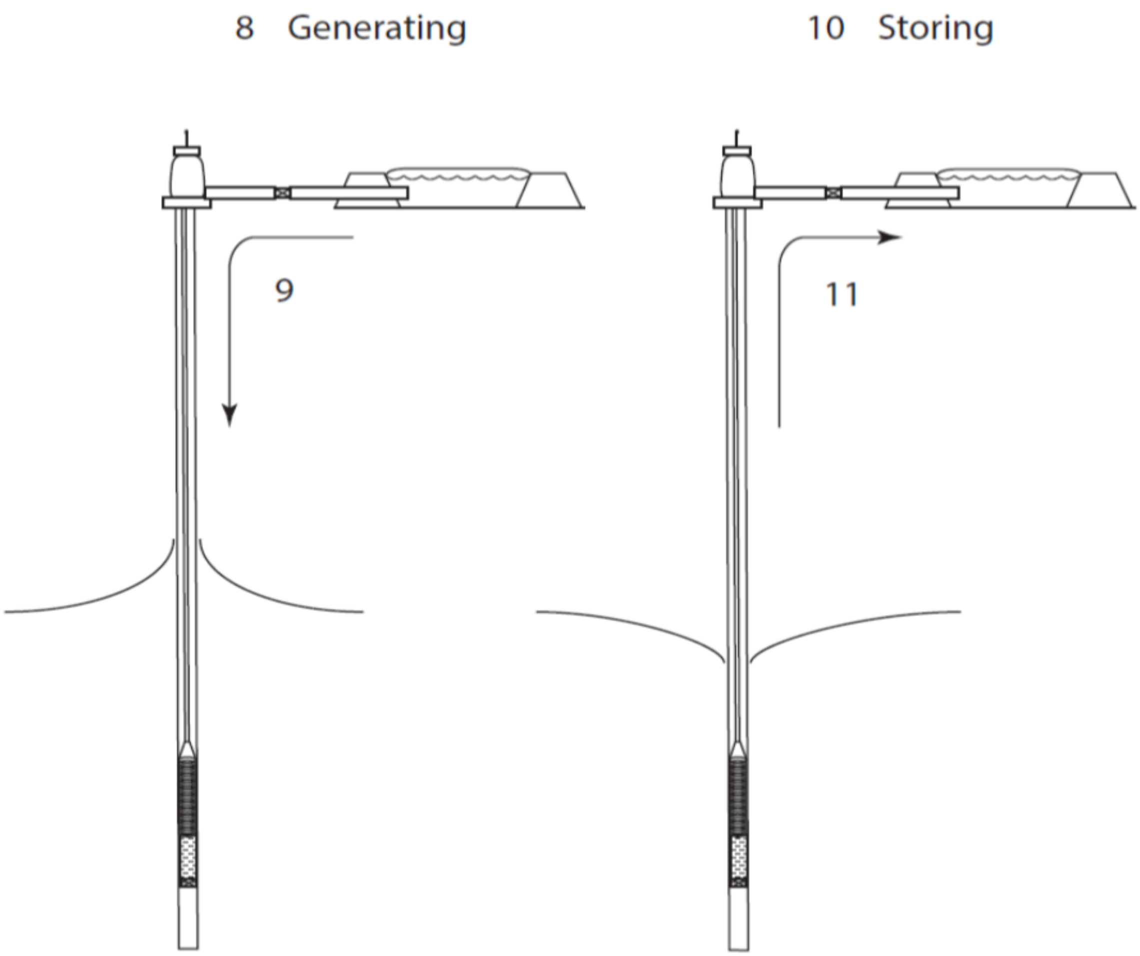


Figure 4 shows the hydraulics of the APH modular pumped hydroelectric system when generating electricity in the generation operational mode 8. Electricity is generated when water flows down the well hole and turns the turbine 9. The figure also shows the energy storage operational mode 10. Kinetic energy is stored as potential energy when water is pumped up the well hole 11. Water is cycled up and down the aquifer.

Figure 5: Interaction of APH unit with the electrical grid

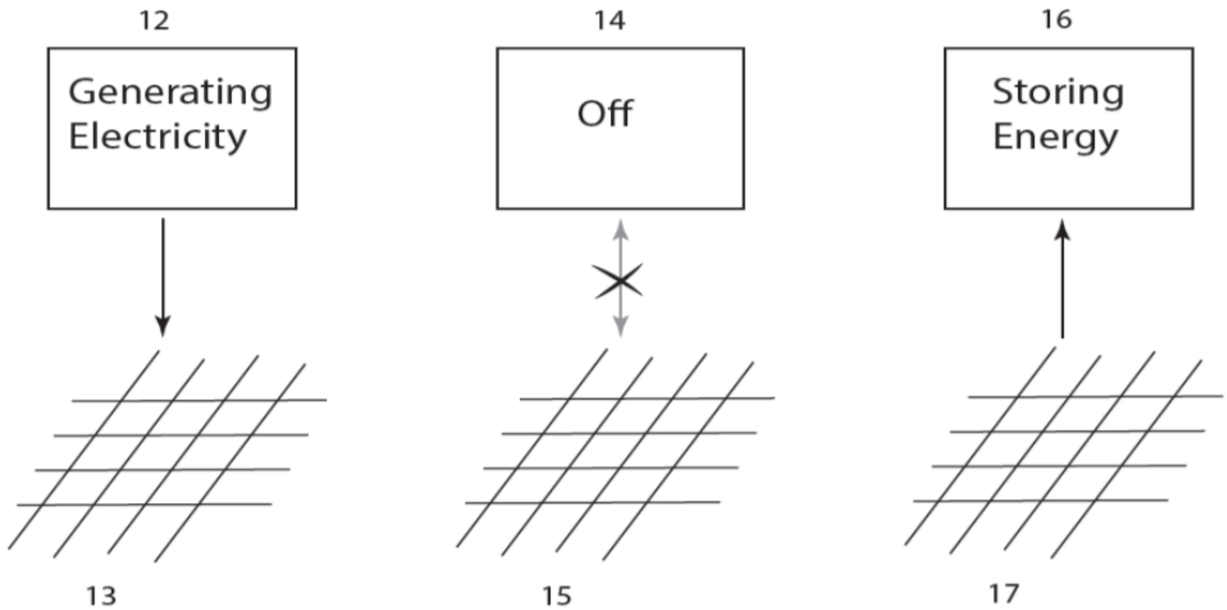


Figure 5 shows interaction of one module of the pumped hydroelectric system with the electric grid when the unit is generating electricity 12 and how electricity flows to the grid when it needs additional power 13. It also shows the unit shut off and on standby 14 when the grid is stable 15. Additionally, it shows the module storing energy 16 when the grid has an oversupply of power 17. The three operational modes of the modular pumped hydroelectric system enable generation, standby, and storing of energy providing the flexibility needed to track the demand curve of the grid precisely and rapidly. The switch from generating electricity to storing energy nearly doubles the impact of each unit on the demand curve of the grid. For example, a 150 kW pump/turbine has a swing of about 300 kW when it is initially pumping water with a 150 kW motor, is turned off, and then restarts as a 150 kW generator.

Figure 6: APH modules within the well array

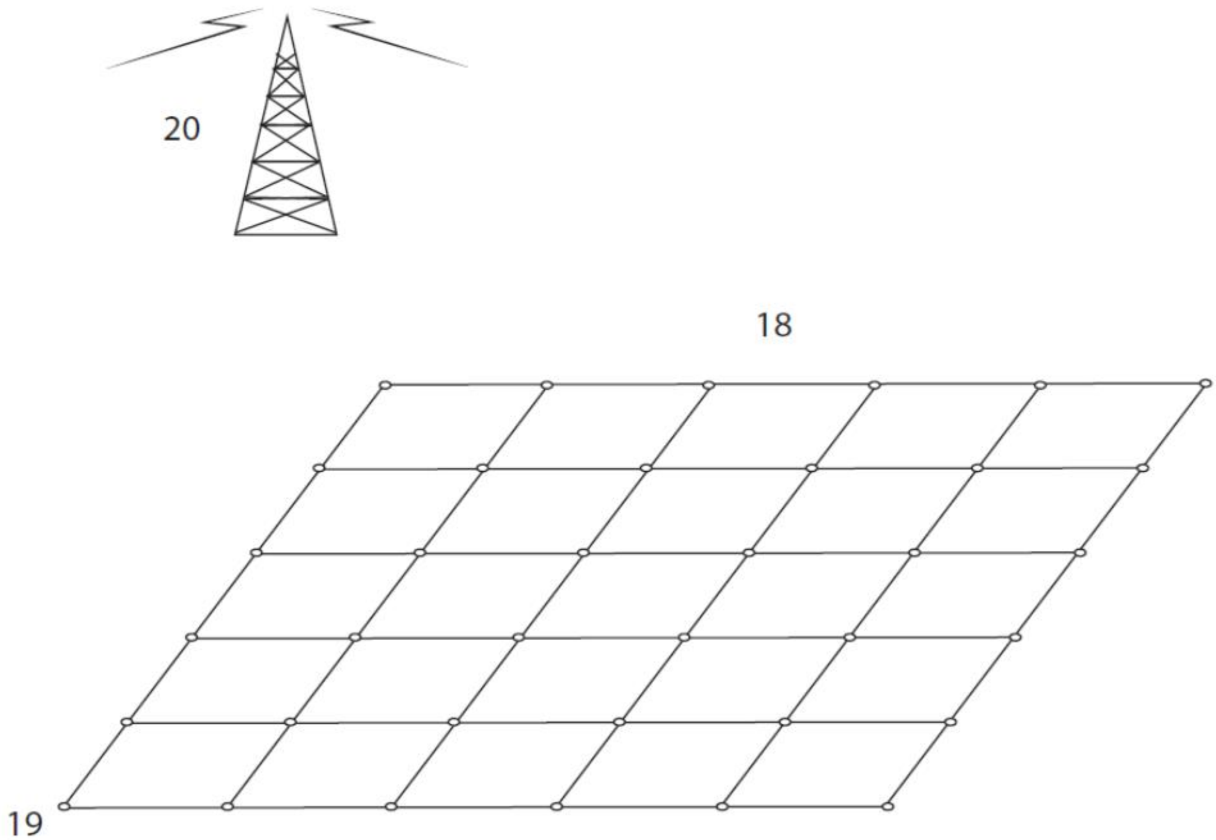


Figure 6 illustrates how all of the modules within the well array will be coordinated and controlled remotely to optimize benefits to the grid. The array of wells 18 will cover a wide area of the grid's distribution system. Individual modules 19 will be controlled by a remote signal 20 that could come from a radio/microwave transmitter, the internet, or through a hard connection. The array of wells may be located in the electric distribution system of the grid or adjacent to major electric transmission lines. Command and control can be initiated locally or by an Independent System Operator (an entity that manages the electricity flow and operates the electric grid to maximize the benefits to the grid).

2.1 Key Parameters for Power Generation

The physical parameters that affect the power generation are "Pump-As-Turbine" (generation) efficiency, head on turbine generator, pump flow rate, groundwater aquifer transmissivity, and adequate land for a surface reservoir. For WSWB site, the values of these parameters are:

1. Depth to groundwater – The WSWB has a 350 ft. average depth to groundwater level which provides the head available to drive the generation mode.

2. Pumping Capacity – The pumping capacity or discharge rate of a groundwater well is typically measured in Gallons Per Minute (GPM) or cubic feet per second (cfs). The pumping

capabilities of the WSWB wells are in the range of 1500 GPM to 2000 GPM, which are typical for agricultural and municipal water supply programs.

3. Transmissivity – The transmissivity at the site ranges from 2,900 to 3,500 feet-squared per day (sq. ft/day) which is considered low to medium rate of water flow through the soil matrix. Transmissivity values in the range of 5,000 to 10,000 feet-squared per day allow water to move faster which correlates to lesser drawdown and mounding head losses and higher generation output. Most groundwater banking or Aquifer Recharge and Extraction (AR&E) projects in the Western United States have transmissivity values of 5,000 to 10,000 sq. ft/day or greater[4].

4. Surface reservoir – The facilities Master Plan for WSWB includes a reservoir that would be used to regulate flows from the groundwater extraction well field to a high-lift pump station used for pumping water back to the California Aqueduct. For APH analysis, it is assumed that the well spacing will allow all wells to be served by this common reservoir. Therefore, the costs for a surface reservoir and associated land costs have not been included in the total capital cost of an APH unit at WSWB (Table 8).

Appendix A describes a sensitivity analysis which compares the effects of various input parameters on the mounding head loss and power generation equations. The results show that flow rate, transmissivity and well radius have the greatest impact on mounding losses.

2.2 Round Trip-Efficiency and Head Loss Effects

The capability to generate electric power is greatly affected by the system's component and cumulative efficiencies. The "Round-Trip Efficiency" refers to the efficiency of the complete operating cycle from storage (pumping) through generation (injection). As indicated in the project proposal, the primary downside of Aquifer Pumped Hydro (APH) is its low round-trip efficiency of around 40%-45%. Therefore, a round-trip efficiency much lower than 40% will render an APH project non-viable (Antelope Valley Water Storage (AVWS), 2015).

The head loss component has a significant effect on the round-trip efficiency. Head loss comes from the energy needed to pull water out of the aquifer and to push the water into the aquifer. These losses take the form of a cone of depression (drawdown) due to pumping and a mound that is created when water is injected into the aquifer, and are determined by site-specific parameters which can be used to assess system efficiency. Drawdown and mounding head loss can be measured from ground water levels during a well pumping and injection testing program.

2.2.1 WSWB Site - Aquifer Pumped Hydro Round-Trip Efficiency

Actual well drawdown data obtained during well development was used to calculate head loss due to drawdown. A theoretical equation was used to calculate the potential mounding.

4 Although the typical transmissivity values for Aquifer Recharge and Extraction (AR&E) projects in the Western United States are in the range of 5,000 to 10,000 sq.- ft./day or greater, they can vary widely depending on the saturated aquifer thickness, the concentration of wells and the layout of the project. If there is a lot of area to put wells and percolate water, it is possible to have lower transmissivity values and still have a viable project (Email communication with John Koreny, HDR Engineering, Inc. (HDR), October 3, 2016).

Separate drawdown and mounding efficiencies were calculated and used to calculate the overall round-trip efficiency of APH at WSWB site.

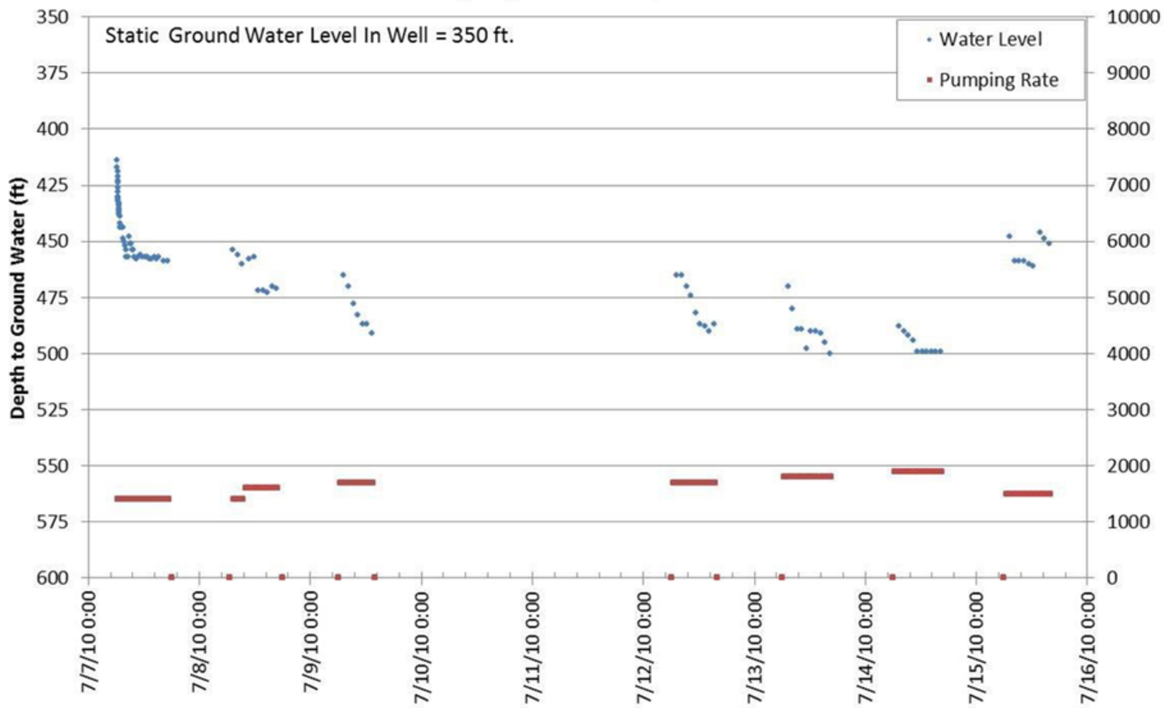
Table 1 provides well drawdown levels for three wells AV-2, AV-3 and AV-5 at the WSWB site. The average of the well drawdown for the three wells after 4 hours of pumping was used to determine head loss due to drawdown. Figure 7, Figure 8, and Figure 9 graphically indicate the relationship between pumping time, flow rate, and drawdown.

Table 1: Summary of Pump Test Data for WSWB Wells AV-2, AV-3 and AV-5

Well ID, Pumping Rate During Aquifer Test	Ground Water Level Decrease During Pumping Test			
	Well Drawdown (ft.) After 1 Hour of Pumping	Well Drawdown (ft.) After 2 Hours of Pumping	Well Drawdown (ft.) After 3 Hours of Pumping	Well Drawdown (ft.) After 4 Hours of Pumping
AV-2, 1400 gpm	115	120	125	133
AV-5, 2100 gpm	120	131	135	136
AV-3, 1300 gpm	101	124	140	158

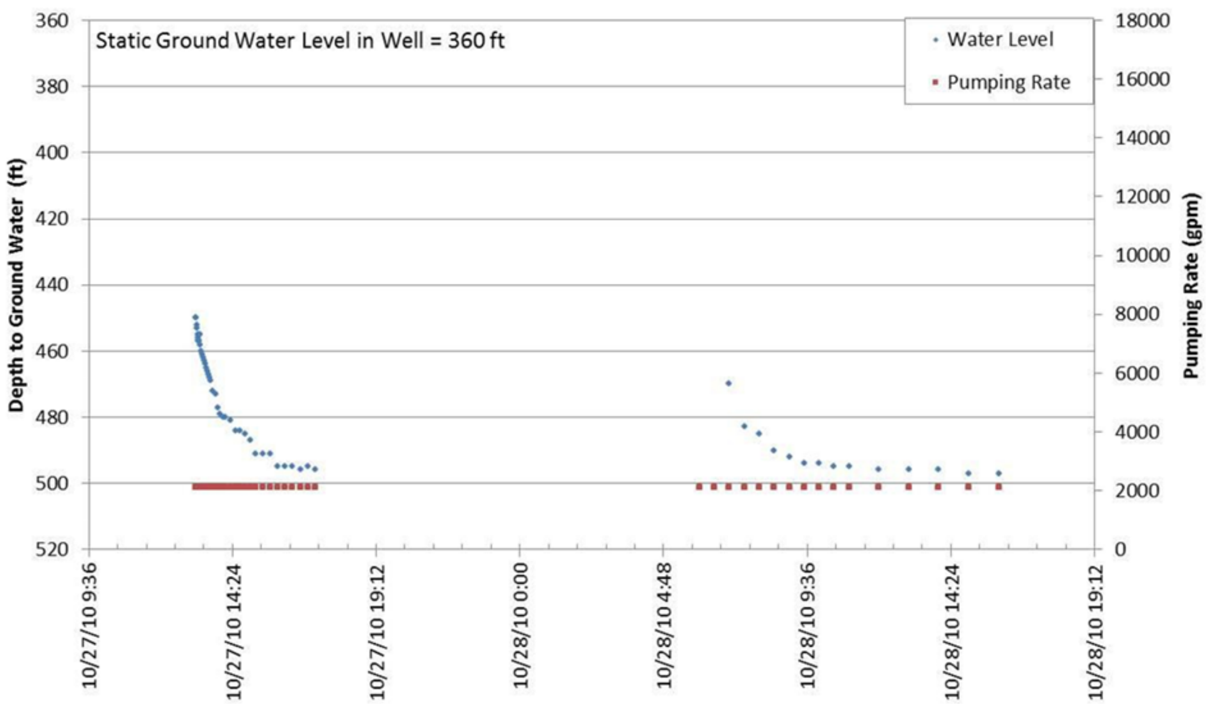
Source: (Koreny, 2016)

Figure 7: Pump Test Data for WSWB Well AV-2



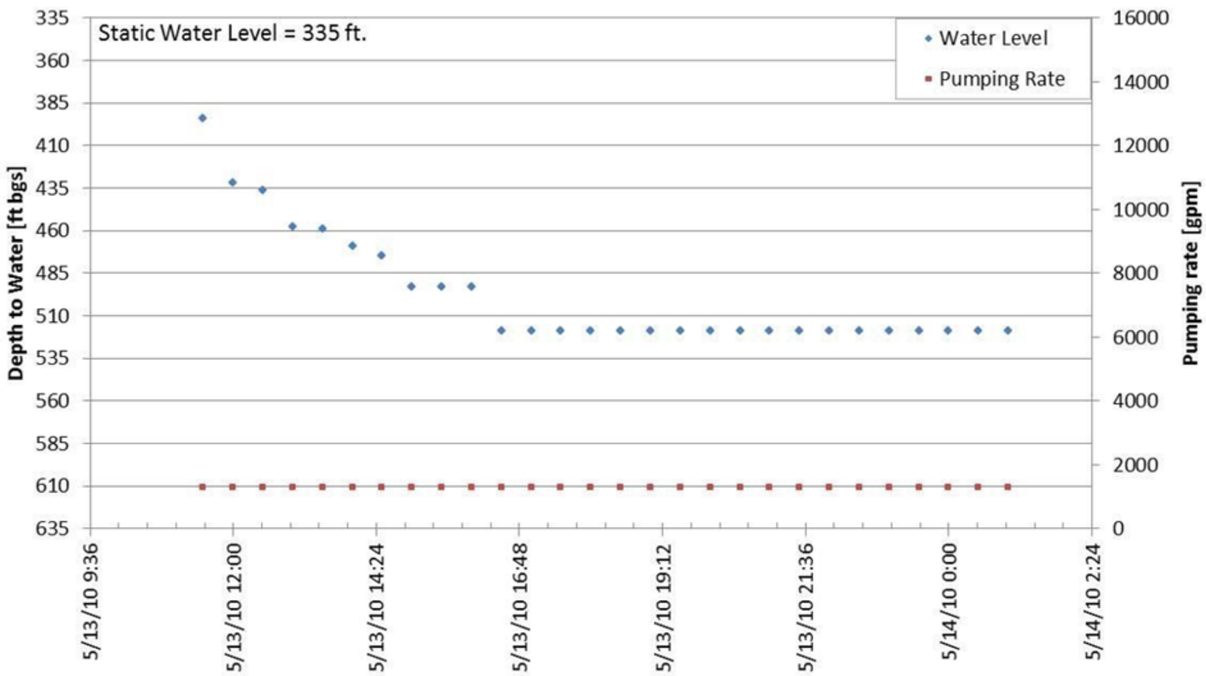
Source: (Koreny, 2016)

Figure 8: Pump Test Data for WSWB Well AV-5



Source: (Koreny, 2016)

Figure 9: Pump Test Data for WSWB Well AV-3



Source: (HDR Engineering, Inc., 2016)

As shown in Figure 9, the static water level (level of water in a well when it is not being pumped) corresponds to a relatively low depth to groundwater (higher water table). When the water is pumped, the water level in the well drops (well drawdown) and the water table in the vicinity of the well is lowered. This is manifested in the increased depth to groundwater. As pumping continues, the drawdown reaches a steady-state as the pumped water is replaced by the groundwater flow from the surrounding area. The rate of drawdown (and consequently, the water level in the well and depth to groundwater) therefore eventually stabilizes.

2.2.2 Head Loss Due to Drawdown and Mounding

HDR Engineering evaluated the drawdown and approximate increase in ground water levels (mounding) that will occur if the WSWB extraction (or production) wells were operated as injection wells (Koreny, 2016). According to this evaluation, "The groundwater level increase in the production wells will be approximately the inverse of the ground water level decrease during pumping. For example, if the ground water level in the well decreases by 100 feet after pumping at 1,000 GPM, the ground water level in the well will rise by approximately 100 feet during injection at 1,000 GPM. This is only a rough approximation and the initial increase in ground water level mounding may vary depending on well screen intervals, aquifer lithology in the vadose zone and other factors." Instead of assuming the mounding effects are the inverse of drawdown effects, this study uses the Cooper-Jacob approximation to the Theis equation to calculate the head loss due to mounding.

2.2.2.1 Drawdown Efficiency

Actual well development data is used to determine drawdown effects. The potential head loss due to drawdown can then be calculated as an efficiency component as follows:

Assumptions:

Average depth to water level:	350 ft.	
Reservoir Water Level:	5 ft.	
Total System Static Head:	355 ft.	
Drawdown (Average):	142 ft.	
Total Pumping Head Required:	497 ft.	(For Pumping, excludes pipe friction losses)

Efficiency Calculation:

The pump will be required to lift the water an added 142 ft.; in other words, 40% (142/355) more pump head in addition to the system static head of 355 ft. is required to lift water into the reservoir for a total of 497 ft. of pumping head. Therefore, the pumping stage efficiency is less than 100% and can be calculated as follows:

Efficiency during pumping stage:

System static head = 355 ft. equates to 100% efficiency

Pumping stage efficiency = (355 ft. – 142 ft. = 213 ft.) / 355 ft. = 0.60 = 60% (average)

The following table summarizes the average efficiency for the three wells and supports the average calculation of 60%.

Table 2: Summary of Drawdown Efficiency

Well No.	Drawdown (ft.)	Head Required (ft.)	Efficiency %	Transmissivity (sq. ft/day)
AV-2	133	222	62%	2,900
AV-3	158	197	55%	1,100
AV-5	136	219	62%	3,500

Required Head corresponds to Pumping Stage Efficiency.

2.2.2.2.Mounding Efficiency

The head loss due to mounding effects is calculated using a theoretical equation, the Cooper-Jacob approximation to the Theis equation. This equation can be used for unconfined aquifers, and provides the height of the injection mound. The equation was used to calculate h_m = potential mounding (feet) in the aquifer due to injection of flow through the well into the aquifer. The equation in imperial units is:

$$h_m = \frac{(2.3 \times Q)}{4 \times 3.14 \times T} \times \text{Log}\frac{(2.25 * T * t)}{r^2 \times S}$$

Where: Q=267.38 (injection flow rate in ft^3 /minute)

S = 0.05 (Storage Coefficient)

T= 2.45 (Transmissivity of aquifer in ft^2 /minute)

t = 360 (time in minutes)

r = 1.0 (well radius in (ft.))

h_m = 91.7 ft. (potential mounding)

Efficiency Calculation:

System static head = 355 ft. equates to 100% efficiency

Available head during the generation stage after mounding loss = 355 ft. - 91.7 ft. = 263.3 ft.

Mounding Efficiency during generation stage = 263.3 ft. / 355.0 ft. = 0.74 or 74%

2.2.2.3 Round-Trip Efficiency Calculation

The round-trip efficiency of the system using components can be evaluated as shown in Table 3

Table 3: Target Average Efficiency of Aquifer Pumped Hydro Energy Storage

Component	Pump/Motor System, %	Turbine/Generator System, %
1. Variable Frequency Pump Drive*	95	-
2. Power wires*	98	-
3. Motor/generator*	96	96
4. Pump/turbine**	80	80
5. Pipe friction*	98	98
6. Rectifier/inverter*	-	93
7. Drawdown (213 ft. required head/ 355 ft. total head) ***	60	
8. Mounding (263.3 ft. available head/ 355 ft. total head)***		74
TOTAL	42.0%	51.8%
ROUND-TRIP (21.8% makes APH infeasible)	**21.8% < 42%**	

*** Target efficiencies**

Sources:

**From calculations by Hydro resources (Hydro resources, 2013)

***Calculated above

2.2.3 Key Finding

The evaluation in Table 3 indicates that the round-trip average system efficiency for the site is 21.8%. This is less than the 42% estimated in the initial proposal (Antelope Valley Water Storage (AVWS), 2015) and is too low to be practical as described in the economics analysis in Section 5.3.3). This low round trip efficiency for APH is much lower than efficiency for alternative energy storage technology (% Efficiency column, Table 4).

Table 4: Energy Storage Efficiency and Costs

Technology Option	Maturity	Capacity (MWh)	Power (MW)	Duration (hours)	% Efficiency (total cycles)	Total Cost ($/kW)	Cost ($/kW-h)
Bulk Energy Storage to Support System and Renewables Integration							
		1680-5300	280-530	6-10	80-82	2500-4300	420-430
Pumped Hydro	Mature	5400-14,000	900-1400	6-10	(>13,000)	1500-2700	20-270
Conventional Turbine-CAES (underground)		1440-3600	180	8		960	120
	Demo			20	(>13,000)	1150	60
Compressed Air Energy Storage (CAES):underground		1080	135	8		1000	125
	Commercial	2700		20	(>13,000)	1250	60

Technology Option	Maturity	Capacity (MWh)	Power (MW)	Duration (hours)	% Efficiency (total cycles)	Total Cost ($/kW)	Cost ($/kW-h)
Sodium-Sulfur	Commercial	300	50	6	75 (4500)	3100-3300	520-550
	Commercial	200	50	4	85-90 (2200)	1700-1900	425-475
	Commercial	250	20-50	5	85-90 (4500)	4600-4900	920-980
Advanced Lead-Acid	Demo	400	100	4	85-90 (4500)	2700	675
Vanadium Redox	Demo	250	50	5	65-75 (>10,000)	3100-3700	620-740
Zn/Br Redox	Demo	250	50	5	60 (>10,000)	1450-1750	290-350
Fe/Cr Redox	R&D	250	50	5	75 (>10,000)	1800-1900	360-380
Zn/air Redox	R&D	250	50	5	75 (>10,000)	1440-1700	290-340
Energy Storage for ISO Fast Frequency Regulation and Renewables Integration							
Flywheel	Demo	5	20	0.25	85-87 (>100,000)	1950-2200	7800-8800
Li-ion	Demo	0.25-25	1-100	0.25-1	87-92 (>100,000)	1085-1550	4340-6200
Advanced Lead-Acid	Demo	0.25-50	1-100	0.25-1	75-90 (>100,000)	950-1590	2770-3800
Energy Storage for Utility T&D Grid Support Applications							
CAES (aboveground)	Demo	250	50	5	(>10,000)	1850-2150	390-430
Advanced Lead-Acid	Demo	3.2-48	1-12	3.2-4	75-90 (4500)	2000-4600	625-1150
Sodium-Sulfur	Commercial	7.2	1	7.2	75 (4500)	3200-4000	445-555
Zn/Br Flow	Demo	5-50	1-10	5	60-65 (>10,000)	1670-2015	340-1350
Vanadium Redox	Demo	4-40	1-10	4	65-70 (>10,000)	3000-3310	750-830
Fe/Cr Flow	R&D	4	1	4	75 (>10,000)	1200-1600	300-400
Zn/air	R&D	5.4	1	5.4	75 (4500)	1750-1900	325-350
Li-ion	Demo	4-24	1-10	2-4	90-94 (4500)	1800-4100	900-1700

Source: (Electric Power Research Institute (EPRI) and Energy and Environmental Economics, Inc. , 2010)

This finding is further demonstrated in Table 5 below, which determines the power required for pumping versus the power generation potential for one “Pump As Turbine” setup at WSWB. A single setup will require 278 kW to pump groundwater into the surface reservoir and will have a power generation potential of 62 kW. Therefore, system efficiency is 22% as predicated in Table 3. Even if on-peak electric rates for generation are 4.5 times the off-peak rates for pumping, APH will not pay for itself. Given the low average system efficiency of 22% APH is not economically feasible for WSWB site.

Table 5: Power Calculation for One "Pump As Turbine" Setup at WSWB

Components	Pumping Mode Pump/Motor System, %	Generating Mode Turbine/Generator System, %
1. Variable Frequency Pump Drive*	95	-
2. Power wires*	98	-
3. Motor/generator*	96	96
4. Pump/turbine**	80	80
5. Pipe friction (calculated and shown below)		
6. Rectifier/inverter*	-	93
Well Data: well diameter = 2.0 ft. Flow Rate: Q= 2,000 GPM = 4.45 ft^3/sec;		
Power Requirement:		
Reservoir water elevation above ground surface (ft.)	5.0	5.0
Depth to groundwater from surface (ft.)	350.0	350.0
Gross Head (ft.)	355.0	355.0
Pipe Friction loss (ft.)	33.2	33.2
Drawdown due to pumping (ft.) (field test)	142.0	-
Head loss due to mounding (ft.) (calculated)	-	91.7
Net Head (ft.)	530.2	230.2
Power required for Pump Mode (kW)	**278**	
Power potential for Generation Mode (kW)		**62**

*** Target efficiencies**

Source:

**From calculations by Hydro resources (Hydro resources, 2013)

The study scope included execution of field testing at WSWB to assess the aquifer response to a full cycle of well pumping and well injection. Because of the low round-trip efficiency discussed above it was concluded that conducting this test at WSWB will be premature and the test should be postponed to a future pilot-study to determine commercial viability of the APH technology. To that end, this section focuses on providing supporting documentation for development of a template[5] to evaluate APH potential at other groundwater banks including at existing Aquifer Storage and Recovery (ASR) and recycled water projects and to identify potential pilot sites for APH. ASR projects and recycled water projects that inject water into the groundwater aquifer can use the injection process to generate peak hydropower without pumping groundwater to a surface reservoir first. For these projects the energy cost for the injection cycle (or the generation stage of APH) is a part of existing operational costs. Also,

5 Template tool has been described in Section 4.6

these projects already have most of the capital infrastructure needed to generate hydropower using injection wells with the exception of the electrical/mechanical package needed to generate power and integrate the system with the electric grid.

2.3 Power Generation for a Single APH Turbine Setup

Power generation for a single Aquifer Pumped Hydro unit consists of one "Pump As Turbine" well setup, one reservoir and connection piping.

The AV-5 groundwater well at WSWB was selected for this evaluation and the potential power generation was calculated based on the input parameters given in Table 6.

Table 6: Potential Power Generation for Well AV-5 at WSWB

Well Data:			
Well Diameter (ft.)	2.0		
Injection Flow (cfs)	4.45		
Pump as Turbine Efficiency	0.80		
Generator Efficiency	0.96		
Rectifier/inverter Efficiency	0.93		
Water Density (lb./ft.^{3})	62.35		
Power Calculations:			
Transmissivity (ft.^{2}/day)	3,526.0	5,000.0	10,000.0
Gross Head (ft.)	355.0	355.0	355.0
Pipe Friction loss (ft.)	33.2	33.2	33.2
Mounding Head Loss (ft.)	91.7	70.2	37.3
Net Head (ft.)	230.2	251.7	284.6
Power Generation (kW)	62.0	67.0	76.0

The Transmissivity at the AV-5 well site is 3,500 sq. ft/day. Based on a Net Head of 230.2 ft. available to generate power, the power potential is 62.0 kW or 0.06 MW. In comparison, for Transmissivity values of 5,000 sq. ft/day and 10,000 sq. ft/day the power generation potential is 67.0 kW (or .07 MW), and 76.0 kW (or 0.08 MW) respectively. A 42 % increase in Transmissivity results in a power potential increase of 8%; and a 184% increase in Transmissivity results in a 23 % increase in power generation potential.

In order to achieve 5 MW of power generation at the WSWB site 84 wells would be required (5.0 MW/ .06 MW per well = 84 wells). The planned 62 wells at WSWB would have potential to produce on the order of 3.7 MW. WSWB recharges water via spreading grounds instead of injection wells so to implement APH, the water needs to be first pumped to a surface reservoir. However, even if Aquifer Pumped Hydro is used as an energy generation system (water does not need to be first pumped to a surface reservoir) rather than as a storage system at the WSWB site, this level of power generation would not justify the added capital expense required to deliver power to the SCE grid. See Section 4.3.1 for description of project sites where power generation using wells can be economically viable and offset operating costs.

2.4 Cost Estimates

The incremental cost of installing one Aquifer Pumped Hydro (APH) storage unit includes the following items:

- Cost of 2 AF upper reservoir, including 0.5 acres of land
- One 300 HP, 480 Vac (Volts, alternating current), 2000 GPM well
- Electrical Package to generate power with the well motor, and system controller and electrical equipment to connect the generator to the SCE grid.

Table 7 summarizes the additional capital cost of $1.6 M needed to install one APH unit at a groundwater bank. All other capital costs such as for pipelines are assumed to be part of the original water bank or ASR project.

Table 7: Capital Cost of Facilities for One Aquifer Pumped Hydro Unit

Aquifer Pumped Hydro Component	Calculation	Cost, $ M*
1. Surface reservoir @ 2.0 AF storage & 0.5 acres of land for 5- peak hour generation period	The 2016 master plan for WSWB facilities (GEI Consultants, Inc., 2016) includes a cost estimate of $1.32 M for a 48 AF lined reservoir, excluding engineering and contingency. For a 2 AF reservoir the cost will be = (2/48) ($1.32 M) (1.24 for engineering & contingency.) = $0.07 M. Land cost for 0.5 acres is about $0.002 M @ $3,000/acre in Kern County.	$0.072 M
2. One 300 HP well with Variable Frequency Drive (VFD)	($860,000 per well+ $130,000 per VFD) (1.24) = $1.23 M	$1.23 M
3. Electrical / Mechanical Package	Motor Generator Power Electronic Controller ---------------------- $ 6,000 Grid tie inverter/rectifier--- $92,000 System Controller --$80,000 Electric system modifications ---$20,000 Well shaft modification and pressure control equipment --------- $40,000 Electric/Mechanical Package Total $238,000 = $0.24M x 1.24 = $0.30 M	$0.30 M**
4. Total	Total additional cost due to one "Pump As Turbine" Aquifer Pumped Hydro storage unit	$1.6 M

Sources:

* Unit cost estimates based on 2016 GEI master plan update for WSWB (GEI Consultants, Inc., 2016) and adjusted to include 24% more for contingencies, design, and construction management.

** Item costs estimated by author(s) based on industry research.

At WSWB, the additional capital cost needed to install one APH unit is $0.30 M due to the cost for the addition of the Electrical and Mechanical Package as indicated in Table 8. Only the electrical/mechanical package cost is included because the other components are assumed to be part of the WSWB project. Assuming WSWB may be operated as an ASR project for purposes of generating peak hydropower, the energy costs associated with pumping groundwater for storage can be eliminated. Since any other annual operational and maintenance costs are covered by the WSWB operating budget, no additional operating costs are included. For 62 wells, the incremental cost would be $18.6M to implement 3.7 MW of peak hour hydropower generation or $5,100/kW.

Table 8: Costs to generate hydropower using existing wells at WSWB

Item	Assumptions	Comments
1. Well capacity	4.5 cfs each (8.9 AF/day, 2.9 mgd or 2000 gpm)	Existing irrigation wells
2. Well motor size	300 horsepower (hp) (225 kW)	Typical municipal motor size
3. Depth to water	Up to 350’ (depth to water)	
4. Surface storage	Storage Vol. = (GPM x 5 hr. x 60 min. per hr. x 0.13368) = Storage Vol. (ft.^{3}) (Storage Vol. x 1.20) = Acres Required (5 ft. x 43,560 ft.^{2}) For 2000 GPM, storage vol. = 80,208 ft.^{3} = 1.8 acre-ft. (use 2 acre-ft.) Acres required = 0.44 acres (use 0.5 acres)	Lined, covered reservoir
5. Capital Cost to add one Aquifer Pumped Hydro Unit	From Table 6 = $0.30 M	Electrical package
6. APH Capacity	0.06 MW/well x 62 wells = 3.7 MW	
7. Capital cost	($0.30 M/well)(62) = $18.6 M	
8. Unit capital cost	$18.6M/3.7 MW = $5,100/kW	
9. Annual O&M	Zero cost assumed operating cost is covered by water bank or ASR operations.	
10. Total Cost (Capital and O&M)	$18.6 M /3.7 MW = $5,100/kW	

These costs are feasibility study level. More precise cost estimates should be developed as part of a next step pilot program.

2.5 State Water Resources Control Board (SWRCB) Regulations

This study also looked at the field testing requirements for the Aquifer Pumped Hydro (APH) technology. This information informed the development of criteria for evaluating the potential of APH technology at other groundwater banks in California.

All short term field testing and long term projects must comply with SWRCB and applicable United States Environmental Protection Agency (U.S. EPA) requirements. Short term field testing projects are for the purpose of conducting a pilot test of the technology for a specific site where water is withdrawn from a groundwater producing well and retained at the surface for a short period before being injected back into the groundwater aquifer. Long term projects refer to projects that have been shown to have economic benefit and the project owner seeks to install a permanent project.

The project team consulted Regional Water Quality Control Board (RWQCB) staff to determine the potential regulatory requirements for both short term and long term projects.

2.5.1 Short Term Pilot Test

The regulatory requirements for short term pilot testing of APH technology are:

- RWQCB permit will be required for 1 to 2-day pumping into a lined pond and 18-20 hours discharge back into a well.
- The permitting process will include formal consultation with RWQCB and submittal of a formal permit application along with technical report and project documents.
- It is expected that no treatment will be required if it can be shown that water quality will not be affected during period of discharge.
- For source groundwater that includes constituents such as Hexavalent Chromium (Cr(VI)) or other constituents that may affect groundwater quality and may be an issue, RWQCB will require time for additional review before determining how to proceed.
- CEQA categorical exemption may be required.

2.5.2 Long Term Projects

The regulatory requirements for long term pilot testing of APH technology are:

- RWQCB permit is required and the permitting process is anticipated to be more extensive than the one described above for a pilot test.
- Covered ponds are required due to algae growth, solids and bacteria issues.
- Open ponds are allowed if water is treated (undergoes filtration and disinfection) before injection (treatment requirements may vary on a case by case basis).
- Monitoring wells are required for groundwater monitoring program to track impacts.
- Appropriate CEQA documents would be required in all cases.

Compliance with these preliminary regulatory requirements will require additional time and funding and should be considered in planning feasibility studies for APH[6] projects.

2.6 Demand Response Potential of the Well Field

62 production wells are planned for WSWB. Each production well is expected to have a 300 horsepower (0.225 MW) motor. As determined above in Sections 2.2 and 2.3, utilizing the WSWB 62 planned extraction wells in an energy generation or pumped storage system to generate peak electric power is impractical. However, the 62 wells represent a combined demand reduction potential of 14.0 MW. If used in a *demand response program* the wells could potentially reduce the power demand on the electric grid by 14 MW. This demand response potential is significant and can be realized by shutting down the well pumps for 5 hours a day during weekdays in the summer months[7]. This would result in a 4% reduction in groundwater pumping which can be made up with a small number of additional wells. 62 wells are needed at buildout and 2 more wells are required to enable demand response (4% of 62 wells $\approx$ 2 wells) at a cost of $1.07 M/well (Table 14). The surface reservoir (which is part of WSWB facilities master plan) will buffer any impact on WSWB operations and will enable a constant flow to the WSWB pump station.

Operating the well field in a demand response program will require a specified response time for wells to be turned-on and turned-off following an order from California Independent System Operator (California ISO) or an investor-owned electric utility operator. Therefore, a field test was conducted to determine the startup and shutdown durations for manual operation of the well field at Willow Springs Water Bank (WSWB) site. Confirming the time required for each cycle will support decision making on whether to implement an automated cloud-based Supervisory Control and Data Acquisition system to monitor and control the well field equipment.

2.6.1 Automated Remote Control of the Well Field System

A key factor for implementation of demand response at WSWB is being able to shut off 62 wells and turn them on again rapidly. The results of the field test provided on page 2 of Appendix B show that the time required to start up each well and drive to the next well is on average 5.1 minutes; or a total start-up period of 5.3 hours with one operator. The time required to shutdown each well and drive to the next well is similarly on average 5.0 minutes; or a total shutdown period of 5.2 hours with one operator. It would take over 5 hours for one operator to start-up or shutdown all 62 wells. This is not practical for operation of a large well field let alone for a 5-hour window for demand response.

---

6 Aquifer Storage and Recovery (ASR) projects are regulated separately by the State Water Resources Control Board Water Quality Order 2012-0010 – General Water Discharge Requirements for Aquifer Storage & Recovery Projects that Inject Drinking Water into Groundwater.

7 For the duration of the on-peak period, assumption of 5 hours has been used. This is based on the recently released proposed on-peak periods for the IOUs including Southern California Edison (SCE). The new on-peak period for SCE is proposed to be 4 pm – 9 pm on summer weekdays (Association of California Water Agencies (ACWA), 2017).

Remote activation is necessary. The legacy systems in use to remotely monitor and control well field equipment are referred to as Supervisory Control and Data Acquisition (SCADA) systems and include a computer server and control center located at the agency's operations headquarters. These systems collect data from the onsite well. The well is equipped with a Program Logic Control data logger that sends data to the SCADA control center and the data is stored in the control center server. With this type of system, the process of shutting down a well is immediate and an entire well field can be programmed to start-up or shut-down on a given schedule or at a moment's notice.

A cloud-based Supervisory Control and Data Acquisition system such as the XiO cloud-based Field Installed Well Control Unit replaces the typical Program Logic Control based data logger and is widely used throughout the water supply industry to monitor and control wells. Using a cloud-based SCADA system eliminates the need for an agency based computer server.

The Field Installed Unit sends all monitoring data by internet connection via an onsite modem to the cloud. The cloud data is sent to a highly secure commercial data manager contracted with XiO. Any authorized agency employee can access the cloud data and turn on and shut off the well pumps from a desktop computer, laptop or smart phone. This eliminates the need and cost for onsite server hardware and software, programming the Program Logic Control to communicate with the server, and costly employee training to operate the system.

The team obtained a budgetary quote from XiO to install one XiO Field Installed Well Control Unit at a single well. The cost per well ranges from $7,700 for a controller without water level sensor to $9,700 for a controller with water level sensor and $74 per month for cloud access and internet access (Table 9).

Table 9: Cost to Install one XiO Field Installed Well Control Unit

Controller & Options without Sensor	Unit Price	Monthly Fee
Field Control Unit without water level sensor	$4,600	$39/controller (cloud services)
System Pressure monitoring	$700	n/a
Remote VFD	$545	n/a
PtP- Link IP radio with Yagi Antenna	$1,100	n/a
Cloud-Link Cellular Modem Package	$750	$35/modem (internet access)
Totals	$7,700	$74/month
Controller & Options with Sensor	**Unit Price**	**Monthly Fee**
Field Control Unit with water level sensor	$6,642	$39/controller (cloud services)
System Pressure monitoring	$700	n/a
Remote VFD	$545	n/a
PtP- Link IP radio with Yagi Antenna	$1,100	n/a
Cloud-Link Cellular Modem Package	$750	$35/modem (internet access)
Totals	$9,700	$74/month

Sources: (XiO, Inc., 2017)

The process of turning all 62 wells off and then on should be straightforward if the well field design incorporates an automated remote on/off switch. All wells will need a slow start capability to comply with current Southern California Edison (SCE) requirements.

CHAPTER 3:
Peak Hour Pumped Storage at Willow Springs Water Bank

Willow Springs Water Bank (WSWB) plans to use Peak Hour Pumped Storage (PHPS) to produce hydropower during the peak hours of the day. PHPS will use pipe, pump, and reservoir facilities that are part of the water bank. Dual use of these facilities for hydropower as well as water storage reduces capital costs.

Power generation via PHPS can potentially occur independent of whether the water bank is recharging, idle, or extracting water. It is expected that WSWB will recharge water during wet years. Wet years occur about 1 in every 3 years ("wet" years as defined by California Department of Water Resources (DWR) have occurred 32% of the time based on historical record). Generating peak power every year is more valuable that generating it once every 3 years. Water used to generate electricity will be replaced during the non-peak hours.

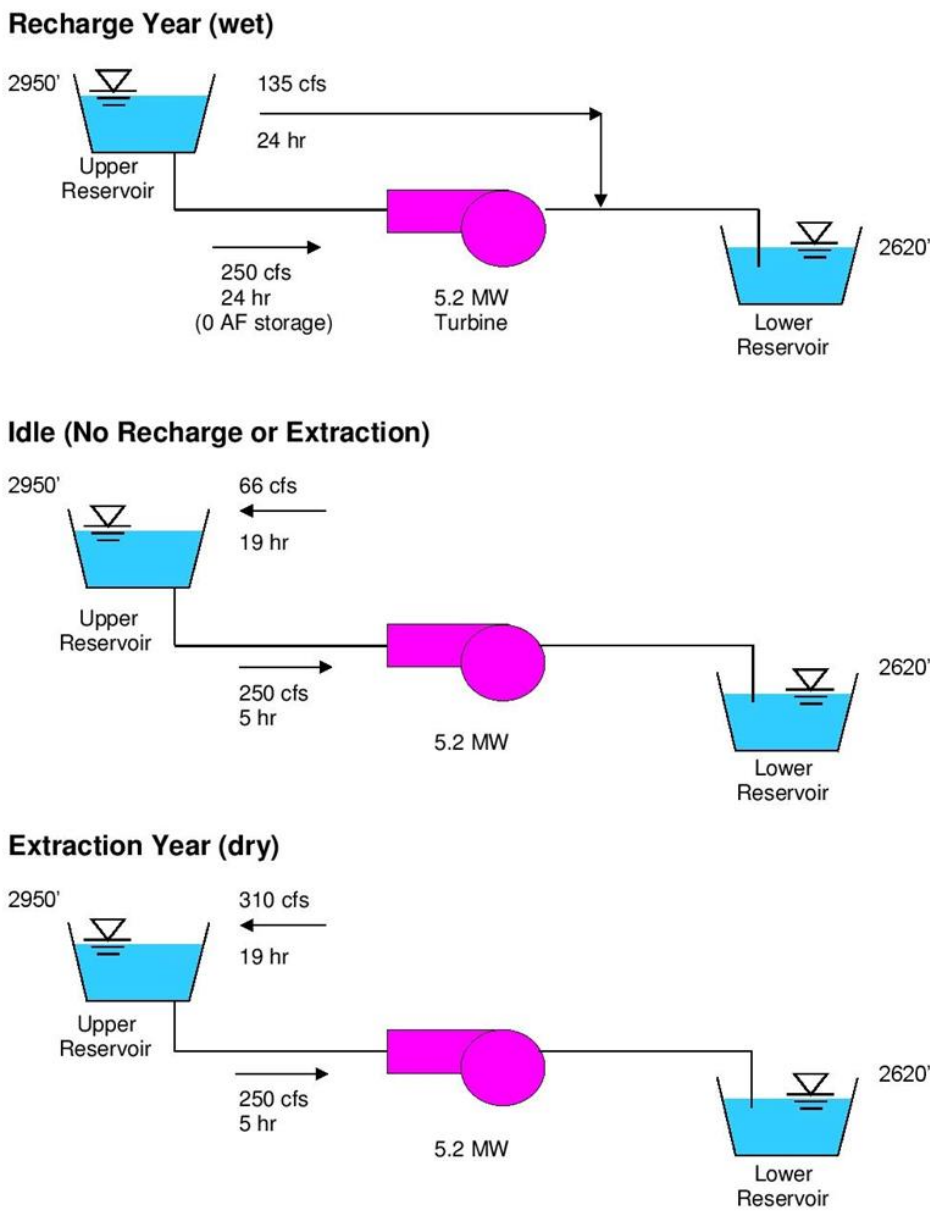
Key Assumptions for PHPS analysis are summarized below:

- Evening Ramp Up – Electric peak hour rates will apply during summer weekdays from about 4:00 p.m. to 9:00 p.m. for SCE and SDG&E. This is the evening ramp up of demand when solar arrays stop generating power but the evening demand is still high. While peak rates for the future are not known, it can be assumed that they will be high enough to discourage pumping during the evening ramp up (California Public Utilities Commission (CPUC), 2015).
- Summer Peaks – Peak hour rates occur during the 3 summer months, 5 days a week, and for only about 5 hours per day. This is 4% of the time. If additional power can be generated during peak hours, a significant grid benefit can be realized. Similarly, pumping from wells to the surface could be eliminated during peak hours as well to reduce peak demand.
- WSWB Intermittent Recharge – WSWB will recharge water intermittently (about once every three years on average). If hydropower generation is limited to only the recharge years, a significant opportunity is lost.
- WSWB Buildout – WSWB will be built out in phases. The first phase has a recharge capacity of 385 cubic feet per second (cfs) and an extraction capacity of 140 cfs. The second phase has a recharge capacity of 385 cfs and an extraction capacity of 310 cfs.
- Flow to and from California Aqueduct – Prior studies for WSWB assumed that water flow from or to the California Aqueduct could vary during a 24-hour day. Since DWR will not allow daily flow changes into the California Aqueduct, an upper reservoir is needed to enable shutdown of booster pumping during the 5 peak summer hours.

3.1 Operating Scenarios

Pumped storage implementation must not interfere with normal operations of the water bank. Consequently, three operating scenarios were assessed for PHPS analysis: a recharge (wet) year, a neutral or idle year, and an extraction (dry) year[8]. These scenarios are shown graphically in Figure 10 and described in the subsequent paragraphs.

Figure 10: WSWB Hydropower Generation Operations



8 Based on Sacramento River data since 1906, California Department of Water Resources (DWR) classifies a water year (Oct 1 – Sep 30) as a wet year, an above normal year, a below normal year, a dry year or a critical year (DWR, 2017). In this report, the term "wet" indicates a wet year as defined by DWR, "neutral" is used for above normal and below normal year types, and "dry" represents the DWR defined dry and critical hydrologic year types.

- Recharge Year (wet): A recharge year involves up to 385 cubic feet per second (cfs) of recharge. It will occur during wet or normal year conditions. That enables a total recharge of 280,000 acre-feet per year. 250 cfs will be used to generate electricity 24 hours a day and 135 cfs will bypass the turbine. The estimated occurrence rate is 1 year in 3 based on historical record (32%).
- Idle Year: An idle year does not have any predetermined recharge or extraction activity. 250 cfs of water will be used to generate electricity for the 5 hours daily from the upper reservoir. The water will be replaced over the other 19 hours. It will be pumped at a flow rate of 66 cfs to minimize pipe friction losses. 103 acre-feet of storage volume is needed to provide 5 hours of power generation. The estimated occurrence rate is 1 year in 3 based on the historical record (33%).
- Extraction Year (dry): Extractions of water from the water bank will occur in a dry year. 250 cfs will be pumped back to the California Aqueduct and 60 cfs will be delivered to the Antelope Valley-East Kern Water Agency potable system for exchange or to the Aqueduct. The total extraction requirement is 310 cfs. During the peak hours, electricity will be generated by sending 250 cfs from the upper reservoir down to the generator. 103 acre-feet of storage volume is needed to provide 5 hours of generation. The 4% extraction reduction will be made up by slightly increased extractions in the non-summer months. The estimated occurrence rate is 1 year in 3 based on historical record (35%).

3.2 Components and Factors for Peak Hour Pumped Storage

As described in the WSWB Fact Sheet (Attachment I), the onsite facilities at WSWB include an 84” diameter recharge pipe, percolation ponds, a pump station, and 62 wells. When fully built out, WSWB will have most of the elements needed for a pumped storage project: topography that enables a large change in elevation, a big conveyance pipe, a pump station/turbine, and potential sites for large upstream and downstream reservoirs. Along with operational considerations described in the preceding section, factors such as friction losses associated with cycling water, turbine type and costs, and availability of potential reservoir sites also affect the ability to add pumped storage to an existing groundwater storage project.

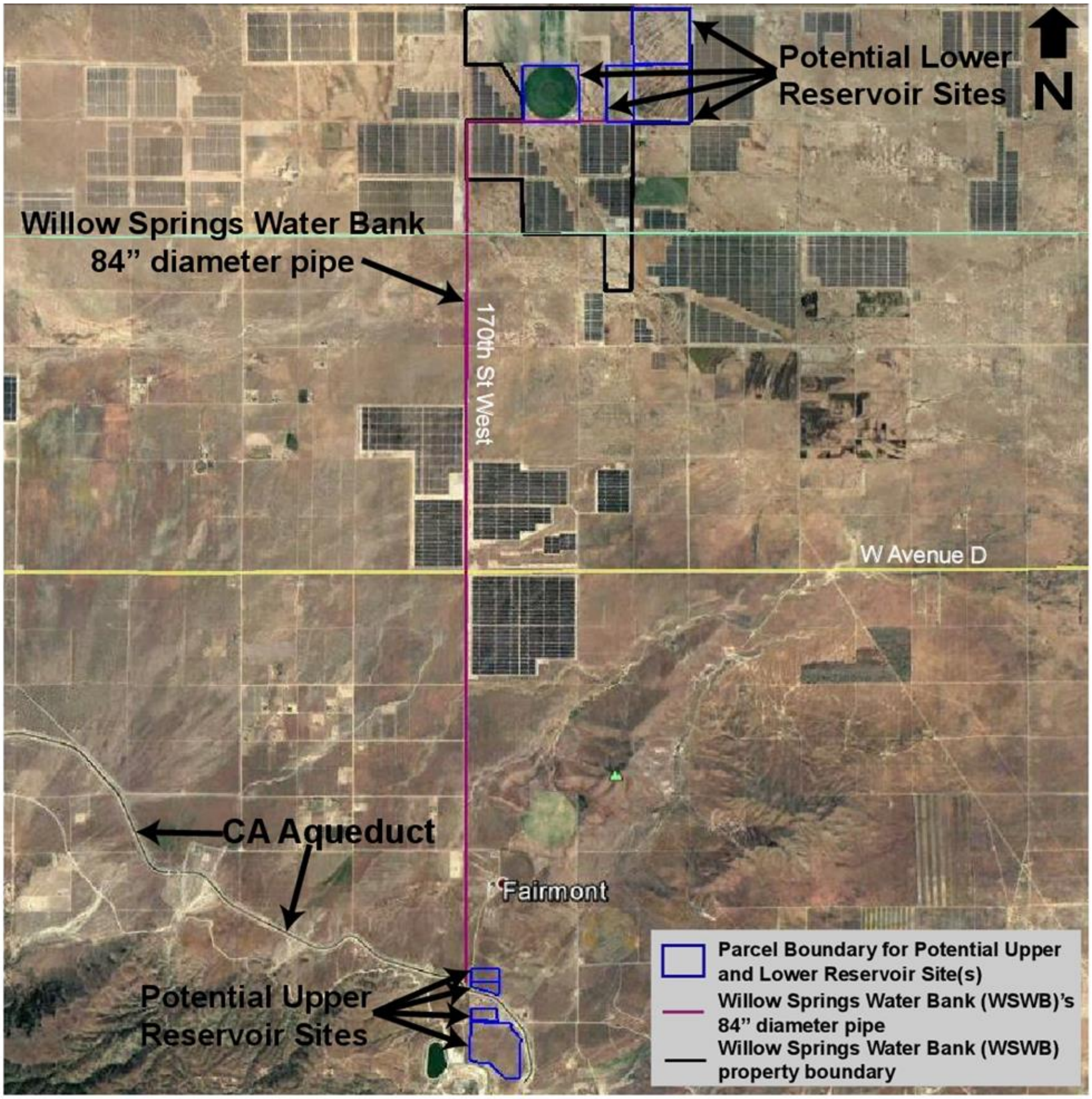
3.2.1 Reservoir Site Analysis

A pumped storage project needs both an upper and a lower reservoir. This enables hydropower operations regardless of whether the water bank is recharging, extracting, or is idle. Water is pumped to the upper reservoir during the off-peak period. It is drained down to the lower reservoir during the on-peak period. Power is generated when water flows through the turbine generator and into the lower reservoir. This can occur 365 days a year.

Originally, it was assumed that DWR may allow the California Aqueduct to serve as the upper reservoir by enabling daily flow variation. Subsequent discussions with DWR staff indicated that the department is adamantly opposed to this (Craig Trombly, personal communication, August 5, 2016). Consequently, potential sites for the upper reservoir were identified near the

California Aqueduct. All sites meet the criteria of target reservoir water surface elevation of approximately 2950'. Figure 11 shows a map of the potential upper and lower reservoir sites.

Figure 11: Potential Upper and Lower Reservoir Sites



The upper and lower reservoirs isolate the operations of the Aqueduct from the hydropower operations. They also isolate WSWB operations from hydropower operations. This ensures that power generation will not interfere with the operation of other water banking infrastructure.

3.2.1.1 Potential Upper Reservoir Sites

Four possible sites with enough land at the right elevation for the upper reservoir were identified (Table 10). Two are north of the Aqueduct and two are south of it. Potential sites were identified based on whether the land is vacant, whether it is at the right elevation, whether 14 acres or more of land is available, and proximity of the site to the WSWB turnout structure. Available parcels range from 13 acres to 114 acres as shown in Appendix C-1. Phasing can be accomplished by utilizing more than one site or one of the larger parcels.

The two reservoir sites north of the Aqueduct are at elevations lower than the 2955' water surface in the Aqueduct. These sites are 5' to 25' lower than the Aqueduct's water surface. To make these sites viable, a 250 cfs, 378 HP low lift pump station (10' to 30' lift) and piping to CA Aqueduct will be needed to pump the water back into the Aqueduct. Most years, WSWB will be idle or recharging water. Pumping is only needed during dry years.

Table 10: Summary of Potential Land for Upper Reservoir

Location	Assessor Identification Number (AIN)	Elevation	Size, Acres	Value/acre based on taxes	Land Use
North of Aqueduct	3236-020-003	2930'	17	$2,813/ac.	Vacant
North of Aqueduct	3236-020-004	2950'	13	$3,028/ac.	Vacant
South of Aqueduct	3236-021-009	3000'	114	$1,044/ac.	Vacant
South of Aqueduct	3236-020-008	3000'	15	$3,333/ac.	Vacant

Sources:

APN, Land Use, Value and Size (Los Angeles County Office of the Assessor, n.d.)

Elevation (Google Earth)

The two reservoir sites south of the Aqueduct are at elevations higher than the 2955' water surface in the Aqueduct. They are 45' higher than the Aqueduct's water surface. An upper reservoir located at any of these two sites will require a lift of 50' to receive water from the Aqueduct. Appendix C-2 through Appendix C-5 show Google Earth images of all of these four sites.

One upper reservoir site that has been considered is the Los Angeles Department of Water and Power's (LADWP's) abandoned Fairmont Reservoir #1. This site is at an elevation of 3033' and provides the highest lift differential of the reservoir sites considered. It is also vacant. WSWB has not yet approached LADWP about using this location due to the availability of other alternative sites.

3.2.1.2 Potential Lower Reservoir Sites

Four lower reservoir sites were also considered and are shown in Appendix C-6. All of these sites are on land owned by WSWB. This eliminates the need to purchase new right-of-way for these sites. Table 11 describes the four lower reservoir sites of interest, along with the corresponding elevation differences.

The lower reservoir is an integral part of the facilities needed to build out WSWB. This is because the control of 62 wells is too difficult operationally unless the reservoir provides a fixed water surface level. The fixed hydraulic grade line also makes variable speed drives unnecessary. Finally, it serves as the well for the pump station. It does double-duty as storage volume to enable both pumped storage and demand response by the wells.

Table 11: Summary of Potential Land for Lower Reservoir

Location	Assessor Parcel Number (APN)	Elevation	Size, Acres	Cost ($)	Land Use	Owner
Gaskell & 160th	261-196-24	2640'	25	0	Vacant	WSWB
Willow and 150th	359-041-11	2630'	25	0	Vacant	WSWB
Gaskell & 150th NW	359-041-12	2620'	25	0	Vacant	WSWB
Gaskell & 155th NW	359-041-13	2630'	25	0	Vacant	WSWB

Sources:

APN, Land Use, and Size (Kern County California, n.d.)

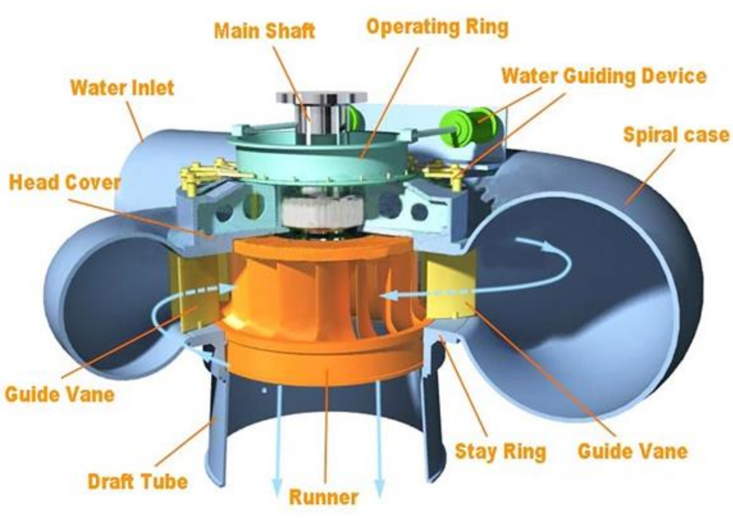
Elevation (Google Earth)

3.2.2 Selection of Generator Type

With pumped storage, it is possible to generate electricity by running the pump in reverse as a turbine generator. This is possible with reaction pumps like Francis or Kaplan turbines (Figure 12). Running the pump in reverse is the simplest and least expensive way to generate electricity.

The use of a reaction turbine, however, may create hydraulic control problems. For example, valves and controls are needed to make sure the pump never becomes a "runaway turbine". Hydraulic surge is also more difficult to deal with, especially if the pipe and pump system is being shut off regularly. Also, dual purpose pump/turbines are generally not available in a size smaller than 50 MW. Units available in the 5 MW size limit the options to a separate pump and turbine system.

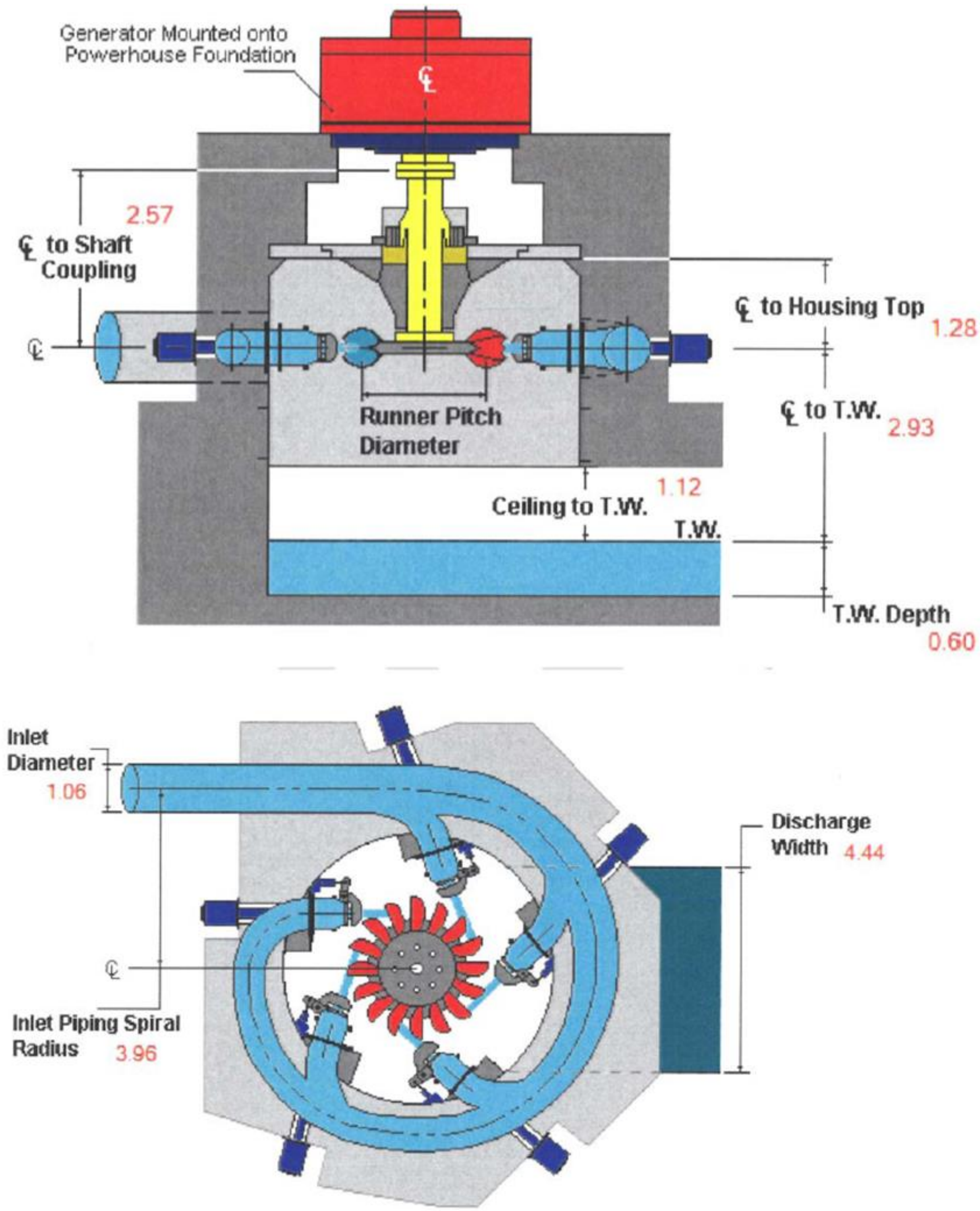
Figure 12: Francis Turbine



Source: (Eternoo Machinery Co., Ltd, n.d.)

An impulse turbine like a Pelton Wheel (Figure 13) is more expensive to install than running an existing pump in reverse. However, an impulse turbine is more cost effective overall than a reaction turbine because factors such as reduced hydraulic control, surge costs and the lack of a suitable pump/turbine can be avoided.

Figure 13: 5-Jet Pelton Wheel Impulse Turbine (Elevation and Plan Views)



Source: (HDR, 2017)

3.2.3 Total Energy Losses

Pipe friction and pump/turbine energy efficiency losses must be added to the static head to calculate the total dynamic head. The total dynamic head determines the power needed for the pump station. It also determines the amount of energy that can be generated from a turbine. Table 12 lists the pipe friction and pump and turbine efficiency loss assumptions used for this project.

3.2.3.1 Static Lift

The static "lift" is the elevation difference between the upper reservoir and the lower reservoir. This elevation difference determines the amount of head or lift available to generate energy. The larger the lift, the better. The upper reservoir sites considered are located near the California Aqueduct at W Avenue H and 170th St. W. They range from elevations of 2930' to 3000'. The lower reservoir sites range in elevation from 2620' to 2640'. This creates a range of potential lifts from 290' to 380'. A 330' static lift is used for power and hydraulic calculations in this report. This is based on the most likely ultimate sites for the upper and lower reservoirs.

3.2.3.2 Pipe Friction

The largest energy efficiency losses come from pipe friction. These losses are 16', 47', and 71' for an 84" dimeter pipe that is 9.25 miles long and has water flowing at 140 cfs, 250 cfs, and 310 cfs, respectively. These friction loss rates are based on HDR's hydraulic calculations for WSWB site (HDR, 2017)

3.2.3.3 Pump and Motor Efficiency

Pump and motor efficiency affects energy losses. A pump efficiency of 87% and a motor efficiency of 96% is used for this study. Similarly, a turbine efficiency of 91% and a generator efficiency of 96% is used for this study. These values are based on the pumped storage operation characteristics provided in HDR report (HDR, 2017) and were developed from standard industry assumptions. The turbine type assumed is a multi-jet Pelton Wheel impulse turbine because a Francis type reaction turbine is not available in the 5 MW size range.

3.3 Calculation of Hydropower Generation

Table 12 summarizes the potential hydropower generation at WSWB. The potential is split into two phases to match the planned phased buildout of WSWB. Static lift is 330' for both phases. Phase 1 flow is 140 cubic feet per second (cfs). Phase 2 flow is 250 cfs. The size of both the upper and the lower reservoir for Phase 1 is 58 AF, requiring 14 acres of land. The size of both the upper and the lower reservoir for Phase 2 is 103 AF, requiring 25 acres of land (Table 13). This results in a capacity of 3.2 MW for the Phase 1 generator and 5.2 MW for Phase 2 generator (Table 12).

The size of the pump/turbine is determined by power (horsepower (hp)) needed for the pump station The detailed hydropower estimates are shown in the HDR report (HDR, 2017).

Table 12: Reservoir, Generator, and Pump Power Calculations

Phase	Flow, cfs	Generator/Turbine or Pump/Motor Efficiency	Static lift	Pipe Friction Loss	Total Dynamic Head	Turbine or Pump Power
Phase 1 Generator	140	96% & 91%	330’	16’	314’	3.2 MW
Phase 1 Pump	140	87% & 96%	330’	16’	346’	4.9 MW (6,600 hp)
Phase 2 Generator	250	96% & 91%	330’	47’	283’	5.2 MW
Phase 2 Pump	310	87% & 96%	330’	71’	401’	10.2 MW (13,700 hp)

3.4 Extended Duration Battery Potential

Pumped storage at WSWB has the potential to function much like an extended duration battery. Instead of a 5-hour discharge period, if the upper and lower reservoirs are made larger, the power generation can be extended to up to 12 hours daily if this benefits the grid. Pumped storage could also be used to provide power during an emergency or during a potential early morning ramp up.

The upper reservoir volume is sized to match the volume of the lower reservoir. This enables one complete pumped storage cycle during a 24-hour period.

The potential for extending the duration of power generation is demonstrated in Table 13. For a 5-hour energy generation duration, the upper reservoir needs 25 acres of land when the WSWB is fully built out. The lower reservoir also needs about 25 acres of land. This calculation assumes 5’ maximum berm height plus 1’ of freeboard to avoid being considered a dam (a dam is >6’ berm height). A lined and covered earthen bermed reservoir is assumed. It is also assumed that the total area needed for each of the reservoirs includes 20% more land than the wetted area to account for berms and access roads.

Table 13: Summary of Upper and Lower Reservoir Sizing

Reservoir	Elevation	Water Depth	Volume	Surface Area	5-Hour Size*	8-Hour Size*	12-Hour Size*	24-Hour Size*
Upper, Phase 1	2950’	5’	58 AF	12 acres	14 acres	22 acres	33 acres	66 acres
Upper, Phase 2	2950’	5’	103 AF	21 acres	25 acres	40 acres	60 acres	120 acres
Lower, Phase 1	2620’	5’	58 AF	12 acres	14 acres	22 acres	33 acres	-
Lower, Phase 2	2620’	5’	103 AF	21 acres	25 acres	40 acres	60 acres	-

***Includes 20% more land for non-wetted area.**

The 12-hour duration reservoir requires 60 acres. Longer durations like 24-hour generation are possible, but it would be a one-time discharge because 12 hours is needed to refill the upper reservoir daily. Phasing of the water bank requires that a second reservoir be built that is roughly the same volume as the first reservoir to handle 250 cfs flows.

Longer durations of power generation for up to 12 hours may help fill the gap between batteries and large hydropower resources. It could also be used to help address a potential second daily spike in demand in the early morning. The ability to generate electricity for up to 12 hours could be utilized as needed to add more power to the grid. The only requirement is that the upper and lower reservoirs are built large enough to enable extended power generation.

3.5 Demand Response Potential of the Pumping Plant

Demand response is the ability to reduce use of electricity when the grid has a shortage. This is possible at WSWB in an extraction year. Similar to the demand response potential of the well field described in Section 2.6, pumps at the pumping plant also have the potential to provide demand response. Like the well pumps, the pumping plant pumps could be shut off for 5 hours a day during years that water is being pumped back to the California Aqueduct. Extraction is expected to occur 1 year in 3 during dry conditions. The upper reservoir will maintain a constant flow to the Aqueduct with a small, low-lift pump (10’) at the reservoir site.

The demand response potential of the pumping plant corresponds to the size of the pumps, or 10.2 MW. It can be realized by shutting down the pumping plant to the Aqueduct for 5 hours a day during weekdays in the summer months. The 4% reduction in summer water delivery to the Aqueduct can be made up during deliveries at other times of the year because DWR allows 9% peaking for its facilities.

3.6 Cost Estimates

The incremental capital cost of installing Peak Hour Pumped Storage (PHPS) and demand response includes the following items:

- Cost of a 103-AF upper reservoir, including 25 acres of land
- Cost of a 250-cfs, 378 hp low lift pump station and piping to CA Aqueduct
- Cost of two new 3.4-MW impulse turbine
- The cost of 4% additional well capacity to enable demand response (2 wells)

All other costs for pump stations, pipelines, lower reservoir, and wells are part of the original water bank and do not increase project costs. Table 14 summarizes the cost of the additional capital cost needed to install PHPS and incorporate demand response at WSWB. The total cost estimate is $10.0 M to implement 5.2 MW of Peak Hour Pumped Storage and 24.2 MW of demand response.

These costs are feasibility study level. More precise cost and schedule estimates will be made during preliminary and detailed design, including whether the project should be built out in two phases or built out completely in one step only.

There are no additional costs needed to provide 24-hour power generation in recharge (wet) years. Hydropower generation during wet years supplements the demand response and peak hour power generation benefits during dry years.

Operating costs will increase because the pump station will be operated during recharge, idle, and extraction years. If hydropower was not part of the WSWB, the pump station would be operated only during extraction years. The annual operating cost of the pump station is estimated at $100,000/year based on adding one staff as an operator ($100,000/operator/year). This has a present worth of $1.06 M[9].

Table 14: Capital Cost of Facilities for PHPS and Demand Response

Component	Details	Cost, $ M
1. Upper reservoir @ 103 AF & 30 ac. of land*	Upper reservoir is only needed if pumped hydro is built. The 2016 master plan for WSWB facilities (GEI Consultants, Inc., 2016) includes a cost estimate of $1.32 M for a 48 AF lined reservoir, excluding engineering and contingency. For a 103 AF reservoir the cost will be = (103/48) ($1.32 M) (1.24 for engr. & contingency.) = $3.51 M. Land cost for 30 acres is about $0.09 M @ $3,000/acre in Kern County.	$3.6 M
2. 250 cfs low lift pump @ 378 hp, 10' lift*	[378 hp ($1,000/hp) + 250 cfs ($500/cfs)] (1.24) = $0.62 M. Pumps water from upper reservoir to the Aqueduct during extraction years.	$0.6 M
3. 5.2 MW of impulse turbine capacity**	Two 3.4 MW 5-jet Pelton Wheel turbines @ $1.5 M ea. and 24% for engineering & contingencies.	$3.7 M
4. Two more 300 HP wells @ $1.07 M each*	($860,000 per well) (2) (1.24) = $2.13 M Two more wells to make up the water not pumped during the 5-hour shutdown on peak days.	$2.1 M
6. Total capital cost	Total additional cost due to Peak Hour Pumped Storage and demand response	$10.0 M

Sources:

* Unit cost estimates based on 2016 GEI master plan update for WSWB (GEI Consultants, Inc., 2016) and adjusted to include 24% more for contingencies, design, and construction management.

** (HDR, 2017)

3.7 CEQA Considerations

Construction of an upper reservoir will likely trigger the need to prepare and adopt either a Subsequent Environmental Impact Report (EIR) or a Supplemental EIR tiered off the existing WSWB adopted California Environmental Quality Act (CEQA) EIR. No action was taken as part of this project that might trigger CEQA. Instead, design and construction of the upper reservoir were deferred until the PHPS project has proven to be cost effective.

If PHPS is proven to be economically feasible and full-scale implementation is desired it is anticipated that the project would need to obtain Federal Energy Regulatory Commission (FERC) approval to generate electric power to be provided to the electric grid. It is anticipated that the pumped storage project would qualify for a *Conduit Exemption* for Small/Low- Impact Hydro projects that are planned to generate less than 40 MW of power, and must be located on a

9 The present worth factor used is 10.6 based on a discount rate of 7% and a 20-year planning period.

Conduit used for agricultural, municipal, or industrial consumption. The exemption only covers the powerhouse and pipeline connections to the Conduit. Other FERC Conduit Exemption project provisions include:

- May be subject to Federal and State fish and wildlife conditions under section 30(c) of the Federal Power Act (FPA), 16 U.S.C. § 823a(c);
- 3-stage consultation required under Code of Federal Regulations (CFR), 18 C.F.R. § 4.38; however, with concurrence from all resource agencies, the applicant may seek waiver of the consultation requirements under 18 C.F.R. § 4.38(e);
- Conduit Exemption projects are categorically exempt from preparing an environmental document such as an Environmental Assessment (EA) or Environmental Impact Statement (EIS) under 18 C.F.R. § 380.4(a)(14) that would not be prepared by FERC unless determined necessary.

If a Conduit Exemption is obtained from FERC, then the only environmental document required for the pumped storage project is either a Subsequent EIR or Supplemental EIR as described in the first paragraph above. The Subsequent EIR or Supplemental EIR would address impacts from the upper reservoir, powerhouse, pipeline connections, and an electric transmission line to send the generated electric power to the grid.

If the pumped storage project is unable to obtain a Conduit Exemption, then it is likely that the FERC Traditional Review process would be implemented to obtain a License to generate electric power. Under the licensing process a Federal nexus would exist which would trigger the need to prepare an EIR/EIS to comply with CEQA and NEPA (National Environmental Policy Act).

3.8 Summary of WSWB Pumped Storage Analysis

Potential power generation and demand response at WSWB is summarized in Table 15.

Table 15: Power Generation and Demand Response Potential at WSWB

Application	Peak Hour Power (every year)	Recharge Year Power	Recharge Year Occurrence	Demand Response	Extraction Year Occurrence
1. Turbine or Pump*	5.2 MW for 5 hours	5.2 MW for 24 hours	32%	10.2 MW for 5 hours	35%
2. Well field (62 wells, 300 hp each)	Impractical	Impractical	-	14.0 MW for 5 hours	35%
3. Totals	5.2 MW	5.2 MW	32%	24.2 MW for 5 hours	35%

*** To simplify the results, only the Phase 2 power and demand response values are shown.**

In a dry year WSWB will extract water and pump it to the California Aqueduct. The net peak hour power benefit in a dry year is the value of the electricity generated (5.2 MW) plus the reduced power for groundwater pumping (14.0 MW) plus the reduced power for the pump station (10.2 MW). This totals 24.2 MW of combined energy benefits. Effectively, energy benefits are leveraged by the combination of power generation and demand response. This will occur 35% of the time. The incorporation of demand response at pumping plants is possible at any site that has room for upper and lower reservoirs and incorporates a lift to get water into or out of the bank. Demand response using well pumps is possible at any site that has room for a small reservoir and wells with remote on/off switches (Figure 14).

In years when the bank is idle, the net peak hour benefit is the value of the 5.2 MW of electricity generated. This will occur 33% of the time.

In wet years, WSWB will recharge water into the bank's percolation ponds. Recharge flow is a constant 250 cfs. This will generate electricity 24 hours a day for the entire year. The benefit is the value of the 5.2 MW of electricity generated constantly over the year. This occurs 32% of the time.

The hydrologic cycle is random. Consequently, the combined benefits of power generation and demand response are unpredictable. The years in which these benefits occur are not correlated to other load-inducing factors such as hot summer temperatures.

For implementing PHPS technology at WSWB, turbine type will need to be further evaluated to verify that a reaction pump cannot be run in reverse as a generator in the 5 MW size range and a separate impulse turbine is required. This will involve preliminary design. The cost ramifications are about $3.7 M. This does not include the cost of additional hydraulic and surge control that may be needed. The best sites and optimum sizes for the upper and lower reservoirs will also need to be determined. Additionally, the right-of-way will need to be acquired for the upper reservoir and the facilities plan updated to set aside land at WSWB for the lower reservoir.

Figure 14: A Groundwater Well at Willow Springs Water Bank

Figure 14 shows one of the smaller groundwater wells (with a 200 hp motor) at Willow Springs Water Bank (WSWB). Most groundwater banking projects have recovery wells that can potentially be automated for demand response.

Photo Credit: Tommy Ta, Antelope Valley Water Storage, LLC (AVWS)

Results of the WSWP specific evaluation were incorporated into the Peak Hour Pumped Storage (PHPS) and Aquifer Pumped Hydro (APH) templates. The templates allow the calculation of pumped storage, hydropower generation, and demand response potential of the well field and pump station(s) for other groundwater banking projects. The permitting requirements for both the pumped storage technologies have been briefly discussed in the context of implementing pumped storage at WSWB. As discussed in Chapter 4, a next-step pilot project may need to consider permitting in more detail.

CHAPTER 4: Statewide Applicability Analysis

This chapter describes the technical feasibility of implementing the Peak Hour Pumped Storage (PHPS) and Aquifer Pumped Hydro (APH) technologies at groundwater banks around the State.

In determining the potential of any storage system, ease of deployment and scalability plays an important part. Therefore, the feasibility criteria identified in the preceding chapters were used to evaluate statewide potential of the pumped storage at groundwater banks. The two energy storage systems are not mutually exclusive and a single groundwater banking facility can potentially deploy both. To determine the statewide potential, the study takes into account various kinds of groundwater banking operations including recycled water projects. Recycled water projects that use injection wells need only have the generating cycle of APH and therefore may have considerable potential for generating peak energy. This is because in most instances, recycled water needs to be recharged daily. Recycled water also has most of its particles removed so there is lower risk of well screens getting clogged.

Groundwater banking projects around the state also have capability to provide demand response during extraction years. Estimates of the statewide demand response potential and its value were also developed as part of this project.

An important component of the statewide analysis is development of a template that makes it possible to evaluate pumped storage potential for any groundwater banking project including those that are currently being planned to recharge the overdrafted groundwater basins around the State of California.

4.1 Literature Review and Statewide Survey

Given the number of groundwater banking agencies and complexity and diversity of their individual conveyance systems and operational metrics, a statewide survey was developed to obtain key information to determine pumped storage system feasibility at various groundwater banking sites. Information from the survey responses was supplemented by literature research with the goal of identifying promising sites for pumped storage and formulating follow up questions to the surveyed agencies that pass the preliminary screening. To that end, the literature review focused on researching the urban water management plans and other reports and analyzing this information in conjunction with the survey responses. The results from both of these data collection activities are summarized in Appendix D-1 through Appendix D-7.

Statewide survey outreach started in Dec 2016. All of the agencies on the List of CA Groundwater Banking Projects (Antelope Valley Water Storage (AVWS), 2016) were contacted at least twice. The received survey responses were incorporated into the statewide master database compiled for this study. The response rate was found to be inadequate to provide a statewide picture of the pumped storage potential at groundwater banks particularly with regards to Peak Hour Pumped Storage (PHPS).

4.2 Analysis Approach for Peak Hour Pumped Storage

To determine potential of PHPS technology, information on flow rate and elevation difference between source conveyance and recharge basin(s) is necessary. Previous studies have acknowledged the difficulty of obtaining comprehensive data about specific water system facilities and operational flows since this information is generally not available in public domain for security reasons (Navigant Consulting, June 2006).

Therefore, an alternative approach to PHPS statewide analysis was adopted. Since hydropower generation and PHPS both require similar criteria (namely sufficient head and flow) for successful implementation, statewide estimates for small hydropower potential can be used to give a preliminary estimate of Peak Hour Pumped Storage (PHPS) potential at groundwater banking projects.

An existing study, *Statewide Small Hydropower Resource Assessment* (Navigant Consulting, June 2006) estimates the statewide potential for small hydropower in manmade conduits (pipelines, aqueducts, irrigation ditches, and canals) by using annual water entitlements to extrapolate the computed small hydropower generation potential for the surveyed population to the population of water agencies that were not surveyed. The study recognizes the potential of in-conduit hydropower to be used in conjunction with pumped storage facilities for generating power during peak periods.

The developable hydropower potential in man-made conduits is estimated to be 140 MW- 170 MW which is 50-60% of the statewide undeveloped small hydropower nameplate potential (278 MW) (Navigant Consulting, June 2006; Kane, 2005). The statewide in-conduit small hydropower coincident peak capacity occurs during July and August and is estimated to be 230 MW (Navigant Consulting, June 2006; Kane, 2005). Annual water entitlements and available county level coincident peak hydropower capacity data was used to interpolate small hydropower potential for the groundwater banking agencies. For example, if groundwater banking water agencies located in a particular county have total water entitlements that constitute 39% of the total county water entitlements, the cumulative hydropower production potential for these districts was estimated to be 39% of the countywide hydropower potential (kW) of all (both groundwater banking and non-groundwater banking) districts (Appendix E shows these calculations.) In the reference statewide small hydropower study, the small hydropower generation potential was extrapolated using estimation factors that were developed based on size, primary water system function (irrigation vs. municipal) and geographic region (north, central and south) of the surveyed and non-surveyed agencies. Because of unavailability of the entire reference study database, the interpolation method described above takes into account only the annual water entitlements and geographic region. It is acknowledged that annual water entitlements are insufficient to compute hydropower or pumped storage potential in absence of other information, particularly head losses. However, it can be assumed that the available static head[10] to generate power does not differ significantly for the water districts located in the same county. This assumption is borne out by the findings of the reference study which indicate that

10 Elevation difference between the upper and lower reservoir.

the different regions of the state have distinct advantages or drawbacks regarding available head and operational flows (Navigant Consulting, June 2006). Additionally, analysis of countywide annual water entitlements data from *Statewide Small Hydropower Resource Assessment* (Navigant Consulting, June 2006) in conjunction with countywide small hydropower potential data from *California Small Hydropower and Ocean Wave Energy Resources* (Kane, 2005) shows that for a particular region, counties with higher annual water entitlements generally have higher small hydropower generation potential than those with lower annual water entitlements . Therefore, it can be assumed that the annual water entitlements are largely responsible for the difference in hydropower potential between the water districts situated in the same county[11]. This estimated countywide small hydropower potential for groundwater banking agencies was rolled up to give the potential for each hydrologic region (Table 16).

4.2.1 Statewide PHPS Potential at Groundwater Banking Projects

The cumulative PHPS potential of groundwater banking agencies will be lower than the cumulative small hydropower potential (Table 16) because PHPS differs from small hydropower in several key ways which constrain the statewide PHPS potential:

1. A minimum head of 9 feet and a minimum flow rate of 120 cfs is required to install a small hydropower facility in an existing manmade conduit (Navigant Consulting, June 2006). Although the small hydropower criteria flow rate of 120 cfs is a reasonable minimum threshold for PHPS, the elevation difference between the upper reservoir and lower reservoir would need to be much greater than 9 feet for PHPS to be economically feasible at a site. Additionally, pipe length has a significant impact on pipe friction and pipe friction losses can be kept to a minimum for a given flow rate at sites where the length of pipe between upper reservoir and generator can be minimized. The uncertainty in the computed statewide PHPS potential is therefore largely due to information gaps regarding elevation data and length of conveyances.

2. The reference study (Navigant Consulting, June 2006) assumes a "run of the river (canal in most cases)" hydropower development with no more than part day storage. PHPS will need closed conduits (pipelines) to cycle the water. A previous study[12] (California Department of Water Resources, April 1981) indicates that most of the pipelines with small hydroelectric generation potential are clustered in the southern portion of the state and that in this region, majority of the man-made conduits that have hydropower potential are pipelines. In contrast, in northern and central regions, majority of conveyance systems with hydropower potential are canals. Besides the large operational flows, the density of pipelines in Southern California is another reason to focus on this region for potential PHPS opportunities or demonstration projects. This also implies that particularly in northern and central regions of the state, PHPS is

---

11 This does not imply that higher flow rates or volumes will consistently result in higher hydropower potential. As described in the WSWB PHPS analysis (HDR, 2017) conducted for this project, the friction loss rate in a given pumped storage operation increases rapidly after the flow rate exceeds a certain point.

12 The map, "Potential Small Hydroelectric Sites at Existing Hydraulic Facilities" in "Bulletin 211 Small Hydroelectric Potential at Existing Hydraulic Structures in California" shows dam, canal, and pipeline facilities that have small hydroelectric potential.

lower than the small hydropower generation potential (Table 16). This is why the statewide PHPS was assumed to be 50% (44 MW) of the total small hydropower generation potential of about 88 MW.

3. The reference study identified 128 renewable portfolio standard (RPS) eligible small hydropower sites for the water purveyors that were surveyed. Given that the in-conduit hydropower potential on large regional conveyance systems has largely already been developed, 67% of these potential sites had capacity less than 1 MW (Navigant Consulting, June 2006). Economic evaluation (discussed in Chapter 5) indicates that PHPS facilities with characteristics similar to that of WSWB and with generating capacity of 5 MW will find it difficult to be economically viable if operated as a pumped storage system during neutral years and as an energy generator during wet years. Addition of dry year demand response can potentially make these systems economically feasible and will also result in greater economic and grid benefits.

4. The research and survey results indicate that the pump back operations of many groundwater banking agencies do not involve pumping to the source conveyance. Even if they did, the use of large regional conveyance systems for PHPS is unlikely to be allowed[13] which necessitates construction of an upper reservoir even for groundwater banking agencies situated close to a large conveyance. Many groundwater banking districts (particularly the irrigation districts) may already have a lower reservoir but would likely need to construct an upper reservoir to implement PHPS. Sites that are located in highly urban and dense areas with few or no options available for reservoir siting will not be able to develop PHPS.

5. The undeveloped small hydropower potential is greatest in southern region followed by northern and central regions (Navigant Consulting, June 2006). The distribution of regional PHPS potential is expected to be similar. Groundwater storage capacity is not a good indicator of the PHPS potential. Central California has significant groundwater storage capacity but low small hydropower and pumped storage potential because of insufficient head and flow. The water systems in Northern California have higher head and flow but relatively few groundwater banking agencies and closed conduits with small hydroelectric potential. Therefore, PHPS potential appears to be largely limited to Southern California which region has several large groundwater banks (Appendix E) and higher density of pipelines. However, this potential is curtailed because of the predominantly urban nature of the region which may make land acquisition for an upper reservoir difficult.

Assuming generation for 5 hours 365 days a year, implementing PHPS at groundwater banks across the State can potentially provide 80,300,000 kWh (80 gigawatt-hours) of energy annually. The value of this generation at different locations may be different depending on the extent to which a PHPS facility contributes to improving grid operations at a particular location. This value analysis is beyond the scope of this study and for the purposes of benefits evaluation, a single annual value of pumped storage was calculated and used.

---

13 California Department of Water Resources is opposed to the use of California Aqueduct as the upper reservoir. (Personal communication with Craig Trombly, California Department of Water Resources, August 5, 2016)

Table 16: Peak Hour Pumped Storage (PHPS) potential at Groundwater Banking Projects

<table>
<tr><th>Geographic Region</th><th>Hydrologic Region</th><th>Annual Water Entitlements (AWE) for Groundwater Banking Agencies</th><th>Estimated Small Hydropower Potential (kW) for Groundwater Banking Agencies</th><th>Estimated Statewide Pumped Storage Potential (kW) for Groundwater Banking Agencies [a]</th></tr>
<tr><td>N</td><td>Sacramento River</td><td>422,000</td><td>3,102</td><td rowspan="8">44,000</td></tr>
<tr><td>S</td><td>South Lahontan [b]</td><td>466,800</td><td>12,050</td></tr>
<tr><td>N,C</td><td>San Francisco Bay</td><td>512,500</td><td>4,952</td></tr>
<tr><td>S</td><td>Colorado River</td><td>546,200</td><td>1,926</td></tr>
<tr><td>C,N</td><td>San Joaquin River</td><td>609,000</td><td>4,686</td></tr>
<tr><td>S</td><td>South Coast</td><td>2,129,590</td><td>30,173</td></tr>
<tr><td>N,C,S</td><td>Tulare Lake</td><td>4,608,994</td><td>30,653</td></tr>
<tr><td></td><td>Total</td><td>9,295,084</td><td>87,542</td></tr>
</table>

[a] Estimated statewide pumped storage potential is assumed to be half of the statewide small hydropower potential for groundwater banking agencies due to the constraints discussed in the section, "Statewide PHPS Potential at Groundwater Banking Projects."

[b] Includes water entitlement and Peak Hour Pumped Storage (PHPS) potential for Antelope Valley Water Storage (AVWS)'s groundwater banking project, Willow Springs Water Bank (WSWB).

4.3 Aquifer Pumped Hydro Potential

Relative to PHPS, literature review for APH was more successful in that it yielded detailed information for several groundwater banking facilities which was used to screen agencies for APH feasibility. Transmissivity was one of the key criteria used in the screening. The sensitivity analysis results discussed in Appendix A-2 indicate that transmissivity is one of the primary factors in determining the round trip losses. Aquifers with high transmissivity allow the injected water to move away faster from the site of injection which decreases the head losses associated with mounding. In the absence of high transmissivity, the round trip losses may significantly reduce the statewide potential for APH as described in the Willow Springs Water Bank (WSWB) APH assessment in Chapter 2.

4.3.1 Aquifer Storage and Recovery (ASR) Projects

Aquifer Storage and Recovery (ASR) projects are a type of groundwater banking projects that use injection wells to store water in the aquifer when water is available and later recover the water from the same well. ASR projects are typically sited in areas where the underlying aquifer has high transmissivity. Most ASR projects in Western US typically have transmissivity in the range of 5,000 to 10,000 sq. ft/day or greater (Antelope Valley Water Storage (AVWS) LLC, 2016). Additionally, for these projects, the head losses are halved because groundwater does not need to be first pumped to a surface reservoir. Given the above, the well field at these projects can potentially be used to generate hydropower during recharge activities. However, further evaluation using statewide template and results from economic analysis indicates that the capital costs associated with retrofitting injection wells for hydropower production may be cost prohibitive for most agencies. Whether or not energy generation is viable at a particular ASR project will greatly depend on the project's location and how well the generating capacity at that specific location compares to the costs for installing the generator and electrical package. The Pendleton project in eastern Oregon is an example of a groundwater banking (ASR) project that uses microturbine generators in its ASR injection wells to generate hydropower and offset its operating costs (Profita, 2011) (Pendleton) . The project's prototype can generate 47% of the pumping power needed to deliver water to the site (Profita, 2011). This is double the efficiency (22%) of the APH project at WSWB.

4.3.2 Recycled Water for Direct Injection

Recycled water projects that inject treated water into the ground as part of their routine operations obviate the need to pump the groundwater to a surface reservoir prior to its injection. These projects (as Aquifer Storage and Recovery (ASR) projects discussed above) have higher potential to generate peak energy cost-effectively than comparable Aquifer Pumped Hydro (APH) projects. As with APH projects however, the injection process can cause clogging and other complications if the water is not pretreated using appropriate methods. This study looked at which tertiary treatment methods (membranes, gravity filters or cloth filters) result in a low enough turbidity to make recycled water suitable for direct injection.

The Division of Drinking Water (DDW) has treatment requirements for producing recycled water for groundwater recharge. For both surface spreading and subsurface injection projects, the recycled water must meet the disinfected tertiary recycled water treatment requirements of Title 22 of California's Water Recycling Criteria. The requirements for projects recharging water via direct injection are stricter than those for surface spreading projects and preclude the use of cloth filters or gravity filters. Microfiltration with reverse osmosis and disinfection is required before recycled water can be injected (Environmental Science Associates , 2005; RMC Water and Environment, 2007; RMC Water and Environment, 2016). The turbidity of the filtered wastewater that has been passed through a microfiltration, ultrafiltration, nanofiltration, or reverse osmosis membrane does not exceed 0.2 Nephelometric Turbidity Units (NTU) more than 5 percent of the time within a 24-hour period and 0.5 NTU at any time (RMC Water and Environment, 2016; State Water Resources Control Board Division of Drinking Water, 2014).

Literature review indicates that at present there are four large scale groundwater recharge operations in California that inject recycled water into the ground. All of these projects provide water for saltwater barriers to protect aquifers against seawater intrusion (Table 17). Since membrane filtration is mandatory for all projects that inject recycled water, all of these four projects use microfiltration and reverse osmosis.

Table 17: Projects Using Recycled Water for Groundwater Recharge via Injection

S.No.	Project Name	Amount Recycled (Acre-Feet/Year) [a]	No. of injection wells	Notes
1.	West Coast Basin Saltwater Barrier	14,000	153	The recycled water for the West Coast Barrier is treated by the West Basin Municipal Water District Edward C. Little Water Treatment Facility. The facility can provide up to 75% of the water injected into the West Coast Basin Barrier. An increase up to 100% is planned. The facility produces softened Reverse Osmosis water which is secondary treated wastewater purified by micro-filtration (MF), followed by reverse osmosis (RO), and disinfection for groundwater recharge (West Basin Municipal Water District, n.d.).
2.	Alamitos Saltwater Barrier	3,360	43	Recycled water for the Alamitos Barrier is produced by Water Replenishment District of Southern California (WRD)'s Leo J. Vander Lans Water Treatment Facility. This treatment plant can provide up to 50% of barrier water with recycled water. The remainder water for the barrier is imported. The facility receives tertiary-treated water from the Sanitation Districts of Los Angeles County and provides advanced treatment that includes microfiltration, reverse-osmosis, and ultraviolet light.
3.	Dominguez Gap Barrier Project (DCBP) or Harbor Recycled Water Project	5,600	94	This project uses recycled water from the City of Los Angeles Department of Water and Power (LADWP)'s Terminal Island Treatment Plant (TITP) Advanced Water Treatment Facility. The plant is permitted to provide up to 5 million gallons per day (mgd) or 5,600 AFY, or 50% of the total barrier supply, whichever is less. The water is treated with microfiltration, reverse osmosis, and chlorination before being injected.
4.	Orange County Groundwater	72,000	36	Approximately 30 MGD of the GWRS facility treated water is used for injection

S.No.	Project Name	Amount Recycled (Acre-Feet/Year) [a]	No. of injection wells	Notes
	Replenishment System (GWRS); Spreading/Injection			into the Talbert Barrier. Unlike other barrier projects in Southern California, 100 percent GWRS water is able to be used for injection into the seawater intrusion barrier without blending with other sources. Water at the GWRS facility is treated using microfiltration, reverse osmosis (RO) and ultraviolet (UV) disinfection with hydrogen peroxide.

[a] The water may need to be blended with other sources prior to recharge. The recycled amount estimates may change depending on how much water is needed for barrier projects in future.

Sources:

Amount Recycled: (Sanitation Districts of Los Angeles County, 2011)

Number of injection wells (For projects 1,2,3): (Johnson, 2007)

Number of injection wells (For project 4): (Orange County Water District, n.d.)

Recycled water treatment and facility details (For projects 1,2,3) unless otherwise indicated: (Water Replenishment District of Southern California, 2011)

Recycled water treatment and facility details (For project 4): (Groundwater Replenishment System (GWRS))

A few planning stage projects are also assessing the feasibility of using recycled water for groundwater recharge via injection (Table 18).

Table 18: Planned Projects Using Recycled Water for Groundwater Recharge via Injection

S.No.	Project/Agency Name	Amount Recycled (Acre-Feet/Year)	No. of injection wells	Notes and Sources
1.	Camp Pendleton	435-870	12	The project will provide protection against salt water intrusion in the Lower Ysidora Sub-basin. Pilot testing was completed in 2012. (RMC Water and Environment, 2012 (Revised 2013)).
2.	City of San Buenaventura	4000-7000	3-5 wells capable of sustained injection rates of between 2,500 to	The potential groundwater recharge reuse project (GRRP) in Mound Groundwater Basin will be used to store and reuse highly treated recycled water for Indirect Potable Reuse (IPR). The advanced treatment will involve desalination through a membrane process, advanced oxidation, and

S.No.	Project/Agency Name	Amount Recycled (Acre-Feet/Year)	No. of injection wells	Notes and Sources
			4,340 gpm	ultraviolet light (Hopkins Groundwater Consultants, Inc., 2013).
3.	City of Oxnard's Groundwater Recovery Enhancement and Treatment Program (GREAT Program). Program's partners are United Water Conservation District (UWCD) and the Fox Canyon Groundwater Management Agency (FCGMA).	Ultimate plant capacity is 25 mgd	Design and permitting of pilot injection wells system is underway.	The Advanced Water Purification Facility (AWPF) and recycled water membrane treatment facility will provide high-quality water for groundwater injection and use as a seawater intrusion barrier (in the south Oxnard Plain) as well as for other uses including industrial processes and irrigation (Watersheds Coalition of Ventura County, 2006).

Because of the higher treatment costs associated with direct well injection of recycled water, majority of the planned groundwater recharge reuse projects are expected to use surface spreading rather than injection wells for groundwater recharge of recycled water (Sanitation Districts of Los Angeles County, 2011). Therefore, statewide hydropower generation potential from injecting recycled water for groundwater recharge is concentrated in a few regions of Southern California and as with ASR and APH projects, this potential is constrained by hydrogeological, site specific and operational parameters[14].

4.4 Demand Response Potential of Groundwater Banks

Reducing groundwater usage provides a substantial opportunity to reduce water-related energy consumption of IOU energy (GEI Consultants/Navigant Consulting, Inc., 2010). Likewise, "demand response", that is, the ability to shift groundwater pumping from peak hours to non-peak hours can reduce peak energy requirements and contribute towards overcoming the barriers to renewable penetration. Water storage can be used to shave off more than one-third of the peak load associated with groundwater use (California Energy Commission, 2005). Having an onsite surface reservoir allows the water agencies or irrigation districts to pump groundwater during off-peak hours and store it for use during on-peak hours. It is common for many irrigation districts in California to have regulating reservoirs with volumes typically

14 One of these parameters is head loss or pressure loss. There used to be power generating stations at Water Replenishment District of Southern California (WRD) saltwater barrier facilities when the pressure of imported water (which is used for blending with recycled water) was sufficiently high. Energy generation has been discontinued however because of current low flows and reduced pressures (Ted Johnson (Chief Hydrogeologist, WRD), personal communication (EPC 15-049 Technical Advisory Committee Meeting), November 17, 2016).

ranging from 50,000 cubic meters (~ 40 AF) to 320,000 cubic meters (~260 AF) (Irrigation Training and Research Center (ITRC)). Peak load curtailment and generation projects at several water agencies including groundwater banking agencies such as North Kern Water Storage District (NKWSD) and Berrenda Mesa Water Storage District have been funded with successful results (Irrigation Training and Research Center (ITRC), 2005). Additionally, groundwater banks that involve a significant pumping lift to deliver the extracted groundwater offer a unique opportunity to combine demand response capabilities of pumping plants and well pumps at a single site.

4.4.1 Peak Energy Requirements at Groundwater Banks

While pumped storage and associated peak hour generation benefits can potentially occur in all hydrological year types, demand response benefits at groundwater banking projects will occur largely in dry years since that is when most groundwater banking projects recover banked water for delivery to partners or customers. The electric demand to pump the stored water from a groundwater bank for delivery to participating agencies can be significant and add considerably to the daily and seasonal peak summer loads. Therefore, groundwater banking projects with demand response capability can decrease peak energy requirements which opportunity has been recognized in earlier studies (Irrigation Training and Research Center (ITRC), 2003). The facilities used to provide energy storage and peak energy generation at groundwater banks can also be used for demand response. As with pumped storage, in most cases only minor modifications to existing operations will be needed to enable shifting the pumping demand out of the peak hours.

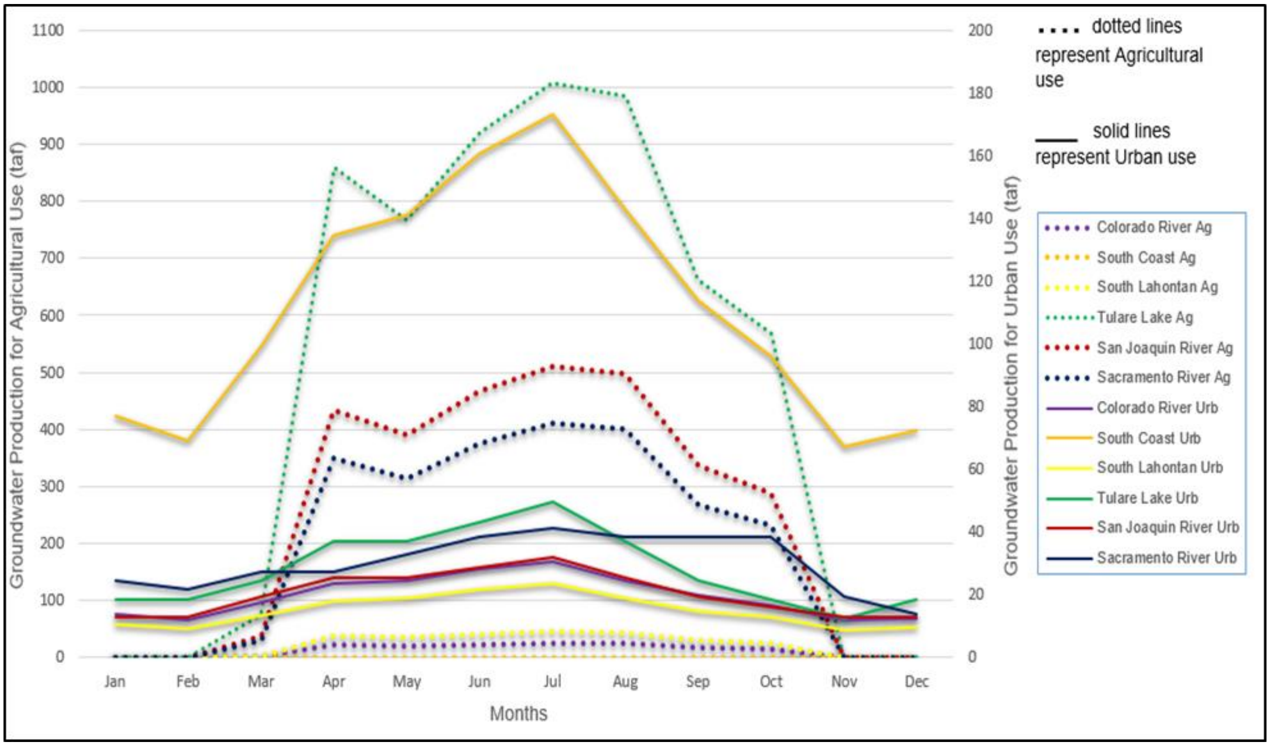
4.4.2 Demand Response Potential associated with Well Pumps

This study focuses on the demand response potential of relatively large groundwater banking agencies that are likely to have clusters of high production wells. Though demand response can be implemented at smaller agencies, data gaps and the scope of this study necessitate that evaluation be restricted to large groundwater banking operations where closely located high pumping capacity wells make the water storage and demand response practical and cost-effective. This approach gives a preliminary estimate of statewide demand response potential which in conjunction with the pumped storage and peak energy generation assessment provides useful insights about the potential of groundwater banks to meet grid needs.

Since there is no statewide database providing information about well density or well pump power consumption at various groundwater banks, groundwater banking agencies that are likely to have clusters of wells were identified using the recovery volumes from the master database (Antelope Valley Water Storage (AVWS), 2016) submitted with this report. The selected groundwater banking projects have annual recovery volumes in thousands of acre-feet at a minimum. The results from the literature review conducted for the Aquifer Pumped Hydro (APH) and the statewide survey responses for the two pumped storage technologies were also used to provide information on the number of wells and pumping capacity for selected groundwater banking agencies. This information was compared to the pumping capacity estimates derived from the recovery volumes to ensure that the assumptions do not result in an overestimation of the demand response potential.

Figure 15 shows the monthly groundwater production profiles for selected hydrologic regions where majority of large groundwater banking projects are situated. These regions include Tulare Lake, San Joaquin River, and Sacramento River hydrologic regions which together comprise what is commonly referred to as the Central Valley region of California. On average, approximately 76% of the total groundwater pumped statewide every year is used to meet agricultural demands (State of California Natural Resoures Agency, Department of Water Resources , April 2015). Unlike urban groundwater use, agricultural groundwater use varies considerably during the year (Figure 15). Seasonal demand response potential is therefore also higher for agricultural sector. Central Valley has several large irrigation districts, many of which have onsite groundwater banking operations as shown in Appendix F). Consequently, this region has the highest groundwater pumping use (State of California Natural Resoures Agency, Department of Water Resources , April 2015) and demand response potential as well as the highest groundwater storage capacity (Table 19).

Figure 15: Monthly Groundwater Production (taf) by Hydrologic Region and Type of Use



taf= thousand acre-feet

Statewide, only 2% of the groundwater extracted on an average annual basis is used for managed wetlands (State of California Natural Resoures Agency, Department of Water Resources , April 2015). For the purposes of this analysis, it is assumed that no groundwater is pumped for managed wetlands use and all the extracted groundwater is used to meet Ag or Urban demands.

Agricultural water demand is projected to decrease in the South Coast hydrologic region (California Department of Water Resources, 2013). For this analysis, percentage of groundwater used for agriculture is assumed to be negligible (~0 AF) for the South Coast hydrologic region.

Sources:

Average Annual Groundwater Supply by Hydrologic Region and Type of Use (State of California Natural Resoures Agency, Department of Water Resources , April 2015)

Monthly Profiles for Groundwater Production (%) by Hydrologic Region and Type of Use (GEI Consultants/Navigant Consulting, Inc., 2010)

Table 19: Demand Response Potential of Well Pumps at Groundwater Banking Projects

Hydrologic Region	Total Storage Capacity (MAF) of listed projects	Demand Response Potential (MW) of listed projects
Central Coast Hydrologic Region	5.9	99
South Coast Hydrologic Region		
Colorado River Hydrologic Region		
South Lahontan Hydrologic Region		
San Joaquin River Hydrologic Region	0.3	2
Sacramento River Hydrologic Region	2.36	2
Tulare Lake Hydrologic Region	11.48	115
San Francisco Bay Hydrologic Region	0.23	2
Total	~20	~220

MAF=Million Acre-Feet

Sources:

The storage capacity is from the master list of groundwater banking projects which was also one of the study deliverables (Antelope Valley Water Storage (AVWS), 2016)

Demand Response Potential estimates are provided in Appendix F.

4.4.3 Demand Response Potential associated with Pump Station(s)

Any groundwater bank that has area for siting upper and lower reservoirs and relies on pumping plants to get water into or out of the bank can potentially provide demand response benefits by shifting peak summer demand to off-peak hours in an extraction year. Assuming the statewide PHPS potential is 44 MW (Table 16), groundwater banks across the State can free up more than 44 MW in cumulative peak capacity (The PHPS assessment for Willow Springs Water Bank (WSWB) indicates that for a given PHPS lift, the power demand to pump water to the upper reservoir is likely higher than the power produced during the generation cycle). A project's operational pumping capacity is the key indicator of its demand response capability.

4.5 Regulatory Considerations

Current and future regulatory criteria will also impact the technical and economic feasibility of pumped storage. As discussed in Chapter 2 the low round-trip efficiency makes APH deployment on a large scale unlikely. The success of APH is likely only at groundwater banking sites that currently operate as ASR projects and are therefore located in areas of relatively high transmissivity. Assuming that the APH deployment is restricted to sites with active ASR operations, permitting requirements would be minimal since an existing ASR project will typically have approved injection and extraction operations that have been evaluated for compliance with water quality and other regulatory criteria. For these sites, permitting would generally only be needed to equip the existing wells with turbines to generate power and to obtain approval for utility interconnection. Permitting requirements will be more extensive for sites that do not have active ASR activities. At the very minimum, these projects will have to meet Regional Water Quality Control Board (RWQCB) requirements to pump, store, and inject groundwater.

For Peak Hour Pumped Storage (PHPS), both upper and lower reservoirs will need to be covered and lined to keep out tumbleweeds and dust. Floating covers could be used for the purpose. For full-scale implementation of a PHPS project, a Federal Energy Regulatory Commission (FERC) approval or "Conduit Exemption" and an environmental document such as Supplemental Environmental Impact Report (EIR) or Subsequent EIR will be needed at a minimum. An Environmental Impact Statement (EIS) may also be required if a FERC Traditional Review process to obtain a license has to be implemented.

Appendix G lists additional permits and registrations, some or all of which may be needed to test and deploy pumped storage at a groundwater banking project. Compliance with regulatory criteria will ensure that any negative environmental impacts that may result from implementation of pumped storage at groundwater banks are avoided or suitably mitigated.

4.6 Template to Assess Pumped Storage Potential

The objective of the template is to provide a decision-making tool to assess current and future groundwater banking operations for energy storage and demand response potential. The template walks the user through a series of preliminary questions and calculations to determine a site's technical and economic viability for pumped storage implementation. The template incorporates criteria pertaining to a site's physical and operational parameters, preliminary regulatory requirements and economics (including threshold generation capacity (MW), and value of on-peak energy generation and any other grid benefits) to provide a conceptual estimate of a site's feasibility for APH or PHPS. The template and its accompanying documentation submitted with this report describe the criteria in detail.

The template also includes an assessment of a project's potential to participate in a demand response program. Demand response benefits have traditionally come from turning off the pumps at the pumping plant and groundwater well pumps during the peak hours but increasingly are looking at increasing demand during renewable overgeneration hours. The demand response program will be most effective in places where high capacity wells are located close together so as to require a single reservoir for storing the water pumped during off-peak hours. For evaluation of demand response potential, appropriate criteria including number of additional wells that may be needed have been incorporated in the template.

While the template can be used by any groundwater banking project, it is recommended that only projects that meet certain criteria should do an in-depth evaluation of the pumped storage potential for their specific site using the template tool(s). The in-built preliminary criteria in the template will assist a project owner in determining whether a more detailed pumped storage evaluation is warranted for a specific project site. Evaluation is done using an analysis process similar to the one for WSWB described in this report.

The developed template may be used to identify candidate sites for pilot testing of APH and PHPS. Along with the technical criteria, the template also includes regulatory costs for pilot stage projects. These costs will impact the economics of future pilot stage projects and have also been considered in this analysis.

4.7 Summary of Statewide Analysis

At the outset of the study, it was presumed that the available underground storage capacity in the State is a good indicator of the undeveloped statewide pumped storage potential at groundwater banks (Antelope Valley Water Storage (AVWS), 2015). The State's total groundwater banking capacity is estimated to be 22 MAF (Lund, Munevar, Taghavi, Hall, & Saracino, 2014) and WSWB capacity is 2.3% (1/44th) to 4.5% (1/22nd) of this total[15]. The statewide pumped storage potential extrapolated as a function of the storage capacity using the initial pumped storage estimates (6 MW to 13 MW) for WSWB resulted in an order-of-magnitude estimate of 70 MW to 140 MW of statewide storage benefits (assuming either energy storage system is applicable at 50% of groundwater banks). This indicated that either pumped storage concept has the potential to meet 1% to 2% of the State's storage needs (assuming the State needs 6000 MW of storage to meet the 50% renewable penetration goal by 2030[16])

A key goal of the statewide analysis was to determine more precise estimates for the statewide pumped storage potential at groundwater banks. The following key findings (discussed in detail in the previous sections of this report) indicate that the estimated statewide pumped storage potential (44 MW) at groundwater banks is at the low end of the initial estimates:

1. APH at WSWB site is not feasible because of the high round-trip losses. The statewide pumped storage potential of the well fields at groundwater banks can be considerably impacted if a large number of groundwater banks have physical site parameters similar to that of WSWB. Due to the variability in the site specific parameters and their effect on APH performance, the study provides only qualitative estimates for the statewide technical and economic potential associated with APH facilities. Although for a particular groundwater banking site, APH potential may be higher or lower than at WSWB, template evaluation results indicate that across the State, pumped storage and hydropower generation using the well field will likely be limited to sites that currently use dual injection/extraction wells (ASR projects) and have high transmissivities.

2. The statewide power generation potential at groundwater banks that use recycled water for groundwater recharge is low since the injection method for recharge requires advanced water treatment. Therefore, majority of the groundwater recharge reuse projects use surface spreading instead of subsurface injection as the choice method of recharge. Therefore, these

15 Although the 2006 EIR for WSWB approved the total bank volume of 500,000 AF, later groundwater modeling results indicate that the bank can store up to 1,000,000 AF of water with put and take capacities of 250,000 AFY. Using 1,000,000 AF estimate for WSWB's groundwater banking capacity provides conservative estimates for statewide pumped storage potential.

16 California is likely to require between 3,000 MW to 4,000 MW of fast acting energy storage by 2020 to integrate the projected increase in renewable energy. The California 2030 Low Carbon Grid study projects need of 2550 MW to be built between 2020 and 2030 to enable 50% reductions in grid GHG emissions below 2012 levels by 2030 (57% renewable penetration by 2030). The baseline case in this study assumes 33% renewable penetration (No change from 2020 levels of renewable penetration). Therefore, by 2030, CA is likely to need roughly 6000 MW of storage to meet renewable integration goals. (California Energy Commission, 2015) (National Renewable Energy Laboratory (NREL), 2014).

projects typically do not have a well field that has power generation potential. These recycled water projects also have negligible potential for PHPS since elevation differences from treatment facilities to the recharge basins are unlikely to be significant.

3. Demand response potential of groundwater banking projects is significant and can reduce peak hour demand associated with well pumps by 220 MW during dry years. Additional peak demand reduction may result if groundwater banking projects (like WSWB) have a substantial lift to the delivery conveyance. These estimates assume that most of the large groundwater banking projects have the operational flexibility to shift the pumping demand and vary water delivery amounts. Costs associated with additional surface storage capacity and wells are included in the costs and benefits analysis of statewide demand response potential at groundwater banks. PHPS and APH templates can be used to determine the total demand response potential at a particular groundwater banking project.

Information gaps relating to the statewide peak power demand data for well pumps, typical well densities at groundwater banking projects, elevation differences, and pipeline length will need to be addressed to obtain more precise estimates of pumped storage and demand response capabilities of groundwater banks.

CHAPTER 5: Economics Evaluation

As part of this project, Water & Energy Consulting (WEC) was retained to evaluate the value of pumped storage at groundwater banks. Energy storage is recognized as being critical to California's energy future to accommodate intermittent renewable generation (California ISO, 2014)). Energy storage can provide two types of services: long duration services, for example charging during periods of renewable overgeneration and generating during other periods, and short duration services, such as ancillary services (Mathias, Doughty, & Kelly, 2016). This project assesses both these attributes. The economics evaluation was submitted in two technical memorandums (House L. W., 2017 a; House L. W., 2017 b) to the California Energy Commission. This chapter contains excerpts from these memorandums and lays out the characteristics of pertinent markets/services, and the economics of pumped storage at Willow Springs Water Bank (WSWB) and at groundwater banks around the State.

5.1 Participation in ISO Markets

The California Independent System Operator (California ISO) provides markets for various services and access to the transmission grid. California ISO currently runs three primary wholesale energy markets: Day-Ahead, Real-Time, and Ancillary Services (California ISO, n.d.).

5.1.1 Day-Ahead market

The Day-Ahead market is made up of three market processes that run sequentially. First, the ISO runs a market power mitigation test. Bids that fail the test are revised to predetermined limits. Then the integrated forward market establishes the generation needed to meet forecast demand. And last, the residual unit commitment process designates additional power plants that will be needed for the next day and must be ready to generate electricity. Market prices set are based on bids. The Day-Ahead market opens for bids and schedules seven days before and closes the day prior to the trade date. Results are published at 1:00 p.m.

5.1.2 Real-time market

The Real-time market is a spot market in which load serving entities can buy power to meet the last few increments of demand not covered in their day ahead schedules. It is also the market that secures energy reserves, held ready and available for ISO use if needed, and the energy needed to regulate transmission line stability. The market opens at 1:00 p.m. prior to the trading day and closes 75 minutes before the start of the trading hour. The results are published about 45 minutes prior to the start of the trading hour. The Real-time market system dispatches power plants every 15 and 5 minutes, although under certain grid conditions the California ISO can dispatch for a single 1-minute interval.

5.1.3 Ancillary service market

Ancillary services are energy products used to help maintain grid stability and reliability. These services are functions performed by electrical generating, transmission, system-control, and distribution system equipment and people to support the basic services of generating capacity, energy supply, and power delivery. The Federal Energy Regulatory Commission (FERC 1995) defined ancillary services as "those services necessary to support the transmission of electric power from seller to purchaser given the obligations of control areas and transmitting utilities within those control areas to maintain reliable operations of the interconnected transmission system." There are four types of ancillary services products currently procured: regulation up, regulation down, spinning reserve and non-spinning reserve. Regulation energy is used to control system frequency, which must be maintained very narrowly around 60 hertz, and varies as generators change their energy output. Resources providing regulation are certified by the ISO and must respond to automatic control signals to increase or decrease their operating levels depending upon the need. Spinning reserve is standby capacity from generation units already connected or synchronized to the grid and that can deliver their energy in 10 minutes when dispatched. Non-spinning reserve is capacity that can be synchronized to the grid and ramped to a specified load within 10 minutes.

Generators participating in the ISO markets are limited to one megawatt or more. Their ability to participate in the various markets is limited by their configuration (various ancillary service markets have response/performance requirements) and their operation (many of the ancillary services markets require direct ISO control of the generator).

5.1.4 Load Participation

Load can also participate in California ISO markets. California ISO rules allow load and aggregation of loads capable of reducing their electric demand to participate as price responsive demand in the ancillary services market and as curtailable demand in real-time markets. Load can participate in some ISO markets via a Proxy Demand Resource (PDR) or via a Reliability Demand Response Resource (RDRR). PDR and RDRR only allow for load curtailment, not load consumption or the export of energy to the grid.

Proxy Demand Resource (PDR) is a participation model for load curtail introduced in 2010 to increase demand response participation in the ISO's wholesale Energy and Ancillary Services markets. PDR helps in facilitating the participation of existing retail demand response into these markets: Day-Ahead, Real-time, Spinning and Non-Spinning Reserves like a generator resource, but it cannot ever inject energy into the grid. PDR can only be dispatched in one direction – to reduce load.

Reliability Demand Response Resource (RDRR) is a product created to further increase demand response participation in the ISO markets by facilitating the integration of existing emergency-triggered retail demand response programs and newly configured demand response resources that have reliability triggers and desire to be dispatched only under certain system conditions. RDRR may participate in the Day-Ahead and Real-time markets like a generator resource, but may not submit *Energy Self-Schedules*, may not *Self-Provide* Ancillary services, and may not submit *Residual Unit Commitment (RUC) Availability* or Ancillary service bids.

Electricity storage can participate in the ISO markets also. A storage device could participate using the ISO's non-generating resource (NGR) participation model. The main difference of NGR compared to a generator is that the NGR can have negative output (absorbing electricity from the grid). Additionally, NGRs are ISO metered entities requiring them to comply with ISO metering and telemetry requirements. All utility interconnection requirements would need to be met which may include the need to obtain a Wholesale Distribution Access Tariff (WDAT) interconnection, similar to any other generator connected at the distribution level that participates in the wholesale market.

5.1.5 Other Markets/Services

There is a California Public Utilities Commission (CPUC) proceeding (R.15-03-011) and an ISO stakeholder initiative on Energy Storage and Distributed Energy Resources that is investigating additional markets/service for energy storage and distributed energy resources. Table 20 provides a summary of the reliability and non-reliability services that are being investigated in these proceedings.

Table 20: Storage Reliability Services and Non-Reliability Services

Domain	Reliability Services	Non-Reliability Services
Customer	None	TOU bill management; Demand charge management; Increased PV self-consumption; Back-up power
Distribution	Distribution capacity deferral; Reliability (back-tie) services[2]	Voltage support; Resiliency/microgrid/islanding
Transmission	Transmission deferral; Inertia; Primary frequency response; Voltage support; Black start	None
Wholesale Market	Frequency regulation; Spinning reserves; Non-spinning reserves	Imbalance energy
Resource Adequacy	Local capacity; Flexible capacity	System capacity

Source: (California Public Utilities Commission, 2017; House L. W., 2017 b)

It should be emphasized that there are a number of services listed in Table 20 for which there is currently no existing market (back-tie services, inertia, primary frequency response, and resiliency). For reliability services, there can be reliability impacts to the system if the resource does not follow instructions from the ISO or utility distribution company (UDC).

Groundwater bank energy storage systems could participate as either a generator or as a demand (load) in the ISO markets, but not all markets/services are available to both operations. A summary of the available and potential markets and services as applicable to groundwater pumped storage projects is provided in Table 21.

Table 21: Potential Markets and Services for Groundwater Bank Pumped Storage Operation

Market or Service	Groundwater Bank Operation	Comments
Bulk Energy Supply (day ahead, real time, retail energy shift)	Generation Load	If there is water available at elevation to run through hydroelectric generators If operating via PDR or RDRR
Frequency Regulation	Generation (currently) Load (theoretically as dedicated Demand Response)	If generation configured properly, is operating and under ISO Automatic Generation Control (AGC) If configured properly, load operating and dedicated to ISO control
Spinning Reserves	Generation Load	If generation configured properly, is operating and under ISO control If operating via PDR
Non-Spinning Reserves	Generation Load	If generation configured properly If operating via PDR
Regulation Energy Management	Generation Load (theoretically)	If configured properly and participating in ISO regulation up/down markets If configured properly and participating in ISO regulation up/down markets
Flexible Ramping	Generation Load (theoretically)	If configured properly.

Market or Service	Groundwater Bank Operation	Comments
		If configured properly and allowed to provide service
Investment Deferral	Generation Load	Generators or reduction in load that is capable of reliably and consistently reducing net loading on desired distribution infrastructure.
Reactive Power/Voltage Support	Generation Load	If configured properly and operated under ISO control Not applicable.
Resource Adequacy	Generation Load	If configured and operated properly and participates in ISO markets
Demand Response	Generation Load	Not applicable Depends upon ability to curtail/shift load
Black Start	Generation Load	Only if there is water available at elevation to run through hydroelectric generators and configured for black start. Not applicable.

Source: (House L. W., 2017 b)

A key point to remember from Table 21 is that all these markets/services have specific performance requirements which may not be compatible with groundwater banking operations. The primary purpose of groundwater storage banks is to store water and the operation of a pumped storage project cannot interfere with that water storage priority. A pumped storage addition will need to be carefully configured to provide some of these services without compromising the water bank operation. Water bank operator may be reluctant to turn operation of their facility over to the ISO in order to participate in some ancillary markets.

For example, *Resource Adequacy (RA) capacity* is classified as system, local, or flexible. The rules for system and local RA define the *qualifying capacity (QC)* of a storage resource to be the maximum discharge rate the resource can sustain for four hours[17]. If a storage resource is

17 A storage resource that can store 4 MWh of energy would typically be able to sustain a 1 MW discharge rate for 4 hours and would therefore qualify to provide 1 MW of system or local RA capacity.

counted toward a load serving entity's resource adequacy obligation, then it must participate in the wholesale market and be subject to a must-offer obligation. A must-offer obligation requires the resource to participate in the market during specific time periods and with specific rules, it is a requirement to bid or schedule the capacity into the ISO's Day-Ahead and Real-time markets in accordance with specific ISO tariff provisions, and to be able to perform to fulfill its ISO schedule or dispatch instructions. A groundwater pumped storage facility would have to maintain sufficient water in elevated storage for 4 hours of operation at all times to qualify for Resource Adequacy.

5.2 Economics Analysis Approach

The economic feasibility of pumped storage at WSWB was determined and used as a baseline to extrapolate the value of pumped storage to the groundwater banking sites around the State where pumped storage appears to be technically feasible. The potential benefits and their corresponding economic values have also been incorporated into the two pumped storage templates which can be used to evaluate the economics of pumped storage at a particular groundwater banking site.

5.3 Economic Feasibility at Willow Springs Water Bank

Pumped storage can potentially occur in all hydrological year types (Figure 10). However, for simplicity of economics analysis, it is assumed that to be compatible with groundwater banking operations, pumped storage will occur only in the idle (or neutral) year type i.e., when no recharge or extraction activities are taking place. In a wet year, the Bank will be recharging the water year-round and will be operated in the hydropower generation mode. In a dry year it will be extracting or pumping the water year-round and therefore, has the potential to provide demand response. Additionally, while the technical analysis is based on the planning documents for WSWB (GEI Consultants, Inc., 2016) which indicate an average pumping demand of 225 kW/well (300 hp/well), for economics analysis, 278 kW/well (about 375 hp/well) has been used which is a conservative estimate and includes 20% for hydrogeologic uncertainty related to drawdown.

5.3.1 Operating Scenarios

Pumped storage will supplement the hydropower generation and demand response potential of WSWB and will enable use of the Bank's facilities even in the absence of recharge and recovery activities. The benefits to the grid were assessed based on the operating scenarios which will determine whether the Bank operates as a hydroelectric generator, a pumped storage facility or as a load.

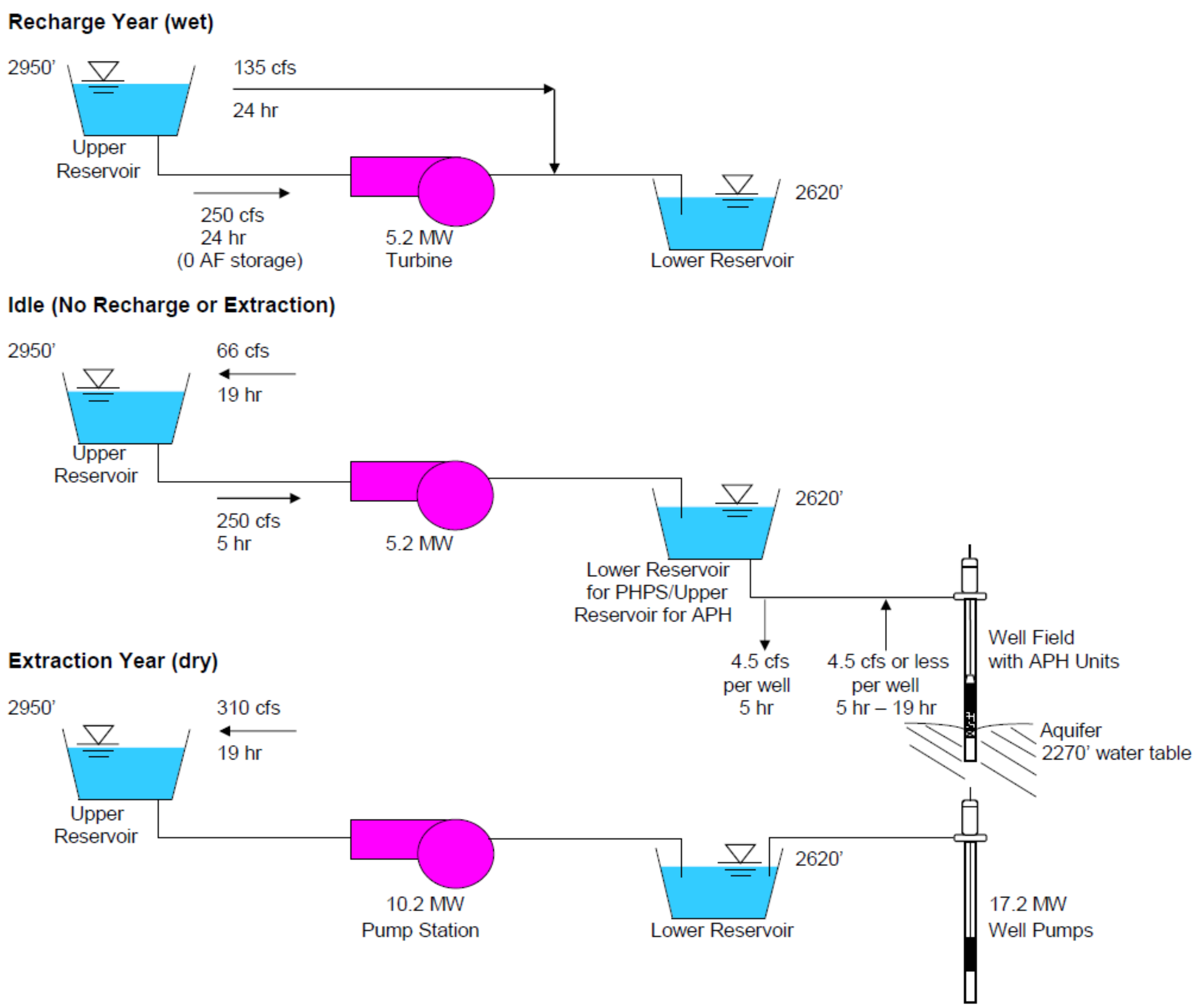
- Recharge Year (wet): A recharge year involves up to 385 cubic feet per second (cfs) of recharge. That enables a total recharge of 280,000 acre-feet per year to the water bank. 250 cfs will be used to generate electricity 24 hours a day and 135 cfs will bypass the turbine. The estimated occurrence rate is 1 year in 3 based on historical record (32%).
- Idle (Neutral) Year: An idle year does not have any predetermined recharge or extraction activity. For PHPS, 250 cfs of water will be used to generate electricity for the 5 hours

daily from the upper reservoir. The water will be replaced over the other 19 hours. For APH operation, each APH unit will use a flow rate of 4.5 cfs to generate energy for 5 hours daily from the surface reservoir. The water will be replaced over the other hours. The estimated occurrence rate is 1 year in 3 based on the historical record (33%).

- Extraction Year (dry): Withdrawals of water from the water bank will occur in a dry year. 250 cfs will be pumped back to the California Aqueduct and 60 cfs will be delivered to the Antelope Valley-East Kern Water Agency potable system for exchange or to the Aqueduct. The total extraction requirement is 310 cfs. The estimated occurrence rate is 1 year in 3 based on historical record (35%).

These operating scenarios are illustrated in Figure 16 which shows WSWB being operated to provide hydropower generation (in wet year), pumped storage (in idle year), and demand response (5 hours daily curtailment on summer weekdays in dry year).

Figure 16: Operating Configurations for WSWB by Year Type



In a neutral year, the Peak Hour Pumped Storage (PHPS) and Aquifer Pumped Hydro (APH) facilities can be operated to provide energy storage benefits. While the PHPS facilities can also be used in a wet year for hydropower generation, APH

facilities have only been evaluated for neutral year operation because using the well field for year-round generation in a wet year was found to be economically infeasible.

5.3.2 StorageVET™ Model

Water & Energy Consulting (WEC) used the Storage Value Estimation Tool (StorageVET™) to evaluate the value of the two pumped storage technologies at WSWB (House L. W., 2017 a). StorageVET™ is publicly available via the EPRI website (http://www.storagevet.com/) and allows consistent estimation of benefits and costs of various energy storage projects. Since the pumped storage function in this tool is not ready yet, the PHPS and APH technologies were modeled as a battery using the specific parameters described in the following sections. The pumped storage dispatch was simulated based upon charge ratio after ensuring that there was enough of a cost spread between on and off peak prices (off peak price/charge ratio < on peak costs). StorageVET™ does not allow a non-tax paying entity to own the storage (it allows only utility or an independent power producer (IPP) ownership) and won't produce results without depreciation, investment tax credit, and other parameters that do not apply to WSWB. Consequently, all the financial results produced by the model were ignored and only operational results were used.

5.3.3 Aquifer Pumped Hydro (APH) Economics

Aquifer Pumped Hydro at WSWB will require the addition of reversible pump turbines to existing recovery wells. Assuming the other components (such as surface reservoir) are part of the WSWB project, the only additional capital cost will result from the addition of the electrical and mechanical Package ($0.30 M/well).

Neutral year operation of APH was assessed as an energy storage project in StorageVet (Table 22), using 2015 SCE DLAP (Default Load Aggregation Point) prices. (DLAP reflects the costs SCE avoids in procuring power during the time period.) The operation was evaluated in the Bulk Energy Market (Day-Ahead Energy Market) generating when electricity prices were high, and pumping water from the ground when prices were low. It was not evaluated in either the Flexible Ramping or the Demand Response markets because participation in both these markets necessitates that the surface reservoir be full. As discussed in Chapter 2, the round-trip efficiency of APH at WSWB is so low (22%) that it was impractical to keep the surface reservoir full. This operational characteristic prevents the project from providing these additional services.

Table 22: StorageVET™ Technology Parameters Used for WSWB APH Simulation

Parameter	Value
Pumping Capacity [kW] [a]	17,236 kW
Generating Capacity [kW]	3,700 kW
Energy Storage Capacity [kWh]	18,500 kWh (3.7 MW*5 hours)
Upper Limit, Operational State of Charge [%]	100
Lower Limit, Operational State of Charge [%]	0
Pumping (Charge) Efficiency [%]	0.416
Generating (Discharge) Efficiency [%]	0.518
Max Discharge Ramp [kW / min]	1,000
Annual O&M [b]	0
Capital Cost [c]	$18.6 M

[a] Assuming power required for pump mode is 278 kW/well (Table 5).

[b] Assuming operating cost is covered by existing water bank operations.

[c] For 62 wells, the capital cost would be $18.6M to implement 3.7 MW of hydropower generation ($5,100/KW) (Table 8).

Source: (House L. W., 2017 a)

Even in the Day-Ahead Energy Market the project has limited potential for participation with the result that the APH operation virtually never runs – the round-trip efficiency is so low there is rarely enough of a daily price spread to economically pump and generate. Therefore, the Net Present Value is a large negative number (Table 23).

Table 23: Economics of APH Operation at WSWB

		Value
Benefit	**MARKET**: Day Ahead Energy	$4,044 per year
Cost	Debt Service	-$1,599,072 per year
	O&M	0
Net Present Value	(20 year, 6% discount rate)	-$18,294,846

StorageVet Simulation for APH at WSWB using 2015 SCE DLAP prices

Source: (House L. W., 2017 a)

During wet years the water bank is doing recharge around the clock. However, the well field cannot operate as a constant year-round generator during a wet year. Some of the recharge water (State Water Project (SWP) water) could potentially be injected into the ground; however, because the recharge would be by injection instead of percolation using spreading grounds, the project would need to meet additional the Regional Water Quality Control Board (RWQCB) water quality criteria. This requirement would increase the capital cost of the project and make it infeasible.

5.3.4 Peak Hour Pumped Storage (PHPS) Economics

PHPS at WSWB will require the addition of an upper reservoir and two 3.4 MW 5-jet Pelton Wheel turbines.

5.3.4.1 Neutral Year (33% probability) – Pumped Storage Mode

Neutral year operation of PHPS was assessed as a pumped storage project in StorageVet (Table 24) generating when electricity prices were high, and recharging water into the ground when prices were low (5.2 MW generation, 10.1 MW demand for pump station use).

Table 24: StorageVET™ Technology Parameters Used for WSWB PHPS Simulation

Parameter	Value
Pumping Capacity [kW]	10,124 kW
Generating Capacity [kW]	5,223 kW
Energy Storage Capacity [kWh]	26,000 kWh (5.2 MW*5 hours)
Upper Limit, Operational State of Charge [%]	100
Lower Limit, Operational State of Charge [%]	0
Pumping (Charge) Efficiency [%]	0.834
Generating (Discharge) Efficiency [%]	0.874
Max Discharge Ramp [kW / min]	1,000
Annual O&M	$100,000
Capital Cost	$7.9 M

Source: (House L. W., 2017 a)

The operation was evaluated using 2015 SCE DLAP (Default Load Aggregation Point) prices and in the Day Ahead Energy Market. Since PHPS can provide generation during the morning and evening ramp periods, and increased demand (load) during the afternoon periods to refill storage reservoirs, it was evaluated for Flexible Ramping and Demand Response markets along with Day Ahead Market (Table 25)[18].

18 Unlike APH, PHPS can be assessed in Flexible Ramping and Demand Response markets because the slow response time is not an issue with PHPS. Because the APH set-up uses the same pump/generator, when the mode is switched from pumping to generation (or vice versa), the pump has to stop, the water column in that well has to stabilize and

Table 25: WSWB PHPS Operation (Neutral Year – 33% Probability)

Market	Annual Value
Day Ahead Market (Energy)	$94,852
Flexible Ramping	$384,637
Demand Response	$384,637
Total	**$791,079**

StorageVet Simulation for PHPS neutral year at WSWB using 2015 SCE DLAP prices. Numbers are not rounded to reflect model results.

Source: (House L. W., 2017 a)

5.3.4.2 Wet Year (32% probability) – Hydropower Generation Mode

During wet years, the water bank is storing water and will recharge water into the Bank's percolation ponds for storage at a constant flow of 250 cfs. Therefore, the Bank can use PHPS facilities (the two 3.4 MW Pelton Wheel turbines) to operate as a year-round hydroelectric generator during a wet year. For this scenario, the project was evaluated as a 5.2 MW hydroelectric generator operating 24 hours a day. 2015 SCE DLAP hourly prices were used in the evaluation. Table 26 shows the annual benefit of WSWB operating as a hydroelectric generator during wet years. There is additional flexibility possible with this technology. The Bank could use the upper reservoir component of PHPS to curtail generation for 5 hours per day during the afternoon period when there is a surplus of renewable generation.

Table 26: WSWB Hydroelectric Generator Mode (Wet Year – 32% Probability)

Market	Annual Value [a]
Day Ahead Energy	**$1,386,330**

[a] **5.2 MW operating 24/7, priced at 2015 SCE DLAP prices, assuming no curtailment or load following.**

Source: (House L. W., 2017 a)

5.3.4.3 Aggregate Summary for PHPS and Hydropower generation at WSWB

PHPS at WSWB was evaluated for neutral year (Table 25). In the pumped storage configuration, depending on the time of day, the Bank will serve as a load or a generator. PHPS facilities can also be used to generate electricity year-round during a wet year (Table 26) and in this scenario, the Bank will function as a hydropower generator. Table 27 provides a probability weighted

then reverse direction, and the generator has to start (or vice versa). This has to happen with 62 different wells to get the full benefit. For PHPS, the pump stops and the generator can start instantly (or vice versa) since they are different units and using different water columns and there are a few pumps and just a couple of generators. Additionally, the flow of water in the aquifer has to stop, stabilize, and then reverse when the operation is switched from pumping to generating or vice versa. The low transmissivity of the aquifer results in a longer aquifer response i.e. the aquifer takes longer to move from drawdown during pumping back to equilibrium, and from mounding during injection back to equilibrium. Also, in PHPS, surface storage is used for both upper and lower reservoirs and the reservoir (pond) can instantly switch from rising to dropping (or vice versa) since the water is "pushing" against air rather than interstitial spaces in the aquifer.

summary of the cost effectiveness of integrating PHPS and hydropower generation to the existing WSWB configuration. The cost of the necessary enhancements to the existing WSWB to develop a PHPS project is estimated at $7.9 million. The NPV (net present value) of the probability weighted operation of this facility is a negative $0.99 million for a 20-year investment horizon[19].

Table 27: Cost effectiveness of PHPS and Hydropower Generation at WSWB

Year Type	Probability	Operated As	Annual Value
Wet	32%	Generator	$1,386,330
Neutral	33%	Pumped Storage [a]	$791,079
Probability Weighted Annual Benefit			$704,682
Annual O&M			-$100,000
Annual Debt Service ($7.9M at 6% for 20 years)			-$691,243
Annual Net Benefit			-$86,561
NPV of PHPS and Hydropower Generation			**-$992,853**

[a] **Cost-Effectiveness evaluation based on standard protocol (DNV-GL Energy and Sustainability, 2013).**

Source: (House L. W., 2017 a)

5.3.5 Dry Year (35% probability) – Demand Response

Demand response (DR) is the ability to reduce or vary electricity use when needed. This is possible at WSWB in an extraction or dry year and will reduce load during the late afternoon ramping period and evening peak. In a dry year WSWB will extract water and pump it to the California Aqueduct. This year was evaluated for demand response (curtailing electricity use in response to system needs). The electricity demand is continuous from groundwater pumping (17.2 MW) plus power for the pump station (10.1 MW). Therefore, the project was evaluated as a 27.3 MW continuous year-round load operating 24 hours a day, with the ability to be curtailed up to 5 hours per day for up to 320 hours per year.

Pumps at the pumping plant could be shut off for 5 hours a day during years that water is being pumped back to the California Aqueduct. The demand response potential of the pumping plant corresponds to the size of the pumps, or 10.1 MW. It can be realized by shutting down the pumping to the Aqueduct for 5 hours a day. In addition, the 62 extraction wells (17.2 MW) could be curtailed for those 5 hours also. To provide for this level of demand response two additional extraction wells would need to be added to make up for the 320 hours annual pumping curtailment[20].

19 Assuming no escalation in annual benefits, a 20-year horizon, and a 6% discount rate.

20 Additional curtailment would require the addition of additional extraction wells.

The project was evaluated for demand response using values from 2025 California Demand Response Potential Study (Lawrence Berkeley National Laboratory, 2017). This study recognizes three primary types of demand response: Shift, Shed, and Shimmy (Table 28).

Table 28: Types of Demand Response

Service Type	Description	Grid Service Products/Related Terms
Shift	Demand timing shift (day-to-day)	Flexible ramping DR (avoid/reduce ramps), Energy market price smoothing
Shed	Peak load curtailment (occasional)	CAISO Proxy Demand Resources/Reliability DR Resources; Conventional DR, Local Capacity DR, Distribution System DR, RA Capacity, Operating Reserves
Shimmy	Fast demand response	Regulation, load following, ancillary services

Source: (Lawrence Berkeley National Laboratory, 2017)

The Shift service type is demand response that moves load to desired times during the day, increasing energy consumption during periods of the day when there is surplus generation, and reducing consumption during periods of the day when there is excess load.

The Shed service type describes loads that can occasionally be curtailed to reduce customer demand during peak net load hours.

The Shimmy service type involves using loads to dynamically adjust demand on the system to alleviate ramps and disturbances at timescales ranging from seconds up to an hour.

Table 29 shows the annual benefit of WSWB providing demand response services during a dry year.

Table 29: WSWB Operated as a Continuous Load (Dry Year – 35% Probability)

Demand Response Service	Market Value (low)	Market Value (high)	Unit	WSWB Annual Value (low)	WSWB Annual Value (high)
Shed	$4	$4	$/kW-year	$109,200	$109,200
Shift	$20	$52	$/MWh	$174,720	$454,272
Shimmy – load following	$35	$45	$/kW-year	$955,500	$1,228,500
Shimmy – regulation	$57	$98	$/kW-year	$1,556,100	$2,675,400
			Total	$2,795,520	$4,467,372

WSWB dry year demand response simulation assumes availability of up to 5 hours of daily curtailment; 27.3 MW curtailable up to 320 hours per year.

Source: (House L. W., 2017 a)

5.3.5.1 Adding dry year demand response to APH and PHPS

To complete operations analysis for all three year types, dry year demand response was added to APH and PHPS (Table 30). Adding dry year demand response to neutral year PHPS and wet year hydropower generation modes increases their NPV to almost $8 million, but is still not enough to make APH cost effective. A summary of the operational modes for APH and PHPS facilities and their corresponding services is given in Table 30.

Table 30: Comparison of WSWB APH and PHPS Characteristics and Analysis

	WSWB Aquifer Pumped Hydro (APH)	WSWB Peak Hour Pumped Storage (PHPS)	Demand Response
Components needed	Reversible pump-turbines, surface storage reservoir, aquifer is lower reservoir	Hydroelectric generator, upper and lower surface reservoirs	2 additional groundwater wells for 320 hours curtailment
Pumping Capacity	17.2 MW	10.1 MW	27.3 MW
Generating Capacity	3.7 MW	5.2 MW	
Energy Storage (5 hours of generation)	18.5 MWH	26.0 MWH	Curtailable up to 320 hours per year
Pumping Efficiency	41.5%	83.4%	
Generating Efficiency	51.7%	87.4%	

	WSWB Aquifer Pumped Hydro (APH)	WSWB Peak Hour Pumped Storage (PHPS)	Demand Response
Round Trip Efficiency	21.6%	72.9%	
Capital Cost	$18.6M	$7.9M	$2.1M
Net Present Value (@6%, 20 years)	-$18.2M (generator operating in neutral years)	-$0.9M (generator operating during wet and neutral year)	$9.1M (dry year)
Capital Cost with Dry Year Demand Response	$20.3M	$10M	
Net Present Value (@6%, 20 years) with dry year demand response	-$9.1M	$8.1M	
Markets/Services:			
Day Ahead Hourly Market	Yes	Yes	
Flexible Ramping	No, response time too slow, operational parameters preclude this.	Yes	
Demand Response	Yes	Yes	
Real Time Energy Time Shift	No	No	
Retail Energy Time Shift	No, lack of load on site	No, lack of load on site	
Frequency Regulation	No, not configured for, wish to maintain local control of operations	No, not configured for, wish to maintain local control of operations	
Spinning Reserve	No, not configured for, wish to maintain local control of operations	No, not configured for, wish to maintain local control of operations	
Non-Spinning Reserve	No, not configured for, wish to maintain local control of operations	No, not configured for, wish to maintain local control of operations	
Regulation Energy Management (REM)	No, not configured for, wish to maintain local control of operations	No, not configured for, wish to maintain local control of operations	
Investment Deferral	No. Area of WSWB is an unconstrained SCE area	No. Area of WSWB is an unconstrained SCE area	
Reactive Power/Voltage Support	No, not configured for, wish to maintain local control of operations	No, not configured for, wish to maintain local control of operations	

	WSWB Aquifer Pumped Hydro (APH)	WSWB Peak Hour Pumped Storage (PHPS)	Demand Response
Resource Adequacy Capacity (RA)	No, expected operations preclude	No, expected operations preclude	
Black Start	No, not configured for	No, not configured for	

Source: (Water & Energy Consulting, 2017a)

As Table 30 shows, there are a multitude of ancillary services that could be possible using the PHPS and APH facilities – if they were configured properly and if the water bank was willing to turn over operational control of the facilities to the Independent System Operation (Frequency Regulation, Spinning Reserve, Non-Spinning Reserve, Regulation Energy Management [REM], Reactive Power/Voltage Support, and Black Start require the generation facilities to be under ISO control). WSWB's primary purpose is as a water storage facility and the Bank is therefore reluctant to invest in the additional facilities necessary to perform these services or turn over operation of the water bank to the ISO in order to participate in many of these markets. Therefore, the ancillary services options for WSWB were limited.

5.4 Economic Evaluation for Statewide Pumped Storage at Groundwater Banks

Pumped storage additions to existing groundwater banking facilities have the potential to provide electrical grid benefits from 1) generation of electricity during period of high system demand; 2) increase in pumping demand (load) during renewable overgeneration periods to reduce the risk of overgeneration; 3) reduction of load during high system ramping requirements and system demand; and 4) delivery of a plethora of ancillary services, depending upon the configuration of the groundwater bank and its ability to cede operational control to the ISO. Assuming that WSWB operations are typical of most groundwater banking projects, the operating configurations and their associated costs and values identified for WSWB can be used to evaluate economic feasibility of pumped storage, hydropower generation, and demand response benefits at groundwater banks around the State.

5.4.1 Potential Markets and Services

As discussed in the preceding sections, a groundwater bank's facilities (including additional pumped storage facilities) can be configured to operate in different modes to participate in markets applicable to pumped storage, hydropower generation and demand response. A summary of the characteristics of these markets/services is provided in Table 31.

Table 31: Potential Markets for Groundwater Bank Energy Operations

Market/Service	Definition	Time Period	Applicable to Groundwater Bank Pumped Storage Facilities	WSWB APH Simulation	WSWB PHPS Simulation
Day Ahead Energy Time Shift	Hourly market energy prices established for the next day. Based upon unit commitment on the day prior to the actual operating day.	Hour	In both generating and pumping mode.	Yes	Yes
Real Time Energy Time Shift	The real-time market is a spot market in which utilities can buy power to meet the last few increments of demand not covered in their day ahead schedules.	15-minute procurement, 1 hour continuous requirement	In both generating and pumping mode.	No	Yes
Retail Energy Time Shift	Hourly energy and demand prices based upon utility retail tariffs.	Hour	If significant on-site electricity use	No	No
Frequency Regulation	Maintaining the grid frequency within the given margins by continuous modulation of active power. Capacity that follows (in both the positive and negative direction) a 4-second ISO power signal.	Seconds	Have to be operating and have special generation configuration for rapid response.	No	No
Spinning Reserve	Spinning reserve is standby capacity from generation units already connected or synchronized to the grid and that can deliver their energy in 10 minutes when dispatched. Dispatched within 10 minutes in response to system contingency events. Must be frequency responsive and be able to run for 2 hours.	10 minutes	If generation configured properly, and operating, could be provided in generating mode.	No	No
Non-Spinning Reserve	Non-spinning reserve is Off-line Generation Resource capacity	10 minutes	If generation configured properly, and	No	No

Market/Service	Definition	Time Period	Applicable to Groundwater Bank Pumped Storage Facilities	WSWB APH Simulation	WSWB PHPS Simulation
	that can be synchronized to the grid and ramped to a specified load within 10 minutes and run for at least 2 hours.		operating, could be provided in generating mode		
Regulation Energy Management (REM)	Regulation energy is used to control system frequency, which must be maintained very narrowly around 60 hertz. Composed of regulation up (increased generation) and regulation down (decreased generation). Capacity that follows (in both the positive and negative direction) a 4-second ISO power signal. It requires 1 -hour of continuous response. Capacity is limited by the resource's 5-minute ramp.	5-10 minute, must be available for 60 minutes	Have to be operating and include equipment necessary to follow regulation signal.	No	No
Flexible Ramping	The ability to change generation (ramp) in response to system needs. Requires participation in market with bids and 3-hour continuance response capability.	5 minutes	Depends upon pump and generator characteristics	No, response time too slow	Yes
Investment Deferral	The ability to defer additional investment in distribution system, substations, or transmission lines. Resource capable of reliably and consistently reducing net loading on desired infrastructure.	Year	Depends upon location of groundwater bank	No. Area of WSWB is an unconstrained SCE area	No. Area of WSWB is an unconstrained SCE area
Reactive Power/Voltage Support	The injection or absorption of reactive power to maintain transmission system	Seconds	If generation configured properly	No	No

Market/Service	Definition	Time Period	Applicable to Groundwater Bank Pumped Storage Facilities	WSWB APH Simulation	WSWB PHPS Simulation
	voltages within required ranges. Resource capable of dynamically correcting excursions outside voltage limits as well as supporting conservation voltage reduction strategies in coordination with utility voltage/reactive power control systems.				
Resource Adequacy Capacity (RA)	Assurance that there is adequate physical capacity in existence to serve likely peak load and the ability of the ISO to call on it to perform when needed for system reliability. Must provide net qualifying capacity (NQC) for 4 hours over 3 consecutive days up to a total of 24 hours per month. The resource must bid into the ISO day-ahead and real-time markets.	Hour	For flexible capacity, and be 2 hours charging and 2 hours discharging.	No	No
Demand Response	Demand response is a change in the power consumption of an electric utility customer in response to utility system needs (typically a reduction in customer demand)	Hour	In both generating and pumping mode.	Yes, if additional extraction wells added.	Yes, if additional extraction wells added.
Black Start	Generation able to start itself without support from the grid and with sufficient real and reactive capability and control to be useful in system restoration.	Minutes	If water stored at elevation, and generation configured appropriately.	No	No

Source: (House L. W., 2017 b)

5.4.2 Statewide Potential from Adding Pumped Storage to Groundwater Banks

Technical feasibility analysis detailed in Chapter 4 indicates that the statewide PHPS potential is 44 MW and statewide demand response potential associated with existing well pumps at groundwater banks is 220 MW.

Groundwater storage projects can have a variety of configurations, depending upon sources of water, the configuration of the underground storage basin, method of getting water underground (either passive via recharge basins that let the water percolate into the ground or, less frequently, active injection of water into the ground). While all groundwater banks may not have enough topographical variation to support hydroelectric generation, they all have one thing in common, an electricity demand when they are extracting the water from underground for delivery to customers. And, depending upon their delivery requirements, they may have the ability to vary that pumping load to accommodate electrical system needs.

Table 32 provides an estimate of the statewide potential for pumped storage, hydropower generation using PHPS facilities, and demand response at groundwater banks. The annual net benefit, and the expected capital cost was extrapolated from WSWB specific analysis.

Table 32: Statewide Potential, Benefits, and Costs of Pumped Storage at Groundwater Banks

Type	MW potential	Annual Net Benefit	Facilities Needed	Capital Cost	NPV per kW[1]
Peak Hour Pumped Storage (PHPS) Facilities – generation, pumped storage	44 MW	$-44K[2]	Upper and lower surface storage reservoirs, connecting piping, hydroelectric generators and controls, utility interconnection	$66.8M ($1,518/kW)[3]	-$190/kW
Aquifer Pumped Hydro (APH) Facilities – pumped storage	Impractical	-$431/kW	Surface storage reservoir, reversible pump turbines and controls, connecting piping, utility interconnection	($5,000/kW)[4]	-$4,945/kW
Flexible Load (Demand Response)	220 MW	$6.3M ($28.64/kW)[5]	Surface storage reservoirs, existing and additional extraction wells	$18M ($82/kW)[6]	$332/kW

[1]Assuming a 20-year life and a 6% interest rate. Based upon generating capacity for pumped storage and hydropower generation, and curtailed capacity for demand response.

[2]The probability weighted annual net benefit for WSWB PHPS facility generation was -$17/kW.

[3]The capital cost of WSWB PHPS facilities was $1,518/kW

[4]The capital cost of WSWB APH was $5,000/kW.

[5]The annual net benefit for demand response for WSWB was $29/kW.

[6]The capital cost of adding a 5 hours' surface storage reservoir (to provide 320 hours/year curtailment) and additional extraction wells was $82/kW (cost for extra wells was $78.1/KW and cost for reservoir was $3.9/kW for a total of $82/kW).

Source: (House L. W., 2017 b)

Demand Response (DR) is a very cost effective investment with an annual statewide benefit of $6.3 M. Aquifer Pumped Hydro (APH) never pays for itself, due to high capital cost, low round trip efficiencies, and limited operating flexibilities. PHPS is cost effective, if operated with dry year demand response. Assuming statewide PHPS projects have similar characteristics as the WSWB PHPS facility, the 44 MW PHPS statewide potential (providing pumped storage in neutral years and hydropower generation in wet years) would have an annual net benefit of $5.9 M if evaluated with onsite dry year demand response (House L. W., 2017 b).

Therefore groundwater banks can make a valuable contribution to demand response and energy storage, but have unique operating characteristics that the current DR and energy storage programs do not either recognize or allow.

- Current DR programs only allow shedding of load. They do not recognize or pay for shift – flexible ramping, or shimmy – load following or regulation. Current storage programs focus on shifting load and generation. DR programs need to be adjusted to recognize and pay for shift – flexible ramping and shimmy – load following and regulation. CPUC proceeding A1701012 (demand response) and R.15.03.011 (energy storage) and ISO shareholder initiative, energy storage and distributed energy resources phase 2, are the regulatory proceedings that are addressing changes in the demand response programs and energy storage programs.
- Participation in both the programs requires consistent operation year after year. Operational configuration of groundwater banks varies based upon the hydrologic year type. The water banks typically base their operating mode on the April DWR snow survey. Current DR and energy storage programs therefore need to be modified to allow annual changes in operational characteristics.

It must be noted that APH economic analysis is constrained by the fact that only general qualitative conclusions could be drawn about statewide APH potential. Additionally, while WSWB operations are typical of a groundwater banking project, variability in site specific parameters such as transmissivity can substantially affect the generation potential, round-trip efficiency, and hence economic feasibility of a particular APH facility. Therefore, the above analysis only provides a preliminary, conceptual estimate of the economic feasibility of statewide APH potential and is likely an underestimate. A more advanced estimate would require pilot testing and addressing of information gaps. The objective of using WSWB analysis as the basis for drawing conclusions about statewide potential is to provide insights about the comparative performance of each technology in various hydrological year types and about the parameters that affect their implementation. The key takeaway is that groundwater banking projects, in general, are likely to find a PHPS facility coupled with demand response more economically viable than an APH one with or without demand response.

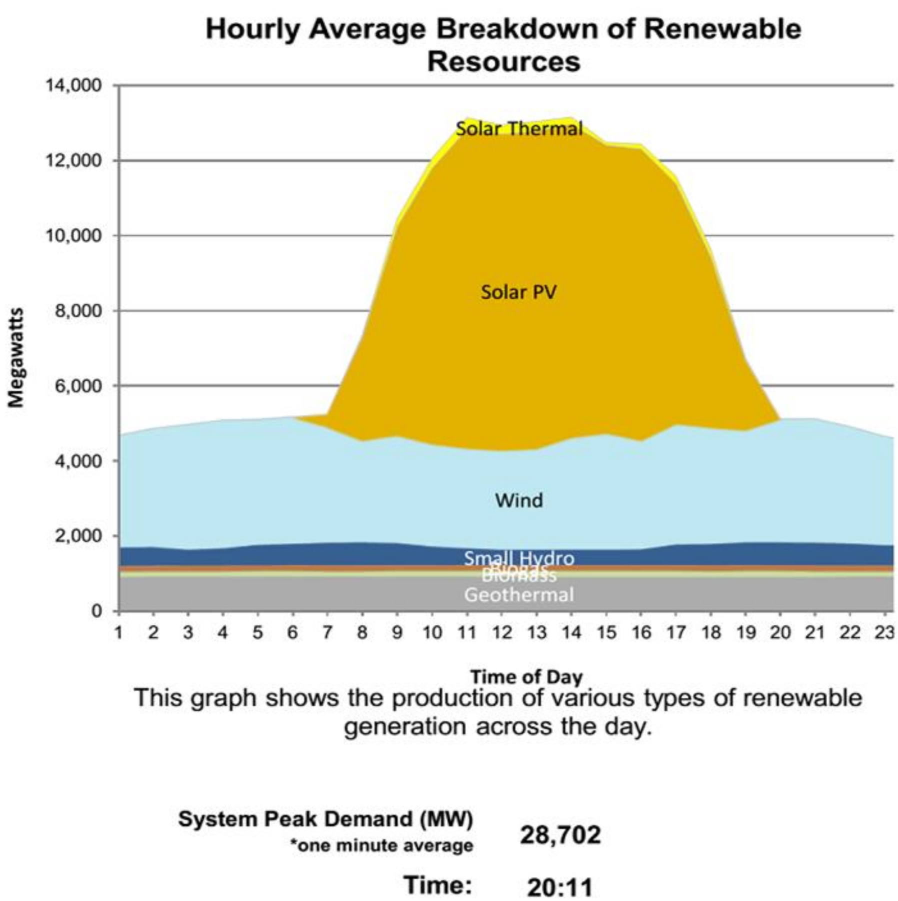
CHAPTER 6: Project Benefits

Pumped storage at groundwater banks will provide benefits to the electrical grid. Facilities used for pumped storage can also be used for hydropower generation and demand response. This section discusses the benefits associated with each of these operating configurations.

6.1 Addressing the Duck Curve Problem

The pumped storage facilities at groundwater banks could assist in addressing "duck curve" operation issues in all hydrologic year types. California is experiencing an abundance of renewable generation, and this is causing system operating issues. As illustrated in Figure 17, there is a huge amount of solar generation occurring during the afternoon hours.

Figure 17: Renewable Energy Generation, April 27, 2017



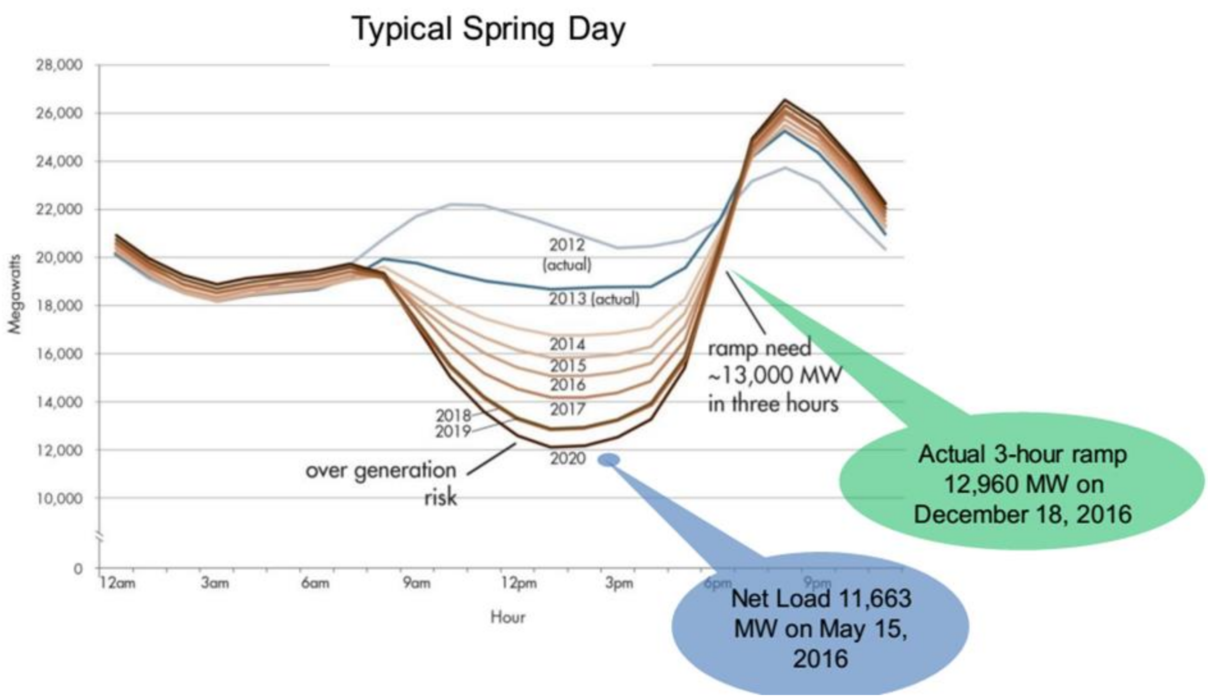
California ISO data for April 27, 2017

Source: (House L. W., 2017 b)

This overabundance of solar generation during afternoon hours has resulting in the operating phenomenon known as the "duck curve", so named by California ISO staff due to its resemblance to the bird profile (Figure 18).

The ISO "duck curve" is the net generation load – generation requirements after renewable generation has been subtracted out. Figure 18 illustrates the operational issues facing California: specifically, an overabundance of renewable generation during the afternoon hours, a very steep ramping requirement during the late afternoon, and a peak generation requirement during the evening. The "duck curve" is forecasted to only get worse as California installs more and more renewable generation.

Figure 18: California ISO "Duck Curve"



Source: (California ISO; National Renewable Energy Laboratory; First Solar)

A number of methods have been proposed for coping with an increasing "duck curve", including:

- Exploiting regional diversity in generation resources and demand
- Installing more dispatchable generation
- Adding more energy storage
- Increased demand management:
    - Time-of-use pricing (TOU) and real-time pricing
    - Increased demand response
    - Smart grid technology

Onsite pumped storage facilities at WSWB illustrate how these facilities can be employed in various configurations and hydrologic years to mitigate the duck curve problem. WSWB is an example of a typical groundwater banking operation and the benefits can be duplicated at other groundwater banks that have pumped storage potential.

6.1.1 Wet Hydrologic Year

During a wet hydrologic year, the WSWB can operate as a hydroelectric generator. As illustrated in Figure 19, the Bank's operations can be configured to curtail generation for 5 hours per day, ideally during the afternoon renewable generation overproduction period. This would assist with the "belly" of the "duck curve", the period of renewable energy overgeneration.

Figure 19: WSWB PHPS Hypothetical Operation During Wet Year

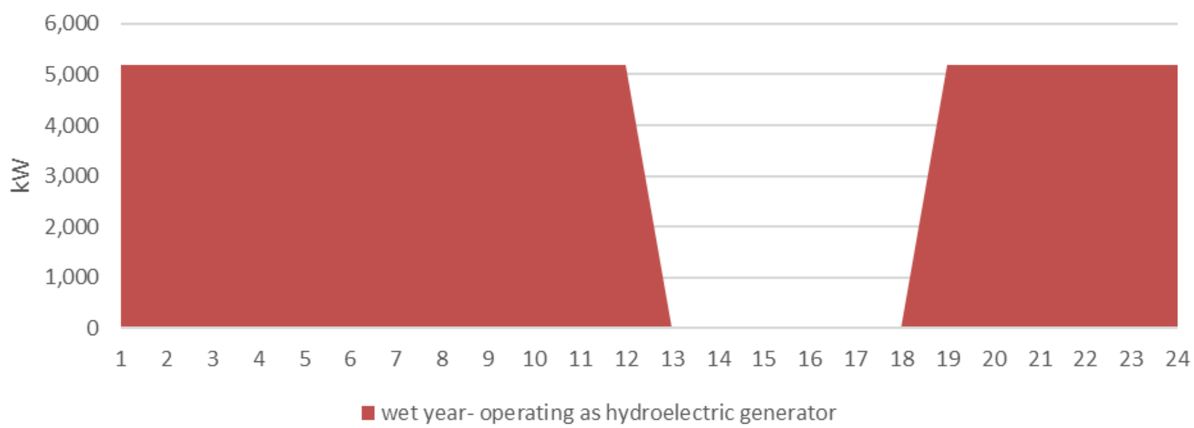


Figure 19 shows WSWB PHPS facility operating as generator

Source: (House L. W., 2017 b)

6.1.2 Neutral Hydrologic Year

During a neutral hydrologic year, the WSWB can operate as a pumped storage facility. Figure 20 shows the PHPS operation, from the StorageVet simulation based upon Day Ahead market prices. PHPS provides generation during the morning and evening ramp periods, and increased demand (load) during the afternoon renewable overproduction periods to refill storage reservoirs.

Figure 20: WSWB PHPS Hypothetical Operation During Neutral Year

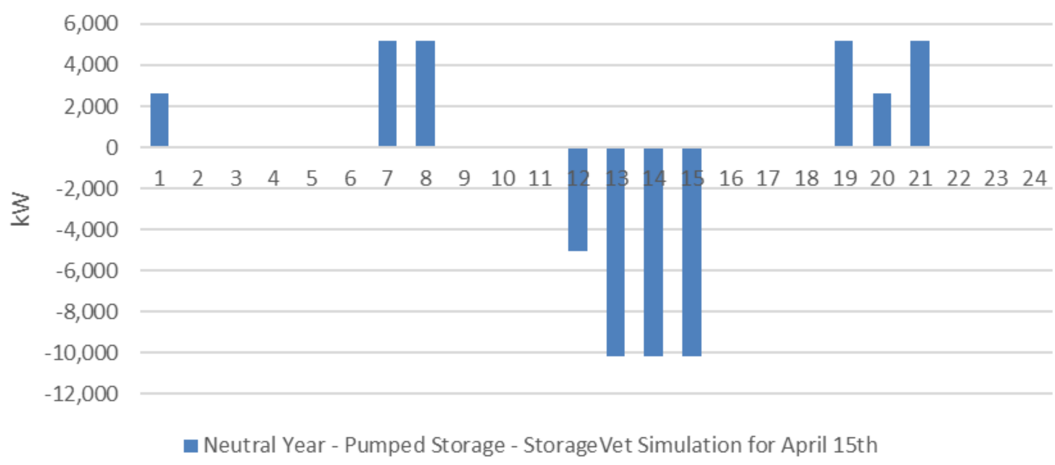


Figure 20 shows WSWB PHPS facility operating as pumped storage

Source: (House L. W., 2017 b)

6.1.3 Dry Hydrologic Year

During a dry hydrologic year, the WSWB operates as a load (pumping water out of the ground and delivering it to California Aqueduct) and could be configured to accommodate 5 hours of curtailment if necessary. Figure 21 shows hypothetical WSWB operation during this period, using the surface reservoirs. WSWB can be configured to reduce load during the late afternoon ramping period and evening peak.

Figure 21: WSWB Hypothetical Operation During Dry Year

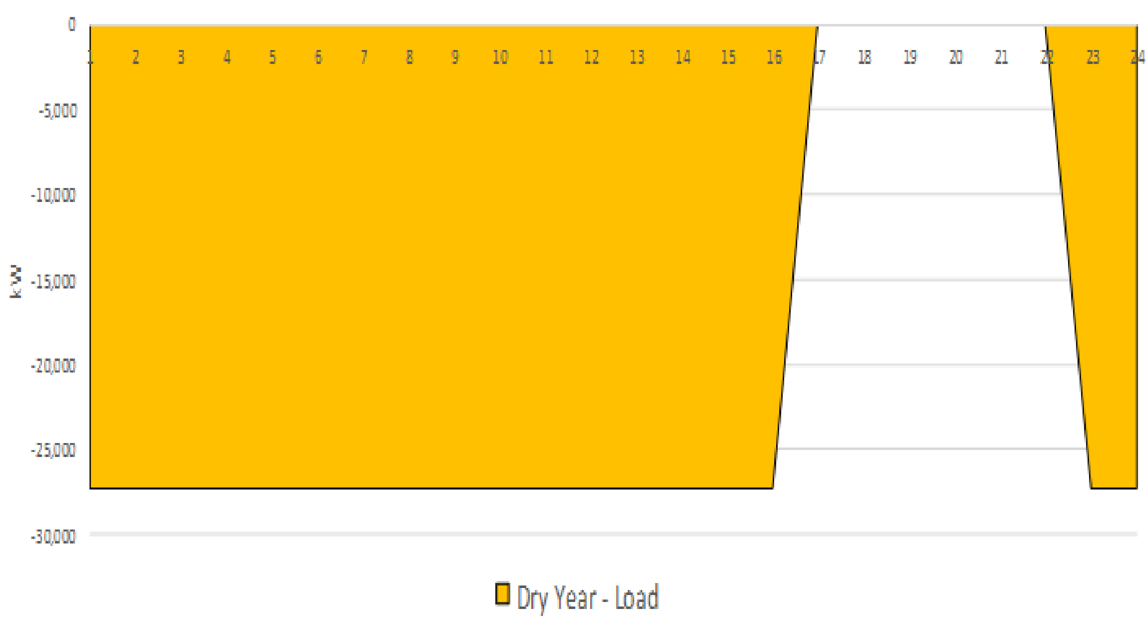


Figure 21 shows demand response operations at WSWB

Source: (House L. W., 2017 b)

6.2 Greenhouse Gas (GHG) Emissions Reduction

Peak Hour Pumped Storage (PHPS) facilities will benefit the environment because they can potentially be used regardless of the hydrological year type and can reduce the need for fossil fuel based power plants, thereby resulting in greenhouse gas emissions reduction (Table 33).

Table 33: Annual GHG Emissions Reduction from PHPS at Groundwater Banks

Statewide PHPS potential at groundwater Banks (MW)	kWh generated by natural gas based peaker plants	Heat Rate (therm/kWh) for natural gas fired peaker plants	kWh generated by pumped storage at groundwater banks*	Therm reduced	Metric tons of CO_2e GHG reductions**
44	3310*10^6	0.1027	80,300,000	8,250,000	44,000

For Table 33 only Peak Hour Pumped Storage (PHPS) potential was considered since Aquifer Pumped Hydro (APH) is impractical for large scale deployment.

*** Assuming statewide implementation of PHPS for 5 hours daily over 365 days.**

****To provide a conservative estimate of GHG Emissions reduction, the analysis has been restricted to an idle or neutral year when no recharge activities are taking place. The annual GHG reductions will be more in a wet or recharge year since pumped storage can be supplemented or replaced with hydropower generation that can potentially occur up to 24 hours a day year-round in a wet year. The GHG reductions may be less in a dry or extraction year depending on how much capacity is available to implement pumped storage.**

Sources:

KWh generated by Peaker Plants (Table 2 page 3 (Nyberg, 2014))

therm/kWh converted from Heat Rate (Btu/kWh) (Table 2 page 3 (Nyberg, 2014))

Emissions Factor(CO_2e) for Gas: 0.0053 metric tons/therm (Table 3 (California Energy Commission, 2015 a))

CHAPTER 7: Results and Conclusions

Energy storage shifts the renewable energy from the belly (excess) to the head (shortage) of the 'duck curve' thereby supplying the electric grid when the generation requirements ramp up and peak. Pumped storage at groundwater banks has the potential to provide 44 MW of storage capacity in California. Assuming the State needs 6000 MW of storage to meet the 50% renewable penetration goal by 2030, implementing pumped storage at groundwater banking projects can meet up to 1% of the State's storage needs and provide additional benefits in the form of demand response and year-round hydropower generation.

The analysis shows that based on the hydrological year type, a typical groundwater banking operation can use pumped storage facilities to provide hydropower generation and demand response services besides pumped storage. Additionally, a pumped storage operating configuration permits participation in multiple markets. Therefore, the Bank operating in the PHPS mode in a neutral year can participate in flexible ramping and demand response markets as well as in the Day Ahead Market. It is of interest to note that the traditional way for evaluating pumped storage – using Day-Ahead energy market prices and generating when prices are high and extracting water when prices are low, is the least valuable of the services evaluated. In a dry year, the Bank can participate in the demand response market to provide various types of demand response. This demand response potential has the greatest value and configuring the operations to provide demand response in a dry year also enhances the economic feasibility of pumped storage and hydropower generation operations in neutral and wet years respectively. Demand response will be online in 1/3 years and incorporating PHPS at a groundwater banking project can provide revenue during the remaining 2/3 of the years when Demand response is offline.

The technical, operational and economic analyses show that Aquifer Pumped Hydro (APH) technology can have significant round-trip losses that will make it economically non-viable for groundwater banking regions that have transmissivities at the low end of the typical range. ASR projects overlying highly transmissive soils and which use injection wells to recharge water may have the potential to generate energy during recharge activities. The decision on installing a generator in an injection well is not clear-cut and will have to be determined on a case by case basis since the associated capital costs can be prohibitive. For the agencies that are not already injecting treated recycled water, the increased costs to treat the water before it can be injected and other regulatory costs are likely to make it economically infeasible to pursue well field generation in a wet year. Therefore, an APH facility setup can have significant efficiency constraints that will generally make the technology less viable than PHPS though individual site characteristics will determine which (if any) technology is more feasible at a particular groundwater banking site. The APH and PHPS templates developed as part of this study can be used by existing and planned groundwater banking operations to determine the potential of either or both pumped storage systems at a particular site. More studies are needed to address the knowledge gaps related to statewide pumped storage potential at groundwater banks and to move the technology towards implementation. An important next step in this process is a pilot or field test. The evaluation templates and the groundwater banks database created for this project provide a good starting point to identify candidate sites for in-depth evaluation and testing of either or both of the systems.

GLOSSARY

Term	Definition
ASR (Aquifer Storage and Recovery) project	A type of groundwater banking project that uses injection wells to inject water underground for storage when water is available and later recovers the water from the same well.
cloud data	Cloud data refers to data accessed, managed and transmitted through the cloud. The cloud refers to a network of servers that enable a user to access a range of storage and applications services remotely via the Internet.
CO_2e (carbon dioxide equivalent)	Carbon dioxide equivalent is the standard unit to measure and compare the emissions from various greenhouse gases based upon their global warming potential. The global warming potential of each different greenhouse gas is expressed in terms of the amount of carbon dioxide that would cause the same amount of global warming.
demand response	Demand response is the change in electricity consumption in response to the electric grid needs, electric rates and/or incentives.
EPIC (Electric Program Investment Charge)	The Electric Program Investment Charge, created by the California Public Utilities Commission in December 2011, supports investments in clean energy technologies that benefit electricity ratepayers of Pacific Gas and Electric Company, Southern California Edison Company, and San Diego Gas & Electric Company.
hydrologic year type	Three hydrologic year types are used in this study: “wet” is the California Department of Water Resources (DWR) definition of a wet year; “neutral” is above normal and below nomal year types, and “dry” is the DWR defined dry and critical hydrologic year types based on Sacramento River data since 1906 (DWR, 2017).
Supervisory Control and Data Acquisition (SCADA)	A system often used in water, energy, and other industries for controlling equipment operations and gathering real time data remotely.
T (Transmissivity)	Transmissivity is the rate of horizontal flow of groundwater through an aquifer (underground water-bearing rock or soil).
Water bank or Groundwater bank	An underground storage facility used for banking or storing water. Stored water can be recycled, imported or surface water.

REFERENCES

Allen, R., Doherty, T., & Kannberg, L. (1984). *Underground Pumped Hydroelectric Storage.*

Antelope Valley Water Storage (AVWS). (2015, December). Attachment 4-Project Narrative Form. *Proposal "Groundwater Bank Energy Storage Systems - A Feasibility Study" for California Energy Commission GFO-15-309: Reduce the Environmental and Public Health Impacts of Electrical Generation.*

Antelope Valley Water Storage (AVWS). (2016, October 12). Memorandum "List of CA Groundwater Banking Projects".

Antelope Valley Water Storage (AVWS) LLC. (2016). *Memorandum- Aquifer Pumped Hydro:Impact of Draw-Down/Mounding Losses on System Efficiency.*

Association of California Water Agencies (ACWA). (2017, April 21). Surplus Solar Energy Brings Pricing Changes to Water Agencies. *ACWA News, 45*(4). Retrieved August 3, 2017, from https://issuu.com/acwa/docs/an_vol45_no3_apr_17

Blomquist, C. A., Frigo, A. A., & Degnan, J. R. (1979). *Evaluation of Advanced Hydraulic Turbomachinery for Underground Pumped Hydroelectric Storage. Part 2. Two-Stage Regulated Pump /Turbines for Operating Heads of 1000 to 1500M.*

Blomquist, C., Frigo, A., Tam, S., & Clinch, J. (1979). *Underground Pumped Hydroelectric Storage (UPHS).* Program Report.

Braat, K., van Lohuizen, H., & de Haan, J. (1985). *Underground Pumped Hydro-Storage Project for the Netherlands.*

Budris, A. (2014, June). How to Reduce Municipal Electric Bills by Using Existing Water Towers and Aquifer Well Pumps to Store Energy for Peak Demand Periods, in Pump Tips & Techniques Column. *WATERWORLD.*

Burt, C., Howes, D., & Wilson, G. (2003). *California Agricultural Water Electrical Energy Requirements.* Retrieved April 7, 2017, from http://agwaterstewards.org/wp-content/uploads/2016/08/EnergyReqs.PDF

California Department of Water Resources. (2013). *California Water Plan Update South Coast Hydrologic Region.* Retrieved April 21, 2017, from http://www.water.ca.gov/waterplan/docs/cwpu2013/Final/Vol2_SouthCoastRR.pdf

California Department of Water Resources. (April 1981). *Bulletin 211 Small Hydroelectric Potential at Existing Hydraulic Structures in California.* Retrieved from http://www.water.ca.gov/waterdatalibrary/docs/historic/Bulletins/Bulletin_211/Bulletin_211__1981.pdf

California Energy Commission. (2005). *California's Water-Energy Relationship Final Staff Report.* Retrieved April 21, 2017, from http://www.energy.ca.gov/2005publications/CEC-700-2005-011/CEC-700-2005-011-SF.PDF

California Energy Commission. (2015 a, October). Attachment 12 References for Energy End-Use, Electricity Demand and GHG Emissions Reference and Calculations. *GFO-15-309 Reduce the Environmental and Public Health Impacts of Electrical Generation*.

California Energy Commission. (2015). *Public Interest Energy Research 2014 Annual Report.* Retrieved April 21, 2017, from http://www.energy.ca.gov/2015publications/CEC-500-2015-009/CEC-500-2015-009-CMF.pdf

California ISO. (2014). *Advancing and Maximizing the Value of Energy Storage Technology – A California Roadmap.*

California ISO. (n.d.). *Market processes and products*. Retrieved from California ISO: https://www.caiso.com/market/Pages/MarketProcesses.aspx

California ISO; National Renewable Energy Laboratory; First Solar. (n.d.). *Using Renewables to Operate a Low-Carbon Grid: Demonstration of Advanced Reliability Services from a Utility-Scale Solar PV Plant.* Retrieved from http://www.caiso.com/Documents/UsingRenewablesToOperateLow-CarbonGrid.pdf

California Public Utilities Commission (CPUC). (2015). *Beyond 33% Renewables: Grid Integration Policy for a Low-Carbon Future.* A CPUC Staff White Paper.

California Public Utilities Commission. (2017). *R.15-03-011, Joint Workshop Report and Framework Multiple-Use Applications for Energy Storage CPUC Rulemaking 15-03-011 and CAISO ESDER 2 Stakeholder Initiative.*

Chang, G., Thompson, P., Allen, R., Ferreira, A., & Blomquist, C. (1980). *Pumped-Storage Hydroelectric Plants with Underground Lower Reservoirs.*

DNV-GL Energy and Sustainability. (2013). *Energy Storage Cost-Effectiveness Methodology and Results, Final Project Report.* California Energy Commission, Energy Research and Development Division.

Doherty, T. (1982). *Report on Technical Feasibility of Underground Pumped Hydroelectric Storage in a Marble Quarry Site in the Northeast United States.*

DWR. (2017, March 21). *WSIHIST: Chronological Reconstructed Sacramento and San Joaquin Valley Water Year Hydrologic Classification Indices*. Retrieved July 9, 2017, from Department of Water Resources. California Data Exchange Center: http://cdec.water.ca.gov/cgi-progs/iodir/WSIHIST

Electric Power Research Institute (EPRI) and Energy and Environmental Economics, Inc. . (2010). *Electricity Energy Storage Technology Options- A White Paper Primer on Applications, Costs, and Benefits.* Technical Update. Retrieved May 25, 2017, from http://large.stanford.edu/courses/2012/ph240/doshay1/docs/EPRI.pdf

Environmental Science Associates . (2005). *Appendix E. Analysis of Developing and Implementing a Groundwater Recharge Reuse Project In The Antelope Valley.* Retrieved

April 17, 2017, from http://www.lacsd.org/civicax/filebank/blobdload.aspx?blobid=2171

Eternoo Machinery Co., Ltd. (n.d.). *Products*. Retrieved June 13, 2017, from Eternoo Machinery Co., Ltd: http://www.eternoohydro.com/turbines/francis-turbines.html

Fairley, P. (2015, March 18). A Pumped Hydro Energy-Storage Renaissance. IEEE Spectrum. Retrieved from http://spectrum.ieee.org/energy/policy/a-pumped-hydro-energystorage-renaissance

Farquhar, O. (1982). *Geotechnical Basis for Underground Energy Storage in Hard Rock.* Final Report.

Frigo, A. A., & Pistner, C. (1980). Evaluation of Advanced Turbomachinery for Underground Pumped Hydroelectric Storage. Part 3. Multistage Unregulated Pump /Turbines for Operating Heads of 1000 to 1500M.

Frigo, A. A., Blomquist, C. A., & Degnan, J. R. (1979). *Evaluation of Advanced Hydraulic Turbomachinery for Underground Pumped Hydroelectric Storage. Part 1. Single-Stage Regulated Pump Turbines for Operating Heads of 500 to 1000M.*

GEI Consultants, Inc. (2016). *Willow Springs Water Bank (WSWB) Facilities Master Plan.* Memorandum.

GEI Consultants/Navigant Consulting, Inc. (2010). *Embedded Energy in Water Studies Study 1: Statewide and Regional Water-Energy Relationship.* Retrieved April 21, 2017, from https://www.waterenergyinnovations.com/publication/view/cpuc-embedded-energy-in-water-studies-1-statewide-and-regional-water-energy-relationship/

Groundwater Replenishment System (GWRS). (n.d.). Retrieved April 21, 2017, from https://www.ocwd.com/media/4267/gwrs-technical-brochure-r.pdf

HDR. (2017). *Antelope Valley Water Storage Project Pumped Storage Study.*

Hopkins Groundwater Consultants, Inc. (2013). *Recycled Water Master Plan Groundwater Replenishment and Reuse Project Ventura, California.* Preliminary Hydrogeological Study. Retrieved April 21, 2017, from https://www.unitedwater.org/images/stories/Resource-Conservation/GW-Management/Groundwater-Hearing/Exhibits/U326%20-%202013%20Hopkins%20GW%20Replentishment%20and%20Reuse%20Mound%20Basin.pdf

House, L. W. (2017 a). *EPC 15-049 Tech Memo No.1 : Economic Potential of Peak Hour Pumped Storage and Aquifer Pumped Hydro Technologies at Willow Springs Water Bank.* Memorandum, Water & Energy Consulting.

House, L. W. (2017 b). *EPC 15-049 Tech Memo No.2: Statewide Benefits of Pumped Storage at Groundwater Banks.* Memorandum, Water & Energy Consulting.

Hydro resources. (2013, December 3). Willow Springs Water Bank- Feasibility check at different flow rates for pumping and injection.

Irrigation Training and Research Center (ITRC). (2003). *California Agricultural Water Electrical Energy Requirements Final Report.* Retrieved April 21, 2017, from http://agwaterstewards.org/wp-content/uploads/2016/08/EnergyReqs.PDF

Irrigation Training and Research Center (ITRC). (2005). *CEC Agricultural Peak Load Reduction Program-Water Agencies-Final Report.* Retrieved April 21, 2017, from http://www.itrc.org/reports/pdf/cecaplrp.pdf

Irrigation Training and Research Center (ITRC). (n.d.). *Irrigation System Regulating (Buffer) Reservoirs.* Retrieved April 21, 2017, from http://www.itrc.org/papers/pdf/regulating.pdf

Johnson, T. (2007). *Battling Seawater Intrusion in the Central and West Coast Basins.* Retrieved April 21, 2017, from http://www.wrd.org/sites/pr/files/TB13_Fall07_Seawater_Barriers.pdf

Kane, M. (2005, April). California Small Hydropower and Ocean Wave Energy Resources. Retrieved April 25, 2017, from http://www.energy.ca.gov/2005publications/CEC-500-2005-074/CEC-500-2005-074.PDF

Kern County California. (n.d.). *Home.* Retrieved June 13, 2017, from Kern County Assessor Recorder: http://assessor.co.kern.ca.us/prop_search.php

Koreny, J. (2016). *AV-2, AV-3 and AV-5 Pumping Test Data Summary Willow Springs Water Bank, Kern County, CA.* Memorandum, HDR.

Lawrence Berkeley National Laboratory. (2017). *2025 California Demand Response Potential Study, Final Report on Phase 2 Results.*

Los Angeles County Office of the Assessor. (n.d.). *Property Assessment Information System.* Retrieved June 13, 2017, from Assessor Los Angeles County: http://maps.assessor.lacounty.gov/GVH_2_2/Index.html?configBase=http://maps.assessor.lacounty.gov/Geocortex/Essentials/REST/sites/PAIS/viewers/PAIS_hv/virtualdirectory/Resources/Config/Default

Lund, J., Munevar, A., Taghavi, A., Hall, M., & Saracino, A. (2014, November). *Integrating Storage in California's Changing Water System.* Retrieved April 21, 2017, from https://watershed.ucdavis.edu/files/biblio/Storage_White_Paper_20Nov2014.pdf

Madlener, R. a. (2013). An Exploratory Economic Analysis of Underground Pumped-Storage Hydro Power Plants in Abandoned Coal Mines.

Martin, G. a. (2007). *Aquifer Underground Pumped Hydroelectric Energy Storage for Agriculture.* University of Colorado at Boulder. Retrieved from www.colorado.edu/engineering/energystorage

Mathias, J., Doughty, C., & Kelly, L. (2016). *Bulk Energy Storage in California.* California Energy Commission.

National Renewable Energy Laboratory (NREL). (2014). *The California 2030 Low-Carbon Grid Study (LCGS) Phase I Results Summary.* Retrieved April 21, 2017, from http://lowcarbongrid2030.org/wp-content/uploads/2014/08/LCGS-Phase-I-Results-Summary-Slides.pdf; http://lowcarbongrid2030.org/

Navigant Consulting, I. (June 2006). *Statewide Small Hydropower Resource Assessment.* Retrieved May 23, 2017, from http://www.energy.ca.gov/2006publications/CEC-500-2006-065/CEC-500-2006-065.PDF

Nyberg, M. (2014, September). Thermal Efficiency of Gas-Fired Generation in California: 2014 Update. *Staff Paper*. Retrieved June 20, 2017, from http://www.energy.ca.gov/2014publications/CEC-200-2014-005/CEC-200-2014-005.pdf

Orange County Water District. (n.d.). *Groundwater & location maps*. Retrieved April 21, 2017, from Orange County Water District: https://www.ocwd.com/what-we-do/groundwater-management/groundwater-location-maps/

Pendleton. (n.d.). Retrieved August 10, 2017, from Public Works Projects: http://www.pendleton.or.us/public-works/projects

Pickard, W. (2012). The History, Present State, and Future Prospects of Underground Pumped Hydro for Massive Energy Storage. *Proceedings of the IEEE, 100*(2).

Profita, C. (2011, Dec 29). *In Pendleton: Newfound well power.* Retrieved August 10, 2017, from Oregon Public Broadcasting (OPB): http://www.opb.org/news/blog/ecotrope/in-pendleton-newfound-well-power/

Ridgway, S. L., Dooley, J. L., & Hammond, R. P. (1979). Underground Storage of Off-Peak Power.

RMC Water and Environment. (2007). *City of Lancaster Groundwater Recharge Feasibility Study.* Retrieved April 17, 2017, from http://www.ladpw.org/wwd/avirwmp/docs/Lancaster%20Report.pdf

RMC Water and Environment. (2012 (Revised 2013)). *North San Diego County Regional Recycled Water Project.* Regional Recycled Water Facilities Plan. Retrieved April 21, 2017, from http://nsdwrc.org/pdfs/Regional Recycled Water Facilities Plan.pdf

RMC Water and Environment. (2016). *Carpinteria Valley Recycled Water Facilities Plan Final Report.* Retrieved April 17, 2017, from http://www.carpinteria.ca.us/PDFs/pw_Recycled%20Water%20Facilities%20FINAL%20REPORT2016.pdf

Rogers, F. C. (1975). *Existing Hydroelectric Generation Enhanced by Underground Energy Storage.*

Rogers, F. C., & Larson, W. E. (1974). *Underground Energy Storage (Hydroelectric Plant).*

S.Y., K., & I.E., D. (2017). Underground Pumped Hydroelectric Energy Storage in South Africa using Aquifers and Existing Infrastructure. *In: Schulz D. (eds) NEIS Conference 2016.* Wiesbaden: Springer Vieweg.

Sanitation Districts of Los Angeles County. (2011). Groundwater Recharge of Recycled Water. Retrieved April 18, 2017, from http://www.lacsd.org/civicax/filebank/blobdload.aspx?blobid=6779

Scott, F. M. (2007). Hydropower from Underground Pumped Storage. *Am. Chem. Soc., Div. Fuel Chem., 19*(4). Retrieved from http://dx.doi.org/10.1080/00908317508945949

Semitropic Water Storage District. (2017, May 17).

State of California Natural Resoures Agency, Department of Water Resources . (April 2015). *California's Groundwater Update 2013. A Compilation of Enhanced Content for California Water Plan Update 2013.* Retrieved March 31, 2017, from http://www.water.ca.gov/waterplan/docs/groundwater/update2013/content/statewide/GWU2013_Ch_2_Statewide_Final.pdf

State Water Resources Control Board Division of Drinking Water. (2014). *Alternative Treatment Technology Report for Recycled Water.* Retrieved April 17, 2017, from http://www.waterboards.ca.gov/drinking_water/certlic/drinkingwater/documents/dwdocuments/Alternative%20Treatment%20Technology%20Report%20for%20RW%2009_2014.pdf

Tam, S., Blomquist, C. A., & Kartsounes, G. (2007, April 27). *Underground Pumped Hydro Storage – An Overview.* Argonne National Laboratory. Retrieved from http://dx.doi.org/10.1080/00908317908908068

Uddin, N., & Asce, M. (2003). Preliminary Design of an Underground Reservoir for Pumped Storage, Geotechnical and Geological Engineering. *21*, 331. doi:doi:10.1023/B:GEGE.0000006058.79137.e2

Water Replenishment District of Southern California. (2011). *Engineering Survey and Report.* Retrieved April 21, 2017, from http://www.water.ca.gov/urbanwatermanagement/2010uwmps/Long%20Beach%20Water%20Department/Attach_E.pdf

Watersheds Coalition of Ventura County. (2006). *Integrated Regional Water Management Plan .* Retrieved April 21, 2017, from https://www.ventura.org/wcvc/IRWMP/docs/Section_5_Water_Management_Strategies_Used_To_Meet_Plan_Objectives.pdfhttps://www.ventura.org/wcvc/IRWMP/docs/Section_5_Water_Management_Strategies_Used_To_Meet_Plan_Objectives.pdf

West Basin Municipal Water District. (n.d.). *Recycled Water > Edward C. Little Water Recycling Facility*. Retrieved April 21, 2017, from West Basin Municipal Water District: http://old.westbasin.org/water-reliability-2020/recycled-water/water-recycling-facility.html

Willett, D. C., & Warnock, J. G. (1983). *Evolution ofa Technological Opportunity: Underground Pumped Hydro Storage.*

XiO, Inc. (2017, May 1). XiO pricing for Willow Springs Water Bank project.

APPENDIX A: Sensitivity Analysis

This document provides an analysis of the parameters that affect the calculation of mounding losses, which have a direct impact on the potential power generation and provides conclusions on which parameters have the greater impact on mounding losses relative to others.

Equations Utilized

Power generation potential is calculated utilizing the following procedure:

Step 1 – A theoretical equation will be used to calculate h_m = potential mounding (feet) in the aquifer due to injection of flow through the well into the aquifer. The equation1 in imperial units is:

$$h_m = \frac{(2.3 * Q)}{(4 * 3.14 * T)} \times \text{Log} \frac{(2.25 * T * t)}{(r^2 * S)}$$

The equation is the Cooper-Jacob approximation to the Theis equation. The equation provides the height of injection mound by correlating the drawdown, or head to the negative drawdown (height of the injection mound).

Q= injection flow rate (ft^3 /minute); S = Storage Coefficient; T= Transmissivity of aquifer (ft^2 /minute); t = time (minutes); r = well radius (ft.). If h_m is known from actual field data, then it can be used in Step 2 instead of the theoretical value calculated in Step 1.

Step 2 - The h_m = potential mounding (feet) calculated in Step 1 will be used to calculate the available H_t =Head to Turbine for power generation using the equation: H_t= H (depth to water

datum) – h_m. Then, P = potential power generation is calculated from the equation below in imperial units:

$$P = \frac{Q * H_t * E * 0.746}{3960}$$

P = kW (kilowatts); H_t = Head on turbine (feet)

Q = Injection flow rate (gallons per minute)

E = turbine efficiency

1 horsepower (hp) = 746 watts = 0.746 kW = 3,960 gpm-ft.

To evaluate the effect of each input parameter in the potential mounding head loss equation = h_m, refer to the attached excel spread sheet. Each of the parameters is varied and the effect on mounding head loss is evaluated.

T= Transmissivity; Q= Flow Rate; r = well radius; S = storage coefficient; T = time period

The resulting impacts on h_m = mounding head loss is as follows:

Variable	Range of h_m	Overall Effect	Specific Impact
T = 3,526 ft.^{2}/day T = 20,000 ft.^{2}/day	h_m = 91.7 ft. h_m = 18.8 ft.	A 467% increase in T, results in 80% decrease of h_m	For each 6% increase in T results in 1% decrease in h_m
Q = 1,800 gpm Q = 2,000 gpm	h_m = 16.9 ft. h_m = 18.8 ft.	An 11% increase in Q, results in 11% increase in h_m for a given T.	Each 1% increase in Q results in 1% increase in h_m for a given T.
r = 1.0 ft. r = 2.0 ft.	h_m = 91.7 ft. h_m = 79.7 ft.	A 100% increase in r, results in 13% decrease in h_m for a given T.	For each 8% increase in r results in 1% decrease in h_m for a given T.
S = 0.001 confined aquifer S = 0.1 unconfined aquifer	h_m = 171.1 ft. h_m = 115.5 ft.	A 10,000% increase in S, results in 33% decrease in h_m for a given T.	Each 303% increase in S results in a 1% decrease in h_m for a given T.
t = 350 minutes t = 400 minutes	h_m = 123.5 ft. h_m = 125.1 ft.	A 14 % increase in t, results in 1% increase in h_m for a range of T.	Each 14% increase in t, results in a 1% increase in h_m for a given T.

Results

Based on the sensitivity analysis Flow Rate, Transmissivity and well radius have the greatest impact on mounding losses. The lower the injection flow rate and larger the well radius the lower the resulting h_m = mounding losses. With an 11% increase in flow rate from 1,800 gpm to 2,000 gpm the mounding losses increase 11% for a given Transmissivity (this can be expected by examination of the h_m equation). The storage coefficient S is fixed for an unconfined aquifer such as WSWB, however as the S decreases to a confined aquifer condition where S = 0.001, the mounding head loss increases by approximately 33% over a range of Transmissivity. As the t = time increases the mounding losses tend to increase.

Finally, one of the questions that the Technical Advisory Committee (TAC) requested be considered in the study was, "Does temperature of recharge water have an effect on hydraulic conductivity of the aquifer materials as it relates to potential power generation with Aquifer Pumped Hydro (APH) technology?

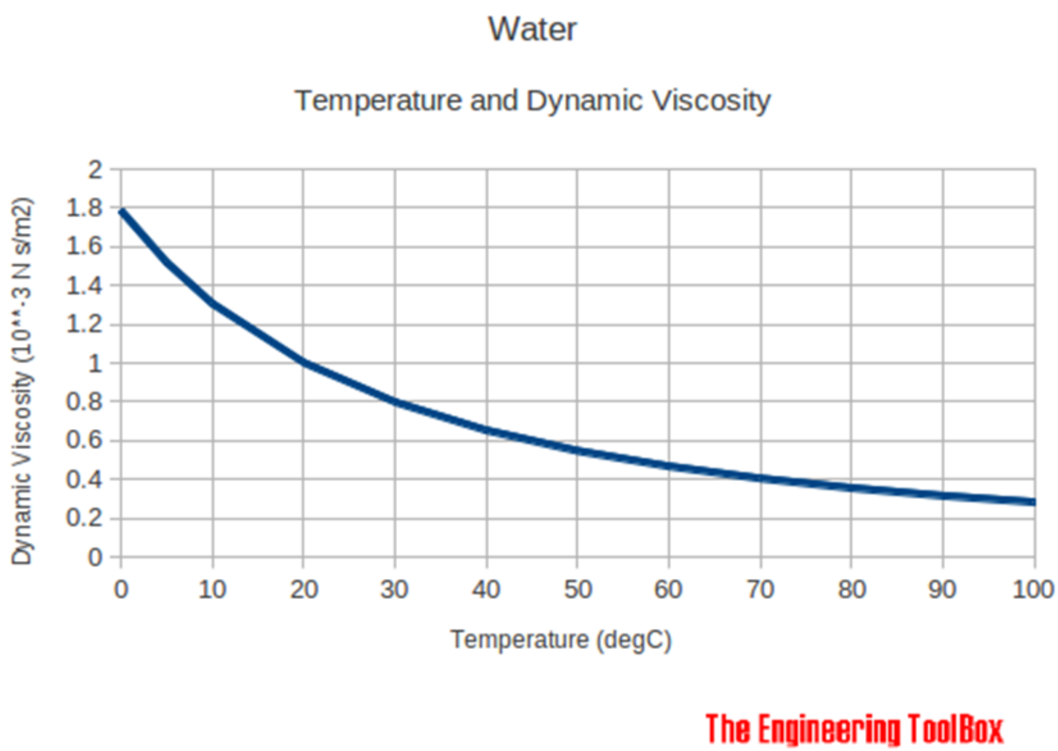
UC Berkeley and David Keith Todd Consulting Engineers, Inc. [1] provide the following definitions:

Given that T= transmissivity = K*t where K= hydraulic conductivity and t= aquifer thickness. The hydraulic conductivity of a soil is its ability to transmit in a unit of time a unit volume of groundwater at the prevailing kinematic viscosity of the water through a unit section of area.

Intrinsic permeability is the ability of a soil to transmit a fluid; and is defined by the following equation:

k = intrinsic permeability = K * u * 1/ (unit weight of water x gravity); where u is the dynamic viscosity of water. As can be seen in the figure below, dynamic viscosity decreases with increasing temperature.

If surface water for recharge is colder than 50 to 60 degrees F, the water will warm to the temperature of groundwater as it percolates into the aquifer. Within the upper 1,000 feet of soils the groundwater temperature ranges from 50 to 60 degrees F, therefore, very cold recharge water will have negligible effect on mounding losses



Source: [2]

Reference:

[1] UC Berkeley and David Keith Todd Consulting Engineers, Inc. Groundwater Hydrology, Second Edition. John Wiley & Sons Publisher.

[2] The Engineering Toolbox. (2017, June 23). Retrieved June 23, 2017, from http://www.engineeringtoolbox.com/water-dynamic-kinematic-viscosity-d_596.html

APPENDIX B: Field Measurement of Well Startup & Shutdown Time Durations

Test Protocol

1. Field Ops. Staff (FOP = Steve Tapia) stands at Well K-160.
2. FOP walks to, and enters truck, drives to Well G-160, and stops truck.
3. FOP exists truck, performs start-up on G-160, and signals when flow meter indicates full flow rate.
4. FOP preforms shut-down of G-160, and signals when well and flow stops.
5. FOP walks to, and enters truck, drives back to Well K-160, and stops truck.

Assumption: 15 MPH Speed Limit (per Berkshire Hathaway Energy's (BHE's) protocol)

Field Data

Activity Description	Duration Seconds (range)	Comments
TRAVEL: Well to well Field Ops. Staff (FOP) standing at Well K-160 walks to, and enters truck, drives to Well G-160, and stops truck.	118 to 160 Average = 140	Depends on driving speed, distance between wells, and distance truck is parked from a well. (K-160 & G-160 are ½ mile apart.) BHE's protocol sets a Speed Limit of 15 MPH.
TURN ON WELL: FOP exits truck, walks to well head, performs start-up on G-160, and signals when flow meter indicates full flow rate.	18 to 37 Average = 28	Depends on multiple factors: • Distance truck is parked relative to well • Whether well is equipment with "Soft Start" motor control or has the old instant start panels, and also ramping settings of Soft Start Panel. • H.P. of the Well Motor. • Depth of water and size of column pipe. • Flow rates across pump curves.

Activity Description	Duration Seconds (range)	Comments
TURN OFF WELL: FOP exits truck, walks to well head, turns off well at panel, and signals when motor has come to full stop.	16 to 28 Average = 22	Similar variables to above.
TRAVEL: Well to well Field Ops. Staff (FOP) standing at Well G-160 walks to, and enters truck, drives to Well K-160, and stops truck.	118 to 160 Average = 140	Depends on driving speed, distance between wells, and distance truck is parked from a well. (K-160 & G-160 are ½ mile apart.) BHE's protocol sets a Speed Limit of 15 MPH.

Results:

Start-up duration: 140 [travel] + 28 [turn on well] + 140 [travel] = 308 sec. = 5.13 minutes/well

Shut-down duration: 140 [travel] + 22 [turn well off] + 140 [travel] = 302 sec. = 5.03 minutes/well

It would take one operator over 5 hours to start or stop all 62 wells if they are not equipped with remote start and stop capability.

APPENDIX C:
WSWB Upper and Lower Reservoir Site Maps

This appendix is available as a separate volume, Publication Number CEC-XXX-2017-XXX-APC

APPENDIX D:
Statewide Survey Results

Statewide Survey Responses

Lead Agency	Proceed or Not with Pumped Storage (Yes/No)	Reason
Central Coast Hydrologic Region		
Monterey Peninsula Water Management District (MPWMD) - ASR	Yes	Proceed for Peak Hour Pumped Storage (PHPS) and Aquifer Pumped Hydro (APH) studies. They are currently operating an ASR project and survey indicates pipeline system does pump recovered water back to source conveyance in Carmel Valley.
Monterey Regional Water Pollution Control Agency	No	They do not have any service wells nor do they operate any groundwater bank.
Pajaro Valley Water Management Agency	No	They do not have any ASR project nor injection wells. There is no indication if pump water goes back to source conveyance.
Goleta Water District	Yes	Proceed for Aquifer Pumped Hydro (APH) study only. They do have an ASR project as well as injection wells
Santa Barbara, City of, Water Resources Division	Yes	They may have potential for Peak Hour Pumped Storage (PHPS) technology. There is significant elevation difference between source conveyance and recharge facility for energy generation.
Colorado River Hydrologic Region		

Lead Agency	Proceed or Not with Pumped Storage (Yes/No)	Reason
Coachella Valley Water District (CVWD)	No	They do not have an ASR project or any injection wells. No indication if water gets pumped back to source conveyance
Sacramento River Hydrologic Region		
Sacramento Groundwater Authority (SGA)	No	They do not have an ASR project or any injection wells. They do not manage their own water directly, but they do oversee their Joint Powers Authority (JPA)
Sacramento Regional County Sanitation District (Regional San) The Nature Conservancy	No	They do not have an ASR project or any injection wells. They also do not manage any ground water banks.
Sacramento Suburban Water District	Yes	They may have potential for Aquifer Pumped Hydro (APH) technology. They do not have an ASR project, but they do have 88 active wells and most wells have 200 ft. of ground water depth or more.
Regional Water Authority	No	They do not manage any water banks. Instead, they oversee the operations of other water agencies.
Yuba County Water Agency	No	They do not have an ASR project or any injection wells. They also do not have an existing pipeline system. They do have a canal system that is used for in-lieu recharge only.
City of Tracy - ASR	Yes	Proceed for Aquifer Pumped Hydro (APH) study and maybe for Peak Hour Pumped Storage (PHPS). They have nine extraction

Lead Agency	Proceed or Not with Pumped Storage (Yes/No)	Reason
		wells with one well also used for injections. They have a pilot ASR project. They do have an existing pipeline system, not sure however if water is pumped back to the source
City of Roseville - ASR	No	Their water agency currently only uses surface water, with no water pumping from wells. They do have ASR wells, but only turn on ASR wells once a month for testing purposes.
San Francisco Bay Hydrologic Region		
Zone 7 Water Agency - ASR	No	They replied via Email that they do not operate any ground water bank
Santa Clara Valley Water District (SCVWD) - ASR	No	They do not manager their own water supply. They recommend to contact Semitropic or Kern County water agencies for information. They do not have any ASR or injection wells.
San Joaquin County	No	They do not manage any ground water banks currently
San Joaquin River Hydrologic Region		
Stockton East Water District (SEWD)	No	They may have potential for Aquifer Pumped Hydro (APH) technology. Their ground water project site does not have any elevation difference or existing pipeline system.

Lead Agency	Proceed or Not with Pumped Storage (Yes/No)	Reason
		Instead, the water is transferred through the use of canals
Northeastern San Joaquin County Groundwater Banking Authority	No	Their Joint Powers Authority (JPA) consists of 11 members. They oversee other water agencies and do not manage any ground water banks directly.
Root Creek Water District	Yes	They may have potential for Aquifer Pumped Hydro (APH) technology. They do not have ASR or injection wells, but they do have 15 wells with at least 350 ft. depth to ground water level.
South Coast Hydrologic Region		
Camp Pendleton - ASR	No	Their injection wells are used to pump water for salt water barrier. Their project site is not a ground water banking site
Compton Water Department	Yes	Proceed for Aquifer Pumped Hydro (APH) only. They currently have active ASR project.
Foothill Municipal Water District	Yes	Proceed for Aquifer Pumped Hydro (APH) only. They have three injection wells in service at their project site.
La Verne, City of; Three Valleys Municipal Water District		
City of Lakewood	No	All the water that flows through their service area are traveling in one direction and they do not have any injection wells

Lead Agency	Proceed or Not with Pumped Storage (Yes/No)	Reason
Orange County Water District	Yes	Proceed for Aquifer Pumped Hydro (APH) only. They have 200 large wells in their service area, and they have injection wells for basin replenishment.
Los Angeles County Department of Public Works - ASR	No	They do not have any ASR projects or use any aquifers for storage
Los Angeles Department of Water and Power - ASR	No	They do not have any current ASR projects or use any aquifers for storage
Main San Gabriel Basin Watermaster	No	They do not have any ground water banks. They oversee the operations of other water agencies.
Cucamonga Valley Water District	No	They do not have any injection wells. The water flows through their service area in one direction only.
Eastern Municipal Water District - ASR	No	They do not have any injection wells. The water flows through their service area in one direction only.
Raymond Basin Management Board - ASR	No	They are a Watermaster that oversee other water agencies, they do no manage any ground water projects. Their water operating system does not have elevation difference or put/take amounts.
San Bernardino Valley Water Conservation District	No	They do not have an existing pipeline system, ASR project, or extraction wells
Three Valleys Municipal Water District	No	They already have a hydroelectric facility. They do not have any injection wells

Lead Agency	Proceed or Not with Pumped Storage (Yes/No)	Reason
Helix Water District [El Monte Valley]	No	They do not have an ASR project or any injection wells. They also do not manage any ground water facilities
Sweetwater Authority	No	They do not have any ASR project or manage any ground water banks. They have a desalination plant that utilizes reverse osmosis to purify water for customer use
United Water Conservation District - ASR	No	Their project site has low elevation difference, and no existing pipeline system. They do not have any injection wells or ASR projects
Western Municipal Water District	No	They do not have any injection wells, nor do they have an existing pipeline system in operation.
Castaic Lake Water Agency	No	Taken from survey response: Castaic Lake Water Agency (CLWA) does not operate any ground water banking programs.
South Lahontan Hydrologic Region		
Mojave Water Agency	Yes	They do not have any injection wells. They may have potential for Peak Hour Pumped Storage (PHPS) because they have an existing pipeline system that is in use.

Lead Agency	Proceed or Not with Pumped Storage (Yes/No)	Reason
Tulare Lake Hydrologic Region		
Kern Water Bank Authority	No	The elevation difference at their project site is not enough for Peak Hour Pumped Storage (PHPS) technology. They do not have any injection wells.
City of Bakersfield 2800 Acre Water Bank	Yes	They do not have an ASR project, but they have 53 wells with deep enough 340 ft. depth to groundwater level
James Irrigation District	No	Prior research found their project site to have low elevation difference, and no existing pipeline; Background study also found injection wells inefficient
Rosedale-Rio Bravo WSD		
Wheeler Ridge Maricopa Water Storage District	No	They do not have any pumped storage or aquifer storage facilities
Shafter Wasco Irrigation District	No	They are just getting started on building out their ground water bank facility and wells. They are not in operation yet.
Southern San Joaquin Municipal Utilities District	No	They are trying to outsource their water. They do not operate any ground water banks currently
Kaweah Delta Water Conservation District	No	They do not have any pump storage in operation
Pixley Irrigation District/Lower Tule River Irrigation District	No	They only have surface water storage for agriculture, but no pipeline system available

Lead Agency	Proceed or Not with Pumped Storage (Yes/No)	Reason
North Coast Hydrologic Region		
Butte County	No	They do not manage or own any water banks

APPENDIX E:
Small Hydropower Potential for Groundwater Banking Agencies

Geographic Region	Hydrologic Region	County	Total Annual Water Entitlements (AWE) for County (AFY)	Water Purveyors having Groundwater Banking Projects [a]	Annual Water Entitlements (AWE) for Water Purveyor (AFY)[b]	Countywide Small Hydropower Potential (kW)[c]	Estimated Small Hydropower Potential (kW) for Water Purveyors
N	San Francisco Bay	Alameda		Alameda County Water District (ACWD)	42,000	3,200	3,200
				East Bay Municipal Utilities District (EBMUD)	150,000		
				Alameda County FC & WCD, Zone 7	68,000		
			260,000	**3**	**260,000**		
C	Tulare Lake	Fresno	**2,446,395**	City of Fresno	60,000	6,426	2,503
				Consolidated Irrigation District (CID)	240,000		
				Fresno Irrigation District (FID)	550,000		
				James Irrigation District	59,220		
				Tranquillity Water District/Tranquillity Irrigation District	43,857		

Geographic Region	Hydrologic Region	County	Total Annual Water Entitlements (AWE) for County (AFY)	Water Purveyors having Groundwater Banking Projects [a]	Annual Water Entitlements (AWE) for Water Purveyor (AFY)[b]	Countywide Small Hydropower Potential (kW)[c]	Estimated Small Hydropower Potential (kW) for Water Purveyors
				5	**953,077**		
S	South Lahontan	Kern		Antelope Valley Water Storage	250000[d]	19,177	21,860
	Tulare Lake			Arvin-Edison Water Storage District (AEWSD)	351,675		
				Berrenda Mesa Water District (BMWD)	140,000		
				Buena Vista Water Storage District (BVWSD)	185,000		
				Cawelo Water District	75,000		
				Kern Delta Water District	220,000		
				Kern Tulare Water District	40,000		
				North Kern Water Storage District	222,000		
				Rosedale-Rio Bravo WSD (RRBWSD)	70,000		
				Semitropic Water Storage District	500,000		
				Shafter-Wasco Irrigation District (SWID)	89,600		
			2,461,275	Tehachapi-Cummings County Water District (TCCWD)	25,000		

Geographic Region	Hydrologic Region	County	Total Annual Water Entitlements (AWE) for County (AFY)	Water Purveyors having Groundwater Banking Projects [a]	Annual Water Entitlements (AWE) for Water Purveyor (AFY)[b]	Countywide Small Hydropower Potential (kW)[c]	Estimated Small Hydropower Potential (kW) for Water Purveyors
				Wheeler Ridge Maricopa Water Storage District (WRMWSD)	220,000		
				13	**2,138,275**		
C	Tulare Lake	Kings		Kings County Water District Apex Ranch Conjunctive Use (KCWD)	256,938	4,054	1,788
			582,508	**1**	**256,938**		
S	South Lahontan	Los Angeles		Antelope Valley-East Kern Water Agency (AVEK)	141,000	56,932	20,525
	South Coast			Los Angeles Department of Water and Power (LADWP)	795,454		
				City of Long Beach Water Department	46,475		
				San Gabriel Valley Municipal Water District[e]	28,800		
				Three Valleys Municipal Water District (TVMWD)	51,000		
			3,807,645	West Basin Municipal Water District (WBMWD)	160,000		

Geographic Region	Hydrologic Region	County	Total Annual Water Entitlements (AWE) for County (AFY)	Water Purveyors having Groundwater Banking Projects [a]	Annual Water Entitlements (AWE) for Water Purveyor (AFY)[b]	Countywide Small Hydropower Potential (kW)[c]	Estimated Small Hydropower Potential (kW) for Water Purveyors
				Water Replenishment District of Southern California (WRD) (previously called Central and West Basin Water Replenishment District)	150,000		
				7	**1,372,729**		
C	San Joaquin River	Madera		Chowchilla Water District	239,000	6,793	4,103
				Madera Irrigation District (MID)	295,000		
			884,000	**2**	**534,000**		
S	South Coast	Orange County		Orange County Water District (OCWD)	225,000	1,189	840
			318,500	**1**	**225,000**		
N	Sacramento River	Placer		City of Roseville Water District	32,000	778	108
			231,200	**1**	**32,000**		
S	Colorado River	Riverside		Coachella Valley Water District (CVWD)	508,100	3,961	2,480
			1,123,216	Desert Water Agency[f]	38,100		

Geographic Region	Hydrologic Region	County	Total Annual Water Entitlements (AWE) for County (AFY)	Water Purveyors having Groundwater Banking Projects [a]	Annual Water Entitlements (AWE) for Water Purveyor (AFY)[b]	Countywide Small Hydropower Potential (kW)[c]	Estimated Small Hydropower Potential (kW) for Water Purveyors
	South Coast			Eastern Municipal Water District (EMWD)	77,016		
				Rancho California Water District (RCWD)	30,000		
				Western Municipal Water District (WMWD)	50,000		
				5	**703,216**		
S	South Coast	San Bernardino		Inland Empire Utilities Agency (previously known as Chino Basin Municipal Water District)	25,000	17,728	12,723
				San Bernardino Valley Municipal Water District (SBVMWD)	102,600		
	South Lahontan			Mojave Water Agency (MWA)	75,800		
			283,417	**3**	**203,400**		
N	Sacramento River	Sacramento		City of Sacramento, Utilities Department[g]	90,000	1,506	692
			196,000	**1**	**90,000**		
S	South Coast	San Diego		City of San Diego Public Utilities Department	235,245	4,874	2,254

Geographic Region	Hydrologic Region	County	Total Annual Water Entitlements (AWE) for County (AFY)	Water Purveyors having Groundwater Banking Projects [a]	Annual Water Entitlements (AWE) for Water Purveyor (AFY)[b]	Countywide Small Hydropower Potential (kW)[c]	Estimated Small Hydropower Potential (kW) for Water Purveyors
				Helix Water District	35,500		
				Sweetwater Authority	22,500		
			634,245	**3**	**293,245**		
N	San Joaquin River	San Joaquin		Stockton East Water District (SEWD)	75,000	7,406	1,726
	Tulare Lake			Southern San Joaquin Municipal Utilities District (SSJMUD)	147,000		
			952,713	**2**	**222,000**		
C	San Francisco Bay	Santa Clara		Santa Clara Valley Water District (SCVWD)	252,500	2,058	1,752
			296,541	**1**	**252,500**		
C	Tulare Lake	Tulare		Delano-Earlimart Irrigation District (DEID)	183,300	12,258	8,559
				Kaweah Delta Water Conservation District (KDWCD)	440,000		
				Lower Tule River Irrigation District (LTRID)	330,302		
				Pixley Irrigation District	31,102		
				Porterville Irrigation Districts	46,000		

Geographic Region	Hydrologic Region	County	Total Annual Water Entitlements (AWE) for County (AFY)	Water Purveyors having Groundwater Banking Projects [a]	Annual Water Entitlements (AWE) for Water Purveyor (AFY)[b]	Countywide Small Hydropower Potential (kW)[c]	Estimated Small Hydropower Potential (kW) for Water Purveyors
			1,595,072	Saucelito Irrigation District	54,000		
				Terra Bella Irrigation District	29,000		
				7	**1,113,704**		
S	South Coast	Ventura		Calleguas Municipal Water District	95,000	154	127
			115,000	**1**	**95,000**		
N	Sacramento River	Yuba County		Yuba County Water Agency (YCWA)	300,000	2,464	2,303
			321,000	**1**	**300,000**		

Notes

[a] The listed water purveyors have groundwater banking projects as identified in the master database, "CA Groundwater Banking Projects" compiled for this study. Where more than one water purveyor is listed for a water entitlement, at least one of the agencies has groundwater banking operations. It is assumed that the reference study (Statewide Small Hydropower Resource Assessment, Navigant Consulting, Inc.) includes all the groundwater banking agencies/districts which have PHPS potential.

[b] Peak Hour Pumped Storage (PHPS) can happen every year regardless of hydrology and as long as there is available water for 'cycling' an agency should be able to implement PHPS regardless of source of water. An agency can potentially use water entitlements besides banked water if needed. The water entitlements database was assembled from multiple sources which include information on water rights, State Water Project (SWP) deliveries, Central Valley Project (CVP) deliveries and well data (Navigant Consulting, June 2006).

[c] Small hydropower capacity is defined as 30 MW or less and the minimum size unit to be considered in the source study was 100kW. Very small water purveyors with annual water entitlements less than 20,000 AFY were not included in the small hydropower (kW) computation since they did not have sufficient amount of water to meet the source study's (Navigant Consulting, June 2006) minimum threshold of 100 kilowatts generation potential. The remaining Large, Medium or Small agencies total 164 in number. The source study used estimation factors to calculate kW potential for medium and small purveyors that were not surveyed; the large ones were evaluated through site survey or interview only and their potential was not used to develop estimation factors (Navigant Consulting, June 2006).

[d] Antelope Valley Water Storage (AVWS) was not one of the entities included in the reference database. The peak hour generation potential (via Peak Hour Pumped Storage) and hydropower generation potential for AVWS (5.2 MW) was calculated as part of this project and has been added to the interpolated small hydropower potential (kW) for groundwater banking agencies in Kern County.

[e] Main San Gabriel Basin Watermaster is included in the master database, "CA Groundwater Banking Projects." The Watermaster administers adjudicated water rights and manages and protects groundwater resources within the Main San Gabriel Groundwater Basin. San Gabriel Valley Municipal Water District is one of the three agencies delivering supplemental SWP water to the basin for recharge.

[f] Desert Water Agency and Coachella Valley Water District partner to recharge groundwater (Master Database, CA Groundwater Banking Projects)

[g] City of Sacramento is a member agency of Sacramento Groundwater Authority. The Authority is included in the master database, "List of CA Groundwater Banking Projects." The City has participated in water transfer efforts previously and may do so in future (City of Sacramento Department of Utilities. 2010 Urban Water Management Plan. October 2011. Prepared by Carollo Engineers, Inc.)

Sources:

Small hydropower potential (kW) by County (California RPS-Eligible Small Hydropower Potential (2004 Draft Report), Navigant Consulting, Inc.; California Small Hydropower and Ocean Wave Energy Resources (Staff Paper) (Kane, 2005)

Information about water entitlements for County/Region (Navigant Consulting, June 2006)

Groundwater banking agencies (including those with ASR projects). (Master Database, CA Groundwater Banking Projects. Groundwater Bank Energy Storage Systems: A Feasibility Study for Willow Springs Water Bank. 2017. Prepared by Antelope Valley Water Storage (AVWS), LLC

APPENDIX F:
Well Pumps Demand Response Potential for Selected Groundwater Banking Projects

Hydrologic Region	Lead agency for Groundwater Banking Project	Groundwater Basin/Subbasin Name	Recovery (AFY)	Energy Intensity (kWh/AF)[21]	Annual kWh	Estimated Pumping Capacity (kW)[22]	Notes from literature research/survey
CC	Monterey Peninsula Water Management District	Carmel Valley, Seaside	3000	388	1,164,000	199	Phase 1 ASR includes two ASR wells with combined injection capacity 3,000 gpm and recovery capacity 3,500 gpm. Phase 2 ASR project includes two ASR wells with maximum annual diversion limit of 2,900 acre-feet/year, combined injection rate of 3,600 gpm, and annual yield of 1,000 acre-feet.
SC	Elsinore Valley Municipal Water District; Western Municipal Water District	Elsinore Valley, Riverside-Arlington and Temescal	4000	541	2,164,000	370	
SC	Foothill Municipal Water District	-	3000	541	1,623,000	277	

21 Energy Intensity is for the year 2000, a "normal" water year from Table G-1 in Embedded Energy in Water Studies Study 1: Statewide and Regional Water-Energy Relationship (GEI Consultants/Navigant Consulting, Inc., 2010)

22 To calculate annual kW demand, around-the-clock operations for 244 days (~ 8 months) are assumed regardless of whether a project is in-lieu or has direct artificial recharge. It is assumed that the recovery operations use only electric motors and no diesel engines.

Hydrologic Region	Lead agency for Groundwater Banking Project	Groundwater Basin/Subbasin Name	Recovery (AFY)	Energy Intensity (kWh/AF)[21]	Annual kWh	Estimated Pumping Capacity (kW)[22]	Notes from literature research/survey
SC	Inland Empire Utilities Agency	-	140,000	541	75,740,000	12934	
SC	Inland Empire Utilities Agency; Three Valleys MWD; Chino Basin Watermaster	Chino, Cucamonga	33000	541	17,853,000	3049	
SC	La Verne, City of; Three Valleys Municipal Water District	-	1000	541	541,000	92	
SC	Long Beach Water Department	Central	4300	541	2,326,300	397	
SC	Long Beach Water Department and City of Lakewood	Central	1200	541	649,200	111	
SC	Main San Gabriel Basin Watermaster	San Gabriel Valley	60000	541	32,460,000	5543	
SC	Orange County Water District	Coastal Plain of Orange County	22000	541	11,902,000	2032	
SC	San Bernardino Valley Municipal Water District (Valley District)	Rialto-Colton, Bunker Hill, Yucaipa	29500	541	15,959,500	2725	
SC	San Diego, City of, Public Utilities Department	San Pasqual Valley, San Diego River Valley	5800	541	3,137,800	536	
SC	Three Valleys Municipal Water District	-	5,000	541	2,705,000	462	There are two groundwater production wells.

Hydrologic Region	Lead agency for Groundwater Banking Project	Groundwater Basin/Subbasin Name	Recovery (AFY)	Energy Intensity (kWh/AF)[21]	Annual kWh	Estimated Pumping Capacity (kW)[22]	Notes from literature research/survey
SC	Water Replenishment District of Southern California	West Coast, Central	245000	541	132,545,000	22634	
SC	United Water Conservation District	Oxnard	15000	541	8,115,000	1386	United Water's Oxnard-Hueneme Delivery System (O-H system) supplies 15,000 AF/year water to several agencies. O-H system is supplied by 12 wells that draw from Oxnard Plain Groundwater Basin. Wells have flow rate 1,800-2,500 gpm, and water to wire efficiencies >65%.
SF	Santa Clara Valley Water District (SCVWD)	Santa Clara, Llagas Area	35000	342	11,970,000	2044	
SJ	Madera Ranch Water Bank, operated by Madera Irrigation District	-	55000	223	12,265,000	2094	
SJ	Root Creek Water District	Madera	6000	223	1,338,000	228	A total of 15 deep and shallow extraction wells are located across district. Well capacity ranges from 1600 gpm-2000 gpm. This was excluded from further consideration since

Hydrologic Region	Lead agency for Groundwater Banking Project	Groundwater Basin/Subbasin Name	Recovery (AFY)	Energy Intensity (kWh/AF)[21]	Annual kWh	Estimated Pumping Capacity (kW)[22]	Notes from literature research/survey
							wells are owned by private land owners which would make demand response program difficult to implement.
SL	Willow Springs Water Bank	Antelope Valley	225000	342	76,950,000	13140	The demand response potential at Willow Springs Water Bank is estimated to be 14.0 MW (Details are provided in Chapter 2 of this study). 62 production wells are planned for WSWB. Each production well is expected to have a 300-horsepower motor, or 0.225 MW.
SL	AVEK Godde Bank operated by Antelope Valley-East Kern Water Agency	Antelope Valley	40000	342	13,680,000	2336	
SL	Planned Enterprise Bank operated by Antelope Valley-East Kern Water Agency	Antelope Valley	83300	342	28,488,600	4865	
SL	Mojave Water Agency	Cronise Valley, Lower Mojave River Valley, Middle Mojave River Valley, Upper Mojave	50000	342	17,100,000	2920	

Hydrologic Region	Lead agency for Groundwater Banking Project	Groundwater Basin/Subbasin Name	Recovery (AFY)	Energy Intensity (kWh/AF)[21]	Annual kWh	Estimated Pumping Capacity (kW)[22]	Notes from literature research/survey
		River Valley, El Mirage Valley, Kane Wash Area, Lucerne Valley, Langford Well Lake, Fremont Valley, Goldstone Valley, Superior Valley, Searles Valley, Salt Wells Valley, Grass Valley, Warren Valley, Deadman Lake, Bessemer Valley, Ames Valley, Means Valley, Upper Johnson Valley, Iron Ridge Area, Lost Horse Valley					
SL	Palmdale Regional Groundwater Recharge and Recovery Project	-	24250	342	8,293,500	1416	
SR	Sacramento Suburban Water District	-	4500	184	828,000	141	The District provides water to its customers from 88 active groundwater wells. The groundwater basin underlying the District is located in a portion of the North American subbasin: 47 wells with capacity of 180-3500 gpm and

Hydrologic Region	Lead agency for Groundwater Banking Project	Groundwater Basin/Subbasin Name	Recovery (AFY)	Energy Intensity (kWh/AF)[21]	Annual kWh	Estimated Pumping Capacity (kW)[22]	Notes from literature research/survey
							50-250 hp motor, 37 wells (with capacity of 600-2950 gpm and 75-300 hp motor and 3 wells with capacity of 400-650 gpm and 75 hp motor.
SR	Yuba County Water Agency	-	30000	184	5,520,000	943	
SR	Sacramento Regional County Sanitation District (Regional San)/The Nature Conservancy	-	30000	184	5,520,000	943	
TL	Buena Vista Water Storage District	Kern County	40000	369	14,760,000	2520	
TL	Semitropic Water Storage District	Kern County	365000	369	134,685,000	22999	
TL	Arvin-Edison Water Storage District	Kern County	170235	369	62,816,715	10727	
TL	Kern Water Bank Authority	Kern County	240000	369	88,560,000	15123	Kern Water Bank has no injection wells. Recharge is via approximately 7,000 acres of recharge ponds or in-lieu. There are 85 recovery wells which on average are about 750-feet deep and produce as much as 5,000 gallons-per-

Hydrologic Region	Lead agency for Groundwater Banking Project	Groundwater Basin/Subbasin Name	Recovery (AFY)	Energy Intensity (kWh/AF)[21]	Annual kWh	Estimated Pumping Capacity (kW)[22]	Notes from literature research/survey
							minute of water. Wells are spaced 1/3 of a mile or more apart.
TL	Fresno Irrigation District (Waldron Pond)	-	9000	369	3,321,000	567	
TL	North Kern Water Storage District	Kern County	250000	369	92,250,000	15753	The District successfully curtail 9 MW of peak load using regulating reservoirs, telemetry equipment and timers on over 60 groundwater wells (Burt, Howes, & Wilson, 2003)
TL	City of Bakersfield 2800 Acre Water Bank	-	89000	369	32,841,000	5608	The City pumps groundwater from Kern County groundwater basin with 53 active wells. These wells have a combined capacity of about 89,000 AF/year. From survey response, active wells have a flow capacity of 3200 gpm, 250 hp motor, and 40-65% efficiency. (For the calculations of demand response potential, the earlier recovery estimate of 46000 AFY from Pacific Institute Report

Hydrologic Region	Lead agency for Groundwater Banking Project	Groundwater Basin/Subbasin Name	Recovery (AFY)	Energy Intensity (kWh/AF)[21]	Annual kWh	Estimated Pumping Capacity (kW)[22]	Notes from literature research/survey
							was replaced by 89000 AFY).
TL	Consolidated Irrigation District	-	8000	369	2,952,000	504	
TL	Kings County WD Apex Conjunctive Use	-	4000	369	1,476,000	252	
TL	James ID Lateral K	-	2000	369	738,000	126	
TL	Kern County Water Agency	-	98000	369	36,162,000	6175	
TL	Rosedale-Rio Bravo WSD	-	62500	369	23,062,500	3938	
TL	Cawelo Water District	Kern County	5500	369	2,029,500	347	
TL	Kern Delta Water District	-	94000	369	34,686,000	5923	
TL	Pixley Irrigation District	Tule	30000	369	11,070,000	1890	
TL	Wheeler Ridge Maricopa Water Storage District	-	50000	369	18,450,000	3151	
TL	Buena Vista Water Storage District and West Kern Water District	-	45000	369	16,605,000	2836	
TL	Kern Co Water Agency Pioneer Recharge and Recovery Project	-	98000	369	36,162,000	6175	
TL	James Irrigation District	Kings	4000	369	1,476,000	252	Groundwater supply is pumped from 63 extraction wells, 28

Hydrologic Region	Lead agency for Groundwater Banking Project	Groundwater Basin/Subbasin Name	Recovery (AFY)	Energy Intensity (kWh/AF)[21]	Annual kWh	Estimated Pumping Capacity (kW)[22]	Notes from literature research/survey
							wells are within district boundaries, and 35 wells are in easement area of City of San Joaquin. The 63 wells have flow capacity of 2400 gpm, pumping capacity of 210 cfs, and 75% efficiency. It is not clear how many of these extraction wells are used for recovery from groundwater banking project.
TL	Berrenda Mesa Water District	-	50000	369	18,450,000	3151	
TL	Kaweah Delta Water Conservation District	Kaweah	35000	369	12,915,000	2205	
TL	West Kern Water District	Kern County	20000	369	7,380,000	1260	
CR	Cadiz, Inc.	-	50000	369	18,450,000	3151	
CR	Coachella Valley Water District	Indio, Mission Creek, Desert Hot Springs	300000	369	110,700,000	18904	More than 100 wells across district boundaries pump groundwater.
Total					1,272,835,615	217,354	

CC=Central Coast, SC=South Coast, SF=San Francisco Bay, SJ=San Joaquin River, SL=South Lahontan, SR=Sacramento River, TL=Tulare Lake, CR=Colorado River

APPENDIX G:
List of Required Permits and Registrations

Note- not all of these may be applicable to all groundwater banking sites used for energy storage.

Agency	Permit / Registration	Criteria	Comments
FERC – Federal Energy Regulatory Commission	Hydro exemption or license	Will need either a conduit exemption, a 10-MW exemption, or a license, depending upon characteristics of hydro generator	Consult FERC small hydro website: https://www.ferc.gov/industries/hydropower/gen-info/licensing/small-low-impact.asp
	Qualifying Facility	80 MW or less using renewable generation	Form 556
EIA - Energy Information Administration	Generator Registration	1 MW or larger	EIA Form 860
CAISO – California Independent System Operator	FNM – Full Network Model	1 MW or larger	GRDT – Generation Resource Data Template
	Interconnection	If connected to transmission system	FERC wholesale interconnection application http://www.caiso.com/planning/Pages/GeneratorInterconnection/InterconnectionRequest/Default.aspx
	NRI – New Resource Integration	1 MW or larger (occasionally 500 KW or larger)	http://www.caiso.com/Documents/NewResourceImplementationGuide.doc
CEC – California Energy Commission	Small Hydro Certification	Required for RPS (Renewable Portfolio Standard)	CEC RPS-1
	Generating Unit ID	1 MW or larger	CEC-1304
WREGIS – Western Renewable Energy Generation Information System	QRE (Qualified Reporting Entity) Generating Unit ID		Credit for RECs (Renewable Energy Certificates)
SWRCB – State Water	Nonconsumptive Water Use Right		

Agency	Permit / Registration	Criteria	Comments
Resources Control Board			
	401 permit	Water Quality Certification	
Electric Utility	Interconnection	If connected to Distribution System	
	PPA (Power Purchase Agreement)	If selling output to utility	
Environmental Documents	CEQA (California Environmental Quality Act)	EIR (Environmental Impact Report)	
	USACE (U S Army Corps of Engineers) 404 permit	Discharge permit	
	CDFW (California Department Fish and Wildlife) 1602 permit	Streambed alteration permit	

Source: (House L. W., 2017 b)

ATTACHMENTS

Attachment I: Willow Springs Water Bank (WSWB) Fact Sheet

Publication Number CEC-XXX-2017-XXX-ATI

Attachment II: Pumping Test Data Summary for Willow Springs Water Bank. HDR Memorandum.

Publication Number CEC-XXX-2017-XXX-ATII-ATV

Attachment III: HDR Antelope Valley Water Storage (AVWS) Project Pumped Storage Study

Publication Number CEC-XXX-2017-XXX-ATII-ATV

Attachment IV: EPC 15-049 Tech Memo No. 1 – Economic Potential of Peak Hour Pumped Storage and Aquifer Pumped Hydro Technologies at Willow Springs Water Bank

Publication Number CEC-XXX-2017-XXX-ATII-ATV

Attachment V: EPC 15-049 Tech Memo No. 2- Statewide Benefits of Pumped Storage at Groundwater Banks

Publication Number CEC-XXX-2017-XXX-ATII-ATV