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FINAL PROJECT REPORT

California's In-Conduit Hydropower Implementation Guidebook

A Compendium of Resources, Best Practices, and Tools

Gavin Newsom, Governor

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PREFACE

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

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

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

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

California's In-Conduit Hydropower Implementation Guidebook: A Compendium of Resources, Best Practices, and Tools is the final report for Contract Number EPC-16-025 conducted by Stantec Consulting Services Inc., in partnership with NLine Energy Inc. and Stanford University. The information from this project contributes to the Energy Research and Development Division's EPIC Program.

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

ABSTRACT

Water systems in California have large untapped potential to recapture energy with in-conduit hydroelectric generation. Despite the promise of a high in-conduit hydropower market through a number of incentives over the past decade, the actual development of projects is below its potential mainly due to lack of knowledge in many critical aspects of in-conduit hydropower project life cycles. This project developed a guidebook and a business-case assessment tool that can assist various water purveyors with cost-effective implementation of in-conduit hydropower projects, specifically through the review of conventional and emerging turbine technologies, potential sites for project implementation, current regulatory and permitting requirements, interconnection processes, project financial viability assessments, and the design and performance monitoring of in-conduit hydropower systems.

In addition to providing a guidebook and a business case assessment tool, this report provides an update on the assessment of in-conduit hydropower potential in California based on the analysis of multiple data sources from the United States Geological Survey, State Water Resources Control Board Data, and California Department of Water Resources. The assessment estimates that 414 megawatts of maximum untapped in-conduit hydropower potential are available in California.

Keywords: in-conduit hydropower; small hydropower; energy recovery; energy efficiency; renewable energy; water supply systems; hydro-turbines; water conduits

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Introduction

Water systems in California have the large untapped potential to recapture energy with in-conduit hydroelectric generation, which would significantly reduce net energy consumption and provide renewable resource power to the electric grid. In-conduit hydropower is defined as the hydroelectric generation potential in engineered water conduits such as tunnels, canals, pipelines, aqueducts, flumes, ditches, and similar engineered structures for water conveyance. According to the last statewide resource potential assessment developed by the California Energy Commission (CEC) in 2006, more than 255 megawatts (MW) of hydropower projects could be developed across the state. Since this last assessment, several important and positive updates have changed the landscape for small hydropower. For example, many turbine technology manufacturers developed modular "water-to-wire" systems that target the in-conduit hydroelectric less than 1-MW market for a variety of applications, leading to cost-effective and promising installations. In addition, federal and state regulations and permitting processes have been simplified in the past decade. These advancements now provide opportunities to reconsider sites previously thought to have little or no potential for in-conduit hydropower.

Despite the advancements, the actual development of projects has waned over the past 10 years. The most recent Federal Energy Regulatory Commission (FERC) Notice of Intent report shows that since 2013, FERC only approved 26 in-conduit projects in California totaling 13.5 MW or about five percent of the 255 MW in-conduit potential forecasted in 2006. Additionally, the CEC's Renewable Portfolio Standard List of Facilities indicates 16 in-conduit hydroelectric facilities as eligible for Renewable Portfolio Standard certification or precertification since 2006, totaling about 12.4 MW. From this analysis, it is clear that, although the regulatory, environmental, and technical landscapes appear to encourage stakeholders to develop in-conduit hydroelectric projects, a total market penetration of only about five percent has been developed. Several reasons for this low market penetration include:

- Both new and conventional in-conduit hydroelectric technologies require an in-depth knowledge and understanding of the regulatory, environmental, and financial attributes of the small hydropower market. Water purveyors also lack guidance on project development cycles.
- Very few in-conduit hydroelectric projects take advantage of tax advantages or partner with private entities as part of a Power Purchase Agreement or lease structure (e.g., Federal Investment Tax Credit or Production Tax Credit).
- In-conduit hydroelectric projects over 500 kilowatts (kW) tying into the electric grid must comply with the often-complex California Independent System Operator's (California ISO) New Resource Implementation, Full Network Model, and California ISO metering requirements.
- Interconnection rules are not streamlined for reactive power generation projects such as in-conduit hydroelectric projects.

While a few agencies outside of California are compiling handbooks on small hydropower systems, these documents still have limitations since they often lack specificity on new generation in-conduit hydropower applications, guidance on equipment and site selection, design, implementation, regulatory frameworks, and lessons learned from case studies and applications at utilities or agencies. Research is needed to better provide guidance on the implementation and operation of in-conduit hydropower.

Project Purpose

The goal of this project was to develop a guidebook and business case assessment tool to promote cost-effective implementation of in-conduit hydropower projects and provide a comprehensive assessment of in-conduit hydropower generation potential in California. This project ultimately provided an invaluable knowledge base for municipal (water and wastewater), agricultural, and industrial agencies currently considering hydroelectric power, avoiding energy waste in water supply networks, and integrating in-conduit hydropower into their respective energy mixes. The project achieved those goals through execution of the following objectives:

- Review of conventional and emerging turbine technologies specifically for in-conduit hydropower, potential sites for projects, current regulatory and permitting requirements, interconnection processes, and project financial viability
- Assessment of current in-conduit hydropower generation potential in California
- Analysis of case studies that identify outcomes, success factors and barriers, current practices and lessons learned from in-conduit hydropower applications, and collect supporting operational and economic data
- Development of guidelines on various in-conduit hydropower life cycles including feasibility assessment, design and construction, operation, and performance monitoring
- Development of a business-case-assessment tool to assist utilities in the feasibility of in-conduit hydropower generation projects
- Evaluation of the benefits for Californians from this project

Project Approach

The research approach for project implementation guidance and its corresponding business case assessment tool entailed the six major activities listed below.

- Literature review. This literature search and analysis provided a comprehensive and critical review of current knowledge of in-conduit hydropower generation including resources required for implementation, operational performance and economics, regulatory frameworks, and existing guidebooks and handbooks developed by various agencies on in-conduit hydropower both in the United States and elsewhere.
- Questionnaire to association of California Water Agencies members. This activity was to develop a web-based questionnaire to solicit input from water agencies on both their current and potential in-conduit hydropower installations and to supplement existing findings from the literature review.

- Technology developer interviews. A series of interviews with technology providers increased understanding of their offerings and products, their main features, capabilities, and applications. Application samples were collected from both municipal and non-municipal sectors to document their implementation benefits and challenges
- Case studies and operational data analysis. These studies analyzed eight utilities from different parts of California to identify outcomes, success factors, barriers, current practices, and lessons learned from in-conduit hydropower applications. Operational and economic data was also collected.
- Workshops with hydropower experts. The project team joined a number of in-conduit hydropower experts and technology providers to attend a stakeholder workshop in California to identify key issues related to in-conduit hydropower potential and project implementation, as well as to develop recommended best practices.
- Assessment of in-conduit hydropower potential in California. This assessment provided an update on a current estimate of in-conduit hydropower potential in California. This assessment included multiple data sources such as the United States Geological Survey, State Water Resources Control Board, and the California Department of Water Resources. A Monte-Carlo simulation analysis, an approach to model the possible results by repeated random sampling, estimated the in-conduit hydropower potential from each data source.

Project Results

Review of In-Conduit Hydropower Technologies

Turbine technologies evolved substantially over the last decade. Project developers could therefore choose from among multiple alternative turbines, depending on their applications. This selection of technologies depended upon the water type (potable water, raw water, wastewater), available head and flow at the sites, and the tailrace layout (downstream-pressure requirement). Systems with downstream-pressure requirements typically use reaction turbines including pump-as-turbines; systems that discharge pressure to the atmosphere generally employ impulse turbines such as Pelton turbines.

In-Conduit Hydropower Project Life Cycle and Implementation Guidance

Any in-conduit hydropower project progresses through three main stages: a feasibility assessment, design and construction, and operation and performance monitoring.

During feasibility assessment the project developer focuses on site assessment and technology selection, meeting the regulatory and permitting requirements (including those pertaining to the interconnection process), and assessing project financial viability.

There are multiple potential sites for in-conduit hydropower in water conveyance and distribution infrastructures including diversion structures, irrigation chutes, check structures, run-of-the-river schemes in irrigation systems, pipelines from the source water, inlets to service reservoirs and along the water distribution network, wastewater treatment plant outfalls, and groundwater recharge sites. The energy potential of the site is either a function of the hydraulic head and water flow or the kinetic energy of flowing water. The head and flow parameters generally dictate the type of turbine; reaction turbines apply to low-head systems and impulse turbines are better suited for medium-high-head applications. However, some newer-generation impulse turbines can also operate in low-head systems. In addition to reaction and impulse turbines, there is growing interest in hydrokinetic turbines, although to date their implementation is not as widespread in California as in other western states, including Colorado and Washington. Based on the current analysis of publicly available literature, there are no hydrokinetic turbines installed for either pilot-or large-scale projects in engineered conduits in California. Given the large menu of options, both water and wastewater utilities must carefully evaluate available hydropower turbines, based upon site-specific applications and type of water conduits.

Project developers should also meet all federal and state regulations and permitting requirements for in-conduit hydropower projects. The federal government has simplified their process to increase market penetration for this renewable resource. Projects built within existing infrastructure, with capacity of less than five MW, may be eligible for a non-licensing and exemption process requiring only a Notice of Intent with the Federal Energy Regulatory Commission. Electric utilities should comply with any interconnection requirements, particularly for projects designed for grid export. In-conduit hydropower projects connecting to a utility grid must meet the interconnection standards and requirements of the local electric grid. California's Rule 21 requires additional protective equipment since hydroelectric turbines are rotating-equipment (non-inverter) technologies that provide reactive power to the grid. Simplification of the permitting process not only reduces permitting costs but also aids efficient project completion.

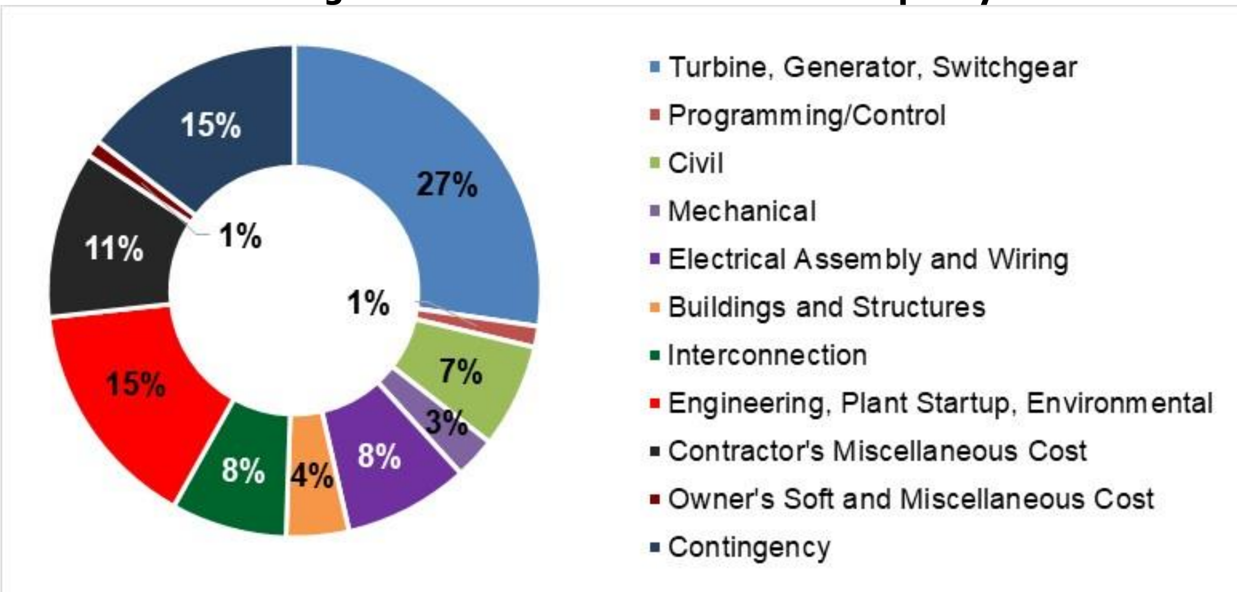
The financial feasibility of the project depends on initial project capital investment, annual (O&M) costs, and project benefits calculated on average annual energy generation and the price of the generated electricity. Turbine-generator systems typically contribute the most to the total investment cost, as shown in Figure ES-1. Operations and maintenance cost are usually not extensive for this type of project. It is important to note, however, that costs can vary widely between projects and should not be generalized.

The financial viability assessment should also consider the impact of changing tax structures and available electric utility programs (e.g., net energy metering, net energy metering aggregate, renewable energy self-generation bill credit transfer, electric-renewable market adjusting tariff, and others) that could affect the project's economics. In-conduit hydropower projects are typically financially feasible if total project costs are in the range of $5,000-$15,000/kW, with a pay-back period of fewer than 15 years. The project cost can be offset by a variety of grants available for California utilities including the Self-Generation Incentive Program administered by the California Public Utilities Commission.

Once the feasibility assessment is complete and the project is deemed technically and financially feasible, the project moves on to design and construction. There are multiple benefits in installing the powerhouse in a by-pass loop as a redundancy for turbine maintenance or if water flow cannot meet turbine requirements. The by-pass configuration is a useful safety measure that ensures the powerhouse does not interfere with current water-delivery operations. Once the turbine begins operation, both regular maintenance and performance monitoring are important.

The system's monitoring is through either a utility's supervisory control and data acquisition system or third-party dashboards that display generation performance, either in-house or remotely.

Figure ES-1: Example of Capital-Cost Breakdown of In-Conduit Hydropower Project Using a Francis Turbine With 500 kW Capacity



Source: Stantec, 2019

Business Case Assessment Tool

An Excel®-based workbook developed in this study will help water and wastewater utilities and other water purveyors assess the technical and economic feasibility of installing in-conduit hydropower in their service areas. The workbook includes calculations for estimating hydropower potential at a specific site and under specific conditions: optimal in-conduit hydropower technologies most suitable for the project, related life-cycle capital, (O&M) costs, and environmental benefits from greenhouse gas emission reductions.

In-Conduit Hydropower Potential in California

This report updates the assessment of in-conduit hydropower potential in California. This project incorporated multiple data sources including from the United States Geological Survey, the California State Water Control Board, and the California Department of Water Resources. Based on these data, the maximum estimated in-conduit hydropower potential in the State of California is 414 MW, as shown in Table ES-1.

Table ES-1: Summary of Assessments

Assessment	Estimated Potential (MW)
Minimum potential uninstalled capacity (USGS)	368
Maximum potential uninstalled capacity (SWRCB and DWR)	414
Currently installed capacity	343

Source: Stanford University, 2019

The installed in-conduit hydropower systems in Southern California are concentrated along the coast near the cities of Los Angeles and San Diego; there is still, however, available capacity for installations in both areas. While most installed systems in Northern California are concentrated in or near irrigation districts in the state's central valleys, assessment results suggest that there are significant available capacities in both the San Francisco and San Jose areas.

Conclusions and Recommendations

Development of in-conduit hydropower, unlike solar or wind power, can potentially provide a source of capacity and renewable energy to California that is not fundamentally intermittent. Incorporation of in-conduit hydropower in the energy mix will bring the state closer to its mandated Renewable Portfolio Standard goals and advance achievement of renewable resource targets – 100 percent clean energy and carbon neutrality by 2045 – enshrined in Senate Bill 100 and Executive Order B-55-18. Unlike large hydropower systems, in-conduit hydropower systems have minimal environmental impacts since they directly integrate the related technology into the existing infrastructure.

The recent technological Renaissance in turbine technologies offers improved performance, modularity, portability, and scalability, which together have created new opportunities to revisit sites that were initially deemed unfeasible for expedient and cost-effective energy production. Simplification of the regulatory and permitting processes also provides more fertile ground for in-conduit hydropower projects. Nevertheless, project financial viability still requires project cost assessments, revenue opportunities, and availability of grants and incentives. The financial viability assessment should also consider changing tariff rates and individual electric utility programs. Experts suggest planning the interconnection process with the local electric utility to avoid potential delays related to grid interconnection. The design and operating strategies of in-conduit hydropower projects should also minimize interference with current water-delivery operations.

While many water utilities in California have already implemented in-conduit hydropower systems, there is still large in-conduit hydropower untapped potential in the state's water-supply systems. This research study identified various key issues that limit in-conduit hydropower market penetration, and further provides recommendations for future research:

- Implementation of modular turbine technologies with standardized components to reduce powerhouse construction costs
- Better promotion of in-conduit hydropower at state and federal levels that emphasizes environmental and financial benefits and aids attainment of advantageous tariffs
- Development or reintroduction of tariff structures based on rates that generate sustainable and predictable cash flows for in-conduit hydropower projects (for example, E-ReMAT). Nearly all of the in-conduit hydropower potential resides within tax-exempt municipal agencies in the state; these future projects should be financially encouraged with programs that are not solely reliant on federal tax subsidies or changing grants and subsidies.

- Identification of new funding opportunities that promote greater understanding of the regulatory landscape for in-conduit hydropower projects
- Understanding the role and sensitivity of critical parameters on project economics
- Establishment of better mandates that simplify the interconnection process for conduit hydropower projects
- Application of a more holistic approach to integrated water-energy management based upon the participation and communication of different stakeholders impacted by in-conduit hydropower system installations (water utilities, irrigation districts, end users, and regulators)
- Better understanding of the potential for harnessing hydrokinetic energy and its corresponding technology.

Knowledge Transfer (Advancing the Research to Market)

The project team shared this research project's results through:

- A workshop with in-conduit hydropower experts and technology providers who identified key issues and recommended best practices related to in-conduit hydropower potential and project implementation.
- An Excel®-based workbook developed as a tool to assist water and wastewater utilities and other water purveyors in assessing the technical and economic feasibility of installing in-conduit hydropower systems in their respective service areas. The workbook helps them evaluate hydropower potential at specific sites and under specific conditions, optimal in-conduit hydropower technologies suitable for the project, life-cycle capital and O&M costs, and the environmental impact of greenhouse gas emissions
- Publication of the manuscript *Recent Innovations and Trends in In-Conduit Hydropower Technologies and Their Applications in Water Distribution Systems*, published in the *Journal of Environmental Management*, in August 2018.
- Preparation of a manuscript on the statewide in-conduit hydropower resource assessment.
- Oral presentations of the project's work at the National Hydropower Association WaterPower Week in Washington, D.C., between April 30 – May 2, 2018, and at the American Water Works Association's Annual Conference and Exposition in Denver, California between June 10 – June 12, 2019.
- A webinar conducted in collaboration with the Water Research Foundation to present results of the study to that organization and to CEC subscribers, water and hydropower professionals, government agencies, electricity providers, and academics. The webinar had more than 200 attendees.

Benefits to California

The installation of in-conduit hydropower provides the opportunity to generate renewable-resource electricity that is not intermittent and has minimal environmental impact. This project's conclusions will promote technological advancements and breakthroughs that overcome barriers to achievement of California's statutory energy goals by providing:

- A comprehensive update of California's in-conduit hydropower potential assessment.
- A knowledge base and guidebook on expected project performance including equipment, siting criteria, design and performance monitoring, costs, regulatory frameworks, and other relevant information to assist in developing in-conduit hydropower systems.
- A business-case assessment tool that will help utilities select the technology best suited to determining life-cycle cost and other environmental benefits.

The conclusions of this project will enable utilities, businesses, and communities to simplify and speed up project development, provide knowledge on both traditional and emerging technologies, and assist in permitting and licensing. The project will also benefit ratepayers with greater electricity reliability, lower costs, and increased safety by removing the uncertainty from investment decisions and facilitating development of cost-effective in-conduit hydropower generation.

CHAPTER 1: Introduction

Background

Rising energy demand and its cost, together with climate change concerns, have hastened the transition from traditional fossil-fueled generation to renewable energy sources. Several states in the United States have developed and adopted policies that encourage renewable-resource energy development. One of the most important examples in California is the adoption of Renewable Portfolio Standard (RPS), a market-based policy requiring electricity retailers in the state to increase their sales from renewable energy sources (CEC, 2002). To date 29 states have successfully adopted RPS policies that cover 56 percent of total U.S. electricity retail sales from renewables (Johnson and Hadjerioua, 2015).

Hydropower, one of the earliest sources of electricity generation, is still a major source of electricity generation in the U.S. due to the robustness of its available technology and its simple integration with existing systems (Doig, 2009). The U.S. hydropower fleet consists of 2,198 active plants with a total capacity of 79.64 gigawatts (GW), accounting for approximately seven percent of all U.S. generating capacity (Uría-Martínez et al., 2015). In recent years, the development of large hydropower (more than 30 megawatts [MW]) has declined due to concerns with regulatory and permitting issues, land acquisition costs, and environmental impacts (Lisk et al., 2012). Nonetheless, according to the Hydropower Vision initiative of the U.S. Department of Energy (DOE), hydropower growth is still expected to grow to nearly 150 GW by 2050 (DOE, 2016) because of the following factors:

- Upgrades at existing hydropower plants
- Powering of non-powered dams
- New stream-reach developments (NSDs)
- New pumped-storage hydropower (PSH)
- Powering existing canals and conduits

Within the above hydropower project portfolio, small hydropower systems are an important source of renewable energy in the U.S. and in other parts of the world. Small hydropower is a unit process capable of generating capacity up to 10 MW (FERC, 2017a). Small-hydro systems can be further classified as mini-hydro (fewer than 2,000 kilowatts [kW]), micro-hydro (fewer than 500 kW), and pico-hydro (fewer than 10 kW) (Paish, 2002). The two key advantages of small hydropower are in its higher efficiency (70-90 percent efficiency) and high capacity factor compared to wind and solar energy (Uhunmwangho and Okedu, 2009). Existing small hydropower comprises about 75 percent of the current U.S. hydropower fleet, with a total of 1,640 plants with a combined generating capacity of approximately 3,670 MW (Johnson and Hadjerioua, 2015). However, despite existing extensive installations, there remains large untapped small-hydro potential. According to a study funded by the CEC in 2006, California has 2,467 MW of undeveloped small-hydropower potential in the majority of natural water courses (2,189 MW), with the remaining part in man-made water conduits (255-278 MW) (Park, 2006).

In-conduit hydropower is the hydroelectric generation potential in engineered conduits such as tunnels, canals, pipelines, aqueducts, flumes, ditches, and similar engineered water conveyances. Engineered conduits distribute water for agricultural, municipal, and industrial consumption. The untapped potential of in-conduit hydropower generation has largely remained unexplored and has recently received the attention of regulators in a number of states. In 2013, two sets of legislation to increase the efficiency of the regulatory process included the Hydropower Regulatory Efficiency Act of 2013 (H.R. 267) and the U.S. Bureau of Reclamation's *Small Conduit Hydropower Development and Rural Jobs Act* (H.R. 678) (Johnson and Hadjerioua, 2015). In addition, the recent technological Renaissance in off-the-shelf, low-cost, and modular "water-to-wire" turbines for in-conduit hydropower has greatly improved the efficiency and potential of those technologies. Many turbine technology manufacturers developed modular "water-to-wire" systems to target the in-conduit hydroelectric market with size less than 1-MW market and claimed cost-effective systems in a variety of promising installations.

Despite the above regulatory and technological advancements, the actual development of projects has waned over the last 10 years. The most recent Federal Energy Regulatory Commission (FERC) Notice of Intent shows that since 2013, FERC only approved 26 in-conduit hydropower projects in California for a total of 13.5 MW or about five percent of the 255 MW in-conduit potential forecasted in 2006 (FERC, 2017b). Additionally, the CEC's RPS list of facilities indicates 16 in-conduit hydroelectric facilities eligible for certification or precertification since 2006, totaling about 12.4 MW (The Energy Commission, 2019). From this analysis, it is clear that, although the regulatory, environmental, and technical landscapes appear to encourage stakeholders, only a total market penetration of less than five percent (based on the 2006 Statewide Resource Assessment market potential) is proceeding to development. Several potential reasons explaining this low market penetration include the following:

- Lack of knowledge of the new and conventional in-conduit hydroelectric technologies required for conducting initial project feasibility assessments
- Only a few in-conduit hydroelectric projects take advantage of tax benefits or collaborate with a private partner in a Power Purchase Agreement or lease structure (e.g., Federal Investment Tax Credit or Production Tax Credit).
- In-conduit hydroelectric projects over 500 kW and exporting to the grid must comply with the often complex California Independent System Operator (California ISO) New Resource Implementation Full Network Model and metering requirements.
- Interconnection rules are not streamlined for reactive power-generation projects such as in-conduit hydroelectric projects.

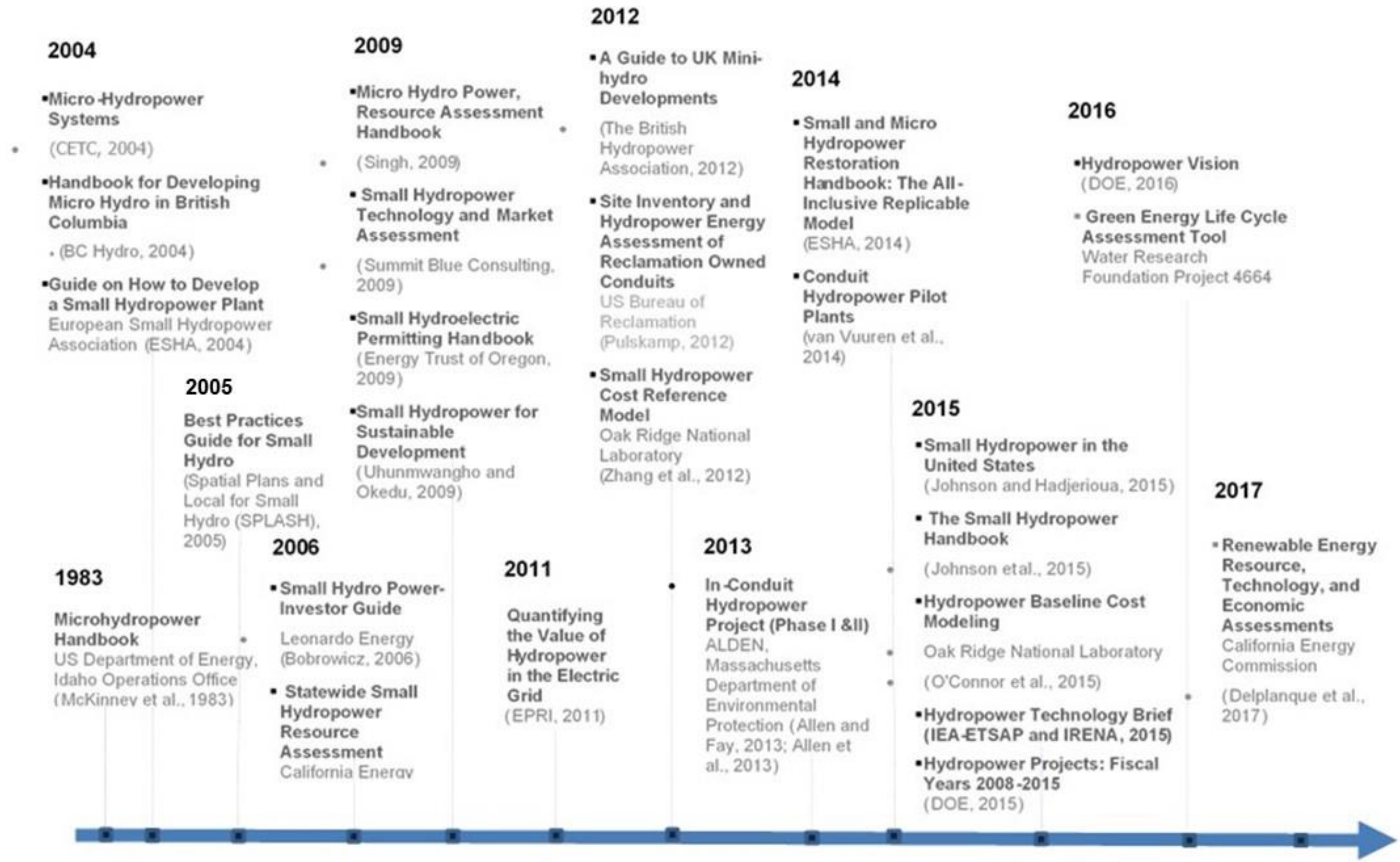
The above issues are supported by the fact that the last resource assessment for in-conduit hydropower was conducted more than a decade ago. Recent technology advancements provide opportunities for revisiting sites deemed ineligible for in-conduit hydropower development. An update on the in-conduit hydropower potential assessment in California is therefore also a timely research need. As California is heading toward 100 percent clean energy and carbon neutrality by 2045, as mandated in Senate Bill 100 and Executive Order B-55-18 (Executive Order B-55-18, 2018; SB-100, 2018), incorporation of in-conduit hydropower into the power mix becomes imperative.

Over the last decade a number of agencies have compiled information that provide high level, “directional guidance” for on-site and equipment selection and commissioning, operating, and testing small hydropower systems. Figure 1 presents a list of selected handbooks and guidebooks published since 1983. Most of these publications provide general information about small hydropower systems including feasibility, technologies, and economic and environmental assessment (McKinney et al., 1983; BC Hydro, 2004; CETC, 2004; Bobrowicz, 2006; Summit Blue Consulting, 2009; Uhunmwangho and Okedu, 2009; Johnson and Hadjerioua, 2015; Johnson et al., 2015). Several handbooks and reports additionally focus on specific topics related to small hydropower including resource assessment (Park, 2006; Singh, 2009), cost and economic assessment (EPRI, 2011; Zhang et al., 2012; O'Connor et al., 2015; Delplanque et al., 2017), regulations and permitting (Energy Trust of Oregon, 2009), and grid interconnection guidelines (Energy Trust of Oregon, 2010). Other reports discuss development of in-conduit hydropower projects (Pulskamp, 2012; Allen and Fay, 2013; Allen et al., 2013). Nevertheless, there are several limitations associated with publicly available handbooks and guidebooks, including:

- Lack of specificity on new in-conduit hydropower applications.
- Technologies discussed are generally outdated.
- Lack of case studies, best practices and lessons learned, including solutions to typical barriers and challenges, from the applications of peer utilities and agencies.
- Lack of information about recent changes in regulations and permitting.
- Cost-benefit analyses are outdated and not tailored specifically for in-conduit hydropower.
- Lack of a comprehensive assessment of in-conduit hydropower potential.
- Lack of guidance for developing a business case for project development.

In addition, information about new technologies developed in the past 10 years is dispersed and hard to locate in the literature. Lack of knowledge and examples on the development of new in-conduit hydropower technologies and their associated case studies may also cause risk-aversion behavior toward adoption of new technologies by prospective developers. Unlike large hydropower, small hydropower installations have at their disposal a wide variety of designs, layouts, equipment, and materials, which need to be fully understood before construction (IEA-ETSAP and IRENA, 2015).

Figure 1: Relevant Handbooks and Guidebooks Published 1983 – 2017



Source: Stantec, 2019

Project Objectives

The goals of this project were to develop a guidebook and a business case assessment tool to assist cost-effective implementation of in-conduit hydropower projects and provide a comprehensive assessment of in-conduit hydropower generation potential in California. The project achieved these goals through the following objectives:

- Review conventional and emerging turbine technologies specifically for in-conduit hydropower development, potential sites for project construction, current regulatory and permitting requirements, interconnection processes, tariff alternatives, and financial viability
- Assessment of current in-conduit hydropower generation potential in California
- Analysis of case studies to identify outcomes, success factors and barriers, current practices and lessons learned from in-conduit hydropower applications, and collect supporting operational and economic data on this generation alternative
- Development of guidance on in-conduit hydropower project life cycles including feasibility assessment, design and construction, and operation and performance monitoring
- Development of a business case assessment tool that will assist utilities in determining the feasibility of in-conduit hydropower generation projects
- Evaluation of the benefits of in-conduit hydropower to ratepayers in California

Organization of the Report

This report guidebook is organized into the following chapters:

Chapter 1: Introduction;

Chapter 2: Overview of Research Approach;

Chapter 3: Review of In-Conduit Hydropower Technologies:

Chapter 4: Project Implementation Guidance;

Chapter 5: Business Case Assessment Tool Development;

Chapter 6: Assessment of In-Conduit Hydropower Potential in California;

Chapter 7: Knowledge Transfer Activities;

Chapter 8: Conclusions and Recommendations; and

Chapter 9: Benefits to Ratepayers.

CHAPTER 2: Overview of Research Approach

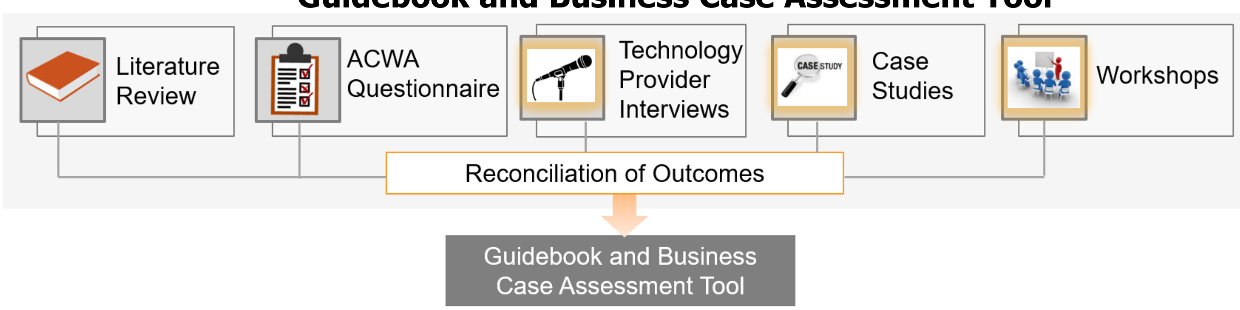
The objective of this chapter is to provide an overview of various tasks that meet the main objectives of this project, particularly in relation to the following:

- Development of comprehensive guidance on development of in-conduit hydropower, as well as the corresponding business case assessment tool
- Comprehensive assessment of the in-conduit hydropower generation potential in California

Method for In-Conduit Hydropower Implementation Guidance and Business Case Assessment Tool Development

This section introduces the study's approach to develop guidance for in-conduit hydropower development and the corresponding business case assessment tool. The approach is comprised of five different activities, as illustrated in Figure 2. This section briefly discusses the methodologies used to conduct a literature review, utility questionnaire, interviews with technology developers, case studies, and workshops with in-conduit hydropower experts.

Figure 2: Overview of the Research Approach for the Development of the Guidebook and Business Case Assessment Tool



Source: Stantec, 2019

Literature Review

The objective of this activity was to conduct a literature search and analysis that provides a comprehensive and critical review of the current state of knowledge on in-conduit hydropower installations and better understanding of its global practices. This activity focused on collecting and reviewing a variety of documents including handbooks and guidebooks, gray and peer-reviewed articles, case studies, white papers, conference proceedings and project reports, developers' and technology providers' fact sheets and other publications collected from academics, research agencies, technology providers, and utilities. In particular, the literature review focused on the following aspects of in-conduit hydropower projects:

- Site assessment and selection
- Conventional and emerging technologies

- Regulatory and permitting requirements
- Cost-benefit analysis
- Environmental assessment

The information collected through the review of literature provided an overview of the recent innovations and trends of hydropower generation from water conduits. This information was further integrated with the knowledge obtained through the activities presented in the following chapters.

Questionnaire Distributed to Association of California Water Agencies Members

This activity focused on developing a web-based questionnaire to solicit input from water and wastewater utilities on their current or potential in-conduit hydropower projects. The information collected from the questionnaire supplemented the findings of the previous literature review and provided data for the statewide resource assessment. The questionnaire included 48 questions in a multiple-choice format and was distributed in the following key areas:

- General utility information
- In-conduit hydropower feasibility assessment and status
- Information about current installed hydropower systems
- Information about current installed in-conduit hydropower systems
- In-conduit hydropower operating challenges

The team distributed the questionnaire through the ACWA's newsletter as well as in person during the ACWA meeting in Anaheim, California, held from November 28 to December 1, 2017. A total of 39 responses were received from water agencies, consultants, and technology providers that are, for the most part, located in California. Table 1 provides a list of agencies that participated in the questionnaire; some agencies are anonymous because they preferred not to disclose their names as part of this effort.

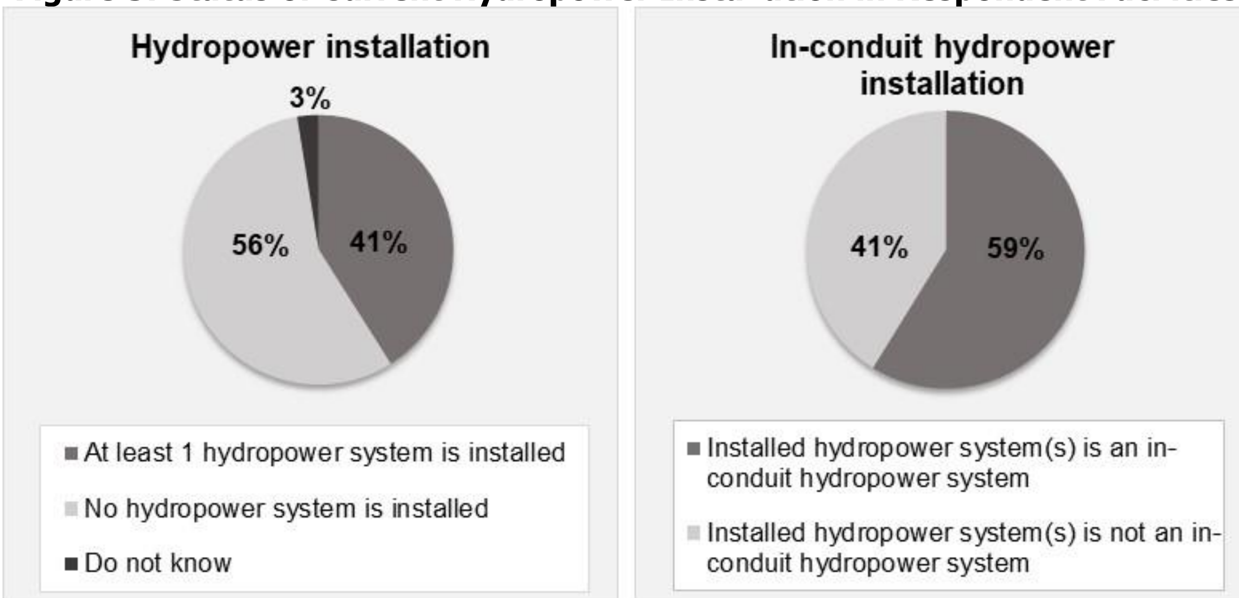
As shown in Figure 3, 41 percent of the respondents to the questionnaire have at least one hydropower system installed at their facilities, of which 59 percent are considered to be in-conduit hydropower systems. As also shown in Figure 4, the majority of the installed hydropower systems at these facilities are less than five MW, with 41 percent of the facilities of capacities between 100 kW to 1000 kW. While a good share of the respondents did not know the annual energy generation from their hydropower facilities (25 percent), about 33 percent of the facilities generate less than one gigawatt-hour (GWh) per year. Further outcomes of the questionnaire have been embedded within the discussion of the following chapters.

Table 1: Agencies Responding to the Questionnaire

ID	Agency Name	City/Town	State
1	Calaveras County Water District	San Andreas	CA
2	Calaveras Public Agency District	San Andreas	CA
3	Calleguas Municipal Water District	Thousand Oaks	CA
4	City of Benicia	Benicia	CA
5	City of La Verne	La Verne	CA
6	City of Lakewood	Lakewood	CA
7	City of San Diego	San Diego	CA
8	City of Vacaville	Vacaville	CA
9	Civiltec Engineering, Inc.	Monrovia	CA
10	D.A. Lampe Construction	Chico	CA
11	DJ Warren & Associates, Inc.	Grapeview	CA
12	East Bay Municipal Agency District	Oakland	CA
13	Georgetown Divide Public Agency District	Georgetown	CA
14	Marina Coast Water District	Marina	CA
15	Massachusetts Water Resources Authority	Winthrop	MA
16	Metropolitan Water District of Southern California	Los Angeles	CA
17	North Marin Water District	Alameda	CA
18	Natel Energy (two responses)	-	-
20	Placer County Water Agency	Auburn	CA
21	Rancho California Water District	Temecula	CA
22	Sacramento Suburban Water District	Sacramento	CA
23	San Diego County Water Authority	San Diego	CA
24	San Gabriel Valley Water Company	El Monte	CA
25	San Jose Water Company	San Jose	CA
26	Silicon Valley Clean Water	Redwood City	CA
27	Sonoma County Water Agency	Santa Rosa	CA
28	South Tahoe Public Agency District	South Lake Tahoe	CA
29	Sunnyslope County Water District	Hollister	CA
30	Tollhouse Energy Company	Graham	WA
31	United Water Conservation District	Camarillo	CA
32	Valley Center MWD	Valley Center	CA
33	Voith Hydro Inc.	York	PA
34	Agency A (Anonymous)	Northern California	CA
35	Agency B (Anonymous)	Northern California	CA
36	Agency C (Anonymous)	Northern California	CA
37	Agency D (Anonymous)	Southern California	CA
38	Agency E (Anonymous)	Southern California	CA

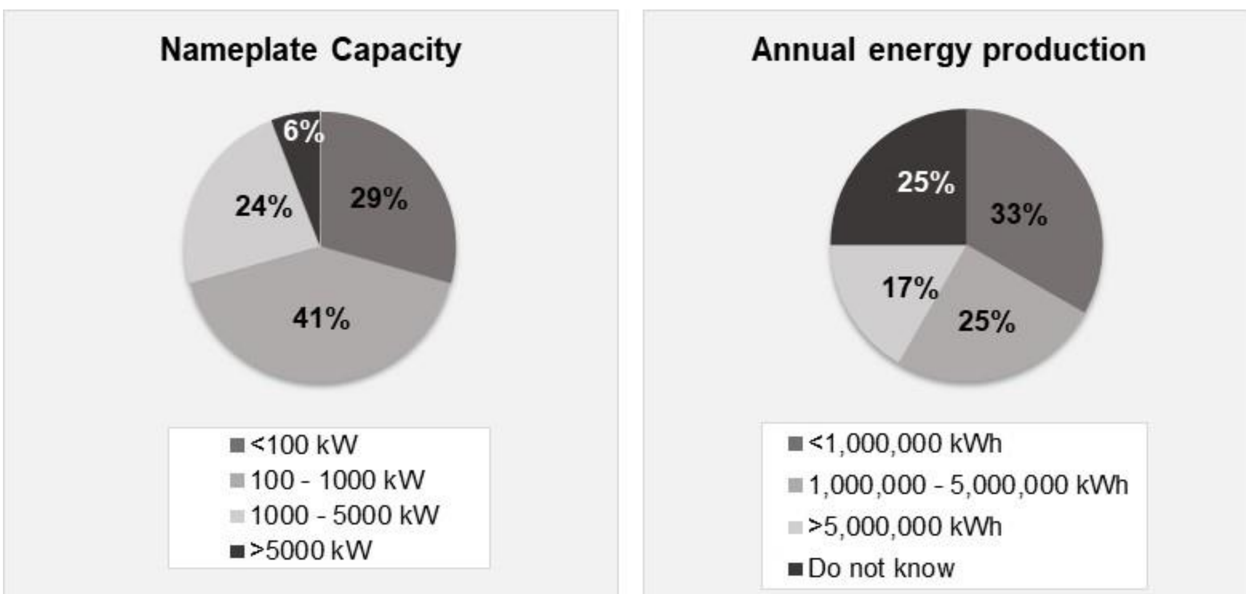
Source: Stantec, 2019

Figure 3: Status of Current Hydropower Installation in Respondent Facilities



Source: Stantec, 2019

Figure 4: Nameplate Capacity and Annual Energy Production of the Installed In-Conduit Hydropower Systems in Respondent Facilities



Source: Stantec, 2019

Interviews with Technology Providers

Phone interviews with several technology participants provided additional knowledge on current products and services related to in-conduit hydropower generation. These interviews also provided the opportunity to learn more about the application of these technologies at water and wastewater utilities. Table 2 presents the list of technology developers that participated in the interviews.

Table 2: List of Technology Providers Participated in the Interviews

No	Utility Name	Technology
1	Helio Altas	Modular waterwheel
2	Mavel	Pelton, Francis, siphon turbines
3	Instream Energy Systems	Hydrokinetic turbine
4	Canyon Hydro	Pump-as-turbine
5	Emrgy	Twin hydrokinetic turbines

Source: Stantec, 2019

Overall, the discussions covered the following topics:

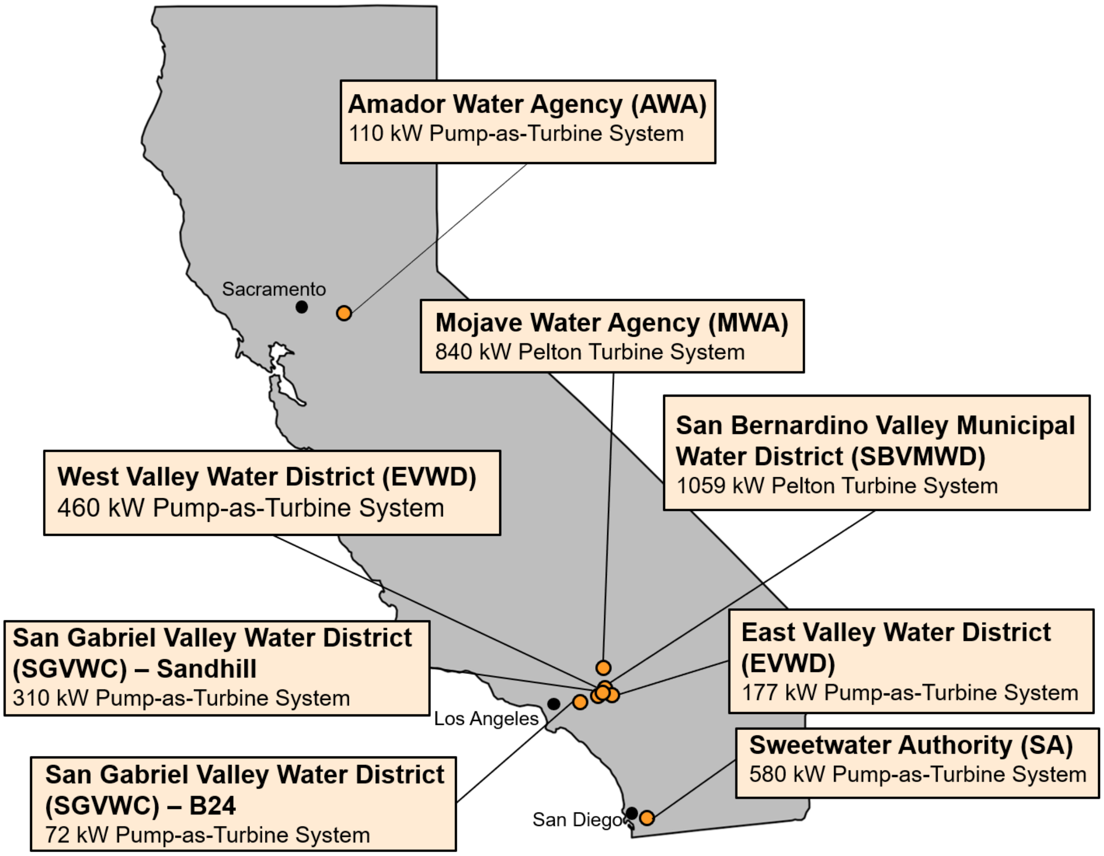
- Overview of the products, in terms of main features, capabilities and applications
- Examples of applications in the municipal and non-municipal sectors
- Discussion of the benefits and challenges from implementation of various products
- Information on potential municipal and non-municipal case studies considered for this project
- Request for sharing documentation and information pertinent to the case studies and product applications

Key information from these communications with technology providers is embedded within the following chapters.

Development of Case Studies

The main objective of this activity was to identify outcomes, success factors and barriers, current practices, and lessons learned from in-conduit hydropower applications, and to collect supporting operational and economic data. For this project, eight in-conduit hydropower projects that were constructed or will be constructed by 2019 in California were selected as case studies: Amador Water Agency (AWA), East Valley Water District (EVWD), Mojave Water Agency (MWA), San Bernardino Valley Municipal Water District (SBVMWD), San Gabriel Valley Water Company (SGVWC) – Sandhill, SGVWC- B24, Sweetwater Authority (SA), and West Valley Water District. (WVWD). The selection of the case studies was based on criteria that provide a meaningful, diverse response to the broadest possible audience interested in constructing in-conduit hydropower projects. Figure 5 presents the location and brief description of each case study.

Figure 5: Case Studies Selected for This Project



Source: Stantec, 2019

The case studies included the following steps:

- Review Documents and Identify Questions. Relevant information required for this study was collected from utility engineering and operations staff, energy managers, energy operators, and regulatory liaisons. After reviewing the provided documents, questions were formulated for follow-up interviews.
- Interview Case-Study Utilities. A series of face-to-face meetings with the utilities was conducted to gain additional information from end-user perspectives as well as to confirm the information provided in the previous step.
- Summarize Case Study Findings. The final step of this task was to incorporate and analyze all the information obtained from the documents review and on-site meetings and summarize those findings in a document. The case study summaries include the following critical information from each project:
    - Project drivers, classification of conduit, water source and type
    - Technology and manufacturer characteristics (turbine, generator, other equipment)
    - Estimated nameplate capacity, annual generation, capacity factor
    - Environmental consideration and California Environmental Quality Act (CEQA) filing type, FERC licensing and exemption type

- Water rights and/or water quality characteristics
- Interconnection process and type, energy-use type (on-site or export)
- Tariff and Power Purchase Agreement characteristics
- Project cost with detail on major non-construction, equipment, construction items
- Incentive/grant/subsidy characteristics applied to the project
- Financing characteristics (cash-in-hand, bonds) and cost-benefit estimates
- Contracting method for engineering services, equipment, and construction
- Review of actual performance since installation

Workshop

The project team held a facilitated workshop with in-conduit hydropower experts on July 10, 2018 at the Stantec office in Sacramento, California. A total of 24 water and wastewater utilities, technology providers, and hydropower experts were invited and attended the workshop. Table 3 shows the distribution of the workshop participants based on different categories.

Table 3: Distribution of Workshop Attendees

Category	Number of Participants
Utilities	4
Technology providers	9
Consultants	8
Energy Commission & Water Research Foundation project managers	3

Source: Stantec, 2019

The first part of the workshop consisted of overall project updates and a short presentation from the attending technology providers, as presented in Table 4.

Table 4: List of Technology Providers Participating to the Workshop

Technology Provider	Product
Canyon Hydro	Pelton, Francis, In-line Francis, Pump-as-Turbines, Pico hydro turbines
Mavel	Kaplan, TM Modular Micro turbines (Siphon turbines)
Natel Energy	Linear Pelton hydroEngine
Instream Energy Systems	Hydrokinetic turbines
Emrgy	Twin Module Hydrokinetic turbines
Gilkes	Francis, Pelton, and Turgo turbines
Helio Altas	Modular waterwheel (Helios PowerWheel)

Source: Stantec, 2019

In the second part of the workshop, the participants were divided into two break-out groups to facilitate discussion and interaction. Each break-out group covered, in different sub-sessions, two different themes and their corresponding discussion items, as presented in Table 5. The break-out groups' objective was to assess the current state of knowledge on each of the themes, discuss the related challenges, issues, trends, and their associated opportunities and recommended practices. For the break-out discussions, each group was assigned a leader and a scribe. The leader ensured that the topics were covered and summarized within the allotted time frame, whereas the scribe captured and recorded the discussion items. The leader then summarized the major points and presented them back to the entire group.

Table 5: Breakout Group Themes

Theme	Discussion Topics
Theme #1: Business Case Assessment	• Resource assessment and site selection • Understanding of the rate structures • Funding/incentives • Internal and external communication and approval for funding • Potential for harnessing hydrokinetic energy and the corresponding technology
Theme #2: Project Implementation and Operation	• Technology selection and procurement practices • Interconnection issues • Coordination and approval issues with electric utilities • Supervisory control and data acquisition (SCADA) system and control strategies • Integrated water production and energy generation

Source: Stantec

Reconciliation of Outcomes

The team compiled and critically revisited the information, outcomes, and conclusions from the various tasks to develop a guidebook and a business-case assessment tool to assist municipal, agricultural, and industrial water purveyors with development of in-conduit hydropower generation projects.

It is important to note that current and recommended practices developed through the report are the result of the information collected through the various tasks conducted in this study and based on the discussion with selected project developers, technology providers and utility case studies. Therefore, some of the findings and outcomes may not be applicable and suitable for applications in water and wastewater utilities with different business goals, configurations, and operating conditions.

Method for Statewide Resource Assessment

The main objective of this task was to revisit the previous estimates reported by the CEC in 2006 pertaining to untapped in-conduit hydropower potential in California, and to provide an update on the estimation using a new methodological approach. This novel data-driven methodological approach coupled a number of datasets including total surface water withdrawals in the state and metered water deliveries from different water agencies. This drew a more holistic estimate of potential in-conduit hydropower generation. Figure 6 illustrates an overview of the assessment method used.

Figure 6: Overview of the Statewide Resource Assessment Method Used in this Project

Source: Stanford University, 2019

Briefly, the team collected data from multiple sources, namely the United States Geological Survey, the California Department of Water Resources, and the State Water Resources Control Board. These datasets were pre-processed using an in-house-developed algorithm for the following purposes:

- Removal of duplicates and errors
- String matching to combine data sources
- Back calculation to supplement data gaps
- Review of missing data
- Standardization of data formats

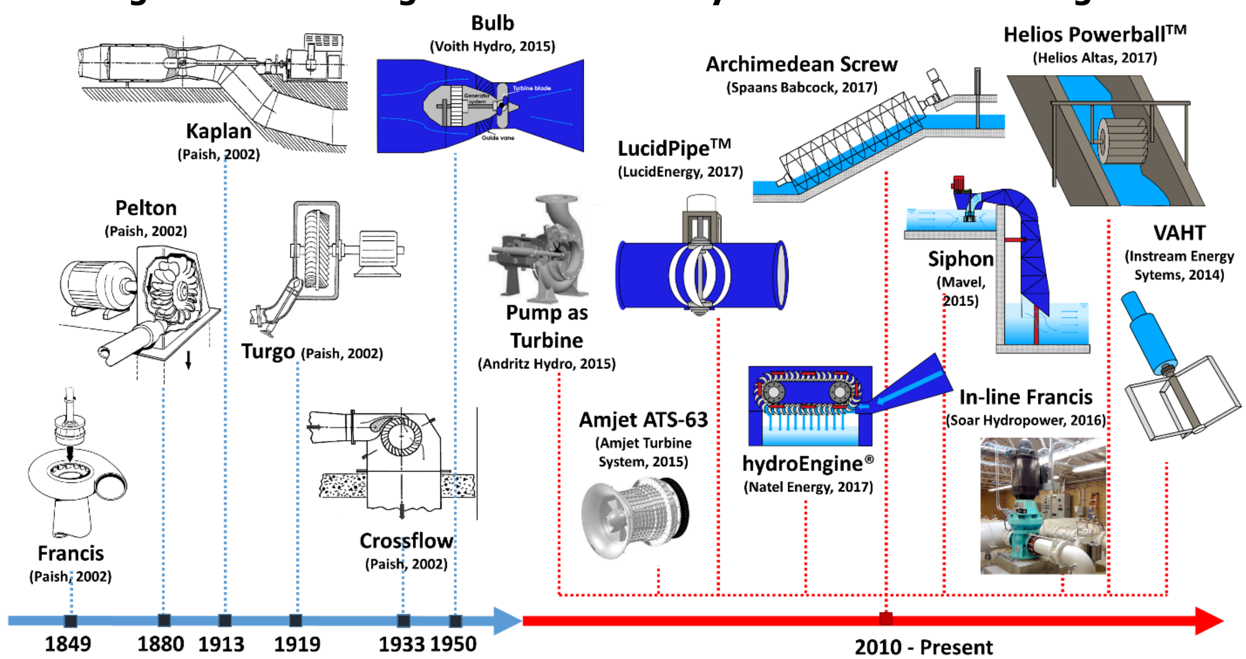
After data pre-processing, the key variables to estimate hydropower potential including head, flow, capacity factor, and load factors were identified. These variables were then used as inputs for Monte-Carlo simulations. A Monte-Carlo analysis was conducted to provide the most probable value of capacity that can be developed at each site considering the distribution of possible head and capacity factors. Those factors were based on the estimated values of these variables across existing systems. Detailed information about the methods for the statewide resource assessment conducted in this project is provided in Chapter 6.

CHAPTER 3: Review of In-Conduit Hydropower Technologies

Turbine technologies have substantially evolved in the past century, especially in the last decade. Figure 7 shows the chronological evolution of several hydro-turbine technologies. This chapter provides necessary background information on hydro-turbine technologies, particularly in relation to the following:

- Review of conventional turbine technologies
- Review of the new and emerging technologies developed over the past 10 years
- Comparison of new and conventional technologies in terms of their specifications, applications, benefits and limitations, as well as their technological readiness levels

Figure 7: Chronological Evolution of Hydro-Turbine Technologies



Source: Sari et al., 2018

Conventional Technologies

Using conventional turbines to generate electricity from moving water started more than a century ago. Based on their main operating principles, the majority of turbines can be broadly categorized as either reaction or impulse turbines. A reaction turbine, such as Francis and Kaplan turbines, uses both pressure and water movement to generate an upward hydrodynamic force that rotates the runner blades. An impulse turbine, such as Pelton, Turgo, and Crossflow turbines, uses runners that are rotated by water jets at high velocities. General information regarding these turbines is discussed in the following paragraphs and summarized in Table 6 for comparison purposes in relation to their design specifications and capacities, benefits and limitations.

Kaplan Turbines

Kaplan turbines were first developed in the early 20th Century and designed to operate in low-head systems (less or equal to 3 – 131 feet) with high water flows (100 – 1,050 cubic feet per second). The turbine utilizes water flowing through the inlet guide vanes that act upon the propeller-like blades to create shaft power (Figure 8 (a))**.** The runner blades for Kaplan turbines are adjustable, making them one of the most adaptive turbines on the market. The generator for Kaplan turbine is usually installed outside of the water conduit. Although it is relatively expensive, it is highly adjustable and characterized by its high efficiencies (more than 85 percent for design flow above 50 percent). Kaplan turbines are generally installed in canals, dam spillways, and diversion structures (Johnson et al., 2015).

Francis Turbines

Francis turbines develop torque and power by imparting a whirl velocity to the water. Designed in the late 19th Century, these turbines were intended to operate under a wide range of heads (less or equal to 164 – 328 ft). In Francis turbines, water is introduced radially at the entrance of the runner and turns 90 degrees within the runner to discharge water axially at the outlet (Figure 8 (b)). Similar to Kaplan turbines, Francis turbines are generally simpler and have high efficiency (75-85 percent for design flow above 50 percent). However, one of the limitations of Francis turbines is in their low capability to operate effectively with flows that are outside the design range (15 – 800 cubic feet per second [cfs]). Francis turbines are commonly utilized in dam and irrigation canals.

Bulb Turbines

Bulb turbines (also known as tubular or pit turbines) are propeller-type turbines with an operating principle similar to that previously described for Kaplan turbines. In the bulb turbine's fully axial design, the generator, the wicket gate, and the runner are housed together in a large bulb (hence the name "bulb turbine") so that the entire device is placed inside the water delivery tube (Figure 8 (c)).

Pelton Turbines

Pelton turbines are usually designed for high-head water systems (328 – 4,265 ft), with a wide range of flows (0.2 – 75 cfs). These turbines have a nozzle located in the spear jet to direct the water flow into the buckets on the runner at a right angle (Figure 8 (d)). Some advantages of using a Pelton turbine include its capability of handling low-water discharges, its high efficiency (85-90 percent for design flow above 50 percent), and its suitability for operation in silt-laden waters. Although the applications are intended mainly for high-head systems, some manufacturers such as Powerspout supply smaller Pelton turbines for low-head applications (9.8 – 427 feet) (PowerSpout, 2014). Pelton turbines are commonly installed in irrigation ditches.

Turgo Turbines

The design and operating principles of Turgo turbines are similar to those of the Pelton turbine and only differ in the direction of the angle (acute instead of right angle) at which the water jet strikes the center of the buckets on the runner (Figure 8 (e)). Turgo turbines can also generally be operated at lower heads (33 – 1,640 ft) and higher flow rates compared to Pelton turbines (1 – 350 cfs). In addition, their speed is about twice that of Pelton turbine for the same head and runner diameter (McKinney et al., 1983). Turgo turbines are commonly installed in run-of-the-river hydro schemes and in aqueducts.

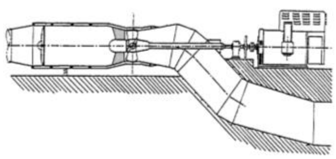
Crossflow Turbines

Similar to Turgo turbines, crossflow turbines (also known as Banki turbines) are designed to operate at higher water flows (1.5 – 175 cfs) and lower heads than Pelton turbines (18 – 2,132 ft) and are commonly used under highly variable flows. The crossflow turbine utilizes a cylindrical runner with a solid disk at each end and curved blades joining the two disks. As shown in Figure 8 (f), the water jet enters from the top part of the runner and passes through the gutter-shaped blades twice before emerging on the far side of the runner. The gutter-like shape of the blades allows the water to transfer some of its momentum on each passage before falling away, with little residual energy (Paish, 2002). The cylindrical shape of the runner and inlet nozzle increase the turbine's flow capacity, allowing the turbine to accommodate lower heads. However, the efficiency of this Crossflow turbine is low due to its complex flow path (McKinney et al., 1983). Similar to Turgo turbines, Crossflow turbines are commonly installed in aqueducts, diversion structures, or siphon penstocks.

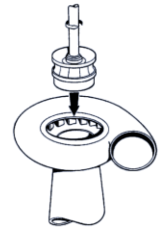
Pump-as-Turbines

Pump-as-turbines (PATs) essentially contain a centrifugal pump that is operated in reverse mode and functions similarly to a Francis turbine, both physically and hydraulically. An example of a PAT, manufactured by Andritz, is depicted in Figure 8 (g). Initially, the use of PATs was intended to decrease the high investment cost associated with turbine installations and provide a short delivery time and easy installation (Agarwal, 2012). These turbines are available in a number of standard sizes for a wide range of heads and flows and with large accessibility to spare parts. Additionally, the standard pump motor can be used as a generator (Williams et al., 1998). The attractive features of PATs have fostered more research and studies to understand the application of this technology for recovery energy losses in water distribution systems (Agarwal, 2012; Lydon et al., 2015; Rossi et al., 2016; Lima et al., 2017). Due to its compact design, PATs can be a low-cost and energy-efficient solution to replace pressure-reducing valves in water distribution systems. However, despite its promising features, PATs' performance, especially for installation in pipelines, needs to be further assessed. It is well known that the water flow variability (±50 percent of the daily average) can be quite significant as it is mainly controlled by user demand (Corcoran et al., 2013). PATs' performance can be greatly affected by variation in water flow, thus it is recommended to only use PATs for systems with stable water flows.

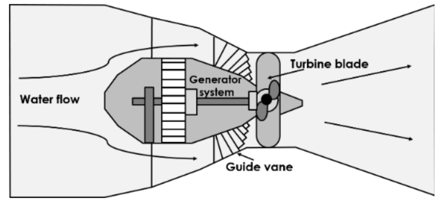
Figure 8: Schematic Representation of Various Turbines



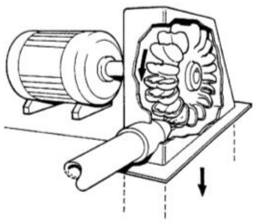
(a) Kaplan Turbine



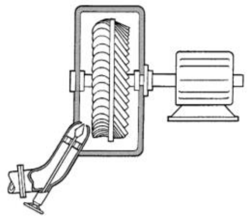
(b) Francis Turbine



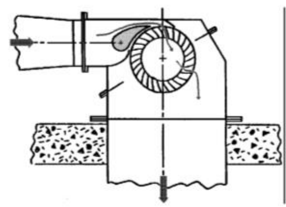
(c) Bulb turbine



(d) Pelton Turbine



(e) Turgo Turbine



(f) Crossflow Turbine

(g) Pump as Turbine

(a) Kaplan Turbine, (b) Francis Turbine, (c) Bulb Turbine, (d) Pelton Turbine, (e) Turgo Turbine, (f) Crossflow Turbine, and (g) Pump-as-Turbine

Source: Paish, 2002; Andritz Hydro, 2015

Table 6: Key Features of Conventional Turbines for Small Hydropower Systems

Technology	Type	Range of net head (ft)	Range of water flow (cfs)	Capacity (kW)	TRL*	Benefits	Limitations	Applications	Manufacturer	US	Non-US	Refs.
Kaplan	Reac-tion	≤33 – 131	100 – 1050	300 - 15,000	9	- Highly adjustable - High efficiency (>85% above 50% design flow) - Can work at low head	- Relatively expensive - Need heavy duty generator - Need very large flow rate	- Dam spillway - Existing canals/ diversion - Low head canal	Canyon Hydro, Ossberger, Mavel, Voith Hydro, Andritz	✓	✓	(John-son et al., 2015) (Bob-rowicz, 2006) (Voith Hydro, 2015)
Francis	Reac-tion	≤164 – 328	15 – 800	300 - 35,000	9	- Reliable and simple - Adjustable - Small runner and generator - Small change in efficiency - 78-50% efficiency (>50% design flow	- Very narrow operating range - Difficult to inspect - Prone to cavitation - Water hammer effects	- Dam - Irrigation canals	Canyon Hydro, Gilkes, Mavel, Voith Hydro, Andritz	✓	✓	(John-son et al., 2015) (Bob-rowicz, 2006) (Voith Hydro, 2015)
Bulb	Reac-tion	7 – 98	NA	1,000 – 10,000	9	- Compact - No powerhouse needed	- Difficult to access for service - Require special air circulation and cooling	- Canals - Pipelines	Ossberger, Voith Hydro, Andritz	✓	✓	(Voith Hydro, 2015)

Technology	Type	Range of net head (ft)	Range of water flow (cfs)	Capacity (kW)	TRL*	Benefits	Limitations	Applications	Manufacturer	US	Non-US	Refs.
Pump as turbine	Reac-tion	up to 262	28 – 212	20 - 750	8	- Low cost - Available in standard sizes - Easy installation - Can use pump motor as generator	- Its performance is difficult to predict - Generally, requires stable pressure and flow	- Irrigation channels - Aqueducts - Pipelines	Rentricity, Cornell pump, Andritz, KSB	✓	✓	(Bob-rowicz, 2006) (Andritz Hydro, 2015)
Small Pelton	Im-pulse	9.8 – 427	0.004-0.35	0.1 - 1.6 (single unit)	8	- Small - Relatively cheap - Can handle lower head than large pelton	- Must be installed at a higher level than water surface (must build platform to place the turbine)	- Overflow pipe alongside a penstock	PowerSpout	✓	✓	(PowerSpout, 2014)
Pelton (conventional)	Im-pulse	328 – 4265	0.2 – 75	300 - 35,000	9	- Can be mounted on both horizontal and vertical shafts - High overall efficiency (85-90% efficiency (>50% design flow - Can be operated in silted water - Has flat efficiency curve	- Efficiency decreases over time - Large-sized components - Variation in operating head is difficult to control	Irrigation ditches	Canyon Hydro, Power Spout, Gilkes, Mavel, Voith Hydro, Andritz	✓	✓	(John-son et al., 2015) (Bob-rowicz, 2006) (Voith Hydro, 2015)

Technology	Type	Range of net head (ft)	Range of water flow (cfs)	Capacity (kW)	TRL*	Benefits	Limitations	Applications	Manufacturer	US	Non-US	Refs.
Turgo	Im-pulse	33 – 1640	1 – 350	up to 10,000	9	- Simple to manufacture, cheap - Has a good efficiency and reliability - Has higher specific speed - Can handle higher flows than Pelton turbine	- Requires more head height than other turbines - Has to be connected to a pipe or penstock to function	- Run-of-river hydro schemes - Aqueducts	Gilkes, PowerSpout	✓	✓	(Bob-rowicz, 2006) (Gilkes, 2003)
Crossflow (Banki)	Im-pulse	18 – 2132	1.5 – 175	100 – 1,000	9	- Suitable for seasonally fluctuating flow sources - One turbine can operate over a large range of flow - Designed for self-cleaning	- Requires draft tube to capture the water power - For a very narrow turbine, the loss of efficiency is quite large	- Siphon penstock - Diversion to hydro-power - Aqueducts	Canyon Hydro, Ossberger	✓	✓	(John-son et al., 2015) (Bob-rowicz, 2006)

Note: Technological readiness levels (TRL) for small hydropower system based on (Zhang et al., 2012; Delplanque et al., 2017). TRL 0 – 3 = Technologies are still in conceptual design stage; TRL 4 – 6 = Technologies are in prototype testing stage; TRL 7- 9 = Technologies are approaching or have reached commercial deployment.

Source: Stantec

Emerging Technologies

Over the last decade, there has been a technological Renaissance in 'water-to-wire' solutions that solve rising energy demand and improve conventional turbines yet feature robust designs with turbines of better efficiency and possibly lower cost performance. Several companies such as Natel Energy, Lucid Energy, Instream Energy Systems, Amjet, Andritz, Hydrospin, Mavel, HelioAltas, KSB, SOAR, Rehart, Landustrie, and Spaans Babcock have recently offered novel turbine technologies for wider applications and sites that have not been considered previously. The description and the current development state of these new technologies, along with their benefits and limitations, are discussed in the next sections; their comparison is presented in **Error! Reference source not found.**.

Modular Water Wheel

Water wheels have been used for centuries to generate power at low cost. However, the conventional water wheel is considered to be less efficient than other turbines designed specifically for electricity production. Therefore, modifications of such systems have been made to increase power production by incorporating a high-ratio gear box and specialized controls to increase the speed (NorthWestern Energy, 2016). A new generation of water wheel is now smaller in size, modular, and can be used in existing infrastructures such as canals, concrete-lined chutes, industrial water loops, etc.

The Helios Powerball™ by HelioAltas Corp. is one example of a new generation water wheel turbine (Helio Altas, 2017). The typical range of power output from these systems is between 100-500 W; however, the unit if connected into an array, as a new system called HydroFarms™, allows the power output to be scaled up. As shown in Figure 9, all of the generation components are also contained within the shell of the unit, making it the first modular water wheel available in the market.

Figure 9: The Helios Powerball™ by HelioAltas Corporation

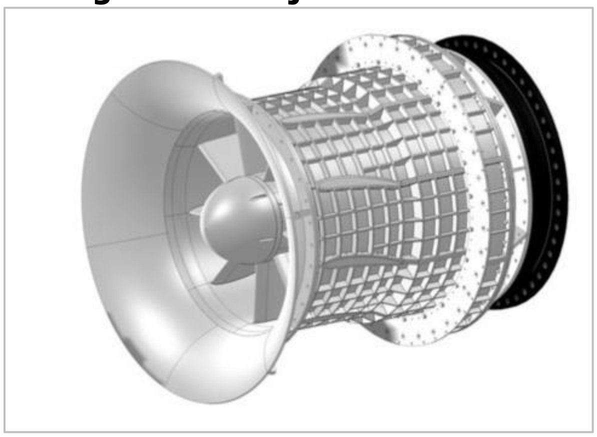
Source: Helio Altas, 2017

The unit is small and can be applied in an existing conduit such as a concrete-lined chute (Helio Altas, 2017). The unit can also cope well with debris, silts, very low-flow conditions, as well as variations in temperature and weather conditions. In 2016, HelioAltas Corp., in collaboration with DA Green Power Consulting, installed such systems to provide valuable renewable energy to the Philippines' power grid, as well as to rural areas with no access to the main grid (Helio Altas, 2016). Current installations in the U.S. are not available.

Axial-Type Propeller Turbine Generator Unit

This unit uses propeller turbine technology in an axial flow compact-composite design. Since both turbine and generator are combined in one unit, the need to use a powerhouse is eliminated, thereby lowering installation costs considerably. The unit can be applied in a wide range of applications such as irrigation canal drops, in-pipe installations to replace pressure reducing valves (PRVs), non-powered low-head dams, and more. Some examples of units currently available on the market include the Hydromatrix turbine by Andritz Hydro (Andritz Hydro, 2014), the StreamDiver turbine by Voith Hydro (Voith Hydro, 2015), and the Amjet ATS-63 turbine by Amjet Turbine System (Amjet Turbine System, 2015) (Figure 10).

Figure 10: Amjet ATS-63 Unit

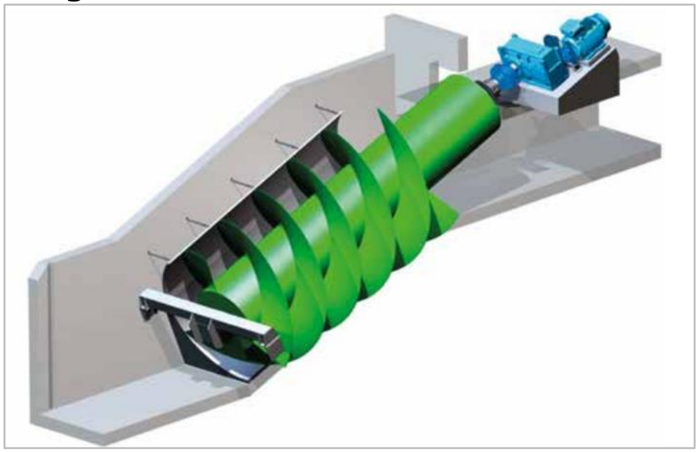


Source: Amjet Turbine System, 2015

Archimedean Screw Turbine

These hydrodynamic screw turbines use the principle of the Archimedean screw pump in reverse, using the hydrostatic pressure difference across the blades. Figure 11 shows that the water enters the screw at the top and its weight pushes the helical flights, causing the screw to rotate as water falls to the lower level. The rotational energy produced can be extracted by an electrical generator. The screw turbine is commonly used for low-head and high-flow applications such as existing dams or weirs and outlets of sewage treatment. One notable advantage of using an Archimedean screw turbine is that it provides safe fish passage compared to other turbines. New England Hydropower Company, LLC, installed the first Archimedes hydrodynamic screw turbine in the U.S.; it is located at the Hanover Pond in Meriden, Connecticut (NEHC, 2017). The run-of-the-river scheme project is expected to generate 920,000 kW of electricity annually.

Figure 11: Archimedean Screw Turbine

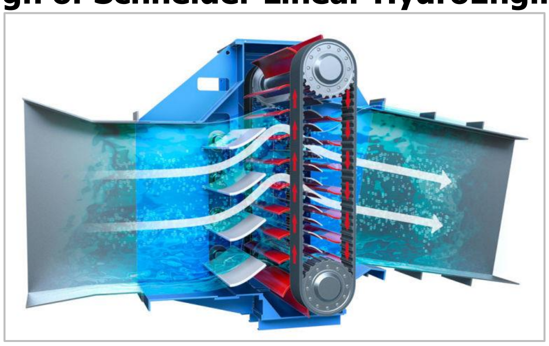


Source: Spaans Babcock, 2017

HydroEngine®

The hydroEngine® turbine by Natel Energy is one example of an impulse-style turbine that can handle lower-head systems with a wide range of flows. Figure 12 shows the first generation of hydroEngine® turbine (Schneider Linear hydroEngine® (SLH)), consisting of two parallel shafts connected with a belt of blades moving in a linear racetrack-like path between the shafts. The unit was designed to be used in similar system configurations as a Kaplan turbine such as at small dam walls or canal drops. However, unlike Kaplan turbines, the unit can be installed above the tail water, which consequently reduces excavation costs.

Figure 12: The Design of Schneider Linear HydroEngine® by Natel Energy

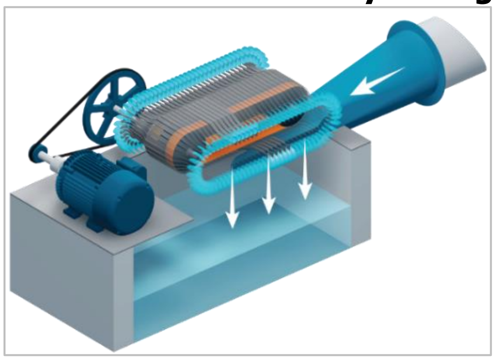


Source: Natel Energy, 2016a

The prototype version was deployed for pilot test at an irrigation drop in Buckeye, Arizona, in 2010. The test was conducted to evaluate its performance under conditions such as presence of suspended sediments and a corrosive environment. In 2015, Natel Energy commissioned its first project installation of SLH100 unit for an existing irrigation drop on the North Unit Main Canal in Madras, Oregon (Monroe Hydro Project) (Natel Energy, 2015). The plant has an installed capacity of 250 kW, a capacity factor of 43 percent, and an estimated annual generation of 1,000 MWh. The second installation of hydroEngine® was conducted as part of a mill renovation project in Freedom, Maine in spring 2016 (Natel Energy, 2016b) with a plant of installed capacity of 35 kW with an expected annual generation of 60 MWh.

Several modifications were made to the original turbine and the latest version, the Linear Pelton hydroEngine®, is currently available on the market (Natel Energy, 2017). Unlike its predecessor, the SLH version, the LP version utilizes a series of Pelton-style buckets on a linear power train. As shown in Figure 13, water enters the engine through a rectangular nozzle that converts pressure to velocity and directs the jet of water toward a series of buckets. The transfer of momentum from water to bucket is then harnessed as useful torque that turns the shaft.

Figure 13: Linear Pelton HydroEngine®



Source: Natel Energy, 2017

LucidPipe™

LucidPipe™ is an inline spherical turbine that can be installed directly in the primary conduit of a pressurized system (LucidEnergy, 2017). The installations of conventional hydropower technologies that have been adapted for in-pipe applications usually require a bypass loop due to significant pressure loss (up to 95 percent). LucidPipe™ offers a solution to this critical problem because it can operate in a wide range of pressure and flows without requiring a bypass (Figure 14). The system is also available for a wide range of pipe diameters (24-60 inches); its power capacity depends on the pipe diameter and the range is about 18 – 100 kW per unit with minimum flow of 35 – 198 cfs. The system has already been tested and certified by the National Science Foundation (NSF) International or American National Standard Institute (ANSI) Standard 61 for use in potable water systems as well as agricultural, industrial, and wastewater pipeline systems (LucidEnergy, 2015a). LucidPipe™ units are currently installed at Riverside Public Utilities (Riverside, California) and Portland Water Bureau (Portland, Oregon).

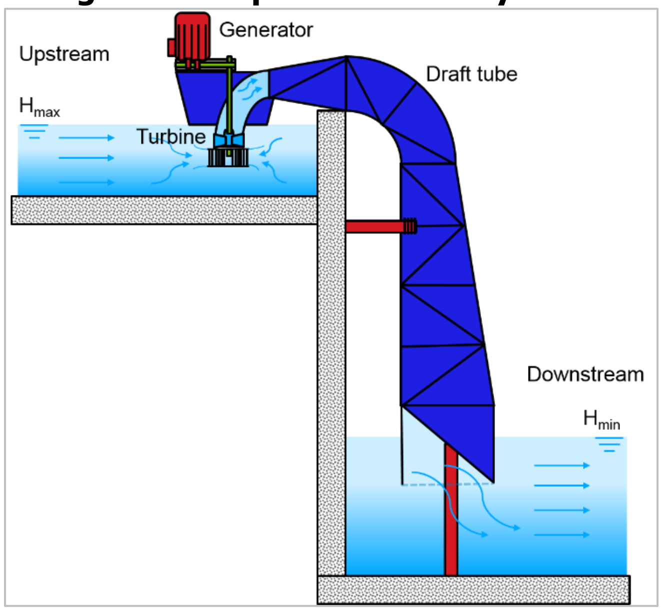
Figure 14: LucidPipe™ Spherical In-Line Turbine

Source: LucidEnergy, 2017

Siphon Turbine

This turbine utilizes siphon technology to capture the water's energy by using a Kaplan-type runner with four manually adjustable blades (Figure 15). Similar to a bulb turbine, this technology does not require a powerhouse since the generator and the turbine are combined into one unit. One of the examples of a siphon turbine is TM Modular Micro Turbine by Mavel (Mavel, 2015). Although 65 units have been installed globally, the first U.S. installation was in 2015 (Mavel, 2015) at a project in Idaho. The project site is a diversion structure that divides the flow of the main canal into three branch canals. Eight modular turbines with a total capacity of 1,224 kW were then installed in those divided canals.

Figure 15: Siphon Turbine by Mavel



Source: Mavel, 2015

Inline Hydro and Micro Hydro Turbines

SOAR Hydropower's ILS series (now part of Canyon Hydro) is one example of a modified conventional turbine (Francis turbine in this case) for in-pipe applications (SOAR Hydropower, 2016a). Unlike the LucidPipe™ turbine, the SOAR hydro turbines are designed for smaller pipes (4 - 24 inches) (Figure 16, left image). The unit is commonly installed in parallel with existing PRVs. In addition to the ILS series, SOAR Hydropower also offers a micro-hydro turbine with a maximum capacity of 300 watts (M300 series) that is suitable for running remote terminal units , supervisory control and data acquisition (SCADA) systems, monitoring equipment, sump pumps, lighting, blowers, fans, and pressure management devices (SOAR Hydropower, 2016b). This plug-and- play micro unit can be installed on any 2-inch or larger pipeline (Figure 16, right image).

Figure 16: SOAR Hydropower ILS Series (left) and M300 Series (right)

Source: SOAR Hydropower; SOAR Hydropower, 2016b

Hydrokinetic Turbines

Hydrokinetic turbines generate electricity by harnessing the kinetic energy of moving water instead of the potential energy from hydraulic head. The hydrokinetic turbines are modeled after wind turbines with two common classes: axial-flow turbines and cross-flow turbines. The rotor shaft for an axial-flow turbine is oriented parallel to the water current. A cross-flow turbine is oriented perpendicular to the water current. The shaft for cross-flow turbines can be oriented either vertically or horizontally.

One example of a hydrokinetic turbine designed for engineered waterways is offered by Instream Energy Systems (Figure 17, left image). The vertical axis hydrokinetic turbine (VAHT) unit is designed to produce electricity without adversely impacting the environment and at lower cost and reduced potential for regulatory issues (Instream Energy Systems, 2014). The rated capacity for each unit is 25 kW, and its application is suitable for engineered waterways such as irrigation canals and aqueducts.

Most of the current VAHT units are installed in natural waterways such as dam discharge channels (Duncan Dam near Kaslo, British Columbia, Canada), rivers (SEENEOH Bordeaux Tidal Estuarine site in France and the living bridge project in New Hampshire), and marine environments (Morlais demonstration zone in Anglesey, Wales, UK) (Instream Energy Systems, 2017). However, since 2013, Instream Energy Systems, along with the U.S. Bureau of Reclamation (USBR), installed the unit in an engineered conduit near Yakima, Washington (Roza Canal). One of the main objectives of the project was to demonstrate that the unit is not detrimental to existing infrastructure and the surrounding environment (Gunawan et al., 2017).

Another type of hydrokinetic turbine unit available in the market is offered by Emrgy (Emrgy, 2018). Each unit consists of twin turbines, thereby offering higher performance than a single turbine (Figure 17, right image). The unit can also be deployed without permanent anchoring or infrastructure changes due to the use of a portable frame (EMRGYFLUME™) that provides ballast to the overall system. One pilot study for the system was conducted in Denver Water's concrete canal overlooking Ralston Reservoir in Golden, Colorado in 2017. Denver Water planned to install 10 turbines in a section of a nine-mile long canal, with each turbine potentially generating about 80 MWh in a year in continuous operation (Chesney, 2017).

Figure 17: Vertical Axis Hydrokinetic Turbine by Instream Energy Systems (left) and Hydrokinetic Twin Module Offered by Emrgy (right)

Source: Instream Energy Systems, 2014 and Emrgy, 2018

Table 7: List of Emerging Turbines Currently on the Market

Technology	Type	Range of head (m)	Range of water discharge (m^3/s)	Capacity/ unit (kW)	TRL*	Benefits	Limitations	Applications	Manufacturer	US	Non-US	Refs.
Inline Hydro Turbine	Inline Francis turbine	26 – 570	0.35 – 70	Up to 2,000	8	In-pipe application	Bulkier than LucidPipe	In-pipe	Canyon Hydro/ Soar Hydro	✓		(SOAR Hydropower, 2016a)
TM Modular Micro Turbine	Siphon turbine	4.9 – 20	4.9 – 177	5 – 160	8	No powerhouse required	-Only for specific use -Requires a draft tube	Divided canals	Mavel	✓	✓	(Mavel, 2015)
Amjet ATS-63	Kaplan turbine/ generator combination	5 – 42	318 – 918	100 – 2,500	4	-No powerhouse required -Lower installation cost -Wide range of applications	Design still under evaluation	-Canals -Pipelines -Non-powered dams	Amjet Turbine Systems	-	-	(Amjet Turbine System, 2015)
Helios Powerball ™	Modular water wheel	NA	2 – 6 (minimum)	0.1 – 0.5	8	-Modular design -Can cope with harsh conditions -Environmentally friendly	Small capacity	-Canals -Concrete-line chutes -Wastewater outlet	HelioAltas Corp.		✓	(Helio Altas, 2017)

Technology	Type	Range of head (m)	Range of water discharge (m^3/s)	Capacity/ unit (kW)	TRL*	Benefits	Limitations	Applications	Manufacturer	US	Non-US	Refs.
Archimedean hydrodynamic screws	Reversed screw pump	3.3 – 33	4 – 530	5 – 500	8	-Good operating efficiency -Long life bearings -Robust, hard-wearing and reliable -Debris tolerant -Fish friendly	-Bulky and heavy -Construction may be complicated	-Smaller dams -Diversion structures -Irrigation weirs -Sewage plants outlet	Rehart, Landustrie, Spaans Babcock	-	✓	(Landustrie, 2015)
Linear Pelton hydroEngine®	A series of pelton buckets on linear powertrain	9.8 – 66	18 – 494	25 – 1,000	7	-Low cost -Easy to install -No cavitation -Less excavation cost	-Requires a penstock -Not suitable for pipelines	-Run of river schemes -Irrigation canals -Over tailwater -In dam or weir	Natel Energy	✓		(Natel Energy, 2017)
LucidPipe™	Spherical in-line turbine	NA	35 – 198 (minimum)	18 – 100	7	-No bypass required -No impact on water delivery -Available in many sizes	1034 kPa (150 psi) max working pressure	In-pipe installations	LucidEnergy	✓		(LucidEnergy, 2017)

Technology	Type	Range of head (m)	Range of water discharge (m^3/s)	Capacity/ unit (kW)	TRL*	Benefits	Limitations	Applications	Manufacturer	US	Non-US	Refs.
Vertical Axis Hydrokinetic Turbine	Hydrokinetic turbine	NA	NA	25	6	- Based only on flow, not head - Does not disrupt environment - Modular	Fairly new technology	- Irrigation canals - Aqueducts	Instream Energy Systems, Emrgy	✓		(Instream Energy Systems, 2014; Emrgy, 2018)

Note: Technological readiness levels (TRL) for small hydropower system based on (Zhang et al., 2012; Delplanque et al., 2017). TRL 0 – 3 = Technologies are still in conceptual design stage; TRL 4 – 6 = Technologies are in prototype testing stage; TRL 7- 9 = Technologies are approaching or have reached commercial deployment.

Source: Stantec

Comparisons of Conventional and Emerging Turbine Technologies

A brief summary comparison between conventional and emerging technologies based on the discussion presented in previous sections is summarized in Table 8.

Table 8: Comparisons Between Conventional and Emerging Technologies

Category	Conventional Technologies	New Technologies
Equipment lifespan	Longer lifespan (more than 30 years)	Unknown (installation periods are still relatively short)
Technology Maturity	Mostly are categorized as TRL 8-9 (mature technology with good performance proven for decades)	Some technologies are still in prototype stage (TRL 4-6), although some have already evolved to the next stage (TRL 7-8)
Data availability	The information regarding equipment, design, installation, and cost are more comprehensive	There is still a lack of information regarding equipment, design, installation, and cost due to inadequate testing period
Modularity	Less modular	Generally designed to be more modular
Generator size	Sometimes large generator is needed	Smaller generator is needed, therefore less power consumption
Civil work cost	Usually high due to powerhouse constructions	Generally, less since the units are mostly compact and modular

Source: Zhang et al., 2012; Perkins, 2013; Ak et al., 2017; Delplanque et al., 2017

Conventional turbines are generally very robust and operate for decades. For example, the Francis and Pelton turbines employed in several irrigation canals of the Hood River, Oregon, have been operating for almost three decades (Perkins, 2013). Since most of these technologies have proven to perform well over decades, they are usually categorized as TRL nine on their level of maturity (Zhang et al., 2012; Delplanque et al., 2017). Due to their high maturity level, there is abundant information about conventional technologies as well as case studies that can be used as references for new developers.

In contrast, most of the newer technologies have TRLs of less than eight since their installation periods are still relatively short. In addition, some of the technologies are still prototypes (TRLs from four to six). More time is required to determine the robustness of new turbine technologies since most of the current units have been operating for fewer than 10 years. Due to the inadequate testing period, there is still a lack of information regarding the effectiveness of the units, the installations (engineering and construction works), and the cost components. In addition, the designs are continuously updated. For example, the first generation of hydroEngine® by Natel Energy (the SLH model) has been recently replaced by the LP model (Natel Energy, 2017). While some information is available about the installations of the SLH model, there is limited information about the newer configuration.

In relation to design specifications, conventional turbines typically require construction of a powerhouse, which according to a recent study by the Oak Ridge National Laboratory accounts for a large portion of the initial capital cost (Zhang et al., 2012). Conventional turbines are also considered to be less efficient and, in some cases, more energy-intensive when a large generator is required. However, most of the new turbine technologies offer a cost-effective solution to this problem by combining the turbine and generator into one modular system, thereby minimizing the need to build a powerhouse. The modular design also utilizes a small generator with lower energy requirements. In addition, the modular design allows the unit to be easily scalable, depending on the site characteristics and power demand. For example, multiple hydrokinetic turbines can be installed in a large canal in multiple configurations for maximum power production (Instream Energy Systems, 2014; Emrgy, 2018). Some hydrokinetic turbines can also be stacked vertically for larger cross-sectional flows (Emrgy, 2018).

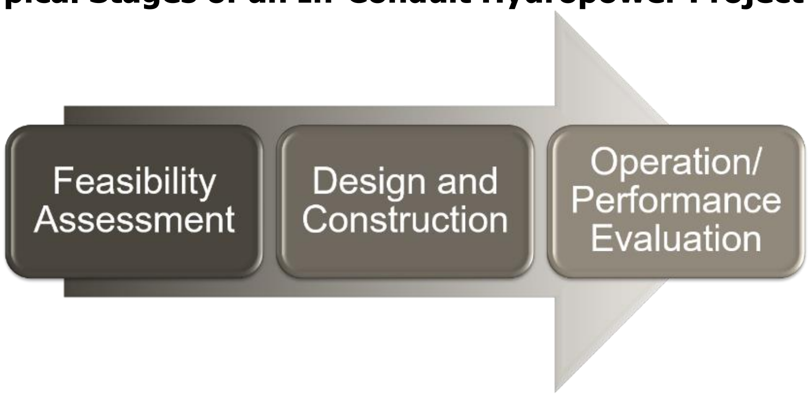
With regard to equipment costs, the comparison between conventional and new technologies is not as straightforward since the turbine cost sometimes varies depending on the site and the turbine characteristics (Okot, 2013). For example, a recent study estimated that the Archimedean screw turbine has a higher hydromechanical and electrical cost compared with Kaplan turbines for wastewater output applications (Ak et al., 2017). However, the total cost of installing a Kaplan turbine is higher than for an Archimedean screw turbine due to the higher cost of the intake structure and powerhouse construction. The modular design of the screw turbine also allows lower powerhouse construction costs, which eventually lead to reduced total installation costs.

Chapter 4 provides guidance on various life-cycle stages of implementation of these in-conduit hydropower turbine technologies.

CHAPTER 4: Project Implementation Guidance

Any in-conduit hydropower project progresses through three main stages: the feasibility study and assessment, the design and construction phase, and the operation and performance evaluation stage (as conceptualized in Figure 18). This chapter provides an in-depth analysis and guidance on aspects related to these life-cycle stages of an in-conduit hydropower project. This information served as the basis of the Business Case Assessment Tool discussed in the following Chapter 5.

Figure 18: Typical Stages of an In-Conduit Hydropower Project Development



Source: Stantec, 2019

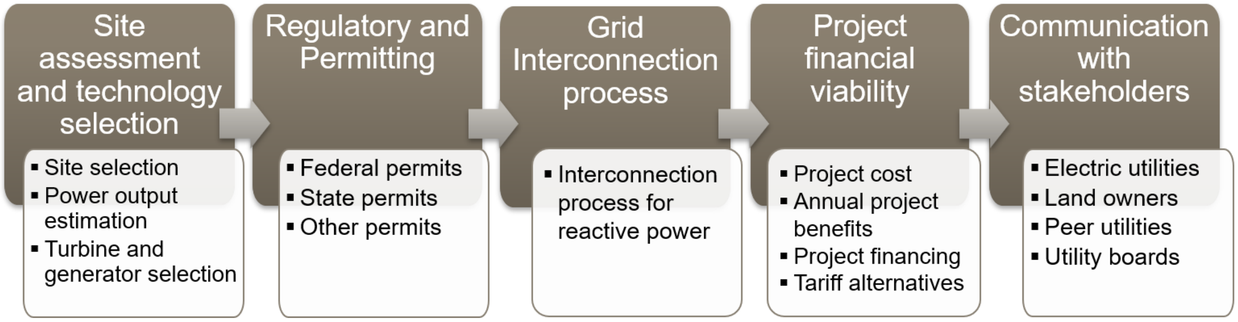
Feasibility Assessment for In-Conduit Hydropower Projects

The key elements of a feasibility assessment discussed in this chapter and summarized in Figure 19 include the following:

- Site assessment and technology selection
- Regulatory and permitting assessment
- Interconnection process
- Project financial viability assessment
- Internal and external communication with stakeholders

It is important to note that, although discussion in the following sections is California-centered, some of the concepts and approaches are applicable to other areas in the U.S.

Figure 19: Key Elements of an In-Conduit Hydropower Project Feasibility Assessment



Source: Stantec, 2019

Site Assessment and Technology Selection

Water supply and conveyance systems are often characterized by more energy than required for water-flow deliveries. This excess energy can damage the delivery system by, for example, eroding canal walls and pipeline ruptures. Energy dissipating devices such as PRV and canal drops are commonly installed to limit the impact of damages caused by excess energy. The conduit sites where energy-dissipating devices are installed can potentially serve as energy-harvesting spots where the extracted excess energy is converted to electricity by installing in-conduit hydropower systems. The excess energy at these conduits is usually small; however, the vast water delivery networks offer enormous untapped energy potential.

During the feasibility assessment, the water utility or other developer of an in-conduit hydropower project should consider assessing:

- The potential site for development of the in-conduit hydropower system.
- The hydropower potential of the site.
- The turbine and generator suitable to capture the potential energy.

The following subsections discuss key information associated with each topic.

Site Assessment

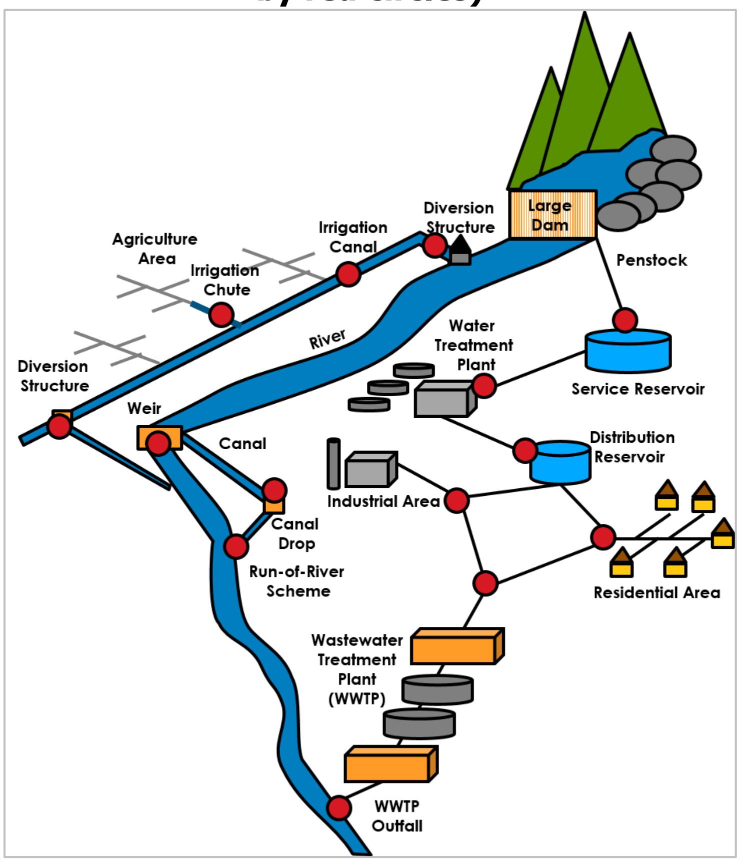
The sites suitable for in-conduit hydropower projects may contain elevation drops in canals, laterals, drains, pipelines and tunnels, or turnouts or siphons used to deliver water from larger to smaller canals. These potential spots for energy generation from existing water conduits are shown in Figure 20**.** In general, there are several major potential areas within a water distribution or conveyance system to harvest embedded energy:

- Dam releases into bulk supply
- Bulk pipelines from the source water
- Inlets to service reservoirs (and distribution reservoirs) where PRVs are commonly installed
- Water distribution network (at the location of PRVs, or at turnouts on large-diameter water transmission pipelines to a retail customer's pipeline)

- Wastewater treatment plant outfalls in cases where there is elevation above the discharge point
- Irrigation systems at diversion structures, weir walls, irrigation chutes, check structures, or along the length of canals (Loots et al., 2015)
- Run-of–the-river-type scheme where little or no water storage is needed;
- Groundwater recharge sites where surface water is recharged into the groundwater basin through a discharge pipeline (MWA, 2016)

In all these scenarios a flow-control facility may be constructed to reduce excess pressure in the pipeline and the hydroelectric turbine that is installed parallel to the flow-control facility to recover wasted energy.

Figure 20: Potential Sites for Implementation of In-Conduit Hydropower (marked by red circles)



Source: Adapted from Loots et al., 2015

In addition to the conditions that are favorable to installation of in-conduit hydropower projects, other important criteria for the selection of the site include the availability of flow throughout the year, space availability, proximity to grid interconnection, tailrace layout, and downstream pressure requirements.

Estimating In-Conduit Hydropower Potential

A prerequisite for successful conduit hydropower implementation is a basic understanding of the energy potential of the site under consideration. Potential energy from a hydropower system is either a function of the hydraulic head and water flow or based on the hydrokinetics power obtained from harnessing the kinetic energy of flowing water.

Estimation of In-Conduit Hydropower Potential based on Head and Water Flows.

The estimation of head and flow is critical for determining a site's hydropower potential. Based on Bernoulli's equation, the hydraulic head is the sum of the velocity head, elevation head, pressure head, as well as resistance head from friction loss. In most cases, especially for pipelines, the velocity head is negligible compared with pressure and elevation heads (Corcoran et al., 2015). For small hydropower plants, the head loss is particularly important because the hydraulic head is usually low compared with larger hydropower systems. The power output of a hydropower system can be calculated using the equation (0-1):

$$P = \rho \times g \times \Delta H \times Q \times \varepsilon \tag{0-1}$$

Where P is the mechanical power produced at the turbine shaft (Watts), ρ is the density of water (1,000 kg/m^3), g is the acceleration due to gravity (9.81 m/s^2), ΔH is the net extracted head (m), and Q is the volumetric flow rate of water passing through the turbine (m^3/s). The term ε is introduced in the equation to represent the overall efficiency of the system and accounts for turbine, drive system, and generator efficiencies. The overall efficiency of a hydropower system is commonly between 80-90 percent (Nasir, 2014), although it reduces with size. Smaller systems typically have efficiencies of less than 80 percent (CETC, 2004; Allen and Fay, 2013).

Since power generation capacity is directly related to the local net head and water flow (or velocity), information must be obtained about parameters along the conveyance and distribution systems. It should be noted that the estimation of head and water discharge at a particular site needs to be refined in the feasibility assessment phase to account for system losses and flow variability (Johnson et al., 2015). This is particularly important for pipeline applications since pressure and flow vary substantially according to water demand in downstream distribution systems.

The gross head at a particular site is classified into three categories:

- Low head (less than 10 meters (m) or 33 ft)
- Medium head (10 - 50 m or 33 – 164 ft)
- High head (above 50 m or 164 ft)

Estimation of gross head at a site can be accomplished by using simple tools such as a global positioning system (GPS) and barometric altimeters, USGS topographical maps, or Google Earth (Canyon Hydro, 2013; Johnson and Hadjerioua, 2015). However, this simple estimation can only be done at a preliminary stage since the selection and optimization of hydro turbines depend strongly on an accurate head measurement. Direct distance and pressure measurements are considered to be more accurate for head estimation (Canyon Hydro, 2013). However, these manual measurements can be time-consuming and prone to human error.

While the measurement of gross head is important at a preliminary stage of the project, system losses have to be considered to determine the net head, which eventually dictates the type of hydro turbine to use. Sites with high head are generally preferred because smaller energy-recovery equipment can be used (Uhunmwangho and Okedu, 2009). However, many potential locations for in-conduit projects have smaller heads subject to changes in pressure. For example, most in-conduits owned by USBR (approximately 47,336 miles of pipelines, canals, laterals, drains, and tunnels) have small heads and flows (Pulskamp, 2012). A minimum head of five ft (1.5 m) is still considered to be technically feasible for micro-hydropower projects according to low-head turbine manufacturers, hydropower developers, and the study conducted by USBR (Pulskamp, 2012). However, some Archimedean hydrodynamic screw turbines can also handle head as low as 3.3 ft (one m) (Landustrie, 2015; Rehart USA, 2017).

Water discharge is commonly measured using available historic hydrology data or various types of flow meters. Table 9 provides information on the selection of common water measurement devices for different types of engineering conduits. Similar to the head measurement, accurate estimation of flow data is imperative for selecting the most appropriate hydro turbines. Since actual flows are variable through the seasons, it is also recommended that data be obtained from various sources at different times to ensure precision of the data. For example, water flows in conduits owned by USBR are continuously monitored and recorded using gages. However, these data are also compared with those obtained by local officials at the sites as well as any available historical data (Pulskamp, 2012).

Table 9: Selection of Flow Rate Measurement Devices for Engineering Conduits

Application	Flow rate measurement devices
Spillways	Sluice gates, radial gates, broad-crested weirs, short-crested weirs
Large canals	Check gates, sluice gates, radial gates, overshot gates, long-throated flumes, broad-crested weirs, short-throated flumes, acoustic velocity meters
Small canals	Check gates, sluice gates, radial gates, overshot gates, broad-crested weirs, sharp-crested weirs, acoustic velocity meters, float-velocity area methods
Farm turnouts	Pipe turnouts: metergates, current meters, weirs, long-throated flumes, short-throated flumes; Others: constant head orifice, rated sluice gates, movable weirs
Large pipes	Venturi meters, orifices, acoustic velocity meters
Small - intermediate pipes	Venturi meters, orifices, propeller and turbine meters, magnetic meters, acoustic meters, pitotmeters, elbow meters, trajectory methods

Source: USBR, 2001

Case Study Highlight

Estimating annual recharge rates for hydroelectric facility in groundwater recharge sites

Due to variations in flow throughout the years, it is important for hydropower facilities in recharge basins to project future flows to the greatest possible extent. Accurate prediction of flow will allow for accurate sizing of the equipment. The annual recharge rates can be projected using multiple models and analyzed against historic allocations.

For example, during a feasibility assessment on the Waterman hydroelectric project, SBVMWD projected the flow based on the State Water Project (SWP) percentage allocation to the state water contractor on an annual basis. A historic allocation percentage, actual recharge history, and a hydrologic year matrix were created as a modeling tool to forecast future groundwater recharge rates and duration, and subsequent available flows for a hydroelectric unit. Available head was calculated based on actual recharge rates, using a friction-loss-calculation tool. Detailed information on the SBVWMD's hydroelectric station is provided in Appendix A.

Recent on-site surveys conducted by NLine Energy from 2010 to 2018 provided estimates of available heads and flows from 142 sites in California, based on facility type including canal drops, flow control facilities, existing hydroelectric facilities, pressure-reducing stations, reservoir outlets, and water treatment plants. As shown in Table 10, canal drops have, on average, much lower head and greater flow than other facility types. On the other hand, water treatment plants have the largest head but lower flow.

Table 10: Minimum and Maximum Head and Flow by Site from On-Site Surveys Conducted by NLine Energy

Facility Type	Number of Sites	Head (ft) Min.	Head (ft) Max.	Flow (cfs) Min.	Flow (cfs) Max.
Canal Drop	22	5	293	33	1084
Flow Control Facility	13	230	315	16	220
Hydroelectric Facility	7	38	440	7.8	500
Pressure Reducing Valve	53	141	950	3	620
Recharge Facility	3	219	534	25	30
Reservoir Outlet	23	12	1080	1.4	9000
Water Treatment Plant	21	37	1162	4.3	160

Source: Stantec, 2019

Case Study Highlight

Available flows and heads at hydroelectric facilities

All the hydroelectric facilities included in case studies are located in pressure-reducing stations upstream of water treatment plants, a storage facility, or groundwater recharge basins. The available heads and flows at these sites are summarized in Table 11. The flow characteristics from these sites are similar, with maximum flow less than 30 cfs. Similarly, the available heads are also similar, although the heads from groundwater recharge sites are slightly higher.

Table 11: Hydrologic Year and Water Recharge Allocation

Case Study Utility/Site	Facility Type	Available head (ft)	Available flow (cfs)
AWA	WTP	130 - 210	3.5 - 14
EVWD	WTP	213 - 277	3 - 11
MWA	Groundwater Recharge Basin	465 - 535	3 - 20
SBVMWD	Groundwater Recharge Basin	468 - 497	28
SGVWC – B24	Storage Facility	145 - 160	3 - 9
SGVWC – Sandhill	WTP	280 - 350	4 - 13
SA	WTP	310 - 322	10 - 30
WVWD	Groundwater Recharge Basin	269 - 308	6 - 27

Source: NLine Energy, 2019

Potential for Hydrokinetic Energy Generation. Power can also be generated by harnessing the kinetic energy of flowing water instead of from its potential energy from hydraulic head (i.e., hydrokinetic power). Hydrokinetic power can be harvested from canals, rivers, and tidal or ocean water currents to generate electricity. The power output for hydrokinetic systems can be estimated by equation (0-2):

$$P = \frac{1}{2} \times \rho \times A \times V(z)^3 \times \eta \qquad (0\text{-}2)$$

Where, in addition to the P, ρ, and η parameters previously identified for equation (0-1), A is the cross-sectional area (m^2), and V(z) is the current velocity (m/s) which is a function of depth (z) and channel geometry (Lalander, 2010). The efficiency of a hydrokinetic turbine is dependent on the drag coefficient, which is a function of the fraction of the cross-section occupied by the turbine (i.e., blockage ratio) (Vennell, 2012).

While most hydrokinetic energy resource assessments have been conducted mostly for wave, ocean current, and river sites (Hagerman and Scott, 2011; Defne et al., 2012; Ravens et al., 2012; Yang et al., 2015), there is only limited information regarding assessments in canals and waterways. Since the U.S. canal system is made up of tens of thousands of miles of canals with different characteristics, the potential for commercial hydrokinetic energy harvesting is high. Favorable characteristics for an economically feasible hydrokinetic energy development include (Gunawan et al., 2017):

- High current speeds (>five ft/s).
- High free-board level (i.e., vertical distance between the water surface and the top of the channel, to allow greater flexibility of water level variation prior to water exceeding free-board limits of the canal).
- Good accessibility.
- Presence of lined channels, generally due to their resistivity to scour.

Despite the attractiveness of hydrokinetic energy harvesting, there are still some challenges associated with its implementation, including:

- Potential disruption of water supply operations. The installation of turbines at irrigation canal intakes may affect head-discharge conditions.
- Increased flood risks from blockage and backwater effects.
- Potential reductions of power generation from downstream hydropower plants, if any, due to change in plant inflows, tailwater levels, and net head.
- Increased channel instabilities that can lead to unfavorable morphological conditions;
- Potential change in hydrodynamics of the canal that may affect its primary function.
- Impact of seasonal variability on the amounts of water conveyed.
- Challenges associated to reliable flow and velocity data acquisition from the site of interest.

All these factors need to be carefully considered during feasibility assessment to avoid any unwanted events in the canals such as flooding, silting, or scouring. In addition, currently there is only limited information regarding maintenance and the lifecycles and durability of hydrokinetic turbines. Thus, client and customer education on the new technology is highly critical and better coordination between technology developers and infrastructure owners may improve and promote integration of hydrokinetic turbines within existing infrastructure. In California, for example, there might be a big opportunity to collaborate with DWR to provide a more accurate estimation of the hydrokinetic energy in the state and promote development of hydrokinetic energy projects.

Turbine and Generator Selection

The following sections provide guidance on the selection of turbines and generators for in-conduit hydropower projects.

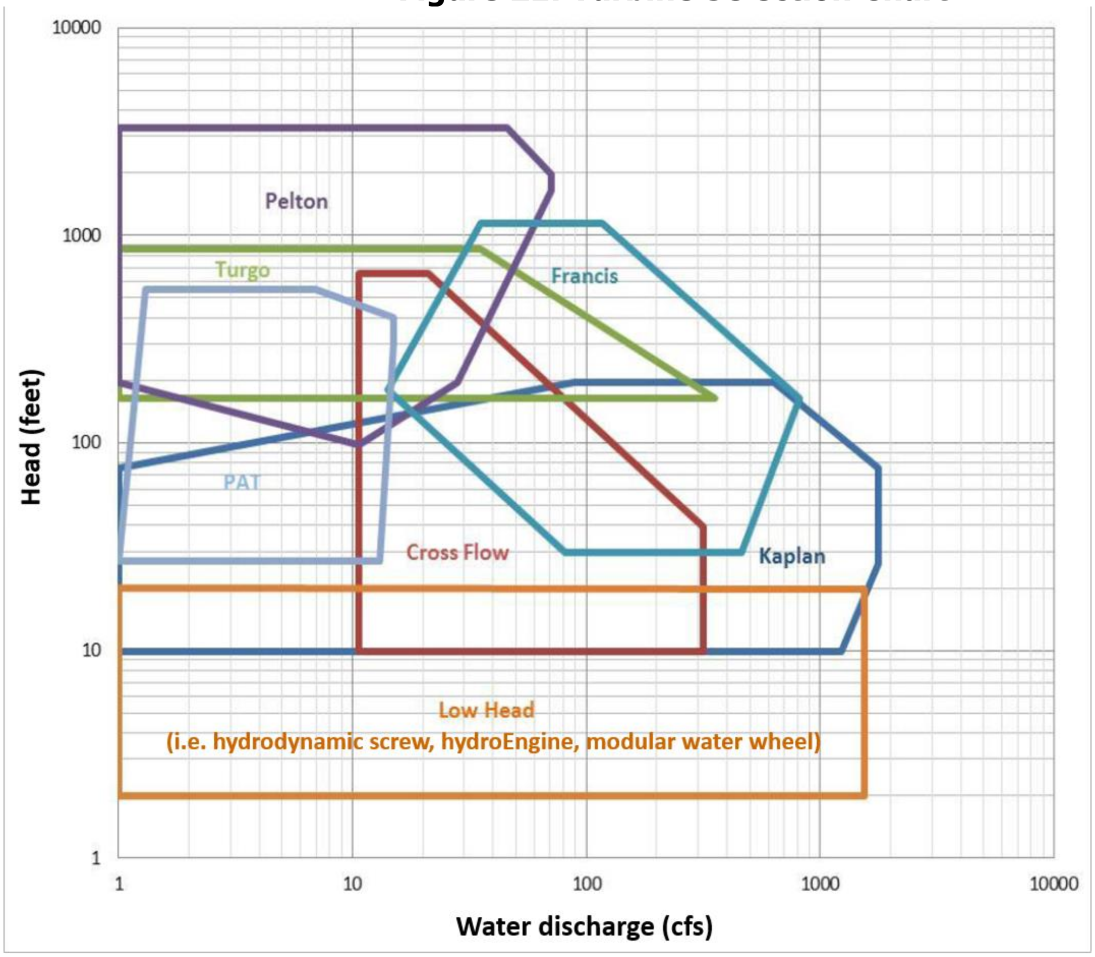
Turbine Selection

There are several parameters that need to be considered to select the appropriate turbine for energy harvesting. These parameters include:

- Head and friction losses
- Flow availability and stability
- Downstream pressure requirements

Generally, the head and flow parameters dictate the type of turbine. Reaction turbines are generally applicable to low-head systems, whereas impulse turbines are more suitable for medium-high-head applications. However, as shown in Figure 21, there is considerable overlap in their practical applications (McKinney et al., 1983). Some newer generations of impulse turbines, for example, can also operate in low-head systems such as hydrodynamic screw turbines, Natel Energy's hydroEngine®, modular water wheel, and others. In addition to reaction and impulse turbines, there is a growing interest in hydrokinetic turbines, although to date their implementation is not as widespread.

Figure 21: Turbine Selection Chart



Source: Johnson et al., 2015

The type of turbine also depends on the pressure requirement downstream of the hydroelectric facility. In general, if pressure is required downstream, the most suitable type of turbine is a reaction turbine. Whereas, when no pressure is required (i.e., pressure is discharged to the atmosphere), impulse turbines are usually more suitable. For example, as shown in Table 12, all flow-control facilities use reaction turbines because these facilities require downstream pressure. In contrast, the majority of hydroelectric facilities at canal drops or reservoir outlets use impulse turbines since pressure is usually discharged to the atmosphere.

Table 12: Type of Turbine Used at Different Facilities Based on NLine Energy's On-Site Surveys

Facility Type	Percentage of facilities using impulse turbines	Percentage of facilities using reaction turbines
Canal Drop	85%	15%
Flow Control Facility	0%	100%
Hydroelectric Facility	25%	75%
Pressure Reducing Valve	29%	71%
Reservoir Outlet	70%	30%
Water Treatment Plant	17%	83%

Source: Stantec, 2019

Given the variety of options, water and wastewater utilities must carefully evaluate hydropower turbines available on the market based on their site-specific applications and type of water conduits. The selection of various turbine technologies for different types of water conduits is summarized in Table 13.

- Diversion Structures: A diversion structure such as a weir or barrage channels a portion of a natural river through a canal or penstock. A diversion structure slightly raises water levels, allowing diversion of water through a canal located at one or either of its banks. Implementation of hydropower is beneficial at these sites as diversion structures can use all the flow from rivers. Turbines can be constructed right next to the structure (run-of-the-river scheme) or built into the diversion structure wall.
- These sites usually have low-head and high-flow rates; therefore, reaction turbines such as Kaplan or propeller-type turbines are suitable for this particular application. Kaplan turbines with an embedded generator in the system (such as bulb or Amjet ATS-63 turbines) can also offer a more cost-effective solution as they do not require powerhouse construction. Kaplan and bulb turbines are commonly built into the wall of diversion structures. The alternative options to these turbines include siphon turbines, hydroEngine®, and Archimedean screw turbines. Archimedean screw turbines and hydroEngine® can also be constructed next to the diversion structure (i.e., run-of-the-river scheme) to reduce the need for excavation.
- Irrigation Canals: There are several potential locations for hydropower installations along water conveyance systems for irrigation such as at canal drops or check structures, or along sections of the canals, ditches, and chutes. Kaplan, bulb, and siphon turbines can be installed at the wall of the canal drops with smaller heads. HydroEngine® and Archimedean screw turbines can also be suitable alternatives at these sites. The energy potential along canal sections is mainly dictated by the flow volume and velocity instead of the pressure head. Therefore, there is growing interest in using hydrokinetic turbines along sections of concrete-lined canals since their performance is only affected by flow. For smaller canals or ditches, a modular waterwheel may be appropriate.
- Concrete-Lined Chutes: Concrete-lined chutes for irrigation purposes are usually characterized by their medium to high head. As most of them are usually not enclosed

(i.e. not piped), the water is discharged to atmosphere and thus impulse turbines such as Pelton, Turgo and Crossflow turbines are suitable for this application.

- Pipelines: Opportunities for tapping excess energy in potable water-supply systems depend on the pressure zones. Pressure control is of vital importance in water distribution networks to prevent pipeline ruptures (Lima et al., 2017). Therefore, energy-dissipating devices such as pressure-reducing valves or pipeline turnouts are commonly installed at critical locations such as at the outlets of:
    - Source water penstocks to source-water reservoirs.
    - Bulk pipelines from source-water reservoirs to water-treatment plants.
    - Bulk pipelines from water-treatment plants to distribution reservoirs.
    - Bulk pipelines from distribution reservoirs to retail-customer pipelines.

  PRVs can also be installed to reduce pressure in discharge pipelines for groundwater recharge (MWA, 2016). Locations where energy-dissipating devices are installed can potentially serve as energy harvesting spots. Hydropower systems can be used to replace the PRVs since turbines dissipate pressure (Knapp and MacDonald, 2016), or installed in parallel with the PRVs (in bypass mode). (White, 2011).

  Several conventional turbines used for in-pipe applications with downstream pressure requirements are in-line Kaplan turbines, in-line Francis turbines, and PATs. Although a bypass loop may be necessary for turbine applications in pipelines, there is growing interest in applying in-line turbines where a bypass loop is not required. New technologies such as LucidPipe™ can also be an attractive option, especially when technology offers the ability to directly retrofit into the water mains without the need of a bypass loop. However, installation of a turbine on a bypass loop is often a necessary redundancy that allows maximum flow over the turbine, additional flows when total flow does not meet minimum requirements, and maintenance.

  In some cases, turbines can be installed in pipes that discharge to the atmosphere, for example in groundwater-recharge sites. Impulse turbines such as Pelton, Turgo, and Crossflow turbines are suitable for this application.

- Waste Water Treatment Plant (WWTP) outfalls: A wastewater-treatment outfall is generally suitable for a small hydropower installation due to the high volume and constant water flow (Advanced Energy Conversion, 2011). The parameters required for hydro installations such as head and flow are also monitored continuously as part of the WWTP process; therefore the selection of a turbine is quite straightforward and the turbine’s performance can be relatively easy to monitor. Applicable turbines for this site include Archimedean screw turbines, Kaplan turbines, and modular waterwheel turbines (Helios PowerballTM).

Table 13: Selection of Turbines Based on Different Types of Water Conduits

Diversion structure	Canals	Concrete-lined chutes	Pipelines	WWTP outfalls
Built into the diversion structure wall: - Kaplan[a] - Bulb/Amjet ATS-63[b] - Siphon[c] - Archimedean screw[d] - Hydroengine®[e]	**Canal drops:** - Kaplan[a] - Bulb/Amjet ATS-63[b] - Siphon[c] - Archimedean screw[d] - HydroEngine®[e]	- Pelton[a] - Turgo[a] - Crossflow[a] - Modular waterwheel[g]	**With downstream pressure requirement:** - In-line Francis[h] - Bulb[i] - Francis[j] - PAT[k] - LucidPipe™[l]	- Archimedean screw[d] - Kaplan[m]
Run-of-the river scheme: - Archimedean screw[d] - HydroEngine®[e]	**Along canal section:** - Vertical axis hydrokinetic turbine (VAHT)[f] - Modular waterwheel[g]		**Without downstream pressure requirement:** - Pelton[a] - Turgo[a] - Crossflow[a]	

a (Johnson et al., 2015); b (Andritz Hydro, 2014); c (Mavel, 2015); d (Spaans Babcock, 2017); e (Natel Energy, 2016c); f (Instream Energy Systems, 2014; Emrgy, 2018); g (Helio Altas, 2017); h (SOAR Hydropower, 2016a); i (Samora et al., 2016); j (White, 2011); k (Andritz Hydro, 2015); l (LucidEnergy, 2015b); m (Low Impact Hydropower Institute, 2014).

Source: Stantec, 2019

Case Study Highlight

Turbine selection for pressure reducing station upstream of water treatment plants

Table 13 summarizes information about the hydropower facilities included in the case studies. Five of eight facilities are located upstream of water treatment plants (WTPs), while the remaining are located upstream of a water storage facility and groundwater recharge basins. The facilities located upstream of WTPs or a storage facility need to maintain pressure downstream of the powerhouse, so reaction turbines for pipeline application are suitable for these sites. As shown in Table 14, these facilities use PATs. Francis turbines were previously considered as they commonly can handle flow variations better than PATs, which have narrowly defined head-flow operating curves. However, Francis turbines become unstable below 40 percent of full flow and cannot operate well at less than 40 percent full electric load. Based on assessment of historic flows, however, these facilities could demonstrate stable water flow for at least one-year operation, thus PATs were selected rather than Francis turbines. Despite their narrow operating curves (thus requiring stable water flow condition), two or more PAT units can be combined to manipulate most site flows without sacrificing potential generation. PATs are also one-third to one-quarter the total cost of a single Francis turbine, which opens up a sub-500 kW conduit hydroelectric market in the U.S. for this technology. In contrast, facilities located upstream of groundwater recharge basins discharge pressure to the atmosphere, thus according to Table 13**,** impulse turbines such as Pelton, Turgo, or Crossflow turbines are suitable for these sites. The case study facilities use Pelton turbines due to the flow and head characteristics of these sites.

Table 14: In-Conduit Hydropower Systems Selected for the Case Studies

Case Study Utility/Site	Location of powerhouse	Capacity (kW)	Annual power generation (kWh)	Turbine unit(s)
AWA	Upstream of WTP	110	580,475	Two PAT units
EVWD	Upstream of WTP	177	1,034,000	Two PAT units
MWA	Upstream of groundwater recharge basin	1100	6,100,000*	2-Nozzle Horizontal Pelton
SBVMWD	Upstream of groundwater recharge basin	1059	3,947,000*	Pelton
SGVWC – B24	Upstream of water storage facility	72	433,000*	One PAT unit
SGVWC – Sandhill	Upstream of WTP	310	1,000,000	Two PAT units
SA	Upstream of Upstream of WTP	580	3,440,000	Two PAT units
WVWD	Upstream of WTP	460	2,947,000	Two PAT units

***Estimated annual power generation (projects are still in construction phase during the creation of this report)**

Source: NLine Energy, 2019

Generator Selection

There are three types of generators currently available (Greacen et al., 2013):

- Synchronous generators
- Induction generators
- Direct Current (DC) generators with inverters

The most common generators used for hydropower are synchronous and induction generators. A synchronous generator consists of a magnetic field on the rotor that rotates and a stationary stator containing multiple windings that supplies the generated power (Alternative Energy Tutorials, 2017). Synchronous generators are generally more complex since their frequency and phase must be synchronized before connecting to the grid (Greacen et al., 2013). In contrast, the voltage frequency in induction generators is regulated by the power system to which the induction generators are connected; synchronization is therefore not required. Nonetheless, induction generators cannot generate electricity without a supply of reactive power from the grid. In rural areas where grid interconnection is not available, induction generators can use step-up banks and distribution circuits to provide the reactive support (DOE, 2016).

Both synchronous and induction generators are suitable for small hydropower systems, depending on the applications. Synchronous generators can be used in isolated mini-grids as they do not require a supply of reactive power from the grid (Greacen et al., 2013). For grid interconnection, induction generators generally require simpler protective equipment compared to synchronous generators. In addition, induction generators are suitable for smaller systems as they are typically rugged and less expensive compared to synchronous generators (CETC, 2004). Nonetheless, the full-load efficiencies of synchronous generators are typically higher than induction generators. Efficiencies can vary from 75-90 percent for synchronous generators, whereas the maximum efficiencies for induction generators is 75 percent at full load (CETC, 2004).

In cases when the hydropower system cannot generate sufficient power to meet peak requirements, DC generators can be used for battery storage (CETC, 2004). DC generators can also be used for grid interconnection by using inverters. Grid-tie inverters are generally simpler than synchronous or induction generators as the built-in electronics in the inverters function similarly with protective relays needed for the other type of generators. However, selecting the appropriate inverter is of vital importance as incompatibility can damage the inverter. DC generators usually have full-load efficiencies of 80 percent or greater.

Regulatory and Permitting Assessment

The current regulatory and permitting landscape for small hydropower projects in the U.S. has been significantly simplified, making it more attractive for local water purveyors to implement energy-recovery devices in their existing systems. The installation of in-conduit hydropower also has minimal environmental impacts due to utilization of existing infrastructures. These criteria alone make most of the conduit hydropower projects eligible for FERC exemptions (FERC, 2017c), and for CEQA exemptions for projects completed in California. However, a recent record from FERC showed that very few developers are taking advantage of the new regulations to develop conduit projects due to lack of knowledge of the current regulatory and permitting landscape.

This section provides a summary and general guidance for current federal and state regulations and permitting, particularly those pertaining to California.

Federal Requirements

The federal government requires each utility installing an in-conduit hydropower system to comply with FERC's licenses, exemptions, Notice of Intents (NOIs), federal rights of way, and federal environmental reviews.

Federal Licensing and Exemption for Conduit Hydropower Projects

FERC regulates the non-federal hydropower resources in the U.S. and has the exclusive authority to license hydropower projects. In August 2013, the "Hydropower Regulatory Efficiency Act (HREA) of 2013" was signed into law to promote small hydroelectric and conduit hydropower projects (FERC, 2017a). This act includes:

- Amendment of Section 405 of the Public Utility Regulatory Policies Act of 1978 to define "small hydroelectric power projects" as having a maximum installed capacity of 10 MW.
- Exemption of certain conduit hydropower facilities from FERC's licensing process.
- Authorization for FERC to extend the terms of preliminary permits.
- Promoting hydropower development at non-powered dams and closed-loop pumped storage projects.

In response to this act, FERC issued several regulations pertaining to conduit hydropower projects:

- No license or exemption is required by FERC for hydropower facilities located on non-federally owned conduits with installed capacity of five MW or less. However, the applicant must file an NOI to construct a qualifying conduit hydropower facility with FERC, as well as show that the conduit is not used primarily for electricity generation and was not licensed or exempted on and before August 9, 2013. The criteria for a qualifying conduit hydropower facility are listed in Table 15.
- A small hydroelectric facility utilizing an existing engineering conduit operated primarily for non-hydroelectric purposes (e.g., irrigation canals and water distribution pipes) with installed capacity up to 40 MW may be eligible for a conduit exemption. Although this particular case is also categorically exempted from an Environmental Assessment (EA) or an Environmental Impact Statement (EIS), FERC can still prepare the environmental assessment if the project is deemed detrimental to the environment. A small hydroelectric project of 10 MW or less is also eligible for an exemption from FERC's licensing process.

Table 15: Criteria for a Qualifying Conduit Hydropower Facility

Statutory provision	Description
Federal Power Act (FPA) 30(a)(3)(A), as amended by HREA	The conduit the facility uses is a tunnel, canal, pipeline, aqueduct, flume, ditch, or similar manmade water conveyance that is operated for the distribution of water for agricultural, municipal, or industrial consumption and not primarily for the generation of electricity
FPA 30(a)(3)(C)(i), as amended by HREA	The facility is constructed, operated, or maintained for the generation of electric power and uses for such generation only the hydroelectric potential of a non-federally owned conduit
FPA 30(a)(3)(C)(ii), as amended by HREA	The facility has an installed capacity that does not exceed five megawatts
FPA 30(a)(3)(C)(iii), as amended by HREA	On or before August 9, 2013, the facility is not licensed, or exempted from the licensing requirements of Part I of the FPA

Source: FERC, 2017c

Since 2013, FERC has approved 93 projects as Qualifying Conduit Hydropower Facilities, of which 25 are located in California (FERC, 2017b). As previously mentioned, these facilities need only file an NOI to FERC. To date, there is a total of 626 projects with active exemption from FERC, of which 232 received conduit exemptions (FERC, 2017d). The rest of the facilities must still apply for the exemption. The application process of the exemption can take about nine months and cost around $50,000-$60,000 (House, 2013). Before submitting the application to FERC, the facility must undergo an environmental assessment, if required by FERC, and send a notice of public hearing followed by a 60-day comment period. The FERC review can take about three to six months when there is no opposition but can take longer if issues arise. The lengthy and costly exemption process can be a major obstacle for development of in-conduit hydropower projects. It is desired that FERC further simplify its exemption application process.

Case Study Highlight

FERC requirement for in-conduit hydropower facilities

Most of the facilities included in the case studies were qualified as Qualifying Conduit Hydropower Facility, which only required them to file an NOI to FERC. The only facility that received conduit exemption was SGVWC (Sandhill), as the project started before the HREA signed in August 2013.

The process for filing an NOI generally takes about 45 days, which is significantly faster than FERC exemption or licensing processes (FERC, 2014).

Federal Right-of-Way

In a case where a utility or developer needs to access utility lines over federal lands, a right-of-way permit from a relevant land management agency is needed to ensure that the project does not interfere with other projects. Therefore, it is critically important to identify landowners and the type of authorization required to eliminate resource complications.

Federal Environmental Review

Conduit projects with capacity below 40 MW are categorically exempt from environmental review under the FPA. However, any developer should still prepare for environmental review if FERC assesses that a negative environmental impact exists.

Other Federal Agencies Requirements

Additional review and licensing processes for hydropower development may be needed by other federal agencies such as the U.S. Army Corps of Engineers (USACE), USBR, and Department of Defense. For conduit projects, USACE authorization may be needed if the projects affect navigable waters of the U.S. or utilize USACE structures. Any non-federal hydropower projects located on USBR conduits or dams will still need a USBR lease of Power Privilege despite being exempted from FERC's licensing process.

State Requirements – California

In addition to complying with federal regulations, utilities that are interested in developing hydropower facilities must also comply with state rules. To date, not every state in the U.S. has separate regulations regarding hydropower generation in addition to federal rules. The only states that require additional state-level permitting include California, Washington, Colorado, New York, Vermont, and Alaska (DOE, 2017).

California state agencies play a large role in a number of federal permitting and review processes for hydropower development. They also work with local commissions to regulate any development through land-use plans in accordance with statewide goals and policies. All discretionary proposed projects conducted or approved by California public agencies must undergo environmental reviews according to CEQA unless exempted. If the project must undergo CEQA environmental review, the process requires consultation with California Native American Tribes. Obtaining a Certificate of Public Convenience and Necessity or a permit to construct power lines from the California Public Utilities Commission (CPUC) is also required in California for hydropower transmission extension projects. A permit to construct power lines is required for transmission lines with a voltage between 50-200 kilovolt (kV), while a Certificate of Public Convenience and Necessity is required for transmission lines with a voltage greater than or equal to 200 kV (CPUC, 1995).

The general steps for the state-level hydropower permitting process follow:

Land Use Plan

The initial step for any hydropower development is to obtain information about the state land-use restrictions for the project location. This information is important to ensure that the project is not obstructing any existing project in the same location.

State Right-of-Way

A right-of-way lease from California's State Lands Commission is needed if there is any portion of the project that will occupy certain state lands under the jurisdiction of the commission. The proposed project must meet the requirements of CEQA before being able to obtain the right-of-way lease. In cases where the project or associated utility lines are located on privately owned land, the developer may need to obtain a property right from the land owner.

Water Rights

The developer may need to apply to the California State Water Resources Control Board for a non-consumptive water-use right. Section 401 Water Quality Certification is not needed for a qualifying conduit hydropower project.

Case Study Highlight

CEQA exemption

All facilities included in the case studies were qualified for the CEQA's Class 28 exemption for small hydroelectric projects (Section 115328, titled "Small Hydroelectric Projects at Existing Facilities".

Environmental Review

Projects at existing canals and pipelines with generating capacity of 5 MW or less are categorically exempted from environmental review according to CEQA's Class 28 exemption for small hydroelectric projects. While most of the physical requirements for a categorical exemption can be met by most small hydroelectric projects, further assessment of the system may be conducted to determine if:

- The project will not entail any construction on or alteration of a site included in or eligible for inclusion in the National Register of Historic Places.
- Any construction will not occur in the vicinity of any rare or endangered species.

To address these requirements, utilities may obtain biological and historical databases including:

- California Natural Diversity Database (California Department of Fish & Game).
- Biological databases of the U.S. Fish and Wildlife Service.
- Historic resources record searches.

RPS Certification

RPS Certification from the CEC may be needed for a small hydropower project with capacity of 40 MW or less as confirmation that the project is an eligible resource of renewable energy.

Interconnection Requirements

Although the electricity generated from small hydropower can be directly used for on-site application, there are several benefits of grid interconnection (Energy Trust of Oregon, 2010). By interconnecting to the grid, the utility can export the excess electricity to the electric utility, thus offering an opportunity for the unit to generate additional revenue by selling electricity to the utility through a Power Purchase Agreement. In addition, it allows the system to rely on grid electricity when on-site generation from the in-conduit hydropower system is not available. Lastly, the grid interconnection provides the required electrical input for start up to induction generators.

Despite the many benefits of grid interconnection, there are two major challenges which need to be overcome by the hydropower operators (Greacen et al., 2013):

- Maintaining frequency and voltage regulation
- Coordinating the operation of protective relays and reclosers

Since hydroelectric turbines are rotating equipment (non-inverter) technologies providing reactive power to the grid, additional protective equipment is required as part of California's Rule 21 interconnection standards. It is important for the generator to be able to safely connect to the grid at the correct frequency and phase, supply electricity at adequate quality as required by the utility, as well as disconnect quickly and safely during any disturbance event and reconnect when it is safe to do so. In addition to the above challenges, the interconnection process generally involves several steps that can be time-consuming, costly, and generally burdensome, especially for small developers. This issue is also corroborated by the lack of familiarity about interconnection with small hydropower systems compared to other small renewable energy systems such as wind and solar from the electric utility side. It is recommended that the regulatory process for permitting be simplified, especially for small generators that are net metered (Sale et al., 2014).

Since the regulations for grid interconnection vary by state, it is recommended to obtain information early during project development. In California, in-conduit hydroelectric projects sized over one MW and exporting to the grid must comply with the California ISO's New Resource Implementation, Full Network Model, and metering requirements (California ISO, 2017). However, some investor-owned utilities require California ISO metering installation for projects sized over 500 kW, depending on the type of Power Purchase Agreement secured. Obtaining and understanding such information can be challenging for prospective developers.

Therefore, a comprehensive grid interconnection guidebook that is tailored specifically to each state can be extremely helpful for prospective developers. For example, the Energy Trust of Oregon published a guidebook for grid interconnection for small-scale renewable energy generation systems in the State of Oregon in 2010 (Energy Trust of Oregon, 2010). To date, such guidebook is not yet available for the State of California.

Case Study Highlights

Interconnection cost for in-conduit hydropower projects

For the case studies analyzed in this project, the interconnection costs varied from zero (net energy metering applications have no interconnection application fees) up to approximately $250,000. The interconnection cost is mainly dependent on the location of the hydroelectric facility with respect to the electric provider's distribution grid and on the status of the nearby grid infrastructure.

For example, the Sandhill hydroelectric project owned by SGVWC was one of the first hydroelectric stations to interconnect with Southern California Edison (SCE) distribution grid in over 20 years. Throughout the interconnection process, the SCE's review and design process was over 18 months given the lack of staff awareness, fluency in reactive power equipment, and issues with project management. While the project commissioning was slightly delayed, this project served as an example for SCE and other investor-owned utilities to improve their knowledge and processing of small hydroelectric project interconnection applications.

In contrast with Sandhill hydroelectric project, the Tanner hydroelectric facility owned by AWA was implemented at the end of Pacific Gas & Electric (PG&E)'s grid circuit. Therefore, the system had minimal impact on PG&E's system, resulting in a low interconnection cost (approximately $2,500). The hydroelectric facility owned by SA had no interconnection cost as it provided grid level services for San Diego Gas & Electric (SDG&E).

Significant interconnection costs can be overwhelming for smaller projects, therefore identification and understanding of the impact of interconnection costs early in the process is imperative.

Project Financial Viability Assessment

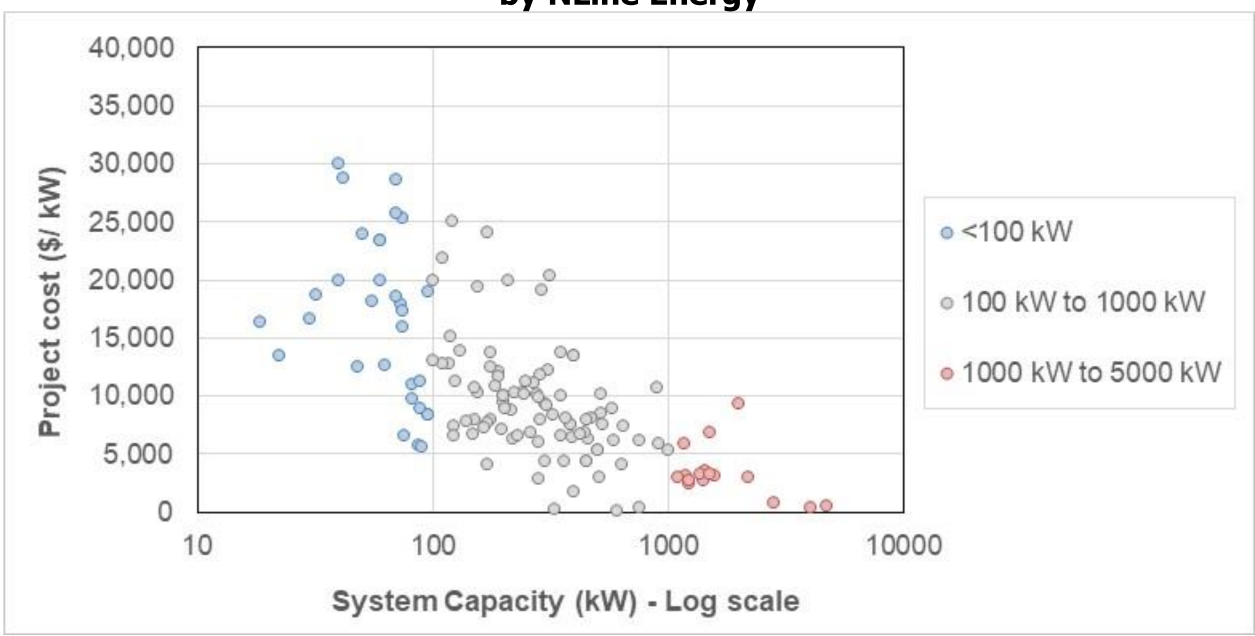
The financial feasibility of a project depends on the initial project capital investment as well as annual O&M costs, and on the annual project benefits calculated on the average annual energy generation and the price of the generated electricity (Allen and Fay, 2013). This section provides an analysis of the key cost components of an in-conduit hydropower project and quantification of a project's benefits and discusses the available opportunities for project financing.

Project Cost

The total cost of an in-conduit hydropower project should be calculated based on the cost of civil, electrical, and mechanical components as well as the regulatory and permitting processes. In addition, some projects qualify for grants, which can have a considerable role in offsetting some of the total project cost and shortening the payback period. The total project cost of small hydropower is estimated to be between \$2,000/kW - \$8,000/kW based on the report by the Electric Power Research Institute in 2011 (EPRI, 2011). This is consistent with the estimation of conventional hydropower projects with capacity between 100 kW and 30 MW by the U.S. DOE, which is in the order of \$4,000-\$5,000/kW. Nonetheless, recent case studies indicate that the project costs can be higher, at an average of \$8,600/kW, and can climb to \$16,000/kW (Allen et al., 2013). Based on information obtained from on-site surveys of 143 locations in California for potential in-conduit hydropower implementation conducted by NLine Energy, the project costs can be even higher. As shown in Figure 22, the project cost of systems with capacity less than 100 kW ranges from \$10,000/kW up to \$30,000/kW, with an average of \$28,000/kW. For 100 kW to 1,000 kW-systems, the range of cost is even wider; however, the average cost for this capacity range is lower at \$9,000/kW, which is close to values reported by other studies (e.g., EPRI, DOE). The cost also seems to decrease with increasing size, as the average cost for systems with capacity between 1,000 kW and 5,000 kW is around \$3,500/kW. It is important to note, however, that costs from on-site survey results are expected total project costs not inclusive of grants or other types of incentives. In general, most feasible projects are within the \$5,000-\$15,000/kW range.

The following subsections further discuss the components considered for estimation of total project cost.

Figure 22: Estimated Project Costs From 142 Locations in California by NLine Energy



Source: NLine Energy, 2019

Capital Investment

For small hydropower projects, the major project cost usually comes from site preparation and the capital cost of equipment (Doig, 2009). Compared to larger hydropower projects, small hydropower projects do not have the advantage of economies of scale where unit costs usually get smaller with larger plants and high heads of water (Zhang et al., 2012). However, utilizing existing infrastructure like water pipes can reduce cost, shorten delivery time, and simplify O&M (CETC, 2004). In addition, the higher capacity factor of in-conduit hydropower compared to conventional hydropower can result in higher annual energy generation. Table 16 provides examples of these capital costs associated with different cost categories.

Table 16: Key Elements of Capital Cost for In-Conduit Hydropower Project

Capital Cost Type	Capital Cost Examples
Turbine system	• Turbine unit(s) • Generator • Switch gear • Valves
Grid interconnection and coupling equipment	• Transformers • Power conversion systems (bi-directional inverters) • Breakers or disconnect switches, protection devices, cables and busducts
Site specific work	• Civil engineering • Structural work • Mechanical work • Electrical work • Other design and construction costs • Commissioning • Land acquisition
Data communication and management	• SCADA integration • Cybersecurity • Control software • Energy management dashboards • Metering and telemetry
Permitting	• Interconnection permits • City permits • Local permits
Shipping and transportation	• Shipping/transportation costs • Transportation
Hidden costs	• Facility shut down for finalizing powerhouse connection and start utilization

Source: Stantec, 2019

A recent study by the Oak Ridge National Laboratory in 2012 showed a breakdown of capital costs based on data from three different small hydropower projects (Zhang et al., 2012). The study identified civil works and electromechanical equipment as the two major components of the total initial investment. The cost of these components is highly sensitive to the head and capacity of the site. Turbines are also identified as key cost drivers among the electromechanical equipment, especially for low-head sites. Development and implementation of innovative technologies for low-head turbines, which can balance cost, efficiency, and reliability, are highly recommended. The study also indicated that powerhouse construction accounts for 40-68 percent of the civil work cost, recommending minimizing the powerhouse construction in a low-head generating system, particularly for existing conduits. It should be noted that this cost information provided by the Oak Ridge Laboratory is based on limited datasets. However it is informative on the breakdown of costs associated with small hydropower (Zhang et al., 2012).

Annual Operation and Maintenance Costs

Annual O&M costs typically include loan costs, land leases, maintenance and interim replacement insurance, personnel and labor, taxes and duties, general operation and administration, transmission line maintenance, FERC, and contingencies (BC Hydro, 2004; Zhang et al., 2012). Table 17 presents the typical cost elements for the life-cycle O&M calculation of an in-conduit hydropower project. The regression analysis of O&M costs by Oak Ridge National Laboratory shows that the O&M cost has a linear relationship with the plant capacity (Zhang et al., 2012). O&M costs are also often quoted as a percentage of the investment cost per kW, typically ranging from one to six percent for small hydropower projects (IRENA, 2012). For comparison, the percentage range for large hydropower plants is usually between 2 - 2.5 percent due to the economies of scale.

Table 17: Key Elements of Life Cycle O&M Costs for an In-Conduit Hydropower Project

O&M Cost Type	O&M Cost Examples
Labor	• Labor cost (operators, staff, engineers) • Trainings
Equipment inspection and maintenance	• Scheduled maintenance (e.g. oil inspection and change) • Unforeseen maintenance • Yearly turbine inspection
Degradation and replacement costs	• Replacement of fatigued materials • Disposal and recycling of materials
Site visits and consultations and general support	• Project developers • Technology providers • Software providers
Other costs	• Insurance • Grid fees • Taxes • Warranty contracts

Source: Stantec, 2019

Levelized Cost of Energy

The performance of a hydropower plant can be assessed through its levelized cost of energy (LCOE), which is defined as the present value of all resource costs (initial cost, O&M), divided by the present value of energy across a full-project lifetime, usually presented in $/kWh (Summit Blue Consulting, 2009). The initial capital cost is the major driver of LCOE, with limited contributions from the head, plant capacity, or capacity factor (Zhang et al., 2012). The cost per watt for small hydropower projects is typically high due to the high-low-head turbine cost; however, they usually have a longer lifespan, especially for those utilizing existing systems such as conduit projects. Due to longer lifespans, the cost can be distributed across a longer timeframe, resulting in comparatively similar LCOE with larger hydropower. For small hydropower plants, the LCOE typically ranges from $20/MWh - $100/MWh, whereas the LCOE of larger plants is usually around $20/MWh - $190/MWh (IEA-ETSAP and IRENA, 2015). It should be noted that very small hydropower projects (i.e., pico hydropower) can have higher LCOE (>$270/MWh).

Project Benefits

The annual project benefits depend on the annual energy produced from the hydropower system and the value of energy (Allen and Fay, 2013). As shown by equation (0-3), the annual energy produced (E, in kWh) can be calculated by multiplying the power output P (in kW, refer to equation (0-1)), with the number of hours in one year. However, a capacity factor that is defined as the ratio of a plant's annual power production to the power it could have produced if it ran at 100 percent, must be taken into consideration during the calculation of annual energy production:

$$E = P \times 8760\ hrs/year \times CF \tag{0-3}$$

Capacity factor accounts for the number of times the plant is not operating due to daily flow variations, environmental releases, or plant outages. The typical capacity factor of a conventional hydropower system is about 40 percent (Uría-Martínez et al., 2015). However, higher capacity factors can be achieved for smaller hydropower, especially conduit projects, as the daily flow variations are substantially less than those observed for conventional hydropower systems. The capacity factor of small hydropower systems is usually above 50 percent (The British Hydropower Association, 2012). The average capacity factor based on the NLine Energy's on-site surveys of 143 locations in California (with various topographies) is about 56 percent.

The value of generated electricity includes the tangible (retail rates or wholesale prices) and non-tangible energy assets. The tangible energy asset depends on the end-use of the energy. For example, when there is a demand of energy at a particular site, the generated energy from hydropower can be used to offset the energy that would have been purchased. On the other hand, when the on-site energy demand is non-existent, the generated energy is usually sold to the grid for wholesale prices (via Power Purchase Agreement). The average retail and wholesale prices vary between states in the U.S.

Renewable Energy Certificates (RECs), sometimes also known as Green Tags or Tradeable Renewable Certificates, represent the environmental attributes of the 1 MWh power produced from renewable energy and sold separately from the commodity electricity (O'Shaughnessy et al., 2016). These certificates can be sold, traded, or bartered. There are two markets available for selling RECs:

- Compliance Markets created by RPS.
- Voluntary Markets.

Each state has different RPS goals and electric utilities in the state are required to purchase RECs equivalent to the RPS goal. For example, California mandated that all its electricity retailers adopt RPS goals of 20 percent of electricity retail sales from renewable energy sources by the end of 2013, 25 percent by the end of 2016, and 33 percent by the end of 2020. When a state does not have an RPS, the RECs can be sold in voluntary markets at a lower rate.

Case Study Highlights

Benefits experienced by utility implementing in-conduit hydropower in its facility

The hydroelectric facility owned by SGVWCC located in Sandhill Water Treatment is one example of a utility that greatly benefits from the implementation of in-conduit hydropower in its water treatment plant.

All the generated energy from the site is exported to the grid and SGVWC receives credit based on the energy consumption in the water treatment at the same tariff as what they would have purchased under the net energy metering agreement. As of February 2018, the annual power generation was about 1,121,087 kWh, which was used to offset power in the entire facility (606,808 kWh). SGVWC even received an additional $12,000 from SCE for the excess energy generated (514,279 kWh).

Project Financing

Various federal and state financing programs are available for development of small hydropower. DOE's Water Power Technologies Office continuously provides funding opportunities for development and deployment of innovative technologies for hydropower. For example, DOE awarded nearly $17 million of three-year funding for 16 hydropower projects in 11 different states in 2011 (DOE, 2011). Ten of these projects, with grants ranging from $56,000-$1,500,000, considered development of sustainable small hydropower. The U.S. Department of Agriculture's Rural Energy for America Program also provides renewable energy development assistance, with a maximum aggregate amount of $100,000 in a federal fiscal year for rural small businesses and agricultural producers (U.S. Department of Agriculture-Rural Development, 2016).

The State of Oregon has long been the pioneer in hydropower development, providing assistance in each stage of development through various agencies such as the Energy Trust of Oregon, Oregon Department of Energy, Oregon Department of Environmental Quality, and Oregon Economic and Community Development Department (Summit Blue Consulting, 2009). In the State of California, the Self-Generation Incentive Program (SGIP) administered by the CPUC provides incentives that support behind-the-meter distributed energy technologies, with funding available from Pacific Gas & Electric Company, Southern California Edison, Southern California Gas Company, and San Diego Gas & Electric. The qualifying technologies include wind turbines, waste-heat-to-power technologies, internal combustion engines, gas turbines, fuel cells, energy storage systems, pressure reduction turbines, and microturbines. For pressure- reducing turbines, the program offers an economic incentive equal to $1.25/W) based on the nameplate rating of the turbine-generator system. Eligible sites for this program must first offset their on-site power consumption before they are permitted to export up to 25 percent of net energy produced for on-site purposes. In addition to SGIP, funding from the CEC for development of advanced small hydropower technology may also be available under its Electric Program Investment Charge (EPIC) program (The Energy Commission, 2016).

Case Study Highlights

Financial assessment of hydroelectric facilities included in the case studies

Table 18 provides an overview of financial metrics from hydroelectric projects included in the case studies, which include the total project cost, incentives (SGIP and other grants), annual O&M costs, and payback period. The total cost of these hydroelectric projects from eight utilities in California conducted in the last 5 years, ranged from $1,184,000 to $4,684,000. In terms of $/kW, the project costs ranged from $3,570 - $16,444/kW, which is within the range of values reported by other studies, as previously discussed in the Project Cost section.

Six out of eight of these hydroelectric facilities were eligible for SGIP incentives. The facilities that were not eligible for SGIP are the facilities in groundwater recharge basins, as they cannot use the power generated on-site, thus disqualifying them from this program.

SGVWC in Sandhill Water Treatment Plant (WTP) was the only facility that received a cash grant from U.S. Treasury (1603 U.S. Treasury Grant) which covered about 24 percent of the total project cost.

The annual O&M costs for these projects are generally between $6,000 to $10,000. Facilities that utilize Pelton turbines require higher fixed O&M costs compared to facilities that use Pump-as-Turbines.

The calculated payback period for all the facilities is less than 20 years. Both facilities owned by SGVWC have payback period less than or equal to 10 years. Projects smaller than five MW are usually considered financially feasible if the payback period is under 15 years.

Table 18: Financial Metrics of the Hydroelectric Projects Included in the Case Studies

Case Study Utility	Total Project Cost	SGIP	Other Grants	Annual O&M Costs	Payback Period (years)	Estimation Year
AWA	$1,504,000	$133,750	-	$6,000	14	2015
EVWD	$2,543,000	$232,000	-	$6,000	15	2017
MWA	$4,684,000	-	-	$10,000	15	2017
SBVMWD	$3,781,000	-	-	$10,000	11	2015
SGVWC-B24	$1,184,000	$560,000	-	$3,000	10	2017
SGVWC-Sandhill	$1,936,000	$320,290	$462,467	$6,000	8	2014
SA	$2,800,000	$552,000	-	$6,000	17	2017
WVWD	$2,946,000	$454,000	-	$6,000	12	2017

Source: NLine Energy, 2019

If federal or state funding is not available, small hydropower projects can be financed through private investment. However, securing a long-term Power Purchase Agreement with a credit-worthy counter party is important as an assurance to investors that the project will have a continuous revenue stream with an acceptable debt-coverage ratio (Sale et al., 2014).

Electric Tariff Alternatives Assessment

The energy generated through the in-conduit hydropower system can be used to satisfy, entirely or partially, the energy demand of the facility and/or exported to the grid. In both instances, it is critical that the electric utility tariff rates and programs are well understood to make the project economical and increase its benefits. In California, for example, several electric tariff alternatives are available, as summarized in Table 19. It is important to note, however, that the availability of these tariffs and their structures can change over time. Thus, utilities should conduct their feasibility studies by evaluating the project economics under multiple tariff scenarios to estimate the potential impact on project benefits and revenues.

Table 19: Electric Tariff Alternatives for In-Conduit Hydropower Projects

	Behind-the-Meter	NEM	NEMA	RES-BCT	Feed-in Tariff (Re-MAT)*	Std. Offer (QF)	Third Party Sale	CAISO	CCA
Limits	None	None with caveats	None with caveats	Up to 5 MW	Up to 3 MW	3-80 MW	N/A	None	None
Price ($/kWh)	0.11-0.13	0.11-0.13	0.10-0.12	0.06-0.09	0.89	0.35-0.45	N/A	0.35-0.45	0.05-0.150
Standby Charge	Poss.	No	No	Yes, but minimal	No	Yes	Yes	No	No
NSC	N/A	Yes	No	No	No	No	No	No	No
RECs	Retain	Retain	Retain	Retain	Forfeit	Forfeit	Negotiable	Retain	Negotiable
Term	N/A	N/A	N/A	N/A	10,15, 20, years	1-20 years	Negotiable.	N/A	Negotiable

Note: Re-MAT has been suspended since 2018; Net surplus compensation (NSC); Renewable energy credits (RECs), Net energy metering (NEM), Renewable Energy Self-Generation Bill Credit Transfer (RES-BCT), Community Choice Aggregation (CCA)

Source: Stantec, 2019

Net Energy Metering

In California, renewable energy generating facilities that serve a portion or all of their on-site electricity needs are currently available for the state's net energy metering (NEM) program. This program allows customers to receive a financial credit on their electricity bills for any surplus energy sold back to the grid. On a monthly basis, the bill credits excess generation on the utility's bill at the same retail rate that the utility would have paid for the energy consumption. At the end of the utility's 12-month billing period, any balance of surplus energy is matched at a separate fair market value known as net surplus compensation. This rate is based on a 12-month rolling average of the energy market rate, ranging from $0.02/kW to $0.03/kW. Utilities may also receive compensation for the renewable energy credits for their excess generation.

Net Energy Metering Aggregation

Net Energy Metering Aggregation (NEMA) is a subprogram of NEM, which allows an eligible utility (or customer-generator) to aggregate electric load from multiple meters and share NEM credits among all properties that are attached, adjacent, or contiguous to the generating facility. Unlike NEM, however, facilities under a NEMA tariff are not eligible to be compensated under an NSC rate for their surplus energy. Nevertheless, these facilities are still eligible for RECs for their excess energy.

Case Study Highlight

Aligning multiple operation scenarios with the high time-of-use tariff rates

For example, the summer and peaking scenarios for SGVWC's hydroelectric station in Sandhill Water Treatment Plant aligned well with the high time-of-use electric tariff rates that are normally charged to a customer for consumption of electricity during peak periods (i.e., summer and peaking times during the day). Thus, the hydroelectric generation is credited at these high rates under California's NEM Rules.

Small in-conduit hydroelectric projects should consider multiple scenarios (i.e., year-round, summer, and peaking scenarios) at the feasibility stage to identify any possible economic benefit.

Renewable Energy Self-Generation Bill Credit Transfer

Renewable Energy Self-Generation Bill Credit Transfer (RES-BCT) is also a subprogram of NEM that allows local governments and universities to share generation credits from an energy-generating facility located on one government-owned property, with billing accounts at other government-owned properties. Only facilities with generating capacity under 5 MW are eligible for RES-BCT and the bill credits are applied at the generation-only utility's retail rate.

Feed-In Tariff with Electric-Renewable Market Adjusting Tariff

The Electric-Renewable Market Adjusting Tariff (e-ReMAT) program was established by the CPUC in 2013 for small renewable generators less than 3 MW. Through the ReMAT program, up to 493.6 MW are available to eligible projects through a fixed-price standard contract (from $89.23/MWh) to export electricity to California's three largest investor-owned utilities: SCE, SDG&E, and PG&E. Electricity generated as part of the ReMAT program counts towards the utilities' RPS targets. A utility's eligibility for this program is based on several criteria. This information can be obtained from the respective utilities. It is important to note that, as of December 15, 2017, the CPUC suspended any new ReMAT programs, although already executed and existing ReMAT contracts are still in effect.

Community Choice Aggregation

Community Choice Aggregators (CCAs) are programs that allow local governments and special districts to pool electrical load within a defined jurisdiction to secure alternative energy supply contracts.

Case Study Highlight

Billing structure selected by case study hydroelectric facilities

Four out of eight case study utilities are currently under a NEM tariff, as shown in Table 20. Per NEM agreement, these utilities can offset their energy consumption and receive a financial credit on their electricity bills for any surplus energy fed back to the grid. SVWC-Sandhill and SA are the only utilities that feed their surplus energy to the grid, while EVWD and WVWD use the generated energy to offset their energy consumption only.

AWA's facility was the first small hydroelectric project in California to utilize NEMA, allowing them to combine several existing meters on a contiguous property to offset their energy consumption.

The facilities in ground recharge basins (MWA and SBVMWD) are currently under the RES-BCT program and receive generation credits by offsetting their energy consumption.

Table 20: Billing Structure of Case Study Utilities

Case Study Utility	Capacity (kW)	Energy Use	Billing Arrangement
AWA	110	Offset energy consumption, export to the grid	NEMA
EVWD	177	Offset energy consumption	NEM
MWA	1,100	Offset energy consumption	RES-BCT
SBVMWD	1,059	Offset energy consumption	RES-BCT
SGVWC-B24	72	Offset energy consumption	NEM
SGVWC-Sandhill	310	Offset energy consumption, export to the grid	NEM
SA	580	Offset energy consumption, export to the grid	NEM
WVWD	460	Offset energy consumption	NEM

Source: NLine Energy, 2019

Internal and External Communications

Multiple parties are usually involved during the development of in-conduit hydropower projects, including wholesale and water retail agencies, irrigation district authorities, electric utilities, public utility commission, landowners, and others. These parties can have different perspectives and goals and encounter different issues in incorporation of hydropower units in existing water-supply systems. Thus, communication between these different stakeholders should be fostered at all stages of the hydropower project.

Communication with Landowners

Communications should be established at all stages of the project with the land owners and other affected parties. Moreover, certain permits may also be obtained from the land owners to access the site. For example, if a portion of a project will occupy certain land owned by the state or federal government, a right-of-way lease needs to be obtained from the respective owner (RAPID, 2016a; RAPID, 2016b). In cases where the project or associated utility lines are located on privately owned land, the developer may need to obtain property rights from the landowner. Site control can be a very important, yet overlooked, aspect of the project when filing an interconnection application, as well as environmental filings.

Communication with Electric Utilities

Electric utility engagement should start early in the process, at the project planning phase, particularly if the onsite energy portfolio involves more renewable sources and various tariff rate structures. Together the electric providers and the utilities should forecast any potential issues that the implementation of the hydroelectric system may generate to the plant operation and the grid. The utility staff should also work closely and establish good relationships with electric utility account representatives, who are instrumental in assisting the utility during the approval processes of the project and within the implementation timeframe anticipated (for example, the SGIP funding from the local authority has a deadline that needs to be met not to lose the funding). It is also important to involve the electric utility analyst to validate the analysis and financial case of the hydropower developer and provide input on the system performance to maximize savings.

Communication with Utility Boards

The advancement of a project oftentimes depends on the decisions imposed by utility board members. In recent years there has been increasing interest by California utilities to integrate renewable energy projects to offset overall energy consumption as part of their long-term energy management plans. The advancement of small hydropower projects often is challenged by the unavailability of source water flowing through the potential site. For example, initially small hydropower was not considered by Sweetwater Authority in the San Diego area due to the uneven delivery of water from the State Water Project. However, the strong will of the board members made the project advance to the design and implementation phase, especially after Sweetwater was able to secure a substantial grant from SGIP.

In some cases, receiving board members' approval on the advancement of in-conduit hydropower projects can be difficult due to the high initial capital investment associated with these types of projects. However, utilities should be encouraged to conduct a cost analysis between maintaining existing pressure-reducing valves and installation of conduit hydropower. The hydropower project should be considered if the costs of maintaining existing pressure-reducing valves over the years are greater than purchasing a hydro-turbine system. This analysis should be part of the planning process and the outcomes presented to the agency's board members.

Strategic Partnership with Other Agencies

Communication among water agencies in the same area should be established to identify opportunity to build a strategic partnership. For example, communication should be established between the water wholesaler agencies and the corresponding water retail agencies in the same service area. The water wholesaler agencies commonly have much larger reserve account, staff and ability to act as the lead agency for the project development, thus alleviating small retail agencies from excessive staff time on small projects. This type of partnership can further strengthen the bond between the wholesale and retail agencies, forging a long-term partnership, which can be used as the model for another retail agency.

Learning from the experience of peer utilities or other industrial, commercial, or residential implementations on similar projects is also imperative. Therefore, it is recommended that during the planning stage, utilities contact their peers that have already implemented these systems and visit their locations to ask critical questions and solicit input. Sharing of the success of the in-conduit project also helps in the communication of the utility with the public.

Case Study Highlights

Wholesale-retail water agency partnership

In 2013, SBVMWD started to conduct a thorough assessment of their service area to identify locations that are suitable for small hydropower implementations. As SBVMWD supplies SWP water to several water utilities, the assessment was focused on the various locations of pressure reducing stations along the SWP pipeline. The pressure reducing station located upstream of Plant 134, which is owned by EVWD, was considered feasible for conduit hydropower due to its sufficient available pressure. After several joint board meetings between SBVMWD and EVWD, the Plant 134 hydropower project began development in 2014. The cost of constructing the facility was fully financed by SBVMWD, which will be paid back in installment by EVWD on a zero-interest loan recouped as an additional surcharge on a $ per acre/ft formula as they generate revenue from the hydropower during the years.

Design and Construction

Once the feasibility assessment is completed and the project is deemed to be technically and financially feasible, the project can proceed to the design and construction stages. Based on the case studies, most in-conduit hydropower projects can be completed within 2 – 2.5 years, although some projects may require more time to complete (up to 3.5 years). In California, one recurring theme during project implementation is substantial delay from the electric utility side. Thus, it is advised that future developers build a relationship with the electric utility early in the process to avoid any delay.

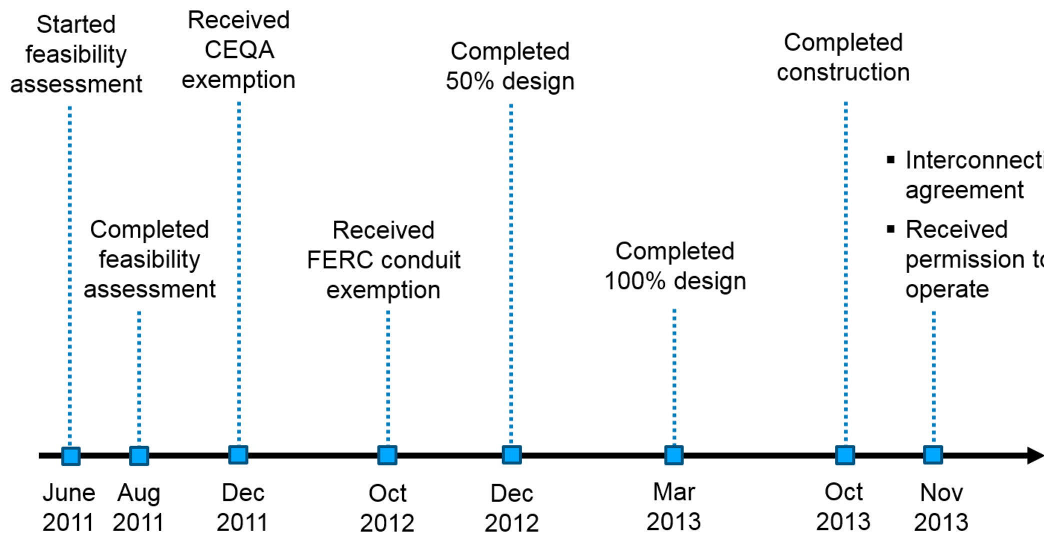
Case Study Highlights

Typical in-conduit hydropower project timeline

An example of a project timeline from SGVWC's Sandhill hydroelectric project is presented in Figure 23. As can be seen, the feasibility assessment took approximately three months. All the environmental and federal permitting processes were then completed within one year after the feasibility assessment. Design and construction took approximately 1.5 – 2 years. The interconnection process was started at the beginning of the design phase, as the utility must submit an Interconnection Application Package, which includes various design information. The review processes by the electric utilities vary, depending on the complexity of the projects and the level of knowledge about interconnection process for small hydropower projects. This review process can be lengthy and result in project delay.

The following sections discuss several important topics during design and construction of in-conduit hydropower facilities.

Figure 23: Timeline of the SGVWC's Hydroelectric Project at Sandhill WTP



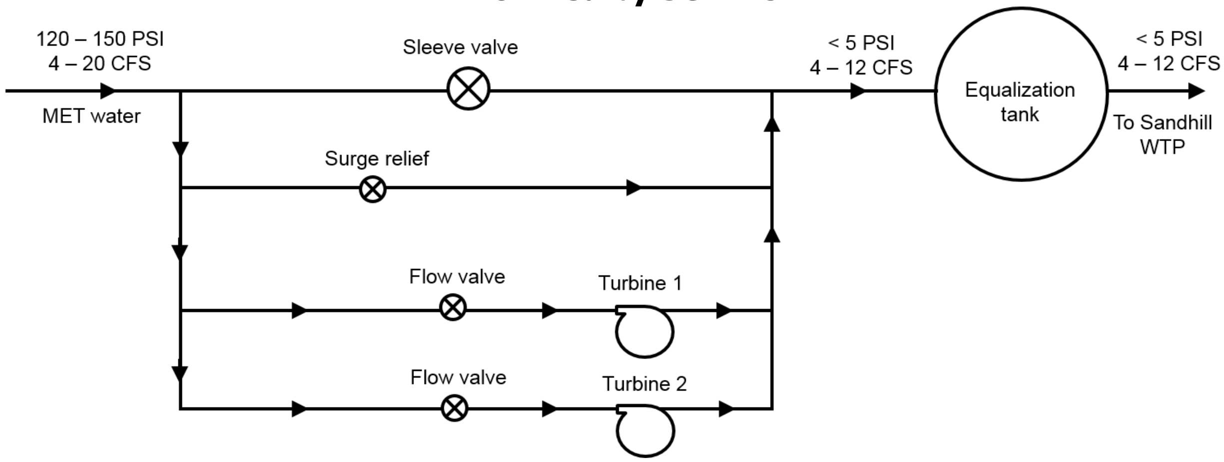
Source: NLine Energy, 2019

By-Pass Loop Installation

By-pass loop installations are common in hydroelectric facilities located in pressure-reducing stations (for example in water treatment plants, groundwater recharge basins, and flow-control facilities), and feature power stations adjacent to existing PRVs. An example of a schematic flow diagram of a hydroelectric station with this configuration is presented in Figure 24. In these configurations, the PRV usually remains in its current location and a new by-pass pipe is connected to the powerhouse. Depending on the project, the components of the power station can vary; however, in general, the powerhouse includes the turbine/generator system(s), switchgear, and electrical controls. Flow is diverted upstream of the pressure-reducing valve to the intake side of the powerhouse. Upon exiting the powerhouse, piping reconnects downstream of the PRV. The installation of turbines in a by-pass loop, although requiring additional cost, is often necessary as a redundancy to allow for maximum flow over the turbine, for flows when total flow does not meet minimum requirements, and for maintenance on the turbine system, if needed. Therefore, lack of accessibility for maintenance purposes should be a major concern for in-conduit hydropower systems with no by-pass loop, as a critical waterway would need to be shut down during repairs.

Installation of powerhouse in a by-pass loop is also beneficial for extending the useful lifetime of the PRV. The cost of maintenance and replacement of PRVs can be taxing over the years. Thus, a hydropower system may be considered if the costs of maintaining existing PRVs over the years are greater than purchasing a hydro-turbine system. The use of control valves upstream of the turbine can also be considered to allow manipulation of flows and heads to maintain high turbine efficiency. This additional equipment increases generation, extends the life of the equipment, and decreases O&M costs.

Figure 24: Flow Diagram of the Hydroelectric Station at Sandhill WTP Owned by SGVWC



Source: NLine Energy, 2019

Integration with Existing Facility

When planning and installing an in-conduit hydropower project, it is important that the system be integrated with the existing facility and infrastructure so that no negative interferences to current operations occur. For example:

The installation of a power station in a by-pass loop is considered beneficial in the case when the powerhouse needs to be shut down and water must be rerouted back to the existing pressure-reducing valve.

The potential in-conduit hydropower site should have sufficient space to accommodate relatively large external energy recovery devices and provide accessible space for equipment construction and maintenance purposes (van Vuuren et al., 2014).

For hydropower stations that are located upstream of water treatment plants, the hydropower system operations are dictated by the operational features of the downstream water treatment plant. Flow rates into the powerhouse are usually manually adjusted by the operations personnel to maximize the energy generation while maintaining the optimal operating parameters in the downstream water treatment plant. Thus, designing a robust control system that can smoothly connect the hydropower system with the existing facility (e.g. water treatment plant) is imperative.

Hydroelectric facilities feeding water to different facilities necessitate complex programming and control logic, as observed for the hydropower station located in Tanner Water Treatment Plant owned by AWA near Sacramento. The station feeds water to the Tanner Water Treatment Plant and a raw water reservoir. This type of programming can be very expensive and extend project timelines. Utilizing the experience of the Programmable Logic Controller (PLC) developer that built the control logic of the existing WTP facility may help in limiting errors and taking advantage of the developer’s familiarity with the existing system.

Debris Straining Upstream of Power Station

Large, raw water transmission pipelines rarely provide adequate debris screening when hydroelectric turbine additions at the existing water facilities are considered. Water flows in large diameter transmission pipes rarely reach mobilization velocity for debris that normally settles on the bottom of the pipeline. If this debris is mobilized, it can become lodged in the turbine runner (reaction-style turbine) or needles / nozzles (impulse-style turbine), causing decreased performance or an outage. A debris mobilization analysis can be conducted in the design phase to determine average and maximum flows in the pipe and the probability of debris mobilization. Additionally, designers should interview operations staff to determine the location, type, and frequency of debris and any debris management plan (e.g., flushing of the pipe with high flows using an open valve to purge any debris). In the case of the Waterman project conducted by SBVMWD, debris is known to exist in the Foothill pipeline and there is not adequate screening at the after bay. Based on this information, the design includes a 24-inch pressurized strainer to protect the needle vales on the Pelton turbine system.

Expanding Powerhouse

For some projects, additional water flows can be expected at the hydroelectric facilities due to upgrades in existing water treatment facilities or additional recharge flows in the future for groundwater recharge sites. Thus, it is important to include such scenarios during the design stage to accommodate the implementation of additional turbine(s). Civil and electrical considerations should include adequate space between the planned powerhouse and the existing pressure-reducing valve, blind flange connections for future piping tie-ins, and additional electrical-capacity planning.

Case Study Highlight

Use of hydropower consultants and project contractors

From the discussion with the case studies, it was highlighted that the support of qualified consultants that have extensive experience in in-conduit hydropower installations can be very helpful for utilities as the projects require deep understanding of multiple tariff structures, changing permitting and regulations, available funding, in addition to design and construction experience. Consultants can help in the design of the powerhouse as well as provide technical expertise throughout the entire project. However, since most in-conduit hydropower projects are retrofit projects, one useful strategy is to use the same contractor that built the existing water facilities, as the contractor is already familiar with the existing system. Similarly, using the same PLC developer for the existing water facilities also allows for smoother system integration, especially in the case of complex control system such as one from the hydroelectric facility in Tanner WTP owned by AWA.

Impact on Aquatic Habitat

Since the hydropower units are installed in existing engineering conduits, their effects on the environment (such as aquatic habitat and river flows), is considered to be minimal. This is mostly true especially for those installed in pipelines (White, 2011). For projects located in irrigation areas, the hydropower units are commonly placed to run in-canal; therefore, it does not significantly interfere with the canal’s flow (IEA-ETSAP and IRENA, 2015). However, it is recommended to set up fish passage and screening when installing hydropower systems in existing irrigation canals (Perkins, 2013). Standards for water quality and fish passage should be identified for manufacturers to use in their design processes.

Operation and Performance Monitoring

Once a utility receives permission to operate at the end of a construction period, the hydropower system can be operated concurrently with the existing water delivery system. There are multiple key elements that must be considered in terms of operation and performance monitoring. These elements are discussed as follows.

Key Operational Strategies

Most in-conduit hydropower systems are retrofitted into existing water delivery systems. Thus, there are several key operational strategies that must be considered:

- The hydropower station should be operated in a way that its generation can be maximized without interrupting the operation of the downstream water facilities/structures.
- The powerhouse performance is essentially dictated by the performance of the downstream water delivery system. Thus, it is important that the powerhouse is configured in a way that its operational parameters can be made adaptable to changes in downstream operations.
- Powerhouse shutdown must be minimized, especially for facilities that are interconnected with the electric grid, as the electric providers can charge the utilities with demand charges, thus reducing the overall financial income from the powerhouse.

It is also important to note that, oftentimes, the powerhouse operation needs to be done manually by the operation personnel. Thus, sufficient training should be given to utility staffs during the initial stage of operation.

Case Study Highlight

Complex operation control in hydroelectric facility owned by AWA

The hydroelectric station owned by AWA feeds water separately to the Tanner WTP and a raw water reservoir (Tanner Raw Bowl). Tanner WTP is not always in constant operation (i.e. "on-off" operation), thus during "off" period, water from hydroelectric station is rerouted to the Tanner Raw Bowl. This mode of operation then allows the powerhouse to run continuously while maintaining the "on-off" operation of Tanner WTP with the Tanner Raw Bowl serving as the equalization basin. This mode of operation also maintains a more constant flow in the source water pipeline, greatly reducing surge and extend the pipeline's life. It is important for the powerhouse to not be shut down as the electric provider (PG&E) could charge the agency with demand charges, reducing the overall financial income of the project. However, there will be times when the powerhouse is shut down because the Tanner Raw Bowl and the clear well are full. These shut down periods are minimized by reducing the Tanner Raw Bowl operating target levels during low demand periods.

Maintenance

During operation, preventive maintenance should be scheduled to ensure longer lifetimes for the infrastructure. The typical maintenance of a hydroelectric station includes:

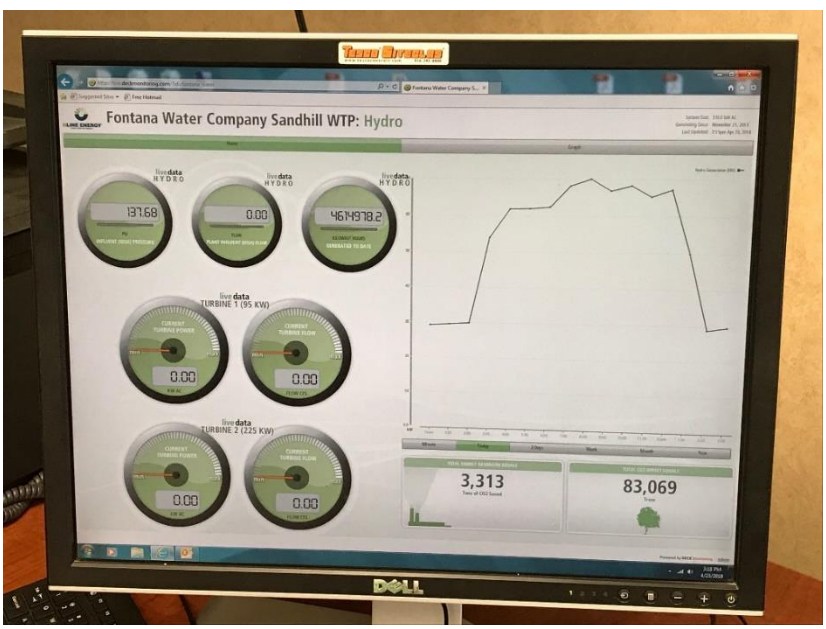
- Daily inspections of the hydroelectric station to detect leaks, excessive moisture buildup, loud noises, excessive vibration and/or heat. Sensors may be used to remotely detect many of these issues to augment physical inspections.
- Quarterly oil inspections and changes on bearings, hydraulic systems, and gearboxes requiring grease or oil. Annual inspection and testing for viscosity, acidity and water content are required, while minimizing different types of oil, if possible. If oil temperatures stay below 60 °C, the oil's useful life is extended dramatically.
- Periodic inspection of flow, pressure, and resulting energy.

The first inspection of the turbine itself should be at 12 months or 8,000 hours of operation. General inspections should occur every year until a history is established and trends are identified. Then the interval can be extended to two or more years. Similar installations may be good indicators of maintenance trends. It is important that maintenance is performed over readings of accurate instruments, therefore calibration should be scheduled on regular intervals.

Performance Evaluations

Monitoring the performance of an in-conduit hydropower station can be performed through third-party-created dashboards or utility SCADA systems. Dashboards can be used to view onsite and remotely, the critical operational parameters such as pressure, head, flow and the calculated energy generation. An example of such a dashboard being used by SGVWC is presented in Figure 25.

Figure 25: Third-Party Dashboard for In-Conduit Hydropower Performance Monitoring



Source: Stantec, 2019

Appropriate key performance indicators (KPIs) can be used to monitor in-conduit hydropower system performance and benchmarking. Using standardized KPIs allows utilities to document historical system performance trends, quantify relative performance across peer utilities, and establish a baseline for determining process efficiency improvements (Haider et al., 2016). The following are some of the criteria for identification and selection of KPIs (Cabrera Jr. et al., 2011):

- Metrics for KPI calculation over time should be developed as a minimum on a facility, but preferably on a more granular level to allow a fast and frequent check of system performance.
- A KPI should be defined clearly so that it is repeatable, widely achievable in measurement across a range of sites, and unique in representing a specific system performance of a specific asset in a given period of time.
- The KPI value should be unambiguous and universally quantifiable and consist of a value expressed in specific units.
- When using KPIs for benchmarking the utility energy performance with those of peer utilities, the KPI should be developed independent from features that characterize only a small number of utilities.

Some examples of KPIs that can be used to assess the performance of energy generation process are provides in Table 21.

Table 21: Examples of KPIs That Can be Used to Assess Energy Performance of Energy Generation Process

Process	Normalizing Parameters	Examples of Key Performance Indicators
Energy Generation	• Energy generated • Energy sold to the grid • Total renewable energy generated • Source-specific renewable energy generated • Customers	• kWh generated/kWh consumed • kWh sold to the grid • % of renewable energy • % of energy offset from grid • kWh produced/person equivalent • Electrical import • % energy neutrality

Source: Stantec, 2019

All information collected for the guidebook development was further utilized to develop the corresponding business case asssessment tool. The tool can be used as a bridge between theoretical knowledge and the practical implementation to help better understanding the development of in-conduit hydropower projects. The guidelines for the tool is provided in Chapter 5.

CHAPTER 5: Business Case Assessment Tool Development

This chapter contains details on the fundamental principles and elements of the Excel-based spreadsheet developed to assist users with assessing the feasibility and the business case for implementation of an in-conduit hydropower project.

Introduction to the Tool

The team developed an Excel®-based workbook as a tool to assist water and wastewater utilities and other water purveyors in the assessment of the technical and economic feasibility of installing an in-conduit hydropower system in selected sites of their service area. The workbook includes functionalities for evaluating their hydropower potential at a specific site and under specific conditions, the optimal in-conduit hydropower technologies that are suitable for the project, the related life-cycle capital and O&M costs, and the environmental impact in terms of GHG emissions. The tool includes a series of input, calculation, and output worksheets, each including different information. Figure 26 shows an overview of the tool and the content of each worksheet.

The workflow presented in Figure 26 includes the following worksheets (tabs):

- Main: Introduction to the tool
- W1 - Project Info: General information on the project
- W2 - Turbine Selection: Hydropower potential and recommendation on turbine selection
- W3 - LCC Assumptions: Assumptions for life cycle cost (LCC) calculations
- W4 - Capital Costs: Capital costs calculations
- W5 - O&M Costs: O&M costs calculations
- W6 - Cost Benefits: Financial cost benefits estimation
- W7 - GHG Emissions: Environmental benefits estimation in terms of GHG emissions
- W8 - Output: Summary of LCC and environmental benefits
- W9. Glossary: Compilation of terms used in the workbook

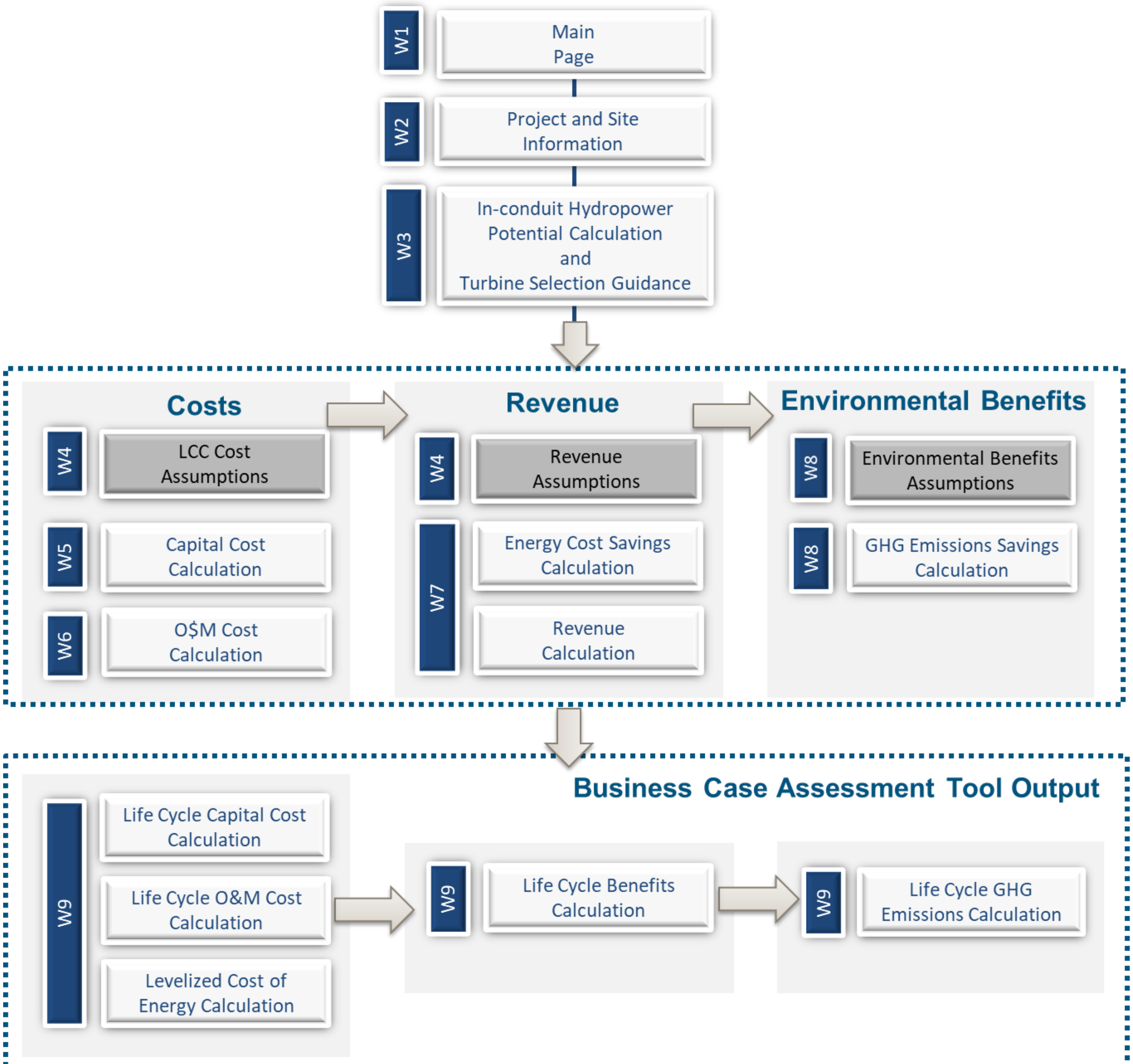
All worksheets in the workbook are unlocked and therefore the user should prevent inadvertent changes to cell formulas and/or values. A color-coding applies to cells in each worksheet, in particular:

- Gray cells: Cells that have a gray fill and black cell outline should not be changed, as they contain formulae rather than values.
- White cells: Cells intended for the user to enter data. These cells are indicated with white cell fill color and black outline.
- Orange cells: Cells containing drop-down menus from which the user should select the most appropriate option

The workbook also includes several help buttons ( ) at specific locations to activate pop-up notes providing additional information or clarification on the related subject.

The following sections provide guidance on the use of the tool and should be used alongside it.

Figure 26: Overview and Workflow of the Business Case Assessment Tool



Source: Stantec, 2019

Description of the Tool

The following section provides guidance on the use of each workbook presented in the tool.

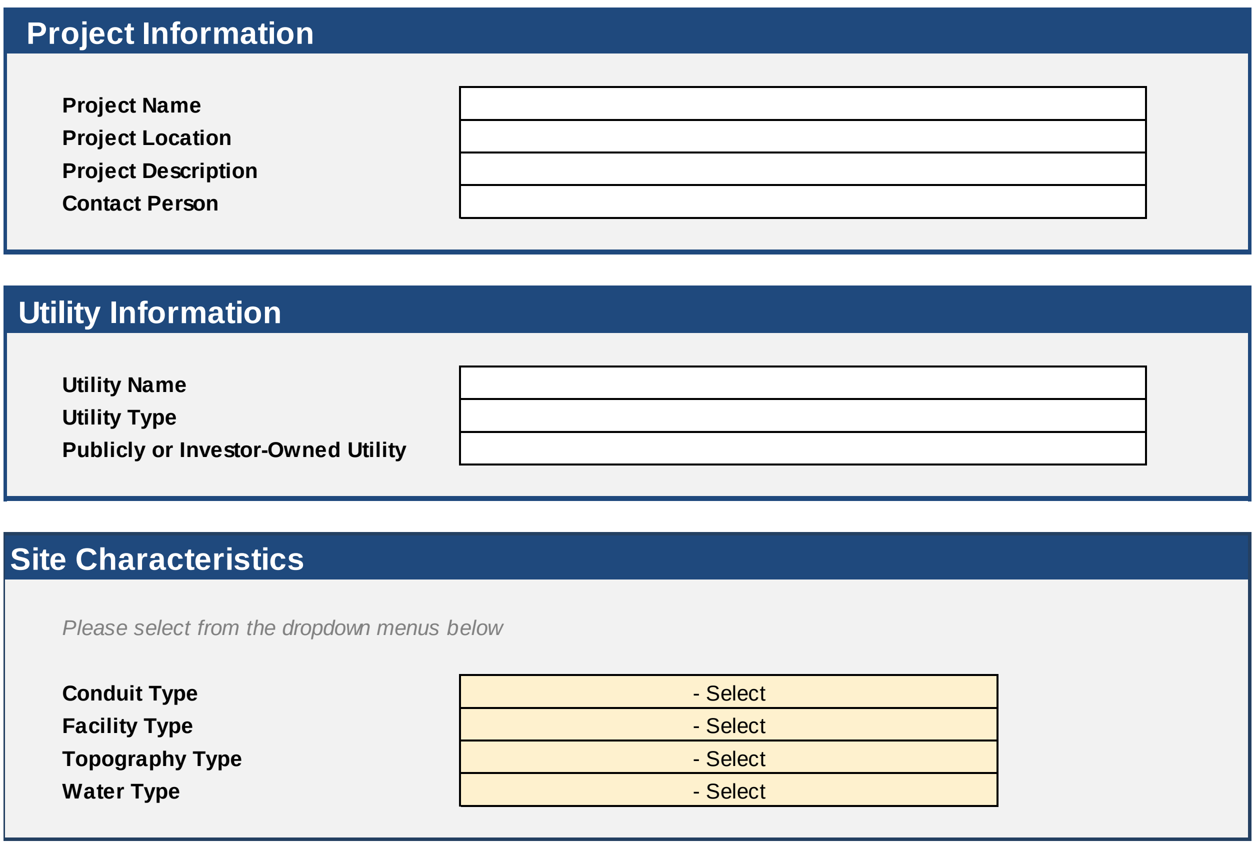
Project Information Worksheet

This input page takes general information regarding the in-conduit hydropower project, site location, and configuration. In particular, the user is expected to select from several dropdown menus the following:

- Conduit type (canal, dam, pipeline, groundwater discharge)
- Facility type (canal drop, flow control facility, existing hydroelectric facility, groundwater recharge, pressure reducing valves, recharge facility, reservoir outlet)
- Topography (coastal, mountain, urban)
- Water type (raw water, potable water, wastewater, reclaimed/recycled water)

Figure 27 shows a screenshot of the Project Information Worksheet.

Figure 27: Overview of the Project Information Worksheet



Project Information

Project Name	
Project Location	
Project Description	
Contact Person	

Utility Information

Utility Name	
Utility Type	
Publicly or Investor-Owned Utility	

Site Characteristics

Please select from the dropdown menus below

Conduit Type	- Select
Facility Type	- Select
Topography Type	- Select
Water Type	- Select

Source: Stantec, 2019

Turbine Selection Worksheet

This worksheet includes all input data required to determine the hydropower potential at a specific site and conditions, and to select an appropriate turbine type for the specific application. To determine the recommended turbine category, the user should first specify the downstream pressure requirements through a dropdown menu. In general:

- If the downstream pressure is required, the recommended turbine is a 'Reaction' type turbine.

- If the downstream pressure is not required, the recommended turbine is an 'Impulse' type turbine.

Given the recommended turbine category, the user has the ability to select the preferred turbine type among those recommended by the tool as a result of the information previously provided. In particular, the user can select the following:

- Turgo or Pelton turbines for Impulse type turbines
- Francis or Pump-as-Turbine for Reaction type turbines

The user is also required to provide the following parameters, by also selecting the preferred units, to determine the system differential pressure, head and hydropower potential:

- Upstream and downstream pressures (in ft, psi, or bar)
- Design flow (in cfs, million gallons per day [mgd], gallon per minute [gpm], or liter per second [lps])
- Capacity factor
- Water-to-wire efficiency

The tool also provides suggestions as "reference value" that the user may consider using for the capacity factor and water-to-wire efficiency parameters based on the previously input data. For example, for the design flows the following reference values are suggested:

- If the recommended turbine is of 'Reaction' type, the typical flows are in the range of 3-200 cfs.
- If the recommended turbine is of 'Impulse' type, the typical flows are in the range of 30-1,000 cfs.

The capacity factor typically varies depending on the water type (e.g., raw water, potable water, wastewater). Thus, the following reference values are suggested:

- 40-45 percent for raw water
- 60-85 percent for potable and reclaimed waters
- >90 percent for wastewater

The water-to-wire efficiency varies depending on the type of turbine selected. For example:

- If the recommended turbine is a 'Reaction' type, the water-to-wire efficiency should be considered in the range of 70-75 percent.
- If the recommended turbine is an 'Impulse' type, the water-to-wire efficiency should be considered in the range of 75-80 percent.

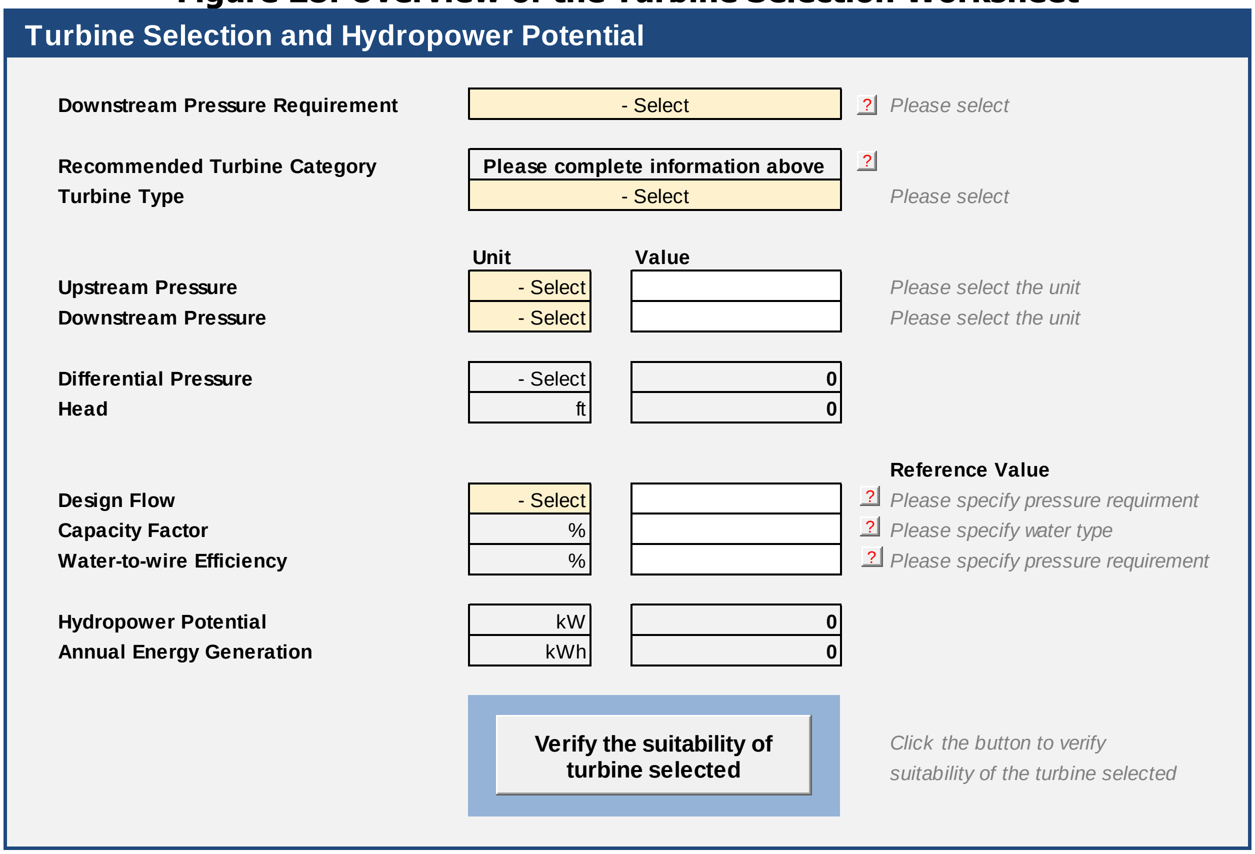
Given the information provided above, the hydropower potential (in kW) can be calculated. The annual generation (kWh) can be consequently calculated using the equation (0-1):

$$Annual\ Generation\ [kWh] = Hydropower\ Potential[kW] \cdot \frac{8760 \cdot Capacity\ Factor\ [\%]}{100} \qquad (0\text{-}1)$$

After completing the required information to calculate the hydropower potential and the annual energy generation, users can check the suitability of the turbine selected for the specified capacity by clicking the "verification button" at the bottom of the worksheet. When the turbine selected is suitable for the specified capacity, a verification message box will appear on the screen and users can continue to the next worksheet. If the turbine selected is not suitable for the capacity specified by users, a warning message box will appear, suggesting that users select a different type of turbine.

Figure 28 shows a screenshot of the Turbine Selection Worksheet. The following sections will provide the cost analysis based on the turbine type and system configuration selected.

Figure 28: Overview of the Turbine Selection Worksheet



Source: Stantec, 2019

LCC Assumptions Worksheet

In the LCC Assumptions Worksheet, the user should insert the assumptions incorporated into the LCC analysis. The assumptions are shown in five categories:

- Life Cycle Assumptions
- Cost Assumptions
- Financial Assumptions
- Economic Assumptions
- Electricity Charges Assumptions

Figure 29 shows a screenshot of the LCC Assumptions Worksheet.

Life Cycle Assumptions

The 'Life Cycle Period' is the time over which projected capital costs and annual costs of project options are evaluated. Life cycle period analysis and estimated useful lives of assets may be—but are not necessarily—the same number of years. In this spreadsheet, the life-cycle period should be at least as long as the expected useful life of the major facility components of the option with the longest useful life. With this tool, the maximum value allowed for the life cycle period is 50 years. If the user is interested in evaluating the different options at different life cycle periods, then different analyses should be performed with the desired LCC assumption input.

In addition to life cycle period, the user must specify the initial year of operation and the year of analysis. The Initial 'Year of Operation' is the first year of the life cycle period that follows the construction period. The 'Year of Analysis' is the date at which the present values of all future LCC are determined. Examples of these values are reported as reference values in Figure 29.

Figure 29: Overview of the LCC Assumptions Worksheet

LCC Period, Cost, Financial and Economic Assumptions

		Unit	Value	Example Value
I	**Life Cycle Assumptions**	**Unit**	**Value**	**Example Value**
	Period	Years		20
	Initial year of operations	-		2019
	Year of analysis	-		2019
II	**Cost Assumptions**	**Unit**	**Value**	**Example Value**
	Cost estimate dollar basis year	-		2019
	Construction cost escalation	% (Annual)		3.5%
	O&M and general cost escalation	% (Annual)		3.0%
III	**Financial Assumptions**	**Unit**	**Value**	**Example Value**
	Capital treatment: lump sum or financed		Select-	D/S
	Financing interest rate	%		5.25%
	Financing maturity	Years		20
	Financing costs, capitalized	%		2.0%
IV	**Economic Assumptions**	**Unit**	**Value**	**Example Value**
	Discount rate (cost of capital)	%		5.25%
	Annual growth in electricty consumption	%		2.0%
V	**Electricity Charges Assumptions**	**Unit**	**Value**	**Example Range**
	Electricity rates (purchase)	\$/kWh		\$0.06 - \$0.20
	Electricity rates (sold)	\$/kWh		\$0.04 - \$0.13
	Net energy metering (NEM)	\$/kWh		\$0.04 - \$0.13
	Net energy metering aggregation (NEMA)	\$/kWh		\$0.04 - \$0.12
	RES-BCT (Bill Credit Transfer)	\$/kWh		\$0.06 - \$0.09
	Other programs	\$/kWh		

Source: Stantec, 2019

Cost Assumptions

The 'Cost Estimate Basis Year' generally is the same as the 'Year of Analysis' reported in the previous section. The 'Construction Cost Escalation' and 'O&M and General Cost Escalation' values should also be provided by the user. Construction cost escalation is typically based on local experience and is sometimes verified by recent history of the Engineering News-Record Construction Cost Index (the "ENR"). The 'O&M and General Cost Escalation' should always be based on local experience but sometimes is verified by recent history of the Consumer Price Index, published by the Bureau of Labor Statistics. Examples of these values are reported as reference values in Figure 28 and Figure 29.

Financial Assumptions

For capital improvement planning purposes, it is customary for some users to assume all 'LCC Capital Costs' are to be long-term debt financed and shown as annual debt service values rather than as lump sum capital requirements. This enables financing costs to be included in the analysis and annual cash flow behavior to be more reflective of actual resulting annual costs. The LCC model allows the user to redefine how capital costs are to be treated: either as bond funded with debt service estimated or as lump sum capital costs. On the basis of this selection, capital costs are treated as lump sums or debt-service costs. But no capital activity can be divided with part financed with debt and the other part on a pay-as you-go basis.

Debt service financing interest rates, bond maturity years, and the financing costs that will be capitalized are the necessary data for the model to compute annual debt service. Debt service is computed using equal annual payments of principal and interest and assumes that the bond sales will not include capitalized bond reserve funding or costs of sureties to cover bond reserve requirements. If bond reserves are required, they will have sequestered reinvestment earnings and any minor deficits will be immaterial. The bond sales will not include capitalized interest; debt service will commence promptly the year immediately following bond sales. For economic comparison purposes of the LCC analysis, it is assumed that level debt service throughout the debt repayment period is appropriate. Similarly, it is assumed that any bond reserve augmentation that may be required by bond indenture(s) shall be handled by a surety instrument or by a capitalized deposit in a sequestered fund that earns reinvestment interest and is used for the final payment of principal and interest. Examples of these values are reported as reference values in Figure 28 and Figure 29.

Economic Assumptions

Economic assumptions include discount rates for computing present values of future costs. A typical discount rate determination is based on risk-adjusted cost of capital. A typical discount rate value should be adjusted to reflect the cost of capital behavior. The final assumption shown on the Economic assumption is the figure for assumed growth in electricity consumption. Examples of these values are reported as reference values in Figure 28 and Figure 29.

Electricity Charge Assumptions

The 'Electricity Charges' assumptions section includes the various electricity rates related to energy purchase, energy sale, or participation to various programs of the local electric utility. For example, this section provides the user the opportunity to include rates associated with NEM, NEMA, RES-BCT, and more that contribute to the generation of revenue from producing renewable energy through the in-conduit hydropower project. Examples of these values are reported as reference values in Figure 28 and Figure 29.

Capital Costs Worksheet

This worksheet receives, by the user, all the necessary input for the calculation of the capital cost in the appropriate cells. All costs are reported in U.S. dollars. If the user lacks the cost information for some or all the fields, the reference values reported can be used. The reference values were determined based on cost curves provided by turbine manufacturers and in-conduit hydropower projects developers. The reference values cannot be modified at the user's discretion. The user should leave the cell unchanged if that cell does not apply to the project.

The main elements included in the capital cost analysis for the in-conduit hydropower project include:

1. Turbine, generator, and switchgear (main equipment).
2. Programming/Control (typically between 5-30 percent of the main equipment cost depending on the type of turbines).
3. Civil work (typically between 10-150 percent of the main equipment cost depending on the type of turbines).
4. Mechanical work (typically 10-30 percent of the main equipment cost depending on the type of turbines).
5. Electrical assembly and wiring (typically 30-35 percent of the main equipment cost depending on the type of turbines).
6. Buildings and structures (typically 15-100 percent of the main equipment cost depending on the type of turbines).
7. Interconnection (typically 5-25 percent of the total construction cost [subtotal 1 through 6]).
8. Engineering, plant start-up and environmental (e.g., permitting) (typically 30-60 percent of the total construction cost [subtotal 1 through 6]).
9. Contractor's miscellaneous costs (typically 15 percent of the total construction cost including interconnection, engineering, plant start-up, and environmental [subtotal 1 through 8]).
10. Owner's soft and miscellaneous costs (typically 10 percent of the contractor's miscellaneous cost).
11. Contingency (typically 20 percent of the construction cost plus 5 percent of non-construction cost. The non-construction cost includes item 8 and 10, whereas the construction cost is the total cost minus the non-construction cost).

Figure 30 shows a screenshot of the Capital Costs Worksheet. On the basis of the input specified, the model automatically calculates the total capital cost for the in-conduit hydropower system previously selected.

Figure 30: Overview of the Capital Costs Worksheet

Input for Determination of Capital Costs of In-Conduit Hydropower Project

	Turbine Type	- Select		
		Units	Value	
	Hydropower Potential	kW	0	
		Unit	Value	Reference Value for the Specified Potential
I	Turbine, Generator, Switchgear	$		#N/A
II	Programming/Control ?	$		#N/A
III	Civil ?	$		#N/A
IV	Mechanical ?	$		#N/A
V	Electrical Assembly and Wiring ?	$		#N/A
VI	Buildings and Structures ?	$		#N/A
VII	Interconnection ?			#N/A
VIII	Engineering, Plant Startup, Environmental ?	$		#N/A
	Subtotal I Though VIII	$	$ -	#N/A
		Unit	Value	Reference Value
IX	Contractor's Miscellaneous Cost ?	$		#N/A
	Subtotal I Though IX	$	$ -	#N/A
		Unit	Value	Reference Value
X	Owner's Soft and Miscellaneous Cost ?	$		#N/A
	Subtotal I Though X	$	$ -	#N/A
		Unit	Value	Reference Value
XI	Contingency ?	$		#N/A

Capital Cost of In-Conduit Hydropower Project

	Unit	Value	Reference Value
Total Capital Cost	$	$ -	#N/A

Source: Stantec, 2019

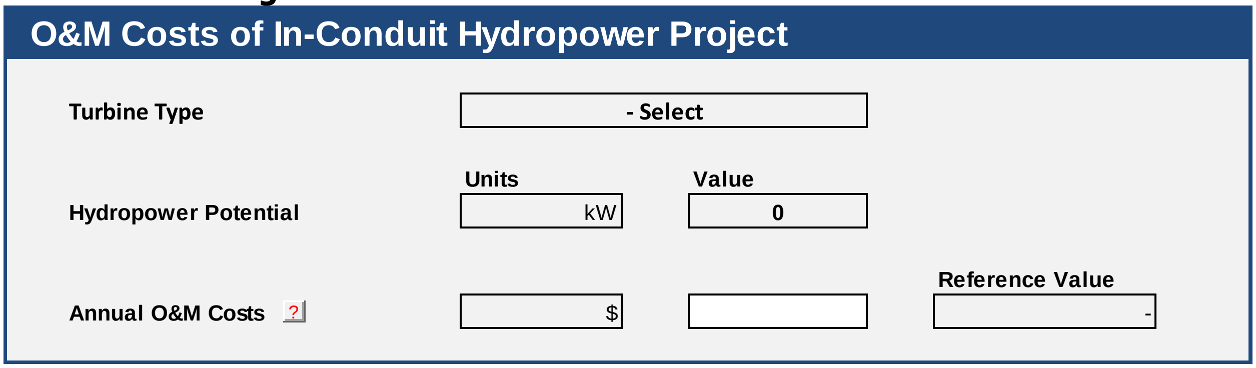
O&M Costs Worksheet

This worksheet allows the user to enter the anticipated O&M costs (fixed and variable) for the project in the appropriate cells. Fixed O&M costs may include labor hours, while variable O&M may include oil consumption and equipment maintenance. Typically, the O&M requirements for these systems are not extensive, therefore as a rule of thumb the following can be considered:

- $6,000 per year for Pump-as-Turbine;
- $10,000 per year for Francis turbines
- Between $5,000-7,000 per year for Pelton or Turgo turbines

The user can decide whether to apply these values or to include different values that are found to be more appropriate for the project. Figure 31 shows a screenshot of the O&M Costs worksheet.

Figure 31: Overview of the O&M Costs Worksheet



Source: Stantec, 2019

Project Grants/Incentives and Financial Benefits

This worksheet provides the user with the opportunity to account for any grants or incentives received to offset some of the capital costs of the project as well as to determine the financial benefits of installing the in-conduit hydropower system. The financial benefits may be associated with the following:

- Avoided energy costs by offsetting the total or a portion of the energy demand from the grid with the energy generated onsite with the in-conduit hydropower system
- Revenues from selling the excess electricity (of that maximum allowed for use onsite) to the grid
- Revenues from participation to electric utility programs such as NEM, NEMA, RES-BCT and other;
- Other forms of revenues as applicable to the utility

Figure 32 shows a screenshot of the LCC Assumptions Worksheet.

Figure 32: Overview of the LCC Assumptions Worksheet

Project Grants / Incentives

	Name	Unit	Value
Grant #1		$	
Grant #2		$	
Incentive #1		$	
Incentive #2		$	
	Total Grants/Incentives	$	**$ -**

Financial Benefits (First Year)

		Unit	Value	
I	**Energy Use**	**Unit**	**Value**	
	Total energy generation	kWh	**0**	
	% Energy used on-site	%		*Please specify*
	Energy used on-site	kWh	**0**	
	Excess energy available for export	kWh	**0**	
II	**Benefits (First Year) - Not escalated**	**Unit**	**Value**	
	Avoided energy cost	$	**$ -**	
	Revenue from selling electricity	$	**$ -**	
	Revenue from NEM	$	**$ -**	
	Revenue from NEMA	$	**$ -**	
	Revenue from RES-BCT	$	**$ -**	
	Revenue from other electric utility programs	$		
	Other revenue	$		
	Total Revenues (First Year)	$	**$ -**	

Source: Stantec, 2019

Greenhouse Gas Emissions

This worksheet includes all input data and calculation of the GHG emissions savings during the first year of operation of the in-conduit hydropower project considered. The accuracy in calculating the GHG emissions that the utility saved by generating its own energy is directly dependent on the accuracy of the data available for energy generation and associated GHG emission factors per unit of energy generated. The GHG emissions savings were calculated with the following equation (0-2):

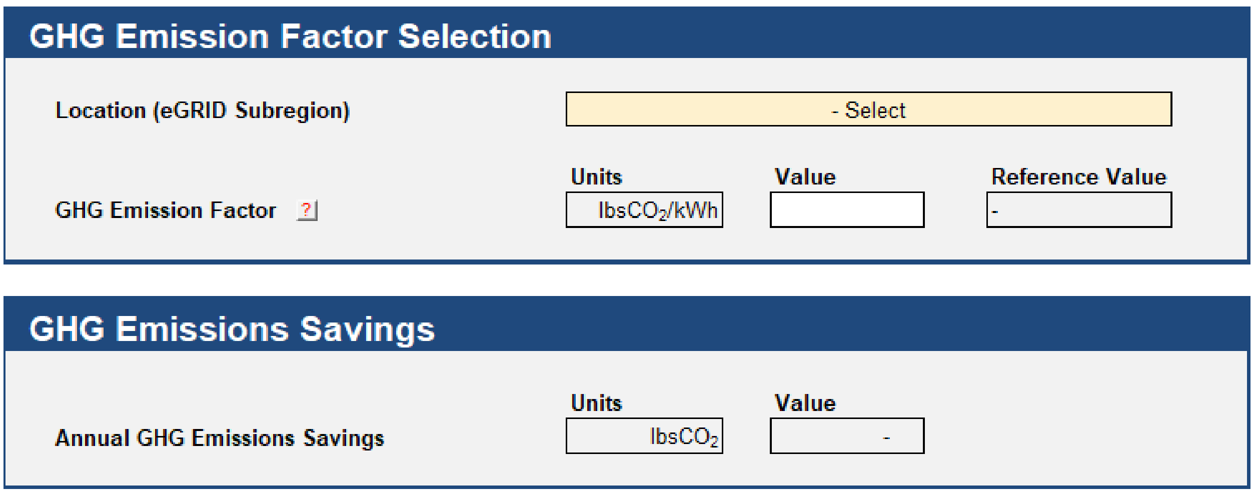
$$GHG_{Savings} = EF_{GRID} \cdot Q \qquad (0\text{-}2)$$

Where: EF_{GRID} = emission factor for the grid (ton-CO_2/kWh); and Q = annual energy generated (kWh).

The emissions factors used in this study were the emission factors for greenhouse gas inventories developed by the U.S. Environmental Protection Agency (EPA) (EPA, 2016) for different subregions in the U.S. The user can select a specific eGrid subregion of the U.S. and automatically the correspondent emission factor is given in the appropriate cell of the worksheet. For example, California is included in the California-Mexico Power Area (CAMX) sub-region of the Western Electric Coordinating Council eGrid subregion with an average emission factor of 527.9 $lbsCO_2/MWh$. The user also has the option to select the U.S. average emission factor of 998.4 $lbsCO_2/MWh$.

Figure 33 shows a screenshot of the LCC Assumptions worksheet.

Figure 33: Overview of the Environmental Benefit Worksheet



Source: Stantec, 2019

Life Cycle Cost Analysis

This worksheet presents the final output of the tool by summarizing the information obtained in the previous worksheets and introducing new LCC cost, LCOE, and life cycle GHG emissions calculations for the in-conduit hydropower project. In particular, the final output worksheet includes:

- In-conduit hydropower project information
- In-conduit hydropower system configuration
- Project grants and incentives
- Life cycle cost analysis
- Levelized cost of energy analysis
- First year and life cycle GHG emissions

An example of the LCC Analysis Worksheet is presented in Figure 34 and Figure 35. The output results allow the user to compare side by side the results of the different alternatives and allow the user to choose the best fitting alternative based on the desired metric: energy savings, GHG emission reductions, and/or economic viability.

Life Cycle Cost Analysis

This worksheet addresses the calculation of life-cycle capital and O&M costs based on the assumptions introduced in the LCC Assumptions worksheet. The total LCC is used to assess the cost and timing of cost of the in-conduit hydropower project. These costs are discounted to a base year by using a present value analysis. Most of the costs mentioned are incurred over the LCC period, which equals or exceeds the life of the asset (for example, 50 years). The present values (PV) of all the future capital and annual costs must be calculated for each alternative being considered. The typical method to compute present values is first to compute a future value ("FV") at year "n" using an appropriate escalation rate and then to compute the present values of that future value using an appropriate discount rate. These computations are shown in Equations (0-3 and (0-4):

$$FV = \sum_1^x C_n * (1 + p)^n \tag{0-3}$$

$$PV = \sum_1^x \frac{FV_n}{(1+i)^n} \tag{0-4}$$

Where: C_n = cost at year "n" for the above indicated cost categories; n = total number of years being considered; p = expected average rate of cost escalation; i = discount rate; and x= number of cost elements.

In evaluating various in-conduit hydropower alternatives, the project with the lowest LCC should be considered as the most attractive of the alternatives in terms of cost, but other non-cost features can be important and should also be considered in the selection of the desired turbine and configuration.

Levelized Cost of Energy

The LCOE was also used as a metric to evaluate the cost of energy generated by the in-conduit hydropower system. The LCOE represents the cost per kilowatt-hour of building and operating a power generation system given an assumed life cycle. The key elements for the LCOE calculation include capital costs, fixed and variable O&M costs, and financing cost. The LCOE can be calculated using the following equation (0-5):

$$LCOE = \frac{LCC}{Q} \cdot (UCRF) \tag{0-5}$$

Where: LCC = present value of the LCC; Q = annual energy generation (kWh); UCRF = uniform capital recovery factor, which is expressed by the equation (0-6):

$$UCRF = \frac{d \cdot (1+d)^N}{(1+d)^N - 1} \tag{0-6}$$

Where: N = analysis period; and d = discount rate.

Life Cycle Greenhouse Gas Emissions Analysis

Life cycle GHG emissions savings were also estimated for the in-conduit hydropower project considered. The calculation of the life cycle GHG is based on the previously calculated GHG emissions and the years of system operation established in the LCC Assumption worksheet.

Figure 34: Overview of the LCC Analysis Worksheet

Project Information

Project Name	0
Project Location	0
Project Description	0
Contact Person	0

Utility Information

Utility Name	0
Utility Type	0
Publicly or Investor-Owned Utility	0

Site Characteristics

Conduit Type	- Select
Facility Type	- Select
Topography Type	- Select
Water Type	- Select

In-Conduit Hydropower System Configuration

	Units	Value
Hydropower Potential	kW	**0**
Annual General potential	kWh	**0**
Turbine Type	**- Select**	

Grants, Incentives, and Revenues

	Units	Value
Total Grants/Incentives	$	$ -
Total Revenues (First Year)	$	$ -

Source: Stantec, 2019

Figure 35: Overview of the LCC Analysis Worksheet (continued)

Life Cycle Cost Analysis

First Year Cost	Units	Value
Capital cost (including grants / incentives)	$	-
Capital cost per kW	$/kW	#DIV/0!
O&M costs	$	-
O&M costs per kW	$/kW	#DIV/0!
Total Cost	$	**-**
Total Cost per kW	$/kW	**#DIV/0!**

Life Cycle Cost	Units	Value
Life cycle capital cost (present value)	$	#VALUE!
Life cycle capital cost per unit energy (present value)	$/kW	#VALUE!
Life cycle O&M cost (present value)	$	#N/A
Life cycle O&M per unit energy (present value)	$/kW	#N/A
Total Life Cycle Cost (Present Value)	$	**#VALUE!**
Life Cycle Cost per Unit Energy (Present Value)	$/kW	**#VALUE!**
Total Life Cycle Benefit (Present Value)	$	**-**
Life Cycle Benefit per Unit Energy (Present Value)	$/kW	**#DIV/0!**

	Units	Value
Payback Period	years	**#DIV/0!**

Levelized Cost of Energy Analysis

	Units	Value
Levelized Cost of Energy	cents/kWh	**#VALUE!**

GHG Emissions Analysis

	Units	Value
Annual GHG Emissions	lbsCO_2	**-**
Life Cycle GHG Emissions	lbsCO_2	**-**

Source: Stantec, 2019

A reset button is also provided at the end of the output worksheet to erase all the entered inputs in all worksheets to provide a blank form for a new assessment.

CHAPTER 6: Assessment of In-Conduit Hydropower Potential in California

Since the last state-wide resource potential assessment of in-conduit hydropower projects developed by the CEC 10 years ago, there have been several important, positive updates that have changed the landscape related to small hydropower in the state. Therefore, it was a timely research need to develop an updated and comprehensive assessment of in-conduit hydropower generation potential in California. This chapter presents the background, methodology and outcomes of the state-wide resource and potential assessment for installation of in-conduit hydropower systems in California.

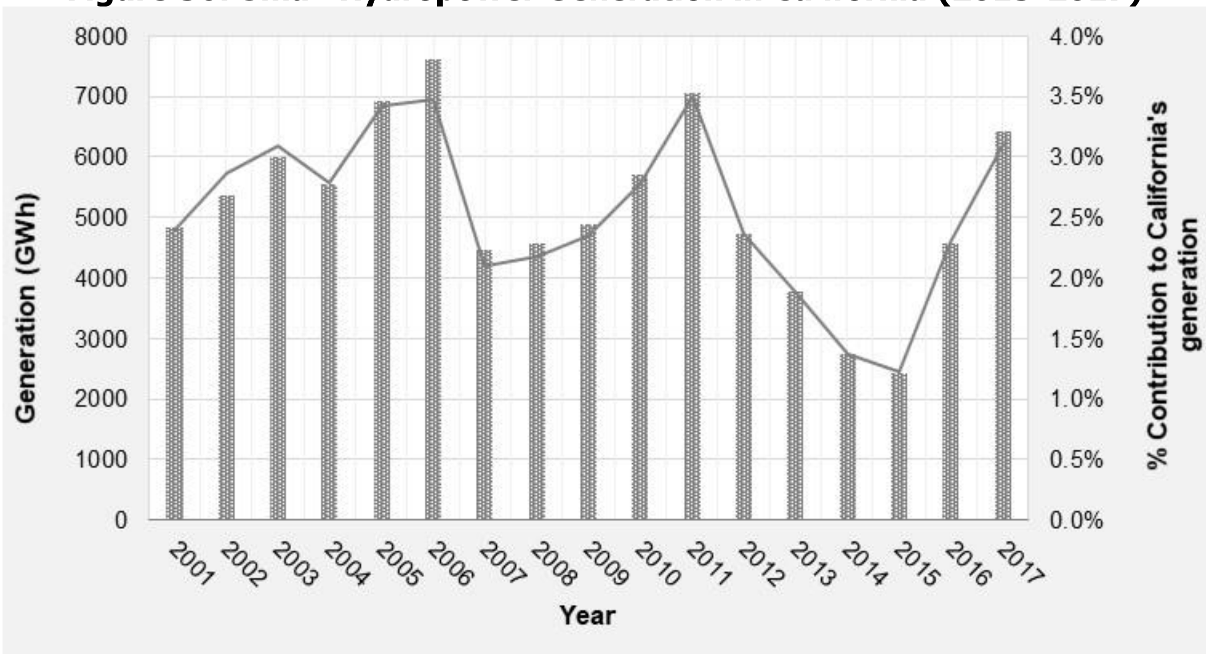
Background

Small hydropower systems (100 kW to 30 MW) are increasingly being considered as an important source of renewable energy in the U.S. and around the world (Doig, 2009). A recent assessment of small hydropower generation in the U.S. conducted in 2018 estimated a potential capacity of about 13,804 GWh, with half of the capacity located in only a few states (Washington, Oregon, and California) (Johnson et al., 2018; Uría-Martínez et al., 2018). On a national scale, a study by USBR showed that 103 MW of potential capacity and 365,219 MWh of potential generation are available at 373 identified sites on reclamation canals (Pulskamp, 2012). In the State of Colorado, it was estimated that approximately 41 potential sites are available with an annual undeveloped small hydropower capacity of 737,975 MWh (Johnson and Hadjerioua, 2015). In the State of California, the latest assessment of small hydropower conducted in 2006 estimated about 2,467 MW of undeveloped small hydropower potential (Park, 2006).

In California, small hydropower has contributed to approximately one percent to 3.5 percent of California's power generation, according to the in-state electric generation information reported by the CEC (Figure 36). (CEC 2018). In California, the level of small hydropower generation seems to be correlated with the hydrologic year since a reduction in small hydropower generation was observed during the historic severe drought between 2012 – 2016. During the drought, in-state generation was reduced by almost 65 percent compared to 2011, to reach as low as 2,616 GWh in 2015. A 40 percent reduction in generation was also observed during the previous 2007 - 2009 drought period.

An important subset of the small hydropower portfolio is represented by in-conduit hydropower systems. In-conduit hydropower is defined as hydroelectric generation potential from man-made conduits such as tunnels, canals, pipelines, aqueducts, flumes, ditches, or similar man-made water conveyances that are operated for the distribution of water for agricultural, municipal, and industrial consumption (Park, 2006). As it is typically installed in existing infrastructure for water conveyance, the environmental impact of in-conduit hydropower systems is considered to be minimal. In 2006, the study published by the CEC concluded that, among small hydropower projects, those associated with in-conduit hydropower systems were more likely to receive eligibility for an RPS program, and this warranted further investigation for future developments. This study also estimated that approximately 255 MW of in-conduit hydropower could be developed at that time using current technologies (Park, 2006).

Figure 36: Small Hydropower Generation in California (2013-2017)



Source: The Energy Commission, 2018

Since this estimation, a series of regulatory and technological advancements have occurred. For example, FERC passed the HREA of 2013 to expedite the process for qualifying conduits located on non-federally owned conduits with installed capacities up to five MW (GPO, 2016). This resulted in 87 projects with a nameplate capacity of 32 MW being approved since 2013 (Johnson et al., 2015). In addition, for the past 10 years, many turbine technology manufacturers have developed several modular "water-to-wire" systems that target the sub in-conduit hydroelectric 1-MW market, further widening the opportunity for in-conduit hydropower project development (Sari et al., 2018). Thus, an update on the in-conduit hydropower potential assessment in California is a timely research need.

This chapter quantifies the in-conduit hydropower potential in California, revisiting, through a new methodological approach, the estimates reported by the CEC's previous studies. The present study also assesses the existing in-conduit hydropower installed capacity in the state. The novel data-driven methodological approach coupled a number of datasets, including the total surface water withdrawals in the state and metered water deliveries from different water agencies, to draw a more holistic estimate of the potential attainable in-conduit hydropower generation. The following sections discuss the novel methodology developed for this assessment and the analysis of the results obtained.

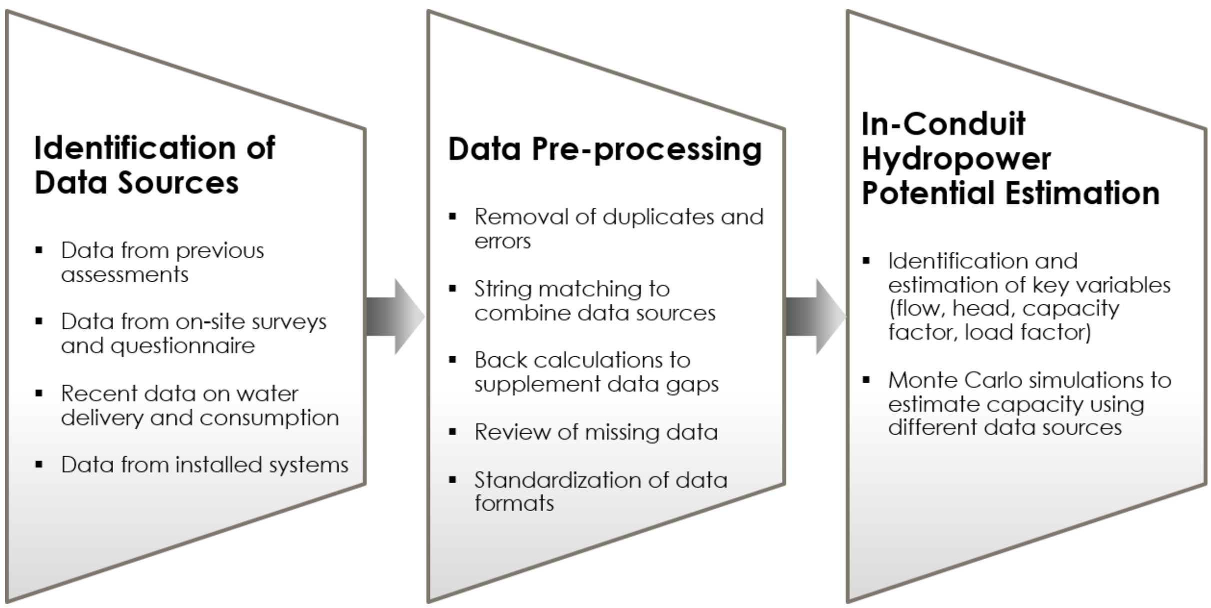
Method

The estimation of potential in-conduit hydropower generation depends on the source of data and factors, or variables that are strictly dependent on the location of the water agency (e.g., head, flow, and efficiency). The following sections provide details on:

- Data sources selected for this study.
- Methodology for data pre-processing and identification and estimation of key variables of influence for the analysis.
- Analytical approach used to determine the in-conduit hydropower potential in California.

An overview of the methodology used to estimate the potential capacity for in-conduit hydropower installations in California is depicted in Figure 37.

Figure 37: Overview of the Statewide Resource Assessment Method Used in The Study

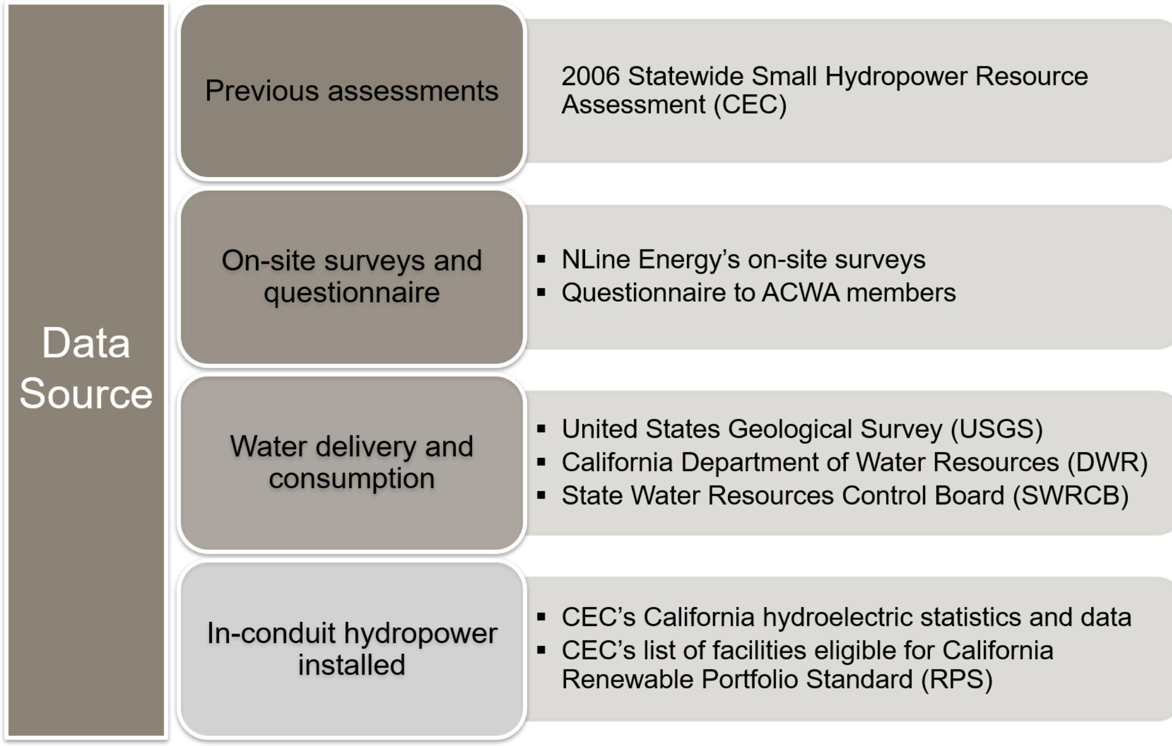


Source: Stanford University, 2019

Data Sources

A systematic and holistic approach based on the use of multiple publicly available state-wide data sources was developed to accurately estimate the small hydropower potential in California. A comprehensive database that includes all the different water agencies/utilities and their various internal connections within the state, is, in fact, not yet in the public domain. Therefore, as part of this effort, eight different datasets were evaluated, as shown in Figure 38.

Figure 38: Datasets Considered in The Study



Source: Stanford University, 2019

Briefly, the assessments conducted by the CEC in 2006 (Park, 2006) and by NLine Energy through on-site surveys were first reviewed to obtain preliminary insights on the in-conduit hydropower potential in the state. Next, the team developed a questionnaire and distributed it to members of the ACWA to gather feedback about existing and/or potential in-conduit hydropower projects at their facilities. Lastly, publicly available data on water delivery and consumption in California were reviewed to conduct bottom-up and top-down estimates of the in-conduit hydropower potential. In particular, three public datasets were considered from USGS DWR, and SWRCB, respectively, to identify the installed capacity of in-conduit hydropower facilities in California and assess the potential for further installations. While the CEC funded the State-wide Resource Assessment (SRA) conducted in 2006 as a reference for the assessment of the current small hydropower generation, the NLine Energy's on-site survey and the ACWA questionnaire served as external validation sources for the bottom-up and top-down estimates. The details associated with the different datasets are summarized in the following sections.

2006 Statewide Small Hydropower Resource Assessment

The 2006 SRA, commissioned by the CEC, aimed at assessing the total RPS eligible in-conduit hydropower in California (Park, 2006). The report included one of the first surveys undertaken towards small hydropower assessment and considered engineering conduits, natural water courses, dams, canals and pipelines to estimate the undeveloped small hydropower potential in the state. The study considered 164 water purveyors, whose size was defined as the total annual water supplied to customers. Of these 164 agencies, 12 large-sized (≥500 kilo-acre-ft) and 16 medium-sized (50 – 499.9 kilo-acre-ft) water agencies were surveyed on-site to assess their small hydropower capacity. The water agencies considered were divided into six categories based on their location (north/central/south California) and type (urban/irrigation supplier). These factors were used to develop six extrapolation factors, calculated using Equation (0-1):

$$Extrapolation\ factor = \frac{Capacity\ surveyed_i}{Size\ of\ surveyed\ water\ agencies_i} \tag{0-1}$$

where i represents a given category. The remaining 136 water agencies that were not surveyed were assigned to one of the six categories based on their location and type. The corresponding capacities at each of the remaining water agencies were obtained through extrapolation based on the size of the water agency and estimated by the product of the extrapolation factor in that category and the size of the water agency.

The methodology adopted by the CEC's 2006 SRA report was based on extrapolation factors using on-site assessments of 12 large-sized and 16 medium-sized water agencies. However, information on whether the on-site assessments were based on the available values of head or any experimental surveys was not specified in the study. Linear interpolation based on the size of the water agency alone could lead to inaccurate generation assessment partly due to ignoring variables such as available head, historic trends in flows, load and capacity factors. The methodology used in this study, which is reported in the following section, helped to overcome the limitations of the 2006 SRA study by integrating various data sources and presenting the range of possible estimates.

NLine Energy's On-site Survey

From 2011-2017, NLine Energy conducted a series of on-site surveys across 122 water agencies within the state to better understand the potential of implementing in-conduit hydropower projects at pressure-reducing stations. The collected data encompassed 122 water agencies that have been surveyed across California between 2011-2017. This data provided a range of values of head and capacity factors corresponding to the range of surveyed capacities.

Questionnaire Distributed to ACWA Members

In December 2017, the project team developed a questionnaire and distributed it to the members of the ACWA to gather information about the potential for developing small hydropower within the state.

USGS Surface Water Withdrawals

Every five years USGS publishes data on surface water withdrawals from each county in the U.S. (USGS, 2018). Data on surface water withdrawals for domestic and irrigation purposes from 2010 and 2015 reports were used to estimate a lower limit on the potential for in-conduit hydropower generation.

SWRCB Drinking Water Supply

Since 2014, SWRCB publishes the annual statistics on drinking water supply from 409 water agencies across the state (SWRCB, 2018). The reported 'Total Monthly Potable Water Production' was considered to estimate monthly variations in flow values across the drinking water agencies. This data was used in the bottom-up analysis developed in this study to estimate the in-conduit hydropower across California.

DWR Public Water Agency Survey

The Water Use and Efficiency Division of DWR annually conducts a survey of public water agencies in the State of California. The data is used to update the California Water Plan – forecast urban water use in California - and estimate regional water demands and plan for future water needs (DWR, 1981). The bottom-up analysis and approach used in this study used the metered water deliveries per month reported in the DWR dataset.

The Energy Commission's California Hydroelectric Statistics and Data

Maintained by the CEC, this dataset provided the range of installed small hydropower capacities (in MW) in California and their annual net generation (in MWh) every year (The Energy Commission, nd). From this dataset, some of the missing variables including the efficiency (capacity factor) as well as the existing installed capacity (below 30 MW) in California in the year 2017 were calculated. This dataset was used to segment the analysis between the existing facilities and potential sites for in-conduit hydropower in California.

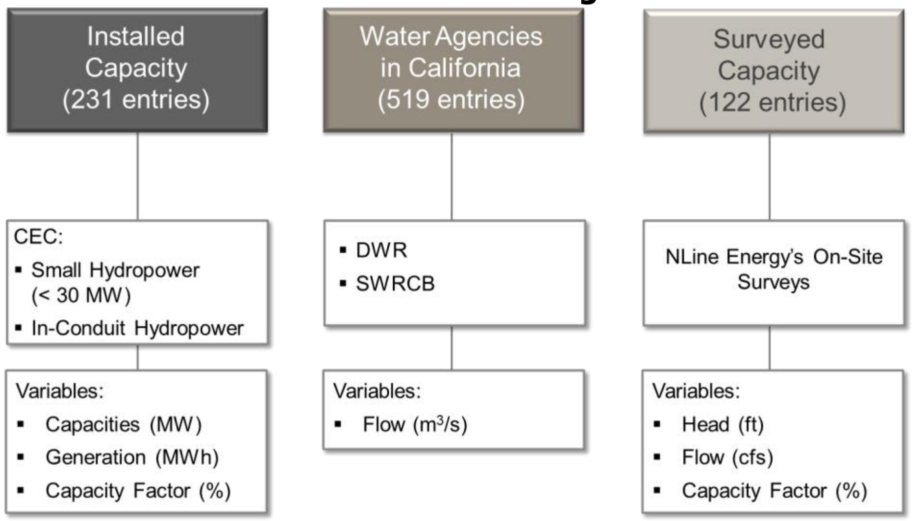
The Energy Commission's List of Facilities Eligible for California RPS

Under California's RPS statutes, retail sellers of electricity in California are required to increase the amount of renewable energy they procure each year. This dataset shows in-conduit hydropower facilities currently pre-certified or certified by the CEC as eligible for RPS.

Data Pre-Processing

The data from the USGS, DWR, SWRCB, and the CEC were combined to allow for a more streamlined analysis by creating three distinctive datasets representative of the 'Installed Capacity', 'Water Agencies in California', and 'Surveyed Capacity', as depicted in Figure 39. Figure 39 also shows the output variables that were estimated using the data of each datasets. Details on the characteristics of each of these distinctive datasets are reported in the following sections.

Figure 39: Organization of the USGS, DWR, SWRCB, and CEC Data in Three Distinctive Data Categories



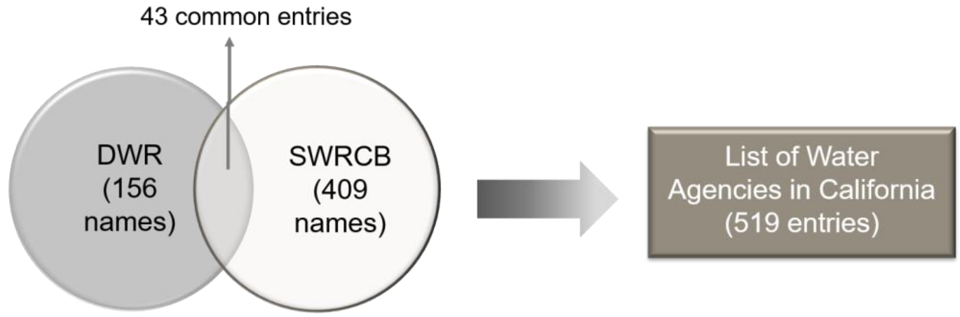
Source: Stanford University, 2019

Dataset of Water Agencies in California

The DWR and SWRCB data sources were combined to make a list of water agencies in California where in-conduit hydropower has potential to be installed. The addresses of these water agencies were found using web-scraping techniques based on the county in which they were located. An address matching algorithm was developed to identify water agencies with the same name and location, such that duplicate information were only counted once within the dataset. The matching data points were manually validated.

Through this approach, it was found that 43 water agencies were common between the two data sources (Figure 40). Of the 43 water agencies, 26 had perfectly matching flow values between the two data sources. Among the remaining 17 water agencies, the data corresponding to the DWR source was found to be reported in different units or erroneous in entries (for example, the same values were repeated across all months and years, indicative of a potentially inaccurate reporting practice). In such cases, the data from the SWRCB source was taken into consideration. Additionally, three erroneous entries from the DWR data source were appropriately removed. These erroneous entries had the same values that were repeated across multiple months. The combined data from both sources thus provides flow values for a list of water agencies in California. The final data set included 519 water agencies.

Figure 40: Combining DWR and SWRCB Data Sources

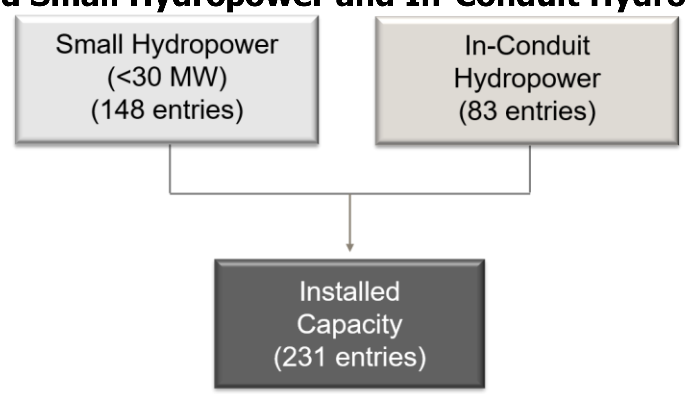


Source: Stanford University, 2019

Dataset of Installed In-Conduit Hydropower Capacities in California

Information regarding the installed in-conduit hydropower facilities and small hydropower facilities below 30 MW obtained from the CEC data sources were combined to estimate the net installed capacity of small hydropower in California, as shown in Figure 41. The resulting installed capacity, for both in-conduit and small hydropower systems, is summarized in Table 22. A name matching algorithm was developed to match and combine these data sets. The names of the water agencies were used to remove common entries between the two datasets and make them mutually exclusive. There were 19 common data points between the two datasets that had the same values reported. It is important to note, there only exists a fraction of facilities that may be in-conduit hydropower facilities in the list of small hydropower facilities. The list only shows small hydropower facilities generating less than 30 MW, without specifying the type of small hydropower (e.g. in-conduit hydropower, small dams, pumped-storage hydropower, etc.). Thus, it is possible that a large portion of the total small hydropower capacity (1,072 MW) belongs to the in-conduit hydropower category.

Figure 41: Installed Small Hydropower and In-Conduit Hydropower in California



Source: Stanford University, 2019

Table 22: Installed Capacities in California

Existing installations in California	In-Conduit Hydropower	Small Hydropower *(under 30 MW)*
Number of facilities	83	148
Installed Capacity (MW)	343	1072

Source: Stanford University, 2019

In-Conduit Hydropower Potential Estimation

The potential at each water agency with no installed in-conduit hydropower facility was estimated using the following equation (0-2):

$$\text{Capacity (kW)} = \text{Head (m)} \times \text{Flow (m}^3\text{/s)} \times \text{Density} \left(\frac{kg}{m^3}\right) \times \frac{g\,\left(\frac{m}{s^2}\right)}{10^3} \times \text{Capacity Factor} \times \text{Load Factor} \qquad (0\text{-}2)$$

This study estimated flow, head, capacity factor and load factor, which are the key variables to determine the in-conduit hydropower capacity based on the approach presented in the following sections.

Estimation of Key Variables

This section provides the approach used to estimate the key variables important for the determination of the in-conduit hydropower potential in California, particularly in relation to the estimation of flows, heads, and turbine efficiencies.

Flow Estimation

Comprehensive water consumption databases were obtained through USGS, DWR and SWRCB. The information included in these databases, such as the monthly metered water deliveries and population served, was used to estimate the monthly variations in flows for each water agency, as flows can be impacted by climatic and hydrologic variability. For example, during the recent drought (2012 – 2016) in California, the mandatory 25 percent water use reduction enacted in California in 2015 affected water deliveries, and therefore flows to various water agencies (Executive Order B-29-15, 2014; Executive Order B-40-17, 2017).

- The data from the USGS on surface water withdrawals was processed to determine the flow rate using the following equation (0-3):

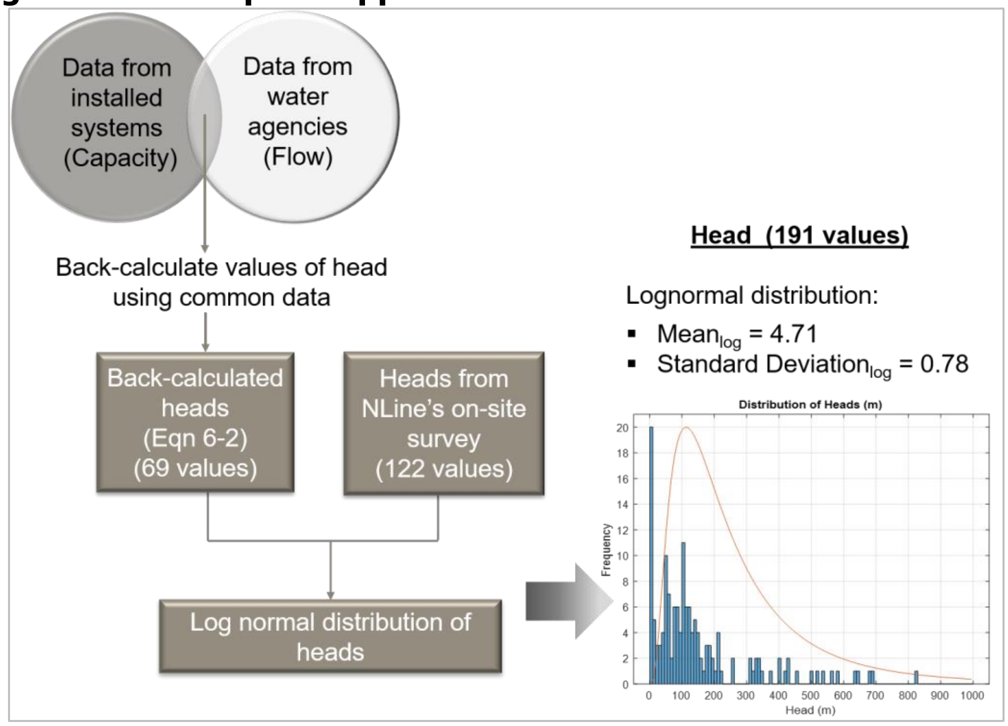
$$\text{Flow rate (m}^3\text{/sec)} = \frac{Total\ Surface\ Water\ Withdrawals\ \left(\frac{MGal}{day}\right)}{86400\ secs/day} \times\ 3.78541\ \frac{m^3}{Mgal} \qquad (0\text{-}3)$$

- Data from DWR and SWRCB on monthly water consumption was converted from Mgal/Gal/Acre-feet/CCF per month to m^3/sec.

Head

Values of available head are highly dependent on the locations of pressure-reducing stations where small-hydro turbines are installed. While flows can be accurately determined based on recorded statistics, values of available head are not publicly available for the majority of the agencies in California. An accurate assessment of these available head values would involve on-ground tests at each pressure-reducing station. Therefore, in this study, a distribution of values of head was estimated using multiple datasets including surveyed capacities (datasets from DWR, SWRCB and NLine Energy) and installed in-conduit hydropower facilities in California (from the CEC databases). A schematic diagram of head estimation using these datasets is presented in Figure 42. The figure shows that 69 common water agencies were found to be listed in the data from installed systems and water agencies. For each agency in the common dataset, the value of head was then back-calculated using the capacity from the installed system and the flow value associated with the water agency (Equation (0-2)). A lognormal distribution was fitted through the range of head values previously obtained and the surveyed list of capacities. The distribution was then used to sample 20,000 head values based on Monte-Carlo simulation.

Figure 42: Conceptual Approach Used to Estimate the Head Values



Source: Stanford University, 2019

Efficiency

The capacity of a turbine can be estimated using the flow and the available head, while its efficiency is calculated using its load factor and capacity factor. Most turbines have an efficiency between 60 - 90 percent due to friction losses in the pipe and conversion from potential energy to kinetic energy within the turbine (Uhunmwangho and Okedu, 2009). Two types of turbines can be used to capture energy: reaction turbines and impulse turbines. Reaction turbines, which are highly efficient, depend on pressure rather than velocity to produce energy. Impulse turbines, which are more commonly used for high-head small-hydro systems, rely on the velocity of water to generate energy (NREL, 2001). The capacity at each factor can, hence, vary depending on the type of turbine used for installation. Therefore, a distribution on available capacity factors is used in this model. Additionally, water consumption in California is expected to decrease through conservation targets set by legislation. Hence, a load factor was included to account for this future reduction in flow.

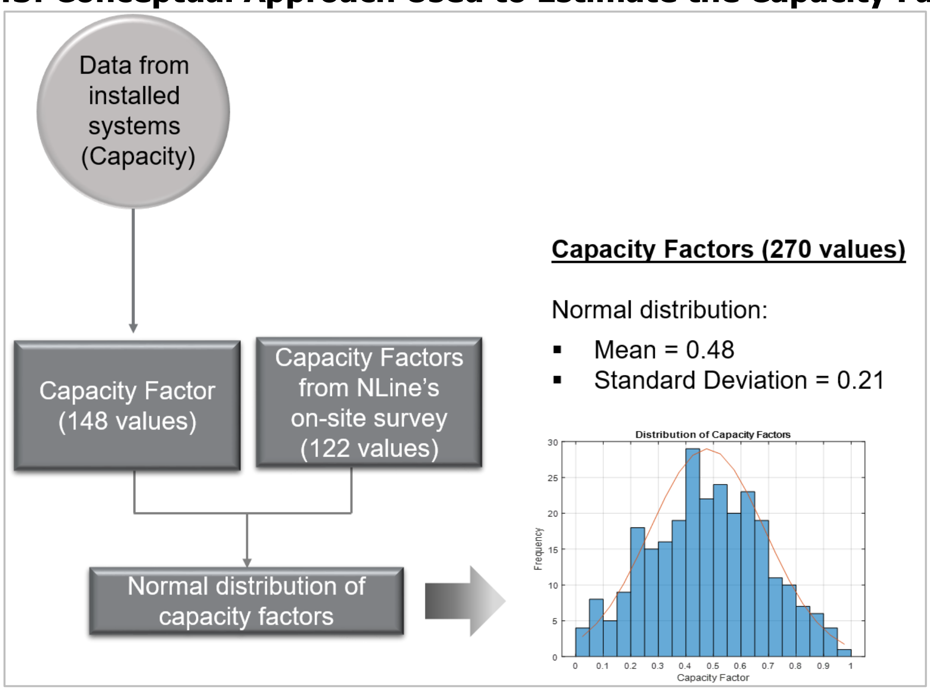
In this study, efficiency is estimated in Equation (0-2) as the product of Load factor and Capacity factor, which are explained as follows:

- Load factor: In preparation for the next drought and changing landscape, the State of California passed two bills, SB 606 and AB 1668, which require water districts to set targets for water use by 2022 (SB-606, 2018). The targets include a daily allowance of 55 gallons per person for indoor water use. Thus, future reduction in flow values due to drought and/or water conservation effort should be accounted for in the capacity assessment. In this study, a load factor of 75 percent was used across all flows to account for monthly variations in future flow values.
- Capacity factor: The capacity factor is defined as the ratio between the actual energy produced by a turbine with respect to the theoretical value of energy production, as presented in Equation (0-4).

$$\text{Capacity factor} = \frac{\textbf{\textit{actual production}}\ (\boldsymbol{MWh})}{\textbf{\textit{nameplate capacity}} \times 86400\, \frac{sec}{day} \times 365.25\ \textbf{\textit{days}}} \tag{0-4}$$

Similar to the approach used for the estimation of head previously discussed, a fitted normal distribution on the range of capacity factors was developed using existing datasets from surveyed list of capacities and installed capacities of in-conduit hydropower, as shown in Figure 43.

Figure 43: Conceptual Approach Used to Estimate the Capacity Factors

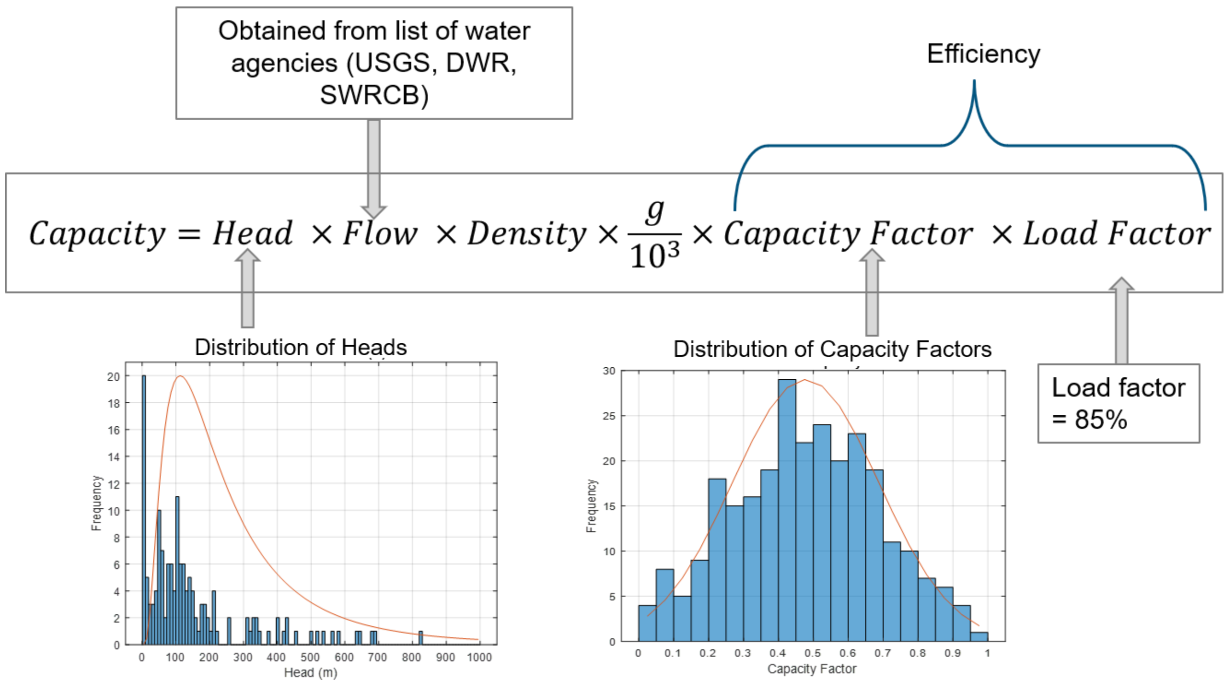


Source: Stanford University, 2019

Monte-Carlo Simulation for Hydropower Capacity Estimation. A Monte-Carlo simulation was performed to determine the hydropower capacity using the variables obtained above and the data sources presented in previous sections. The values assumed for each of the variables are conceptually presented in Figure 44. A Monte-Carlo simulation is, in fact, typically used to resolve an equation with variables that have different probabilistic distributions.

Briefly, for the Monte-Carlo simulations, the distributions for the variables of head and flow were used as inputs. In addition, a load factor of 75 percent was considered to simulate uncertainties in the head and flow that may occur at the county level or at each water agency. For the value of flow at each water agency, 20,000 iterations were run, with each iteration using a realization generated for head and capacity factor based on the fitted lognormal and normal distributions, respectively. The average across all the 20,000 iterations was considered to represent the capacity of the water agency. The capacities across the 450 water agencies were combined to estimate the in-conduit hydropower potential in California.

Figure 44: Monte-Carlo Simulation Approach for the In-Conduit Hydropower Resource Assessment



Capacity is expressed in MW, head is in m, flow in m^3/s, density in kg/m^3, gravity in m/s^2

Source: Stanford University, 2019

Results and Discussion

This section provides on overview of the outcomes of the analysis performed to determine the following:

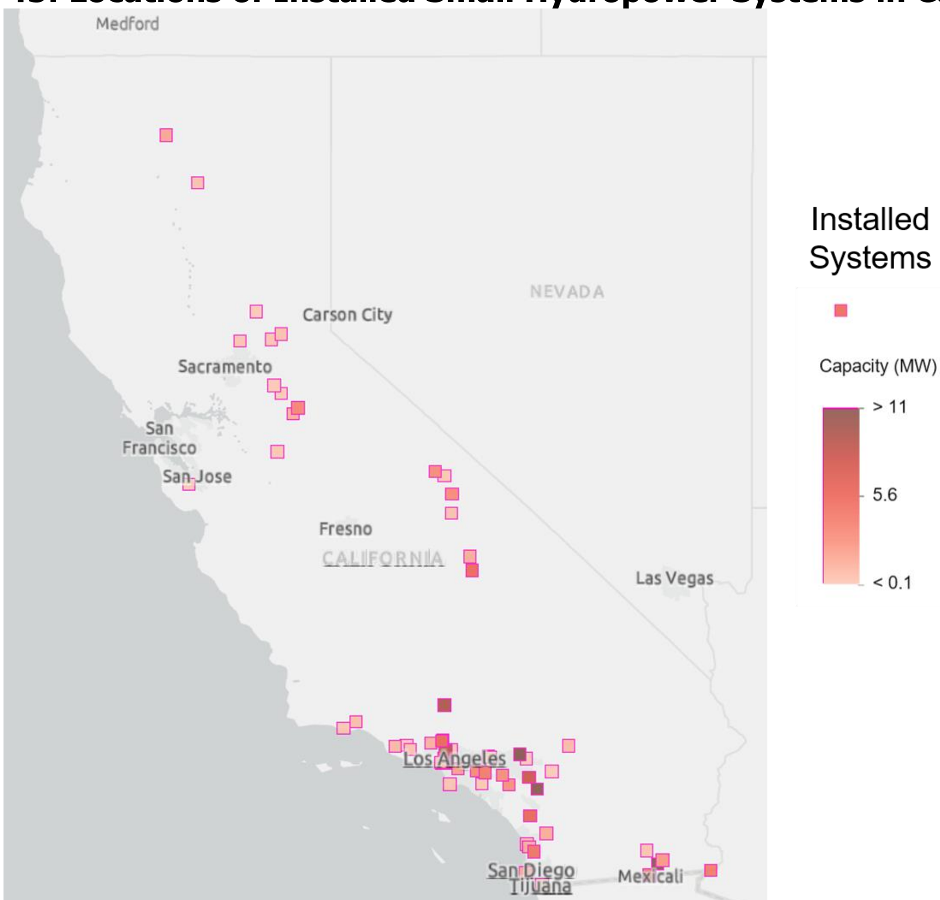
- Installed small hydropower systems in California
- In-conduit hydropower estimates from surveys (2006 SRA, NLine Energy's on-site survey, and ACWA questionnaire)
- Monte-Carlo analysis using three data sources (USGS, DWR, and SWRCB)

The ArcGIS maps, which are based on geographic information, generated from these analyses are also presented in this section to provide a better understanding of the location of installed and uninstalled capacities in California.

Installed Small Hydropower Systems in California

The installed small and in-conduit hydropower capacities were provided in **Error! Reference source not found.** in the Method section. The location of the installed hydropower systems in California was also mapped using data obtained from the CEC data sources. As shown in Figure 45, the installed systems are mostly concentrated in Southern California, close to the urban areas near the coastline such as City of Los Angeles, and City of San Diego. Most of the installed systems are located in facilities owned by water wholesalers and retailers, which receive water from the SWP. In the northern part of California, the installed systems are mostly located away from the coastline, particularly in the irrigation districts.

Figure 45: Locations of Installed Small Hydropower Systems in California

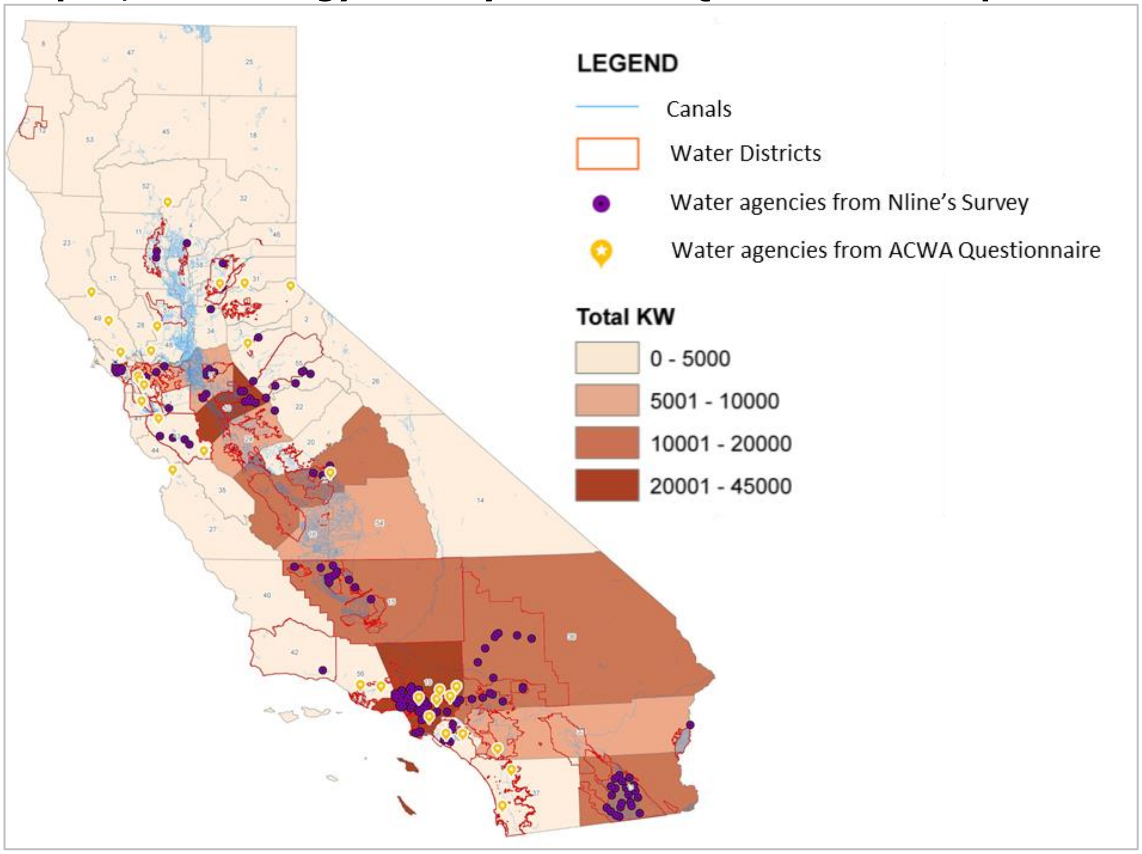


Source: The Energy Commission, 2017

In-conduit Hydropower Potential Estimates from Surveys

This section presents a summary of the estimated in-conduit hydropower potentials derived from the analysis of the 2006 SRA, the NLine Energy's on-site survey and the ACWA questionnaire. These datasets were compared to identify any common water agencies, of which the information could be used for cross-validation. A map of the different water agencies included in the three data sources is presented in Figure 46. The results show that most of the in-conduit hydropower potential is located in Southern California and the irrigation districts in the Central Valley, similar to the findings reported in Figure 45.

Figure 46: Location of Water Agencies Considered in the 2006 Energy Commission Report, NLine Energy's Survey and ACWA Questionnaire Respondents



Source: Stanford University, 2019

The in-conduit hydropower potential estimates from these datasets are also presented in Table 23. The analysis shows that the datasets obtained from the 2006 SRA and the NLine Energy's on-site survey have 31 common water purveyors. Thus, this common data provided an opportunity to cross-validate both datasets. However, since 83 percent of the 2006 SRA was extrapolated data, the results vary substantially compared to the NLine Energy's on-site survey. In addition, the included small number of water agencies limited the potential estimated from Nline Energy's survey and the questionnaire. In 2006, the estimate was placed at 255 MW across the state which has been surpassed today with 343 MW being the current installed capacity across California (as of 2017).

Table 23: Estimates from the 2006 the Energy Commission Report, NLine Energy's Survey and ACWA Questionnaire

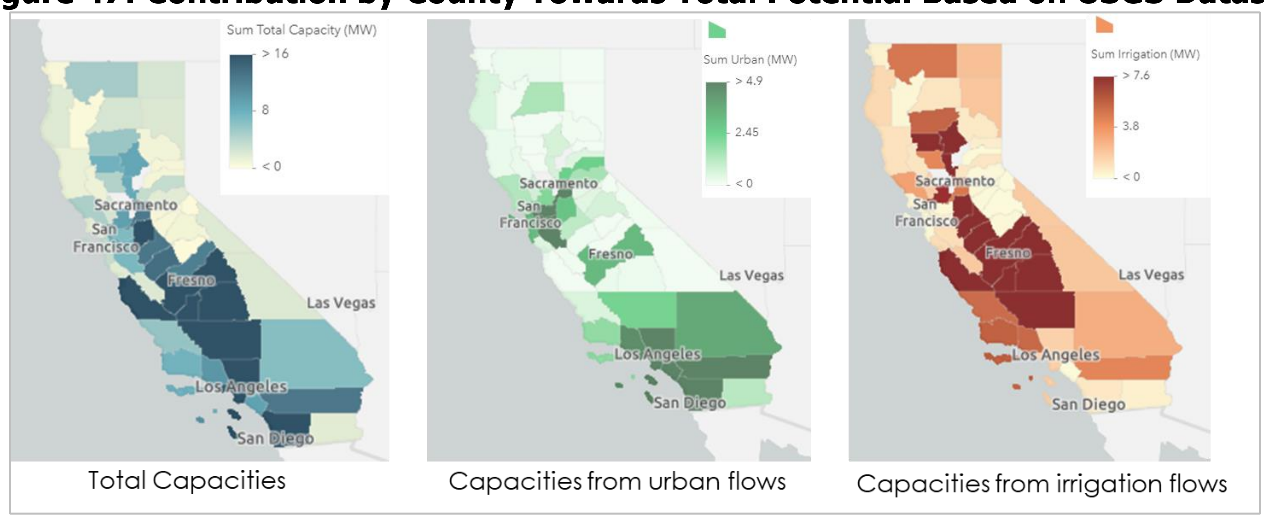
	2006 CEC Report	N-Line	ACWA Questionnaire
Number of Agencies	250	143	44
Timeline	2004 - 2006	2011 - 2016	2017 - 2018
Number of water purveyors surveyed	164	122	44
Estimated Potential (MW)	255	60	17

Source: Stanford University, 2019

In-Conduit Hydropower Potential Estimates from USGS Data

The USGS database of available surface water withdrawals from 56 counties in California was used to determine the available flow rates in each of the counties. A Monte-Carlo analysis was performed on the normalized values of flows for each of the counties to determine the associated capacity. The values of flows corresponding to surface water withdrawals for domestic use and irrigation use were analyzed separately. It was observed that counties around the urban centers of Los Angeles and the San Francisco Bay Area have higher capacities from domestic supplies of water. The seven counties around San Joaquin valley that produce 12.5 percent of America's agricultural produce contribute the most towards capacities generated from irrigation flows (Agricultural Review, 2007). The in-conduit hydropower contribution from each county to the total potential is displayed in Figure 47.

Figure 47: Contribution by County Towards Total Potential Based on USGS Dataset



Note: Total capacity is the sum of capacities from irrigation flows and urban flows.

Source: Stanford University, 2019

The results of the total in-conduit hydropower potential based on the USGS dataset, including those from irrigation and urban flows, are summarized in Table 24. It was estimated that the in-conduit hydropower potential in California using USGS data to be 368 MW. Most of the capacity also came from urban flows (63 percent) rather than irrigation flows (37 percent).

This analysis assumes that there is only one point at which the water consumed within a county is harnessed through in-conduit hydropower. There may exist multiple opportunities in the downstream supply of water where energy can be generated from the same supply of water. Note that as this data was taken from county level, the estimated capacity from this data serves as the lower limit on the potential for in-conduit hydropower generation.

Table 24: In-Conduit Hydropower Potential Based on the USGS Dataset

Potential	Megawatts
Total Capacity	368
Capacity from Irrigation flows	137
Capacity from Urban flows	231

Source: Stanford University, 2019

Assessment from the list of water agencies

Using the Monte-Carlo analysis and the flow data from various water agencies (DWR and SWRCB), the capacities of potential in-conduit hydropower in California were also estimated. The total capacity for each of the data sources are shown in Table 25. The net capacity assessed across the 450 water agencies, where no in-conduit hydropower facilities are yet installed, was 414 MW. The locations of these potential capacities were also mapped in Figure 48.

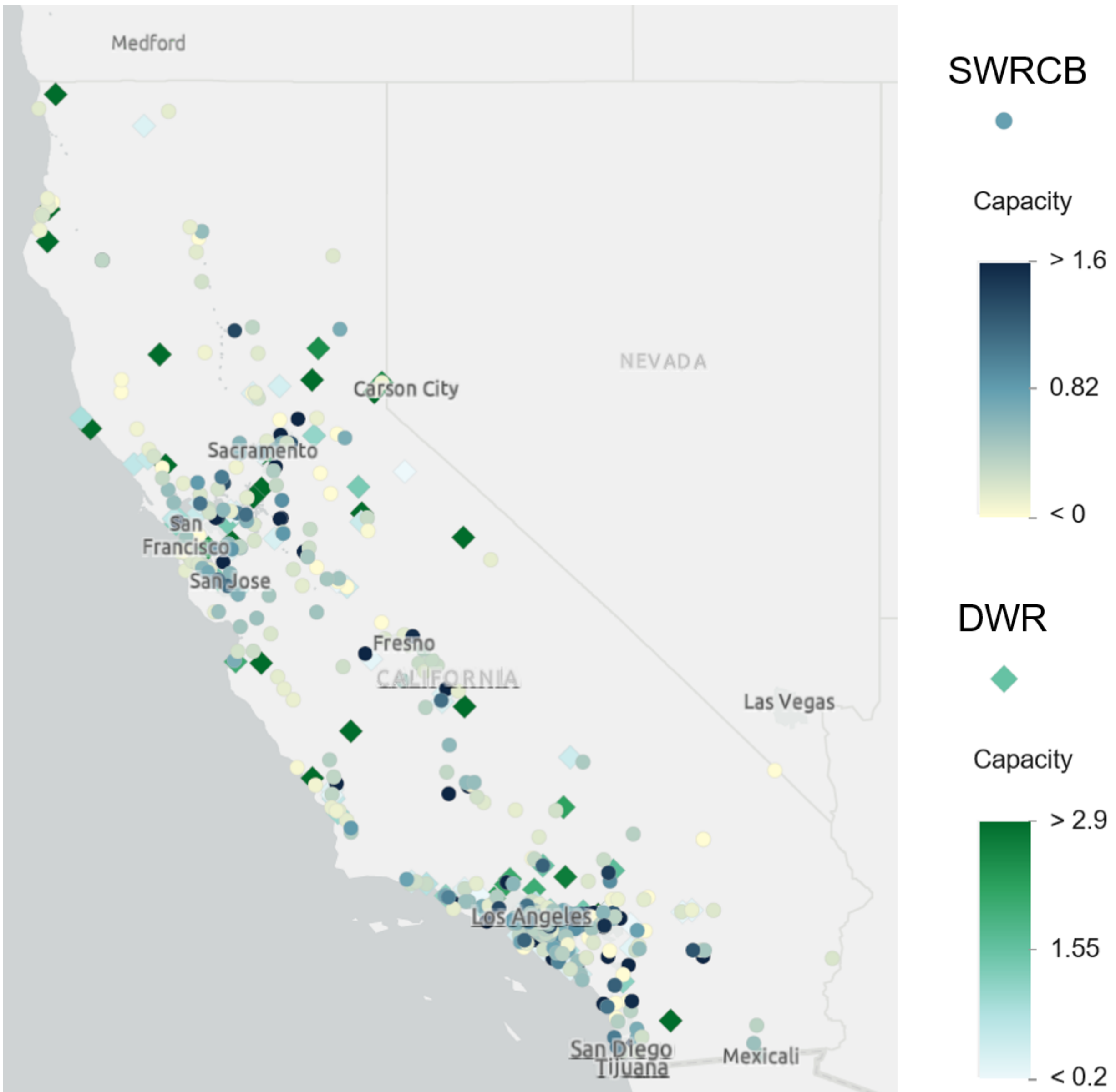
Table 25: Assessment of Potential Across Other Water Agencies in California

Assessment	Capacity (MW)
List of water agencies in California (DWR)	140
List of water agencies in California (SWRCB)	274

Source: Stanford University, 2019

Although there is already a number of installed systems close to the coastal area of Southern California (Figure 45), there is still a significant uninstalled potential in the same area, as shown in Figure 48. Moreover, there is also some potential for hydropower in the irrigation district (northern part) that has not been tapped yet. Similarly, in Northern California, there is still potential for in-conduit hydropower in the irrigation district area, despite the existence of several installed systems. In Northern California, the significant uninstalled potential is in the San Francisco and San Jose areas.

Figure 48: Estimated Uninstalled In-Conduit Hydropower Capacities Using Data from DWR (green diamonds) and SWRCB (blue circles)



Source: Stanford University, 2019

Summary of Findings

In 2006, a project funded by the CEC estimated that 255 MW of in-conduit hydropower had the potential to be developed in California. This estimate was based on the assessment of data from 164 water purveyors through survey and data extrapolation. While the assessment was conducted more than a decade ago, it was one of the first assessments for in-conduit hydropower potential in California and, thus, provided a baseline for further investigation. In this study, the CEC estimates of the in-conduit hydropower potential in California was revisited by analyzing the on-site survey data collected by NLine Energy and the results from a questionnaire distributed to various water agencies during an ACWA meeting held in

December 2018. The on-site survey conducted by NLine Energy estimated about 60 MW of potential, while the potential estimated from the questionnaire responses was around 17 MW both representing a subset of potential sites to develop in-conduit hydropower throughout the state. These assessments, while clearly not comprehensive for potential estimation, were used in this study to estimate the heads and capacities for agencies in which these values were lacking.

In this study, data from multiple sources, namely USGS, DWR, and SWRCB was collected. These data sources provided flow data from county level withdrawals (USGS) as well as from downstream water wholesalers and retailers (DWR and SWRCB), but not head or capacity factor data. Thus, using head and capacity factors estimated from installed systems and on-site survey (data taken from the CEC and NLine Energy) combined the flow values obtained from USGS, DWR and SWRCB, it was possible to estimate the in-conduit hydropower potential. A Monte-Carlo analysis was also conducted to provide the most probable value of capacity that can be developed at each site considering the distribution of possible head and capacity factors constructed based on estimated values of these variables across existing systems. Table 26 summarizes the in-conduit hydropower potential estimated in this project using multiple data sources (USGS, DWR, and SWRCB).

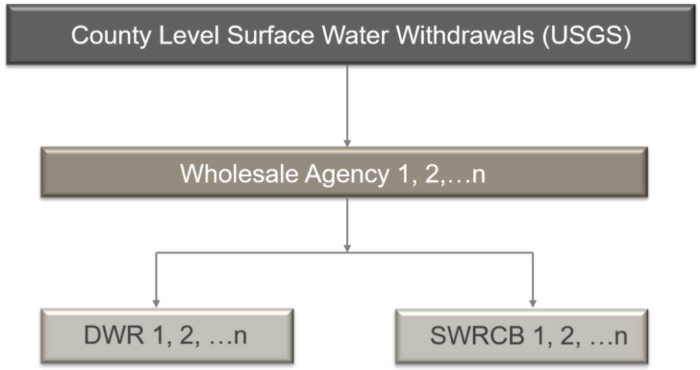
Table 26: Summary of Assessments

Assessment	Estimated Potential (MW)
Minimum potential uninstalled capacity (USGS)	368
Maximum potential uninstalled capacity (SWRCB and DWR)	**414**
Currently installed capacity	343

Source: Stanford University, 2019

An analysis of USGS data estimated the in-conduit hydropower potential in California to be 368 MW. This estimate represented the minimum in-conduit hydropower potential that can be harnessed across California. While there are at least 343 MW of installed in-conduit hydropower facilities in California as of 2017, there is potential for further installation up to 414 MW across 450 different locations in California. If the water withdrawn from the natural resources (estimated by USGS data) is harnessed at multiple locations downstream, such as any of the water agencies in California, there are more potential sites for in-conduit hydropower generation. Correspondingly, as shown in Figure 49, there are more avenues to generate in-conduit hydropower in downstream processes. This explains why the estimate from the USGS data is lower than the SWRCB – DWR estimate.

Figure 49: Relation Between USGS Data and the List of Water Agencies in California



Source: Stanford University, 2019

The locations and their corresponding capacities along with a county-level assessment can also be viewed through this ArcGIS website application:

https://stanford.maps.arcgis.com/apps/View/index.html?appid=c238f407cdf04df2887b77a5ec6416d8

The link provides maps of the following:

- Installed in-conduit hydropower capacities
- County-level uninstalled capacities
- Downstream uninstalled capacities

CHAPTER 7: Knowledge Transfer Activities

The objective of this chapter is to provide a summary of plans to make the knowledge gained, assessment results, and lessons learned from the project available to the public and key decision makers. The activities can be categorized in the following categories, each discussed in the next sections:

- Peer-reviewed journal publication;
- Presentations in national and California-centric conferences and webinars
- Workshops with experts
- Webinars to water purveyors
- Business case assessment tools

It is important to note that some of the activities have already been executed during the project; however, there are some planned activities that will be conducted at the conclusion of the project.

Peer-Reviewed Journal Publications

- Publication of a review paper in a peer-reviewed journal, namely the Journal of Environmental Management, titled *Recent Innovations and Trends in In-Conduit Hydropower Technologies and Their Applications in Water Distribution Systems* in August 2018. The paper provides a comprehensive review on the conventional and emerging turbine technologies suitable for in-conduit hydropower implementation, as well as potential sites for installations in diversion structures, potable and irrigation water distribution systems, and wastewater outfalls. Selected case studies on the application of conventional and emerging turbines for pipelines are also reviewed and discussed in this manuscript.
- Based on the results from a state-wide resource assessment, a manuscript is currently being prepared to be submitted for publication in a peer-reviewed journal. The manuscript will focus the discussion on different data sources, methodologies for data processing and analysis, and the estimation of potential hydropower resource in California, based on Monte-Carlo analysis.

Presentations at National and Local Conferences

Some of the conclusions from this study were presented at the National Hydropower Association (NHA) WaterPower Week in Washington, DC between April 30 and May 2, 2018 and at the American Water Works Association (AWWA')s Annual Conference and Exposition (ACE) in Denver, Colorado between June 10 and June 12, 2019. The project targets presentation of the findings of this project in other relevant local and national conferences.

Webinar for Water Purveyors

In collaboration with the WRF, a webinar will be conducted at the end of the project to present the results of the study to a large audience inclusive of the WRF subscribers, CEC contacts, and various water professionals (consultants, water and wastewater plant managers and operators, utility board members), government agencies, electricity providers, water and hydropower organizations, and academics.

Project Workshop

During the project, a stakeholder workshop was convened with in-conduit hydropower experts and technology providers to identify key issues related to in-conduit hydropower potential and project implementation as well as to develop recommended best practices corresponding to the issues. Details on the workshop attendance and structure were provided in Chapter 2.

Deployment of a Business Case Assessment Tool

As part of the project, an Excel®-based workbook was developed as a tool to assist water and wastewater utilities and other water purveyors in the assessment of the technical and economic feasibility of installing an in-conduit hydropower system in selected sites of their service area. The tool was developed based on the findings of this project, thus transforming the information into a practical application. A guidance manual for the use of the tool is presented in Chapter 5.

CHAPTER 8: Conclusions and Recommendations

Conclusions

This report provides a comprehensive assessment of the in-conduit hydropower generation potential in California, a guidebook, and a business case assessment tool for municipal (water and wastewater), agricultural and industrial agencies considering capturing hydrokinetic or hydrostatic energy, avoiding energy waste in water-supply networks, and integrating renewable energy sources into their existing energy mixes. Key conclusions from this study are presented in the following sections.

1. **Incorporation of in-conduit hydropower in the state's energy mix may help California reach its RPS goals and achieve 100 percent clean energy and carbon neutrality by 2045.** The application of in-conduit hydropower in water distribution systems provides an opportunity to generate renewable energy that is not intermittent and with minimal environmental impacts. As California heads toward carbon neutrality and 100 percent clean electricity in fewer than 20 years, as mandated in SB 100 and EO B-55-18, development of in-conduit hydropower systems will help reach those goals.
2. **Technological Renaissance of in-conduit hydropower turbines has largely encouraged new installations**. Conventional turbines such as Francis, Pelton, and Pump-as Turbines, have proved to be robust for in-conduit hydropower application as they can operate for decades. Information about their applications is readily available in the public domain. However, the recent technological Renaissance in turbine technologies, offering improvement in performance, modularity, portability, and scalability, has created new opportunities to revisit sites that were previously deemed unfeasible for energy harvesting in an expedient and cost-effective manner.
3. **A number of sites with different configurations offer potential for harnessing energy through in-conduit hydropower.** There are multiple potential sites available for in-conduit hydropower development in various engineering-made water conveyance and distribution infrastructure that can potentially become energy harvesting spots. The energy harvested from these spots can be used to counterbalance energy lost in water conduits, making existing systems more energy-efficient while directly benefitting the surrounding community by providing additional sources of revenue. The excess energy at these conduits is usually small though vast water delivery networks offer an enormous untapped energy potential that can amount to hundreds of megawatts.
4. **Simplification of the regulatory and permitting process provides more favorable grounds for in-conduit hydropower projects.** Federal permitting requirements for development of in-conduit hydropower projects have been substantially simplified, making it more attractive for local water purveyors to implement energy recovery devices in their existing systems. Currently, projects of fewer than five MW installed in engineering-made structures can be eligible to construct

a Qualifying Conduit Hydropower Facility by submitting an NOI only to FERC without submitting an application for either licensing or exemptions. Additionally, most in-conduit hydropower facilities are exempted from CEQA permits because they use existing engineering-made structures that are inherently less damaging to the environment when compared with traditional hydropower facilities such as dams.

5. **Project financial viability should comprehensively assess project costs, revenue opportunities and availability of grants and incentives.** In-conduit hydropower projects are typically financially feasible when total project costs are in the range of $5,000-$15,000/kW, with a payback period of fewer than 15 years. Civil works and electromechanical equipment are two major components of the total initial investment, together with the turbine cost. There are currently limited grant opportunities for small hydropower compared with other renewable energy projects. In California, the majority of small in-conduit hydropower projects received funding from SGIP, which is administered by the CPUC. The financial viability assessment should also consider the impact of changing tariff rate structures and electric utility programs (e.g., NEM, NEMA, RES-BCT, and E-ReMAT).
6. **The interconnection process with the grid should be jointly planned with the local electric utility.** In-conduit hydropower projects connecting to the utility grid must adhere to the interconnection standards and requirements of the local electric grid. The interconnection process should be preceded by studies to evaluate any potential impact to the grid and the electrical circuits of the utility hosting the project. The interconnection process and the communication with the electric utility should start at the planning phase of the project and continue as the project progresses through different lifecycle stages. The physical interconnection and their related costs may vary depending on the utility, the characteristics of the local grid, and the electric system arrangement at the utility. Since hydroelectric turbines, for example, are rotating equipment (non-inverter) technologies that provide reactive power to the grid, additional protective equipment is required as part of California's Rule 21 interconnection standards.
7. **Design and operating strategies of in-conduit hydropower projects should minimize interference with current operations.** Since in-conduit hydropower systems are installed in existing engineering-made structures for water conveyance and delivery, it is important to ensure that the retrofitted systems align with existing facilities. For example, design strategies based on a by-pass loop often provide redundancy to allow maximum flow over turbines to achieve minimum requirements or a safety measure in case turbine maintenance is needed. Once the turbine is in operation, regular maintenance and monitoring of the turbine's performance is important through SCADA, third-party dashboards, and specific key performance indicators.
8. **While a number of water utilities in California have already implemented in-conduit hydropower systems, there is still large untapped potential in in-conduit hydropower.** In this project, eight hydroelectric facilities in California built in the last six years served as examples to better understand key elements needed to develop and operate in-conduit hydropower systems. While there are approximately

148 installed small hydropower systems (including in-conduit hydropower systems), there is still tremendous untapped hydropower potential in California. While it is important to understand the generating capacity of a particular site, the end use of the extracted power must also be identified. There should be an existing demand and market for the extracted energy either within or in the vicinity of the site.

9. **The resource assessment performed for this study revealed that in addition to the existing installed capacity, at least 368 MW of energy can potentially be harnessed in California through in-conduit hydropower projects.** In this study, data from multiple sources including USGS, DWR, and SWRCB was collected and analyzed to estimate the potential for in-conduit hydropower installations in California. An analysis of USGS data estimated the in-conduit hydropower potential in California to be 368 MW. This estimate represented the minimum in-conduit hydropower potential that can be harnessed across California. While there are at least 343 MW of installed in-conduit hydropower facilities in California as of 2017, there is potential for further installations up to 414 MW across 450 different locations. From DWR and SWRCB assessments, the uninstalled capacities are still concentrated in Southern California, along the coast near the cities of Los Angeles and San Diego. In contrast, there are significant capacities in the Bay Area in Northern California that have not yet been tapped. This assessment thus warrants further investigation of the actual capacities available in the San Francisco and San Jose areas.

Recommendations

As a result of performing this research, the following future research needs were identified:

1. **Implementation of modular turbine technology can help reduce powerhouse construction costs.** Civil work costs pertaining to powerhouse construction can be substantial. Thus, a modular turbine that is all-inclusive, with standardized components, can be beneficial in reducing civil work costs. Modular systems are also more portable and easily scalable compared with their counterparts.
2. **Better promotion of in-conduit hydropower at state and federal levels, emphasizing its environmental and financial benefits, can help secure advantageous tariffs.** Implementation of small hydropower is still limited compared with other renewable energy sources like solar and wind. It is imperative to learn from other renewables like wind and solar since they are more mature in terms of their respective project development. It is also important that all benefits associated with in-conduit hydropower projects be highlighted and shared with national and state water communities to demonstrate the environmental and economic benefits associated with these renewable sources. Better promotion of in-conduit hydropower may also increase governmental support for projects, both financially and administratively.
3. **Implementation of new pricing tariffs dedicated specifically for in-conduit hydropower.** Currently in-conduit hydropower must compete with other renewable energy sources including solar and wind to secure attractive tariff rates. The availability of these tariffs specifically for in-conduit hydropower may attract prospective project developers.

4. **Development or reintroduction of tariff structures based on appropriate rates that generate sustainable and predictable cash flows for in-conduit hydropower projects.** The often-changing tariff structures for in-conduit hydropower projects can greatly impact project economics and payback periods. E- ReMAT, for example, was previously advantageous for utilities seeking to install in-conduit hydropower and, in some cases, was a preferred option to RES-BCT. While the program has been suspended since 2017, it is important for this program to be reintroduced in the future. In addition, given that nearly all of the conduit hydropower potential exists within tax-exempt municipal agencies in the state, these projects should be promoted by programs that are not solely reliant on federal tax subsidies or changing grants and subsidies.
5. **New funding opportunities should be evaluated and an improved understanding on the regulatory landscape for in-conduit hydropower projects should be established.** New dedicated funding should be made available for in-conduit hydropower projects and released from both the state and the federal government. Utilities should also consider other sources of incentives provided by the CPUC's Electric Program Investment Charge (EPIC) program, the Department of Agriculture (for canal piping projects), USBR and the Department of Energy (DOE) for innovative technology development. Utilities should also develop internal capabilities to apply for external funding and understand regulations and permitting requirements as well as the changing landscape of rate structures. In addition, policies that prioritize the development of new projects should be made by water utility boards.
6. **Understanding the sensitivity of project economics on critical parameters is essential.** Lack of understanding of in-conduit hydropower's economy of scale and the sensitivity of important parameters (e.g., project size, tariff rate structures, on-site power generator type and capacity, and capital investments) for cost-effective projects is limiting faster development. For example, understanding the impact of changing tariff structures and rates on project economics and payback periods should be evaluated. Utilities need to identify other tariff agreements once their current contracts end (for example, in 20-30 years).
7. **Mandates that simplify interconnection processes for conduit hydropower projects are needed**. Large interconnection costs can be overwhelming for smaller projects, therefore identification and understanding of the impact of interconnection costs early in the process is imperative. More engagement from the CPUC is desired to influence a more active role of electric utilities in the process and in communication with water purveyors.
8. **Holistic approaches to integrated water-energy management involving participation from different stakeholders are needed.** Communication should be improved between all stakeholders involved in in-conduit hydropower projects (water and wastewater utilities, land owners, irrigation districts, and electric utilities). Involvement of utility staff and education on their role at all stages of the project will increase acceptance of the system by operations and management and will improve knowledge on how to respond to emergency situations during operations. It is also important that utility staff understand all critical issues pertaining to the in-conduit

hydropower project to assist the developer at every step. Qualified consultants with extensive experience in in-conduit hydropower installations can help fill knowledge gaps.

9. **Understanding the potential for harnessing hydrokinetic energy and the corresponding technology should be improved**. A more accurate estimation of the hydrokinetic energy potential in California is needed. Information about the hydrokinetic energy potential in California is still limited. In addition, information about maintenance as well as lifecycle and the durability of hydrokinetic turbines is still insufficient. Technology developers are encouraged to better coordinate with infrastructure owners (e.g., USBR, DWR) to conduct long-duration testing to obtain sufficient data and identify key elements for successful operations. In California, there might be opportunities to collaborate with DWR for development of hydrokinetic energy projects.

CHAPTER 9: Benefits to Ratepayers

Project results are expected to lead to technological advancement and breakthroughs that will overcome barriers to achievement of California's statutory energy goals by providing:

- A comprehensive update of California's in-conduit hydropower potential assessment.
- A knowledge base and guidebook on performance information, associated equipment, siting criteria, design and performance monitoring, costs, regulatory framework, and other relevant information that will assist California's stakeholders in development of in-conduit hydropower projects.
- A business case assessment tool that assists utilities in selecting the technology for various applications and determines the life-cycle costs and other environmental benefits.

The outcomes of this project are expected to enable utilities, businesses, and communities to simplify and speed project consideration, provide knowledge on traditional and emerging technologies, and assist in permitting and licensing projects. As a result, the project is also expected to benefit ratepayers with greater electricity reliability, lower costs, and increased safety by removing uncertainty from investment decisions and facilitating deployment of cost-effective new-generation in-conduit hydropower technologies.

The specific benefits from this project include:

- Supporting achievement of RPS goals. Many U.S. states are currently increasing their RPS goal to reach 100 percent renewable energy. In-conduit hydropower can play a role in achieving this goal by providing a continuous stream of renewable energy that is reliable and environmentally friendly. However, each state currently issues different regulations regarding the inclusion of hydropower in their respective RPS, which in turn affects price competition between different types of renewable energy generation such as solar and wind. This project can therefore help states promote in-conduit hydropower and its inclusion in RPS programs.
- Lower costs. The tools for evaluating the economic and environmental impacts of in-conduit hydropower generation will help ensure that deployments are cost-effective and will reduce costs for California ratepayers by mitigating the risk of failed projects. In-conduit hydropower could also enable deferral of transmission and distribution expenditures by placing supply resources near the demand, which is not usually the case for traditional resources or even for larger central renewable projects. Because water can be easily stored, and abundant reservoirs are already available, in-conduit hydropower has the potential to displace costly and often environmentally troubling fossil fuel-fired peaking resources.
- Greater reliability and energy security. As with most distributed-generation technologies, in-conduit hydropower could provide resource diversity benefits to system reliability. Deployment of justified in-conduit hydropower could provide a source of

capacity and renewable energy that is not intermittent. The probability and consequences of supply resource failure declines with diversification of those resources.

- Increase safety. By placing in-conduit power generation entirely within already-disturbed environments, natural resources could be conserved and incremental impacts, including safety, minimized.
- Economic development. Further implementation of in-conduit hydropower projects in the state will create California 'green' jobs and tax revenue in the communities where these renewable energy projects are implemented.
- Environmental benefits. By displacing fossil fuels for many years to come (even after the achievement of the 2030 60 percent RPS, which itself would be accelerated by small hydropower deployment), in-conduit hydropower could reduce emissions in California and thereby improve the health and safety of California ratepayers.
- Consumer appeal. Planned workshops and the education and outreach program will engage all stakeholders related to the underdeveloped in-conduit market.

GLOSSARY AND LIST OF ACRONYMS

Term/Acronym	Definition
ΔH	Net extracted head
ε	Overall efficiency of hydropower system, accounting for turbine, drive system, and generator efficiencies (i.e. water-to-wire efficiency)
η	Efficiency of hydrokinetic turbine system
ρ	Density of water
A	Cross-sectional area occupied by turbine (used in hydrokinetic power calculation)
AC	Alternating Current
ACWA	Association of California Water Agencies
Annual power generation	Power generated by a hydropower system in one year, usually expressed in kWh
AWA	Amador Water Agency
CAISO	California Independent System Operator
CAMX	California-Mexico Power Area
Canal	A natural or artificial waterway for water conveyance
Canal drop	A structure constructed across a canal to pass water to a lower elevation while controlling the energy and velocity of the water as it passes over
Capacity	Power generated by hydropower system, usually expressed in kW, calculated as follows: Capacity (kW) = Head (m) × Flow (m^3/s) × Density $(\frac{\mathrm{kg}}{\mathrm{m}^3}) \times \frac{g\,(\frac{\mathrm{m}}{\mathrm{s}^2})}{10^3}$ × Capacity Factor × Load Factor
CCA	Community Choice Aggregation; Programs that allow local governments and special districts to pool electrical load within a defined jurisdiction to secure alternative energy supply contracts
The Energy Commission	California Energy Commission
CEQA	California Environmental Quality Act
CF	Capacity Factor; a ratio of hydropower plant's annual power production to the power it could have produced if it runs at 100

Term/Acronym	Definition
	percent. Capacity factor accounts for the number of times the plant not operating due to daily flow variations, environmental releases, or plant outages. Capacity factor can be calculated as follows: Capacity factor = $\frac{\boldsymbol{actual\ production\ (MWh)}}{\boldsymbol{nameplate\ capacity} \times \mathbf{86400}\,\frac{\boldsymbol{sec}}{\boldsymbol{day}} \times \mathbf{365.25}\ \boldsymbol{days}}$
cfs	Cubic feet per second
Chute	A sloping channel or slide to convey water to a lower level
CPUC	California Public Utility Commission
DAGPC	GA Green Power Consulting
Dam	A barrier constructed to hold back water and raise its level, forming a reservoir used to generate electricity or as a water supply
DC	Direct Current
DEQ	Oregon Department of Environmental Quality
Ditch	A narrow channel dug in the ground, typically used for water drainage
Diversion structure	A diversion structure (i.e., weir, barrage) is a facility that channels a portion of natural river through a canal or penstock
DOD	United States Department of Defense
DOE	United States Department of Energy
Downstream pressure	Pressure required downstream of the hydropower system
DWR	California Department of Water Resources
EA	Environmental Assessment
EF	Emission Factor for the grid (used in GHG emission calculation)
Efficiency	Ratio of the useful work output and the energy input in a system
EIA	Environmental Impact Statement
EPIC	Electric Program Investment Charge
EPRI	Electric Power Research Institute
EVWD	East Valley Water District
FERC	Federal Energy Regulatory Commission

Term/Acronym	Definition
FPA	Federal Power Act
Friction loss	The loss of pressure head that occurs in a conduit due to the effect of the fluid's viscosity near the surface of the conduit.
ft	feet
ft/s	feet per second
FV	Future Value; the value of an asset at a specific date, calculated as follows: $$FV = \sum_{1}^{x} C_n * (1 + p)^n$$ Where C_n is the cos at year n; n is the total number of years considered; p is the expected average rate of cost escalation; i is the discount rate; and x is the number of cost elements
g	Acceleration due to gravity
Generator	In electricity generation, a generator is a device that converts mechanical power into electrical power for use in an external circuit
GHG	Greenhouse Gas
GPS	Global Positioning System; a satellite-based radio navigation system
Grid interconnection	Interconnected network for delivering electricity from producers to consumers
Gross head	Overall head
Groundwater recharge	Replenishment of an aquifer with water from land surface, commonly expressed as an average rate of inches of water per year
GW	gigawatt
GWh	gigawatt-hour
Head	The change in water levels between the hydropower system intake and discharge point
HREA	Hydropower Regulatory Efficiency Act, signed in 2013 by then President Obama
Hydraulic head	The sum of the velocity head, elevation head, pressure head, as well as resistance head due to friction loss

Term/Acronym	Definition
Hydrokinetic energy	Electricity generated from capturing kinetic energy of flowing water
Hydropower	Electricity generated from capturing potential energy of flowing water
Impulse turbine	A type of water turbine uses runners that are rotated by water jets at high velocities
In-Conduit Hydropower	Hydroelectric generation potential in man-made conduits such as tunnels, canals, pipelines, aqueducts, flumes, ditches, or similar man-made water conveyance that is operated for the distribution of water for agricultural, municipal, and industrial consumption
Induction generator	A type of alternating current electrical generator that uses the principles of induction motors to produce power.
Inverter	An electronic device that changes direct current (DC) to alternating current (AC)
IOU	Investor-Owned Utility
JEMA	Journal of Environmental Management
Kaplan turbine	A reaction style turbine designed for low head, high flow application, that utilizes water flowing through the inlet guide vanes that acts upon the propeller-like blades to create shaft power
kW	kilowatt
kWh	kilowatt-hour
lb	pound
LCC	Life Cycle Cost; sum of all recurring and non-recurring costs over the full life span or a specified period of a system
LCOE	Levelized Cost of Energy; the present value of all the resource costs (initial cost, O&M, etc.) divided by the present value of energy across a full project lifetime, usually presented in $/kWh. LCOE can be calculated as follows: $$LCOE = \frac{LCC}{Q} \cdot (UCRF)$$ Where: LCC is the present value of the LCC; Q is the annual energy generation (kWh); UCRF = uniform capital recovery factor, which is expressed by the following equation:

Term/Acronym	Definition
	$$UCRF = \frac{d \cdot (1+d)^N}{(1+d)^N - 1}$$ Where: N is the analysis period; and d is the discount rate
Load factor	A factor that accounts for future reduction in flow values due to drought and/or water conservation effort in the capacity assessment
LP	Linear Pelton hydroEngine®
m	meters
Micro-hydropower	Hydroelectric system with capacity less than 500 kW
Mini-hydropower	Hydroelectric system with capacity less than 2 MW
Monte-Carlo simulation	A technique used to understand the impact of risk and uncertainty in various forecasting models
MW	megawatt
MWA	Mojave Water Agency
MWh	megawatt-hour
Nameplate capacity	Intended full-load sustained power output of a hydropower facility
NEM	Net Energy Metering; a billing arrangement that allows customers to receive a financial credit on their electricity bills for any surplus energy sold back to the grid
NEMA	Net Energy Metering Aggregation; NEMA is a subprogram of NEM, which allows an eligible utility (or customer-generator) to aggregate the electrical load from multiple meters and share NEM credits among all properties that are attached, adjacent, or contiguous to the generating facility
Net head	Gross head (overall head) minus the sum of all friction losses
NOI	Notice of Intent
NSD	New Stream Reach Development
O&M	Operation & Maintenance
P	Mechanical power produced at the turbine shaft (used in capacity calculation)
PAT	Pump-as-turbine

Term/Acronym	Definition
Penstock	A channel for conveying water to a turbine
PG&E	Pacific Gas & Electric
Pico-hydropower	Hydroelectric system with capacity less than 10 kW
PLC	Programmable Logic Controller
Powerhouse	Hydropower system
PPA	Power Purchase Agreement; a legal contract between two parties, one which generates electricity and one which is looking to purchase electricity
PRV	Pressure Reducing Valve; a pressure relief valve to control or limit the pressure in a system
PSH	Pump Storage Hydropower; a type of hydroelectric energy storage. It is a configuration of two water reservoirs at different elevations that can generate power (discharge) as water moves down through a turbine; this draws power as it pumps water (recharge) to the upper reservoir
psi	pounds per square inch
PV	Present Value; the value of an expected income stream determined as the date of evaluation; calculated as follows: $$PV = \sum_{1}^{x} \frac{FV_n}{(1+i)^n}$$ Where FV is the future value; n is the total number of years considered; i is the discount rate; and x is the number of cost elements
Q	Volumetric flow rate
Reaction turbine	A type of water turbine that uses both pressure and movement of the water to generate an upward hydrodynamic force to rotate the runner blades
REAP	Rural Energy for America Program
REC	Renewable Energy Certificate; also known as Green Tag, Renewable Energy Credits, Renewable Electricity Certificate, Tradable Renewable Certificate, is a tradable, non-tangible energy commodity in the U.S. that represents the environmental attributes of the 1 MWh power produced from renewable energy and are sold separately from the commodity electricity

Term/Acronym	Definition
REDA	Renewable Energy Development Assistance
ReMAT	Renewable Market Adjusting Tariff; a feed-in tariff program administered by CPUC, eligible for projects less than 3 MW for a fixed-price standard contract (from $89.23/MWh)
RES-BCT	Renewable Energy Self-Generation Bill Credit Transfer; a subprogram of NEM that allows local governments and universities to share generation credits from an energy generating facility located on one government-owned property with billing accounts at other government-owned properties
RPS	Renewable Portfolio Standard; a market-based policy that requires electricity retailers in the state to supply a minimum percentage of their electricity sales from eligible renewable energy sources
RTU	Remote Terminal Unit
Run-of-the river scheme	A type of hydroelectric generation plant whereby little to no water storage is provided
SA	Sweetwater Authority
SBVMWD	San Bernardino Valley Municipal Water District
SCADA	Supervisory Control and Data Acquisition
SCE	Southern California Edison
SDG&E	San Diego Gas & Electric
SGIP	Self-Generation Incentive Program; a form of state-level incentive to support for behind-the-meter distributed energy technologies, with funding from the state's electricity providers. The qualifying technologies include wind turbines, waste heat to power technologies, internal combustion engines, gas turbines, fuel cells, energy storage systems, pressure reduction turbines, and microturbines.
SGVWC	San Gabriel Valley Water Company
SLH	Schneider Linear hydroEngine®
Small hydropower	Hydroelectric generation with capacity less than 30 MW
SRA	Statewide Resource Assessment
Surface water withdrawals	Fresh water taken from surface water sources

Term/Acronym	Definition
SWRCB	State Water Resources Control Board Data
Synchronous generator	A type of alternating current electric generator where the excitation field is provided by a permanent magnet instead of a coil.
Tailrace	A water channel below natural or man-made restrictions to the flow of water on rivers, canals, streams, or any other flowing current
TRL	Technological Readiness Level; a measurement system used to assess the maturity level of a particular technology
Turbine	A rotary machine that converts potential and kinetic energy of water into mechanical work
USACE	United States Army Corps of Engineers
USBR	United States Bureau of Reclamation
USGS	United States Geological Survey
V(z)	Current water velocity which is a function of depth (z) and channel geometry flowing though the turbine system (used in hydrokinetic power calculation)
VAHT	Vertical Axis Hydrokinetic Turbine
W	Watt
Water-to-Wire	In hydropower system design, the water-to-wire package includes design and manufacturing of the complete powerhouse, including turbine, generator, control system, mechanical and electrical protection, and electricity grid interconnection
WRF	The Water Research Foundation
WTP	Water Treatment Plant
WVWD	West Valley Water District
WWTP	Wastewater Treatment Plants

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APPENDIX A: Case Study Summaries

In this project, eight in-conduit hydropower projects conducted in California were selected as case studies. Background information about the case study hydroelectric projects are summarized in Table A-1. Each case study summary provides the following information:

- Case study participants
- Background table
- Project drivers
- Feasibility assessment
- Permitting and regulation
- Design and construction
- Operations and maintenance
- Costs and financing
- Future planning
- Lessons learned and recommendations

The case study summaries for eight utilities are presented in the next section.

Table A-1: Eight Utilities Selected as Case Studies

Case Study Utility/Site	Location of powerhouse	Turbine unit(s)	Capacity (kW)	Annual power generation (kWh)	Operation start-up year
AWA	Upstream of Tanner Water Treatment Plant	Two Pump-As-Turbine units	110	580,475	2016
EVWD	Upstream of Plant 134 Water Treatment Plant	Two Pump-As-Turbine units	177	1,034,000	2017
MWA	Deep Creek Water Recharge Site	2-Nozzle Horizontal Pelton	840	6,100,000*	2019
SBVMWD	Waterman turnout to groundwater recharge basin	Pelton	1059	3,947,000*	2019 (Q1 est.)
SGVWC - B24 Project	Upstream of B24 water storage facility	One Pump-As-Turbine units	72	433,000*	2019 (Q1 est.)
SGVWC) - Sandhill	Upstream of Sandhill Water Treatment Plant	Two Pump-As-Turbine units	310	1,000,000	2013
SA	Upstream of Perdue Water Treatment Plant	Two Pump-As-Turbine units	580	3,440,000	2016
WVWD	Upstream of Roemer Water Filtration Facility and groundwater recharge basin	Two Pump-As-Turbine units	460	2,947,000	2018

Source: Stantec

Amador Water Agency (AWA) Case Study Summary

Case Study Participants

- Gene Mancebo – General Manager, Amador Water Agency
- Damon Wyckoff – Operations Manager, Amador Water Agency
- Silvia Palma-Rojas – Contract Agreement Manager, California Energy Commission
- Mike Kane – Contract Agreement Manager, California Energy Commission

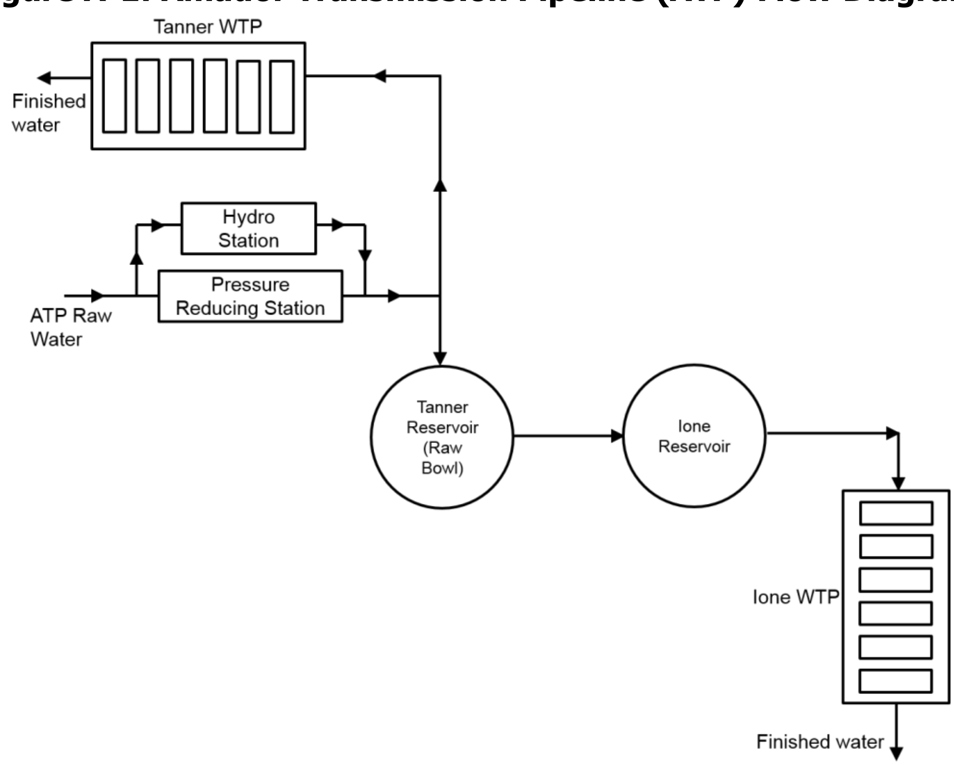
Background

- Site address: 12800 Ridge Rd, Sutter Creek, CA 95685
- Location of hydropower unit: Upstream of Tanner Water Treatment Plant
- Turbine type: Pump-as-Turbine
- Number of hydropower unit: Two units (Lead unit @ 3 cfs, lag unit @ 7 cfs)

- Turbine manufacturer: Cornell Pump Company
- Total capacity: 110 kW Aggregate Turbine nameplate rating
- Estimated annual power generation: 580,475 kWh
- Total project cost: $1,504,000 (2016)
- Electric provider: Pacific Gas and Electric (PG&E)
- Energy use: Export to the grid
- Billing arrangement: Net energy metering aggregation (NEMA)

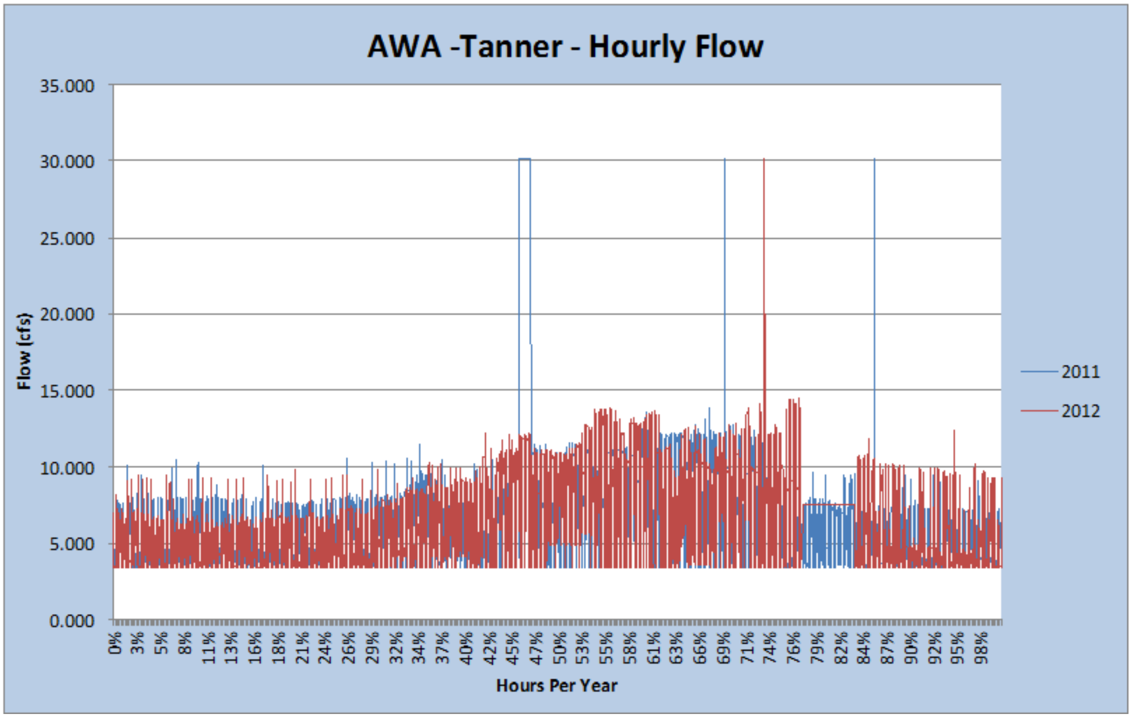
The Tanner hydroelectric station site is located at the Tanner Reservoir dam ("Raw Bowl") located adjacent to the Tanner Water Treatment Plant (WTP) near the Amador Water Agency main office. The water source is the Amador Transmission Pipeline (ATP) that begins at Lake Tabeaud and terminates at a pressure reducing station (PRS) on the crest of the dam (Figure A-1). The ATP supplies raw water to the Tanner Reservoir (Raw Bowl) and the Tanner WTP via the PRS, where the hydropower facility is located. The ATP was completed in 2008 to replace the historic ditch and flume system. The ATP size varies from 20-inch to 30-inch, but the diameter at its terminus at the PRS is 20 inches. The pipeline has a maximum capacity of approximately 33 cubic feet per second (cfs). Current flow rates vary during normal operation between 3.5 cfs and 14 cfs, as depicted in Figure A-2. Pressure test data indicates at static conditions the ATP holds 108 psi pressure at the PRS. According to a test report graph provided by AWA, the pressure drops to 65 psi at 18.5 cfs at the PRS. The differential head at this site is about 150 – 200 ft.

Figure A-1: Amador Transmission Pipeline (ATP) Flow Diagram



Source: Stantec

Figure A-2: Flow Profiles at the Tanner's Pressure Reducing Station in 2011 and 2012



Source: Stantec

The Tanner hydropower station consists of two pump-as-turbine (PAT) units with total capacity of 110 kW (one operates at 3 cfs, and the other at 7 cfs maximum). All the generated energy is exported to the grid and AWA receives credit based on the energy consumption in the facility at the same tariff as what they would have paid. However, AWA is able to combine several existing meters on a contiguous property to use to offset the generation of the hydro project, i.e. Net Energy Metering Aggregation (NEMA). The estimated annual generation capacity at this site is 580,475 kWh. However, currently Tanner hydro station is only generating about 70 percent of its full capacity due to the complex mode of operation required by the downstream Tanner WTP that impacts the pressure and flow to the turbine systems.

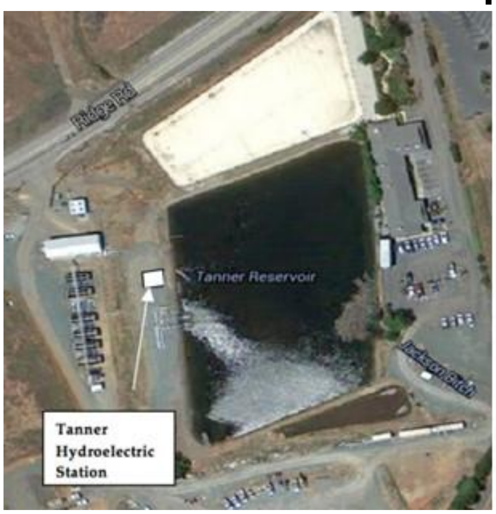
Project Drivers

AWA is one of the many utilities in California that has long expressed interest in incorporating renewable energy in their water distribution systems. Solar energy was initially considered, however, the significant number of pressure zones in the service area makes hydropower to be more economically attractive. The elevation in the service area can go from 300 ft up to 4000 ft, or even up to 7000 – 8000 ft at certain county areas. Due to this high elevation, there is also a system of pressure reducing stations (PRS) in the service area, which are recognized as energy harvesting spots by AWA. During the initial feasibility assessment in 2013, two locations were identified: pressure reducing stations at Tanner WTP and Ione WTP. The head difference in Tanner site is significantly lower than Ione site (200 ft compared to 3.3980 ft), however, the flow through the site is constant and quite substantial compared to Ione site (3.3 – 10 cfs compared to 1 – 4 cfs). Following thorough economic, environmental, technical and regulatory assessment, the Tanner site was considered to have a better return on investment (ROI) at that time and thus the board decided to conduct the first project at Tanner site. This site was also eligible for Self-Generation Incentive Program (SGIP) sponsored by California Public Utility Commission (CPUC).

Feasibility Assessment

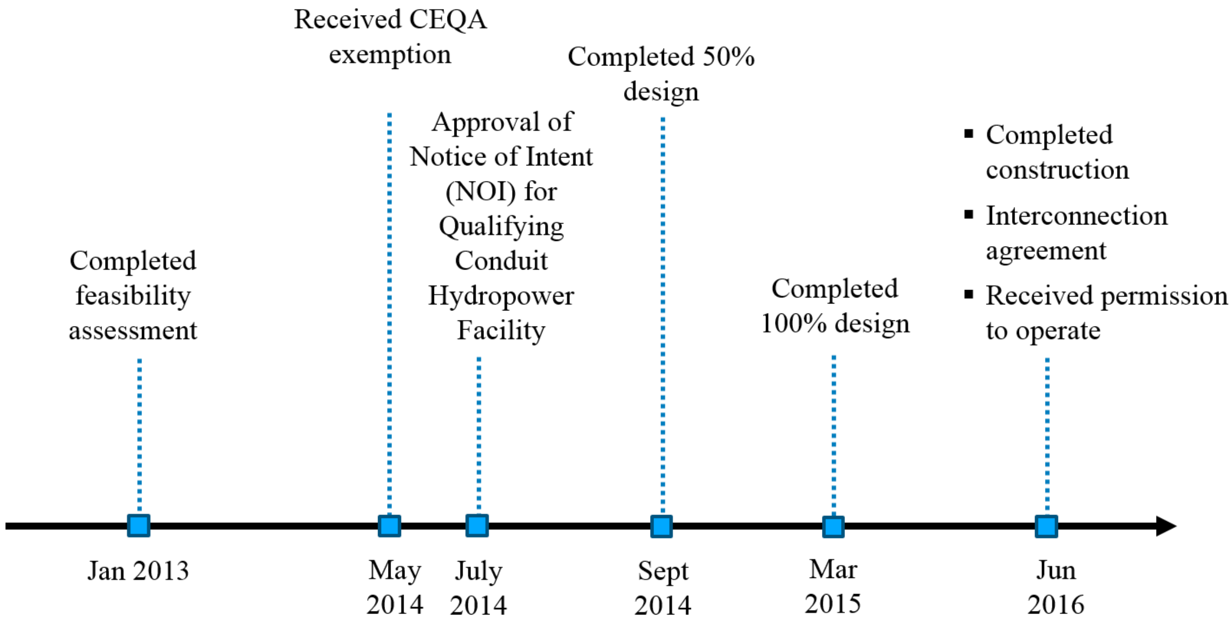
AWA authorized NLine Energy to develop a feasibility assessment on the potential Tanner Hydro project, which was completed in January 2013. NLine Energy analyzed the historical pressure and flows of the site and determined that a two pump as turbine system with a nameplate rating of 110 kW was the best option for the site. The available flow at this site currently ranges from 3.5 cfs to 14 cfs while the net head ranges from 130 ft to 210 ft. Due to future water demand the Tanner Water Treatment Plant is expected to expand as high as 14 cfs. The feasibility assessment determined that the project would cost approximately $1,400,000, would generate 580,000 kilowatt hours annually and would have a 13-year payback. Figure A-3 provides an overview of the project site. After conducting the feasibility assessment, AWA proceeded to complete 100 percent design in March 2015, and finally received the permission to operate in June 2016. It took approximately 2.5 years to complete the project, as depicted by Figure A-4 below.

Figure A-3: Aerial (Left Image) and Close-Up (Right Image) Views of the Tanner Hydro Station



Source: Stantec

Figure A-4: Timeline of the Project Starting from Feasibility Assessment to Operation Startup



Source: Stantec

Permitting and Regulation

California Environmental Quality Act (CEQA)

The California Environmental Quality Act (CEQA) allows a Class 28 Exemption for small hydroelectric projects. Section 15328, titled, "Small Hydroelectric Projects at Existing Facilities". This project qualified for the CEQA exemption. AWA received CEQA exemption in May 2014, as shown in Figure A-4 above.

FERC Conduit Exemption

Under the Federal Power Act (FPA), the Federal Energy Regulatory Commission (FERC) regulates the nation's non-federal hydropower resources. Before August 2013, FERC issues three types of development authorizations: conduit exemptions, five-megawatt (MW) exemptions, and licenses. However, when "Hydropower Regulatory Efficiency Act" was signed in August 2013, there was a significant simplification in small hydropower regulatory processes. One regulation that is especially attractive for small hydropower projects is the elimination of exemption and licensing requirement for hydropower facilities located on non-federally owned conduits with installed capacity of 5 MW or less. The applicant must only file a Notice of Intent (NOI) to Construct a Qualifying Conduit Hydropower Facility with FERC as well as show that the conduit is not used primarily for electricity generation and was not licensed or exempted on and before August 9, 2013. The criteria for a Qualifying Conduit Hydropower Facility is listed in Table A-2.

Table A-2: Criteria for a Qualifying Conduit Hydropower Facility (FERC 2017)

Statutory provision	Description
FPA 30(a)(3)(A), as amended by HREA	The conduit the facility uses is a tunnel, canal, pipeline, aqueduct, flume, ditch, or similar manmade water conveyance that is operated for the distribution of water for agricultural, municipal, or industrial consumption and not primarily for the generation of electricity
FPA 30(a)(3)(C)(i), as amended by HREA	The facility is constructed, operated, or maintained for the generation of electric power and uses for such generation only the hydroelectric potential of a non-federally owned conduit
FPA 30(a)(3)(C)(ii), as amended by HREA	The facility has an installed capacity that does not exceed 5 megawatts
FPA 30(a)(3)(C)(iii), as amended by HREA	On or before August 9, 2013, the facility is not licensed, or exempted from the licensing requirements of Part I of the FPA

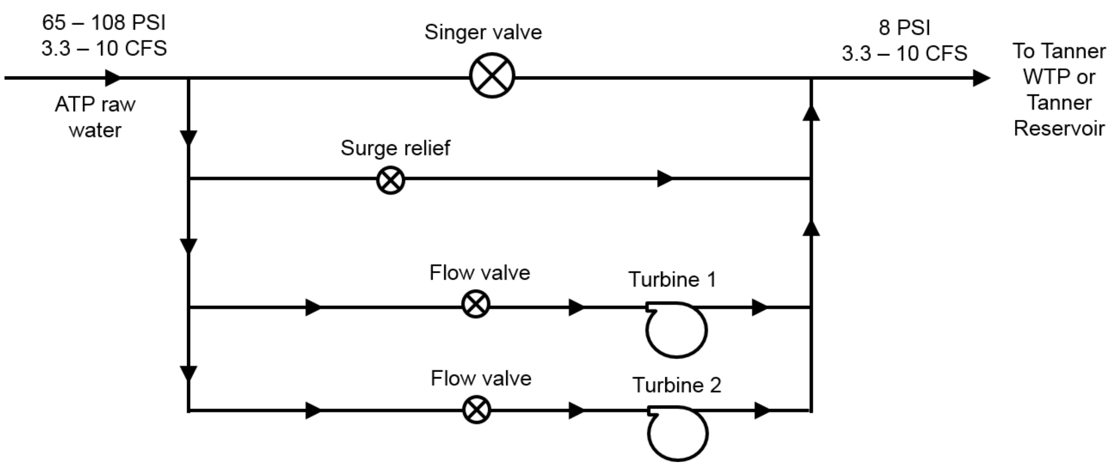
Source: Stantec

The NOI process is generally much faster than exemption process, as the facility does not require to hold a public hearing. The NOI process takes around 45 days to complete. The Tanner hydro station met all the criteria listed above and in July 2014, the NOI was approved by FERC.

Design and Construction

The new Tanner Hydroelectric Station (hydro) operates in parallel with the Tanner Pressure Reducing Station (PRS). A pipeline taps into the high-pressure side of the Tanner PRS (upstream of the 16-inch Singer valve) and is routed to the new powerhouse (Figure A-5).

Figure A-5: Schematic Flow Diagram of the Hydroelectric Unit at Tanner Water Treatment Plant



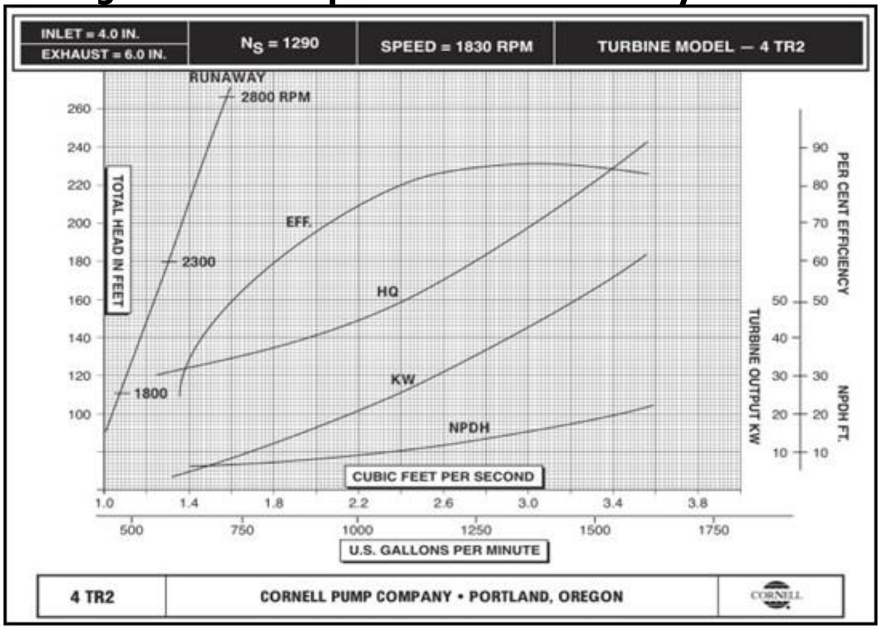
Source: Stantec

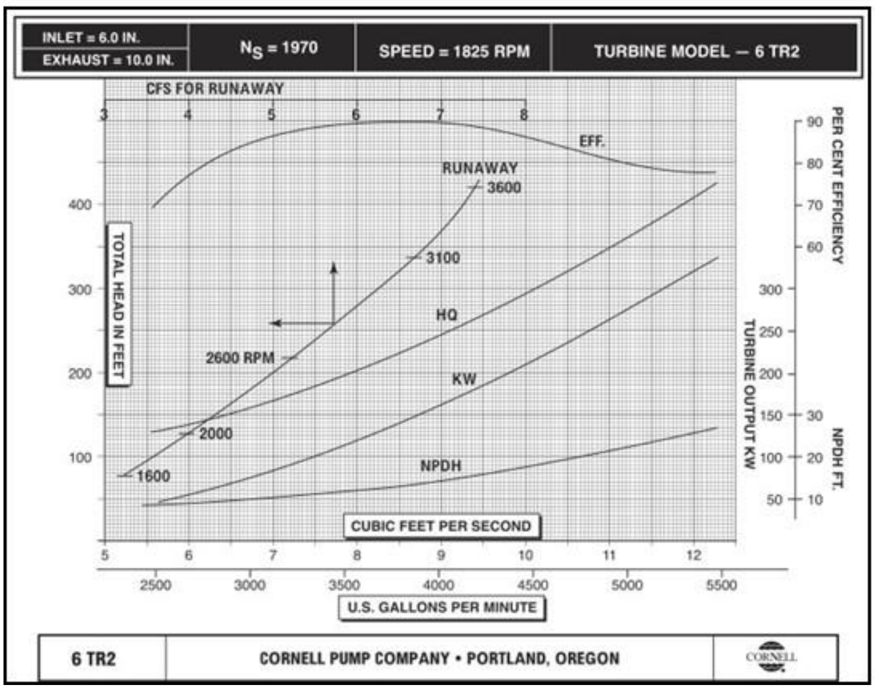
Based on the head and flow conditions for this site, the Cornell Pump-as Turbine (PAT) technology was implemented at this site. PAT machines operate best at optimum design conditions and have a relatively narrow efficiency curve. A PAT operates best at a single flow and head and generally do not operate well below approximately 80 percent of full flow. For maximum flexibility and to capture as much flow as possible, two PAT units were implemented. The PAT units receive the high-pressure water and discharge into a new discharge header near the low-pressure side of the existing PRS. The hydroelectric system consists of two Cornell Pump-as Turbines with a total nameplate rating of 110kW. The PAT system consists of a Cornell PAT 4TR2 rated for approximately 3 cfs/150 ft of net head and a Cornell PAT 6TR2 rated for approximately 7 cfs/200 ft of net head. The efficiency curves for the two turbines are included in Figure A-6 below.

The powerhouse is approximately 580 square feet in size. The building is prefabricated steel with sound attenuation. The powerhouse is supplied from an existing 20-inch connection off the ATL. A new 16-inch pipe supplies water to the new powerhouse. From the powerhouse a 16-inch pipe connects to the existing 16-inch supply pipeline to the Tanner WTP and the Tanner Raw Bowl.

One notable challenge during the design process was the development of a customized Program Logic Controller (PLC) system that can handle various complex operational scenarios. The complex scenarios mainly arise from the fact that the hydro station feeds water to the Tanner Water Treatment Plant and a raw water reservoir. In addition, since the hydro station is located upstream of the Tanner WTP, a minimum pressure must be maintained to serve the WTP. This required pressure also changes constantly, especially during the backwashing period in WTP. During the design stage, the PLC developer (Tesco) worked closely with the AWA operators to simulate possible scenarios that can occur in the downstream WTP and to ensure that the program developed can handle those scenarios.

Figure A-6: Pump-as Turbine Efficiency Curves





Source: Stantec

Operations and Maintenance

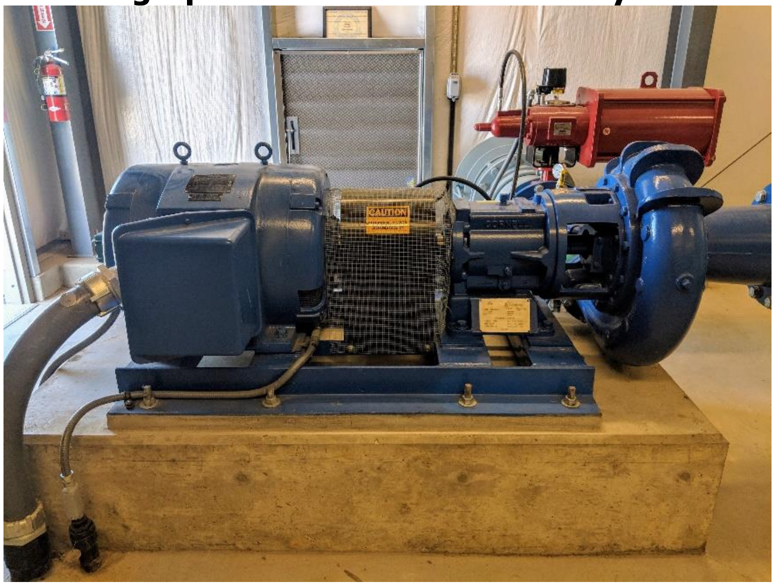
The Tanner Hydroelectric Station (hydro) is operating in parallel with the Tanner PRS. Using a pipeline installed on the high-pressure side of the Tanner PRS (upstream of the 16-inch Singer valve), the two PAT units receive the high-pressure water and discharge into a new discharge header near the low-pressure side of the existing PRS. Similar with PRS, the hydropower systems reduce the pressure by utilizing the pressure and flow to convert hydraulic energy into mechanical energy. The driving head required for the WTP creates a back-pressure on the turbines so that a downstream pressure control valve is not necessary. However, the control valve on the Tanner Raw Bowl discharge side of the header has to maintain upstream pressure to a minimum of 8 psi in order to serve the Tanner WTP.

Due to the “on-off” nature of the Tanner WTP, the control header acts as the flow regulation for directing the discharge either to the Tanner WTP and/or into the Tanner Raw Bowl. This mode allows for the hydro to run continuously and the Tanner WTP to maintain its current on-off operation, with the Tanner Raw Bowl serving as the equalization basin. This mode of operation maintains a more constant flow in the ATP and greatly reduce surge in the ATP and extend its life as a result. It is important that during the on-off operation of the WTP that the hydropower plant to not be shut down, but continue to run. If the hydro shuts down, PG&E could charge the Agency with Demand Charges, which would reduce the overall financial income of the project. However, there will be times when the system will be off because the Tanner Raw Bowl and the clear well is full. These shutdown periods might be minimized by reducing the Tanner Raw Bowl operating target levels during low demand periods. As a result of this type of operation, the demand seen by the hydroelectric station will mimic closely the daily production of the Tanner and Ione WTPs, as opposed to the current meter readings recorded by the magnetic flow meter located just upstream of the Tanner PRS. Another issue during operation is the changing pressure requirement by downstream Tanner WTP due to backwashing. The changes in pressure requirement greatly affect the flow and pressure in the turbine system which affect its power generation capacity. AWA suspected that this issue might be the main cause of production loss which hindered the turbines to generate power at full capacity (currently the hydro station in average is producing 70 percent of its full capacity). The complex operation of Tanner WTP required a sophisticated program logic controller (PLC) system with well-trained personnel.

Typical maintenance of a hydroelectric station includes the following:

- Daily inspections of the hydroelectric station are recommended to detect leaks, excessive moisture buildup, loud noises, excessive vibration and/or heat. Sensors may be used to remotely detect many of these issues to augment physical inspections.
- Quarterly oil inspections / change: bearings, hydraulic systems, and gearboxes require grease or oil. Annual inspection and testing for viscosity, acidity and water content are required, while minimizing different types of oil, if possible. If oil temperatures stay below 60 Celsius, the oil’s useful life is extended dramatically.
- Flow, pressure, and resulting kW production and overall efficiency should be checked periodically and instruments calibrated on regular intervals.
- The first inspection of the turbine itself should be at 12 months or 8,000 hours of operation.
- General inspections should occur every year until a history is established and trends are identified. Then the interval can be extended to two or more years. Similar installations may be good indicators of maintenance trends.
- Annual maintenance costs are assumed to be approximately $6,000 per year.
- Summary of annual maintenance and repair downtime:
    - Assume one week each year
    - Assume three weeks every five years
    - Three months every 25 years

Figure A-7: Photograph of PAT Unit in Tanner Hydroelectric Station



Source: Stantec

Costs and Financing

An overview of the project cost estimated at three different times (preliminary, 50 percent design and after 100 percent design) is provided in Table A-3 below. As can be seen, the project cost after 100 percent design only increased by less than six percent of the original estimation at preliminary stage. The small increase in the budget was mostly due to tight control from the board that required multiple financial assessment at different stages. This strategy was shown to be effective in making sure that the project budget did not stray too far from the original estimation.

Table A-3: Overview of the Project Cost Calculated in January 2013 (Preliminary Stage), September 2014 (50 Percent Design) and June 2015 (After 100 Percent Design)

Cost item	Jan 2013	Sept 2014	June 2015
Estimated Project Costs	$1,423,000	$1,595,000	$1,504,000
Self-generation Incentive Program	$128,000	$140,000	$133,750
Net Project Cost (Less Incentives)	$1,295,000	$1,455,000	$1,370,250
Annual O & M Costs	$6,000	$6,000	$6,000
30-year Net Savings	$2,293,000	$2,620,000	$3,960,000
30-year NPV	$703,000	$982,000	$1,684,000
Payback	19.2 years	17.7 years	13.6 years

Source: Stantec

Future Planning

The Tanner WTP has a maximum day treatment capacity of 4,800 gpm (10.7 cfs) utilizing six filters (Figure A-8). Flow rates processed through the Tanner WTP vary from 0 cfs to approximately 7 cfs (3,140 gpm). An additional set of filters (No. 7 and No. 8) of similar design are scheduled for installation at some time in the future that will increase the capacity to 6,400 gpm (14.2 cfs). The increase in capacity is expected to increase the energy production in Tanner hydro station.

The Raw Bowl feeds the Ione Reservoir and subsequently the Ione WTP. The Raw Bowl holds 11.8 acre-feet when full and the Ione Reservoir holds 26.9 acre-feet when full. The pipe connecting the Raw Bowl and the Ione Reservoir is the Ione Pipeline, which is a 16-inch Ductile Iron pipeline, 7.1 miles in length. The Ione WTP has a maximum day treatment capacity of 2,110 gpm (4.7 cfs) and an upgrade to the Ione WTP was recently completed. The Ione hydro station is currently in design stage.

Figure A-8: Current Configuration of Tanner Water Treatment Plant

Source: Stantec

Lessons Learned and Recommendations

- Interconnection cost: The Tanner Hydro Project was very small and implemented at the end of PG&E’s circuit, so it had minimal impact on PG&E’s system resulting in a low-cost interconnection. Typically, interconnection costs for small hydro projects cost hundreds of thousands of dollars but this project’s interconnection only cost approximately $2,500. Significant interconnection costs can be overwhelming for smaller projects, therefore identification and understanding of the impact of interconnection costs early in the process is imperative.
- Net metering: This was the first small hydro project in the state to utilize Net Energy Metering Aggregation (NEMA). NEM Aggregation enables the customer to combine several existing meters on a contiguous property to use to offset the generation of the hydro project.

- Control system: This hydro station feeds water separately to the Tanner Water Treatment Plant and a raw water reservoir, which necessitated complex programming and control logic. This type of programming can be very expensive and extend project timelines. Utilizing the same PLC developer that build the existing WTP facility also helps in reducing any confusion or error during the process as the developer is already familiar with the existing system.
- Future expansion plan: The Tanner Water Treatment Plant is expected to expand over time, which will increase the maximum water flow processed by the WTP as well as flow available to the hydro unit. Therefore, this project implemented a set of turbines that can process existing flows but also is set up to process higher flows as the WTP expands in the future.

East Valley Water District (EVWD) Case Study Summary

Case Study Participants

- Eliseo Ochoa – Senior Engineer, East Valley Water District
- John Drury – Senior Treatment Plant Operator, East Valley Water District

Background

- Site address: 4588 East Highland Avenue, Highland CA 92346
- Location of hydropower unit: Upstream of Water Treatment Plant 134
- Turbine type: Pump-as Turbine Hydroelectric System
- Number of hydropower unit: Two units Cornell 6TR3 Pump as Turbine (PaT) rated at 7.7 cfs, and Cornell 4TR4 rated at 3.1 cfs
- Turbine manufacturer: Cornell Pump Company (supplied by Canyon Hydro)
- Total capacity: 220 kW turbine nameplate rating
- Estimated annual power generation: 1,034,000 kWh
- Total project cost: $2,543,000
- Electric provider: Southern California Edison (SCE)
- Energy use: Energy used on-site
- Billing arrangement: Net Energy Metering (NEM)
- Project status: In operation

The East Valley Water District (EVWD) is a County District formed in 1954 through an election by local residents who wanted water service by a public agency. Originally called the East San Bernardino County Water District, the name was changed to East Valley Water District in 1982. The district was originally formed to provide domestic water service to the unincorporated and agricultural-based communities of Highland and East Highlands. Later, as the population increased, the need for a modern sewer system to replace existing septic tanks became apparent. The residents voted to give East Valley Water District the responsibility for their sewer system, as they did earlier with their water service.

Over the years, some of the district's service area was annexed to the City of San Bernardino, the water service remained with the District, primarily due to logistics and cost. East Valley

Water District (District) is a California Special District that provides water and wastewater services throughout a 27.7 square mile area in the County of San Bernardino. The District's service area includes the City of Highland, the eastern portion of the City of San Bernardino, the San Manuel Band of Mission Indians, and unincorporated areas of the County.

San Bernardino Valley Municipal Water District (SBVMWD) is one of 29 California Water Contractors and provides raw water to EVWD's water treatment Plant 134. Plant 134 is a surface water treatment facility that is located north of Highland Avenue and east of CA-330 in Highland, California (Figure A-9). Plant 134 was recently converted to a membrane-filtration process that allows the district to increase capacity from 4 million gallons per day (MGD) to 8 MGD. SBVMWD is planning to construct a new raw water supply line to Plant 134 to accommodate their increased flow requirements.

Plant 134's raw water supply is designed to utilize either imported State Water Project (SWP) water, local Santa Ana River (SAR) water, or a blend of both waters. Plant 134's raw water supply facilities were designed to allow SWP water to enter the plant via a dedicated high-pressure pipeline and for local SAR water to be supplied via a connection to the Northfork Canal. Water from both sources enters the plant's Influent Control Structure (ICS). At the ICS the SWP water passes through a pressure reducing valve. Once the pressure is reduced, the two sources of raw water are combined. This combined flow is then divided between the treatment plant, based on current demands of the plant, and a plant bypass to the Northfork Siphon. Raw water inflow to the ICS (from both sources) is maintained at a steady rate during changes in routine treatment plant processes by adjusting the amount of plant bypass flow. Figure A-9 provides an overview of the site layout.

Figure A-9: EVWD Plant 134 Project Site Location

Source: Stantec

The SWP water is sourced by SBVMWD, via their 78" Foothill Pipeline that originates at the Devil Canyon afterbay, a California Department of Water Resources (DWR) hydroelectric facility. An existing 12-inch steel pipe connects to the high-pressure Foothill Pipeline at the Highland-Boulder Connection just west of Highway 30 and travels down Highland Avenue before it transitions to a 16-inch ductile iron pipe in the Plant 134 access road, via the

SBVMWD City Creek Turnout, a flow and pressure control facility. The 16-inch pipeline extends to the influent control structure at the water treatment plant.

Project Drivers

In 2013, SBVMWD started to conduct a thorough assessment of their service area to identify locations that are suitable for small hydropower implementations. As SBVMWD supplies SWP water to several water utilities, the assessment was focused on the various locations of pressure reducing stations along the SWP pipeline. The pressure reducing station located upstream of Plant 134, which is owned by EVWD, was considered feasible for conduit hydropower due to its sufficient available pressure. After several joint board meetings between SBVMWD and EVWD, the Plant 134 hydropower project began development in 2014. The cost of constructing the facility was fully financed by SBVMWD, which will be paid back in installment by EVWD as they generate revenue from the hydropower over the years.

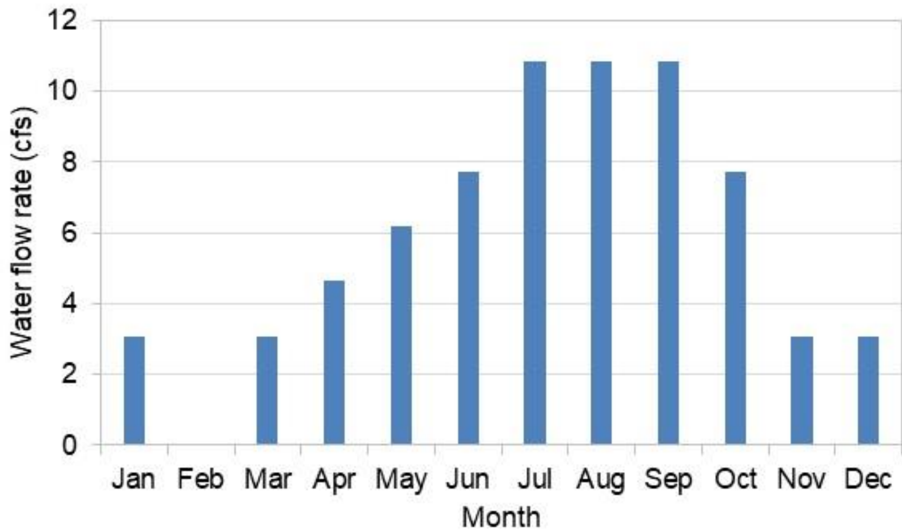
Feasibility Assessment

EVWD authorized NLine Energy to develop a preliminary design report on the potential hydroelectric project, which was completed in April 2014. NLine Energy developed flow data based on expected water demand at Plant 134. EVWD and SBVMWD staff provided the synthesized flow data, by month to accurately forecast future water demands into the Plant through the new City Creek turnout pipeline. Figure A-10 shows a summary of the expected flow by month. Flows ranges approximately from 3 to 11 cubic feet per second (cfs) (2 to 7 MGD) throughout the year with an expected plant shutdown in February. Maximum plant flows were limited to 11 cfs (7 MGD) based on parameters offered by EVWD staff.

The available head for the site was synthesized based on three flow scenarios in the SBVMWD Foothill pipeline (125 cfs, 165 cfs, and 225 cfs), in addition to friction losses from the SBVMWD City Creek turnout and downstream pressure requirements at Plant 134. The models indicate that under the three flow models, available head will fluctuate between 213 and 277 feet throughout the year based on plant demand.

For the station design, a pressure control valve upstream of the turbine that limits the pressure head to as low as 197 feet at times would provide consistent pressure to the turbine. Pressure head must be controlled, otherwise, the turbine does not operate when pressure head rises above the operating curve of the turbine. NLine Energy utilized the midpoint of the pressure differential range of 255 feet in our models and adjusted the pressure downwards as appropriate assuming the pressure control valve would cut pressure to meet the operating curve of the turbine.

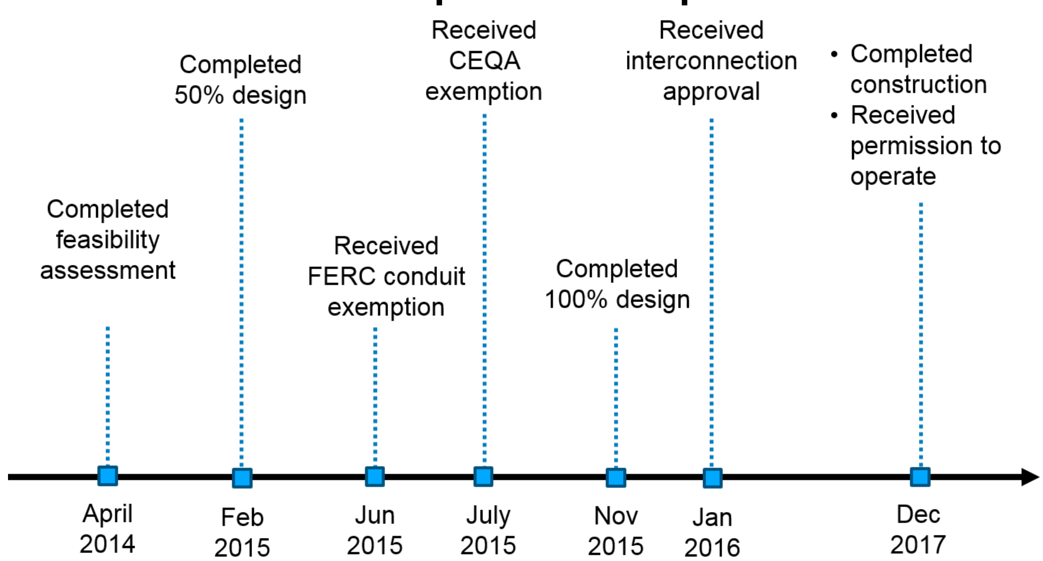
Figure A-10: Plant 134s Synthesized Flow Data – Average Flow 6 cfs



Source: Stantec

The feasibility assessment determined that the project would cost approximately $2.5M, generate 1,034,000 kilowatt hours annually and have an estimated 15-year payback. After conducting the feasibility assessment, EVWD proceeded to complete final design in November 2015, and finally received the permission to operate in December 2017. It took approximately 3.5 years to complete the project, as depicted by Figure A-11 below.

Figure A-11: Timeline of Project from Feasibility Assessment to Operation Startup



Source: Stantec

Permitting and Regulation

California Environmental Quality Act

The California Environmental Quality Act (CEQA) allows a Class 28 Exemption for small hydroelectric projects. Section 15328, titled, "Small Hydroelectric Projects at Existing Facilities". This project qualified for the CEQA categorical exemption.

FERC Qualifying Conduit Facility, Notice of Intent

Under the Hydropower Regulatory Efficiency Act of 2013, the FERC is required to determine whether proposed projects meet the criteria to be considered "qualifying conduit hydropower facilities." Qualifying conduit hydropower facilities are not required to be licensed or exempted by the FERC; however, any person, State, or municipality proposing to construct a facility that meets the criteria must file a Notice of Intent to Construct a Qualifying Conduit Hydropower Facility with the Commission.

A "qualifying conduit hydropower facility" must meet the following provisions:

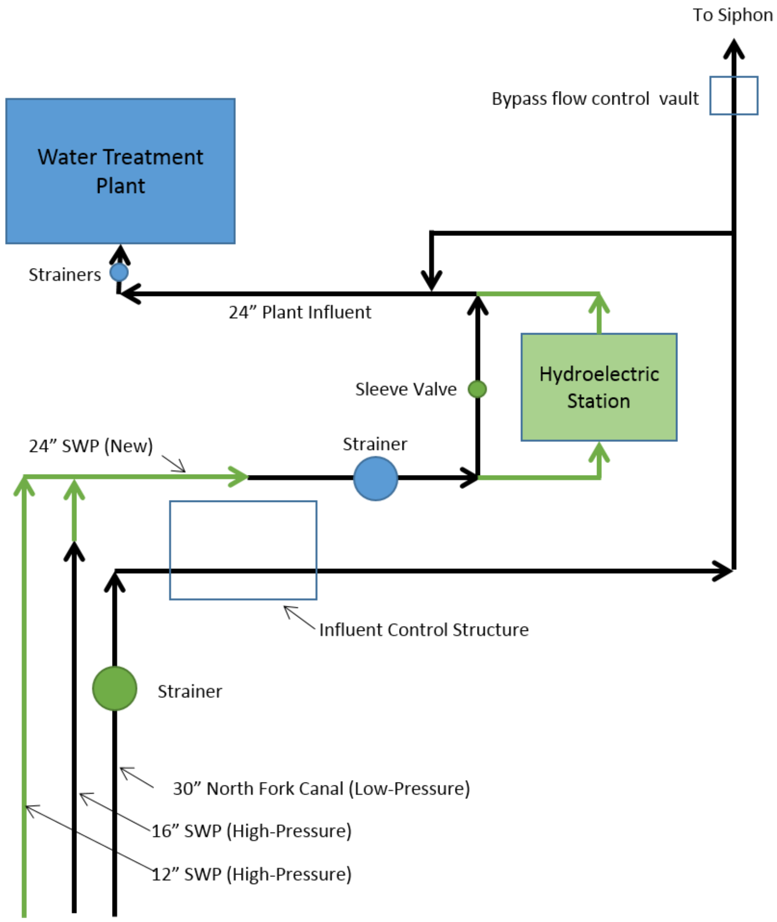
- A conduit is any tunnel, canal, pipeline, aqueduct, flume, ditch, or similar manmade water conveyance that is operated for the distribution of water for agricultural, municipal, or industrial consumption, and is not primarily for the generation of electricity.
- The facility generates electric power using only the hydroelectric potential of a non-federally owned conduit.
- The facility has an installed capacity that does not exceed 5 megawatts (MW).
- The facility was not licensed or exempted from the licensing requirements of Part I of the FPA on or before August 9, 2013.

Based on this information, the Plant 134 Hydro site qualified and completed the Qualifying Conduit Facility, Notice of Intent application process.

Design and Construction

Figure A-12 is a simplified schematic of the plant raw water supply operations after construction of the new raw water supply line and hydroelectric station. The Plant 134 Hydroelectric station is located north of the existing influent control system (ICS), on the east side of the plant property, near the current operations control room. Major components of the power station include: two Pump-As-Turbine/Generators, pressure control valves to provide consistent pressure to the turbines, and a hydro station bypass line and sleeve valve. The hydroelectric station includes a station bypass to allow uninterrupted treatment plant operations when the turbine/generators are not running. The bypass includes a sleeve valve to both reduce pressure and modulate flow through the hydroelectric station while maintaining constant flows to the treatment plant. Two Cornell Pump-as-Turbines were selected for this site. The lead unit is a 6TR3 unit with a name plate rating of 175 kW (max 7.7 cfs) and a second unit which is a 4TR4 with a name plate rating of 45kW (max 3.1 cfs). These units can operate individually or simultaneously. A photograph of one of the turbines installed in this hydroelectric station is provided in Figure A-13.

Figure A-12: Plant 134 Flow Schematic – Raw Water Supply Operations with Hydroelectric Station and New High-Pressure Supply Line



Source: Stantec

Figure A-13: Pump-as-Turbine Unit Installed in Plant 134 Hydroelectric Station

Source: Stantec

Operations and Maintenance

Flow to the EVWD Plant 134 is controlled from flow control valves at the SBVMWD City Creek Turnout. A plant flow rate request is issued by the plant to the Hydroelectric Station Programmable Logic Control (PLC). The hydroelectric station PLC communicates the flow rate to the SBVMWD City Creek Turnout via fiber optic communication link. The City Creek Turnout is also linked to the existing SBVMWD communication network via radio. In case the hydro facility is off-line, all flow from the City Creek Turnout to the plant will be processed via a pressure regulating valve (PRV) in parallel with the hydroelectric station.

The Hydroelectric station continuously monitors pipeline incoming pressure and the target flow rate requested by the plant. The hydro PLC calculates how much energy is available for power generation. Based on the calculation, either one or both turbines is enabled to run. The run command can either automatically start the turbine(s) or a signal can be sent to the operators and they can manually start the turbines at the PLC panel. The hydro PLC modulates the turbine control valve(s) open, while closing the bypass sleeve valve and process the required flow through the turbine(s) and discharge to the water plant. Depending on the WTP flow target and available pressure and flow through the hydroelectric station, the bypass sleeve valve can fine tune the flow in order to maintain the target flow rate. If the downstream plant requires flow greater than the maximum flow that can be handled by the turbine system, the extra flow will be supplemented by flow through the sleeve valve in parallel with the hydroelectric station.

Typical maintenance of a hydroelectric station includes the following:

- Daily inspections of the hydroelectric station are recommended to detect leaks, excessive moisture buildup, loud noises, excessive vibration and/or heat Sensors may be used to remotely detect many of these issues to augment physical inspections.
- Quarterly oil inspections / change: bearings, hydraulic systems, and gearboxes require grease or oil. Annual inspection and testing for viscosity, acidity and water content are required, while minimizing different types of oil, if possible. If oil temperatures stay below 60 Celsius, the oil's useful life is extended dramatically.
- Flow, pressure, and resulting kW production and overall efficiency should be checked periodically and instruments calibrated on regular intervals.
- The first inspection of the turbine itself should be at 12 months or 8,000 hours of operation.
- General inspections should occur every year until a history is established and trends are identified. Then the interval can be extended to two or more years. Similar installations may be good indicators of maintenance trends.
- Annual maintenance costs are assumed to be approximately $6,000 per year.
- Summary of annual maintenance and repair downtime:
    - one week each year
    - three weeks every five years
    - three months every 25 years

Costs and Financing

Table A-4 provides an overview of the project financial metrics. This analysis was performed in December 2017 after construction of the project. T payback period for this project is about 15 years. Any revenue generated from this project will be paid back to the SBVMWD as they provided the loan at the beginning of the project to start the construction.

Table A-4: Overview of the Project Cost Calculated in December 2017 (After Construction)

Cost Item	Value
Estimated Annual Generation (kWh)	$1,034,000
Project Cost	$2,543,000
Self-Generation Incentive Program (Grant)	$232,000
Net Project Costs	$2,311,000
Annual O & M Costs	$6,000
Annual Generation Revenue	$113,000
30-year Net Savings	$3,486,000
30-year NPV	$650,000
Payback	15 years

Source: Stantec

Future Planning

The Plant 134 hydroelectric project was completed and received the Permission to Operate from Southern California Edison in December 2017. The project is expected to generate more than 1,034,000 kilowatt hours annually or the equivalent of 770 metric tons of carbon dioxide or 115 homes electric use for one year.

Lessons Learned and Recommendations

- Wholesale – retail water agency partnership: SBVMWD and EVWD formed a partnership early in the project development whereby SBVMWD fully financed and contracted all work related to the EVWD Plant 134 project. SBVMWD has a much larger reserve account, staff, and ability to act as the lead agency for the project's development, alleviating the small agency, EVWD, from excessive staff time on a small project. EVWD will receive all renewable energy production and grants and pay SBVMWD back on a zero-interest loan recouped as an additional surcharge on a $ per acre/ft formula. This arrangement further strengthened the bond between the wholesale and retail agency forging a long-term partnership, which was used as the model for another retail agency.
- Pre-construction activities: Plant 134 is located on a space-constrained parcel with numerous water lines to include city, county, flood control district water lines, as well as other instrumentation utility lines crossing throughout the path of the new piping and hydroelectric station. A detailed as-built review was conducted, contact with 811 "Dig-Alert," and potholing on key sections of the new piping route. During construction, the General Contractor hit a demobilized water line that was not previously listed on any documentation. Luckily, the former high-pressure water line had been decommissioned, but residential flooding may have ensued if the line was charged. Much of the digging at the hydroelectric station was conducted by hand due to the web

of wiring and piping in and around the project site. Ground penetrating radar may have provided additional information as to the location of these underground pipes and wires.

- Pressure requirements: Plant 134 upgraded to membrane filters requiring a minimum of 17 psi at all times based on the expansion from 4 to 8 MGD design capacity. Significant analysis and design were conducted to ensure that a minimum of 17 psi was always available to the membrane filters in order to provide laminar, unobstructed pressures and water flow irrespective of hydrostation operation.
- Project timeline: The development of small hydropower projects like this usually takes about 2 – 2.5 years to complete. However, the development took about 3.5 years for this particular project. Although the design and construction were already completed, the project startup was postponed to December 2017 due to significant delay from the electric utility side. This is one of the recurring themes in the implementation of conduit hydropower in California. Thus, it is advised for the future developers to build a relationship with the electric utility early in the process to avoid any delay.

Mojave Water Agency (MWA) Case Study Summaries

Case Study Participant

Darrell Reynolds – Director of Engineering, Mojave Water Agency

Background

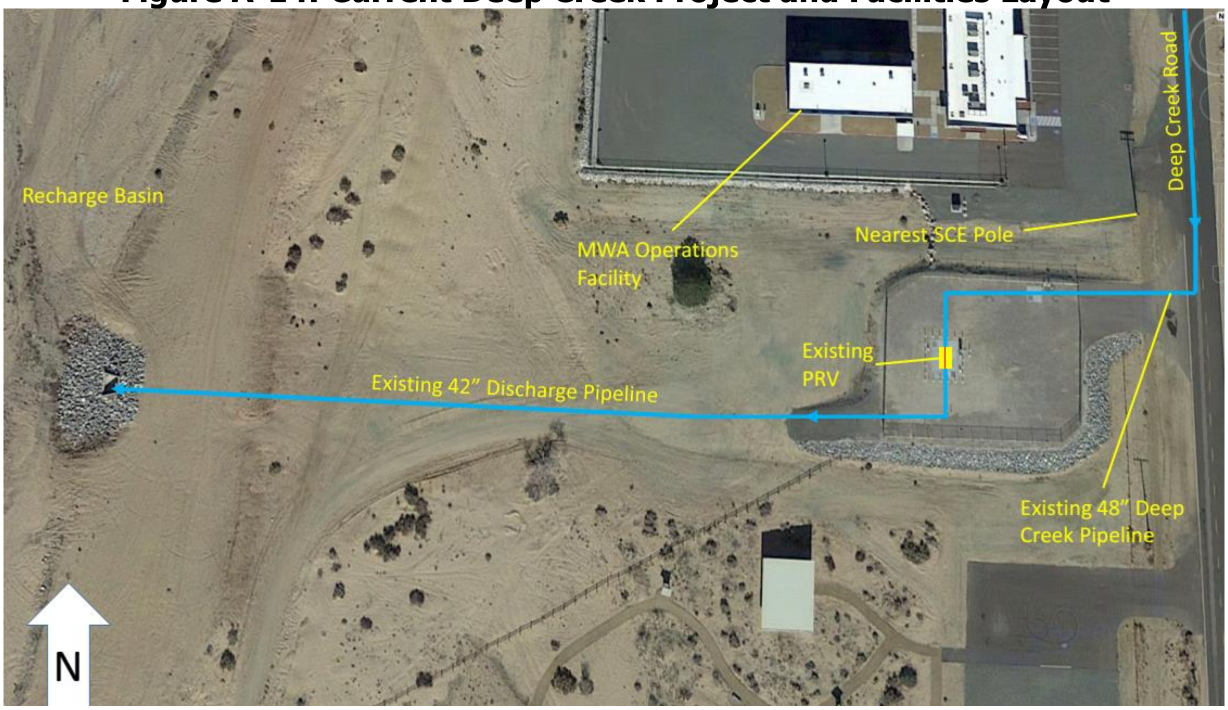
- Site address: 7805 Deep Creek Road, Apple Valley, CA 92307
- Location of hydropower unit: Deep Creek Water Recharge site
- Turbine type: Single, Two-nozzle horizontal Pelton Turbine
- Number of hydropower unit: One unit
- Turbine manufacturer: Canyon Hydro
- Total capacity: 840 kW turbine nameplate rating
- Estimated annual power generation: 6,100,000 kWh
- Total project cost ($) $4,684,000
- Electric provider: Southern California Edison (SCE)
- Energy use: Offset energy use via virtual net-energy metering
- Billing arrangement: RESBCT
- Project status: In construction phase

Mojave Water Agency's (MWA) boundaries encompass approximately 4,900 square miles of the High Desert in San Bernardino County. As a State Water Contractor, MWA is entitled to receive an annual allotment of up to 82,800 acre-feet of water from the State Water Project (SWP) via the California Aqueduct. MWA supplements regional groundwater supplies by providing water to the facilities that optimize the groundwater basin capacity.

At MWA's Deep Creek site, water from the State Water Project is discharged into a groundwater recharge area (referred to as the Deep Creek Water Recharge site). Prior to discharge, water flows through a pressure reducing valve (PRV) to reduce excess pressure.

The proposed project consists of the installation of a hydroelectric station adjacent to, and in parallel with the existing PRV that utilizes the recharge flows to produce electrical energy through a hydroelectric power generating turbine. An overview of the site and layout is shown below in **Error! Reference source not found.**Figure A-14. The project is currently in the construction phase.

Figure A-14: Current Deep Creek Project and Facilities Layout



Source: Stantec

Project Drivers

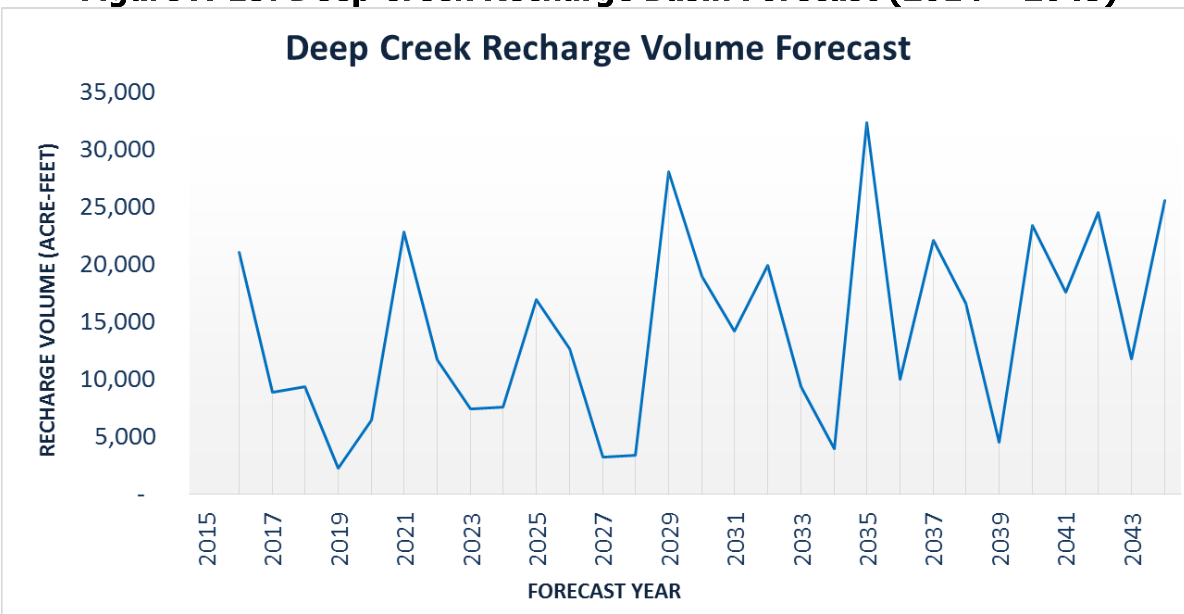
Installation of hydropower at this site had long been planned by MWA during the initiation of the ground recharge project. Moreover, an initial assessment was conducted in 1996 to evaluate the feasibility of Deep Creek site for potential conduit hydropower installation. While the idea of installing a hydroelectric turbine to help prolong the life of a sleeve valve seemed attractive, there were many challenges identified during the initial assessment that prevented the advancement of the hydro project. Two of the major challenges were: (i) the initial cost of the interconnection with Southern California Edison (SCE) and (ii) MWA could not project the incoming water at that time.

MWA attempted to develop the project in 2012, filing an interconnection request with SCE. At the time, the total project cost was estimated at $4.6M. At the conclusion of the SCE study period, the interconnection cost estimate was an additional $4.3M bringing the total project cost to $9.6M. NLine Energy was contracted in 2015 to review the initial design and concluded that a turbine-generator system sized no larger than 850 kW would not trigger excessing interconnection costs. In 2016, a new SCE interconnection application was submitted and the interconnection cost estimated dropped from $4.3M to $250k; hence, the project moved forward with development. Additionally, MWA soon realized that the cost of sleeve valve replacement might be quite substantial, costing the utility about $300,000 - $400,000 every 6 years. Thus, installation of a hydroelectric turbine, although expensive at the beginning, becomes more attractive as it does not only reduce pressure and utilizes the excess energy, but also prolongs the life of the adjacent sleeve valve (as hydroelectric turbine is usually installed on a by-pass loop). For this reason, MWA conducted another feasibility assessment with NLine Energy to re-check the consistency of the receiving water to the potential site in May 2015.

Feasibility Assessment

MWA authorized NLine Energy to develop a preliminary design report on the potential Deep Creek hydroelectric project. MWA provided total annual recharge projections between 6,000 AF/yr and 20,000 AF/yr. Subsequently, MWA provided the 2015 to 2044 forecasted flows based on projected SWP allocations shown in Figure A-15.

Figure A-15: Deep Creek Recharge Basin Forecast (2014 – 2043)



Source: Stantec

NLine Energy conducted an analysis of multiple total-annual-volume and recharge-duration scenarios to identify the most efficient choices of turbine type and capacity. During the course of the analysis, flow projections over a 30-year period were analyzed against historic allocations (Table A-5). MWA staff and NLine Energy conducted multiple models and finally settled on a turbine that would process the vast majority of the expected flows. The turbine sizing also allowed for the unit to act as a peaking resource.

The analysis showed that a single, two-nozzle horizontal Pelton turbine sized for 20 cfs will optimize electrical energy production running at full capacity 13 out of the 29 years of data, with excess flows being bypassed through the PRV. The preliminary design report determined that the project would cost approximately $4,684,000, generate 6,100,000 kilowatt hours annually and have a 15-year payback.

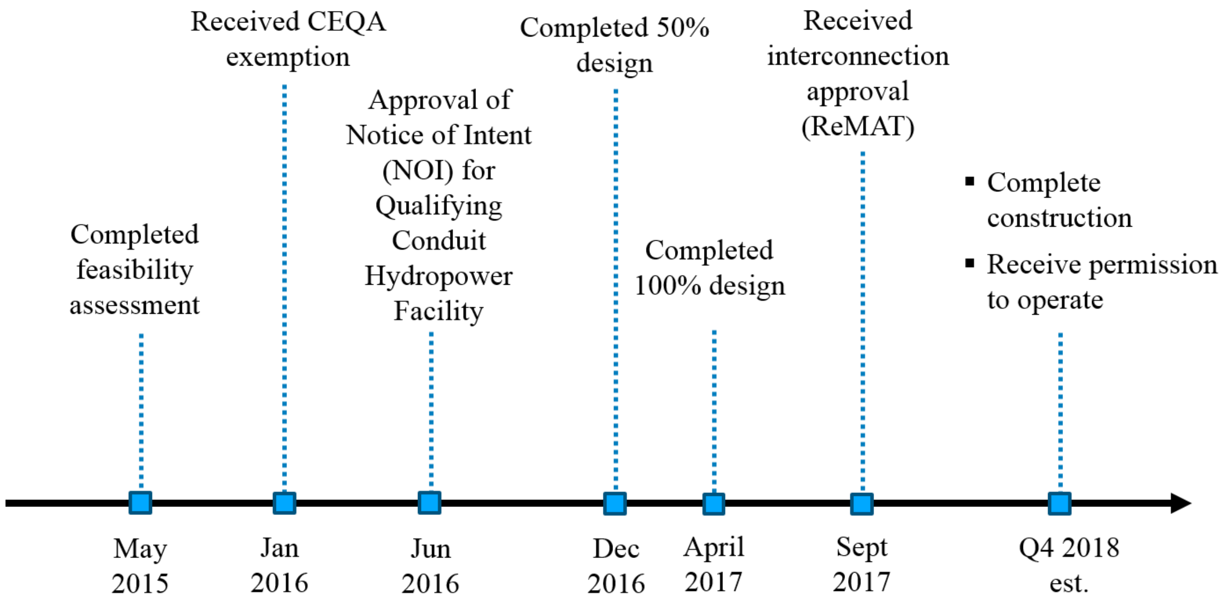
Table A-5: Overview of the Final Groundwater Recharge Scenario

year	Delivery (AF)	Turbine flow (cfs)	Water Volume Though Turbine (AF)	Bypass Volume Through PRV (AF)	Days of Turbine Use
2016	21,029	20	14,479	6,550	365
2017	8,835	12	8,835		223
2018	9,350	13	9,350		236
2019	2,198	3	2,198		55
2020	6,421	9	6,421		162
2021	22,786	20	14,479	8,307	365
2022	11,681	16	11,681		294
2023	7,405	10	7,405		187
2024	7,583	10	7,583		191
2025	16,933	20	14,479	2,454	365
2026	12,671	18	12,671		319
2027	3,226	4	3,226		81
2028	3,221	4	3,221		81
2029	28,076	20	14,479	13,597	365
2030	18,946	20	14,479	4,467	365
2031	14,142	20	14,142		356
2032	19,876	20	14,479	5,397	365
2033	9,352	13	9,352		236
2034	3,929	5	3,929		99
2035	32,350	20	14,479	17,871	365
2036	10,015	14	10,015		252
2037	22,096	20	14,479	7,617	365
2038	16,583	20	14,479	2,104	365
2039	4,494	6	4,494		113
2040	23,413	20	14,479	8,934	365
2041	17,561	20	14,479	3,082	365
2042	24,547	20	14,479	10,068	365
2043	11,725	16	11,725		295
2044	25,597	20	14,479	11,118	365
Total:	416,041		Total water through PRV:	**101,566**	

Source: Stantec

After conducting the feasibility assessment, MWA proceeded to complete final design in April 2017, received interconnection approval in September 2017, and projected to complete construction and receive permission to operate in the last quarter of 2018 (Figure A-16).

Figure A-16: Timeline of the Project Starting from Feasibility Assessment to Operation Startup



Source: Stantec

Permitting and Regulation

California Environmental Quality Act

The California Environmental Quality Act (CEQA) allows a Class 28 Exemption for small hydroelectric projects. Section 15328, titled, "Small Hydroelectric Projects at Existing Facilities". This project qualified for the CEQA exemption. MWA received CEQA exemption in January 2016, as shown in Figure A-16 above.

FERC Qualifying Conduit Facility, Notice of Intent

Under the Federal Power Act (FPA), the Federal Energy Regulatory Commission (FERC) regulates the nation's non-federal hydropower resources. Before August 2013, FERC issues three types of development authorizations: conduit exemptions, five-megawatt (MW) exemptions, and licenses. However, when "Hydropower Regulatory Efficiency Act" was signed in August 2013, there was a significant simplification in small hydropower regulatory processes. One regulation that is especially attractive for small hydropower projects is the elimination of exemption and licensing requirement for hydropower facilities located on non-federally owned conduits with installed capacity of 5 MW or less. The applicant must only file a Notice of Intent (NOI) to Construct a Qualifying Conduit Hydropower Facility with FERC as well as show that the conduit is not used primarily for electricity generation and was not licensed or exempted on and before August 9, 2013. The criteria for a Qualifying Conduit Hydropower Facility is listed in Table A-6.

Table A-6: Criteria for a Qualifying Conduit Hydropower Facility (FERC 2017)

Statutory provision	Description
FPA 30(a)(3)(A), as amended by HREA	The conduit the facility uses is a tunnel, canal, pipeline, aqueduct, flume, ditch, or similar manmade water conveyance that is operated for the distribution of water for agricultural, municipal, or industrial consumption and not primarily for the generation of electricity
FPA 30(a)(3)(C)(i), as amended by HREA	The facility is constructed, operated, or maintained for the generation of electric power and uses for such generation only the hydroelectric potential of a non-federally owned conduit
FPA 30(a)(3)(C)(ii), as amended by HREA	The facility has an installed capacity that does not exceed 5 megawatts
FPA 30(a)(3)(C)(iii), as amended by HREA	On or before August 9, 2013, the facility is not licensed, or exempted from the licensing requirements of Part I of the FPA

Source: Stantec

The NOI process is generally much faster than exemption process, as the facility does not require to hold a public hearing. The NOI process takes around 45 days to complete. The Deep Creek recharge site met all the criteria listed above and the NOI was approved by FERC in June 2016.

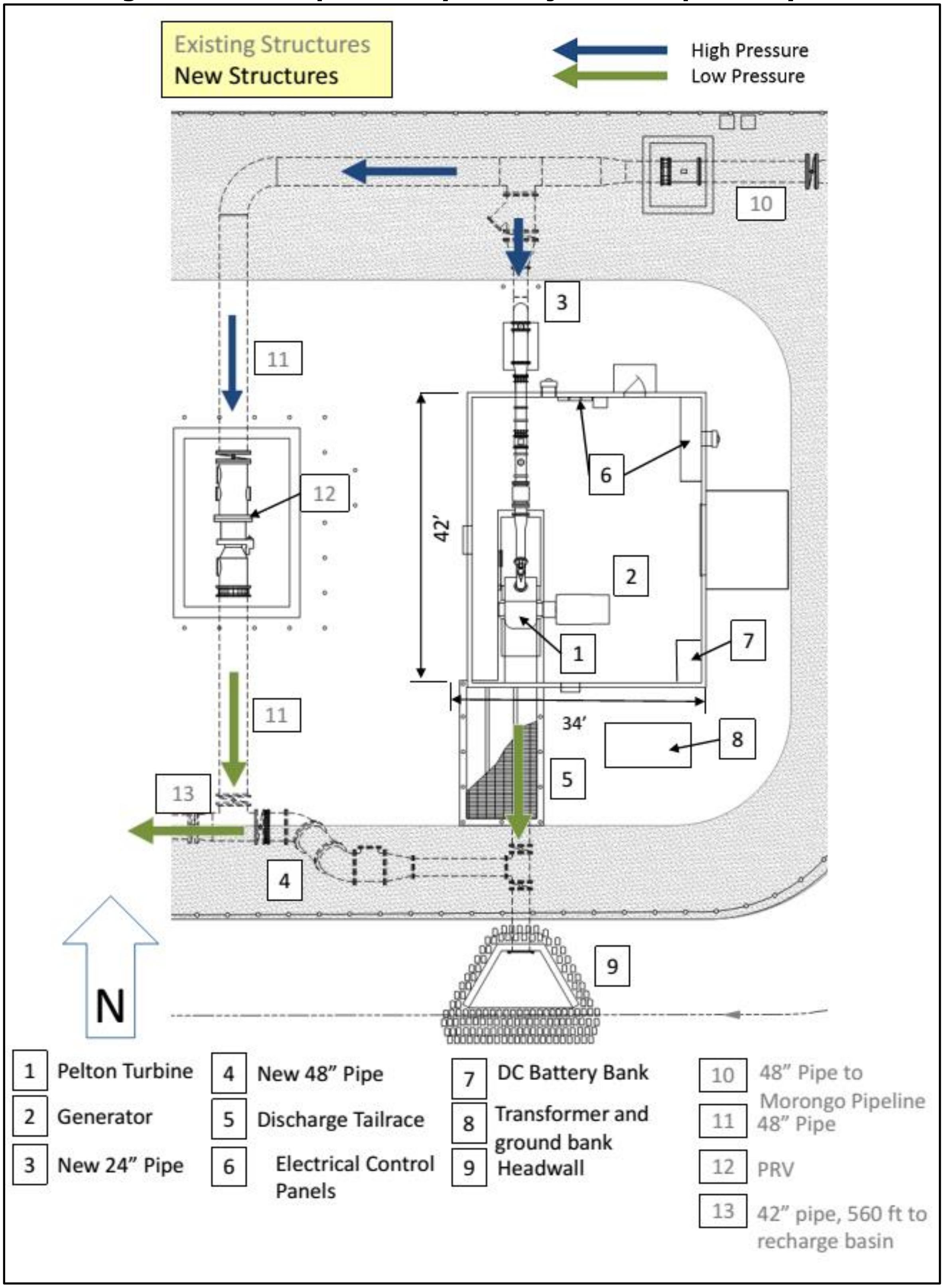
Design and Construction

The Deep Creek hydroelectric station will be located adjacent to the existing PRV and share the 42-inch discharge line to the Mojave River Basin. The 24-inch penstock will connect to the 42-inch Deep Creek pipeline utilizing an existing tee upstream of the PRV. As proposed, the new hydroelectric power station will be in parallel to the existing PRV.

The new powerhouse building will house a single horizontal two-nozzle Pelton turbine, generator, switchgear, and electrical controls in a 42-ft by 34-ft, concrete tilt-up style building. The foundation will be cast-in-place concrete. The tailrace will be cast-in-place concrete.

The powerhouse roof will be equipped with a removable hatch for access to the equipment by mobile crane. A permanent and stationary powerhouse crane is not recommended because of high cost, ongoing certification requirements, permanent structural requirements, and added complexity when expanding the powerhouse to accommodate a second turbine. Once the turbine is in operation, the need to remove the turbine runner or generator will be very infrequent. Therefore, renting a mobile crane will be more cost effective over the life of the project than installing a permanent powerhouse crane. Figure A-17 below shows conceptual profile views of the powerhouse and equipment.

Figure A-17: Deep Creek Hydro Project Conceptual Layout



Source: Stantec

Power equipment shall include the 480V generator, the 480V-rated generator switchgear with redundant relaying protection, 480V main circuit breaker and a 480V load break visible open disconnect switch. A pad mount transformer rated 1,000kVA, 277/480V (wye) 12,000/6,928V (delta) will be located exterior and adjacent to the powerhouse. 600V cables in conduit shall connect the 480V generator switchgear to the pad mount transformer. Other hydro plant power equipment shall include station service transformer and low-voltage panel board, station batteries and charger, and a DC panel board. A 480 V to 120/240V transformer will be included in the control room to provide power for the building (lighting, security alarms, etc.). A battery powered uninterrupted power supply (UPS) will be provided in the PLC to provide power to controls, instrumentation, and SCADA during a disconnection from the Southern California Edison (SCE) grid.

Operations and Maintenance

Groundwater recharge flows at the Deep Creek recharge facility are currently controlled at the PRV vault. The PRV is a 30-inch electronically activated sleeve valve with 48-inch inlet and outlet flanges. Upstream of the PRV there is a 2-inch pressure gauge with an isolation ball valve. Downstream of the PRV water flows through a 42-inch pipeline and is discharged to the Mojave River Recharge Facilities.

Water flow is measured via a 36-inch electromagnetic flow meter located in a vault just upstream of the connection for the proposed hydroelectric project. The meter was installed at the same time as the PRV. (Electromagnetic meters are highly accurate offering a level of accuracy as low as ½ to 1 percent.) Readings from the flow meter and the pressure gauge are sent via direct wiring to the control room. PLC control adjusts the PRV.

The 24-inch penstock to the new power station will be connected directly to the Deep Creek pipeline at the existing 48-inch butterfly valve upstream of the PRV. Flows can be routed to the hydroelectric power station, the PRV, or a combination of partial flows to either one. The system, turbine and PRV, will be able to pass as much as 60 cfs before needing to close the valve between the turbine and the connection with the PRV discharge line.

Typical maintenance of a hydroelectric station includes the following:

- Daily inspections of the hydroelectric station are recommended to detect leaks, excessive moisture buildup, loud noises, excessive vibration and/or heat. Sensors may be used to remotely detect many of these issues to augment physical inspections.
- Quarterly oil inspections / change: bearings, hydraulic systems, and gearboxes require grease or oil. Annual inspection and testing for viscosity, acidity and water content are required, while minimizing different types of oil, if possible. If oil temperatures stay below 60 °C, the oil's useful life is extended dramatically.
- Flow, pressure, and resulting kW production and overall efficiency should be checked periodically and instruments calibrated on regular intervals.
- The first inspection of the turbine itself should be at 12 months or 8,000 hours of operation.
- General inspections should occur every year until a history is established and trends are identified. Then the interval can be extended to two or more years. Similar installations may be good indicators of maintenance trends.
- Annual maintenance costs are assumed to be approximately $10,000 per year.
- Summary of annual maintenance and repair downtime:
    - Assume one week each year,
    - Assume three weeks every five years,

- Three months every 25 years

Costs and Financing

Table A-7 provides an overview of the project financial metrics. This analysis was performed in December 2017 after receiving the Construction bid results. Similar with other utilities, MWA also faced several problems during the process of obtaining necessary permission to operate from SCE. One major hurdle was the requirement to submit information about the generator (capacity and equipment specifications) although the utility had not even gone through the bidding process to physically obtain the generator at that time. During the process, MWA found out that the site would generate more than what was determined initially. However, submitting a change in the energy generation capacity requires the utility to redo the interconnection application process from the beginning, which was time consuming. Thus, MWA decided to size the equipment at smaller capacity in order to avoid additional time loss due to interconnection process.

Table A-7: Overview of the Project Cost Calculated in December 2017

Cost Item	Amount
Estimated Project Costs	$4,684,000
Annual O & M Costs	$10,000
Annual Generation Revenue	$276,000
30-year Net Savings	$8,077,000
30-year NPV	$2,035,000
Payback (years)	15 years

Source: Stantec

Future Planning

As of April 2018, the Deep Creek hydroelectric project is entering the construction phase. The project is expected to start construction in Q2 of 2018 and the project is expected to be completed by the end of 2018. The Deep Creek hydroelectric project is expected to generate more than 6,100,000 kilowatt hours annually or the equivalent of 4,540 metric tons of carbon dioxide or 680 homes electric use for one year.

MWA initially planned to utilize Renewable Market Adjusting Tariff (Re-MAT) program (commonly used by solar energy developers) instead of the Renewable Energy Self-Generation Bill Credit Transfer (RES-BCT) for their energy use. However, as of January 2018, the Re-MAT program was suspended due to a pending lawsuit, thus MWA is currently working to participate in RES-BCT program. Despite having the option to utilize RES-BCT tariff, MWA is still currently looking at all possibilities for local energy use as the recharge site does not consume too much energy. One attractive option that the utility is currently considering is to contribute to Community Choice Aggregation (CCA) which allows small governments and special districts to pool their electricity load.

Lessons Learned and Recommendations

- Groundwater Recharge and turbine sizing: During the course of the analysis, flow projections over a 30-year period were analyzed against historic allocations. MWA staff and NLine Energy conducted multiple models and finally settled on a turbine that would process the vast majority of the expected flows. The turbine sizing also allowed for the unit to act as a peaking resource.
- Flow and Pressure Testing: During the initial design, pressure was not recorded at the site. However, a friction loss model was constructed for the site and a physical flow and pressure test was conducted using calibrated ultrasonic flow and pressure transducers to verify the engineer's initial analysis. Based on this flow and pressure test (Table A-8), the actual readings indicated pressures 3 to 5 percent higher than the engineer's estimate. This new information was transmitted to the turbine manufacturer for fabrication of the runner.

Table A-8: Flow and Pressure Test at The Site

Target Flow Rate (cfs)	Average Flow Rate (cfs)	Average Gage Pressure (psi)	Pressure Head (ft)
10	9.8	231	534
20	19.9	228	527
30	31.4	227	523
40	38.9	217	501
50	49.3	218	502
60	58.5	213	492
70	68.2	208	480
80	78.4	202	465

Source: Stantec

- Expandable Powerhouse: Based on the potential for additional recharge flows in the future, the powerhouse was designed to expand to allow for a second Pelton turbine-generator system at a later date. Civil and electrical considerations included adequate space between the planned powerhouse and the existing PRV, blind flange connections for future piping tie-ins, and additional electrical capacity planning.
- Energy Use: Unlike water treatment plants, the groundwater recharge facility does not consume too much energy. In addition, due to its remote location, it can be challenging for the utility to identify the potential energy use. In the case of MWA, the utility could not identify the nearest facilities (e.g., pump stations, water treatment facility, etc.) that can benefit from the energy generated from this facility through net energy metering aggregation (NEMA). Thus, one attractive option for MWA is to supply energy through Community Choice Aggregation (CCA) which allows small governments and special districts to pool their electricity load.

San Bernardino Valley Municipal Water District (SBVMWD) Case Study Summary

Case Study Participants

- Wen Huang – Manager of Engineering, San Bernardino Valley Municipal Water District
- Mike Esquer – Senior Project Manager, San Bernardino Valley Municipal Water District
- Joanne Chan – Operations Manager, West Valley Water District

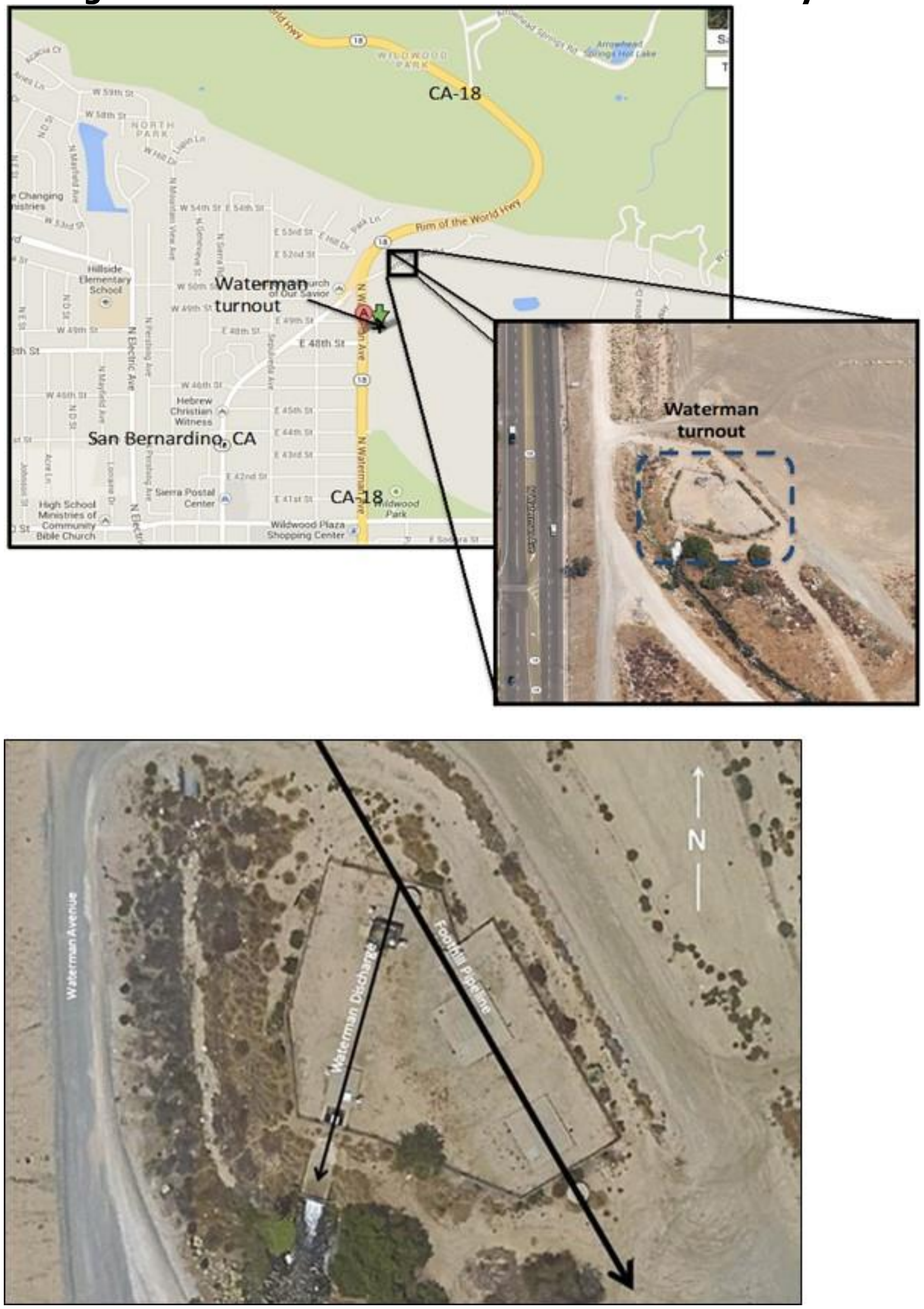
Background

- Site address: 4899 North Waterman Avenue, San Bernardino, CA 92404
- Location of hydropower unit: Waterman turnout to a groundwater recharge basin
- Turbine type: Pelton Turbine Hydro System
- Number of hydropower unit: One unit
- Turbine manufacturer: Gilkes
- Total capacity: 1,059 kW turbine nameplate rating
- Estimated annual power generation: 3,947,000 kWh
- Total project cost: $3,781,000
- Electric provider: Southern California Edison (SCE)
- Energy use: Offset energy consumption
- Billing arrangement: RESBCT
- Project status: Construction bidding

The San Bernardino Valley Municipal Water District ("SBVMWD" or "District") was formed in 1954 as a regional agency to plan a long-range water supply for the San Bernardino Valley, California. The District imports water into its service area through participation in the California Department of Water Resources (DWR), State Water Project (SWP) and manages groundwater storage within its boundaries.

The Waterman turnout provides raw water to a groundwater recharge basin for use by local retail water agencies. The water source for the Waterman Turnout is the 75-inch Foothill Pipeline, which begins at DWR's Devil's Canyon hydroelectric plant after-bay. The distance from the Devil's Canyon after-bay to the Waterman Turnout is approximately 4.1 miles. Just east of the Waterman Turnout, the Foothill pipeline increases to 78-inches in diameter and continues for approximately 11.4 miles. An overview of the site layout is shown below in Figure A-18.

Figure A-18: Waterman Turnout and Facilities Layout



Source: Stantec

The Waterman turnout consists of a 45-degree, 30-inch turnout off of the 75-inch Foothill Pipeline. The 30-inch welded steel pipe is reduced to 24-inch before passing through a motor operated 24-inch Grove rubber seated ball valve that is used as both a guard valve and for flow control. Past the ball valve, the pipeline increases back to 30-inch before entering a venturi tube flow meter. Flow next passes through a 20-inch Howell-Bunger sleeve valve. The Howell-Bunger valve is primarily used for pressure reduction, but it can also be used for both dissipation of energy and flow regulation. The Howell-Bunger valve creates an expanding conical water jet allowing the energy of the water to dissipate over a large area. At the Waterman site, the Howell-Bunger valve discharges into a concrete containment structure to further dissipate energy and prevent erosion where the water flows by gravity into an unlined channel that leads to a groundwater recharge basin. The Waterman hydroelectric station will be located at the existing turnout.

Project Drivers

SBVMWD applied for a FERC conduit exemption for the Waterman Turnout site in 1981 but did not pursue development of the site. In 2013, SBVMWD renewed the feasibility investigation of a hydroelectric generation station located at the Waterman Turnout and groundwater-spreading basin along the Foothill pipeline. A Preliminary Analysis was authorized by the SBVMWD Board on June 18, 2013. In addition, as a water wholesaler, SBVMWD partnered with two of its water retail agencies, East Valley Water District (EVWD) and West Valley Water District (WVWD), to construct hydro projects at EVWD and WVWD sites. These two utilities receive water from State Water Project (SWP) through SBVWMD.

Feasibility Assessment

SBVMWD authorized NLine Energy to develop a feasibility assessment on the potential Waterman hydroelectric project, which was completed in May 2013. Flow projections are largely tied to the SWP percentage allocation to the State Water Contractors on an annual basis. A historic allocation percentage, actual recharge history, and a hydrologic year matrix were created as a modeling tool to forecast future groundwater recharge rates and duration, and subsequent available flows for a hydroelectric unit. 10,000 ac-ft/yr was used for the hydroelectric turbine design (Table A-9).

Available head was calculated based on actual recharge rates, using a friction loss calculation tool. Based on this analysis, that the optimal design flow for the turbine was approximately 28 cfs with net head ranging from 468 ft to 497 ft. NLine Energy analyzed the potential site and determined that multiple technologies were applicable. A two-nozzle horizontal Pelton Turbine was the most appropriate technology for the site conditions, coupled with a synchronous generator. The civil configuration required a rectangular powerhouse that would fit within the confines of the exiting fenced turnout, as to not extend the new facilities beyond the current easement area. Additionally, a 24-inch basket strainer was added to the equipment to screen debris that may be encountered by the Pelton turbine nozzles. A hydraulic transient (surge) analysis was conducted that determined that the flow deflector, needle valves and upstream 24-inch ball valve provided adequate protections to the existing system, as well as the turbine-generator system.

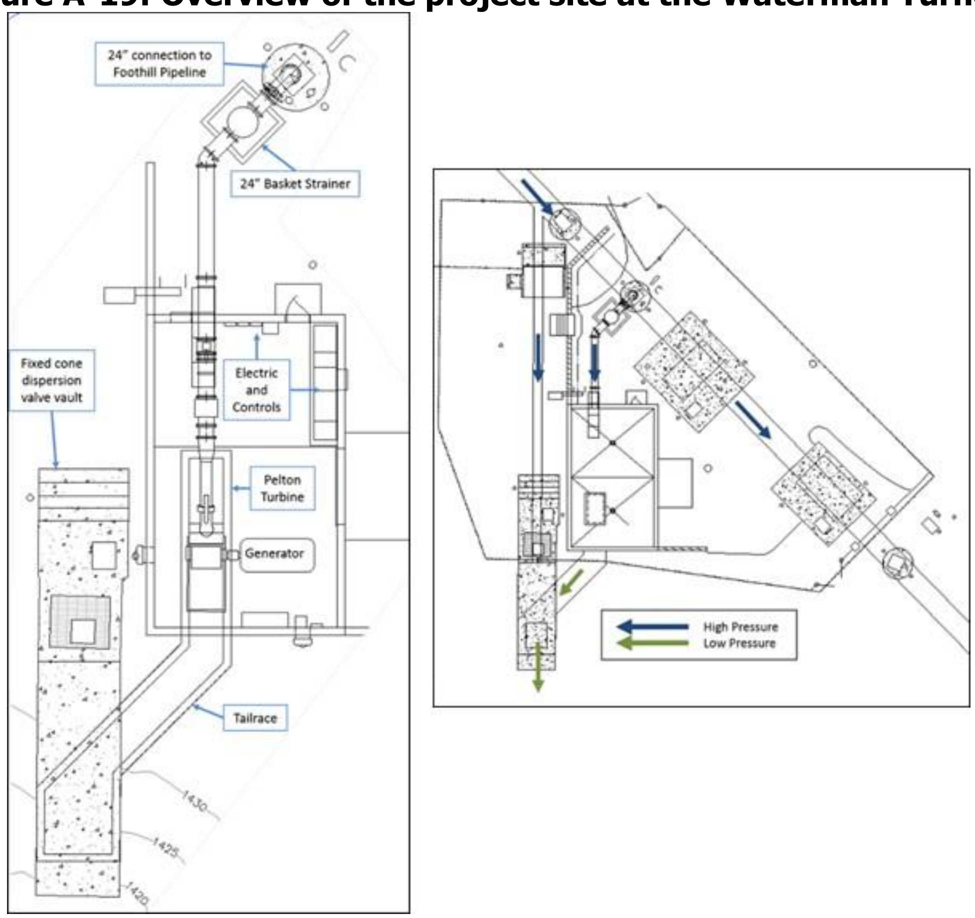
Table A-9: Hydrologic Year & Water Recharge Allocation

Year	Hydrologic year type	Waterman Recharge (Acre-ft)
2013	Dry	7533
2012	Below normal	14089
2011	Wet	10667
2010	Below normal	12499
2009	Dry	9368
2008	Critical	9216
Six-year Average		10562

Source: Stantec

The feasibility assessment determined that the project would cost approximately $3.7M, generate 3,947,000 kilowatt hours annually and have an 11-year payback. Figure A-19 provides an overview of the project site.

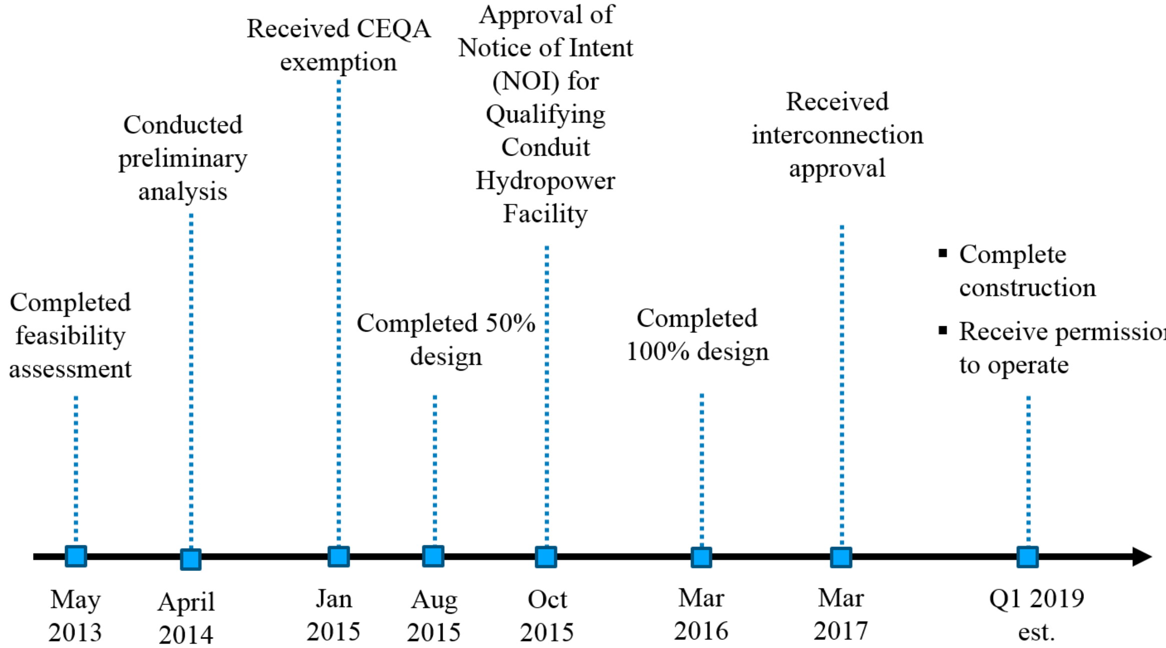
Figure A-19: Overview of the project site at the Waterman Turnout



Source: Stantec

After conducting the feasibility assessment, SBVMWD proceeded to complete final design in March 2016 and received interconnection approval from SCE in March 2017. The project is currently in construction phase and expected to be completed in early 2019. The timeline for this project is presented in Figure A-20 below.

Figure A-20: Timeline of the Project Starting from Feasibility Assessment to Operation Startup



Source: Stantec

Permitting and Regulation

California Environmental Quality Act

The California Environmental Quality Act (CEQA) allows a Class 28 Exemption for small hydroelectric projects. Section 15328, titled, "Small Hydroelectric Projects at Existing Facilities". This project qualified for the CEQA exemption.

FERC Qualifying Conduit Facility, Notice of Intent

Under the Federal Power Act (FPA), the Federal Energy Regulatory Commission (FERC) regulates the nation's non-federal hydropower resources. Before August 2013, FERC issues three types of development authorizations: conduit exemptions, five-megawatt (MW) exemptions, and licenses. However, when "Hydropower Regulatory Efficiency Act" was signed in August 2013, there was a significant simplification in small hydropower regulatory processes. One regulation that is especially attractive for small hydropower projects is the elimination of exemption and licensing requirement for hydropower facilities located on non-federally owned conduits with installed capacity of 5 MW or less. The applicant must only file a Notice of Intent (NOI) to Construct a Qualifying Conduit Hydropower Facility with FERC as well as show that the conduit is not used primarily for electricity generation and was not licensed or exempted on and before August 9, 2013. The criteria for a Qualifying Conduit Hydropower Facility is listed in Table A-10.

Table A-10: Criteria for a Qualifying Conduit Hydropower Facility (FERC 2017)

Statutory provision	Description
FPA 30(a)(3)(A), as amended by HREA	The conduit the facility uses is a tunnel, canal, pipeline, aqueduct, flume, ditch, or similar manmade water conveyance that is operated for the distribution of water for agricultural, municipal, or industrial consumption and not primarily for the generation of electricity
FPA 30(a)(3)(C)(i), as amended by HREA	The facility is constructed, operated, or maintained for the generation of electric power and uses for such generation only the hydroelectric potential of a non-federally owned conduit
FPA 30(a)(3)(C)(ii), as amended by HREA	The facility has an installed capacity that does not exceed 5 megawatts
FPA 30(a)(3)(C)(iii), as amended by HREA	On or before August 9, 2013, the facility is not licensed, or exempted from the licensing requirements of Part I of the FPA

Source: Stantec

The NOI process is generally much faster than exemption process, as the facility does not require to hold a public hearing. The NOI process takes around 45 days to complete. The Waterman Turnout project met all the criteria listed above and the NOI was approved by FERC in October 2015.

Design and Construction

The hydroelectric station will be located adjacent to the existing turnout facilities and share the end of the concrete tailrace structure with the turnout. The 24-inch penstock will connect to the Foothill pipeline utilizing an existing access manway approximately 35-feet downstream from the turnout.

The new powerhouse building will house a single, 2-nozzle Pelton turbine, generator, switchgear, and electrical controls in a 40-ft by 24 ft, concrete tilt-up style building. The roof will be equipped with a removable roof panel for access to the equipment by mobile crane. A stationary powerhouse crane is not recommended for a number of reasons including cost, ongoing certification requirements, and structural requirements. Once the turbine is installed, the need to remove the turbine runner or generator will be very infrequent.

Power equipment shall include the 480V hydroelectric generator, the 480V-rated generator switchgear with redundant relaying protection, 480V main circuit breaker and a 480V load break visible open disconnect switch. A pad mount transformer rated 2,000kVA, 277/480V (wye) 12,000/6,928V (wye) will be located exterior and adjacent to the powerhouse. 600V cables in conduit shall connect the 480V generator switchgear to the pad mount transformer. Other hydro plant power equipment shall include station service transformer and low-voltage panel board, station batteries and charger, and a DC panel board. A 480V to 120/240V transformer will be included in the control room to provide power for the building (lighting, security alarms, etc.). A battery powered uninterrupted power supply (UPS) will be provided in the PLC to provide power to controls, instrumentation, and SCADA during a disconnection from the SCE grid.

Operations and Maintenance

Groundwater recharge flows at the Waterman turnout are controlled by a 24-inch motor operated ball valve. Downstream of the control valve water passes through a flow meter before being discharged through a 20-inch fixed-cone dispersion valve (Howell Bunger valve). The control valve is operated locally at an onsite electrical controls panel.

Since the hydroelectric station's penstock will connect to the Foothill pipeline downstream of the turnout, the turnout and hydroelectric station can be operated independently or in conjunction to supply water for groundwater recharge. A modification to the existing turnout controls has been requested by SBVMWD. Control of the existing turnout control valve and cone valve will be relocated to the new powerhouse.

Typical maintenance of a hydroelectric station includes the following:

- Daily inspections of the hydroelectric station are recommended to detect leaks, excessive moisture buildup, loud noises, excessive vibration and/or heat. Sensors may be used to remotely detect many of these issues to augment physical inspections.
- Quarterly oil inspections / change: bearings, hydraulic systems, and gearboxes require grease or oil. Annual inspection and testing for viscosity, acidity and water content are required, while minimizing different types of oil, if possible. If oil temperatures stay below 60 Celsius, the oil's useful life is extended dramatically.
- Flow, pressure, and resulting kW production and overall efficiency should be checked periodically and instruments calibrated on regular intervals.
- The first inspection of the turbine itself should be at 12 months or 8,000 hours of operation.
- General inspections should occur every year until a history is established and trends are identified. Then the interval can be extended to two or more years. Similar installations may be good indicators of maintenance trends.
- Annual maintenance costs are assumed to be approximately $10,000 per year.
- Summary of annual maintenance and repair downtime:
    - Assume one week each year,
    - Assume three weeks every five years,
    - Three months every 25 years

Costs and Financing

The following table provides an overview of the project financial metrics, which was performed in August 2015.

Table A-11: Overview of the Project Cost Calculated in August 2015 (After 50 Percent Design)

Cost item	Value
Estimated Annual Generation (kWh)	3,440,000
Estimated Project Costs	$3,947,000
Annual O & M Costs	$10,000
Annual Generation Revenue	$360,000
30-year Net Savings	$6,168,000
30-year NPV	$1,928,000
Payback	11 years

Source: Stantec

Future Planning

As of April 2018, the Waterman hydroelectric project is entering the construction phase. The project is expected to start construction in the second half of 2018 and the project is expected to be completed in the first half of 2019. The Waterman hydroelectric project is expected to generate more than 3,947,000 kilowatt hours annually or the equivalent of 2,937 metric tons of carbon dioxide or 440 homes electric use for one year.

Lessons Learned and Recommendation

- Flow Forecasting: Predicting flows at a groundwater recharge site, dependent upon flows from the State can be a challenging exercise as historic recharge rates are not a predictor for the future. In the case of the Waterman project, annual recharge rates were categorized based on hydrologic year type and compared to the State's SWP hydrologic year type for the past 65 years. Additionally, the turbine was sized to process the minimum expected annual recharge rates based on this analysis.
- Site Control: While many municipal agencies control their lands through fee simple ownership, land patents, right-of-way, or permanent easement, additional diligence should be completed in early design phases using boundary survey combined with review of the documents that grant site control. Site control can be a very important, yet overlooked, aspect of the project when filing an interconnection application, as well as environmental filings.
- In-Conduit Debris Strainer: Large, raw-water transmission pipelines rarely provide adequate debris screening when hydroelectric turbine additions at turnouts are considered. Water flows in large diameter transmission pipes rarely reach mobilization velocity for debris that normally settles on the bottom of the pipeline. If this debris is mobilized, it can become lodged in the turbine runner (reaction-style turbine) or needles / nozzles (impulse-style turbine) causing decreased performance or an outage. A debris mobilization analysis can be conducted in the design phase to determine average and maximum flows in the pipe and the probability of debris mobilization. Additionally, designers should interview operations staff to determine the location, type and frequency of debris and any debris management plan (e.g. flushing of the pipe

with high flows using an open valve to purge any debris. In the case of the Waterman project, debris is known to exist in the Foothill pipeline and there is not adequate screening at the afterbay. Based on this information, the design includes a 24-inch pressurized strainer to protect the needle vales on the Pelton turbine system.

San Gabriel Valley Water Company (SGVWC) Case Study Summary

Case Study Participant

Robert DiPrimio – Senior Vice President, San Gabriel Valley Water Company

Background

- Site address: S 14632 Nelson Ave E, La Puente, CA 91744
- Location of hydropower unit: Upstream of the B24 water storage facility
- Turbine type: Pump-as-Turbine
- Number of unit(s): One unit
- Turbine manufacturer: Cornell Pump Company (supplied by Canyon Hydro)
- Total capacity: 73 kW Aggregate Turbine nameplate rating
- Estimated annual power generation: 433,000 kWh
- Total project cost: $1,184,000
- Electric provider: Southern California Edison (SCE)
- Energy use: Offset existing energy
- Billing arrangement: Net Energy Metering
- Project status: In design phase

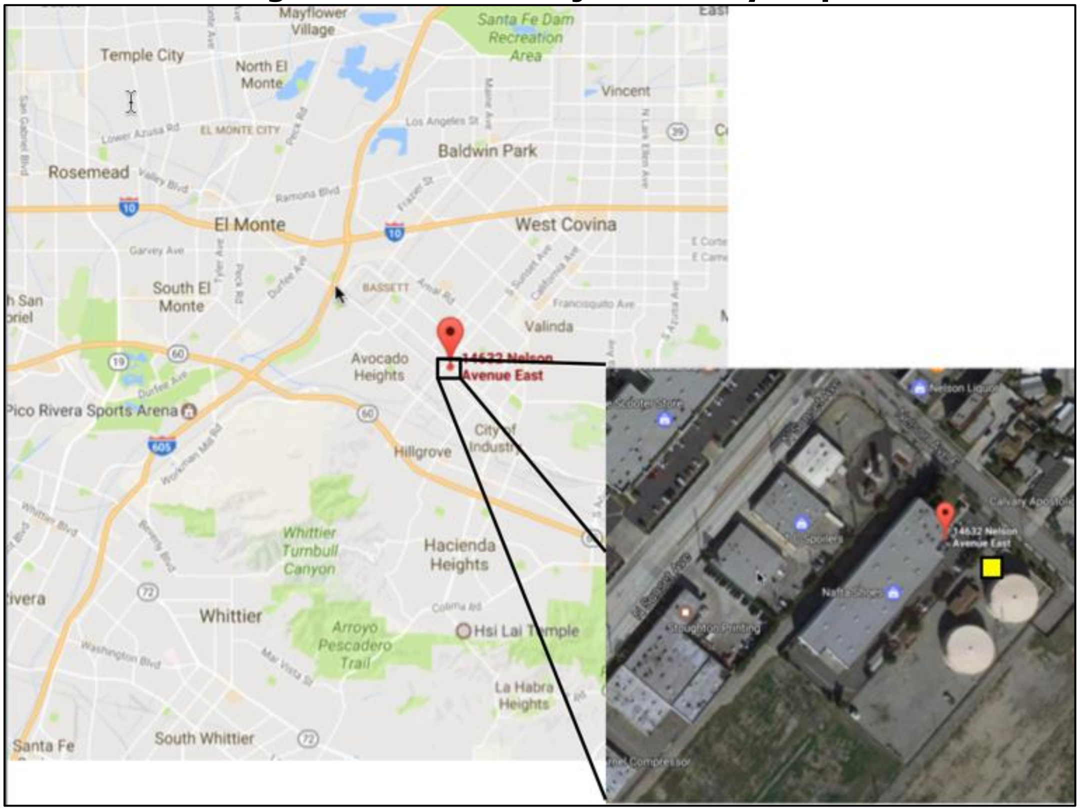
San Gabriel Valley Water Company (SGVWC) is an investor-owned, public utility water company regulated by the CPUC. SGVWC has two operational Divisions: the Los Angeles County division (LAD) and the Fontana Water Company (FWC) division.

The LAD serves a 45 square mile area that includes the communities of Arcadia, Baldwin Park, El Monte, Industry, Irwindale, La Puente, Montebello, Monterey Park, Pico Rivera, Rosemead, San Gabriel, Santa Fe Springs, South El Monte, West Covina, Whittier and unincorporated portions of Los Angeles County, in the communities of Bassett, Hacienda Heights, Los Nietos and South San Gabriel. The FWC serves a 52 square mile area that includes the communities of Fontana, Rialto, Rancho Cucamonga, Ontario, and unincorporated areas of San Bernardino County.

Plant B24 is a water storage facility and pumping station located at 14650 Nelson Ave E, La Puente, CA 91744 (34° 2'9.69" N; 117°58'15.61" W) owned and operated by SGVWC. The site receives potable water from the Reservoir 5 / 6 site, through a water distribution pipeline and breaks pressure using a CLA-Val pressure-reducing valve (PRV) before filling either the B24 or B24A storage tanks rated at 1.5 million-gallon, 30 ft tall each. Potable water is pumped from the storage tanks, via six 150-hp booster pumps to LAD service areas based on demand.

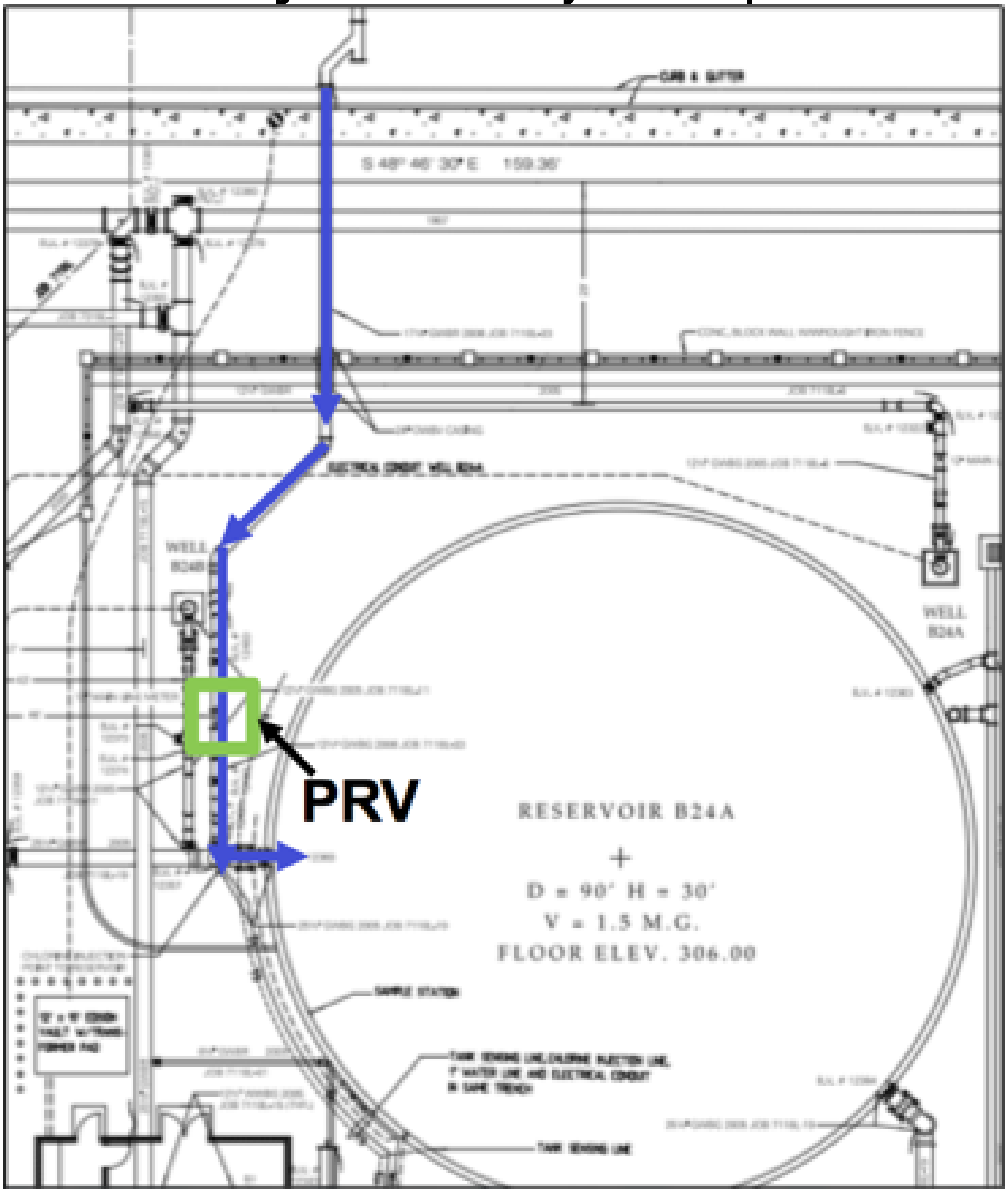
Figure A-21 provides an overview of the site and the yellow box represents the proposed location for the hydroelectric project. Figure A-22 illustrates the location of the current pipe and PRV entering the B24 site that will be utilized in the hydroelectric project

Figure A-21: B24 Project Vicinity Map



Source: Stantec

Figure A-22: B24 Project Site Map



Source: Stantec

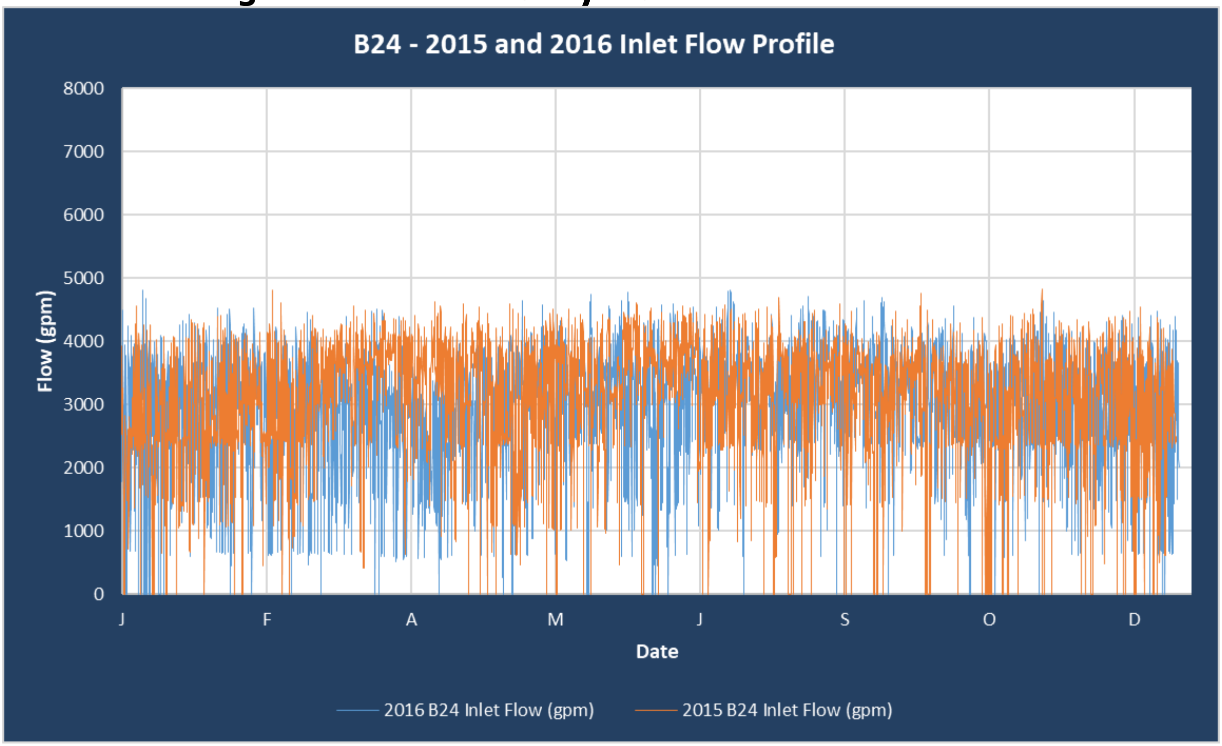
Project Drivers

Prior to this project, SGVWC has successfully installed a conduit hydroelectric system in their Sandhill Water Treatment Plant. The hydroelectric system generates more energy than can be offset at the Sandhill Water Treatment Plant, resulting in an energy net neutral facility. The successful result of the first hydroelectric facility prompted the utility to identify other locations in their service area for another conduit hydropower installation. Although the energy potential is not as significant as the one in Sandhill WTP, the location is still considered to be attractive for energy recovery. With a grant from California Energy Commission's EPIC grant, this location thus serves as a testing site for a small plug-and-play system being developed by NLine Energy.

Feasibility Assessment

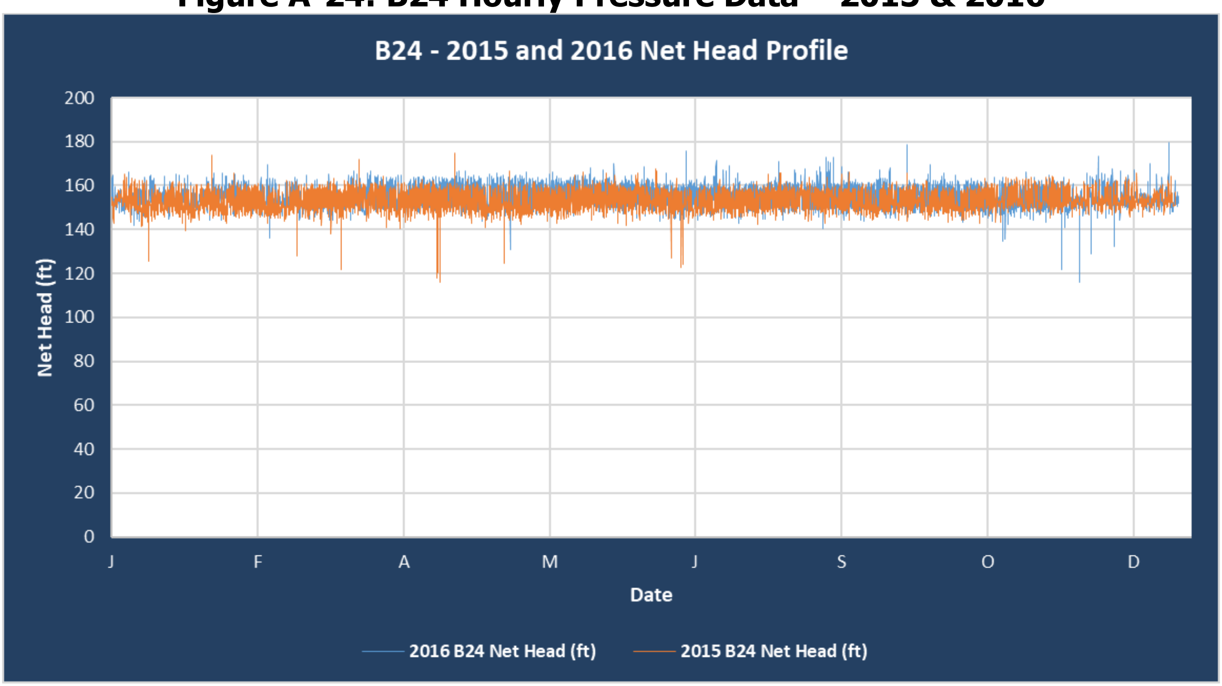
SGVWC authorized NLine Energy to develop a Preliminary Design Report on the potential B24 hydroelectric project, which was completed in Dec 2016. SGVWC provided historical flow and pressure data for 2015 and 2016, which are provided in Figure A-23 and Figure A-24, respectively.

Figure A-23: B24 Hourly Flow Data – 2015 & 2016



Source: Stantec

Figure A-24: B24 Hourly Pressure Data – 2015 & 2016



Source: Stantec

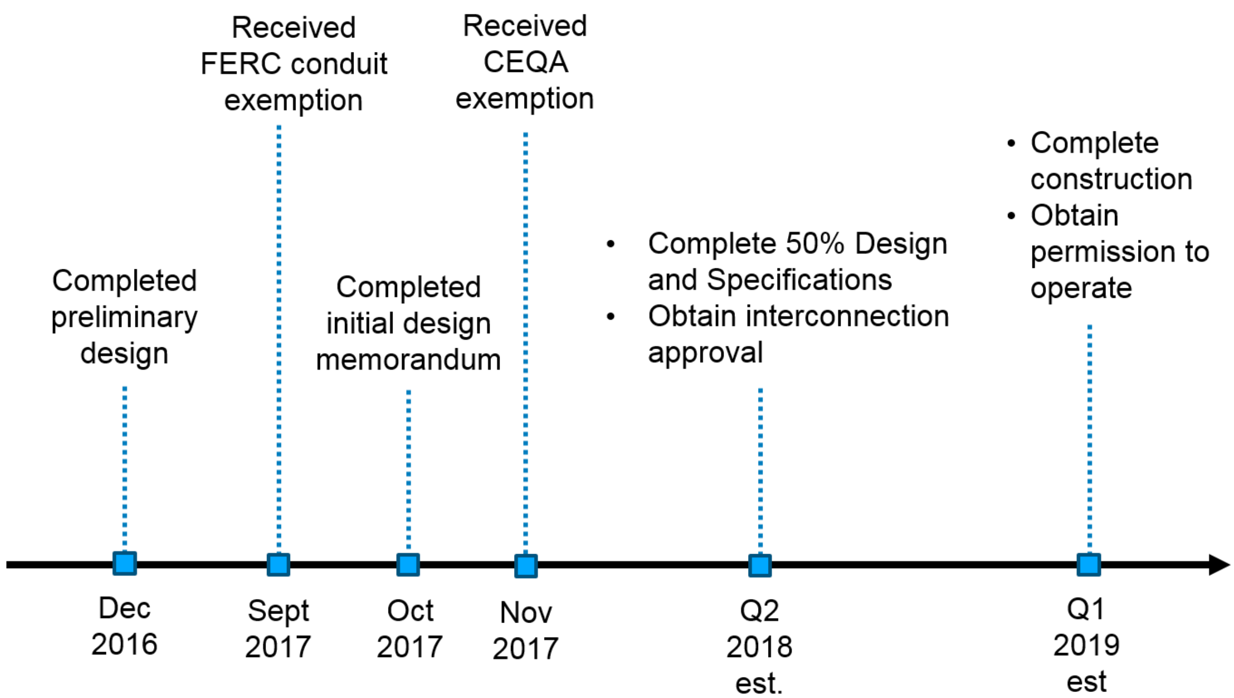
Based on the analysis of the above pressure and flow data, the optimal turbine technology would satisfy the following criteria:

- The B24 inlet flow ranges from 0 to 4,800 gpm. An optimal design would consist of a turbine that can process flows between 1,500 and 4,000 gpm.
- An optimal design would consist of a turbine that can process pressures between 62 psi and 70 psi (145 ft to 160 ft).
- Maintains a residual pressure downstream (reaction-style turbine) of 20 -24 feet.

Based on the requirements determined from the flow and head analysis, a Pump-as-Turbine (PaT) is the most applicable technology for this site. NLine Energy analyzed multiple Cornell pump-as-turbine options and determined that the model 6TR1 was the best technology for this site. The name-plate rating of the turbine is 73 kW and the generator nameplate rating is 93 kW.

The Preliminary Design Report determined that the project would cost approximately $1,184,000, generate 433,000 kilowatt hours annually and have a 10-year payback. SGVWC already obtained approvals from both CEQA and FERC in 2017. By the second quarter of 2018, SGVWC expects to complete the 50 percent design and specifications as well as obtain interconnection approval. The construction is expected to be completed in early 2019. The project timeline is provided in Figure A-25 below.

Figure A-25: Project Timeline for B-24 Hydroelectric Facility



Source: Stantec

Permitting and Regulation

California Environmental Quality Act

The California Environmental Quality Act (CEQA) allows a Class 28 Exemption for small hydroelectric projects. Section 15328, titled, "Small Hydroelectric Projects at Existing Facilities". This project qualified for the CEQA exemption.

FERC Qualifying Conduit Facility, Notice of Intent

Under the Hydropower Regulatory Efficiency Act of 2013, the FERC is required to determine whether proposed projects meet the criteria to be considered "qualifying conduit hydropower facilities." Qualifying conduit hydropower facilities are not required to be licensed or exempted by the FERC; however, any person, State, or municipality proposing to construct a facility that meets the criteria must file a Notice of Intent to Construct a Qualifying Conduit Hydropower Facility with the Commission. A "qualifying conduit hydropower facility" must meet the following provisions:

- A conduit is any tunnel, canal, pipeline, aqueduct, flume, ditch, or similar manmade water conveyance that is operated for the distribution of water for agricultural, municipal, or industrial consumption, and is not primarily for the generation of electricity.
- The facility generates electric power using only the hydroelectric potential of a non-federally owned conduit.
- The facility has an installed capacity that does not exceed 5 megawatts (MW).
- The facility was not licensed or exempted from the licensing requirements of Part I of the FPA on or before August 9, 2013.

Based on this information, the B24 site qualified and completed the Qualifying Conduit Facility, Notice of Intent application process in September 2017.

Design and Construction

As part of the Energy Commission's EPIC grant, the design team has been tasked with researching and modularizing a "plug-and-play" design that can be implemented at multiple sites throughout the country. Research items include pipe size, powerhouse size, a list of turbines that could be implemented based on-site hydraulics, turbine package size, weatherproof standardized set of panels, panel location, valving and meters, pre-casting methodologies, transportation, air flow requirements, and confined space requirements.

The "plug-and-play" concept will feature a piping, turbine/generator, and powerhouse configuration such that the setup can be replicated for future sites. However, unique to each existing site are the existence/location of pressure reducing valves, flow meters, valves, and fittings. Therefore, additional valving or relocation of existing valving pertaining to the hydropower schematic will be positioned outside of the powerhouse, in locations on a site-to-site basis.

The hydroelectric station will be located northwest of the existing B24A tank. Flow from the existing 17-inch pipeline will divert from an above ground tee into a 12-inch pipeline, through the hydroelectric station, and discharge into an underground pipeline that ties in upstream of the B24A tank.

The powerhouse building would be approximately 13-ft by 16-ft and be made of pre-cast concrete. Preliminarily, the wall thickness was assumed to be 18-inches. The wall thickness will likely be less than 18-inches depending on the chosen pre-cast technology. The dimensions inside the powerhouse are approximately 10-ft by 13-ft. The foundation will be comprised of a concrete pad, equipped with continuous spread footings of depth and width of 12-inches per recommendations in the geotechnical report.

To create a smaller powerhouse as part of the “plug-and-play” design, the control valve, flow meter, air relief valve, and panels will be positioned outside. The turbine, generator, and pressure relief assembly will be positioned inside of the powerhouse. The orientation of equipment inside the powerhouse can be rotated on a site-to-site basis to accommodate for different pipe inlet and outlet locations.

The powerhouse will feature flow measurement and all the electrical controls necessary for operation of the hydroelectric station and interconnection protection equipment required for connection to the SCE grid. This will include protective relays within the powerhouse and a transformer and ground bank on the outside of the powerhouse. The new turbine will have an induction generator compliant with the electrical design. There will be a magnetic flow meter and a control valve ahead of the hydroelectric turbine.

The hydro will generate at 480V and ultimately be routed through the existing step-up transformer (480V to 12.47 kV) to the SCE distribution circuit feeding the plant. A new, pad mounted groundbank, approximately 4-ft by 4-ft will be installed adjacent to the site. Key data such as turbine flow, pressure, kW, kWh, voltage, amperage, RPM, vibration, alarms and other information will be routed to on-site controls and recorded.

A set of National Electrical Manufacturers Association (NEMA) 3R rated panels will house the PLC and switchgear. The panels will be positioned outside of the powerhouse to reduce the overall required civil footprint. The new PLC will communicate with the existing PLC inside the pump station via ethernet through a 1-inch PVC underground conduit. Both PLC’s will be integrated into the existing SCADA system. Modifications will need to be made to the existing SCADA software to enable communications from both PLCs. A separate 4-inch conduit will connect the existing switchgear to the new switchgear via three conductors. Additionally, the switchgear will need to tie into the existing main breaker system, which has ample capacity to accommodate for the hydropower system.

The electrical design will also consider the fault current for the utility breakers, emergency power pack sizing calculations, design of the electrical panels, PLC operations, and SCADA vs. operator designed control of the hydroelectric station.

Operations and Maintenance

The hydroelectric station will operate based on flow and pressure supplied from the 17-inch supply line from B5/B6, the demand in Hacienda Heights, and the B24 tank levels. SGVWC has indicated that the future flow profile will include minimal variability on an hourly basis, contrary to current operations. It is anticipated that supply will vary seasonally but consistently produce at least 3,000 gpm. The supply source is relatively constant pressure, ranging from approximately 145 ft to 160 ft of net head for the turbine.

There will be two Cla-Val’s in operation; the existing Cla-Val will be used in the bypass pipeline and a new Cla-Val will be positioned upstream of the 6TR1 to regulate flow/pressure into the turbine. Depending on how much flow is available for operation of the hydroelectric units, the bypass Cla-Val will reduce flow, via a SCADA signal and divert the desired portion of the flow into the hydroelectric station. Flows less than the capacity of the hydroelectric station will be processed through the bypass Cla-Val only. Flows in excess of the hydroelectric station capacity will be divided such that the hydroelectric station will process as much flow as possible, with the remainder proceeding through the Cla-Val.

The PLC will communicate between the hydroelectric station, booster pumps, and the B12 tanks to monitor levels in the B12 tanks and ensure that the hydro is on prior to starting the B24 booster pumps. The existing booster pumps will only be called upon to operate when the hydroelectric station is on or in emergency, in part to minimize large in-rush demand charges. The use of existing soft starters can help the booster pumps slowly ramp up to their fixed operational speed. However, the use of variable frequency drives would allow the booster pumps to operate at various rotational speeds, thereby minimizing startup and shut down as well as keeping the tank levels in B12 consistent by varying the pumping rate based on demands.

The combined flow from the hydroelectric station and bypass will supply the B24 tanks to ensure tank levels are within the safe operating band of 16 to 24 ft. Should the tank levels drop below 16 ft due to B12 demands, the existing on-site wells will be called upon to supplement the B24 tank inflow via the PLC. The on-site wells will shut down once the tank levels have reached a level within the safe operating range.

Typical maintenance of a hydroelectric station includes the following:

- Daily inspections of the hydroelectric station are recommended to detect leaks, excessive moisture buildup, loud noises, excessive vibration and/or heat. Sensors may be used to remotely detect many of these issues to augment physical inspections.
- Quarterly oil inspections / change: bearings, hydraulic systems, and gearboxes require grease or oil. Annual inspection and testing for viscosity, acidity and water content are required, while minimizing different types of oil, if possible. If oil temperatures stay below 60 Celsius, the oil's useful life is extended dramatically.
- Flow, pressure, and resulting kW production and overall efficiency should be checked periodically and instruments calibrated on regular intervals.
- The first inspection of the turbine itself should be at 12 months or 8,000 hours of operation.
- General inspections should occur every year until a history is established and trends are identified. Then the interval can be extended to two or more years. Similar installations may be good indicators of maintenance trends.
- Annual maintenance costs are assumed to be approximately $3,000 per year.
- Summary of annual maintenance and repair downtime:
    - Assume one week each year,
    - Assume three weeks every five years,
    - Three months every 25 years

Costs and Financing

Table A-12 provides an overview of the project financial metrics. This analysis was performed in December 2017 after completing the Preliminary Design.

Table A-12: Overview of Estimated Project Cost

Cost Item	Value
Estimated Annual Generation (kWh)	433,000
Estimated Project Costs	$1,186,000
State Grants (EPIC & SGIP)	$560,000
Net Project Cost	$626,000
Annual O & M Costs	$3,000
Annual Generation Revenue	$48,000
30-year Net Savings	$2,370,00
30-year NPV	$965,000
Payback	10 years

Source: Stantec

Future Planning

As previously mentioned, this project is partially funded by the Energy Commission's EPIC grant. The project success will be considered based on achieving the following goals:

- Design a "plug and play" low-cost, in-conduit hydroelectric package that addresses the sub 100-kW market.
- Demonstrate improved efficiency and performance to maximize the capture of wasted energy in water supply networks.
- Demonstrate the long-term operational capacity of an in-conduit turbine/generator system to provide renewable energy for the state-energy mix.
- Demonstrate qualitative and quantitative benefits to California IOU electric ratepayers, including societal benefits, reduction of energy costs and greenhouse gas emissions mitigation and efficient use of ratepayer money.
- Validate the methodology, tools and technology implementation to expand the use of hydropower in California for the sub 100-kW market and help achieve the state's renewable energy initiatives and improve the understanding of the grid benefits.
- Develop a plan to provide the lessons learned and results to the public and key decision makers.

As of April 2018, the B24 hydroelectric project is in the Design Phase. The project is expected to start construction in Q4 of 2018 and the project is expected to be completed in Q1 2019. The B24 hydroelectric project is expected to generate more than 433,000 kilowatt hours annually or the equivalent of 322 metric tons of carbon dioxide or 48 homes electric use for one year.

Lessons Learned and Recommendations

- Plug & Play Design: The intent of this project is to design, develop and demonstrate a modular in-conduit hydropower system to provide a cost-effective solution that can be deployed in the hundreds of potential sub-100 kW, in-conduit sites throughout California – significantly expanding the use of hydropower and helping achieve the state's renewable energy initiatives, including AB 32 and SB 350.

San Gabriel Valley Water Company (SGVWC) – Sandhill Case Study Summary

Case Study Participants

- Robert DiPrimio – Senior Vice President, San Gabriel Valley Water Company
- Seth Zielke – General Superintendent, Fontana Water Company
- Chris Hamilton – Water Treatment Superintendent, Fontana Water Company

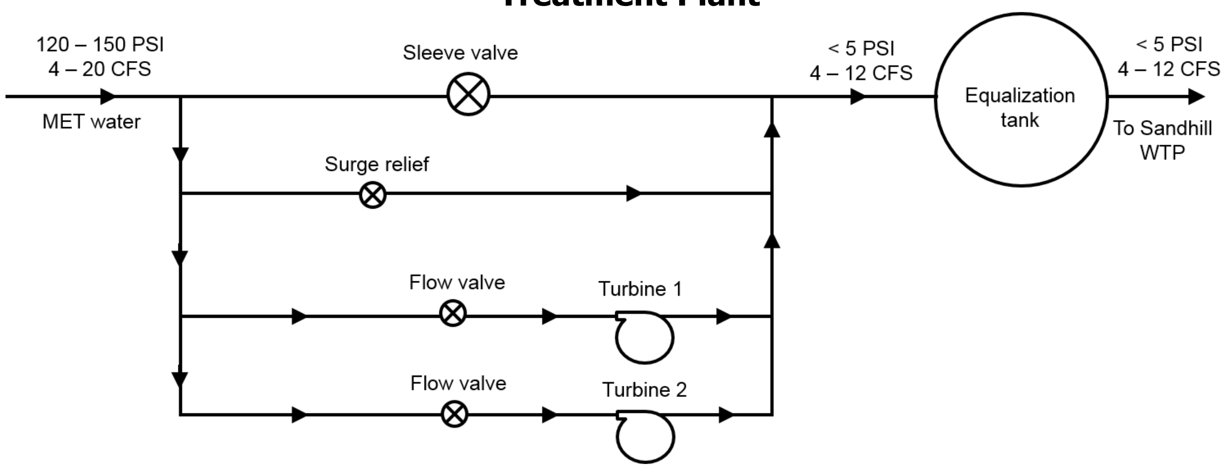
Background

- Site address: Sandhill Water Treatment Plant - 1482 West Summit Avenue, Rialto, CA
- Location of hydropower unit: Upstream of Sandhill Water Treatment Plant
- Turbine type: Pump-as-Turbine
- Number of unit(s): Two units (Lead unit @ 1800 gpm max, lag unit @ 3600 gpm max)
- Turbine manufacturer: Cornell Pump Company (supplied by Canyon Hydro)
- Total capacity: 310 kW Aggregate Turbine nameplate rating
- Estimated annual power generation: 1,000,000 kWh
- Total project cost: $1.936,000 (April 2014)
- Electric provider: Southern California Edison
- Energy use: Export to the grid
- Billing arrangement: Net energy metering (NEM)
- Project status: In operation

San Gabriel Valley Water Company (SGVWC) is an investor owned public utility water company regulated by the California Public Utilities Commission (CPUC). SGVWC has two operational divisions: the Los Angeles County division (LAD) and the Fontana Water Company (FWC) division. The FWC serves a 52 square mile area that includes the communities of Fontana, Rialto, Rancho Cucamonga, Ontario, and unincorporated areas of San Bernardino County. FWC has the flexibility to receive water from both groundwater, local surface water, and imported State Water Project (SWP) water supplies. Ground water supplies include Chino Basin, Rialto Basin, Lytle Creek Basin, and No Man's Land Basin. Local surface water supplies and SWP supplies are treated at the Sandhill Water Treatment Plant (Sandhill) and come either from Lytle Creek or the SWP. SWP supplies are purchased by FWC from either Inland Empire Utilities Agency (IEUA) or San Bernardino Valley Municipal Water District (SBVMWD). IEUA purchases SWP water from the Metropolitan Water District (MWD) for wholesale redistribution to a number of water purveyors, including FWC.

The IEUA supply pipeline (capacity up to 40 cubic feet per second1) enters Sandhill at approximately 120 - 150 PSI through an on-site pressure reducing station (PRS). A sleeve valve is used as pressure reducing valve (PRV) to reduce the pressure to 5 psi. Flow rates are manually adjusted and selected by operations personnel ranging from 4 cfs to 13 cfs. The hydropower station is installed in parallel with the sleeve valve to harness the excess energy. The schematic flow diagram of the hydroelectric station is presented in Figure A-26 below. The hydropower station consists of two pump-as-turbine (PAT) units with total capacity of 310 kW (one operates at 1800 gpm, and the other at 3600 gpm). All the generated energy is exported to the grid and FWC receives credit based on the energy consumption in Sandhill WTP at the same tariff as what they would have paid. As of February 2018, the annual power generation was about 1,121,087 kWh, which was used to offset power in the facility (606,808 kWh). FWC received about $12,000 from the Southern California Edison (SCE) for the excess energy generated (514,279 kWh).

Figure A-26: Schematic Flow Diagram of the Hydroelectric unit at Sandhill Water Treatment Plant



Source: Stantec

Project Drivers

SGVWC has long recognized the large energy potential embedded in their systems, which could be used to offset the energy in their facilities. From the public policy perspectives, there were also initiatives from the California Public Utility Commission to direct utilities to gain better understanding of the water-energy nexus in their systems. In the proceedings, utilities were recommended to estimate the potential embedded energy in their water distribution systems and identify the potential use of this excess energy. SGVWC considered this concept to be attractive as any saving that the facility achieves can indirectly impact customers through lower water bill. After discussion with the board, SGVWC decided to contract with NLine Energy to assist with the development of hydropower station at one of the facilities. NLine Energy also assisted SGVWC in securing some of the funding, which was one of the most important factors in the advancement of this project. SGVWC received a cash grant from U.S. Treasury (1603 U.S. Treasury Grant) which covered 30 percent of the total project cost

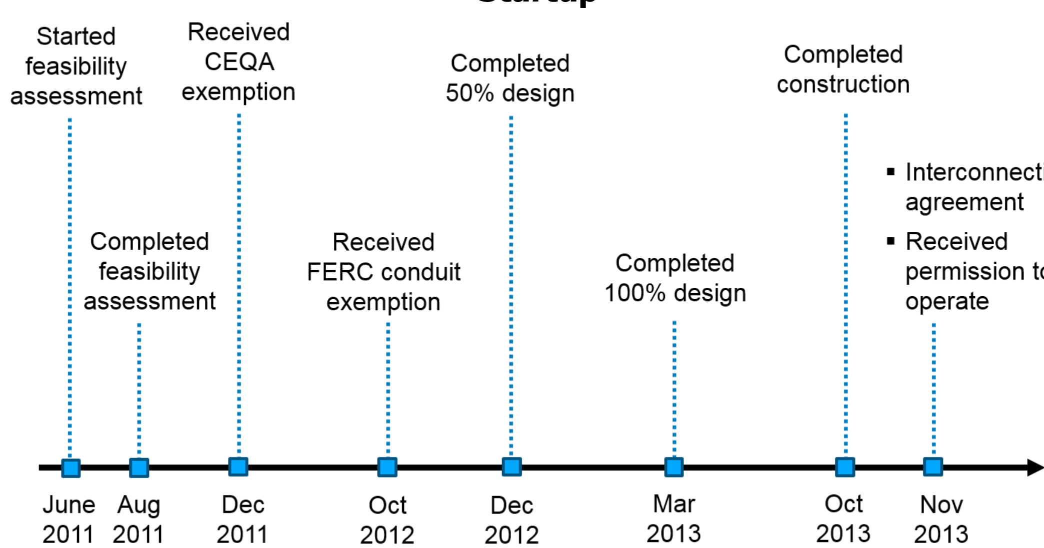
[1] Fontana Water Company 2010 Urban Water Management Plan

for eligible renewable energy projects as well as incentives from Self-Generation Incentive Program (SGIO) sponsored by CPUC.

Feasibility Assessment

SGVWC conducted initial feasibility assessment of the potential project between June and August 2011 (see for project timeline) and identified three alternative locations within SGVWC systems: F13, F14 (Sandhill), and F19. Initial assessment showed that location F14 in Sandhill Water Treatment Plant (managed by FWC) to be the most economically feasible site due to its large pressure differential (breaking 120 – 150 psi to 10 psi). There was also negligible change in the flow rate in this particular pipeline during 24/7 operation (4 – 13 cfs, but generally stays around 10 cfs). Based on these conditions, two types of turbines were proposed: Pump-as-Turbine (PAT) and Francis turbine. For Francis turbine, flow can be varied to accommodate supply or demand variations but at the expense of reduced efficiency and power generation. A Francis turbine also becomes unstable below 40 percent of full flow and does not operate well at less than 40 percent of full electrical load. Thus, it was determined that installation of two Pump-as-Turbines (PAT) would be most suitable for the site. The twin PATs operate in both sequence and parallel, enabling the system to process flows ranging from 4 cfs to 13 cfs with a system nameplate rating of 310 kW. The feasibility assessment determined if the project was feasible from an economic, environmental, technical and regulatory perspective. This preliminarily assessment took approximately 3 months to finish and determined that the initial project cost was approximately $1,400,000, would generate approximately 1,000,000 kilowatt hours annually and would have a sub 10-year payback. It is also important to note that these estimations were made based on the assumption that the IEUA's water uptake capacity was 5000 acre-feet/year which would be taken over a period of approximately seven to nine months, depending on hydrology and water demand. After conducting the feasibility assessment, FWC proceeded to complete 100 percent design in March 2013, and finally received the permission to operate in November 2013. It took approximately 2 years to complete the project, as depicted by Figure A-27 below.

Figure A-27: Timeline of Project Starting from Feasibility Assessment to Operation Startup



Source: Stantec

Permitting and Regulation

California Environmental Quality Act

The California Environmental Quality Act (CEQA) allows a Class 28 Exemption for small hydroelectric projects. Section 15328, titled, "Small Hydroelectric Projects at Existing Facilities". This project meets most of the physical requirements for a Categorical Exemption (CE), however further assessment of the system was conducted to determine if: (i) the project will not entail any construction on or alteration of a site included in or eligible for inclusion in the National Register of Historic Places and (ii) any construction will not occur in the vicinity of any rare or endangered species. To address these issues, SGVWC obtained biological and historical databases including;

- California Natural Diversity Database (California Department of Fish & Game)
- Biological databases of the U.S. Fish and Wildlife Service
- Historic Resources Record Searches

Through assessment of these databases, SGVWC provided full evidence that that its system was eligible for CEQA exemption and Notice of Exemption (NOE) was submitted to the Lead Agency (City of Rialto, California). CEQA exemption was obtained in December 2011, as depicted in the project timeline above.

FERC Conduit Exemption

Under the Federal Power Act (FPA), Federal Energy Regulatory Commission (FERC) regulates the nation's non-federal hydropower resources. As of 2012, FERC issued three types of development authorizations: conduit exemptions, five-megawatt (MW) exemptions, and licenses. In order to qualify for a conduit exemption (less than 40 MW), the following criteria must be met:

- The hydro generator must be installed on a conduit constructed primarily for non-hydropower purpose;
- It must be located on a conduit used for agricultural, municipal, or industrial consumption; and
- The applicant must own the proposed powerhouse and the lands upon which the powerhouse will be located.

The FERC conduit exemption was issued in perpetuity, and projects up to 5 MW were not charged an annual fee. This project qualified and secured the FERC conduit exemption in October 2012. Note that at this time FERC had not simplified its regulation processes for small hydropower projects as the "Hydropower Regulatory Efficiency Act" was only signed in August 2013. This project could have been eligible as Qualifying Conduit Hydropower Facility, which is not required to obtain license or exemption from FERC. Eligible facilities must only file a Notice of Intent (NOI), thus the process is significantly faster (about 45 days) than exemption or licensing processes.

Design and Construction

NLine Energy provided the design of the powerhouse as well as technical expertise throughout the entire project. However, FWC utilized service from the same contractor that built the water treatment plant (RC Foster) during construction. Using the same contractor was considered to be beneficial for a retrofit project as the contractor was already familiar with the existing system.

The hydroelectric station was constructed parallel to the existing sleeve valve adjacent to and south of the existing vault structure (refer to Figure A-28). The existing 30-inch tees (MWD water pipe) remains in their current location and new pipe connects to the existing tees and extend through the vault walls utilizing the cutouts already existing in the vault wall. The new hydroelectric station is supported on a new concrete slab and is housed in a pre-fabricated metal building approximately 24-feet by 20-feet in dimension. Flow is diverted upstream of the sleeve valve to the intake side of the hydroelectric station. Upon exiting the hydroelectric station, piping reconnects downstream of the sleeve valve at the existing 30-inch tee. Flow is measured utilizing the existing flow meter. Supply in excess of optimum flows through the existing sleeve valve. A surge relief valve is also available to protect from excess pressure that might damage the turbines. A building housing the units was constructed for sound attenuation as the turbine-generator was designed for indoor exposure only. The switchgear is also housed inside the turbine-generator building. Re-grading of the site outside the vault structure was necessary.

Since the hydroelectric station was constructed upstream of the water treatment plant, the design flow and pressure for the turbines were determined based on downstream WTP requirements. During the design stage, FWC also specified that 5,000 acre-ft of water from IEUA would be taken over 12-month period. Based on this information, 4 – 12 cfs was determined as the range of design flows that would allow FWC to achieve the 5,000 ac-ft goal, assuming the differential pressure of 130 psi. In order to allow for flow selection flexibility, two PATs were selected. The lead PAT can pass approximately 4 cfs (1800 gpm max) and the lag PAT can pass approximately 8 cfs (3600 gpm max). Both PATs operating together are expected to process up to 12 cfs and produce 310 kW maximum for the hydroelectric station. Photographs of the twin PAT units during construction and operation are provided in Figure A-28.

Figure A-28: Photographs of Hydroelectric Units during Construction (Left Image) and Operation (Right Image)

Source: Stantec

Since the power generated was planned to be exported to the grid, construction pertaining to interconnection with existing utility service connection was also conducted. Since this facility is the first small hydropower facility in the last 20 years to connect with Southern California

Edison (SCE) lines, a new pole with an upgraded reclosers to protect the grid was installed at the facility. FWC was also required to expand the power service to 12 kV powerline.

Operations and Maintenance

The hydroelectric station operates based on flow and pressure supplied from the IEUA pipeline. FWC Operations personnel will determine how much flow is required from the IEUA supply line and manually set the flow as their normal practice. The IEUA source has relatively constant pressure, ranging from approximately 120 psi to 150 psi. This stable pressure in addition to the fact that FWC can set a constant flow greatly increases the operational controls for the turbines, which therefore increases efficiency and simplifies operation. The FWC operators determine their desired flow to Sandhill and set the flow coming into the Pressure Reducing Station and the sleeve valve will operate as normal. Depending on how much flow is desired for operation of the hydroelectric units, the sleeve valve will reduce flow, via a SCADA signal and divert the desired portion of the flow into the hydroelectric station. Flows less than the capacity of the hydroelectric station will be processed through the sleeve valve only. Flows in excess of the hydroelectric station capacity will be divided such that the hydroelectric station will process as much flow as possible, with the remainder proceed through the sleeve valve. Control valves to each hydroelectric unit control on/off operation of the hydroelectric units. Control logic is programmed to select flow to each hydroelectric unit with flow trim being accomplished by the existing sleeve valve.

The two turbine-generator units are controlled through a Programmable Logic Controller (PLC) that engages one or both units depending on the flow and head available for maximum efficiency. An rpm tachometer monitors for speed and once it is close to the utility frequency (approximately 1,800 rpm and 60 Hertz (Hz)), the tachometer allows the close of the motor contactor. The turbine control valve continues to open and load the generator until at maximum flow and load. Once a generating unit(s) is on line, an rpm tachometer will monitor for speed and frequency. The turbine control valve will continue to open and load the generator until at maximum flow and load.

Typical maintenance of a hydroelectric station includes the following:

- Daily inspections of the hydroelectric station are recommended to detect leaks, excessive moisture buildup, loud noises, excessive vibration and/or heat. Sensors may be used to remotely detect many of these issues to augment physical inspections.
- Quarterly oil inspections / change: bearings, hydraulic systems, and gearboxes require grease or oil. Annual inspection and testing for viscosity, acidity and water content are required, while minimizing different types of oil, if possible. If oil temperatures stay below 60˚C, the oil's useful life is extended dramatically.
- Flow, pressure, and resulting kW production and overall efficiency should be checked periodically and instruments calibrated on regular intervals.
- The first inspection of the turbine itself should be at 12 months or 8,000 hours of operation.
- General inspections should occur every year until a history is established and trends are identified. Then the interval can be extended to two or more years. Similar installations may be good indicators of maintenance trends.
- Annual maintenance costs are assumed to be approximately $6,000 per year.

- Summary of annual maintenance and repair downtime:
    - Assume one week each year
    - Assume three weeks every five years
    - Three months every 25 years

Costs and Financing

An overview of the project cost estimated at two different times (50 percent design and nearing completion) is provided in Table A-13 below. During 50 percent design, the project cost was estimated to be around $1,675,000 with calculated payback time of 8.4 years. However, as can be seen, the total project cost increased by $261,000 over the course of 1.5 years during construction. One major cause of this cost increase was the unexpectedly high interconnection cost with the SCE as a new pole with upgraded reclosers must be installed.

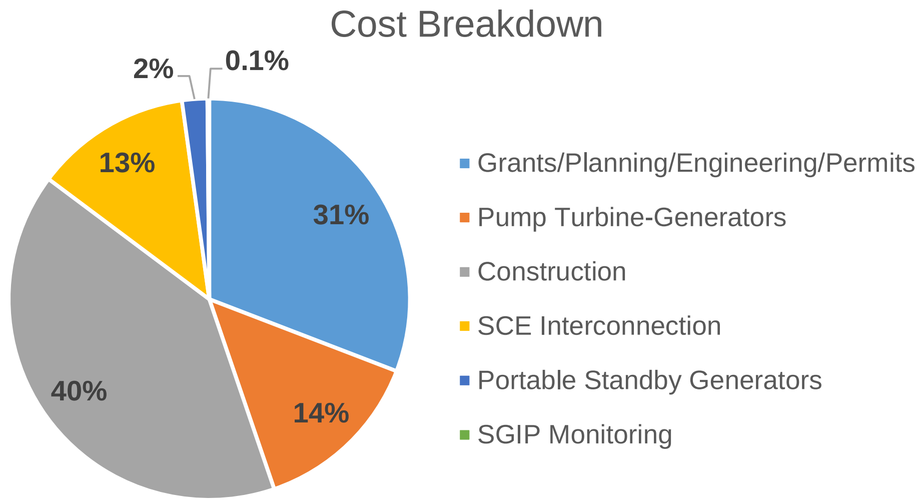
The breakdown of the project cost as of April 2014 is also provided in Figure A-29 below. As can be seen, construction was the major contributor to the total cost (40 percent) followed by engineering, planning, and permitting (31 percent). Interconnection cost was also considered to be significant in this case (13 percent) due to the need to update the outdated equipment owned by SCE and the fact that this project was one of the first small hydropower projects that interconnected with SCE in the last 20 years. The turbine-generator cost was not considered to be major as PATs are generally less expensive than other similar turbines such as Francis turbines.

Table A-13: Overview of the Project Cost Calculated in December 2012 (50 Percent Design) and April 2014 (Nearing Completion)

Cost item	Cost December 2012	Cost April 2014
Total Project Cost	$1,675,000	$1.936,000
Federal Business Investment Grant (U.S. Treasury Grant)	$462,467	$462,467
Self-generation Incentive Program (SGIP)	$320,290	$320,290
Net Investment	$892,243	$1,153,243

Source: Stantec

Figure A-29: Breakdown of Project Cost as of April 2014



Source: Stantec

Future Planning

The Sandhill hydroelectric project has been operating for over four years and has met the initial estimations and expectations for the project, yielding no electric bill for the four years since commissioning using the Net Energy Metering tariff. As previously mentioned, FWC even received a $12,000 check from SCE as the facility has been generating excess energy. However, the tariff used for this excess energy is generally quite small and not attractive for small utilities that are looking to sell their energy.

The project's success has led SGVWC to embark on another in-conduit hydroelectric project. The new project, named B24 Hydro Project, will implement an innovative "Plug & Play" design for a 73-kW pump-as-turbine. It should be noted that the B24 project is being partially funded by California Energy Commission's (the Energy Commission) EPIC Grant.

Lessons Learned and Recommendations

- Scenario planning: During the feasibility assessment, the Sandhill plant has the ability to source water at different times of the year, which provided an opportunity to size the hydroelectric station for year-round, summer, and peaking scenarios. Summer and peaking scenarios aligned with the high time-of-use electric tariff rates that are normally charged to a customer for consumption of electricity during high-use times (peak demand hours). However, when a hydroelectric station is installed, the generation is credited at these high rates under California's Net-Energy Metering rules. Small conduit hydroelectric projects should consider multiple scenarios at the feasibility stage to investigate these opportunities.
- Contractor for construction: FWC utilized the same service from the contractor that built the Sandhill WTP during the construction of the powerhouse. This is a useful strategy for a retrofit project as the contractor is already familiar with the existing system, thus minimizing any confusion and error that can occur during the construction period.

- Pump-as-Turbine technology: PATs are essentially pumps in reverse. Rather than pump water, the runners are manipulated towards energy recovery, which closely resembles a Francis-style turbine. PATs are fixed geometry units and lack any type of wicket gates that a typical Francis-style turbine would possesses. While PAT's have narrowly defined head-flow operating curves, there are multiple versions that can be combined to manipulate a majority of the site flows without sacrificing potential generation. PATs are also one-third to one-quarter the total cost of a single Francis turbine, which opens up a sub-500 kW conduit hydroelectric market in the U.S. for this technology.
- Use of flow control valves upstream of the PATs: The contractor designed and integrated control valves upstream of the turbine, which allowed flows and heads to be manipulated to maintain high-efficiency on the PAT, while also ensuring consistent generation throughout subtle variations in flow that would have shut down the PAT without the use of the valves. This additional equipment increases generations, extends the life of the equipment and decreases O&M costs.
- Interconnection: The Sandhill hydroelectric project was one the first hydroelectric stations to interconnect to the Southern California Edison (SCE) distribution grid in over 20 years. Since hydroelectric turbines are rotating equipment (non-inverter) technologies providing reactive power to the grid, additional protective equipment is required as part of California's Rule 21 interconnection standards. Throughout the interconnection process, SCE's review and design process was elongated over 18 months given lack of staff awareness, fluency in reactive power equipment, and poor project management. While the project commissioning was slightly delayed, this project served as a case study for SCE and other investor-owned utilities to improve their knowledge and processing of small hydroelectric project interconnection applications.

Sweetwater Authority (SA) Case Study Summary

Case Study Participants

- Tish Berge, General Manager, Sweetwater Authority
- Mike Wallace, Engineering Manager, Sweetwater Authority
- Ron Mosher, Director of Engineering, Sweetwater Authority
- Peter Baranov, Director of Water Quality, Sweetwater Authority
- Justin Brazil, Water Treatment Superintendent, Sweetwater Authority

Background

- Site address: Sweetwater Dam .1 NW D, Spring Valley, CA 91977
- Location of hydropower unit: Upstream of Perdue Water Treatment Plant
- Turbine type: Pump-as-Turbine
- Number of hydropower unit: Two units (Lead unit @ 11 cfs, lag unit @ 18 cfs)
- Turbine manufacturer: Cornell Pump Company (supplied by Canyon Hydro)
- Total capacity: 580 kW Aggregate Turbine nameplate rating

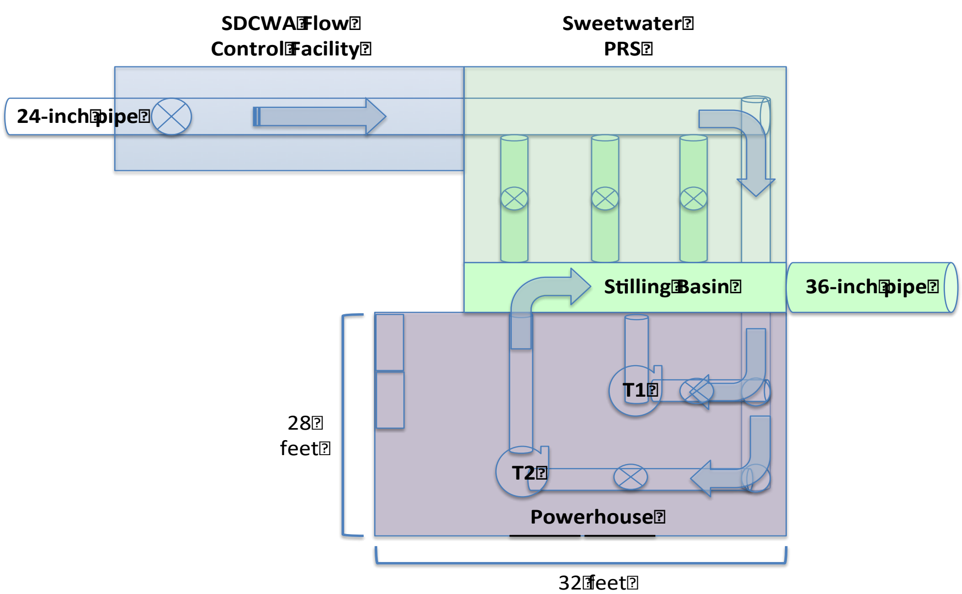
- Estimated annual power generation: 3,440,000 kWh
- Total project cost: $2,800,000
- Electric provider: San Diego Gas & Electric (SDG&E)
- Energy use: Export to the grid
- Billing arrangement: Net energy metering (NEM)
- Project status: In operation

Sweetwater Authority (SA) typically produces 21,000 acre-feet per year (acre-ft/yr) of potable water from various sources: National City Wells, the Richard A. Reynolds Groundwater Desalination Facility (Desal Facility), and the Perdue Plant. Sweetwater operates the National City Wells, which produce potable groundwater. The National City Wells consist of three wells: Nos. 2, 3, and 4, which produce approximately 2,000 acre-ft/yr.

The Perdue Plant is located adjacent to the Sweetwater Reservoir and has a treatment capacity of 30 MGD. A 10 million-gallon potable water reservoir at the site serves as clear well storage for the plant and as the point of delivery into the distribution system. The Perdue Plant processes approximately 12,800 acre-ft/yr, sourced either from the San Diego County Water Authority (SDCWA) or Sweetwater Reservoir dependent upon the hydrologic year. In a "typical" hydrologic year, approximately 7,500 acre-ft/yr is sourced from Sweetwater Reservoir and acre-ft/yr is sourced from the SDCWA.

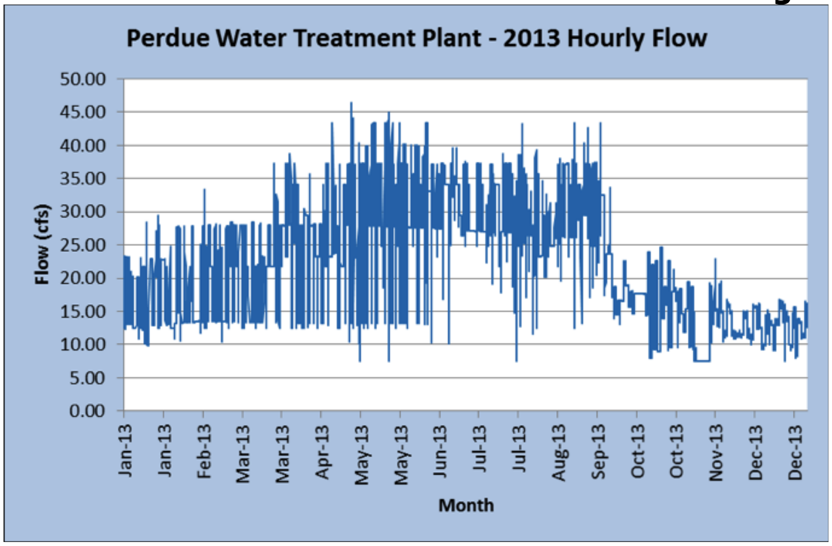
SDCWA's Pipeline 3 is the source for the Perdue Plant off the SDCWA system. Pipeline 3 ranges in size from 61-inch to 96-inch. The turnout into the Perdue Plant from Pipeline 3 is the National City & South Bay No.1 Service Connection (NC/SB1). Pipeline 3 via the NC/SB1 turnout is the source of pressure and flow to the new hydroelectric station. The schematic flow diagram of the Perdue hydroelectric station is presented in Figure A-30. The available flow at this site ranges from 10 – 30 cubic feet per second (cfs) (Figure A-31) while the net head ranges from 133 - 138 pounds per square inch (psi).

Figure A-30: Schematic Flow Diagram of the Hydroelectric Station at Perdue Water Treatment Plant



Source: Stantec

Figure A-31: Flow Profile at the Sweetwater Pressure Reducing Station In 2013



Source: Stantec

Project Drivers

The interest in implementation of conduit hydropower stemmed from an interest in solar energy application to offset overall energy consumption as expressed by several SA board members. During the initial assessment, SA determined that the following facilities are attractive for renewable energy implementation due to their high energy demand: Perdue Water Treatment Plant, Richard A. Reynolds Desalination Facility (major user of electricity), National City wells, the operation center and the administration building. After a thorough analysis of these sites, the selection was narrowed down to Perdue WTP and the desalination facility. In addition to solar, SA also conducted assessment on the applicability of hydropower in these facilities. Initially, hydropower was not deemed to be feasible as SA does not always take water from the State Water Project which is the source of water flowing through the potential site. However, due to strong request from the board members, the project still advanced to the design and implementation. In addition, SA was also able to secure about $500,000 grant from Self-Generation Incentive Program (SGIP) which greatly helped in the project advancement.

Currently, SA employed two types of renewable energy at their sites: conduit hydropower in Perdue Water Treatment Plant and solar in the Richard A. Reynolds Desalination Facility.

Feasibility Assessment

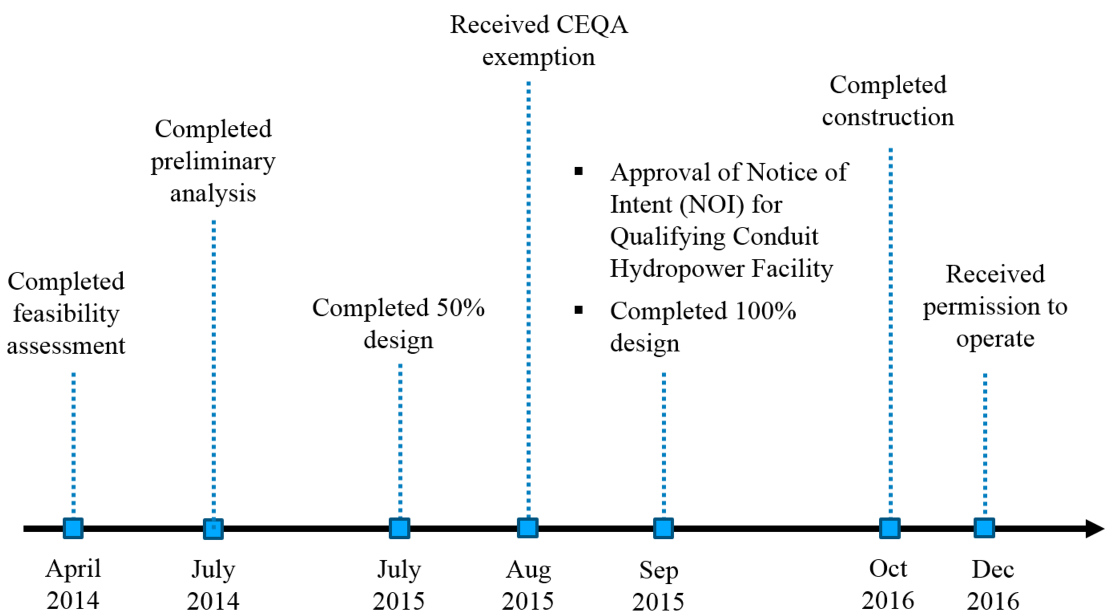
Sweetwater Authority authorized NLine Energy to develop a feasibility assessment on the potential Perdue Hydroelectric project, which was completed in July 2014. NLine Energy analyzed the historical pressure and flows of the site and determined that a two pump-as-turbine system with a nameplate rating of 580 kW was the best option for the site. The available flow at this site ranges from 10 cfs to 30 cfs while the net head ranges from 133 psi to 138 psi. The feasibility assessment determined that the project would cost approximately $2,800,000, generate 3,440,000 kilowatt hours annually, and have a 15-year payback. Figure A-32 provides an overview of the project site.

Figure A-32: Aerial View of the Perdue Water Treatment Plant and the Hydroelectric Facility

Source: Stantec

After conducting the feasibility assessment, SA proceeded to complete 100 percent design in September 2015, and finally received the permission to operate in December 2016. It took approximately 2.5 years to complete the project, as depicted by Figure A-33 below.

Figure A-33: Timeline of the Project Starting from Feasibility Assessment to Operation Startup



Source: Stantec

Permitting and Regulation

California Environmental Quality Act

The California Environmental Quality Act (CEQA) allows a Class 28 Exemption for small hydroelectric projects. Section 15328, titled, "Small Hydroelectric Projects at Existing Facilities". This project qualified for the CEQA exemption. SA received CEQA exemption in August 2015, as shown in Figure A-33 above.

FERC Conduit Exemption

Under the Hydropower Regulatory Efficiency Act of 2013, the Federal Energy Regulatory Commission (FERC) is required to determine whether proposed projects meet the criteria to be considered "qualifying conduit hydropower facilities." Qualifying conduit hydropower facilities are not required to be licensed or exempted by the FERC; however, any person, State, or municipality proposing to construct a facility that meets the criteria must file a Notice of Intent to Construct a Qualifying Conduit Hydropower Facility. The criteria for a Qualifying Conduit Hydropower Facility is listed in Table A-14 below.

Table A-14: Criteria for a Qualifying Conduit Hydropower Facility (FERC 2017)

Statutory provision	Description
FPA 30(a)(3)(A), as amended by HREA	The conduit the facility uses is a tunnel, canal, pipeline, aqueduct, flume, ditch, or similar manmade water conveyance that is operated for the distribution of water for agricultural, municipal, or industrial consumption and not primarily for the generation of electricity
FPA 30(a)(3)(C)(i), as amended by HREA	The facility is constructed, operated, or maintained for the generation of electric power and uses for such generation only the hydroelectric potential of a non-federally owned conduit
FPA 30(a)(3)(C)(ii), as amended by HREA	The facility has an installed capacity that does not exceed 5 megawatts
FPA 30(a)(3)(C)(iii), as amended by HREA	On or before August 9, 2013, the facility is not licensed, or exempted from the licensing requirements of Part I of the FPA

Source: Stantec

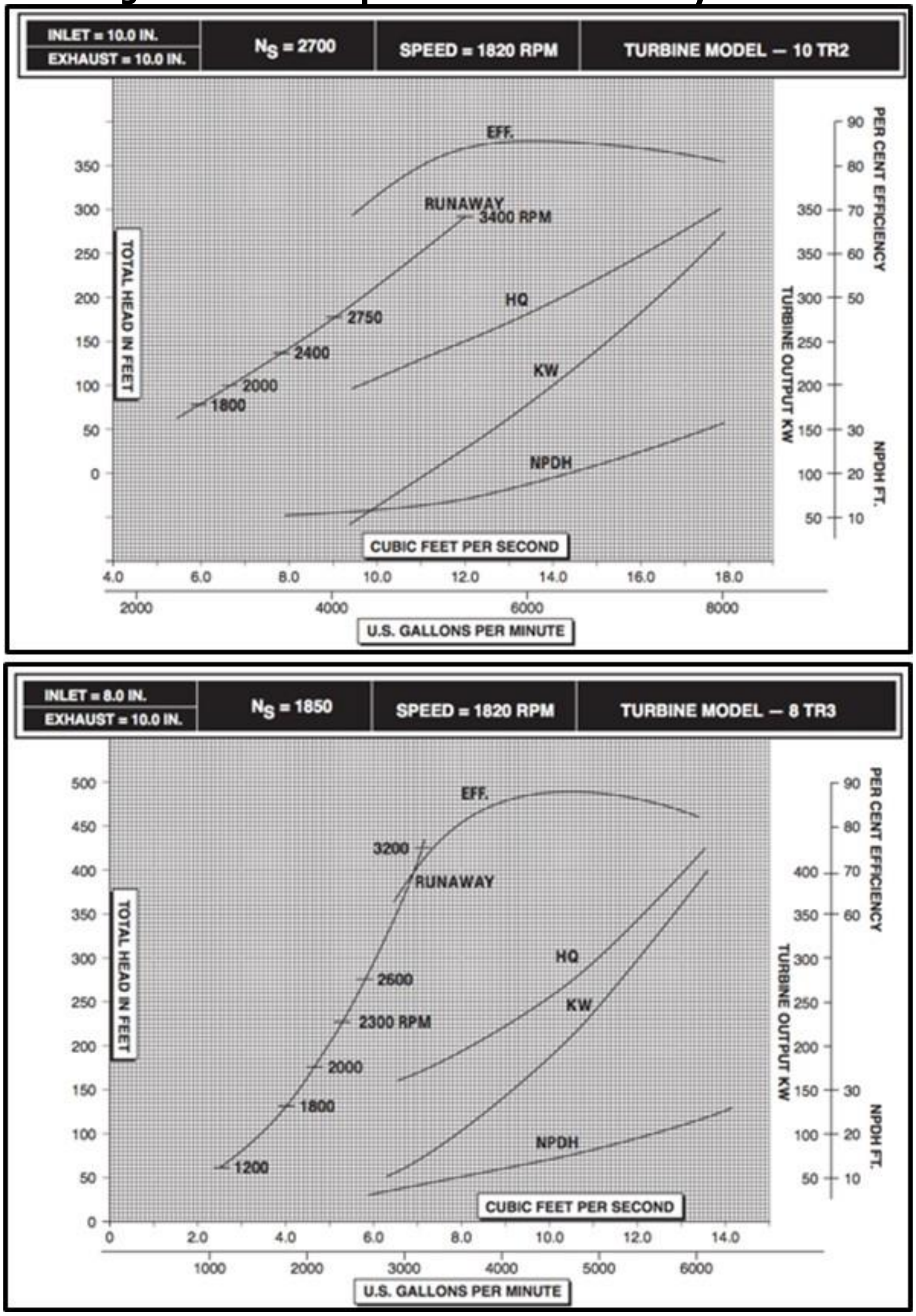
The NOI process is generally much faster than exemption process, as the facility does not require to hold a public hearing. The NOI process takes around 45 days to complete. Based on this information, the Perdue site qualified and completed the Qualifying Conduit Facility, Notice of Intent application process in September 2015.

Design and Construction

The Perdue Hydroelectric Station (hydro) operates in parallel with the Perdue Pressure Reducing Station (PRS). The powerhouse is supplied from a new extension of the existing 24-inch plant supply pipeline off the SDCWA's P3 pipeline. From the powerhouse, water is discharged to the existing stilling basin in the Sweetwater PRV vault and flow by gravity to the water treatment plant.

Based on the head and flow conditions for this site, the Cornell Pump-as Turbine (PAT) technology was implemented at this site. PAT machines operate best at optimum design conditions and have a relatively narrow efficiency curve. A PAT operates best at a single flow and head and generally do not operate well below approximately 80 percent of full flow. For maximum flexibility and to capture as much flow as possible, two PAT units were implemented. The hydroelectric station has a total system power production capacity of 580 kW. The PAT system consists of a Cornell PAT 10TR2 rated at 345 kW with a generator nameplate rating of 372 kW and a Cornell PAT 8TR3 rated at 235 kW with a generator nameplate rating of 260 kW. The turbines have flow capacities of 18 cfs and 11cfs for a total capacity of 29 cfs. The efficiency curves for the two turbines are included in Figure A-34 below. A photograph of the PAT system is provided in Figure A-35. Both of the PATs are housed inside an 880 square feet prefabricated steel building capable of sound attenuation (Figure A-36).

Figure A-34: Pump-as Turbine Efficiency Curves



Source: Stantec

The powerhouse contains a control panel and switchgear panel in a 28-foot by 32-foot above ground, prefabricated building. The existing plug valves in the Sweetwater flow control vault were replaced with new rate-of-flow / RF/PRVs (RF/PRV) with a butterfly valve on the upstream side. This change made the flow control vault a pressure reducing station and is referred to as the Sweetwater pressure reducing station in the remainder of this report. The flow through the RF/PRVs was determined by subtracting the hydroelectric station flow from the SDCWA venture meter flow, assuming an interface between the two facilities is allowed.

Figure A-35: Photograph of the PAT Units in Perdue Hydroelectric Station

Source: Stantec

Figure A-36: Close-Up View of the Perdue Hydroelectric Station

Source: Stantec

Operations and Maintenance

The hydroelectric station operates in parallel with the new Sweetwater Pressure Reducing Station (PRS). The new Sweetwater PRS takes the place of the SDCWA RF/PRV. The SDCWA plunger valve was set to full open. The turbine/generators utilize the pressure and flow delivered to the station to convert hydraulic energy into mechanical energy. Depending on how much flow is processed through the units and how much head is available, either one or both the hydroelectric turbines will be called to operate.

Typical maintenance of a hydroelectric station includes the following:

- Daily inspections of the hydroelectric station are recommended to detect leaks, excessive moisture buildup, loud noises, excessive vibration and/or heat. Sensors may be used to remotely detect many of these issues to augment physical inspections.
- Quarterly oil inspections / change: bearings, hydraulic systems, and gearboxes require grease or oil. Annual inspection and testing for viscosity, acidity and water content are required, while minimizing different types of oil, if possible. If oil temperatures stay below 60 Celsius, the oil's useful life is extended dramatically.
- Flow, pressure, and resulting kW production and overall efficiency should be checked periodically and instruments calibrated on regular intervals.
- The first inspection of the turbine itself should be at 12 months or 8,000 hours of operation.
- General inspections should occur every year until a history is established and trends are identified. Then the interval can be extended to two or more years. Similar installations may be good indicators of maintenance trends.
- Annual maintenance costs are assumed to be approximately $6,000 per year.
- Summary of annual maintenance and repair downtime:
    - Assume one week each year,
    - Assume three weeks every five years,
    - Three months every 25 years

Costs and Financing

Error! Reference source not found. Table A-15 provides an overview of the project financial metrics. The project financials were evaluated based on financing the project at 4 percent debt over a 20-year term. This analysis was performed in February 2017 after project completion.

Table A-15: Overview of the Project Cost Calculated in February 2017

Cost Item	Value
Estimated Project Costs	$2,800,000
Self-Generation Incentive Program	$552,000
Net Project Cost (Less Incentives)	$2,248,000
Annual O & M Costs	$6,000
Annual Generation Savings	$347,000
25-year Net Savings	$2,849,000
25-year NPV	$1,325,000
Payback (years)	17

Source: Stantec

Future Planning

The Perdue hydroelectric project received Permission to Operate in December 2016. As of January 2018, this project has generated more than 895,000 kilowatt hours or the equivalent of 666 metric tons of carbon dioxide or 100 homes electric use for one year.

Lessons Learned and Recommendations

- Turbine system: The Sweetwater Hydroelectric project selected a two-turbine array to accommodate variation in seasonal demand at the Perdue Water Treatment Plant. The pump-as turbine system will operate in sequence and in parallel depending on the pressure and flow conditions resulting from the seasonal demand at the Plant. The Perdue Water Treatment Plant was operational during the construction phase of the project when the hydro units were installed. This issue required close coordination from all teams during construction to ensure that the project did not impact operations.
- Project coordination: The project required a very tight timeline, as it needed to be implemented before one of the aqueducts was shut down due to scheduled maintenance. This aqueduct is the source of water flow to the Water Treatment Facility as well as the hydroelectric turbines. This waterflow is necessary for testing during start up and commission of the hydroelectric turbines. The lesson learned is that during the planning and design phase the team needs to ensure that all Client projects are considered and coordinated with the hydro project to ensure a smooth implementation.
- Interconnection cost: This project had zero interconnection costs as it provided grid level services for SDG&E. Note that during the initial design phase of the project, it was estimated to have approximately $250,000 in interconnection costs.

West Valley Water District (WVWD) Case Study Summary

Case Study Participants

- Wen Huang – Manager of Engineering, San Bernardino Valley Municipal Water District
- Mike Esquer – Senior Project Manager, San Bernardino Valley Municipal Water District
- Joanne Chan – Operations Manager, West Valley Water District

Background

- Site address: 3510 N. Cedar Avenue, Rialto, CA 92376
- Location of hydropower unit: Upstream of Roemer WFF and groundwater recharge basin
- Turbine type: Pump-as-Turbine
- Number of hydropower unit: Two units (Lead 10TR2 @ 17.6 cfs and Lag 6TR3 @ 6.7 cfs)
- Turbine manufacturer: Cornell Pump Company (supplied by Canyon Hydro)
- Total capacity: 440 kW turbine nameplate rating
- Estimated annual power generation: 2,947,000 kWh
- Total project cost: $2,946,000
- Electric provider: Southern California Edison (SCE)

- Energy use: On-site
- Billing arrangement: Net energy metering (NEM)
- Project status: Operational

West Valley Water District's history began on February 28, 1962, when their forbearer, West San Bernardino County Water District, became the owner and operator of three local mutual water companies. During the early years, the District supplied more water for agricultural purposes than for domestic use. During the 1970's and 1980's, the District grew and homes, businesses and schools soon surpassed agricultural water use. There were additional mergers where smaller water companies became a part of the water district. By the end of the 1980's, the District water facilities included 180 miles of pipeline, 12 reservoirs and 15 water wells. In 1992, the District was a partner in building five miles of new pipeline to bring water from the Bunker Hill Basin in San Bernardino. In 1993, the District partnered with the City of Rialto to build a treatment facility for the water flowing from Lytle Creek; the Oliver P. Roemer Water Filtration Facility (Roemer WFF). In 2003, the District changed its name to West Valley Water District (WVWD).

The District currently provides drinking water to customers in portions of Rialto, Colton, Fontana, Bloomington, and portions of the unincorporated area of San Bernardino County, and a portion of the city of Jurupa Valley in Riverside County. The district now encompasses five treatment plants, 360 miles of pipeline, 25 reservoirs, 23 wells, and 20,000 service connections serving drinking water to 66,000 residents in four cities and two counties.

The Roemer WFF is located on N. Cedar Avenue in the city of Rialto, CA and has a current treatment capacity of 14.4 million gallons per day (MGD). WVWD is planning a future expansion at the facility that would include the construction of a 6.0 MGD membrane plant. Water is sourced to the WFF from Lytle Creek (surface water) and State Water Project (SWP) water from the San Bernardino Valley Municipal Water District (SBVMWD), a state water contractor, via the Lytle Creek turnout off of the Devil Canyon-Azusa pipeline (Figure A-37). The source water for the proposed hydroelectric station is only the SWP water through the 30-in diameter Lytle Creek Turnout. The Roemer WFF Hydroelectric project will utilize the available pressure in the SBVMWD's 54-inch Devil Canyon-Azusa pipeline's raw water supply conduit to generate power by utilizing turbines instead of relying on pressure reducing valves to reduce pressure before raw water is delivered to the water treatment plant's filtration system. The following figure provides an overview showing the Roemer WFF and surrounding area.

Figure A-37: Close-Up View of the Perdue Hydroelectric Station

Source: Stantec

Project Drivers

In 2013, SBVMWD started to conduct a thorough assessment of their service area to identify locations that are suitable for small hydropower implementation. As SBVMWD supplies SWP water to several water utilities, the assessment was focused on the various locations of pressure reducing stations along the SWP pipeline. The pressure reducing station located upstream of Roemer WFF and Cactus groundwater recharge basin owned by WVWD was considered to be feasible for conduit hydropower due to its sufficient available pressure. Following joined board meetings between SBVMWD and WVWD, the hydropower project in this particular location was started in August 2014. The cost of constructing the facility was fully financed by SBVMWD and will be paid back in installment by WVWD as they generate revenue from the hydropower over the years.

Feasibility Assessment

WVWD authorized NLine Energy to develop a Preliminary Design report on the potential Roemer hydroelectric project, which was completed in August 2014. Available flow to the hydroelectric station was based on synthesized projections for SBVMWD recharge flows to the Cactus recharge basins and the Roemer WFF planned improvements with data supplied by WVWD. Although the Roemer WFF has a current capacity of 14.4 MGD, only 12 MGD (18.6 cubic feet per second or cfs) was used for the updated flow scenarios based on current demand and expectations for some utilization of surface water from Lytle Creek. Future plant expansion is planned for a 6 MGD (11.1 cfs) membrane plant. Additional supply to the hydroelectric station would come from increased utilization of State Water Project. For design purposes, 80-percent of this additional capacity, or 4.8 MGD (7.4 cfs) was assumed available to the turbines. The synthesized flow data is provided in Table A-16.

Table A-16: Roemer WFF Synthesized flow data

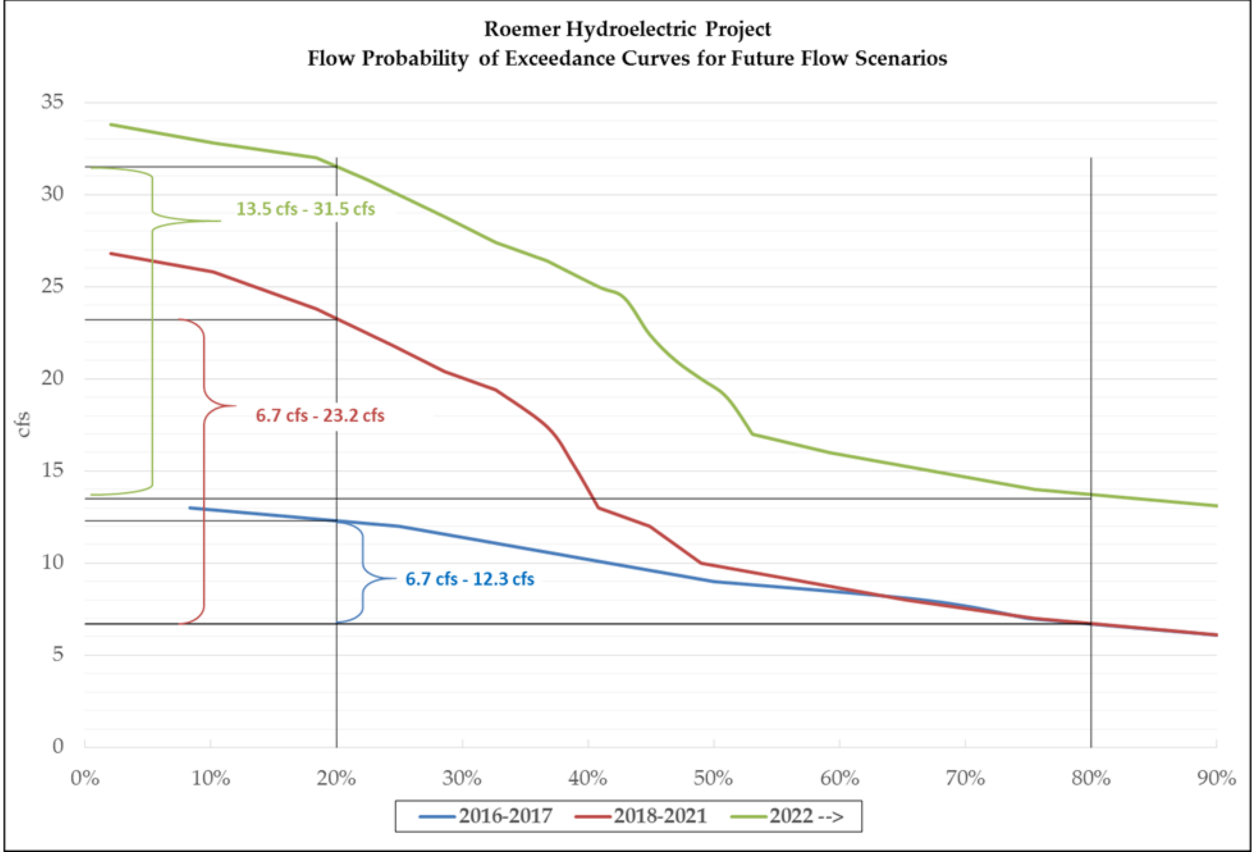
Flow Period/Season	Flow Projections (cfs)
Years 1-6 Hydroelectric station flows	0-18 cfs
April - September	8-13
October - March	6-10
Years 7 + Hydroelectric station flows	0-32 cfs
April - September	15-20
October - March	13-17

Source: Stantec

The Roemer WFF and groundwater recharge flows were also used to create new flow probability of exceedance curves for three, time frames, as depicted in Figure A-38. Briefly:

- 2016 through 2017 - Roemer WFF at current capacity and no groundwater recharge flows (flows ranging from 6 cfs to 13 cfs)
- 2018 through 2022 - Roemer WFF at current capacity with groundwater recharge (flows ranging from 6 cfs to 27 cfs)
- 2023 and beyond – Roemer WFF plant expansion flows and groundwater recharge (flows ranging from 13 cfs to 34 cfs)

Figure A-38: Flow Probability of Exceedance Curves for Future Flow Scenarios



Source: Stantec

Based on the hydraulic loss calculations the available pressure to the Roemer Hydroelectric station will vary not only with the flow to the station, but with the flows in the rest of the upstream transmission system. Table A-17 provides the minimum and maximum available head at the intake to the hydroelectric turbines based on overall flow conditions in the system at various flows to the Roemer plant. An average value of the minimum and maximum head values was selected for modeling of energy generation based on the assumption that head would range between the maximum and minimum values over time.

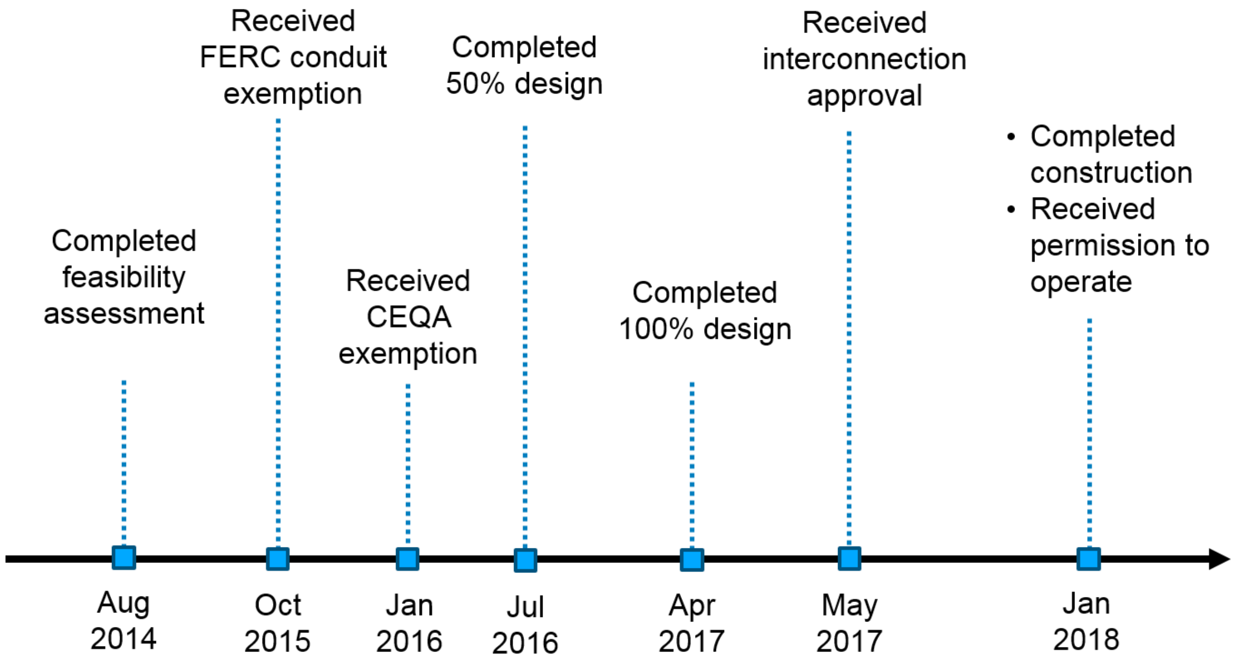
Table A-17: Available Pressure Head to the Roemer Hydro Station

WVWD-Roemer and Cactus Basins Total Flow (cfs)	Minimum Head (ft)	Maximum Head (ft)	Average Head Value used for Energy Generation Modeling
4	291	324	308
6	285	321	303
8	280	320	300
10	274	319	297
12	278	319	299
15	274	317	296
20	267	315	291
25	258	310	284
30	248	305	277
32	245	303	274
35	238	300	269

Source: Stantec

The feasibility assessment determined that the project would cost approximately $2.9M, generate 2,947,000 kilowatt hours annually and have an estimated 12-year payback. After conducting the feasibility assessment, WVWD proceeded to complete final design in April 2017, and finally received the permission to operate in January 2018. It took approximately 3.5 years to complete the project, as depicted by Figure A-39 below.

Figure A-39: Timeline of Project Starting from Feasibility Assessment to Operation Startup



Source: Stantec

Permitting and Regulation

California Environmental Quality Act

The California Environmental Quality Act (CEQA) allows a Class 28 Exemption for small hydroelectric projects. Section 15328, titled, "Small Hydroelectric Projects at Existing Facilities". This project qualified for the CEQA exemption.

FERC Qualifying Conduit Facility, Notice of Intent

Under the Hydropower Regulatory Efficiency Act of 2013, the FERC is required to determine whether proposed projects meet the criteria to be considered "qualifying conduit hydropower facilities." Qualifying conduit hydropower facilities are not required to be licensed or exempted by the FERC; however, any person, State, or municipality proposing to construct a facility that meets the criteria must file a Notice of Intent to Construct a Qualifying Conduit Hydropower Facility with the Commission. A "qualifying conduit hydropower facility" must meet the following provisions:

- A conduit is any tunnel, canal, pipeline, aqueduct, flume, ditch, or similar manmade water conveyance that is operated for the distribution of water for agricultural, municipal, or industrial consumption, and is not primarily for the generation of electricity.
- The facility generates electric power using only the hydroelectric potential of a non-federally owned conduit.
- The facility has an installed capacity that does not exceed 5 megawatts (MW).
- The facility was not licensed or exempted from the licensing requirements of Part I of the FPA on or before August 9, 2013.

Based on this information, the Roemer Hydro site qualified and completed the Qualifying Conduit Facility, Notice of Intent application process.

Design and Construction

During design planning it was indicated that constructing the powerhouse with future expansion capability for the addition of a third turbine/generator unit would be desired as future flows to the hydroelectric station were expected to increase with planned WFF expansion and increased groundwater recharge flows. Updated flow projections were used to model energy generation and revenue under two turbine and a three turbine options. SBVMWD provided updated forecasts of recharge flows based on the anticipated operational time frame of the Cactus recharge basins – beginning in 2018. Annual anticipated recharge volumes were also provided for different hydrologic year types as well as the forecasted percentage of the next 36 years falling into each category based on the following anticipated recharge permissions:

- Cactus Basins will be operable in 2018; therefore, no recharge flows in 2016-2017
- 27 ac-ft/day maximum recharge
- Recharge April through October (7 months)

The forecasted Cactus Basin recharge flows by hydrologic year type are presented in Table A-18. The hydrologic year type data, provided by SBVMWD, gave the number of years out of the next 36 years that each type was forecast. The number of years for each type forecasted was divided by 36 to determine the percentage of years each hydrologic year type was projected. This conversion was then used in the 30-year modeling of estimated power and revenue generation.

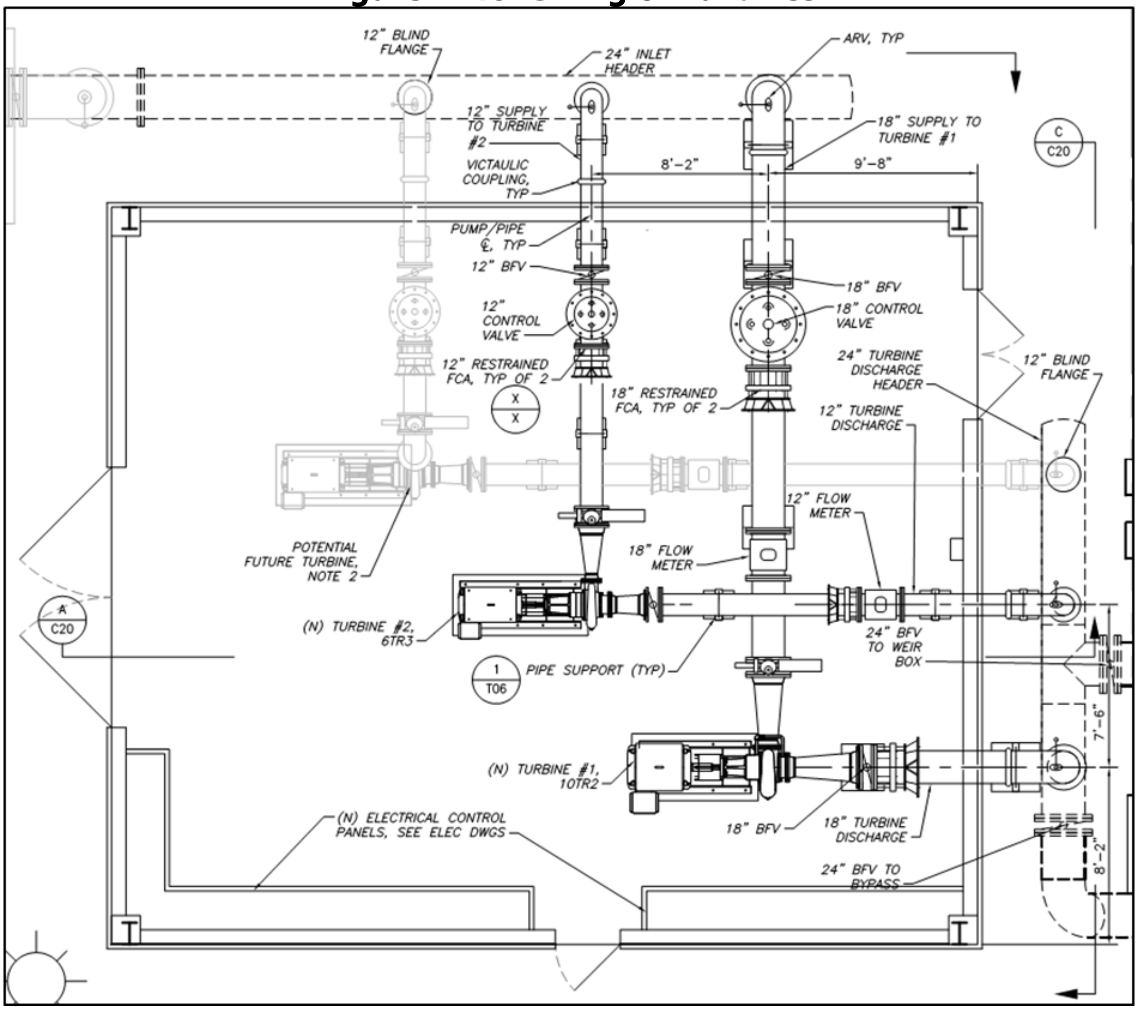
Table A-18: Cactus Basin Groundwater Recharge Projections

Hydrologic Year Type	Annual Recharge (Ac-Ft)	Hydrologic Year Type Occurrence (36-year projection)	Percentage of Occurrence	Recharge flow Rate (cfs) over seven months
Wet year	7000	2	6%	16.5
Average year	5000	8	22%	11.8
Dry year	2700	14	39%	6.4
Very Dry year	0	12	33%	0.0

Source: Stantec

This planning allowed for NLine Energy to predict Roemer WFF and Cactus recharge basin flows in a consolidated flow duration curve in order to correctly size the hydroelectric turbines, which is depicted in Figure A-40 below.

Figure A-40: Sizing of Turbines



Source: Stantec

NLine Energy recommended that WVWD construct a powerhouse that will hold three turbine/generator units but to install only two units at this time. Additionally, the recommendation is to size the electrical system for only the two initially installed generators.

The powerhouse is approximately 1,360 square feet in size. Design includes a prefabricated steel building capable of sound attenuation. The powerhouse can accommodate three PaT turbine/generator units sized to meet the available head and flow anticipated, turbine control valves, piping, valves and fittings, electrical power control (switchgear) and logic control panels.

Roemer WFF is currently served at 12-kV from SCE distribution circuit 17376 from SCE Substation 5672. The feed to the plant is underground to an SCE padmount switch. The padmount switch serves an adjacent SCE padmount transformer. The SCE transformer secondary conduit at 480VAC serves the existing plant 480VAC, 3000-amp Main Switchboard located adjacent to the padmount transformer. The new hydroelectric station output ties into the existing plant main switchboard. The existing SCE revenue meter in the plant main switchboard was replaced with a bi-directional by SCE. Due to the need to add ground fault sensing to the incoming 12kV SCE feeder when on-site generation is added, some rework and additions to the incoming 12kV feeder was required by SCE.

Operations and Maintenance

The hydroelectric station is located adjacent to the pretreatment facility on the Roemer WFF site adjacent to the north property line which runs parallel to North Riverside Avenue. The pipeline system at the new hydroelectric station includes a pressure reducing valve in a bypass around the hydroelectric station so that if the hydroelectric station were inoperable for any reason, operation of the Roemer WFF and the groundwater recharge basin flows to the Cactus Recharge Basin will be maintained. The system has the ability to bypass up to 55 cfs around the hydroelectric station. Since the hydroelectric station will reduce pressure similar to the function of the existing sleeve valve, the sleeve valve located at the Lytle Creek PRS will no longer be required. It was removed and relocated to the bypass at the proposed hydroelectric station.

The hydroelectric station was sized to eventually accommodate three pump-as-turbine (PaT) machines to be able to expand energy generation capacity in the future when flows are expected to be higher. The turbines convert the pressure and flow energy into rotational mechanical energy to produce power. The turbines also reduce all of the upstream pressure head down to the hydraulic grade on their downstream side.

Flow through the turbine is dependent upon the flow characteristics (operation curve) of the turbine and the pressure head on the upstream side of the turbine. Flow through the turbine was adjusted by utilizing pressure control valves on the upstream side of the turbines to match the flow characteristics of the turbine and accommodate the flow setting at the Lytle Creek flow control station (FCS).

Flow control remains at the Lytle Creek FCS. A communication link was established between the new hydroelectric station and the Lytle Creek FCS. When the flow set point is entered at the Lytle Creek FCS PLC by the operator, the pressure reducing valves located just upstream of the hydroelectric turbines at the hydroelectric station will adjust accordingly. If a flow increase is needed to the Roemer WFF, the operators will call SBVMWD for a flow adjustment and the pressure reducing valves at the turbines will adjust to accommodate the flow required by the communications link. The same procedure will be used if less flow is required. If more flow is required to the Roemer WFF than the turbines can process, the bypass sleeve valve will open to supplement the flow. The decision to open the sleeve valve (Hartman) for additional bypass flow will be accomplished in the PLC logic.

If operation of the Cactus recharge is required, the same procedure will be implemented with the bypass sleeve valve providing the flow for the Cactus recharge.

Flow meters were included on the upstream side of each of the hydroelectric turbines to measure flow through each turbine. Flow meters were also provided on the bypass pipe and on the influent pipe leading from the hydroelectric building to the Roemer WFF

Typical maintenance of a hydroelectric station includes the following:

- Daily inspections of the hydroelectric station are recommended to detect leaks, excessive moisture buildup, loud noises, excessive vibration and/or heat. Sensors may be used to remotely detect many of these issues to augment physical inspections.
- Quarterly oil inspections / change: bearings, hydraulic systems, and gearboxes require grease or oil. Annual inspection and testing for viscosity, acidity and water content are

required, while minimizing different types of oil, if possible. If oil temperatures stay below 60 Celsius, the oil's useful life is extended dramatically.

- Flow, pressure, and resulting kW production and overall efficiency should be checked periodically and instruments calibrated on regular intervals.
- The first inspection of the turbine itself should be at 12 months or 8,000 hours of operation.
- General inspections should occur every year until a history is established and trends are identified. Then the interval can be extended to two or more years. Similar installations may be good indicators of maintenance trends.
- Annual maintenance costs are assumed to be approximately $6,000 per year.
- Summary of annual maintenance and repair downtime:
    - Assume one week each year,
    - Assume three weeks every five years,
    - Three months every 25 years

Costs and Financing

Table A-19 provides an overview of the project financial metrics. This analysis was performed in December 2017 after construction of the project. As can be seen, the payback period for this project is about 12 years. Any revenue generated from this project will be paid back to the SBVMWD as they provided the loan at the beginning of the project to start the construction.

Table A-19: Overview of the Project Cost as of December 2017

Cost Item	Value
Estimated Annual Generation (kWh)	2,947,000
Project Cost	$2,946,000
Self-Generation Incentive Program (Grant)	$454,000
Net Project	$2,492,000
Annual O & M Costs	$6,000
Annual Generation Revenue	$235,000
30-year Net Savings	$7,430,000
30-year NPV	$2,402,000
Payback	12 years

Source: Stantec

Future Planning

The Roemer Hydro Project was completed and received the Permission to Operate SCE in January 2018. The Roemer hydroelectric project is expected to generate more than 2,900,000 kilowatt-hours annually or the equivalent of 2,192 metric tons of carbon dioxide or 329 homes electric use for one year.

Lessons Learned and Recommendations

- Hydro station expansion: NLine Energy analyzed the current and future projected flows at the WFF, as well as groundwater recharge flows leading to Cactus basin. This analysis led to the determination that initially the project would implement a two pump-as-turbine system, but allows for the system to accommodate the implementation of a future third pump-as turbine as the WFF and groundwater flows increase. Expansion considerations included blind flange turnouts on the influent and discharge piping, additional electrical capacity, and an expandable powerhouse design.
- Flow projection: Due to variation in flow throughout the years, it is important for hydropower facilities in recharge basins to project the future flows to the best extent possible. Accurate prediction of flow will allow for accurate sizing of the equipment.