PUGET SOUND ENERGY

March, 2014

PUGET SOUND ENERGY

Eastside 230 kV Project

Underground Feasibility Study

PROJECT NUMBER:
130155

PROJECT CONTACT:
POWER ENGINEERS, INC.

POWER ENGINEERS

Underground Report

PREPARED FOR: PSE
PREPARED BY: POWER ENGINEERS, INC.

REVISION HISTORY		
DATE	REVISED BY	REVISION
8/20/12	POWER Engineers, Inc.	1st Draft Issued for Review
8/20/12	POWER Engineers, Inc.	Final Report
3/2014	POWER Engineers, Inc.	Updated Final Report

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PREFACE

In 2012, Puget Sound Energy (PSE) requested POWER Engineers, Inc. (POWER) review the constructability of underground transmission installation as part of the Eastside 230 kV Project. The scope of this work included conceptual designs for undergrounding all of the transmission from their Sammamish to Lakeside to Talbot Hill Substations. A review was performed for three alternatives:

1. Underground transmission on an existing PSE right of way
2. Underground transmission on an alternate alignment, primarily city street right of way
3. Underground transmission on an existing rail road right of way

In addition, PSE requested POWER review the constructability of an underground transmission link between existing Seattle City Light (SCL) overhead transmission lines and the Lakeside Substation. Since this study was completed, PSE has had further discussion with SCL regarding the availability of this corridor. SCL has stated that they have needs for this corridor for their own future development and SCL is not willing to make this corridor available to PSE.

The transmission requirements for all alternatives would be a 230 kV double circuit line, with a rating capacity of 800 MVA continuous per circuit (1600 MVA total).

This report documents the constructability review. Cost estimates have been updated to reflect 2014 pricing.

0.0 EXECUTIVE SUMMARY

Puget Sound Energy (PSE) has requested a feasibility study for a 230 kilovolt (kV) underground transmission line connecting Sammamish Substation to Lakeside Substation and continuing to Talbot Hill Substation as part of its Eastside 230 kV Project. This study focuses on replacing and upgrading the existing 115 kV overhead lines with an underground 230 kV system from an engineering and constructability standpoint only. This study does not take into account:

1. Environmental, local, state, and federal permits and/or mitigation as required,
2. Acquisition of new right of way, easements, or properties, or
3. Local land use preferences among the identified route alternatives.

POWER Engineers, Inc. (POWER) was selected to study the conceptual cable system for this project. POWER identified a project study area for the underground portion of new 230 kV transmission lines and developed the criteria for an underground transmission line route evaluation. POWER evaluated the study area and identified three route alternatives:

1. One route option would utilize the existing 115 kV overhead lines easement,
2. A second option would be within existing street right of way, and
3. The last option would be along an existing railroad right of way.

PSE also requested that POWER investigate route options to “tap in” to 230 kV Seattle City Light (SCL) lines, just west of the Lakeside substation.

Overhead transmission lines generally have larger power transfer capacity when compared to an equivalent insulated cable in an underground installation. Underground cable manufacturers are also limited in the size conductor they can produce to achieve a line rating with one cable per phase. POWER performed ampacity calculations for various underground line configurations to determine preliminary cable sizing requirements and concluded that two cables per phase would be needed to meet rating requirements for the new Eastside 230 kV lines. Two major types of cable systems were evaluated and compared for use on the proposed routes; cross-linked polyethylene (XLPE) and high-pressure fluid-filled (HPFF).

Easement and construction requirements were discussed for each route option describing the size of easements required and the construction impacts. While all three route alternatives present different challenges such as difficult terrain, acquisition of additional easements/right of way, and existing utility conflicts, all routes are constructible.

Cost estimates and project schedules were also created for all routes investigated with summary tables located in Section 5.

Based on this conceptual study, the results of the costs estimates are as follows:

SECTION	LENGTH (miles)	MATERIALS	LABOR & EQUIPMENT	TOTAL
EXISTING OH EASEMENT	16.7	$238,520,375	$153,059,267	$391,579,641
STREET ROW	18.6	$294,934,505	$183,321,823	$478,256,327
RAILROAD	21.3	$331,474,512	$215,669,855	$547,144,366

Table 0-1 XLPE Total Cost Estimate – Two underground transmission lines, each with two cables per phase

SECTION	LENGTH (miles)	MATERIALS	LABOR & EQUIPMENT	TOTAL
EXISTING OH EASEMENT	16.7	$298,821,059	$135,527,697	$434,348,756
STREET ROW	18.6	$359,434,051	$163,967,846	$523,401,897
RAILROAD	21.3	$398,566,198	$180,697,067	$579,263,265

Table 0-2 HPFF Total Cost Estimate – Two underground transmission lines, each with two cables per phase

1.0 PROJECT DESCRIPTION

Puget Sound Energy (PSE) has proposed a rebuild of its Talbot Hill-Lakeside-Sammamish #1 and #2 overhead 115 kV transmission lines to 230 kV, and has identified the need to evaluate three underground route alternatives. PSE has requested that POWER Engineers, Inc. (POWER) perform an underground feasibility study to evaluate conceptual designs for each alternative.

The two major types of 230 kV cable systems used for underground transmission application, high-pressure fluid-filled (HPFF), and cross-linked polyethylene (XLPE), are evaluated and compared as part of this study. In addition, a brief discussion of additional available cables systems are provided but are not considered practical alternatives for undergrounding the transmission lines.

The pros and cons of each major type, HPFF and XLPE are considered for the installation options, and conceptual cable system designs developed for each as well.

This report describes and summarizes:

- The review of conceptual route alignments for new underground transmission lines,
- Considerations for each potential cable system,
- Preliminary cable system design options, and
- Cost estimates for each system considered,

Appendix A contains aerial route drawings for each underground transmission alternate.

Appendix B contains typical detail drawings for each cable system (HPFF and XLPE) evaluated.

2.0 UNDERGROUND CABLE SYSTEMS

The two most common types of underground transmission at 230 kV in the U.S. are cross-linked polyethylene and high-pressure fluid-filled cable systems.

2.1 Cross-Linked Polyethylene Cable Systems

High voltage extruded dielectric cable installations in the U.S. are commonly in duct banks within roadways, one cable per duct, because direct burial and tunnel installations have not proven practical in city streets.

2.1.1 Cable

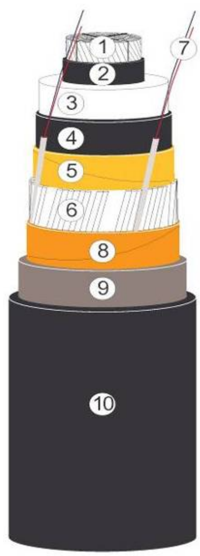
The components of a typical dielectric cable are shown in Figure 2-1. The typical cable consists of a stranded copper or aluminum conductor, inner semi-conducting conductor shield, extruded solid dielectric insulation, outer semi-conducting shield, a metallic moisture barrier, and a protective jacket.

The major insulation materials used for solid dielectric cables include ethylene propylene rubber (EPR) or cross-linked polyethylene (XLPE) thermosetting insulation compounds.

For voltages over 69 kV, the preferred insulation in the U.S. for an extruded cable system is XLPE. This is due to the higher dielectric losses associated with EPR-insulated cables. For undergrounding the 230 kV Sammamish-Lakeside-Talbot lines with an extruded cable system, the insulation would be XLPE.

Materials used for semi-conducting extruded conductor and insulation shields are semi-conducting polyethylene (PE), XLPE, and EPR compounds. PE compounds are used with PE and XLPE insulation, XLPE compounds with XLPE insulation, and EPR compounds with EPR insulation.

Cable jackets are typically extruded PE, and can be high, medium, low, or linear low–density polyethylene.



1 - CONDUCTOR
Material: copper

2 - INNER SEMI CONDUCTIVE SHIELD

3 - EXTRUDED SOLID DIELETRIC INSULATION
Material: cross - linked polyethylene

4 - OUTER SEMI-CONDUCTIVE SHIELD

5 - SEMI CONDUCTIVE SWELLING/BEDDING TAPES

6 - CONCENTRIC COPPER WIRE METALLIC SHIELD

7 – OPTICAL FIBERS

8 - SEMI CONDUCTIVE SWELLING/BEDDING TAPES

9 - MOISTURE BARRIER/SHEATH
Material: copper, aluminum, lead, or stainless steel

10- PROTECTIVE JACKET

Figure 2-1: Typical XLPE Cable

The manufacturing process for extruded cables is of critical importance in ensuring a reliable end product. Triple extrusion is the preferred and recommended technique. Most transmission cable manufacturers use this “true triple head” extrusion technique today. Microscopic voids and contaminants can lead to cable failures. As such, quality control during manufacture of extruded dielectric cables is critical to minimize moisture contamination, voids, contaminants and protrusions. Manufacturers minimize insulation contamination by using super clean insulation compounds, transporting and storing the compounds in sealed facilities, and screening out contaminants at the extruder head.

2.1.2 Cable Accessories

The fundamental cable accessories for extruded dielectric cables include splices, terminations, clamps, and sheath bonding materials.

Pre-fabricated or pre-molded splices are commonly used to join extruded dielectric cables. Cable preparation for each of these types of splices is generally the same. Insulation and shields are removed from the conductor; and the insulation is penciled near the conductor. The conductor ends are then joined by a compression splice or, if aluminum, are welded. An advantage of using these types of splices is that all parts can be factory tested prior to field installation. Figure 2-2 shows typical 230 kV pre-molded splices racked within a splicing vault.

Figure 2-2 Typical 230 kV Pre-Molded XLPE Splices

Terminations are necessary for extruded dielectric cable to allow transitions to overhead lines or above ground equipment. Termination bodies are typically made of porcelain or polymer and include skirts or sheds, which provide additional surface area to minimize the probability of external flashovers due to contamination. Figure 2-3 shows typical 230 kV XLPE terminations.

Figure 2-3 Typical 230 kV XLPE Terminations

Another important component of a high voltage extruded cable system is the grounding/bonding of the cable shield. An underground distribution cable system would typically have the cable shield grounded at each splice and termination. The losses due to heat caused by circulating currents on the cable shield will result in the de-rating of the cable. One way to maximize the ampacity of an underground cable is to eliminate the circulating currents. This is accomplished with underground transmission cables by using special bonding methods such as single-point and cross-bonding. These methods reduce or even eliminate the amount of current that would flow on the cable shield resulting in no or very limited additional heating and ultimately a higher ampacity.

2.1.3 Civil Installation

Open Cut Excavation Method

The most basic and economical method for constructing an underground duct bank is by open-cut trenching, however, trenchless methods may also be necessary for crossing major obstructions. Typical construction results in the use of mechanical excavation to remove the concrete or asphalt surface (for roadways), topsoil and sub-grade material to the desired depth. Removed material is relocated to an appropriate off-site location for disposal, or occasionally reused as fill. Once a portion of the trench is opened, PVC conduit is assembled and lowered into the trench. The area around the conduit is filled with a high strength (3000 psi) thermal concrete. After the concrete is installed the trench is backfilled, generally with the native soil or an engineered backfill with favorable thermal characteristics, and the site restored. Backfill should be clean excavated material, thermal sand and/or a thermal concrete mix. Figure 2-4 shows a typical trench excavation and duct bank installation in a city street, and Figure 2-5 depicts an installation in rural setting.

Figure 2-4 Typical trench excavation and duct bank installation (city street)

Figure 2-5 Typical trench excavation and duct bank installation (rural)

Trenchless Installation

Pipe Jacking / Jack and Bore

The pipe jacking and jack and bore methods are commonly used for short crossings, typically under 400 feet, and where no bends are required. Occasionally, these techniques have been used for longer lengths depending on the soil conditions. These techniques involve the placement of a casing under the obstruction and then installing the conduit inside the casing. With pipe jacking, spoil is removed from the advancing casing by workers inside the casing. Pipe jacking would require a 42-inch minimum casing to perform hand-work within this confined space. This method would be used in a variety of situations and often when rock excavation is expected. A jack and bore utilizes a powered auger that removes spoil from the advancing casing. A bore pit, typical dimensions of 40-ft long x 10-ft wide, is needed for boring equipment and operators, as well as for welding 20-ft sections of casing pipe together. Toward the end of the boring process, an exit pit approximately 10 ft in length will be excavated. As with trenching, the entrance and exit pits may require shoring (and possibly tight sheeting) in accordance with OSHA regulations. While this method has been used for water crossings, other methods might be preferred, as keeping the installation properly dewatered can be challenging. Figure 2-6 shows a typical conduit bundle arrangement within a jack and bore.

Figure 2-6 Typical Jack and Bore Conduit and Casing Arrangement

Horizontal Directional Drilling (HDD)

The HDD method is commonly used for longer crossings and where bends may be needed. A HDD installation for an XLPE cable system consists of installing a casing with conduits inside or just installing the conduits in a bundle by themselves. The HDD method consists of a three step process. First, a small diameter pilot hole is drilled from entry to exit, followed by a reamer that is pulled back to enlarge the pilot hole. Finally, the product pipe is pulled into the enlarged hole. Horizontal boring operations have become quite popular with utilities since it eliminates the need to excavate large bore pits and the work can be performed from the surface. While this method does not require any significant pit excavation, it does require a generous staging area at the entry point and exit points of the drill. A typical entry point site requires a dedicated space of about 100 ft by 150 ft with an exit area of 100 ft by 100 ft. A typical set up used at the HDD entry point is shown below in Figure 2-7 below.

Figure 2-7 Typical HDD Setup

2.1.4 Splicing Vault Design and Installation

Access vaults are needed periodically along an underground route to facilitate cable installation, for maintenance, as well as access for future repairs. Reinforced concrete vaults are typically spaced every 1,500 to 2,500 feet along the route. The splicing vault size and layout is determined by the space required for cable pulling, splicing, and supporting the cable in the vault. The anticipated size of each 230 kV XLPE splicing vault would have inside dimensions of about 7 ft wide by 26 ft long with enough headroom to allow workers to install the cable, as illustrated in Figure 2-8. A vault may be needed for each set of cables for this project, to allow PSE to perform maintenance or repair on one set of cables while keeping the other energized. Figure 2-9 shows an underground transmission splicing vault installation for a 230 kV XLPE project. For this particular installation there were four 3-phase cable sets of and four vaults total.

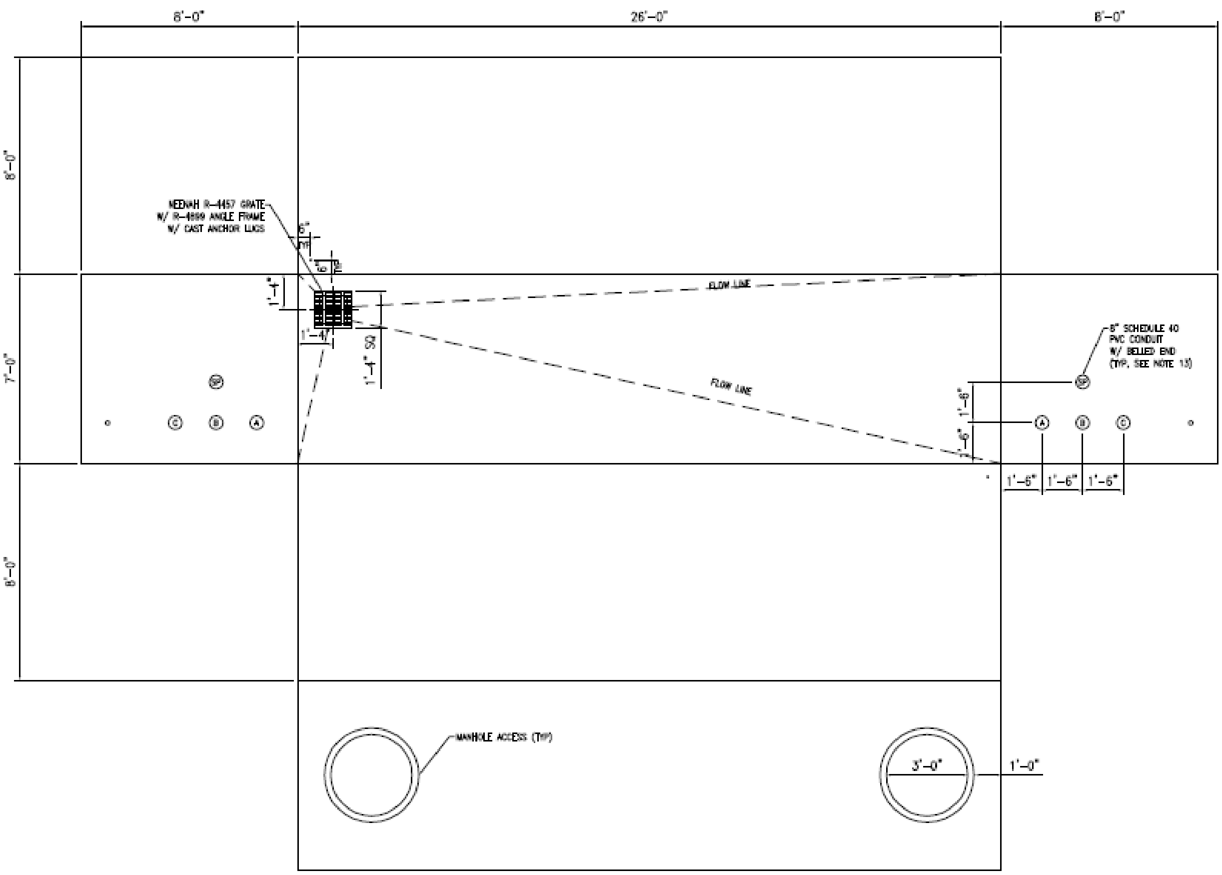


Figure 2-8 XLPE Vault Schematic

Figure 2-9 Splicing Vault Installation

The factors contributing to the final placement of the splicing vaults are: allowable pulling tensions, sidewall pressure on the cable as it goes around a bend and the maximum length of cable that can be transported on a reel based on the reel's width, height and weight. For the preliminary cable sizing identified for the Sammamish-Lakeside-Talbot lines, it is assumed vaults would be positioned approximately every 2,000-ft.

2.1.5 Cable Installation and Testing

Prior to installation of the cable, the conduit would be tested and cleaned by pulling a swab and mandrel through each of the ducts. If the mandrel is pulled successfully, the conduit would be declared suitable for installation of the cable. Cable installation procedures and equipment would be based on environmental conditions, equipment and material placement, and pulling requirements.

The typical cable pulling setup would include setting the reel of cable at the termination structure or at one of the splicing vaults and placing the winch truck at the opposite end. The cable should always be pulled from the termination structure to the nearest splicing vault. The direction of pull between vaults should be determined based on the lowest pulling tensions or sidewall pressures. After the cables have been pulled into a splicing vault from each direction, splicing could commence. This process would be followed until all the cable has been pulled, terminated or spliced. Once this has occurred the cable would be tested. Figure 2-10 shows a typical cable reel set up.

Figure 2-10 Typical Cable Pulling Set up

2.2 High-Pressure Fluid-Filled Cable Systems

2.2.1 Cable

A typical high-pressure fluid-filled (HPFF) cable is composed of a conductor, conductor shield (carbon black or metalized paper tapes), insulation (Kraft paper or paper/polypropylene laminate impregnated ‘LPP’ with dielectric fluid), insulation shield (carbon black or metalized paper tapes), a moisture barrier (non-magnetic tapes and metalized mylar tapes), and skid wires placed in a steel pipe filled with dielectric fluid or gas. The purpose of the dielectric fluid or gas is to keep moisture and contaminants out of the pipe and away from the cable. The moisture barrier prevents moisture and other contamination and loss of impregnating fluid prior to installation. The skid wires prevent damage to the cable during pulling. Three HPFF cables are pulled into a carbon steel pipe to constitute a cable system. The pipe is coated on the inside with an epoxy coating to prevent oxidation prior to pipe filling and to reduce pulling friction and tension. The pipe exterior is typically coated with polyethylene or epoxy to protect the pipe from environmental corrosion and to isolate the pipe from “ground” to allow use of a cathodic protection system. Figure 2-11 shows a typical cable and cable pipe cross-section.

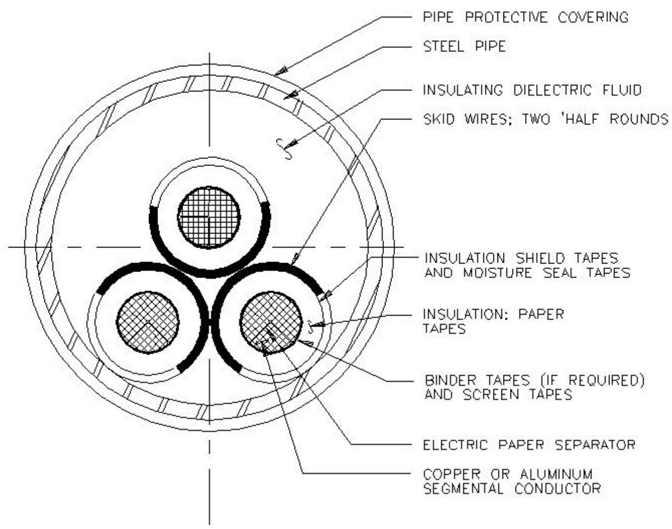


Figure 2-11 Typical Cable and Cable Pipe Cross-Section

The manufacturing process is as follows: a conductor core is covered by helically wound with layers of metalized or carbon black paper tape for the conductor; high quality Kraft paper or paper/polypropylene laminate is then helically wound around the conductor in multiple layers for the insulation; additional layers of metalized or carbon black paper tape helically wound around the insulation to form the insulation shield; the insulated cable is dried and then impregnated with fluid in large pressurized tanks.

Utilities have been increasing use of LPP insulation for voltages 115 kV and above because it has lower losses when compared to conventional Kraft paper. For this reason, the 230 kV Sammamish-Lakeside-Talbot lines would use LPP insulation for an HPFF configuration to meet the rating requirements.

2.2.2 Cable Accessories

Splicing of HPFF cables begins with removal of the insulation and shields from the conductor, the insulation is tapered down to the conductor and the conductor ends are then joined. Insulation paper tape is wound around the spliced conductor, filling the tapered area of the insulation. Metalized tapes or carbon black tapes are used to re-establish the conductor and insulation shields. Hand applied tapes are used, as the three cables are very close together. Figure 2-12 shows a typical HPFF joint.

Figure 2-12 Typical HPFF Joint in a Vault

Terminations are made by first separating the three cables using a trifurcator. Each phase termination is then made in fluid-filled terminators. A typical HPFF cable termination in a substation is shown in Figure 2-13.

Figure 2-13 Typical HPFF Terminations in a Substation

Once the cable system has been installed, the pipe is filled with a synthetic dielectric fluid and is pressurized to a nominal 200 psi pressure. A special pressurization system is needed to monitor and maintain the nominal 200 psi pressure. Figure 2-14 shows a typical HPFF cable system arrangement with a fluid pressurization system.

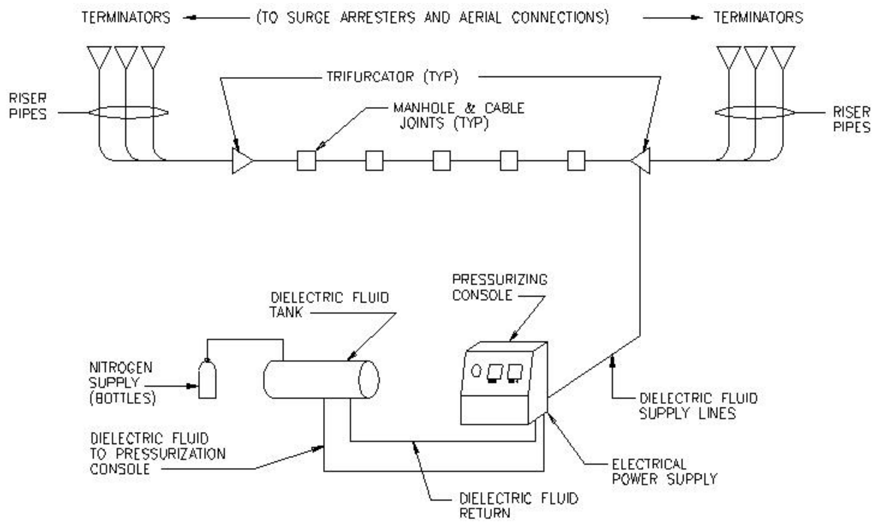


Figure 2-14 Typical HPFF Cable System

A pressurization system for an HPFF cable system consists of three components: a pressurizing console, storage tank and a nitrogen supply. The pressurizing console consists of pressurizing pumps, valves and monitoring equipment. A nominal 200 psi must be maintained in the cable pipe at all times. As the temperature varies during normal operation, the pressure within the pipe would also vary. The system is designed to relieve the pressure as the temperature increases and maintain the pressure as the temperature decreases. A storage tank is provided to accept the extra fluid as the temperature of the cable system increases and provide fluid as the temperature of the cable system decreases or if a leak has occurred. The nitrogen supply maintains a pressure inside the storage tank and prevents any moisture from entering the system. The monitoring equipment controls the operation of the system and communicates the system status to the utility. The size of the pressurization plant would vary depending on the size of the storage tank. A typical size would be 10 feet wide by 50 feet long. Figure 2-15 shows a typical pressurization plant enclosure.

Figure 2-15 Typical Pressurization Plant

The number and location of pressurization plants depend on the length of the cable, elevation changes and other factors affecting fluid pressure in the pipe.

2.2.3 Civil Installation

Open Cut Excavation Method
As with an XLPE duct bank system, open cut trenching would generally be used for a HPFF cable system. Trenchless methods would also be used for crossing of major obstructions. Once the trench is excavated, the steel pipe would be welded together and installed in the trench. The area around the pipe would be filled with thermal sand or a fluidized thermal backfill to provide a good quality thermal environment around the pipe to facilitate heat transfer to earth and meet ampacity requirements. After the pipe encasement is installed, the trench would be backfilled and the site restored. Backfill materials could be clean excavated material, thermal sand and/or a thermal concrete mix.

Trenchless Installation
Trenchless techniques used to jack and bore or HDD would be similar to XLPE. However, since all three cable phases for an HPFF cable system are contained within a single steel pipe, the magnitude of trenchless installations are less than the equivalent XLPE cable system because a large bore diameter and bundle of conduits (with or without casing) to accommodate the cables are not required.

2.2.4 Vault Design and Installation

Like the XLPE cable system, access vaults are needed periodically along an underground route to facilitate cable installation, for maintenance requirements and access for future repairs. Vault would be typically spaced every 2,500 to 3,500 feet along the route. The size of each vault would be about 8 ft wide by 20 ft long, as illustrated in Figure 2-16. Unlike the XLPE cable system, multiple cable pipes could be brought into a single vault for cable installation. For the preliminary cable sizing identified for the Sammamish-Lakeside-Talbot lines, it is assumed vaults would be positioned approximately every 2,500-ft.

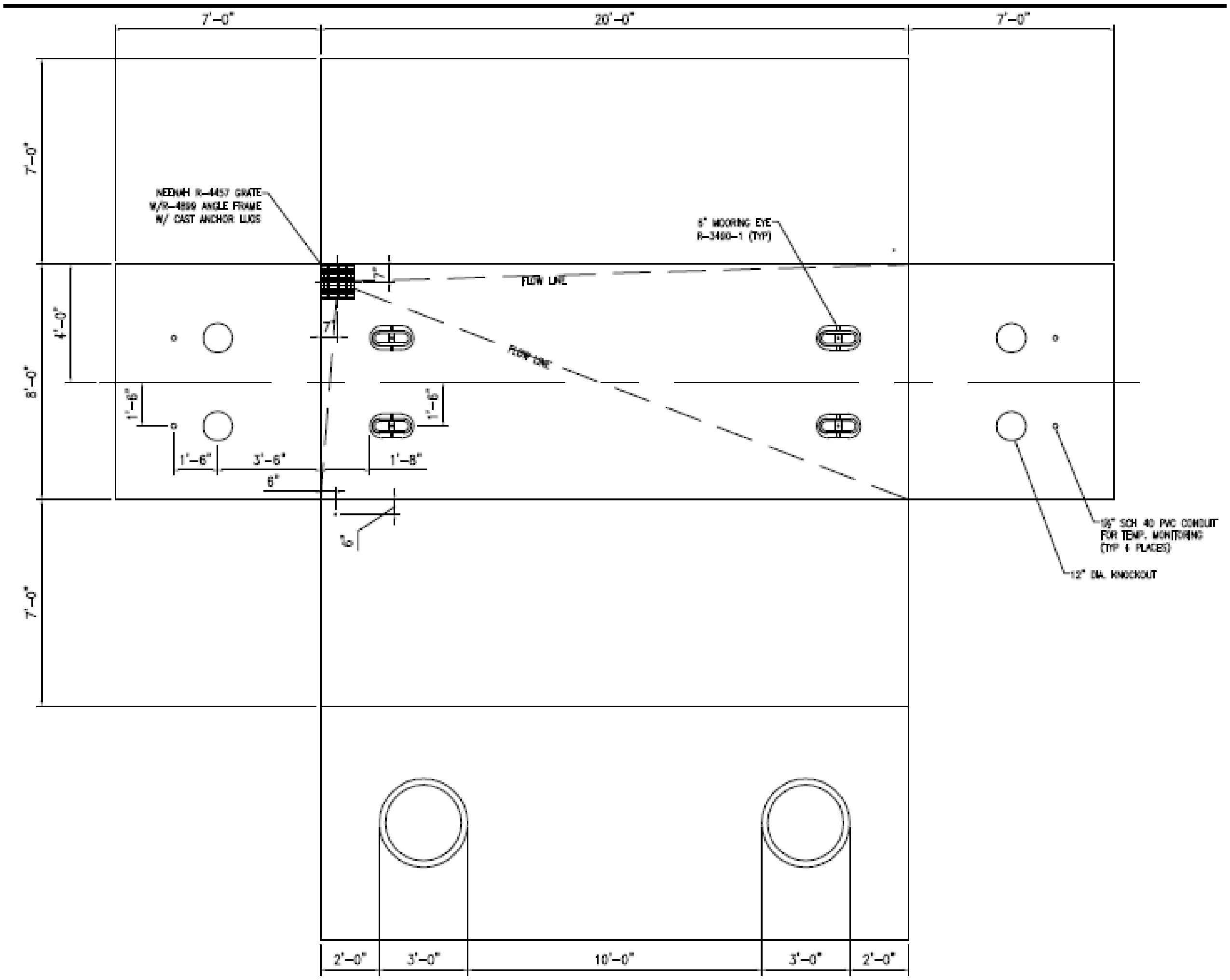


Figure 2-16 HPFF Vault Schematic

2.2.5 Cable Installation and Testing

As with the XLPE cable system, once the cable pipe and vaults have been installed, the cable could be installed. Prior to installation of the cable, the cable pipe would be pressure tested, evacuated tested and cleaned by pulling a mandrel and swab through the cable pipe. If all these tests are successfully completed, the cable pipe would be declared suitable for installation of the cable. Cable installation procedures and equipment would be based on environmental conditions, equipment and material placement and pulling requirements.

While a single cable would be pulled in at one time for XLPE cable systems, all three cables are required to be pulled in simultaneously for an HPFF cable system. The setup would be similar except three reels of cables would be set up at one time.

2.3 Reliability and Cable System Comparisons (XLPE vs. HPFF)

In general, underground transmission cable systems are very reliable. However, the main reliability issue with underground cables compared to overhead transmission is the length of the outage in the event of a cable failure. With overhead transmission, the line can generally be placed back into service in a relatively short amount of time, typically less than a day, thus increasing the line's availability for transmitting load.

Outages on underground transmission cables are primarily caused by dig-ins (i.e., cable damage and fault due to excavation in the vicinity of the underground line). When there is a fault on an underground line, the line may be out of services for a significant amount of time, more than two weeks and up to six months, depending on the type of failure and how quickly it can be located and repaired. The main reason for very long repair times is if new cable and accessories would need to be manufactured, and the time it would take to get such necessary material and qualified personnel to perform the repair work. Because of these longer outage times an underground cable system has a lower circuit availability compared to an overhead line.

HPFF cables have a very good track record and have historically proven to be a robust system with extremely high reliability at all available transmission voltage classes up to 345 kV. However, due to the uniqueness of the fluid pressurized system, very specialized personal are required to install the pipe, cable, accessories, and fluid to ensure successful operation and this high reliability.

Additionally, while XLPE cables themselves have a low intrinsic failure rate because of stringent factory quality control and testing, splices and terminations are susceptible to failure because of their field assembly. Most utilities in the U.S. rely on the cable system manufacturer to provide skilled splicers and special tools to perform repairs of failures on XLPE transmission cables.

XLPE cable systems have their individual pros and cons for consideration and are detailed below.

Pros:	Cons:
• The cable system design, operation, and maintenance is less complex than systems with pressurized dielectric fluid. • Historically, high reliability reported and documented for systems of modern design at voltages 230 kV and below in the U.S., Japan and European countries. • Higher normal operating and short circuit temperature ratings as compared to HPFF systems • Installation environmental condition requirements for splicing and terminating less stringent. • Lower dielectric loses. • Shorter time required for repair. • Concrete encased duct bank systems provide mechanical protection from dig-ins and allow for shortened lengths of trench to be opened during construction installation activities. • The charging current or reactive volt-amperes (VARS) generated by the cable are significantly less than HPFF insulation.	• Susceptible to damage from dig-ins if direct buried, more so than HPFF pipe-type cable systems. • Potential for induced sheath voltages and losses. • Trench for installation of each cable length (direct buried) must be left open for the entire length during cable installation or required to leave cable reel exposed. • Duct bank / conduit installation may reduce thermal performance and increase cost. • It requires extremely strict manufacturing and process quality control because XLPE insulation not as forgiving (HPFF impregnated paper insulation is more tolerant of manufacturing defects and variances). • The high thermal expansion coefficient of the insulation presents special design problems for the metallic sheath and accessories. • Installation on steep slopes is a problem because the cables tend to ratchet downhill in the conduits.

HPFF pros and cons are as follows:

Pros:	Cons:
• Long experience record with extensive use in the U.S. • Very robust and high reliability based on utility records, even if maintenance on the system has been neglected. • Steel pipe affords mechanical strength and protection from "dig-ins". • Short length of trench can be opened for construction activities. • The cable and other materials can be manufactured and installed by firms located in the U.S. • For horizontal directional drilling (HDD) instillations the casing installed can also be utilized as the cable conduit. • Can horizontal directional drill and install a continuous length of cable with no splices for over one mile. • Allows for dielectric fluid circulation to help increase ampacity.	• Pipe susceptible to corrosion. • Requires very large specially designed equipment for installation activities. • Requires specialists for specific installation activities. • May require long repair time in case of faults in the cable system. • Requires installation and maintenance of a cathodic protection system. • Requires maintenance of monitoring and pressurization system. • There is only one cable manufacturer left in North America that produces HPFF cable. • The shunt compensation requirements are significantly higher compared to the requirements for XLPE.

2.4 Termination Stations / Termination Structures

At both ends of an underground transmission line, it is necessary to transition from underground conductors to some form of overhead conductor. This can occur within the terminal substations, at dedicated "transition stations" (fenced in), or at transition structures. If only a portion of the line is underground, an overhead to underground transition would be needed. For low to moderate capacity circuits operating at voltages under 230 kV, this overhead to underground transition can sometimes be accommodated on a single shaft structure, as shown in Figure 2-17.

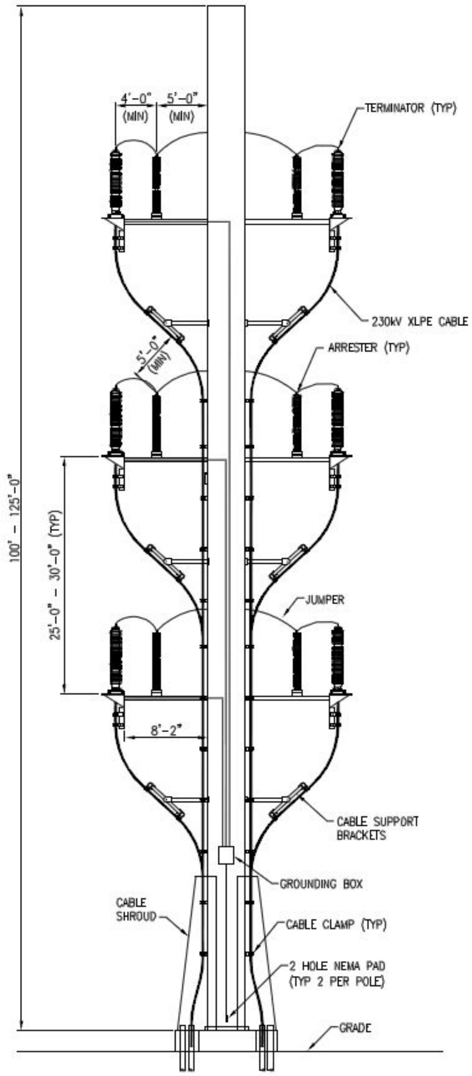


Figure 2-17 XLPE Double Circuit Single Shaft Transition Structure Schematic

Although the undergrounding of new 230 kV Sammamish-Lakeside-Talbot lines from substation to substation would be terminated using common substation structure design and equipment within each station, there is a possibility that PSE may evaluate short segments of underground within a primarily overhead option. These are referred to as "dips" and could be accomplished by use of a "transition structure" or single transition shaft structure to make the conversion from overhead to underground and vice versa. For an XLPE cable dip, the preferred solution is generally a single shaft structure. However, an HPFF cable system would require a "transition station" to accommodate the pressurization plant with terminal structures (standard substation height), as a single shaft structure is not recommended due to the pressure drops that would be associated with high cable termination elevations. An example of an HPFF terminal structure is shown in Figure 2-18. (It could also be used for XLPE cables).

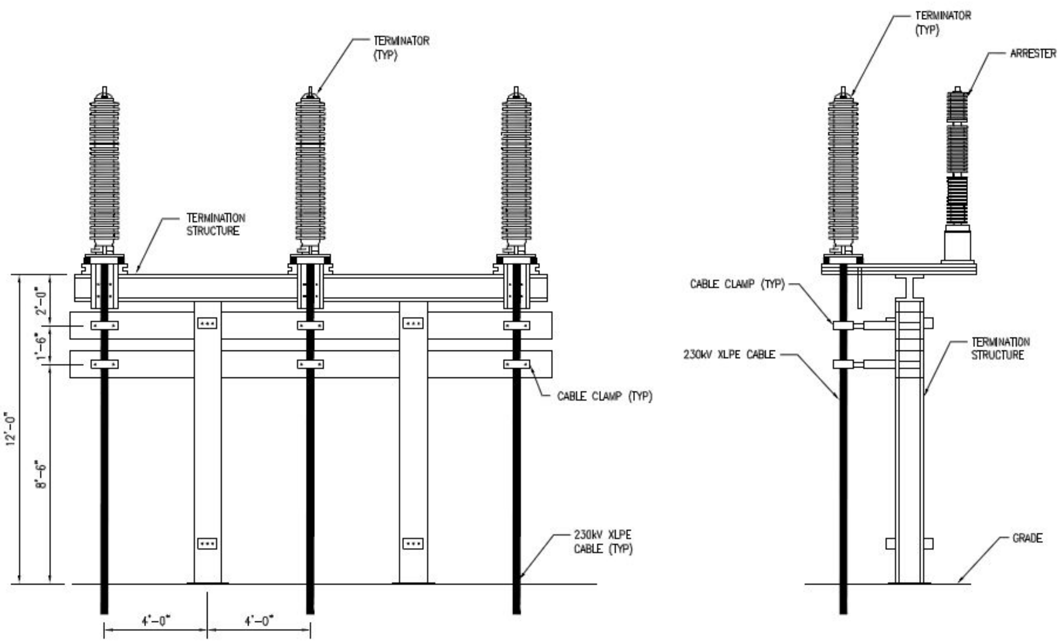


Figure 2-18 XLPE or HPFF Low Profile Transition Structure Schematic

When planning for an underground to overhead transmission line transition, be it a single transition shaft structure or a more complex "transition station", several issues relating to the siting of the structure or station that would need to be considered are: environmental and permitting, community, physical site, and economic considerations.

2.4.1 Reactive Compensation

The electrical capacitance per unit length of the underground transmission line is significantly higher than the capacitance for overhead transmission line because the dielectric constant of the insulation is several times higher than that of air and the ground potential for high voltage cables (the cable shield) is much closer than for overhead lines (the surface of the ground).

For extra high voltage cable systems, the high capacitance of underground cables per unit of length results in relatively high charging current requirements. The reactive mega volt-amperes associated with the cable charging current must either be absorbed by the power system or shunt reactors may be required at one or more locations along the cable circuits. The reactors limit the voltage rise during light-load conditions, especially where the local power system is relatively weak (high system impedances) at the cable location.

The shunt charging of the conceptual cable system designs are provided based on the cable sizing ampacity calculations in Section 5.0. If reactive compensation is needed, PSE would probably install shunt reactors at the ends of the transmission lines, with circuit breakers to disconnect the reactors during high load periods or for maintenance purposes. The capacitance also has a detrimental effect on the utility system for transient overvoltages, circuit breaker capacity, surge arrester duty, etc.

If reactive compensation is required for the underground transmission lines, a "transition station" or additional substation room would be required for the equipment.

2.5 Additional Available Cable Systems

There are additional available cable systems that could be used for the installation of new 230 kV underground transmission, however they are not practical for this project and have not been considered for undergrounding the Sammamish-Lakeside-Talbot lines. A brief discussion of each cable technology is as follows.

2.5.1 Self-Contained Fluid-Filled

Self-contained fluid filled (SCFF) cable systems are very similar to HPFF systems. The cable is typically constructed around a hollow tube, used for fluid circulation, and uses the same Kraft paper or LPP insulation materials. Because the fluid system is “self-contained” the volume of fluid required is significantly less, however, the same distribution of pumping plants would be required. While SCFF cable systems have the longest running history at high voltage levels, their use is typically restrained to long submarine cable installations. (PSE has existing SCFF submarine cables in-service). Although, this technology has been implemented on inland applications with high reliability 230 kV, it is almost never used for land installations today; unless the installation is already related to an existing SCFF system.

2.5.2 Gas Insulated Transmission Line

Gas insulated line (GIL) technology at the 230 kV voltage level has been implemented primarily within substations and not for longer transmission lines. GIL has been incorporated into substation designs with the length typically limited to distances less than 1000 feet. However, the high cost and lack of experience with respect to longer underground transmission lines, and questions of reliability are more of a concern than with the other more prominent cable technologies.

2.5.3 Superconducting Cables

Research is currently underway in the advancement of high temperature superconductors (HTS). Utilizing a unique cable design where all three phases are centered concentrically on a single core, the cables are capable of displaying low electric losses with the same power transfer capabilities as compared with a standard non-superconducting cable. The core, filled with a cryogenic fluid, super cools the conducting material resulting in extremely low losses and high electrical power transfer capacities. Most HTS systems are located adjacent to large metro areas, where they are capable of transferring large quantities of power a few thousand feet, at the distribution level. However, technological advances in the last few years have seen the first 138 kV AC system installed in Long Island, New York in early 2008. Because HTS systems have not been established at 230kV, nor over long distances, superconducting cable would not be a technology option to consider.

2.5.4 High Voltage Direct Current

High voltage direct current (HVDC) underground transmission systems have primarily been used to transmit relatively large amounts of power for long distances that are not feasible for AC underground transmission lines. In most applications HVDC underground transmission lines have been submarine cables. One of the primary advantages of HVDC transmission cables is that they can economically transmit electric power for much greater distances than AC lines. This is a result of the fact that there is no charging requirement for normal operation. The primary disadvantage of HVDC cable systems is that the AC/DC converter stations at both ends of a HVDC transmission line are very expensive. At a minimum, converter stations would be needed at Sammamish, Lakeside, and Talbot Substations. Given the expense, and the short expanse of the lines, an HVDC cable system is not recommended.

3.0 UNDERGROUND CONCEPTUAL DESIGN

The primary route alignment for new 230 kV underground transmission would be within PSE's existing 115 kV overhead line right-of-way (ROW), beginning at Sammamish Substation following the ROW south toward Lakeside. The two alternatives to this route would be using public (street / roadway) ROW or an existing railroad corridor that PSE has purchased the rights to. When routing the underground transmission lines, the type of area and terrain that the line would be crossing play a critical role in the design and cost. The following points of consideration regarding land use are described as it relates to undergrounding transmission lines as part of the conceptual design.

Urban
Urban areas are becoming more and more congested with vehicular traffic and underground utilities. This makes the installation of new underground transmission lines difficult, and extreme care is required to locate the existing underground facilities. The typical location for new underground transmission lines in an urban area is within the road ROW. There is usually very little undeveloped land available that could be used for installing an underground line. To the extent possible, major roads should be avoided because of the large amount of traffic that would have to be controlled. During construction, the entire road (depending on the width) may have to be temporarily closed, with suitable detours, to provide sufficient working space for the installation of the underground cable system. Also, a significant cost of installing lines in urban locations can be traffic control.

Suburban
Suburban areas, like urban areas, are also becoming congested with traffic and construction activities. During construction, the entire road may have to be temporarily closed (with suitable detours) to provide sufficient working space for the installation of the underground cable system.

Rural
Because overhead ROW's are more generally obtainable in rural areas, it is uncommon to install underground transmission lines in these types of areas. If an underground transmission line were to be installed in a rural area, the installation would be relatively easier than in suburban or urban areas primarily due to fewer existing underground utilities and less vehicular traffic.

Rural via ROW
If an underground line were to be installed in a cross country ROW alignment, the type of terrain the underground line must traverse is an important design consideration. A partial list of the different terrains a transmission route may encounter are: flat, rolling hills, mountains, and wetlands or other large water bodies/obstructions. A disadvantage to cross country ROW alignments is the potential for limited accessibility to the route corridor for construction and future maintenance.

The type of terrain and soil conditions can greatly impact the cost of installing an underground cable system.

- Flat terrain – this is normally the easiest type of terrain to perform open cut trenching for transmission cable installation. Typically, a construction road is constructed along the full length of the trenching operation to provide the necessary construction access.
- Rolling hills – this type of a terrain is also well suited for open cut trenching as long as the slope of the hills are not extreme (<10%). Extreme slopes can make open cutting a challenge. The main issue is to be able get all the necessary construction equipment, concrete trucks, tractor trailers, cranes, and cable reels, up and down the slopes to the necessary locations. Suitable access roads

for the construction equipment are needed to get up and down the hill. These access roads can be constructed by cutting into the hill or designing some type of switch back. The type of design is predicated on the extent of the slope. HDD can sometimes be utilized to cross a series of hills to avoid the slope issue. However, gaining access to each drill location would be the primary concern.

- Mountains (rock) – this type of terrain can be a challenge to the construction of an underground cable system. The same issues related to the grade slope discussed above apply to the mountain terrain as well. In addition, mountainous terrain usually indicates the existence of rock. To excavate the rock, explosives may need to be used.
- Wetlands – while open cutting can sometimes be used to cross wetlands, there are significant environmental controls typically applied to the process, and open cutting may be forbidden as a construction technique. In some cases, HDD can be used to span a wetland area.
- Other obstructions – There are other situations where open trenching is not practical. This includes crossing of large rivers, waterways, highways, railroad tracks, and other situations where open cutting is not allowed. Various trenchless techniques or routing changes may be needed in these cases.

Rural Roadway Installations
If the transmission lines are to be installed underground in a rural area, the existing roadway network often provides a routing opportunity. Typically, no easement would be required to install an underground line in a public roadway right-of-way. Rights to install in a public ROW typically take the form of an "occupancy permit" or other license. In some cases, the owner of the road may reserve the right to have the utility relocate the underground line if a future conflict occurs.

3.1 Review of Existing 115 kV ROW (PSE Easement)

The review of PSE's existing ROW was performed by a field reconnaissance in addition to information (data, drawings, etc) obtained by PSE. Only a small portion of the ROW is accessible by vehicle and / or foot, so a large amount of the review was performed using the information provided by PSE and available electronic (online) data.

PSE's existing easement is considered a rural via ROW mixed within a suburban environment. The route is approximately 7.2 miles long from Sammamish to Lakeside, and 9.5 miles from Lakeside to Talbot Hill. The route would generally follow the existing 115 kV PSE Easement as seen in the conceptual route layout in the appendix.

The existing easement contains a number of sensitive areas and obstacles that would need to be addressed in detail during the design of underground transmission for constructability:

- Civil construction – Underground cables are difficult to install where there are steep slopes. Areas would have to be graded where the slopes exceed 10%. There are multiple locations where the slopes exceed 30% where erosion and landslides are also a concern; these major areas are:
  - The northern end of the ROW (Sammamish Substation), shown in Figure 3-1
  - The Lake Hills segment (Lake Hills Connector Road to SE 20th St.)
  - I-90 Crossing, on each side of the Interstate, Figure 3-2
  - Somerset Area – has very severe elevation changes as well, Figure 3-3
  - Coal Creek (and Coal Creek Parkway SE)
  - Cedar River and Maple Valley Highway, Figure 3-4

Figure 3-1 Existing 115kV Corridor just south of Sammamish Substation, looking west

Figure 3-2 Existing 115kV Corridor at I-90, looking south

Figure 3-3 Existing 115kV Corridor in Somerset at 132 Avenue SE, looking south

Figure 3-4 Existing 115kV Corridor crossing at Cedar River and Maple Valley Highway

- Construction access to splicing vaults – Ideally, the vaults for pulling cable and splicing would be spaced close to existing roads so that they are easily accessible via roadway for the initial installation work and for operation to facilitate PSE entrance for maintenance. (Vaults that are spaced approximately 2,000-ft for XLPE, and 2,500-ft for HPFF was selected as the basis for estimating purposes in Section 5). However, there are many long segments along PSE's existing easement that are difficult to access. A heavy-duty construction road would need to be constructed in these areas to allow access for the vehicles and equipment used for both civil construction activities and electrical (cable installation) work. The road would have to be constructed so that tractor trucks with low-profile flatbeds could use it to transport heavy weighted vaults, cable reels, etc to the location needed.
- Cable restraint and anchoring – In areas where there are significant elevation changes along the route, XLPE cables that are installed in conduit would tend to slide downhill due to a ratcheting action. The cable downhill ratcheting is caused by a combination of gravitational forces and the expansion/contraction cycles that occur when the cables heat and cool during daily load cycles. Similarly, for an HPFF system, the cables would want to move in the pipe due to these thermo mechanical forces. If means are not provided to mitigate this then the cables would eventually move downhill resulting in excessive bending of the cable or cable joints in the downhill vault. In order to minimize this and eliminate the potential for failure, additional anchoring vaults may be needed to restrain the cable in areas where there are significant elevation differences between splicing vaults.
- Rock excavation – There are areas along the corridor that would require excavation through rock. Costs can be significant to do so and may require special construction techniques such as drilling and blasting.

Figure 3-6 illustrates the impact and disturbance associated with new underground duct bank and vault placement within an existing transmission easement, with vegetation clearing. This is an example of what it might look like to construct one of the Sammamish-Lakeside-Talbot lines underground. Note, this picture depicts a single underground line with two cable per phase (see Section 3 for the Eastside 230 kV underground conceptual designs) – the civil infrastructure needed for the second Eastside 230 kV underground line would be installed after the civil works have been completed for the first.

Figure 3-5 Duct Bank and Vault Placement in Rural ROW

3.1.1 Olympic Pipe Line

Portions of PSE's 115 kV overhead easement corridor are shared with Olympic Pipe Line Company (OPLC) which operates two steel pipeline systems that transport gasoline, diesel, and jet fuel (petroleum products). OPLC operates their lines pursuant to their own easements and where they overlap, subject to PSE's prior rights. The pipelines are 16-inch and 20-inch in diameter and are coated with a coal tar enamel wrap, buried approximately 3-ft to 4-ft below the surface. Based on existing record data, the lines weave back and forth within PSE's easement, and in some instances leave the corridor onto easement or public ROW and then enter back into PSE's easement corridor further along the route.

Construction of new underground transmission in the vicinity of the OPLC pipelines is viable. However, OPLC provided PSE with stringent construction requirements in the area of their pipelines which would impact the design of new underground transmission lines within the same corridor. The major items are *italicized*, followed by a technical response:

- *"All foreign lines shall cross the pipeline right-of-way at, or as near to, a 90 degree angle as is feasible. In no instance shall the angle of the crossing be less than 45 degrees. The foreign line shall cross under the pipeline with at least ten feet (10') of vertical separation unless the pipeline is at a prohibitive depth."* Because the pipelines follow random alignments and zigzag back and forth within the corridor, new underground transmission lines would be forced to cross under them at multiple locations since the lines cannot be designed and installed in a manner that would eliminate such. Typical installation depth for the new underground transmission lines would be 3-ft, however additional depth would be needed for these crossings which would increase construction costs to accommodate OPLC's 10-ft separation requirements for construction. PSE would most likely require an exception to the 45 degree minimum angle of crossing requirement, as it is unlikely that the design would be able to accomplish this.

- *"In no instance shall the foreign line be placed parallel to the pipeline within the pipeline right-of-way."* It would be a challenge to construct the two new underground transmission circuits outside of Olympics easements and still be within the 100-feet ROW where PSE's operates the existing overhead lines.
- *"A utility with a cathodically protected foreign line which crosses or is placed adjacent to OPLC's pipeline(s) must install a test point and perform interference testing between the utility and OPLC. Please contact OPLC's Corrosion Technician by calling our main office at (425) 226-8883."* An HPFF installation would require cathodic protection and incur additional costs for interference testing.

After contacting OPLC, they have stated to PSE that they will not consent to other underground facilities being installed longitudinally in their easements.

3.1.2 Cedar River and Maple Valley

As the ROW approaches Maple Valley Highway, near the Talbot Hill Substation, the route would require traversing the Cedar River and associated valley. The valley slopes range from 15% to more than 35% with significant elevation changes of more than 225 feet. The presence of rock is likely in this area. These steep slopes would result in challenges that would be difficult to overcome during construction such as grading for access/supply roads and designing a cable anchoring system to resist downhill cable movement. Maintenance of the circuits would also be a concern if there is a repair required in the area.

As a result of the steep terrain near the Maple Valley, the cable system would instead leave PSE's easement and follow NE 3rd Street to Sunset Boulevard (as shown in the Appendix aerial route drawings). The alignment would then follow Renton Avenue to Beacon Way to the Talbot Hill Substation. These streets are considered primarily suburban type construction and would require traffic control during construction.

3.1.3 Easement & Construction Requirements

The existing PSE easement corridor does not contain rights to underground installations. Therefore PSE would have to obtain an easement for underground construction and subsequent maintenance access. During construction the easement would contain an access road (could be gravel, compacted dirt, etc) so equipment and materials can be brought to the work location. Ideally, portions of the road would permanently remain in place for accessing the cable system vaults during maintenance and operation.

Typically the construction easement would be as wide as possible for rural construction. At minimum, a 30 foot construction easement would be needed to install each underground line. Figure 3-6 demonstrates a typical "off-road" cross section of a single trench duct bank installation.

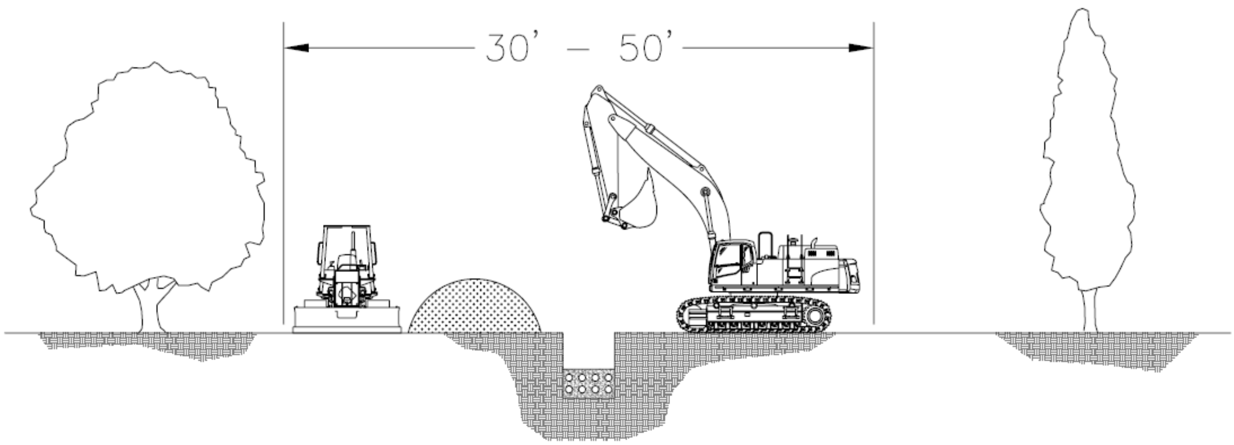


Figure 3-6: Off-road Construction

A 50 foot minimum permanent easement is required to maintain both duct banks post construction. This easement will primarily be used to keep vegetation from interfering with the duct bank, as well as to maintain or repair the lines.

3.2 Review of Roadway Alternate

As an alternate to using PSE's existing corridor, roadways that parallel the route could be used to construct underground transmission lines. They would be primarily within a suburban setting, and although the length of installation would be longer, civil construction would benefit by not having to construct access roads and reduce the amount of cut and fill efforts since the slope changes are less.

The roadway alternative has disadvantages such as:

- Public impact – a significant amount of traffic control would be required and partial, or potentially full street closure may be needed for both civil and electrical installation activities.
- Existing utilities – the presence of many existing facilities would have to be taken into consideration during design and construction.
- Schedule – the overall length of time to install the underground transmission lines within roadways is expected to be longer than within the PSE easement due to existing utilities and road restrictions based on the work hours it would take to control traffic and avoid disturbing residents to the greatest extent possible.

The street routes can be seen in the conceptual route layout in the appendix. For this alternate, the following routes have been identified as potential options for routing the underground transmission lines within the roadway:

3.2.1 Route Summary

Primary Roads Between Sammamish and Lakeside

- 148th Ave NE Route
  - The route begins Sammamish and continues to Willows Road NE. Then heads south on 148th Ave NE to SE 16th St. The route heads west on SE 16th St/Kamber Rd to Lakeside.
  - Route is approximately 7.8 miles long.
  - Majority of route is located on 148th Ave NE, much of which is a divided four lane road. A four lane divided road would allow for better traffic control options, such as closing two lanes while still maintaining two way traffic.
- 140th Ave NE Route
  - The route begins Sammamish and continues to Willows Road NE. Then heads south on 148th Ave NE to Redmond Way, where it turns west to 140th Ave NE to south on Kamber Rd to Lakeside.
  - Route is approximately 7.9 miles long.
  - Majority of route is located on 140th Ave NE, which is primarily a two lane road, making it difficult to maintain two way traffic during construction.
  - In the area of the Bridal Trails there are two lanes however the width of the road is very narrow which would create traffic control challenges and impact the public in the immediate area.

<u>Primary Roads Between Lakeside and Talbot Hill</u>

- West Route
  - The route begins at Lakeside and heads west on SE 30th St to Richards Rd, where it turns south to Coal Creek Parkway SE/Duvall Ave NE. Then heads west on Sunset Blvd and NE 12th St. until it turns south on Sunset Blvd and makes its way to Beacon Way to Talbot Hill.
  - Route is approximately 10.7 miles long.
  - Richards Rd, Coal Creek Parkway and Sunset Blvd are all primarily four lane roads, meaning two way traffic is easier to maintain during construction.
- East Route
  - The route begins at Lakeside and heads west on SE 30th St to Richards Rd, where it turns south to Coal Creek Parkway SE/Duvall Ave NE to NE 4th St. From NE 4th St, the route head east to 156 Ave SE, where it turns south to Maple Valley Highway. The route follows Maple Valley Highway until it turns south on 140th Way SE, then turns west on SE Fairwood Blvd and continues west through residential streets to Beacon Way until reaching Talbot Hill.
  - This route is approximately 15.1 miles long.
  - The north portion of this route is similar to the West Route. However, the south portion of this route is primarily through residential streets.

3.2.2 Easement & Construction Requirements

Using roadways for the underground transmission circuits requires the duct bank installation to occur in public street ROW, requiring associated traffic control. The contractor would be required to provide an approved traffic control plan and obtain any required permits for construction of the underground transmission lines. One lane of traffic must remain open at a time, with flagmen at each end directing traffic.

Typically a 20 foot construction easement is utilized on city streets for a single trench duct bank. Figure 3-7 shows a cross section of a common duct bank construction installation on a public roadway.

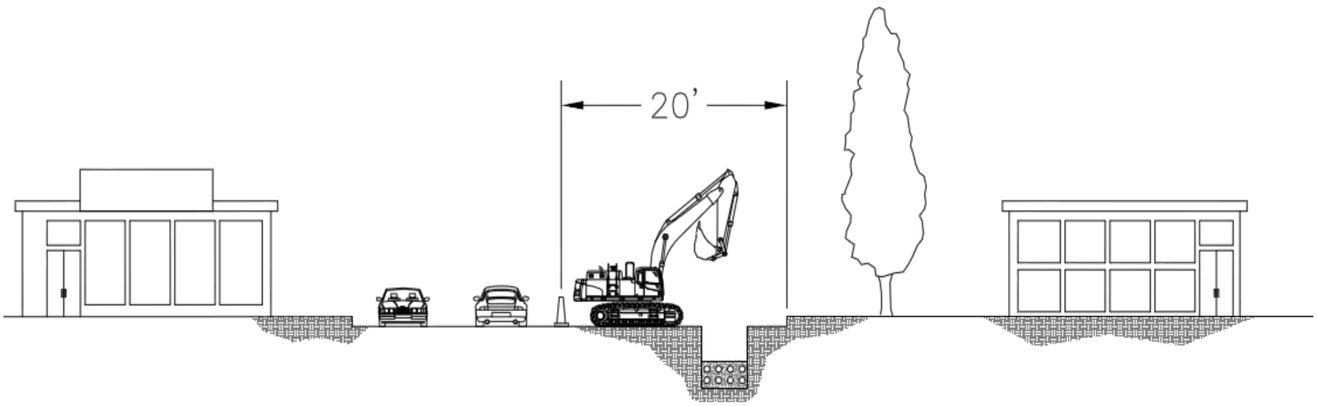


Figure 3-7: City Street Construction

3.3 Review of Railroad Alternate

PSE has acquired an easement along an existing railroad (RR) corridor in King County that might be available to use to install new underground transmission. Civil construction would also benefit by not having to perform significant grading of rolling terrain like the 115 kV ROW, and also lesson impact to the public by avoiding public roadway ROW. Figure 3-8 is a snapshot view of the RR ROW. An example of what the duct bank construction would look like in the RR corridor can be seen in Figure 3-9. This example is from a project in Virginia that contained a retired railroad already converted into a hiker/biker trial. A new 230 kV cable system was installed within the existing trail. Note; the photograph is only for one circuit – PSE would need a second duct bank installed within the easement for the other transmission line.

Figure 3-8 PSE RR ROW

Figure 3-9 Example of duct bank construction in Railroad (retired) Corridor

The PSE RR routing options can be found in the conceptual route drawings in the appendix.

Major disadvantages with the RR ROW are:

- Location of the ROW with respect to the substations – the RR ROW is not close to the existing 115 kV corridor (and associated substations) and routing along it is not logical due to the significant length it would add when compared to the other alternatives. The long segments would still have to be installed within roadways and increase the total construction costs.
- Stability and size of ROW – there are areas of the ROW that become very narrow (less than 40-ft) which would complicate civil construction and also cable installation. There are also steep side slopes (and inverted slopes) that would require grading for stability.
- Multiple use corridor with other easement holders must also be accommodated.
- Due to changes in elevation, the railroad is on bridges in areas which are not conducive for underground transmission installation.
    - A railroad bridge is located just south of the Lake Hills Connector due to grade elevation changes. Underground construction would be challenging due to these profile changes as discussed previously.

3.3.1 Route Summary

<u>Route Between Sammamish and Lakeside</u>

- The route begins at Sammamish and continues to Willows Road NE. Then heads south on 148th Ave NE to Redmond Way, where the route continues west to Kirkland Way. At Kirkland Way, the route turns south and intersects the railroad right of way. The route would follow the Railroad to the northwest corner of the intersection of Highway 90 and 405, where the route crosses Highway 405 by HDD to SE 32nd St to Richard Rd to 30th St. to Lakeside.
- Route is approximately 11.5 miles long.
- Majority of route is located on along the railroad right of way and Redmond Way.
- Crosses Highway 405 four times, two of which would require approximately 1200-ft and 2000-ft long HDD’s.

<u>Route Between Lakeside and Talbot Hill</u>

- The route begins at Lakeside and heads west on SE 30th St to Richards Rd, where it turns south until it turns west on SE 32nd St., then crosses under Highway 405 to intersect the railroad right of way. The route continues on the railroad right of way, eventually coming to Renton Ave. S to Beacon Way to Talbot Hill.
- Route is approximately 9.8 miles long.
- Majority of route is located on along the railroad right of way.
- Crosses Highway 405 twice (one 1200 ft HDD required) and Highway 90 once with a 1000 ft HDD.

3.3.2 Easement & Construction Requirements

The railroad alternate route currently has abandoned ROW that varies from 100 feet to less than 40 feet. The easement requirements for the underground transmission line along the railroad route are similar to the requirements described in the review of the existing PSE 115 kV easement.

3.4 Review of Seattle City Light Tap Alternate

PSE has requested that one double circuit 230 kV alignment “tap in” to the existing 230 kV Seattle City Light (SCL) system with underground transmission near the Highway 405 and Highway 90 intersection, and be routed to Lakeside. Likewise, double circuit 230 kV underground transmission lines would also "tap out" from Lakeside to the same lines. Both alignments would leave Lakeside on SE 30th St. to Richards road. There, one alignment would turn north to SE 26th Pl., and tie into the existing SCL lines at 124th Ave. SE. The other alignment would turn south to SE 32nd St., and tie into the existing SCL lines at 125th Ave. SE.

The SE 26th Pl. route is about 1.2 miles in length, while the SE 32nd St. route is about 0.8 miles in length. Both of these routes are considered to be suburban type construction, and have similar challenges as described in the street alternate.

For an HPFF cable system, the taps would be made at transition stations. For an XLPE cable system, the taps could be accomplished with riser structures used to intercept the existing SCL lines. Figure 3-10 is an example of a double circuit 230 kV overhead to underground riser structure. Each structure contains two underground cables per phase to match the overhead line rating.

Figure 3-10 Typical 230 kV Riser Structure

3.5 XLPE Cable System Design

3.5.1 System Description

Open Trench
For open trench underground construction, the cable system would consist of a double circuit 230 kV XLPE cable, using two cables per phase to meet loading requirements, installed in a 2'-3" x 4'-0" concrete encased duct bank. The duct bank would consist of multiple conduits to carry the transmission line cables and grounding cables. The concrete duct bank would have a compressive strength of 3000 psi and be installed at a depth to provide a minimum of thirty-six inches (36") of cover. The conduit details within the duct bank are as follows:

- Eight (8) eight inch (8") schedule 40 PVC conduits used for the transmission line cable per circuit. Initially, six out of the eight 8" conduits would have cable installed, allowing for two spare conduits.
- One (1) two inch (2") schedule 40 PVC conduit installed for ground continuity cable per circuit.
- One (1) two inch (2") schedule 40 PVC conduit installed for communication cable per circuit.

The final duct bank size and layout would be determined during final design based on PSE's final design criteria. Factors to be considered are electrical requirements, heat dissipation, minimal burial depths, existing facility/utility locations and cable installation requirements. Figure 3-11 shows a typical trench detail and installation cross section.

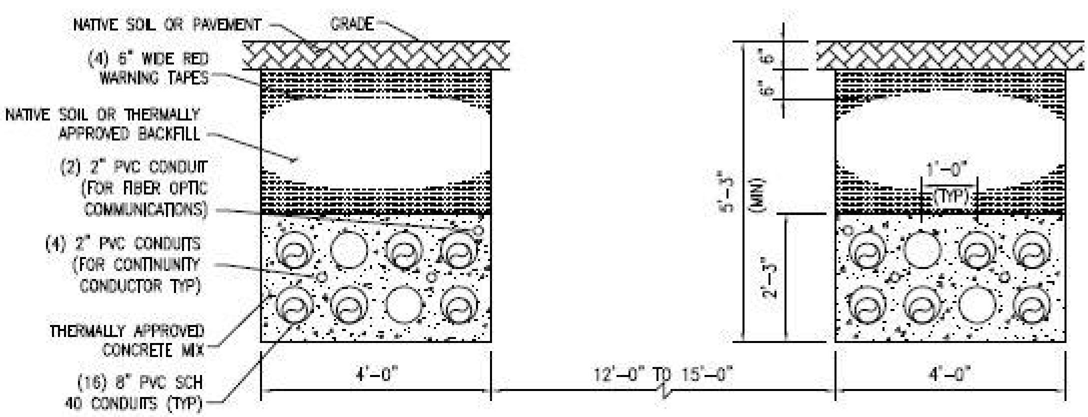


Figure 3-11 XLPE Typical Trench Detail

Trenchless
Two possible trenchless methods for crossing difficult terrain are the horizontal directional drilling method and also the jack and bore (J&B) method. These methods require a transition from the open trench installation to the desired trenchless arrangement. Figure 3-12 and 3-13 show the proposed HDD and J&B conduit arrangements. The bored designs would contain high density polyethylene conduits that are joined by fusion welding to allow for the tensions seen while the conduits are pulled into a borehole. The parameters for these HDD designs are as follows:

- Four horizontal directional drills, utilizing a 25-inch diameter bundle. Each HDD contains one three-phase set of cable ducts and one spare duct for the 230 kV double circuit transmission lines.
- A minimum spacing between drills of 15 feet to minimize mutual heating effects during operation.

- Within each HDD bundle are:
  - Four (4) eight inch (8”) HDPE conduits used for the transmission line cables.
  - One two inch (2”) HDPE conduits used for a ground continuity cable.
  - One two inch (2”) HDPE conduit for communication cables.

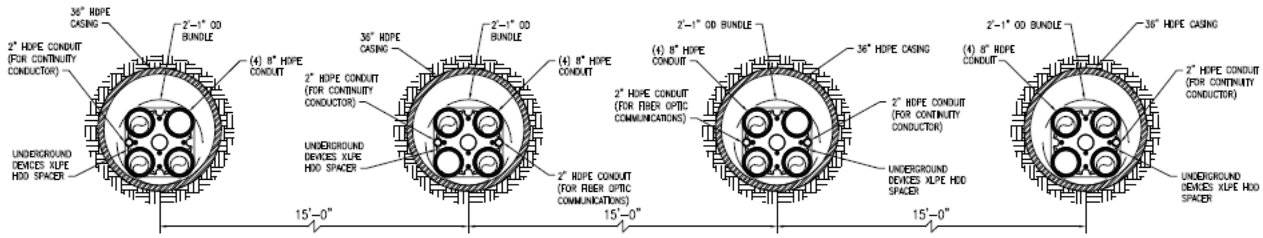


Figure 3-12 XLPE Typical HDD Detail

*The HDD casing may be optional, depending on a geotechnical investigation / requirements.

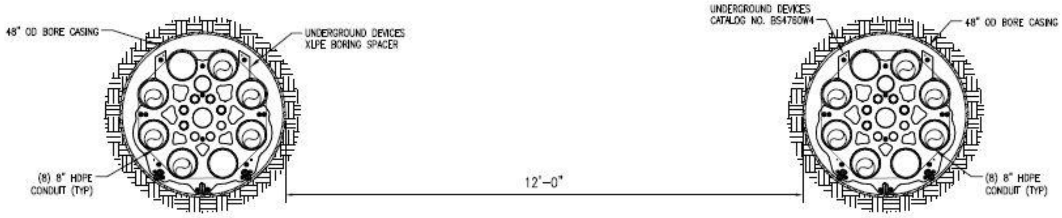


Figure 3-13 XLPE Typical Jack and Bore Detail

The parameters for the J&B design are as follows:

- A jack pit at each end of the forty-eight inch (48”) bore having a forty foot (40’) length and ten foot (10’) width. Each J&B utilizes a bundle that contains two three-phase set of cable ducts and two spare ducts for the 230 kV transmission double circuit.
- A minimum spacing between drills of 15 feet to minimize mutual heating effects during operation.
- Within each J&B bundle are:
  - Eight (8) eight inch (8”) HDPE conduits used for the transmission line cables.
  - Two (2) two inch (2”) HDPE conduits used for a ground continuity cable
  - One two inch (2”) HDPE conduit for communication cables.

3.6 HPFF Cable System Design

3.6.1 System Description

The design and installation of HPFF cables within fluidized thermal backfill, jack and bore, and horizontal directional drill is described below.

<u>Open Trench</u>
For open trench underground construction, the cable system would consist of a double circuit 230 kV HPFF cable, using two cables per phase to meet loading requirements, installed in a 2’-6” x 3’ fluidized thermal backfill (FTB) envelope. The envelope would consist of multiple pipes and conduits to carry the transmission line cables and fiber-optic cables. The FTB would have a compressive strength of approximately 100 psi and be installed at a depth with a minimum of thirty-six inches (36”) of cover. The details within the system are as follows:

- Two (2) 10 inch (10”) carbon steel pipes used for the transmission line cables per circuit.
- One (1) two inch (2”) HDPE conduit for communication per circuit.

The final trench size and layout would be determined during final design and would be based on PSE’s final design criteria. Like a solid dielectric cable system, factors to be considered are electrical requirements, heat dissipation, minimal burial depths, existing facility/utility locations and cable installation requirements. Figure 3-14 shows a typical trench detail.

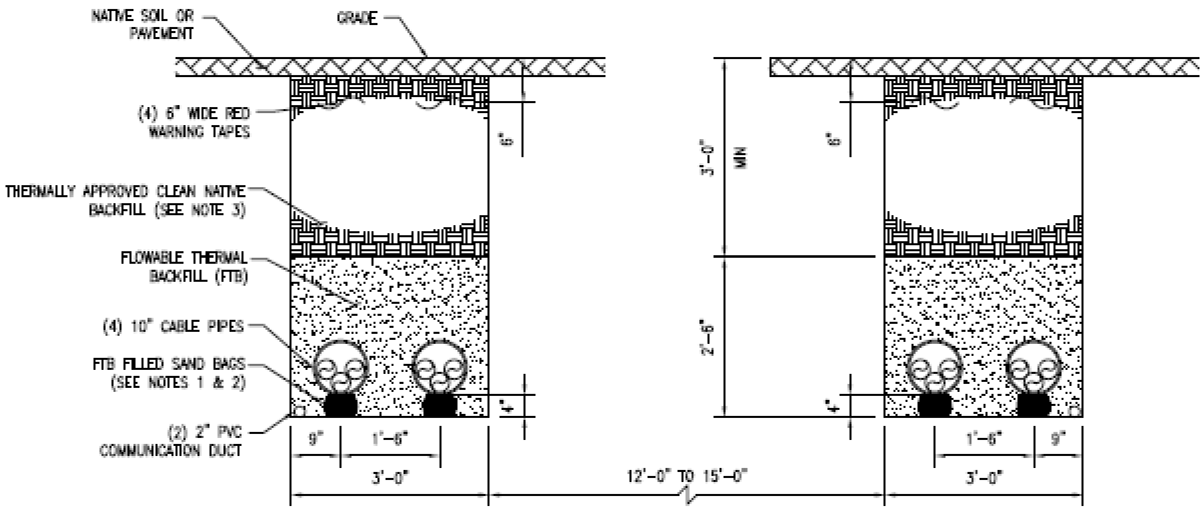


Figure 3-14 HPFF Typical Trench Detail

Trenchless

To accommodate the HDD design, a 0.375” thick wall design allows for an increased protection from kinking the pipe during pull-back operations. Figure 3-15 show the proposed HDD conduit arrangements for HPFF. The parameters of the HDD design are as follows:

- Four horizontal directional drills, each HDD would contain one three-phase set of cables for the double circuit 230 kV transmission line.
- A spacing between drills of 15 feet to minimize mutual heating effects during operation.
- One (1) 10 inch (10”) carbon steel pipe used for the transmission line cables for each HDD.

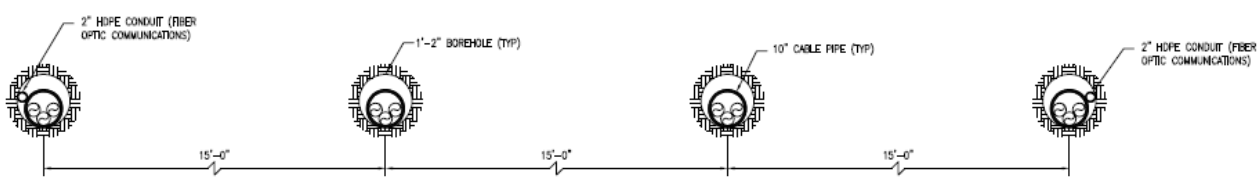


Figure 3-15 HPFF Typical HDD Detail

Figure 3-16 show the proposed J&B conduit arrangements for HPFF. The parameters for the J&B design are as follows:

- A jack pit at each end of the thirty inch (30”) bore having a forty foot (40’) length and ten foot (10’) width. Each J&B utilizes a bundle that contains two three-phase cable pipes for the 230 kV transmission double circuit.
- A minimum spacing between drills of 15 feet to minimize mutual heating effects during operation.
- Within each J&B bundle are:

- Two (2) 10 inch (10”) carbon steel pipe used for the transmission line cables.
- Two (2) two inch (2”) HDPE conduit for communication cables.

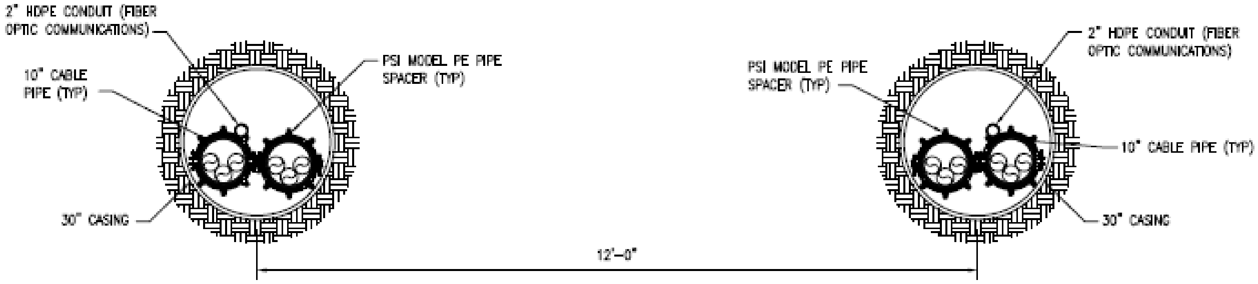


Figure 3-16 HPFF Typical Jack and Bore Detail

4.0 CABLE DESIGN

Overhead transmission lines generally have larger power transfer capacity when compared to an equivalent insulated cable in an underground installation. Underground cable manufacturers are also limited in the size conductor they can produce to achieve a line rating with one cable per phase. For this reason it may be necessary to use multiple cables per phase to meet the meet the rating requirements for the new 230 kV Sammamish-Lakeside-Talbot lines. POWER performed ampacity calculations for various underground line configurations to determine preliminary cable sizing requirements.

Ampacity in an underground cable system is determined by the capacity of the installation to extract heat from the cable and dissipate it to the surrounding soil and atmosphere. The maximum operating temperature of a cable is a function of the damage that the insulation can suffer as a consequence of high operating temperatures. The insulation withstands different temperatures as a function of the duration of the currents, i.e. steady state, transient (or emergency), or short-circuit. Positive, zero, and mutual sequence impedances are used to determine if the cable system is properly protected, locating faults, and determining voltage drops. The impedance calculations are based on cable orientation, spacing, grounding method, and sheath configurations.

For these cable ampacity calculations, the different installations were modeled in the worst case scenario that each would encounter, most often the horizontal directional drill (HDD). The different installation configurations were used to assemble the final ampacity summary tables below.

Soil thermal resistivity values and earth ambient temperatures were based on assumed values. Ampacity calculations were performed using the following system requirements:

Nominal Voltage: ....230 kV
Required Ampacity……………………………….2008 A
Required Power: ....800 MVA
Load Factor……………………………………….60%
Emergency Duration: ....2, 4, 8 & 12 hour

4.1 Cross-Linked Polyethylene Ampacity Calculations

For XLPE cable a combination of installation methods were investigated to meet the ampacity requirements. The first method, open cut trench, would be used in areas where the majority of the terrain is level and/or consists of slight, even grading. Where required, the route could be graded to facilitate the cables in a duct bank. The other method, HDD, would be used for water crossings and treacherous terrain where open cut excavation is not an option. Each method would require two cables per phase for each circuit. The following design parameters were used for the XLPE HDD and duct bank ampacity calculations:

XLPE HDD Design Parameters

Conductor:..3500 kcmil Copper, segmented
Maximum Conductor Operating Temperature:.......90°C (steady-state)
....105°C (emergency)
Assumed Native Soil Thermal Resistivity: ....90°C-cm/W
Assumed Encasement Thermal Resistivity: ....70°C-cm/W
Earth Ambient Temperature:..................................15°C
Calculation Depth:..60 feet
Pipe:...36-inch HDPE casing (Optional, depending on geotechnical investigation / requirements)

XLPE in Duct Bank Design Parameters

Conductor:..3500 kcmil Copper, segmented
Maximum Conductor Operating Temperature:.......90°C (steady-state)
....105°C (emergency)
Assumed Native Soil Thermal Resistivity: ....90°C-cm/W
Assumed Encasement Thermal Resistivity: ....90°C-cm/W
Earth Ambient Temperature:..................................25°C
Calculation Depth:..3 feet (top of concrete)
Duct Bank Design: ....2x4 – 8 inch PVC duct

4.2 High-Pressure Fluid-Filled Ampacity Calculations

The HPFF cable system would require each circuit to have two cables per phase installed by both an open cut trench with backfill and through HDD. Calculations have assumed the use of stainless steel shield tapes and skid wires, and also laminated paper polypropylene insulation.

HPFF Cable System HDD – Design Parameters

Conductor:..3500 kcmil Copper, segmented
Maximum Conductor Operating Temperature:.......85°C (steady-state)
....105°C (emergency)
Assumed Native Soil Thermal Resistivity: ....90°C-cm/W
Earth Ambient Temperature:..................................15°C
Calculation Depth:..58.5 feet
Horizontal Spacing between Cable Pipes:...............15 feet
Cable Pipe: ....10-inch steel pipe, Fusion Bonded Epoxy Coating

HPFF Cable System in Trench – Design Parameters

Conductor:..3500 kcmil Copper, segmented
Maximum Conductor Operating Temperature:.......85°C (steady-state)
....105°C (emergency)
Assumed Native Soil Thermal Resistivity: ....90°C-cm/W
Assumed Encasement Thermal Resistivity: ....90°C-cm/W
Earth Ambient Temperature:..................................25°C
Calculation Depth:..3.5 feet

Horizontal Spacing between Cable Pipes:...............1.5 feet
Cable Pipe: ....10-inch steel pipe, Polyethylene Coating

4.3 Summary of Ampacity Calculations

Final circuit rating would depend on detailed engineering and final configuration of the underground transmission line. The table below summarizes the cable ampacity of the circuits based on the installation parameters described above.

		HPFF		XLPE	
	Calculation	Ampacity/Circuit (Amperes)	Rating/Circuit (MVA)	Ampacity/Circuit (Amperes)	Rating/Circuit (MVA)
Normal	Typical Open Cut Trench	2684	1069	3282	1307
	Horizontal Directional Drill	2122	845	3030	1208

Table 4-1 Normal Operation Ampacity Calculations

		HPFF		XLPE	
	Emergency Calculation	Ampacity/Circuit (Amperes)	Rating/Circuit (MVA)	Ampacity/Circuit (Amperes)	Rating/Circuit (MVA)
2 hour	Typical Open Cut Trench	5470	2179	7178	2860
	Horizontal Directional Drill	4132	1646	7209	2726
4 hour	Typical Open Cut Trench	4596	1831	5910	2354
	Horizontal Directional Drill	3710	1478	6003	2391
8 hour	Typical Open Cut Trench	3988	1589	5013	1997
	Horizontal Directional Drill	3270	1303	5102	2032
24 hour	Typical Open Cut Trench	3402	1355	4343	1730
	Horizontal Directional Drill	2824	1125	4454	1774

Table 4-2 Emergency Operation Ampacity Calculations

4.4 Conclusion of Ampacity Calculations

The HPFF cable system is limited to a maximum conductor size of 3500 kcmil and would require two cables per phase to meet the proposed 800 MVA rating.

XLPE cables can be produced up 5000 kcmil, however the 800 MVA requirement cannot be achieved with one cable per phase. The deeper sections of the bored cable routes would require two cables to meet the proposed 800 MVA rating. The results of the XLPE calculations with a conductor size of 3500 kcmil are somewhat higher than the equivalent HPFF which would mean that a smaller conductor size could most likely be used. Detailed engineering would be required to confirm the assumptions of this study and whether or not a smaller conductor size would meet the ampacity requirements, and provide overall cost savings compared to 3500 kcmil cables.

4.5 High-Pressure Fluid-Filled System Calculations

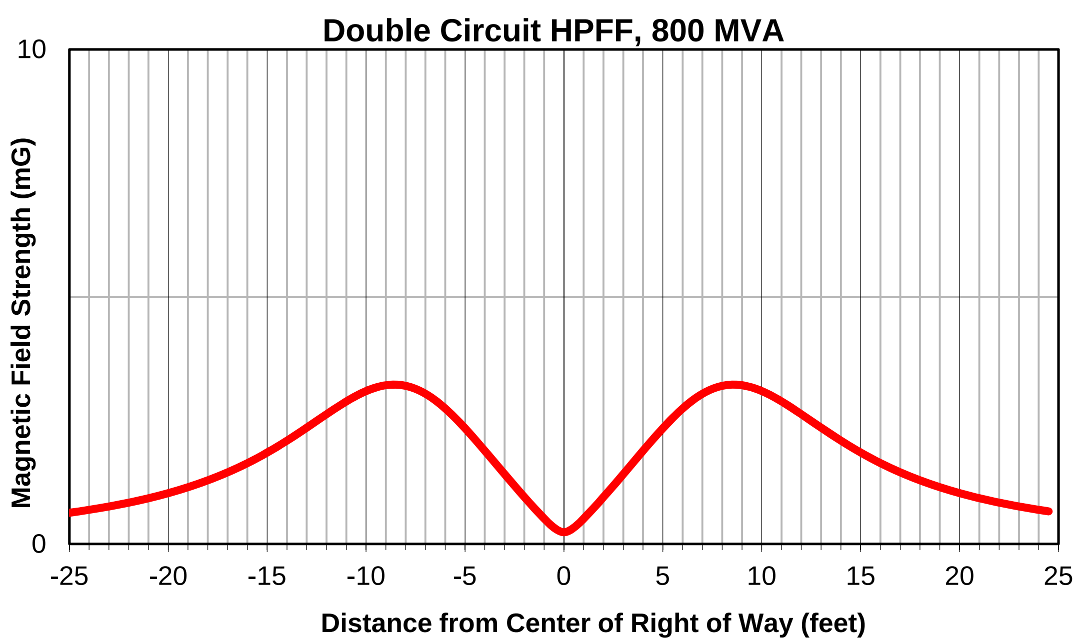
The HPFF cable system calculations use specific cable properties and the following system criterion:

Cable Configuration ....Cradled
Assumed Fault Current.............................. 40,000 A
Calculation Method: ....Neher 1964

HPFF Cable System Calculations (per 1000 ft) (per circuit)	
Positive / Negative Self Impedance	0.0039 + j 0.0214 Ω
Zero Sequence Self Impedance	0.0274+ j 0.0418 Ω
Reactive Charging Power	1.5 MVAR
Capacitance	0.23 μF
Charging Current	11.5 A
Maximum Electromagnetic Field (EMF)*	2.1 mG

***Calculation performed at 1 m above ground** **Table 4-3 HPFF System Calculations**

Electric and Magnetic field intensities were calculated at one (1) meter above grade, at a standard three (3) foot trench depth, and at an 800 MVA rating.



4.6 Cross-linked Polyethylene System Calculations

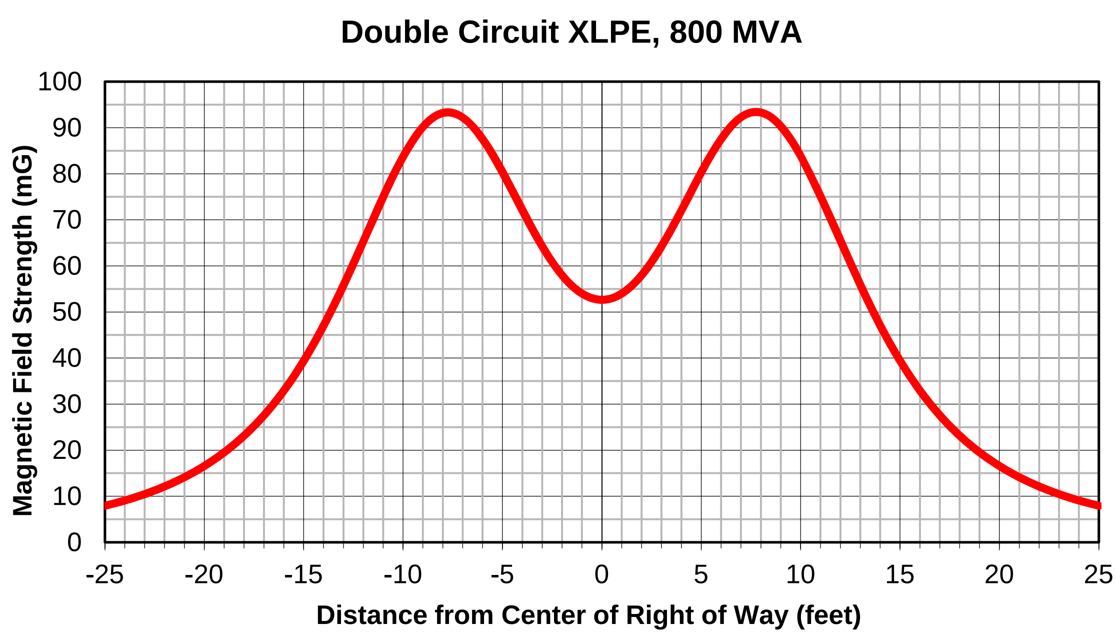
The XLPE cable system calculations use specific cable properties and the following system criterion:

Bonding Method:..Single Point
Ground Continuity Conductor:................................Round Copper
Shield Configuration............................. ....Copper laminate, w/ concentric wires
Cable Spacing:...1.5 ft
Calculation Method: ....Generalized Matrix calculation

XLPE Cable System Calculations (per 1000 ft) (per circuit)	
Positive / Negative Self Impedance	0.001957 + j 0.031 Ω
Zero Sequence Self Impedance	0.045 + j 0.113 Ω
Zero Mutual Impedance	0.019 + j 0.019 Ω
Reactive Charging Power	0.906 MVAR
Capacitance	0.136 µF
Charging Current	6.83 A
Maximum Electromagnetic Field (EMF)*	93.3 mG

***Calculation performed at 1 m above ground** **Table 4-4 XLPE System Calculations**

Electric and Magnetic field intensities were calculated at one (1) meter above grade, at a standard three (3) foot trench depth, and at an 800 MVA rating.



5.0 COST ESTIMATES & SCHEDULE

The cost estimate is based on pricing obtained from recent underground projects. There are many factors that affect the overall cost of an underground project. These factors are:

1. Cost of materials.
2. Contractor/Manufacturer availability.
3. Subsurface conditions. The type and depth of soil and rock that must be excavated to place the cable can dramatically impact the cost. For example, construction costs in rock formations are significantly higher than construction costs in clay soils. The presence of existing underground facilities also presents a significant uncertainty when estimating the cost of an underground project.

5.1 Cost Estimate Assumptions

1. Materials used in the cost estimates meet all applicable industry standards.
2. Construction would be performed by qualified craftsmen experienced in installing high voltage XLPE or HPFF underground transmission systems.
3. Due to the volatility of material costs, these estimates are subject to market fluctuations.
4. Costs to obtain all environmental, local, state, and federal permits and mitigation as required are not included.
5. Costs to obtain all necessary right-of-way, easement, and property as required are not included.
6. No spare cable or parts have been included in the estimates.
7. A 25% contingency has been included.
8. Single point bonding of XLPE cable sheaths were assumed.
9. Material and labor costs reflect the installation of a double circuit 230 kV XLPE duct bank system, two cables per phase, including associated termination structures at each terminal. A double circuit 230kV HPFF cable system would require two cables per phase without forced cooling equipment.
10. Costs to install a fiber optic cable for communication are included. However, the installation of temperature monitoring equipment for the cable system is not included.
11. Substation engineering and construction costs for are not included.
12. Costs for reactive compensation are not included. A system study would need to be conducted to determine the detailed engineering and construction requirements for reactive compensation, if required.
13. Trenchless installation costs assume drilling through favorable soils (non-rock).
14. Engineering has assumed to be 2% of the total construction costs.
15. PSE overhead costs and taxes are not included.

5.2 Summary of Cost Estimates

Tables 5-1 through 5-6 are summaries of the costs for the XLPE and HPFF designs for each route. A detailed breakdown of each estimate by section is in the appendix.

ROUTE	LENGTH (miles)	MATERIALS	LABOR & EQUIPMENT	TOTAL
EXISTING OH EASEMENT	7.2	$99,227,667	$63,204,394	$162,432,061
RAILROAD ROW	11.5	$185,268,917	$121,024,488	$306,293,405
STREET ROW	7.9	$126,138,585	$78,666,269	$204,804,854

Table 5-1 XLPE Sammamish to Lakeside

ROUTE	LENGTH (miles)	MATERIALS	LABOR & EQUIPMENT	TOTAL
EXISTING OH EASEMENT	7.2	$126,930,307	$57,382,537	$184,312,844
RAILROAD ROW	11.5	$219,448,652	$99,410,092	$318,858,744
STREET ROW	7.9	$153,824,834	$69,954,364	$223,779,198

Table 5-2 HPFF Sammamish to Lakeside

SECTION	LENGTH (miles)	MATERIALS	LABOR & EQUIPMENT	TOTAL
EXISTING OH EASEMENT	9.5	$139,292,708	$89,854,873	$229,147,580
RAILROAD	9.8	$146,205,595	$94,645,367	$240,850,961
STREET ROW	10.7	$168,795,920	$104,655,554	$273,451,473

Table 5-3 XLPE Lakeside to Talbot Hill

SECTION	LENGTH (miles)	MATERIALS	LABOR & EQUIPMENT	TOTAL
EXISTING OH EASEMENT	9.5	$171,890,752	$78,145,160	$250,035,912
RAILROAD	9.8	$179,117,547	$81,286,975	$260,404,521
STREET ROW	10.7	$205,609,217	$94,013,482	$299,622,699

Table 5-4 HPFF Lakeside to Talbot Hill

ROUTE	LENGTH (miles)	MATERIALS	LABOR & EQUIPMENT	TOTAL
SCL TAP - 26TH PLACE	1.2	$19,855,077	$12,608,288	$32,463,365
SCL TAP - 32ND STREET	0.8	$14,273,980	$9,155,679	$23,429,658

Table 5-5 XLPE Lakeside to SCL Tap

ROUTE	LENGTH (miles)	MATERIALS	LABOR & EQUIPMENT	TOTAL
SCL TAP - 26TH PLACE	1.2	$25,853,957	$11,933,980	$37,787,937
SCL TAP - 32ND STREET	0.8	$19,021,745	$8,577,623	$27,599,368

Table 5-6 HPFF Lakeside to SCL Tap

The unit cost per mile of duct bank is estimated in Table 5-7 and 5-8 below. These estimates do not include any substation or termination work (transition structures, risers structures, etc) and/or any trenchless construction.

ROUTE	COST PER MILE
EXISTING OH EASEMENT	$21,198,357
RAILROAD ROW	$21,989,707
STREET ROW	$23,774,532

Table 5-7 XLPE Unit Cost Per Mile

ROUTE	COST PER MILE
EXISTING OH EASEMENT	$23,765,677
RAILROAD ROW	$24,368,036
STREET ROW	$26,375,702

Table 5-8 HPFF Unit Cost Per Mile

5.3 Schedule

There are four main parts to the project schedule: engineering design and completion of construction documents, material procurement, civil construction and electrical construction. The timeline for engineering design and completion of construction documents is primarily a function of route length and complexity of the route alignment (terrain, road construction, trenchless construction, etc). Material procurement is based on how quickly suppliers can supply the construction materials needed. Long lead time items are cable and accessories, transition/termination structures and vaults. The civil construction is dependent upon a number of things such as: number of crews being utilized for installation, type of construction (rural, urban, etc) and type of installation (trench vs. trenchless). Number of pulling and splicing crews is the principal variable in electrical construction.

Major assumptions made for high level conceptual timelines are:

- Durations are based on a linear approach to construction. If multiple resources (contractors, crews, etc) are utilized, the overall project schedule could be reduced significantly.
- **Engineering, procurement, and construction activities could overlap as appropriate to reduce total project schedule**. For instance,
    - Materials could be procured once the majority of engineering is complete.
    - Electrical construction could begin after a good portion of civil construction is complete.
- Electrical construction consists of a cable pulling crew and splicing crew. Splicing would follow behind the pulling crew and begin after the first few sections of cable are installed.

5.4 Summary of Schedule

The durations for engineering, procurement, and construction activities required for each option are shown in Table 5-9 below.

Route ROW	Total Length (miles)	Engineering Design (months)	Material Procurement (months)	Civil Construction (months)	Electrical Construction (months)
PSE Easement	16.7	12	12	28	15
Railroad Alternate	21.3	15	12	35	19
Street Alternate	18.6	14	12	36	16

Table 5-9 Schedule Summaries

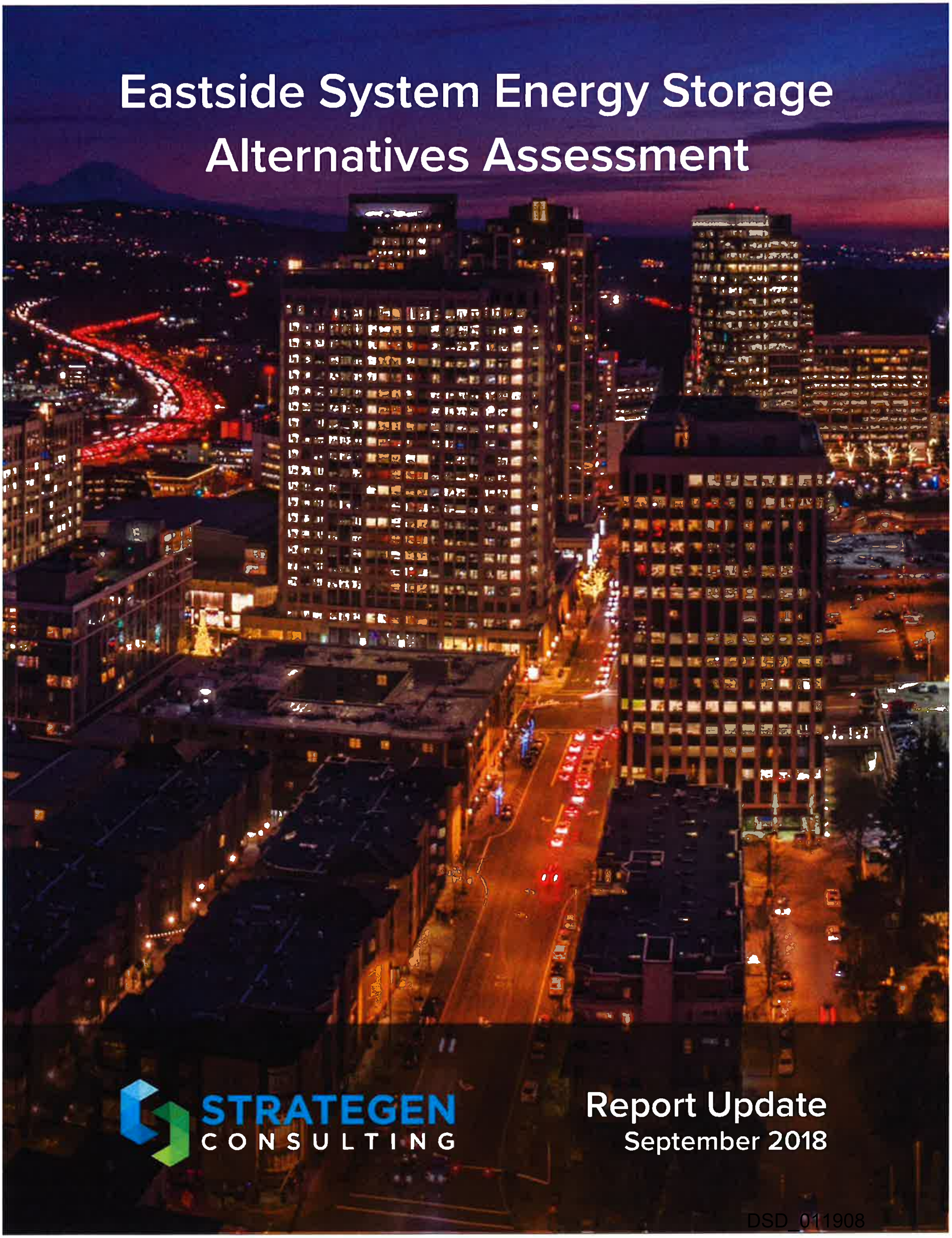
APPENDIX A

Aerial Route Drawings

APPENDIX B

Typical Detail Drawings

Eastside System Energy Storage Alternatives Assessment



STRATEGEN CONSULTING

Report Update
September 2018

Eastside System Energy Storage Alternatives Assessment Report Update – September 2018

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Table of Contents

Executive Summary

Background

In 2014, Puget Sound Energy ("PSE") commissioned Strategen Consulting, LLC ("Strategen") to assess energy storage options for PSE's Eastside transmission capacity deficiency. At the time, PSE was evaluating several possible solutions to meet the transmission capacity deficiency identified in its North American Electric Reliability Corporation ("NERC")-required transmission planning studies. These studies concluded that growth in the Eastside area could cause demand for electricity to exceed the capacity of the Eastside's transmission system as early as winter 2017-2018.

Strategen's assessment culminated in the Eastside System Energy Storage Alternatives Screening Study issued in March 2015 (the "March 2015 Study").[1] Strategen's March 2015 Study concluded that an Eastside energy storage solution was not practical given the unique circumstances of the Eastside transmission system. The study recognized that while energy storage technologies were on the cusp of being commercially viable for some types of large-scale deployments, energy storage is not an effective solution for every type of power system constraint or application. The Energize Eastside constraint is a transmission and distribution ("T&D") reliability application, which differs from the applications of most energy storage deployments globally to date (see Figure 34)[2].

In January 2018, Strategen Consulting was asked to update the March 2015 Study to consider:

- Changes to equipment ratings on the Eastside, such as PSE's development of more seasonally precise and equipment-specific rating of the transformer bank capabilities at both Talbot Hill and Sammamish Substations.[3]
- 2017 refreshed PSE system load forecasts, as well as recent advances in the energy storage market.

2018 Findings

The conclusion of this updated analysis is consistent with the conclusion of the original March 2015 Study: energy storage is not a practical solution for the Eastside. Despite the significant commercial and technological progress made by the energy storage industry in recent years, energy storage is still not a practical solution to meet the Eastside transmission system capacity deficiency.

Notably, the technological and commercial readiness of energy storage is not the factor limiting its ability to meet the Eastside transmission capacity deficiency. Rather, the magnitude of the Eastside transmission system capacity deficiency renders storage an impractical solution. The required system (or systems) would be of unprecedented scale, thereby making it difficult to source, site and construct, even if it were broken into multiple smaller projects. And the physical impact of a storage solution would likely exceed that of a poles & wires solution.

[1] The March 2015 Study can be found here: http://www.energizeeastsideeis.org/uploads/4/7/3/1/47314045/eastside_system_energy_storage_alternatives_screening_study_march_2015.pdf.

[2] While energy storage is becoming more frequently considered for distribution reliability applications, the large power/energy requirements typically necessary at the transmission level have historically rendered storage less practical for transmission reliability.

[3] This rerating dynamically accounts for the age of each individual transformer bank and the effects of seasonal weather on the thermal carrying capacity of each bank.

In this updated analysis, two storage solutions were considered-- an interim solution to meet constraints through 2019 and a complete solution to meet 2027 forecasted need.

1. **Interim Solution**
   The Interim Solution was developed in response to stakeholder interest. Here, Strategen evaluated the feasibility of interim measures sized only to meet the winter 2018/2019 and summer 2019 overload constraints for Talbot Hill Substation and Sammamish Substation, respectively. The Interim Solution assumed all other non-wires alternative ("NWA") load reduction solutions are implemented. The Interim Solution does not comply with planning criteria.

2. **Complete Solution**
   The Complete Solution evaluated an energy storage solution sized to meet the company's 2027 forecasted need, which is required for PSE to be in compliance with planning criteria (the same criteria met by the proposed transmission solution[4]). In this scenario, additional NWA solutions are also included.

The conclusions in this report update are consistent with the findings of the March 2015 Study. The characteristics of an energy storage system designed to meet planning requirements of a solution for the Eastside system are summarized as follows:

1) An energy storage system would be ***significantly more expensive than the proposed transmission wires solution***, costing approximately $825 million for the Interim Solution and increasing to approximately $1.4 billion for the Complete Solution,[5] compared to an estimated $150-$300 million[6] for the transmission wires solution;

2) The energy storage system would need to be of an unprecedented size, ***roughly 19 times the size of Tesla's Hornsdale facility in Australia (the largest currently installed system), just to meet the interim need by summer 2019, and 43 times the size of Hornsdale to meet the 10-year (2027) need***;

3) The commercial and supply-chain viability of an energy storage system for the Eastside area is unclear as ***it would exceed total US energy storage deployments in 2017[7] by approximately 6-13 times[8];***

4) The energy storage capacity required for Eastside by summer 2019 ***is approximately double the 1,233 MWh of total forecasted total energy storage deployments in the US[4] for 2018***[5]; and

5) The physical footprint of an energy storage system of the required scale would be significant: ***approximately 49 acres.***[9]

Strategen also investigated deployment of distributed energy resources such as the installation of small storage systems at homes, businesses, and other buildings in PSE's network. Distributed storage is neither viable nor cost-effective in this case. Even if there was significant customer adoption of behind-the-meter energy storage, it would not materially affect the Eastside transmission capacity deficiency: if every customer in PSE's Eastside area installed a storage system sized comparably to a Tesla Powerwall 2, only about half of the 2019 Eastside transmission

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[4] PSE's proposed transmission solution builds a new substation and upgrades approximately 16 miles of existing transmission lines from Redmond to Renton.
[5] See page 55 for cost assumptions.
[6] https://energizeeastside.com/faq/who-will-pay-for-the-project-and-how-much-will-it-cost
[7] Residential, non-residential and in-front-of-the-meter storage systems.
[8] https://energystorage.org/news/esa-news/us-energy-storage-market-tops-gwh-milestone-2017-annual-deployments-exceed-1000-mwh (Accessed: Apr. 25, 2018; 2,394MWh/431MWh = 5.55 & 5,500MWh/431MWh = 12.76)
[9] Based on a double-stacked/two-level battery facility for the Complete Solution

capacity deficiency would be met, and less than a quarter of the 2027 Eastside transmission capacity deficiency[10] would be met. Theoretically, if enough distributed storage could be deployed to meet the entire Interim Solution, the cost would range from $1.1 to $1.7 billion, and $2.1 billion to $3.1 billion for the entire Complete Solution[11].

We focused our 2015 analysis on the batteries required to prevent system overload at the Talbot Hill substation, which was identified as having the largest need during required planning scenarios. By analyzing the system element with the largest constraint (i.e., the largest energy need on peak days), we were able to calculate the battery size needed to prevent overloads for the entire system. Following the imposition of updated equipment- and seasonally-specific transformer ratings and information from the 2017 King County load forecast, our 2018 analysis found that the largest system constraint moved from the Talbot Hill to Sammamish substation. Peak energy demand also shifted from winter to summer.

Table 1, which follows, summarizes our 2015 findings for Talbot Hill and our 2018 findings for both Talbot Hill and Sammamish substations. Sammamish substation results for 2015 are omitted as they were not analyzed in detail in that report as we concluded that overloads would be prevented with the installation of a storage system sized to meet the larger Talbot Hill constraint. In this table, the Interim Solution represents the most optimistic case for the smallest storage system that can meet the immediate 2019 system need. The Interim Solution does not include cell degradation or the increasing uncertainty in load forecasts as they progress further into the future, because the assessment is for the pending 2018/2019 winter and 2019 summer constraints.

[10] Based on the size required to meet the Interim (2019) and Complete (2027) Solutions.

[11] Indicative cost assuming a quoted price of $6,600 per installed 13.5 kWh system, per www.tesla.com (as viewed on August 16, 2018) for the Interim Solution, and a cost of $4,220 per incremental installed 13.5 kWh system to meet the number of BTM installations required to meet the Complete Solution, per Tables 4 and 5.www.tesla.com (as viewed on August 16, 2018) for the Interim Solution, and a cost of $4,220 per incremental installed 13.5 kWh system to meet the number of BTM installations required to meet the Complete Solution, per Tables 4 and 5.

Table 1: Sizing comparison of the March 2015 Study vs the 2018 Analysis

Constrained Element	Power (MW)	Energy (MWh)	Duration (hours)	Meets 2019 System Need	Meets Solution Requirements Through 2027[12]	Feasibility[13]
Original March 2015 Study Results[14]						
Talbot Hill	**545**	**5,771**	**10.6**	✓	not evaluated	✗
Sammamish[17]	*Assessed to be less than Talbot Hill sizing*					
2018 Analysis						
Interim Solution for 2019[15]						
Talbot Hill	290	1,689	5.8	✗[16]	✗	✗
Sammamish[17]	**365**	**2,394**	**6.6**	✓	✗	✗
Complete Solution through 2027						
Talbot Hill	338	3,679	10.9	✓	✗[16]	✗
Sammamish[17]	**549**	**5,500**	**10.0**	✓	✓	✗

Both the Interim and Complete Solutions would be of globally unprecedented size. This can be seen in Figure 1 where a comparison to total US energy storage deployments[18] per quarter and year can be seen, as well as the largest currently installed system in the world, the Hornsdale Power Reserve in South Australia (developed by Tesla), and the largest proposed procurement in the world, PG&E's 2,270 MWh local capacity procurement, which is comprised of multiple projects and is pending review by the California Public Utilities Commission[19].

[12] Meets 2027 requirements means satisfying the NERC/FERC planning criteria through 2027, the same planning criteria against which the ultimate Eastside solution must be judged (whether a wires or non-wires solution).
[13] Feasibility relates to electrical sizing, physical sizing, timing and the ability of the market to respond.
[14] The March 2015 Study evaluated solution requirements to meet a deferral need through 2021.
[15] Sized only to meet immediate 2019 constraint assuming all other NWAs per E3 NWA Report (2014) are implemented; size requirement would be larger if other NWAs are unable to be implemented.
[16] The Talbot Hill sizing is insufficient to meet the Sammamish need and therefore does not meet the system need for that entire year.
[17] Sammamish was assessed in the March 2015 Study, but Talbot Hill was the more significant constraint that defined the energy storage sizing. Due to several factors detailed in this report, Sammamish is now the greatest constraint that defines the size while Talbot Hill also exceeds NERC requirements.
[18] This includes all types of energy storage (residential, non-residential and utility) in-front-of-the-meter systems installed in a given timeframe.
[19] Source: Utility Dive. https://www.utilitydive.com/news/pges-landmark-energy-storage-projects-snagged-by-pushback/530007/. Accessed August 21, 2018.https://www.utilitydive.com/news/pges-landmark-energy-storage-projects-snagged-by-pushback/530007/. Accessed August 21, 2018.

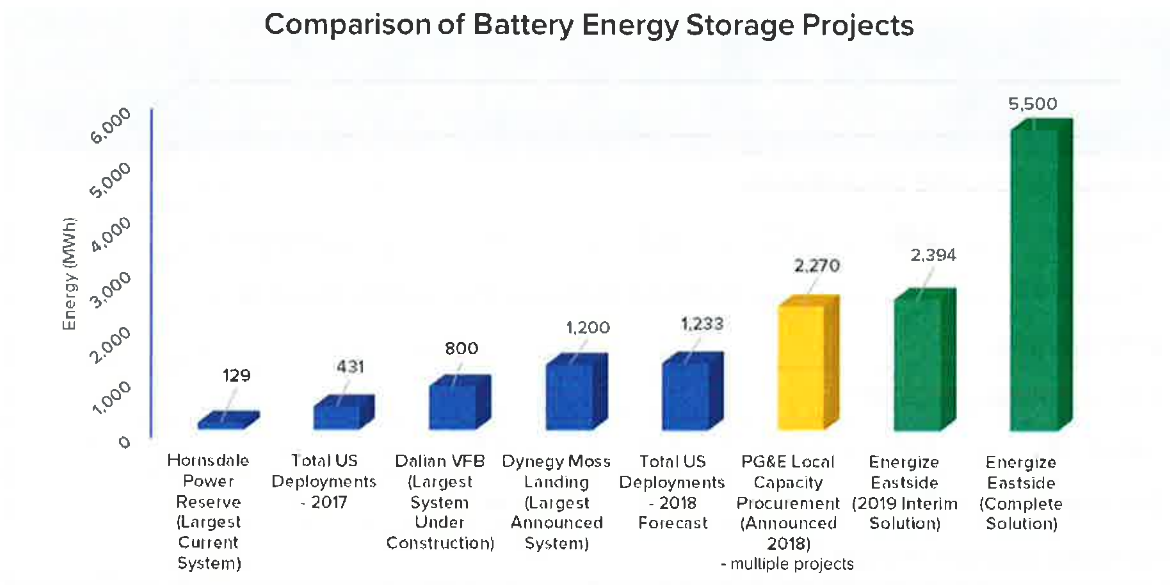

Figure 1: An energy storage system to solve the Eastside constraint in comparison to other projects[20]

In terms of physical impact, the footprint of the Complete Solution is estimated to be 49 acres, approximately one and a half times the size of CenturyLink Stadium. This assumes the solution is built as a single facility, with the Interim solution built as a single-level system and expanded vertically into a double stacked/two-level configuration to meet the Complete Solution. Figure 2 shows an indicative footprint that these arrangements would require if built as a single facility.

Figure 2: Approximate indicative footprint of the Eastside storage solution. Red represents a single-level interim Solution, 59 acres, and yellow represents a double-level Complete Solution, 49 acres.

[20] Source: UtilityDive, PG&E, GTM Research and ESA. PG&E local capacity procurement represents multiple projects with online dates ranging from December, 2019 to December, 2020 if approved by the California Public Utilities Commission.

While storage is becoming a technology embraced by the power sector to modernize and enhance the grid, the specific circumstances and requirements driving the Eastside transmission capacity deficiency are not well-suited to an energy storage solution. Such a solution would need to be of unprecedented scale, exceeding the total forecast 2018 US energy storage deployments,[21] both behind and in front of the meter. It would therefore be impractical to source, site and construct. In addition, it would come at a cost many times that of the traditional poles & wires solution.

For these reasons, despite the commercial and technological progress of energy storage in recent years, the conclusion of this updated analysis remains consistent with the conclusion of the original March 2015 Study. Strategen does not believe energy storage to be a practical option to meet the Eastside transmission capacity deficiency, either as an alternative to the proposed transmission solution or as a way to defer it.

[21] This includes all types of energy storage; residential, non-residential and utility in-front-of-the-meter systems.

1. Eastside System Storage Configurations and Feasibility

Strategen conducted a refreshed analysis to assess how updated conditions in the Eastside area (and of the energy storage market) affect the technical requirements and sizing of an energy storage system that meets the Eastside transmission capacity deficiency.

1.1 Overall Objectives and Methodology

This report evaluates the amount of storage that would be necessary to eliminate overloads at Talbot Hill and Sammamish substations during certain system contingencies each year between 2018 through 2027. Storage deployed in such a use case would avoid or defer the need for a traditional "poles and wires" solution for the Energize Eastside project.

The 2018 Analysis generally used the same methodology developed for the March 2015 Study, with certain exceptions as identified in this report which were designed to refresh or enhance the original March 2015 Study. The methodology is summarized below and detailed in subsequent sections, and sizing using the original methodology was also run for reference, which can be found in the Appendix. The 2018 Analysis did not rerun the cost-effectiveness analysis conducted as part of the March 2015 Study; however, it did reassess whether the original unit cost assumptions remain accurate.

The methodology used to size the storage system relied upon loading forecasts provided by PSE for impacted transformer elements under normal conditions and during N-1-1 system contingencies. In the case of the March 2015 Study, the element loading forecasts were generated using systemwide and King County load forecasts from PSE's 2013 Integrated Resource Plan. In the case of the 2018 Analysis, the element loading forecasts were generated using systemwide and King County load forecasts from PSE's 2017 Integrated Resource Plan.

Strategen assumed that all cost-effective NWAs (other than energy storage) would be implemented according to the timeline identified in the 2014 E3 Non-Wires Alternative Report (see the Appendix for details). Other NWAs include incremental energy efficiency, distributed generation, and demand response.

The remaining need was identified by running hourly power flow assessments assuming:

1. PSE is meeting 100% of its conservation and efficiency goals described in its Integrated Resource Plan; and
2. Normal weather conditions would set the demand forecasts.[22]

To serve as an alternative to the Energize Eastside project, energy storage must reduce loading on the affected transformer banks enough to eliminate overloads that would violate equipment normal thermal operating limits. Given that storage is modular, Strategen evaluated the amount of storage to solve the overloads through 2027 (the "Complete Solution"), along with the amount needed to address the Eastside transmission capacity deficiency incrementally beginning in winter 2018/2019 (the "Interim Solution").

As noted above, the Appendix contains refreshed sizing using the original methodology. It also contains a comparison of the assumptions between the March 2015 Study and the 2018 Analysis. The original methodology and assumptions are detailed in Section 3.1 of the March 2015 Study.

[22] In other words, weather conditions that represent the middle of the climatological bell curve, occurring in approximately 1 out of every 2 years

1.2 Talbot Hill Methodology and Results

1.2.1 Talbot Hill Interim Solution

In this section, we describe the methodology used to calculate the Talbot Hill Interim Solution and discuss the results. In the 2018 Analysis, Strategen found that there may be opportunities to recharge the system in the middle of the day, which the March 2015 Study did not account for. This is because, depending on the load profile, there may be a period during the day between morning peak and evening peak when recharging could occur. This would reduce the total required energy capacity seen in Table 2 (see p. 13 below). This would cycle the battery more than once a day. Increased battery cycling reduces battery operating life; however, more battery cycling allows a system smaller than that identified in Table 2 to be utilized to meet the system need for the Interim Solution. The method described below was used to do this analysis.

- The peak week N-1-1 data was extracted from the complete data set and was shown to occur in January 2019 for Talbot Hill. This represents the peak transformer loading at Talbot Hill within the next five years[23].
- The discharge requirements to maintain the loading on the Talbot Hill transformer were considered and the state of charge ("SOC") of the energy storage system tracked. Any opportunity where the loading was less than the normal rating, the system would be charged as much as possible without exceeding the rating.
  - Over the course of the week, the storage system was assessed, and the sizing increased to maintain the SOC above the minimum 2%.[24]
  - Figure 3 shows the results, where the green line is the loading on the Talbot Hill transformer with the energy storage operating to relieve the constraint through charging and discharging. This system is 290MW/1,689MWh (5.8-hour system).
  - It can be seen in the orange highlighted sections the loading is below the normal rating and during these times the energy storage system can charge, reflected in the SOC increasing. Without these opportunities, the SOC would continue to fall and a larger energy storage system would be required.[25]
  - A cost-benefit analysis could be undertaken to evaluate the reduction in life versus the cost of adding more energy capacity. Figure 4 shows the energy storage output during this period.

[23] The data analyzed assumed other NWA solutions (distributed energy resources) also contributed to reducing the load on Talbot Hill, including energy efficiency, demand response, and DG solar per E3's NWA Report (2014).
[24] Refer to assumptions for 2% minimum SOC.
[25] 2,083MWh – refer to Table 3

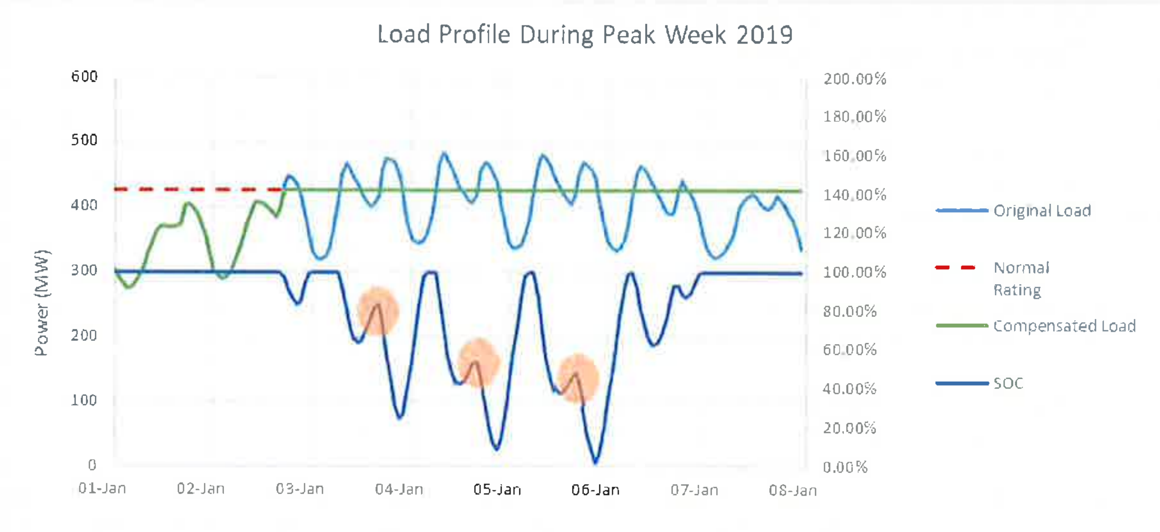

Figure 3: The Interim Solution using the updated methodology during the peak week: 290MW/1,689MWh (5.8-hour system) – circles highlight intra-day recharging

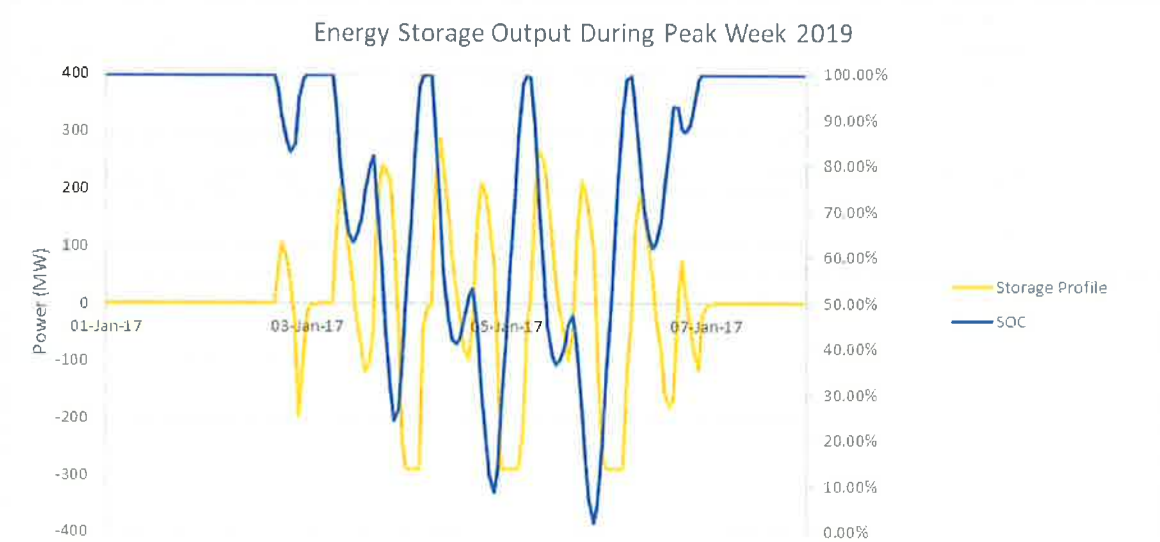

Figure 4: Output of the Interim Solution during the peak week, 290MW/1,689MWh (5.8-hour system)

1.2.2 Talbot Hill Complete Solution

The Complete Solution evaluates an energy storage solution that meets the required 2027 NERC planning criteria (the same as met by the proposed Energize transmission solution). In this scenario, additional NWA solutions[26] are also included to define the minimum plausible energy storage system. In this analysis it was found there was insufficient network capacity to charge the system on a daily basis. However, when there is not enough network capacity to fully recharge the system every day, a larger battery (with a longer duration) can theoretically overcome this issue. The method described below was used to do this analysis.

[26] NWA per E3 NWA Report (2014)

- The January 2027 peak week N-1-1 data for Talbot Hill was extracted from the complete data set. This represented the maximum loading during the 10-year planning horizon.
- The discharge requirements to maintain the loading on the Talbot Hill transformer were considered and the SOC of the energy storage system tracked.
    - Over the course of the week, the storage system was assessed, and the sizing increased to maintain the SOC above 18%. 18% was used to consider cell degradation of 2% per year for nine years.
    - Figure 5 shows the results, where the green line is the loading on the Talbot Hill transformer with the energy storage operating to relieve the constraint by maintaining the loading at the normal rating through charging and discharging. This system is 338MW/3,679MWh (10.9-hour system).
    - Unlike the Interim Solution, where there are actually periods when the system can recharge between morning and evening peak and fully recharge at night, it can be seen in the orange highlighted sections the SOC does not recover to 100% each day as there is insufficient network capacity to allow full charging.
    - Over time the SOC becomes more and more depleted until the load reduces toward the end of the peak week. Therefore, the system is oversized to meet the normal planning overload and maintain a SOC above 18%.
    - At the end of the week the SOC does return to 100% and as this is the peak week, the system should have enough capacity to meet the requirements for all other weeks in 2027. Figure 6 shows the energy storage output during this period.

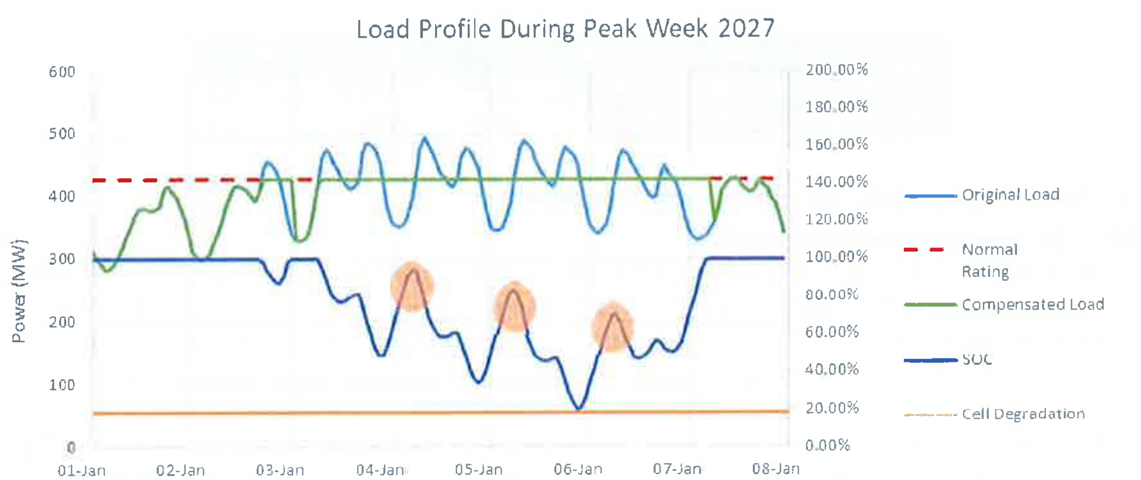

Figure 5: The Complete Solution during the peak week, 338MW/3,679MWh (10.9-hour system) – circles highlight that off-peak recharging insufficient to restore 100% state of charge each night

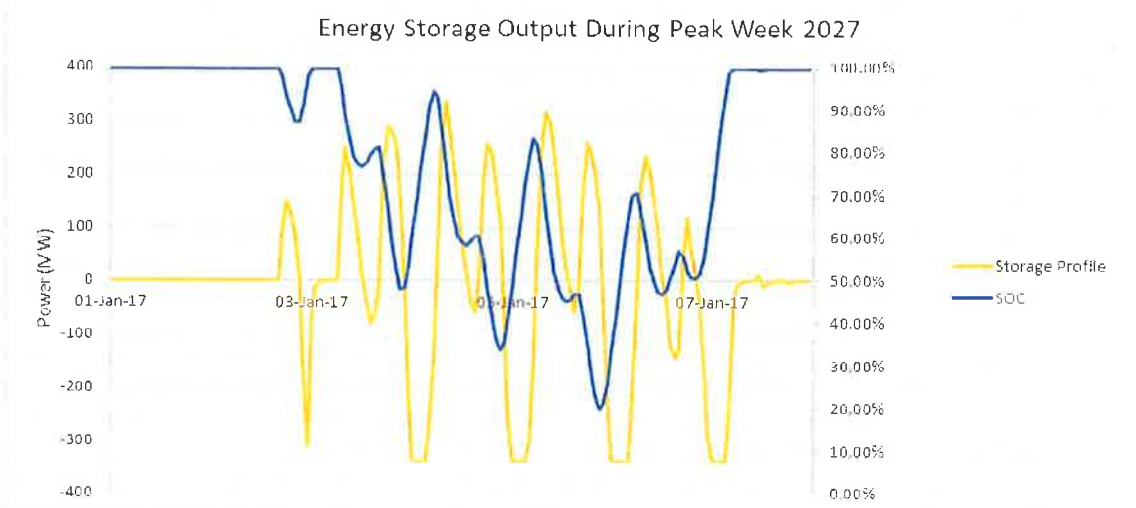

Figure 6: Output of the Complete Solution during the peak week, 338MW/3,679MWh (10.9-hour system)

By considering the Interim Solution and the Complete Solution, a clear picture can be obtained regarding the immediate need that must be met in 2019 and the solution that meets the full requirements over the 10-year planning period for Talbot Hill. Any incremental solution or staged approach would need to be deployed to meet both situations and is summarized in Table 2 below.

Table 2: Talbot Hill Substation Sizing Summary

	MW	MWh	Hours
Interim Solution (2019)	290	1,689	5.8
Complete Solution (2027)	338	3,679	10.9

1.3 Sammamish Methodology and Results

1.3.1 Sammamish Interim Solution

As noted above, the 2018 Analysis represents an update on the methodology used in the March 2015 Study because it considers SOC over the course of the peak week. This allows a more accurate energy storage sizing to be calculated. The methodology and results for the Sammamish analysis are described below.

- N-1-1 data was extracted for the peak week at Sammamish (occurring in August 2019), to determine the peak summer transformer loading within the next five years. This again includes NWA load reductions.
- The discharge requirements to maintain the loading on the Sammamish transformer were considered and the SOC of the energy storage system tracked. If opportunities occurred to recharge mid-day (when loading was less than the normal rating), the system would be charged as much as possible to reduce the system size.
    - Over the course of the week, the storage system was assessed, and the sizing adjusted to maintain the SOC above the minimum 2%.[27]
    - Figure 7 and Figure 8 show the results, where the green line in Figure 7 is the loading on the Sammamish transformer with the energy storage system operating to relieve the constraint.

[27] Refer to the Appendix, p.35, for pre-SOC sizing and assumptions for information about the 2% minimum SOC.

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- This system maintains the loading below the normal rating through charging and discharging. This system is 365MW/2,394MWh (6.6-hour system).
- Figure 8 shows the energy storage output during this period.
- Figure 9 shows data from the peak month, which validates the system sizing is appropriate as the SOC remains above the minimum 2%.

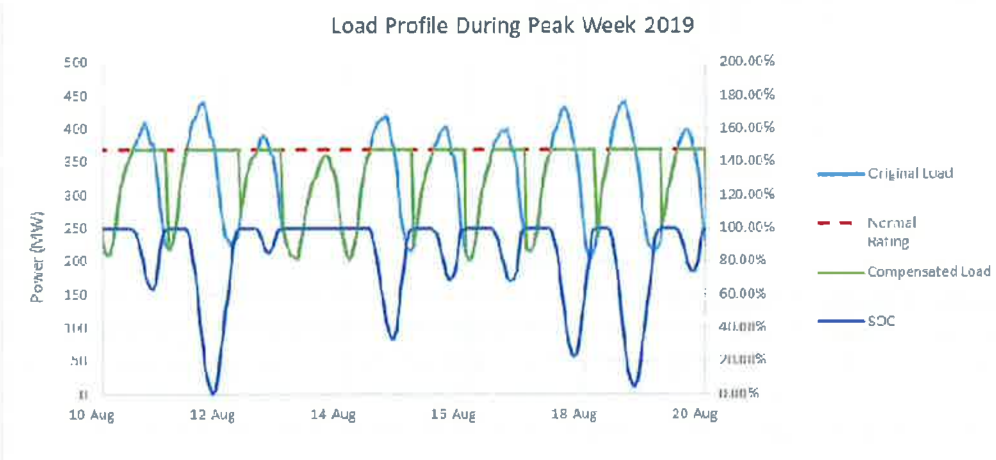

Figure 7: The Interim Solution during the peak week, 365MW/2,394MWh (6.6-hour system)

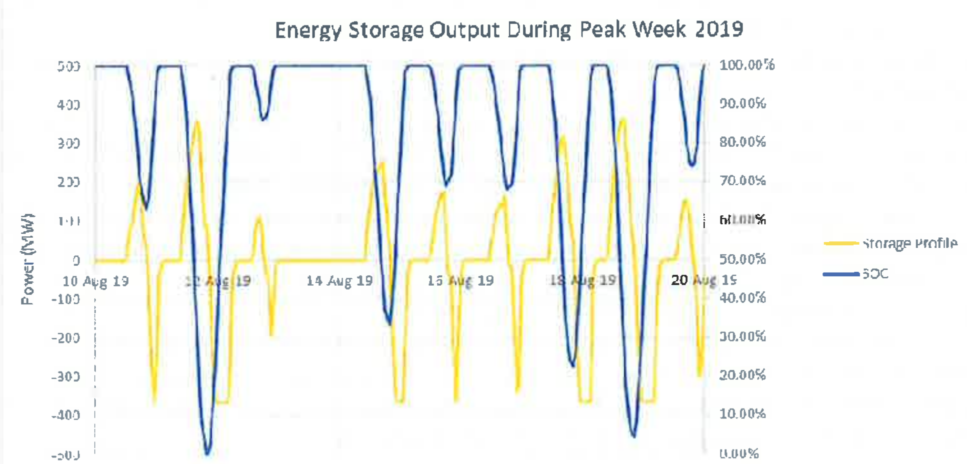

Figure 8: Output of the Interim Solution during the peak week, 365MW/2,394MWh (6.6-hour system)

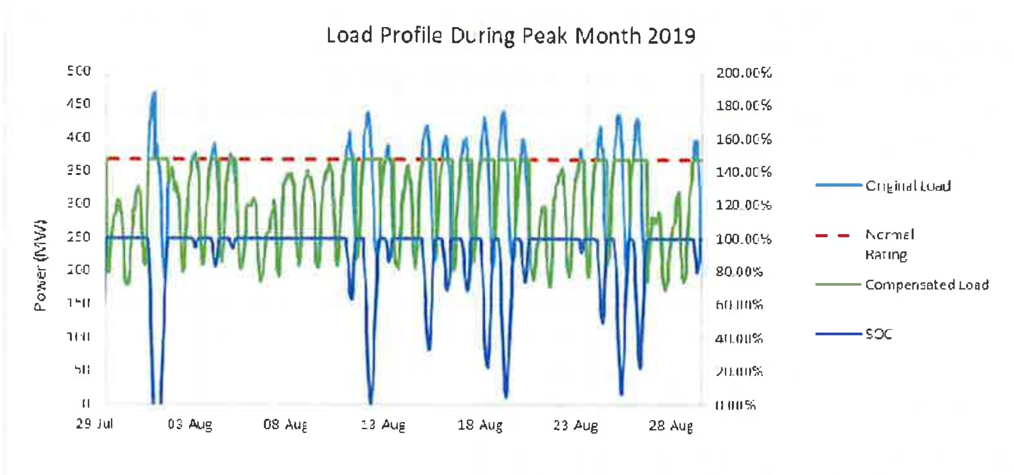

Figure 9: Performance over peak summer month, 365MW/2,394MWh (6.6-hour system)

1.3.2 Sammamish Complete Solution

As noted above, the Complete Solution for Sammamish evaluates an energy storage solution that meets the required 2027 NERC planning criteria (the same as met by the proposed Energize transmission solution). In this scenario, additional NWA solutions[28] are included to define the minimum plausible energy storage system sizing to meet the Sammamish transmission capacity deficiency.

- N-1-1 data was extracted from the peak week in August 2026, which is when the maximum summer loading during the 10-year planning horizon is forecasted to occur.[29]
- The discharge requirements to maintain the loading on the Sammamish transformer were considered and SOC of the energy storage system tracked.
    - Over the course of the week, the storage system was assessed, and the sizing increased to maintain the SOC above 18%. 18% was used to consider both the minimum SOC of 2%[30] and cell degradation of 2% per year for eight years (16%).
    - Figure 10 and Figure 11 show the results, where the green line in Figure 10 is the loading on the Sammamish transformer with the energy storage operating to relieve the constraint at the normal rating through charging and discharging.
    - This system is 549MW/5,500MWh (10.0-hour system).
    - Figure 12 considers the full month where the peak on the 1st is ignored due to the abnormal system condition.
    - During the remainder of the month it can be seen that the peak days, even where consecutive days face overload, the SOC remains above 18%.

[28] NWA per E3 NWA Report (2014)
[29] PSE's planning forecast shows a slight drop in peak load in 2027.
[30] Refer to assumptions for 2% minimum SOC.

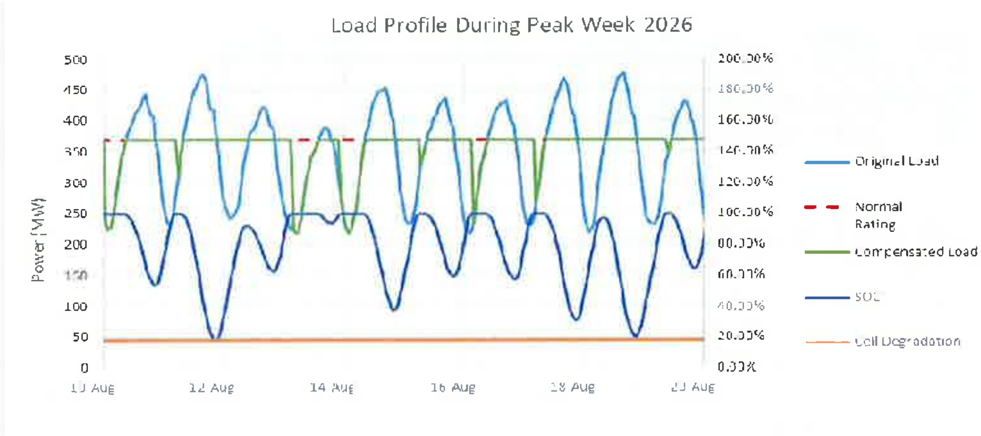

Figure 10: The Complete Solution during the peak week, 549MW/5,500MWh (10.0-hour system)

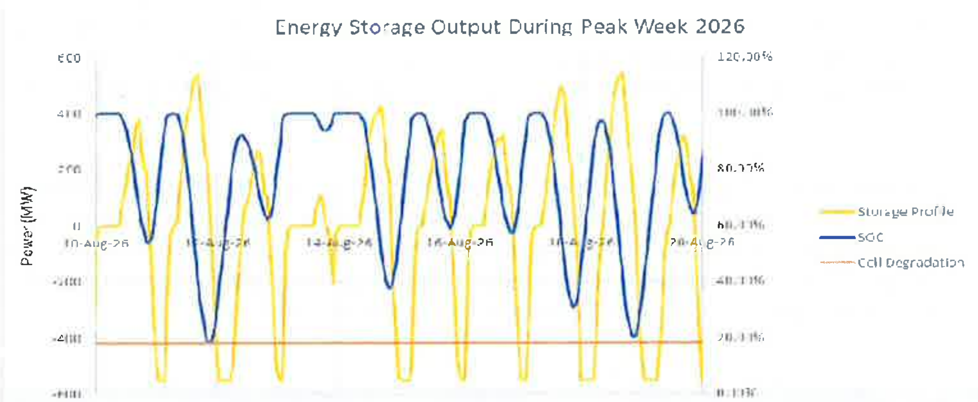

Figure 11: Output of the Complete Solution during the peak week, 549MW/5,500MWh (10.0-hour system)

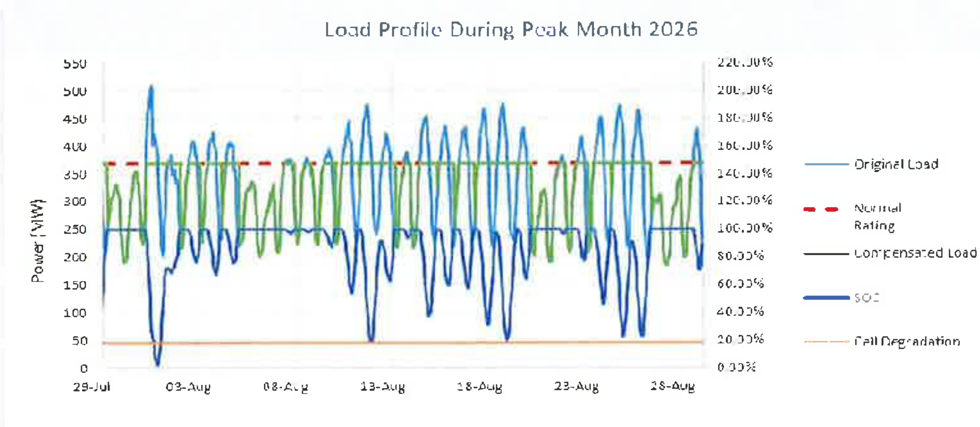

Figure 12: Performance over peak summer month, 549MW/5,500MWh (10.0-hour system)

By considering the Interim Solution and the Complete Solution, a clear picture can be obtained regarding the immediate need that must be met in 2019 and the solution that meets the full requirements over the 10-year planning period. Any incremental solution or staged approach would need to be deployed to meet both situations and is summarized in Table 3 below.

Table 3: Sammamish Substation Sizing Summary

	MW	MWh	Hours
Interim Solution (2019)	365	2,394	6.6
Complete Solution (2027)	549	5,500	10.0

1.4 Behind-the-Meter Energy Storage

Finally, behind-the-meter ("BTM") energy storage was considered as it is becoming more common within the power system. Its aggregated effects can reduce the load on the system, and BTM energy storage can also be controlled and coordinated by utilities to provide specific grid benefits, such as virtual power plant configurations. These arrangements are undergoing trials now but are not yet fully mature planning tools and, as such, in the short term such configurations may result in technical and contractual challenges.

As previously discussed, the effectiveness factor of various locations within the Eastside area was considered, and all locations had a similar effect on the constrained Talbot Hill and Sammamish Substations. Therefore, whether a centralized energy storage system is installed, or a number of distributed storage systems are interconnected, the power and storage requirements remain the same.

When considering BTM energy storage, whether meeting or contributing to the Energize Eastside area, the Interim Solution for Sammamish (365MW/2,394MWh) or the Complete Solution for Sammamish (549MW/5,500MWh) needs to be met. If the Tesla Powerwall 2, a 13.5kWh system or a larger generic 15kWh system is considered, Table 4 and Table 5 portray the number of these systems required to meet the Interim Solution and Complete Solution respectively.

Table 4: Number of residential BTM energy storage systems required to meet the Interim Solution

BTM Residential Energy Storage System	Number of BTM Systems Required	Number of BTM Systems Required (70% confidence factor)[31]	Number of Customers in Eastside Area (130,000)[32]
Tesla Powerwall 2 - 13.5kWh	177,333	253,333	195%
Generic - 15kWh	159,600	228,000	175%

[31] It is not reasonable to assume that all BTM energy storage systems would be online, fully functional, and have all their usable capacity available at the exact time required to relieve the Talbot Hill constraint. Even if controlled and coordinated by the utility, customers would likely use these systems for other utility bill management purposes that could see their system below 100% SOC prior to the event. In addition, even if 1% were offline for maintenance or repair, or on average the SOC was 99% across the entire fleet, this would result in more than a 18MWh shortfall. Therefore, a 70% confidence factor is used to provide a more realistic perspective of the number of BTM energy storage systems required to compensate for some systems being offline, partially discharged or otherwise unable to provide their full usable capacity for the purposes of relieving the Talbot Hill transformer constraint.

[32] Source: (https://energizeeastside.com/need)

Table 5: Number of residential BTM energy storage systems required to meet the Complete Solution

BTM Residential Energy Storage System	Number of BTM Systems Required	Number of BTM Systems Required (70% confidence factor)[31]	Number of Customers in Eastside Area (130,000)[32]
Tesla Powerwall 2 - 13.5kWh	407,407	582,011	448%
Generic - 15kWh	366,667	523,810	403%

Tables 4 and 5 show that the number of BTM energy storage systems required exceeds the number of residential customers in the area. In addition to the information presented in Table 4 and Table 5, there are a number of other reasons that BTM energy storage is an impractical solution for the Eastside's T&D deficiency. These are:

1) The number and timing of BTM energy storage systems required to meet the Interim or Complete solution for the Eastside T&D capacity deficiency far exceed the top residential energy storage uptake rates in leading markets, as seen in Figure 13.

Rank	Residential	Deployments (kW)
1	California	1,870
2	Hawaii	1,218
3	All Others*	728

Figure 13: Top 3 residential energy storage markets, 2017 Q1 deployments[33]

2) The installation of the number of BTM systems required to meet the Interim and Complete Solutions is not realistic from the standpoint of either utility interconnection assessments or local authority permitting processes and capabilities. Installation of a BTM storage system requires an electrical permit. From August 13, 2017 to August 13, 2018, the City of Bellevue processed 309 electrical permits, and had a staff of four people handling electrical permit applications and inspections[34].

3) Purchasing the volume of BTM systems to address the Eastside T&D deficiency would exceed the entire US BTM deployments, as seen in Figure 14, which covers multiple segments.

[33] Source: GTM Research
[34] Source: https://publicrecordscenter.bellevuewa.gov/DSRecords/processing-day-by-permit-type.pdf Accessed August 16, 2018.

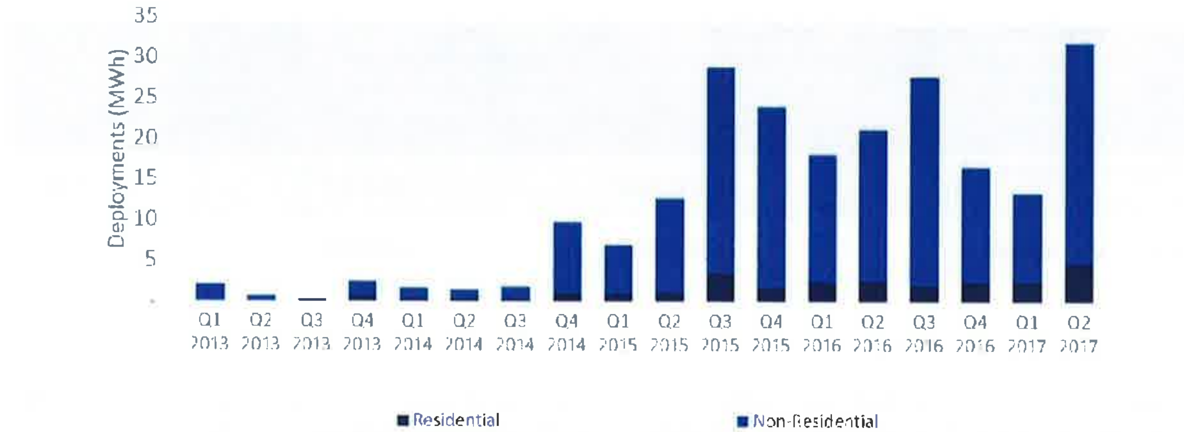

Figure 14: US BTM Energy Storage Deployments by Segment[35]

4) Finally, BTM energy storage systems are often coupled with rooftop solar to store solar energy and enable self-generation. Because of this fact, California uses the number and location of existing rooftop solar installations to predict where BTM energy storage will interconnect.[36] While not the only use case of BTM energy storage, a similar predictive methodology might be applied to King County as a way to estimate customers willing to invest in advanced energy technology. The number of residential distributed generation systems (mostly solar) throughout PSE's King County service territory is approximately 2,300 out of approximately 1.2 million total customers.[37]

If the effect of organic growth of BTM energy storage was considered with regard to reducing the loading within the Eastside area, even if the entire US 2017 Q2 deployments occurred on circuits downstream of Sammamish and Talbot Hill Substations, this would only meet approximately 0.5%-1.5% of the Eastside transmission capacity deficiency[38]. Therefore, the effect of actual installations on downstream circuits can be considered negligible with respect to the Eastside transmission capacity deficiency.

1.5 Capital Cost of Eastside Energy Storage Solution

Strategen reassessed its unit cost assumptions for energy storage in Section 3.4.1. The transmission solution for Eastside is estimated at $150-$300 million.[39] An energy storage system would be significantly more expensive than the proposed transmission solution. An estimate of capital costs can be seen in Figure 15 below and range from approximately $825 million to $1.4 billion.

[35] Source: GTM Research / ESA US Energy Storage Monitor, Q3 2017
[36] Source: DRP working group meetings
[37] Source: PSE 2017 IRP, p.391
[38] 32.5MWh/5,500MWh=0.006, Complete Solution and 32.5MWh/3,007MWh=0.014, Interim Solution
[39] Source: (https://energizeeastside.com/faqs)

PERFORMANCE	Units	Interim Solution (Lithium Ion) Single Level	Interim Solution (Flow-Van'm) Single Level	Complete Solution (Lithium Ion) Double Level	Complete Solution (Flow-Van'm) Double Level
Power	MW	365	365	549	549
Energy	MWh	2,394	2,394	5,500	5,500
Discharge Duration	Hours	6.6	6.6	10.0	10.0
Round Trip Efficiency	%	85%	85%	85%	85%
ASSUMPTIONS					
EPC					
Energy Storage	$/kWh	294	313	194 for incremental 3,106 MWh[40]	207 for incremental 3,106 MWh[40]
Owners Costs					
Land Required	sq ft	2,123,866	1,302,070	2,123,866	1,302,070
Land Cost	$/sq ft	43.60	43.60	43.60	43.60
Permitting	$	Not available	Not available	Not available	Not available
Interconnection	$	28,140,000	28,140,000	28,140,000	28,140,000
RESULTS					
EPC Costs					
Energy Storage	$	703,836,000	749,322,000	1,287,764,000	1,370,522,000
Construction	$	n/a	n/a	n/a	n/a
Owners Costs					
Land	$	92,600,558	56,770,252	92,600,558	56,770,252
Interconnection	$	28,140,000	28,140,000	28,140,000	28,140,000
Subtotal Costs	$	120,740,558	84,910,252	120,740,558	84,910,252
TOTAL COST	**$**	**824,576,558**	**834,232,252**	**1,408,504,558**	**1,455,432,252**
Total $ per kWh		**344**	**348**	**256**	**265**

Figure 15: Capital cost estimate of bulk energy storage to address the Eastside transmission reliability deficiency

If distributed storage were to be pursued in lieu of a centralized solution, costs would likely be substantially higher. For indicative purposes, the cost would range from $1.14 billion to $1.67 billion for the Interim Solution and $2.14 billion to $3.06 billion for the Complete Solution[41].

[40] Assumes an average 36% reduction in capital costs for incremental storage beyond the Interim Solution. See page 55 for cost assumptions.

[41] Indicative cost for the Interim Solution assumes $6,600 per installed 13.5 kWh system, based on the quoted price for a Powerwall 2 per www.tesla.com (accessed August 16, 2018) multiplied by the range of installed systems indicated in Table 4 to meet the Interim Solution. Indicative cost for the Complete Solution assumes a cost of $4,220 per installed 13.5 kWh system for the incremental number of systems required to meet the range shown for the Complete Solution in Table 5 (resulting in a blended cost of $5,258 per system for the Complete Solution).

The March 2015 Study also evaluated the cost-effectiveness of a storage system based on a comparison of the cost with the system benefits it would provide PSE. It is likely that system benefits may be somewhat different today than what was assumed in the March 2015 Study due to changes to load growth patterns, generation mix, and the inclusion of PSE in the Western Energy Imbalance Market. However, Strategen did not reassess the benefits of an Eastside energy storage solution in the 2018 Analysis.

2. Impact Considerations

This part of the report will discuss the physical impacts of energy storage systems and compare these to PSE's preferred transmission solution.

2.1 Physical Impact

System requirements were defined in Part 1 of this report. This section considers some of the practical and logistical aspects of deploying a system of the size defined in the technical requirements section. This will include the location of one or more energy storage systems, the physical sizing requirements as well as upgrades to support the operation of storage and the timing of need to build the preferred solution.

2.1.1 Location

As indicated, the location of a centralized energy storage system or a number of distributed energy storage systems does not impact the effectiveness factor, and therefore the total power and energy required to meet the normal overload condition remains 365MW/2,394MWh for the Interim Solution or 549MW/5,500MWh for the Complete Solution for Sammamish. A centralized system located somewhere between Talbot Hill Substation and Sammamish Substation would offer similar benefits, again as tested through PSE load flow analysis of the effectiveness factor. Distributed systems (provided they are connected downstream of these substations) could provide the same benefit as a single system, requiring coordination of their operation with each other to resolve the constraint.

2.1.2 Footprint

The physical sizing considerations for a centralized Interim Solution and Complete Solution are now considered. Figure 16 shows the Hornsdale Power Reserve, the current largest energy storage project on Earth. This system is approximately 19 times smaller than the Interim Solution and 43 times smaller than the Complete Solution. Its dimensions are used to inform the expected footprint of the Eastside solution along with other projects.

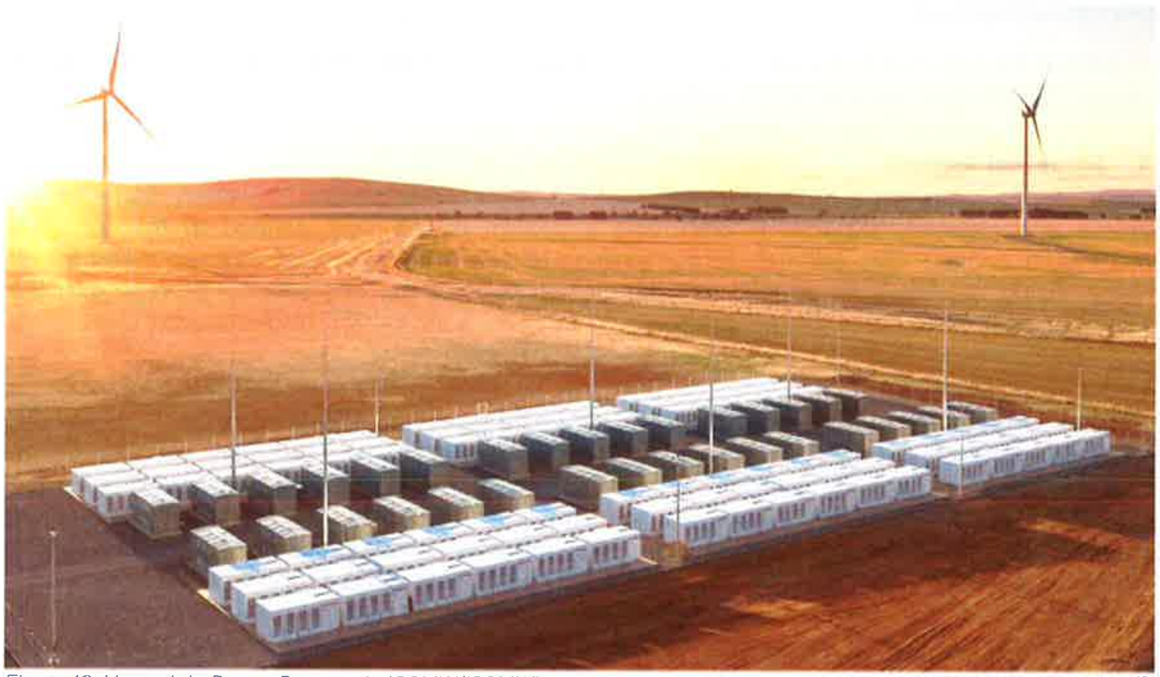

Figure 16: Hornsdale Power Reserve is 100MW/129MWh, approximately 43 times smaller than the Complete Solution[42]

Table 6 summarizes deployed and proposed large-scale energy storage systems. These include lithium-ion and flow batteries on one and two levels. This sizing information is then applied to the power and energy requirements of the Eastside solution.

Table 6: Space requirements for the Energize Eastside solution based on installed and proposed large-scale energy storage projects

Per MWh	Hornsdale Power Reserve	Dalian VFB Rongke Power	Average Single Level	Single Level Halved	Dalian VFB Rongke Power	Average Double Level	Extrapolated Size	Eastside Interim Solution 365 MW 2.394 MWh		Eastside Complete Solution 549 MW 5,500 MWh	
	Single Level			Double Level				Single	Double	Single	Double
Acres	0.04	0.01	0.025	0.013	>0.01	0.01		58.87	21.22	135.25	48.76
Sq. ft	1,669	473	1071	536	237	386		2,564,333	924,461	5,891,325	2,123,866
Size compared to CenturyLink Stadium (1,500,000 Sq. Ft.)								171%	62%	393%	142%

Note: As the projects considered for the sizing are four hours in duration or less, it is more appropriate to use the energy (MWh) rather than power (MW) rating to calculate the Eastside footprint.

CenturyLink Stadium has a footprint of 34.4 acres[43] and the Interim Solution Eastside footprint would, therefore, be more than one and a half times the size if designed over one level. The Complete Solution would require a similar footprint to this if double-stacked over two stories, which is the most likely engineering approach. There have not been any large-scale energy storage projects to date that have been deployed with more than two levels. Figure 17 highlights the

[42] Source: (https://hornsdalepowerreserve.com.au/)
[43] 1,500,000 square feet. Source: (http://www.architravel.com/architravel/building/centurylink-field/)

indicative footprint of a single-stacked Interim Solution (red) vs a double-stacked Complete Solution within the Eastside area (yellow)[44].

Figure 17: Indicative footprint of the Eastside storage solution red, single-level Interim Solution 59 acres, and yellow double-level Complete Solution, 49 acres

2.1.3 Timing of Need to Build the Solution

The 2018/2019 overload constraints represent the largest exceedances in the normal rating within the next five years and drive the timing of any permanent or incremental solution. The following two projects are therefore considered for context on the feasibility of storage given the timing constraint.

Aliso Canyon – Approximately one year to complete a 94.5MW/342MWh project

On May 26, 2016, the California Public Utilities Commission ("CPUC") approved a resolution to expedite a competitive energy storage procurement solicitation to help alleviate an emergency capacity constraint in the 2017 summer, due to a gas leak at the Aliso Canyon natural gas storage facility, which constrained local generation capacity in the Los Angeles basin.

The resolution instructed San Diego Gas and Electric ("SDG&E") to "leverage" its ongoing 2016 Preferred Resource LCR RFO to approach "qualified respondents," and determine if an energy storage solution could be online in time to resolve the immediate Aliso Canyon constraint.

By the date the resolution was issued, SDG&E had completed its pre-evaluation and identified qualified contractors for turnkey, utility-owned projects. SDG&E approached qualified bidders to assess their willingness and ability to execute expedited projects in the 2016 timeframe. The RFO had already allowed pre-evaluation of respondents, which materially shortened the pre-bid activity.

To achieve the targeted January 31, 2017 online date, SDG&E required approval from the commission by August 19, 2016, before which the energy storage supplier could not make significant financial investments in battery modules, inverters, transformers, or containers for the project. The project timeline can be seen in Figure 18.

[44] This assumes a square footprint where the Interim Solution requires a 1,601x1,601 ft. (2.56 million sq. ft.) area and the Complete Solution requires a 1,457x1,457 ft. (2.12 million sq. ft.) (two levels).

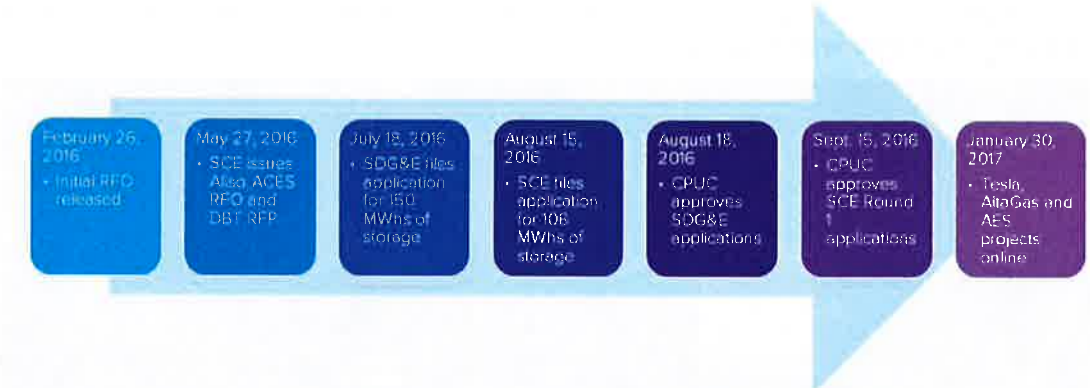

Figure 18: Aliso Canyon battery energy storage system response timeline

The Aliso Canyon Energy Storage Project saw a number of energy storage systems that aggregated to 94.5 MW / 342 MWh, brought online in approximately seven months. However, the original RFO began on February 26, 2016, which materially shortened pre-bid activity for this project. The overall project could, therefore, be considered to take approximately one year.

Hornsdale Power Reserve – Majority of a year to complete 100MW/129MWh project

The Hornsdale Power Reserve, while touted as a 100MW buildout in 100 days, took the majority of 2017 to solicit, award and complete. Neoen and Tesla selected the existing Hornsdale Wind Farm as a suitable site in early 2017 and were selected as the developers in June 2017 after a solicitation. The construction took four months from the signing of the interconnection agreement, which was the period the 100 days focused on. The overall project, therefore, took the majority of 2017.[45] For the Hornsdale Power Reserve, Tesla signed a contract with Samsung to supply the batteries because of uncertainties regarding Panasonic's (its usual supplier) ability to deliver 129MWh of batteries in the required timeframe.

The scale of the Eastside solution is unprecedented but based on a 100MW/129MWh system taking most of 2017 to complete, it is a reasonable assumption that the Interim Solution (365MW/2,394MWh), the most pressing constraint, would take substantially longer. The combination of these factors makes it highly unlikely an energy storage project for Energize Eastside could be permitted, sited, sourced, designed, built and brought online within a year, to relieve the pending 2018/19 winter constraint.

[45] Source: (https://hornsdalepowerreserve.com.au/faqs/)

3. Commercial and Technological Developments

As part of the 2018 Analysis, Strategen was asked to evaluate what technological or commercial advancements have occurred with battery energy storage since the publication of the March 2015 Study. The objective was to determine if there were developments that substantively would impact the technological readiness, commercial readiness and/or cost-effectiveness of a storage solution to meet the Eastside reliability need.

3.1 Methodology

Strategen reviewed publicly available research and news on battery technology developments and cost data (historic and projections). Further, using publicly available information contained in the US Department of Energy's ("DOE") Global Energy Storage Database,[46] Strategen reviewed commercial deployments since the publication of the original March 2015 Study to characterize the ability of storage to be deployed in a scale of magnitude similar to the Eastside reliability need. We evaluated whether there are energy storage facilities currently in operation at the general scale of magnitude sufficient to meet the Eastside reliability need, and whether there are energy storage facilities with operational experience meeting a transmission reliability need similar to that on the Eastside. Strategen also reviewed publicly available operational data for utility-scale storage projects to evaluate any operational challenges or considerations that may impact the ability of a storage solution to reliably address a transmission deferral need, or additional experience (or limitations) identified in deploying storage as a multi-purpose asset[47] (which would impact its cost-effectiveness).

Key factors that have changed since the original March 2015 Study have been highlighted, along with a qualitative assessment of their likely impact on the technological or commercial feasibility of the storage alternative.

3.2 Energy Storage Applications

There are numerous applications for energy storage, which makes energy storage versatile and useful to the modern power system. Figure 19 shows some common applications for energy storage with respect to time.

[46] The Global Energy Storage Database is located at (http://www.energystorageexchange.com).

[47] By multi-purpose asset, we mean the use of storage to meet a transmission reliability need as well as other system needs, such as system (generation) capacity, system flexibility, oversupply reduction, etc.

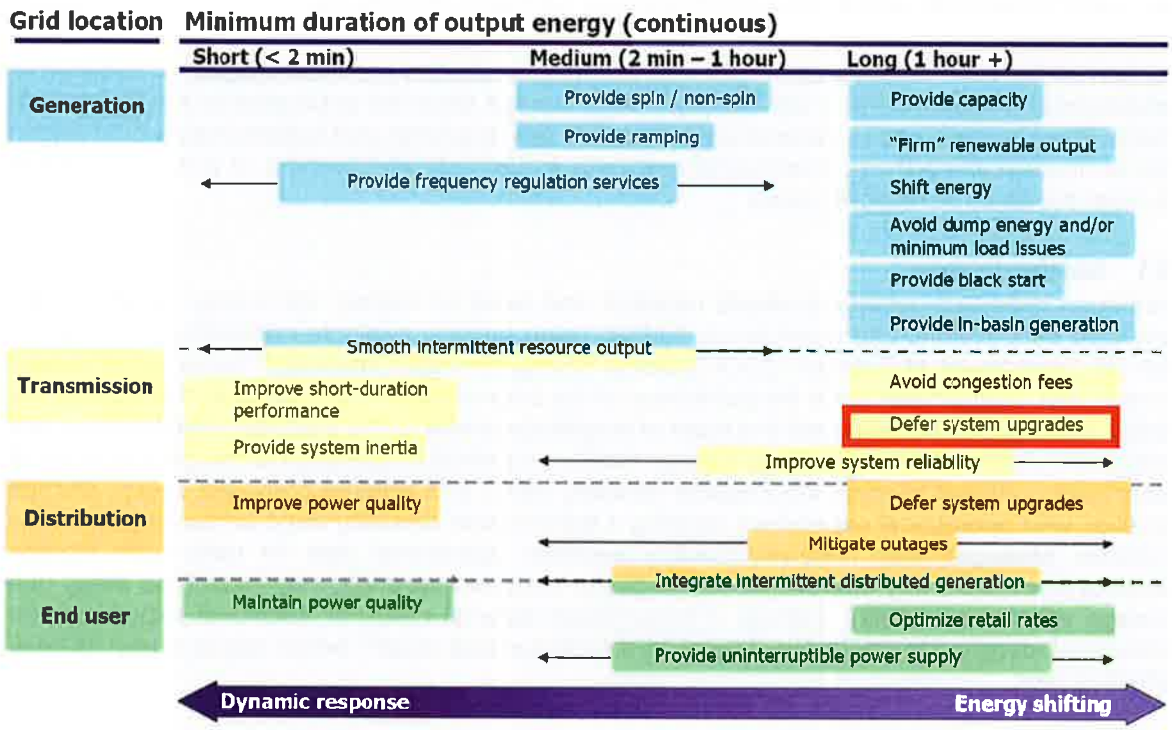

Figure 19: Various use cases for energy storage with respect to time (red box indicates Eastside storage use case)[48]

It is important to understand the application required by energy storage to effectively assess its ability to solve the power system constraint. The Energize Eastside constraint is a transmission reliability application, used to defer system upgrades, as portrayed in Figure 19. Energy storage would be used in this case to reduce the loading on the transformers to within their normal rating. In addition, it could provide other services presented in Figure 19 to increase the value proposition of the installation, but only once it has met the primary purpose and resolved the thermal rating issue.

Not all energy storage applications will be discussed below, only the most relevant. These are frequency regulation, capacity, and T&D deferral as they include the most common use cases and the Energize Eastside use case.

3.2.1 Frequency Regulation/Response

Frequency regulation/response has been the biggest application for energy storage systems to date.[49] This is a high power, low energy application, as shown by its position in Figure 19. Frequency support is required over a short timeframe, from seconds to minutes, and as such, energy storage systems to meet this need do not require a significant amount of batteries, making this typically a more cost-effective application than applications requiring longer timeframes (such as the Eastside need). Energy storage systems installed for frequency regulation are typically 15 minutes to one hour in duration. The Hornsdale Power Reserve in South Australia is approximately a 1.25-hour system (100MW/129MWh), which provides frequency regulation services in addition to

[48] Source: Southern California Edison
[49] Source: DOE Global Energy Storage Database

capacity services. Most of the large energy storage systems installed to date target frequency or stability services that are located on the left side of Figure 19.

Frequency disturbances are caused by an imbalance between generation and load. The variable output of renewable generation such as wind and solar can also add to frequency instability, which inverter-based energy storage can correct effectively with fast responding charging or discharging. In this application, the location of the energy storage system does not play a major factor, as it can contribute to addressing the net difference between generation and load, anywhere within an interconnected power system. The contribution also has a direct effect where every MW of power injected or absorbed by an energy storage system benefits the discrepancy between generation and load within the interconnected power system at a 1:1 ratio if losses are ignored.

Some examples of frequency response markets and installations are below:

- PJM Frequency Response Market – Approximately 265MW of energy storage[50]
- Hornsdale Power Reserve – Tesla and Neoen - South Australia – 100MW/129MWh (this is a secondary service)
- National Grid (UK) Enhanced Frequency Response Solicitation 2016 – 200MW in total

3.2.2 Capacity Services

Capacity services provide power as needed by the power system and as coordinated and dispatched by an electricity market operator. Conventional generation provides capacity services, and battery energy storage can also provide this service by charging at off-peak times to provide this service when required. Capacity services is a growing market for energy storage, particularly coupling energy storage to renewable generation. This allows charging from clean energy sources that are continually becoming more cost-effective, and adding storage to allow the dispatch of this energy at beneficial times as instructed by the market operator. This is the operating method of the Hornsdale Power Reserve in South Australia, which is coupled to an existing wind farm and provides capacity as directed by the market operator.

This capacity service, as discussed, is a fungible service coordinated and dispatched by a market. If there is a failure to deliver, another resource can be procured in its place. Location influences, but is not a major factor in, providing capacity services. This resource fungibility is fundamentally different than what would be required to meet the Eastside reliability need.

Some examples of capacity service installations are below:

- Hornsdale Power Reserve – Tesla and Neoen - South Australia – 100MW/129MWh
  This is the primary application where it is coupled with an existing wind farm to supply energy as directed by the Australian Energy Market Operator.
- Aliso Canyon – Provides capacity at peak times. The gas-fired power station would provide energy during peak times as a "peaker," and Aliso Canyon replicates this service, charging at off-peak times to provide capacity and peak times.

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[50] Source: (https://www.energy-storage.news/news/pjms-frequency-regulation-rule-changes-causing-significant-and-detrimental)

3.2.3 T&D Deferral

T&D deferrals are additional applications for energy storage as seen in Figure 19. In both cases, storage is used as a location-specific load serving resource that allows a traditional wires-based solution not to be built or upgraded for some amount of time. The location of an energy storage system is critical in T&D deferral use cases, as is the assurance to operate when required. Unlike capacity and frequency response services that are less dependent on location and can be substituted by other resources if they do not provide the required service, T&D deferral use cases cannot be replaced by another resource and therefore the consequences in failing to deliver are more severe.

T&D deferral applications can vary in size and duration. While frequency response systems only require minutes to an hour of duration, deferral cases require the amount of energy to offset load on a constraint element which is determined on a case-by-case basis.

The primary differences between transmission deferral and distribution deferral is that transmission deferral use cases generally require offsetting much more power and energy than distribution deferral projects, and transmission deferral applications are typically on a highly networked grid (so the power flow can go in multiple directions), whereas some distribution deferral projects are able to be located within a radial network topology (so power flow is only possible in limited directions). The effect of this on efficacy is described on page 36.

The energy storage market has not been heavily driven by T&D deferral to date, as it is a more energy-intensive application, as seen in Figure 19, and therefore more expensive. As a result, energy storage projects deployed for T&D deferral to date have been much smaller in scale compared to the notable large installations of storage projects used for other purposes around the world. Deferral use energy storage projects have also generally been sited on the lower voltage distribution system rather than the high voltage, networked transmission system. Nevertheless, the market for T&D applications is growing as market and regulatory barriers are removed. An estimated global energy storage system capacity for T&D deferral in 2017 is 331.7MW.[51] This is expected to grow by about 50-fold over the next 10 years as seen in Figure 20. An Energize Eastside non-wires project, however, would be a transmission deferral use case of unprecedented size.

[51] Source: Navigant Research

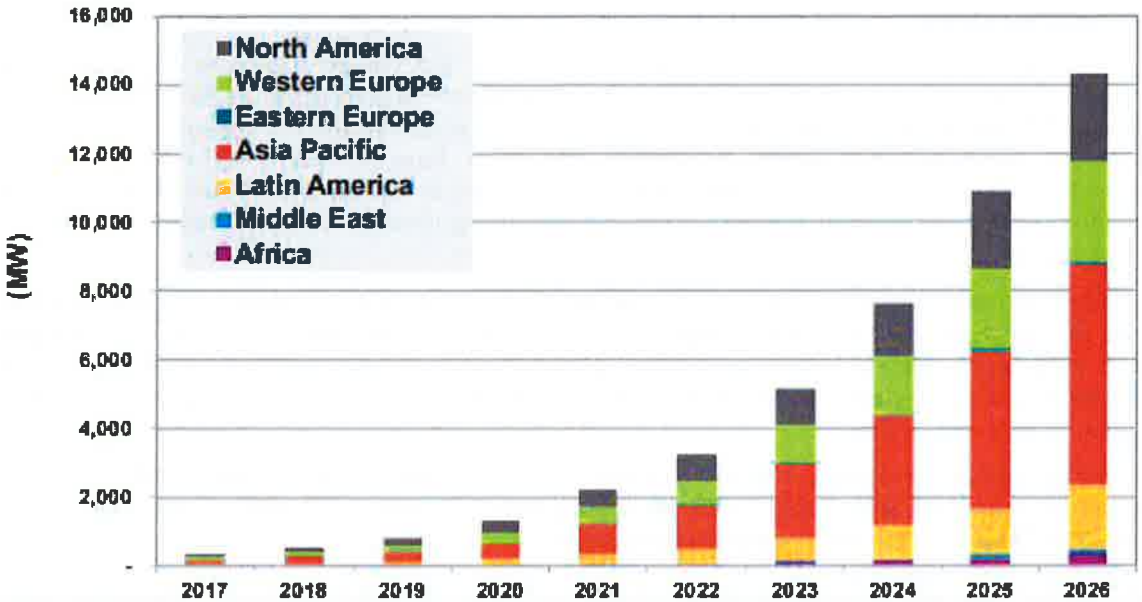

Figure 20: Forecast annual installed energy storage power capacity for T&D deferral by region, 2017-2026[52]

Some examples of proposed T&D deferral installations are below:

- Arizona Public Service (Proposed) – 2MW/8MWh (4-hour system)[53]
- National Grid Massachusetts (Proposed) – 6MW/48MWh (8-hour system)[54]

3.3 Technological Developments

The March 2015 Study compiled by Strategen suggested an energy storage solution for the Eastside system would be technologically possible, although challenging due to electrical infrastructure constraints, supply chain challenges and physical impact considerations. Some relevant advances to the technical aspects of energy storage are discussed in the Appendix.

[52] Source: Navigant Research
[53] Source: (https://www.utilitydive.com/news/aps-to-deploy-8-mwh-of-battery-storage-to-defer-transmission-investment/448965/)
[54] Source: (https://www.utilitydive.com/news/national-grid-plans-to-install-a-48-mwh-battery-storage-system-on-nantucket/510444/)

4. Conclusion

While storage is becoming a technology embraced by the power sector to modernize and enhance the grid, the specific circumstances and requirements driving the Eastside transmission capacity deficiency are not well suited- to an energy storage solution. Such a solution would need to be of unprecedented scale, exceeding the total forecast 2018 US energy storage deployments,[55] both behind and in front of the meter. It would therefore be impractical to source, site and construct. In addition, it would come at a cost many times that of the traditional poles and wires solution.

For these reasons, despite the commercial and technological progress of energy storage in recent years, the conclusion of this updated analysis remains consistent with the conclusion of the original March 2015 Study. Strategen does not believe energy storage to be a practical option to meet the Eastside transmission capacity deficiency, either as an alternative to the proposed transmission solution or as a way to defer it.

The overall amount of storage required to meet the Eastside transmission capacity deficiency was calculated to be 549 MW, 5,500 MWh, compared with 545 MW, 5,771 MWh in the March 2015 study. See Table 7 below for a complete comparison.

Table 7: Comparison of the March 2015 Study and 2018 Analysis for the sizing of an energy storage system for Eastside

Constrained Element	Power (MW)	Energy (MWh)	Duration (hours)	Meets 2019 System Need	Meets Solution Requirements Through 2027[56]	Feasibility[57]
Original March 2015 Study Results[58]						
Talbot Hill	**545**	**5,771**	**10.6**	✓	not evaluated	✗
Sammamish[91]	*Assessed to be less than Talbot Hill sizing*					
2018 Analysis						
Interim Solution for 2019[59]						
Talbot Hill	290	1,689	5.8	✗ [60]	✗	✗
Sammamish[61]	**365**	**2,394**	**6.6**	✓	✗	✗
Complete Solution through 2027						
Talbot Hill	338	3,679	10.9	✓	✗ [90]	✗
Sammamish[91]	**549**	**5,500**	**10.0**	✓	✓	✗

[55] This includes all types of energy storage; residential, non-residential and utility in-front-of-the-meter systems.
[56] Meets 2027 requirements means satisfying the NERC/FERC planning criteria through 2027, the same planning criteria against which the ultimate Eastside solution must be judged (whether a wires or non-wires solution).
[57] Feasibility relates to electrical sizing, physical sizing, timing and the ability of the market to respond.
[58] The March 2015 Study evaluated solution requirements to meet a deferral need through 2021.
[59] Sized only to meet immediate 2019 constraint assuming all other NWAs per E3 NWA Report (2014) are implemented; size requirement would be larger if other NWAs are unable to be implemented.
[60] The Talbot Hill sizing is insufficient to meet the Sammamish need and therefore does not meet the system need for that entire year.
[61] Sammamish was assessed in the March 2015 Study, but Talbot Hill was the more significant constraint that defined the energy storage sizing. Due to several factors detailed in this report, Sammamish is now the greatest constraint that defines the size while Talbot ill also exceeds NERC requirements.

Appendix: Technical Analysis - Additional Information

Technical Analysis Assumptions

The following assumptions were used to conduct this updated analysis. In general, Strategen maintained the assumptions in the original March 2015 Study but where updated data and details are available, those were updated.

The ***assumptions that have remained*** the same between the original March 2015 Study and this assessment are:

Effectiveness factor – The effectiveness factor used in the March 2015 Study was approximately 20%. An explanation and example of effectiveness factor is presented on page 36. *It is important to recognize this is a characteristic of the Eastside system and is not related to the energy storage's round-trip efficiency.*

Note, other energy siting locations were considered (both bulk and distributed) within the Eastside area, and the effectiveness factor remained similar. Therefore, whether the solution is a centralized system located within the area, a distributed solution within the area, or a combination of the two, the total aggregate sizing requirements as identified in this analysis would be very similar. For example, if a 100MW/400MWh system is required, two 50MW/200MWh systems or ten 10MW/40MWh systems would be required and considered equivalent. From an effectiveness factor point of view, there is no benefit to a centralized energy storage system versus a distributed system (or vice versa).

Round-trip efficiency – The round-trip efficiency ("RTE") of the energy storage used in the March 2015 Study was 85% and this remained the same in this study. Lazard's latest annual Levelized Cost of Storage Analysis (LCOS 3.0) uses 85% efficiency in its analysis.[62] As an additional reference, the Tesla Powerwall 2 has a 90% RTE. This is at the start of its operating life, prior to any degradation, and under test conditions where the system is discharged at 66% of its rating.[63] A system designed for the Eastside application would not operate at a 90% RTE during peak times due to the higher charge and discharge rate required. 85% RTE, therefore, remains an appropriate RTE for this analysis. Flow batteries generally have lower RTE due to reduced performance at high charge and discharge rates and also require energy to operate the electrolyte pumps.

Cell degradation – The original March 2015 Study used a 2% per year rate of cell degradation. This is an industry standard for lithium-ion (it is expected that 80% of the installed energy is available after 10 years) and the same 2% rate was considered in this updated analysis. As the energy storage sizing is assessed to meet the 2019 load forecast, cell degradation has very little impact on this sizing. Flow batteries do not generally degrade as much as lithium-ion batteries over time. However, an 85% RTE is being assumed, which is high for flow batteries and therefore the assumption of 2% cell degradation per year will not unfairly diminish a flow battery's capabilities in the assessment. Cell degradation is inherent to electrochemical energy storage, and anyone with a smartphone would have witnessed reduced battery performance and capacity after several years of use due to this phenomenon.

2014 E3 NWA Report – A report in 2014 identified possible NWA and load reductions associated with these measures. As in the March 2015 Study, these were incorporated into the storage sizing

[62] Source: (https://www.lazard.com/perspective/levelized-cost-of-storage-2017/)
[63] Source: (https://www.tesla.com/sites/default/files/pdfs/powerwall/Powerwall%202_AC_Datasheet_en_northamerica.pdf)

analysis to provide the maximum identified reductions. The NWA reductions are presented in Table 8.

Table 8: 2014 E3 NWA Report with potential load reduction opportunity values

	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
Conservation Potential (MW)	18.9	22.7	26.5	30.1	30.1	30.1	30.1	30.1	30.1	30.1
DR Potential (MW)	11.7	11.9	24.3	24.7	24.7	24.7	24.7	24.7	24.7	24.7
DG Potential (MW)	0.5	0.6	0.7	0.8	0.8	0.8	0.8	0.8	0.8	0.8
Total (MW)	31.2	35.3	51.6	55.6	55.6	55.6	55.6	55.6	55.6	55.6

The ***assumptions that have changed*** since the original March 2015 Study due to updated information and data are:

Load data –Talbot Hill and Sammamish representative load data was generated by PSE for the updated analysis, and scaled to account for projected load growth from 2018-2027.

Load forecasts – As part of its 2017 Integrated Resources Plan ("IRP"), PSE updated its system load forecast reflecting a gradual shift from a winter to a summer peaking system. This reduced winter loading at Talbot Hill, and increased summer loading at Sammamish versus the March 2015 Study, which was based on data from PSE's 2013 IRP. Load forecasts are inherently uncertain, especially further out into the future. For this reason, much of the analysis focuses on the near-term load data. Load forecasts inherently contain some degree of uncertainty: the load may either increase or decrease from the forecast. While energy efficiency and DER offer some load reduction opportunities, electric vehicles may add significant additional load, and the timing of this will be important (and remains uncertain). The load forecast below is consistent with distribution planning approaches to meet NERC and FERC planning requirements and is used for this analysis.

Scenarios considered – Both the Talbot Hill winter load data and Sammamish summer load data were evaluated to define the energy storage sizing. The original March 2015 study also considered both data sets but only presented Talbot Hill because it had the greatest exceedance in the normal rating and therefore defined the size of the storage system required to meet the system constraint. In other words, a system that met the larger Talbot Hill exceedance would also meet the lesser Sammamish exceedance. As shown in the load forecast data above, the Sammamish summer load has now become the greatest exceedance and therefore the sizing of both the Talbot Hill and Sammamish are presented.

Normal and emergency ratings – The transformer ratings have changed since the previous March 2015 Study due to the adoption of a new computer simulation that provides a more dynamic, seasonally adjusted and element-specific rating for each element designed to maximize infrastructure performance.[64] In June 2017, PSE established new ratings for transformers using this

[64] PSE chose EPRI's PTLOAD program as it is a widely accepted tool in the industry for rating transformers and is being used by nine out of the 11 utilities PSE surveyed. Moreover, the in-house software and EPRI PTLOAD software are developed using the same IEEE standards. EPRI PTLOAD was rigorously tested and compared to in-house software. EPRI PTLOAD calculates both individual and group ratings similar to the in-house software, which is one of the requirements the unit-specific rating process targets when the individual transformer would experience an accelerated loss of life.

simulation. To meet NERC requirements, PSE plans its infrastructure in accordance with facility ratings.[65] This has resulted in an increase in the normal winter rating at Talbot Hill from 398MW to 426MW. With respect to Sammamish, the normal summer rating has increased from 369MW to 387MW.

To meet NERC requirements, PSE plans its system using normal ratings on its equipment. Both the normal winter rating for Talbot Hill Substation and the normal summer rating for Sammamish Substation increased by 28MW, which reduced the required contribution of any energy storage system compared to the sizing of the original March 2015 Study.

Minimum SOC – In the additional analysis conducted in this report, the SOC is considered. The minimum SOC limit used was 2%. It is not possible to fully discharge a lithium-ion battery without damage. Such systems have a total energy capacity and a usable energy capacity. For example, the Tesla Powerwall 2 has a total energy capacity of 14kWh but has a usable energy capacity of 13.5kWh. To extract this full amount of energy (13.5kWh), the system must be discharged at 3.3kW or less, (66% of the rated at 5kW continuous discharge).[66] The Eastside application would require higher charge and discharge rates and therefore would not be able to extract as much usable energy, making 2% very aggressive. A flow battery can allow for a 100% depth of discharge and provide all the stored energy as usable capacity; however, the electrolyte pumps consume energy and the 85% RTE assumption is high for a flow battery. Therefore, a 2% SOC limit is used to be technology agnostic and provide a conservative assumption for a lithium-ion system. An actual lithium-ion system would need to be sized larger to cater for the inability to use all of the stored energy capacity.

N-1-1 configuration – The N-1-1 configuration occurs when two different elements go out of service in succession. This is the NERC/FERC planning requirement that the system must be able to handle two elements out of service while continuing to reliably supply the system. Due to the specific electrical topology of the Eastside system, the worst-case N-1-1 contingency during the summer has a more significant impact on Sammamish than the worst-case N-1-1 contingency during the winter has on Talbot Hill.

[65] PSE correspondence (3/7/18)
[66] Source: (https://www.tesla.com/sites/default/files/pdfs/powerwall/Powerwall%202_AC_Datasheet_en_northamerica.pdf)

Explaining "Effectiveness Factor"

The effectiveness factor is the ratio of power injected at particular locations to the reduction of power across a constrained element elsewhere in the system. This differentiates energy storage for T&D applications versus energy storage for frequency response or capacity services. Power for frequency and capacity can be measured at the point of injection, while power for T&D deferral depends on the reduction at the constrained element. Frequency response is a correction to the net imbalance to generation and demand, which is not dependent on where the injected power flows. Similarly, capacity adds power to the system; regardless of where it flows, it provides that capacity to the system. However, in T&D deferral applications, the power flows are critical. The energy storage system's primary purpose is to reduce the power flow through one or more constrained elements and therefore *where* the power flows.

There are two typical configurations for a power system, radial and meshed. Radial, as the name suggests, is one or more radial lines connected in one direction between two nodes, while meshed is a number of lines interconnected to provide more redundancy. Radial configurations are more typical in rural applications at the distribution level while meshed configurations are more common in the urban environment and at the transmission level. The trade-off being radial is cheaper, consisting of fewer lines and connections, but is less reliable because a single failure can cause an outage.

A meshed network, however, can sustain a failure, isolate that section, and provide power through a different line route. Meshed systems allow customers to experience both fewer and shorter duration outages. This reliability aspect is important and is why meshed topologies are typically used to supply urban areas. The comparison between radial and meshed networks can be seen in Figure 23.

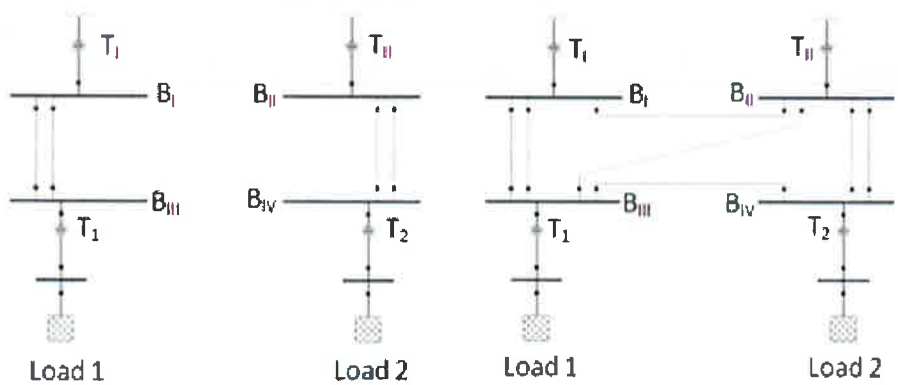

Figure 23: Radial configuration left (dual circuit) and mesh configuration right

When considering energy storage for T&D deferral on a radial line, the effectiveness factor is generally much higher as there are fewer paths for injected power to flow. This concept is shown in Figure 24.

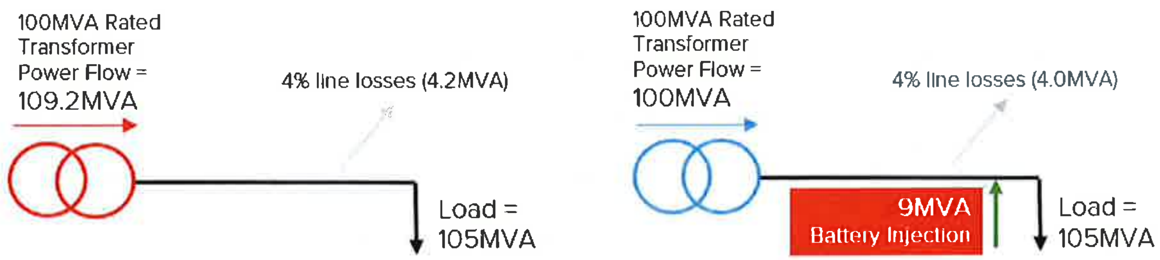

Figure 24: Example of energy storage providing benefit to a radial system

In Figure 24, a transformer rated at 100MVA is overloaded to 109.2MVA. This is a thermal constraint due to the downstream load. In this example, 4% line losses were considered to demonstrate an additional benefit of energy storage. The load consumes 105MVA and 4.2MVA is lost in the power system due to heat (I^2R losses). By installing a 9MVA battery energy storage system near the load, the system has reduced the power flow through the transformer and relieved the constraint. The load still consumes 105MVA but now 9MVA comes from the battery while the power through the transformer supplies 96MVA to the load and 4MVA of power system losses. In this case, the effectiveness factor is 1.0222 because 9MVA of injection by the energy storage system reduces the power through the transformer by 9.2MVA (9.2/9=1.0222). The reason the reduction through the transformer is greater than the energy injected is because the storage system is located closer to the load, so its energy reduces the flow through the transformer, while also reducing the flow through the line, thus reducing the line losses.

The Eastside transmission network is a meshed configuration. In a meshed system, the power flows are very different. Electricity, like water, will take the easiest path which is determined by the resistance (impedance) it faces. The only way to change this is if the physical power system is changed through switching (reconfigured). Figure 25 shows this concept.

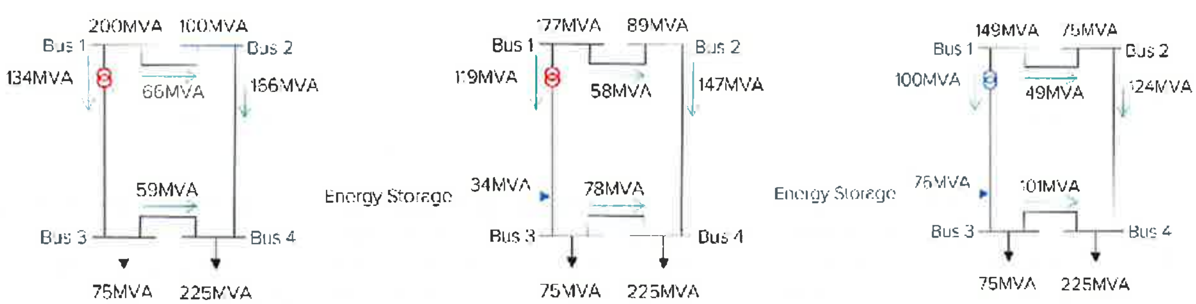

Figure 25: Example of meshed network response to injection and the fact it is not a 1:1 benefit

In Figure 25 the transformer again has a 100MVA rating and is overloaded to 134MVA. However, in this case, simply adding 34MVA of storage does not resolve the thermal constraint as seen. This is because power flows take the path dictated by the system impedance. One-third of the battery injection reduces the contribution at bus 2 while the other two-thirds reduce the contribution at bus 1. The resulting power flows then reduce by that seen in Figure 25. Increasing the battery energy storage system to 76MVA does bring the transformer to its 100MVA rating as seen in Figure 25. In this case, the effectiveness factor is 0.4474 (34/76=0.4474). Therefore, to reduce the loading on the constrained transformer by the required 34MVA, 76MVA of energy storage is required because only 44.74% of the injection of energy storage contributes to reducing the constraint while the remainder reduces the power flows on other lines that are not relevant to the constraint.

The Eastside power system has an effectiveness factor of approximately 20%. The system is highly interconnected, much more so than the simple example shown in Figure 25. This is typical of networks supplying high-density urban areas. This is because a failure can affect so many customers, and the power system is designed to be more interconnected to provide more redundancy, ensuring that customers receive a reliable supply. Various locations were considered within the Eastside area, and all interconnection points had a similar effectiveness factor to the transformer constraints. This again is because of the number of interconnected networks. This effectiveness factor is an important point to understand when comparing systems installed for other applications to the need in the Eastside area.

Explaining "Ability to Charge"

Energy storage, unlike a generator, also acts as a load. For an energy storage system to effectively provide support, it must also have the capability to charge sufficiently without causing a constraint. This ability is determined by network capacity. Figure 26 highlights an example of the required energy discharge (red) and the capacity to charge (green).

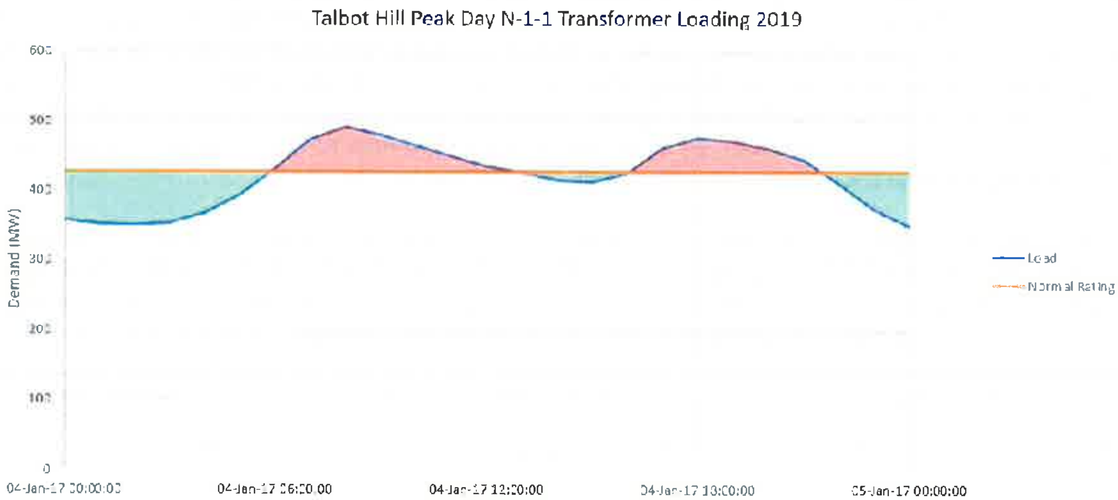

Figure 26: Talbot peak 2017 day (actual load data) and charge capacity (green) and discharge requirement (red)

The green area must be greater than the red area by an amount to compensate for the RTE to effectively charge. For example, if the red area is 80MWh and the green area is 100MWh, with an RTE of 85%, there is sufficient energy to charge the system. 100MWh of charging will enable 85MWh of discharge with 15MWh in energy losses. If the red area is 90MWh and the green area is 100MWh, with an RTE of 85%, there is insufficient energy to charge as 100MWh of charging will only allow 85MWh of discharge. To meet the 90MWh discharge requirement, 105.9MWh of charging must be available to cater for the 85% RTE (90MWh/0.85). If the network cannot support this 105.9MWh of charging without causing an overload, there is insufficient network capacity to allow adequate charging within the daily period studied.

Talbot Hill Solution – Methodology Description, with Comparison to Original Methodology Results

The following steps were taken to assess the energy storage requirements for Talbot Hill Substation based on the original methodology from the March 2015 Study.

1) The recorded Talbot Hill Substation load data was considered and the peak day was extracted. This peak demand is the maximum loading on the substation's two transformer banks and will define maximum power contribution required by a potential energy storage system.
2) During a winter N-1-1 contingency for Talbot Hill Substation, the loading on the remaining transformer at the Talbot Hill Substation would be 78.1% of the full (two transformer) load. The peak day is scaled by this number to compare what the loading would have been on the remaining Talbot Hill transformer.
3) The peak day transformer loading is scaled by the load forecast and relevant N-1-1 scaling factor to provide an N-1-1 load profile for each peak day over the next 10 years, which is presented in Figure 21. Note that even a small change in peak demand has a relatively large impact on the area between the peak loading (solid lines) and the normal transformer rating (dotted red line).

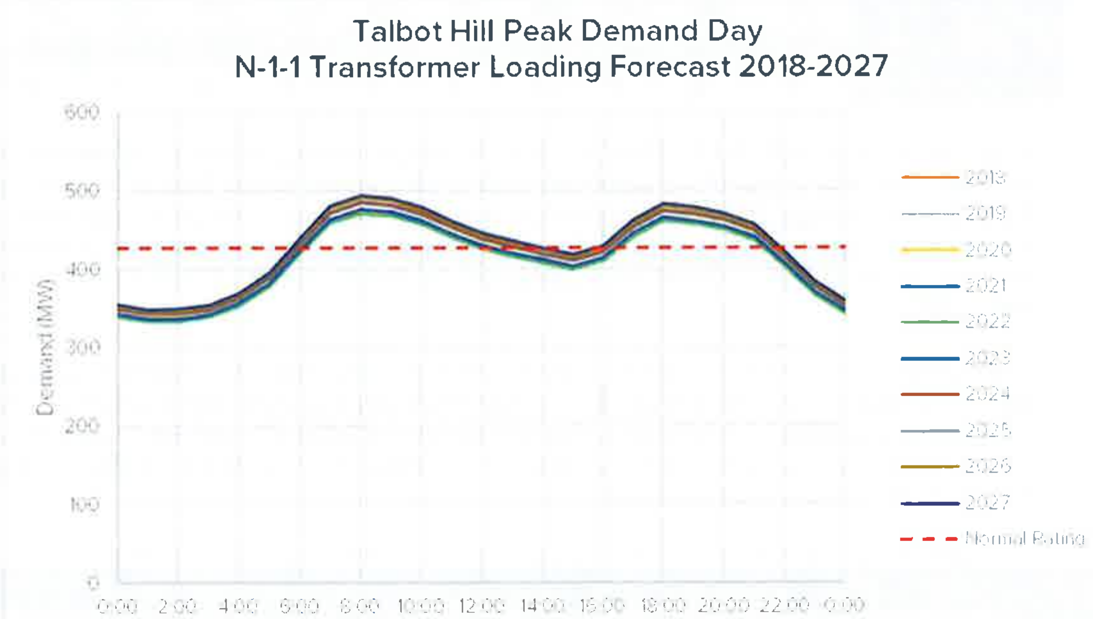

Figure 21: Peak demand loading forecast from 2018 to 2027

4) The peak day of each year is then considered with respect to the normal rating seen in Figure 21. By subtracting the normal rating, the amount the load exceeds the rating defines the load reduction required to meet planning standards.

5) Loading on the overloaded transformer element must be reduced to the normal rating by injecting power onto the grid. Injection of power at the appropriate location on a networked (mesh) power system would reduce this loading at ratio less than 1:1, so this exceedance (which is the exceedance on the transformer element) is then divided by the effectiveness factor. Dividing the exceedance by the effectiveness factor determines the required level of energy injection. The effectiveness factors are approximately 20% for all

scenarios. More information on effectiveness factor concept can be found elsewhere in the Appendix.

6) The NWA load reductions, as identified by the 2014 E3 NWA Report, are then subtracted from the required injection to determine the remainder that must be met by an energy storage system. Similar to the effect of the energy storage system, NWA reductions do not reduce the loading on the constrained element at a 1:1 ratio, and therefore must be subtracted after the effectiveness factor is applied. The NWAs also need to be scaled by the same N-1-1 scaling factor to provide the accurate reduction contribution on the remaining transformer loading.

7) This process identifies the required power and energy of an energy storage system **during the peak demand day** (after NWAs are considered) to reduce the load on the constrained transformer element to the normal rating.

Table 9: Energy storage requirements by year to alleviate Talbot Hill Substation constraint

Net Energy Storage Injection Requirement, by Year[67]										
	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
Power (MW)	210	**290**	244	208	181	204	255	247	282	**294**
Energy (MWh)	1,239	**2,083**	1,559	1,198	935	1,160	1,668	1,586	1,968	**2,105**
Duration (hrs.)	6	**7**	6	6	5	6	7	6	7	**7**

8) It can be seen in Table 9 that 2019 presents the largest energy storage requirement prior to 2027. This year is therefore significant and is considered as the Interim Solution using the old methodology. 2027 is the maximum size required and provides an alternative that is equivalent to the requirements of the proposed transmission solution which meets the need in all years and is therefore considered as the Complete Solution using the old methodology.

9) The sizing required for the Complete (2027) Solution must also be adjusted to assess the energy storage system requirements for a system installed in 2018 and account for 2% per year cell degradation, as any energy storage system installed to meet the Interim Solution requirements will degrade over time prior to meeting the Complete Solution. Table 10 shows the results of cell degradation.

Table 10: An energy storage system installed in 2018 would need to be 2,515MWh to supply 2,105MWh in 2027

	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
Energy (MWh)	**2,515**	2,466	2,418	2,370	2,324	2,278	2,234	2,190	2,147	**2,105**

At this point, the original March 2015 Study compared this discharge need to the charging capability discussed elsewhere in the Appendix.

[67] Cell degradation and usable energy capacity are not considered.

DSD_011947

Sammamish Solution – Methodology Description, with Comparison to Original Methodology Results

The following steps were taken to assess the energy storage requirements for Sammamish Substation based on the original methodology from the March 2015 Study.

1) The recorded Sammamish load data was considered and the peak summer day was extracted. This peak summer demand was the maximum loading on the transformer during the 2017 summer that was of a consistent shape and representative of likely future peak load days. This will define the maximum power contribution required by a potential energy storage system.
2) During an N-1-1 contingency for Sammamish, the loading on the remaining transformer at the Sammamish Substation is 101.4% of the full (two transformer) load. The peak summer day is scaled by this number to compare the loading on a Sammamish transformer under an N-1-1 contingency.
3) The peak summer day transformer loading is scaled by the load forecast and relevant N-1-1 scaling factor to provide an N-1-1 load profile for each peak summer day over the next 10 years as seen in Figure 22.

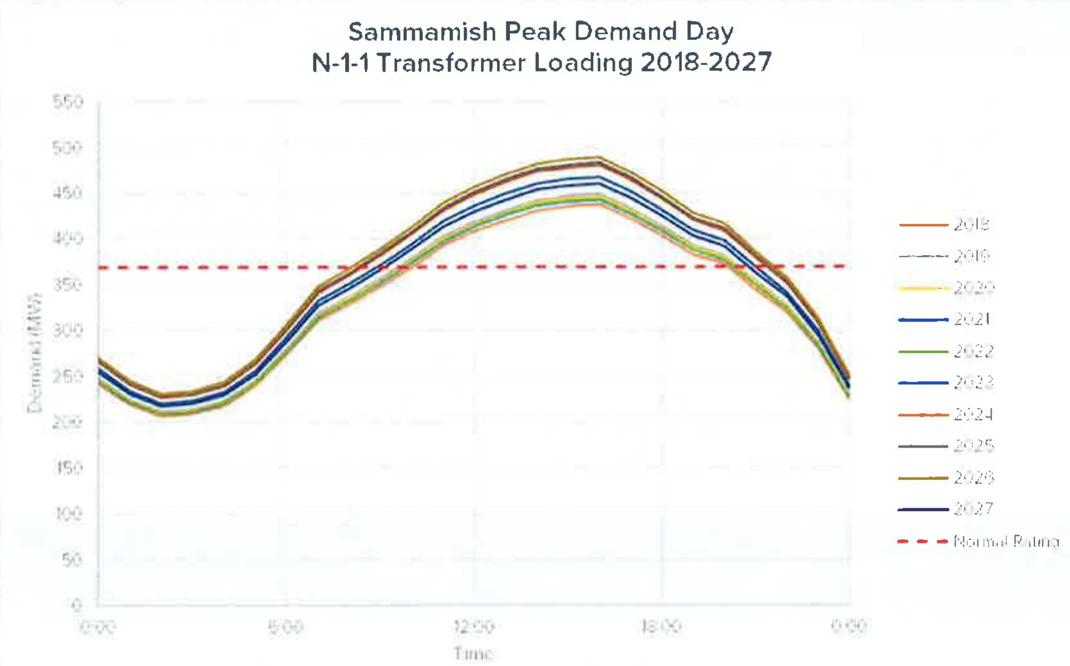

Figure 22: Peak demand day transformer loading forecast from 2018 to 2027

4) The peak summer day in each year is then considered with respect to the normal rating. By subtracting the normal rating, the amount the load exceeds the rating defines the load reduction required to meet planning standards.

5) This exceedance (which is the exceedance on the transformer element) is then divided by the effectiveness factor. The overloaded transformer element must be relieved to the normal rating, and the injection of power reduces this at the ratio of the effectiveness factor. Dividing the exceedance by the effectiveness factor determines the required level of energy injection. The effectiveness factors are approximately 20% for all scenarios, and more information can be found in the Appendix.

DSD_011948

6) The NWA load reductions, as identified by the 2014 E3 NWA Report, are then subtracted from the required injection to determine the remainder that must be met by an energy storage system. Similar to the effect of the energy storage system, NWA reductions do not reduce the loading on the constrained element at a 1:1 ratio, and therefore must be subtracted after the effectiveness factor is applied. The NWAs also need to be scaled by the same N-1-1 scaling factor outlined in the Appendix, to provide the accurate reduction contribution on the remaining transformer loading.

7) This process identifies the required power and energy of an energy storage system, after NWAs are considered, to reduce the load on the constrained transformer element to the normal rating. These results can be seen in Table 11.

Table 11: Energy Storage Requirements by year to alleviate Sammamish Substation constraint

	Net Energy Storage Injection Requirement, by Year[68]									
	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
Power (MW)	310	**365**	332	313	318	439	504	519	**549**	405
Energy (MWh)	1,773	**2,277**	1,953	1,786	1,830	3,033	3,713	3,886	**4,240**	2,687
Duration (hrs.)	5.7	**6.3**	5.9	5.7	5.8	6.9	7.4	7.5	**7.7**	6.6

8) It can be seen in Table 11 that 2019 presents the largest energy storage requirement prior to 2023. This year is therefore significant and considered as the Interim Solution using the original methodology. 2026 is the maximum size required in Table 11 and provides an alternative that is equivalent to the requirements of the proposed transmission solution which meets the need in all years. 2026 is therefore considered as the Complete Solution for Sammamish.

9) Finally, the sizing required for the Complete Solution using the original methodology, 2026, must be adjusted to assess the energy storage system requirements for a system installed in 2018 and account for 2% per year cell degradation. Any energy storage system installed to meet the Interim Solution will degrade over time prior to meeting the Complete Solution and must be considered. Table 12 shows the results of the cell degradation.

Table 12: An energy storage system installed in 2018 would need to be 4,968MWh to supply 4,240MWh in 2026

	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
Energy (MWh)	**4,968**	4,871	4,775	4,682	4,590	4,500	4,412	4,325	**4,240**	4,155

At this point, the original March 2015 Study compared this discharge need to the charging capability as discussed elsewhere in the Appendix.

[68] Cell degradation and usable energy capacity are not considered.

Technical Readiness

Battery energy storage in the power system, until recently, was primarily installed for research and development purposes and proof of concept pilots. In recent years, however, energy storage has advanced, and systems have and are being installed as effective and credible options in some use cases instead of conventional power system solutions. This is depicted in Figure 27 where the progression from demonstration to deployment and now mature technology can be seen in EPRI's energy storage progression plot.

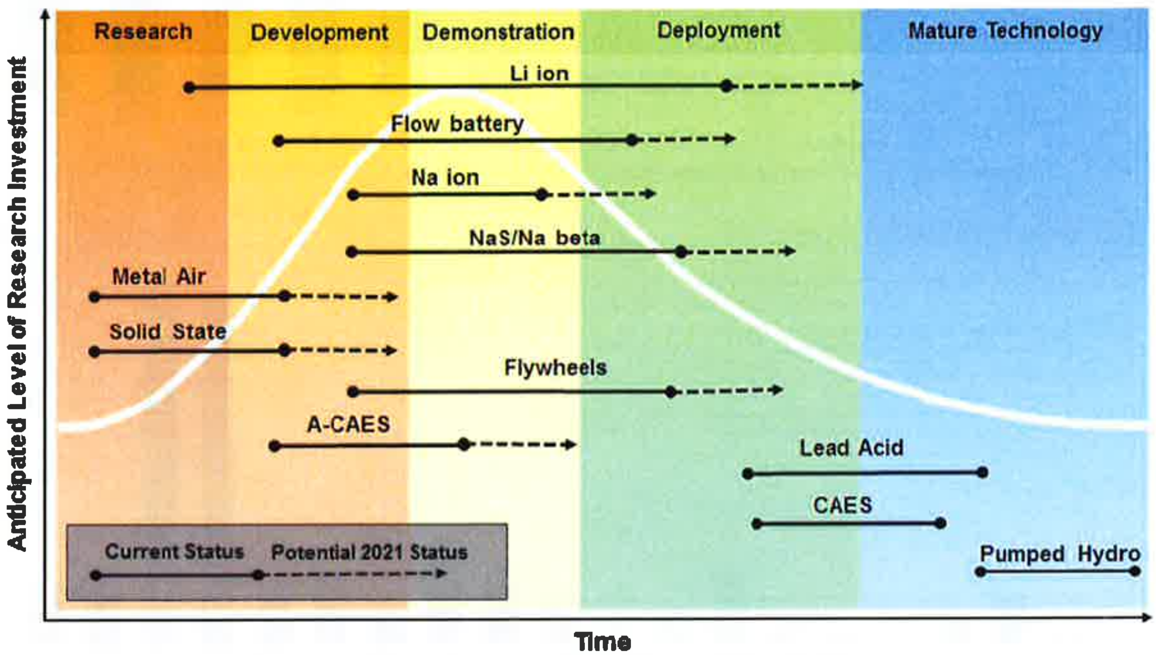

Figure 27: Energy storage progression plot to 2021[69]

The progression is shown in Figure 27 and the transition from demonstration and deployment to a mature technology is evident from the growth of the energy storage industry. Since the March 2015 Study, the deployments of energy storage in terms of energy rating have increased approximately 46% year on year. Figure 28 and Figure 29 capture the annual deployments and quarterly deployments of energy storage respectively. 431MWh of energy storage was deployed in the US in 2017 and it is expected approximately 1,233MWh will be deployed in 2018. This growth rate illustrates the increasing maturity of storage as a technology class, such that today it is generally viewed as a technology that is evolving beyond pilot deployments into commercial applications.

[69] Source: MacColl, Barry. "An EPRI Perspective on the future of distributed energy storage". EPRI, 2017.

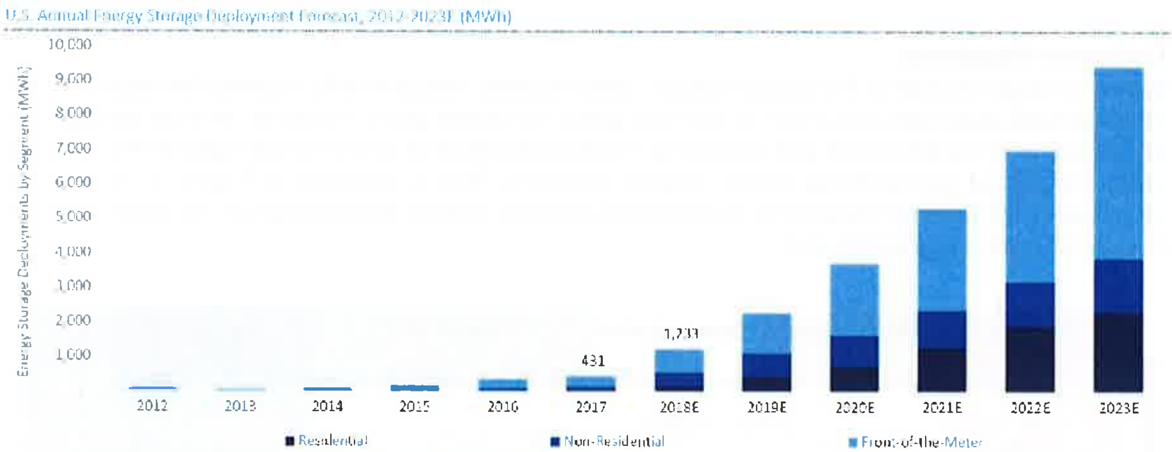

Figure 28: Annual US energy storage deployments by energy capacity (MWh). E = Estimate[70]

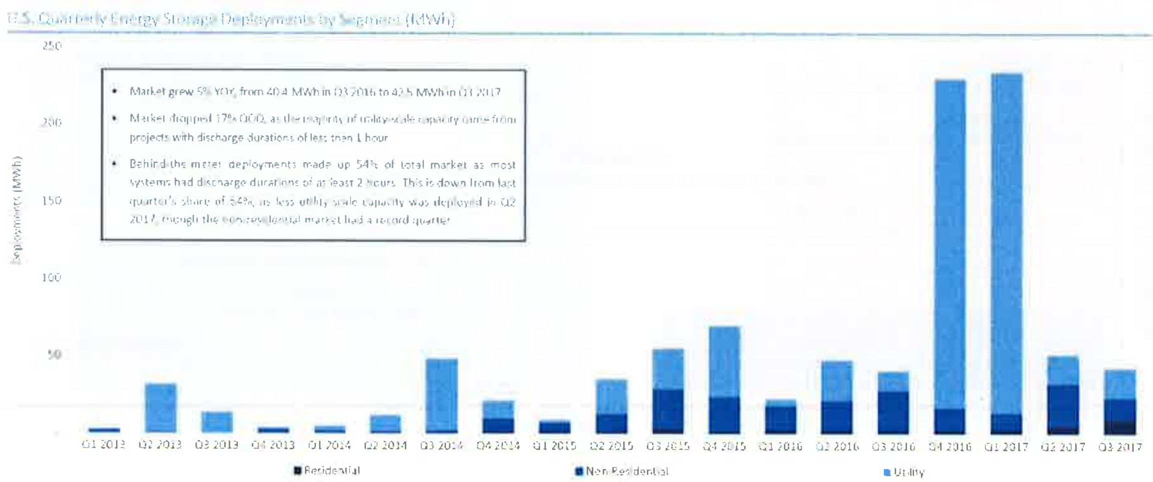

Figure 29: Quarterly US energy storage deployments by total energy (MWh)[53,71]

Excluding pumped hydro, approximately 90% of energy storage capacity deployed in 2016 was a lithium-ion battery chemistry. Other battery chemistries (e.g., redox flow or lead acid) amounted to an estimated 5% of capacity additions, and all other storage technologies combined accounted for the remaining 5%.[72] More recent (Q2 2017) data showed that 94.2% of battery energy storage systems installed were lithium-ion varieties, 5% were flow batteries and approximately 0.5% were lead acid.[73]

It is evident that lithium-ion remains the dominant technology, while flow batteries are also seeing deployments for certain applications. The March 2015 Study assessed a lithium-ion storage system as it anticipated this technology to lead the market, which has proved to have been appropriate on the evidence of recent years.

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[70] Source: GTM Research and ESA (https://www.greentechmedia.com/research/subscription/u-s-energy-storage-monitor#gs.f6=Ow5Q)
[71] Source: GTM Research and ESA (https://www.greentechmedia.com/research/subscription/u-s-energy-storage-monitor#gs.f6=Ow5Q)
[72] Source: (https://www.iea.org/etp/tracking2017/energystorage/)
[73] Source: (https://www.energy-storage.news/news/flow-batteries-leading-the-way-in-lithium-free-niches1)

While they lack the widespread commercialization of lithium-ion,[74] flow battery technology appears to be gaining ground in proposed utility-scale projects, particularly with the announcement of UniEnergy Technology's partnership with Rongke Power in China to develop a 200MW/800MWh flow battery facility in Dalian province of China. According to recent news about the project, groundwork is underway and the project is anticipated to come online in 2020, and "most of the [vanadium batteries] that will fill the site is already built in the manufacturer's nearby facility."[75]

Flow battery technologies may have a few advantages over lithium-ion applications for transmission deferral applications addressing reliability scenarios similar to the Eastside transmission capacity deficiency. They are capable of providing a long-duration, high-power solution and a 20-year ~15,000 cycle life and, unlike lithium-ion solutions, the operational efficiency of flow batteries generally does not degrade over time. However, flow battery solutions generally have a lower round-trip efficiency than lithium-ion solutions, with UET's product fact sheet estimating AC-AC round-trip efficiency of approximately 70%.[76]

Several major deployments further reinforce battery storage becoming a viable alternative grid solution in appropriate circumstances, either where energy storage has been specifically sought due to its technical benefits or where energy storage has been economically competitive in its own right through procurements for grid services. These include:

PJM Frequency Response Market - Between 2011 and 2015, hundreds of megawatts' worth of energy storage have been interconnected to provide frequency response services in PJM's territory. This strong market signal, which has since reduced due to changes in the market, encouraged development extremely effectively, causing an explosion of growth.[77]

National Grid (UK) Enhanced Frequency Response Solicitation 2016 - National Grid sought enhanced frequency response services to assist in stabilizing the power system as the level of synchronous (fossil) generation in the supply mix decreased. The solicitation sought 200MW of service, with a maximum of 50MW from any one system to respond to a frequency disturbance within one second. All winning submissions were energy storage.[78]

Aliso Canyon Energy Storage Deployment - In an emergency response to a gas leak at the Aliso Canyon power station storage facility, which resulted in insufficient capacity to meet the 2017 summer load, 94.5MW/342MWh of energy storage from a variety of vendors and with a variety of configurations was procured, installed and commissioned in less than a year.

Hornsdale Power Reserve - In South Australia, a 100MW/129MWh Tesla energy storage system was installed at the end of 2017 in response to a series of high-profile power outages. This system, coupled to an existing wind farm, will provide capacity, peak shifting, and frequency stability services to the National Energy Market of Australia. The Hornsdale

[74] Source: (https://www.lazard.com/perspective/levelized-cost-of-storage-2017/)
[75] Source: (https://electrek.co/2017/12/21/worlds-largest-battery-200mw-800mwh-vanadium-flow-battery-rongke-power/)
[76] Source: (http://www.uetechnologies.com/images/product/UET_UniSystem_Product_Sheet_reduced.pdf)
[77] Source: (https://www.greentechmedia.com/articles/read/new-market-rules-destroyed-the-economics-of-storage-in-pjm-what-happened#gs.=X5cRS4)
[78] Source: (https://www.nationalgrid.com/uk/electricity/balancing-services/frequency-response-services/enhanced-frequency-response-efr)

Power Reserve energy storage system has since outperformed conventional generation in providing frequency response services.[79]

In addition to these large in-front-of-the-meter energy storage deployments, there are planning mechanisms in place to routinely consider NWAs, such as energy storage, within the distribution planning process. These assist the distribution network by resolving constraints to avoid or defer conventional infrastructure upgrades. Such frameworks highlight that energy storage is now an important consideration in the distribution planning process and implementable as a solution to enhance the grid. Two of these frameworks include:

New York Joint Utilities Non-Wire Alternative Solicitations - The joint utilities of New York were directed by the Reforming the Energy Vision initiative to pursue NWAs to grid constraints in lieu of building conventional infrastructure. This will both allow the optimal solution to be selected, conventional or NWA, with the likely result being that energy storage may play a larger and larger role in the distribution systems of New York in conjunction with other technologies.

The Brooklyn-Queens Demand Management ("BQDM") program was one project that arose from this process. Since this initial project, NWA opportunities are now regularly identified by joint utilities and request for proposals ("RFPs") listed on their websites.[80] And while every NWA need is unique,[81] we note that some projects such as the West 42nd Street Substation deferral are designed to meet transformer overloads in the tens of megawatts.

California Energy Storage Solicitations - As part of the energy storage targets set by the State of California, the CPUC explicitly enabled energy storage to meet the target as being a combination of BTM, third-party owned, and utility-owned. The investor-owned utilities have designed energy storage RFPs and local capacity resources RFPs to routinely procure energy storage to add capacity and defer the need for distribution upgrades.

Energy storage has become a credible tool used in grid planning, and there have also been various technical advances including energy density, manufacturing, configuration, operating life and operation. These all present the case that energy storage has matured since the March 2015 Study, although the deployments have still been significantly smaller than would be needed for the Eastside need. Some of these aspects will be further discussed.

Energy Density/Physical Sizing

Energy density is the amount of energy that a battery can store per given weight or volume. Historically, the energy density of lithium-ion cells has doubled approximately every 10 years, as seen in Figure 30. This represents an increase in density of approximately 8% per year.

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[79] Source: (https://electrek.co/2017/12/19/tesla-battery-save-australia-grid-from-coal-plant-crash/)

[80] Source: (https://www.coned.com/en/business-partners/business-opportunities/non-wires-solutions)

[81] For example, distribution deferral needs might be more easily offset by distributed energy resources, such as storage, because the distribution substation acts as a radial "bottleneck" through which all power must flow, one way or the other, whereas transmission infrastructure may require a higher ratio of generation or storage to offset the need, because power flows are not similarly constrained to flow through a particular point.

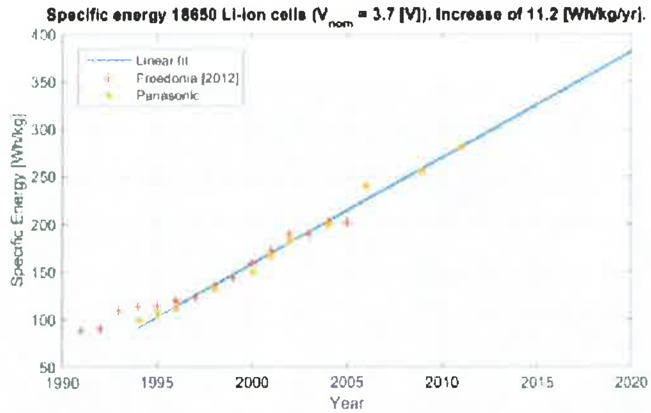

Figure 30: Historic and projected energy density improvement[82]

However, the cells, packing of modules, configuration and auxiliary equipment all contribute to the overall space requirements of an energy storage system, and advances in all areas will ultimately determine the space consumed by a potential energy storage solution. The March 2015 Study provided information on the size of an energy storage solution for the Eastside system. Recent deployments provide additional context for the likely footprint of a modern solution in the Eastside area. The Hornsdale Power Reserve, a 100MW/129MWh energy storage system installed at the end of 2017 in Australia, comprises approximately five acres and can be seen in Figure 31.

Figure 31: Hornsdale Power Reserve (100MW/129MWh) is approximately 2 hectares in size[83]

The Alamitos Energy Center, being constructed by AES in Long Beach, was initially proposed as a 300MW/1200MWh system[84] while it now appears the sizing may have been reduced.[85] The proposal for 300MW called for three 100MW containment buildings. Each building would be 50 feet in height, 270 feet in length, and 165 feet in width and would be composed of three levels: two battery storage levels separated by a mezzanine level. The mezzanine level would contain mechanical equipment such as electrical controls and heating, ventilation, and air conditioning (HVAC) units. Buildings would be set back at least 50 feet from each other and more than 50 feet

[82] Source: Prof. Maarten Steinbuch, Director Graduate Program Automotive Systems, Eindhoven University of Technology
[83] Source: (https://hornsdalepowerreserve.com.au/overview/)
[84] Source: (http://www.renewaesalamitos.com/Alamitos-Fact-Sheet.pdf)
[85] Source: (https://www.businesswire.com/news/home/20170724006035/en/AES-Breaks-Ground-Alamitos-Energy-Center)

from off-site properties.[86] Figure 32 shows the footprint of the original 300MW/1200MWh proposed system in the Long Beach area.

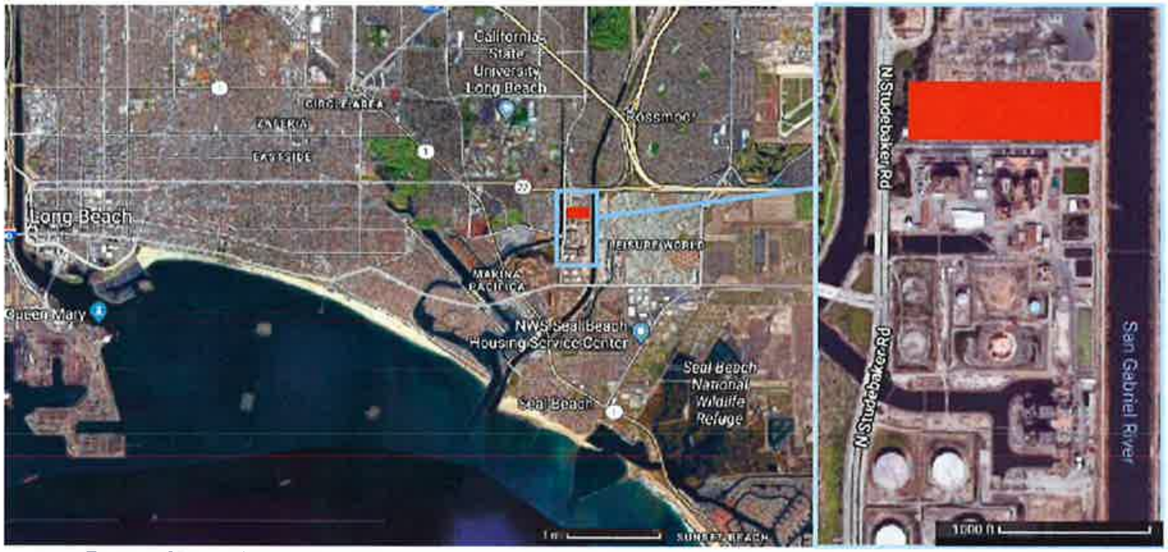

Figure 32: Aerial view of long beach area with Alamitos Energy Center, 300MW/1200MWh shown in red.

As noted above, Rongke Power is developing a 200MW/800MWh flow battery in the Dalian province of China that will be supplied by UET. UET states the following footprint for its flow battery solution on its website:

- Up to 92MWh/acre[87] behind-the-fence deployed footprint
- Up to 184MW/acre[88] behind-the-fence deployed footprint (double-stacked configuration)

Based on these three case studies, Table 13 presents a summary of energy storage system footprint. This will be used to provide an updated perspective for the Eastside system in Section 2.1.2.

Table 13: Summary of space requirements for large-scale energy storage systems constructed and proposed

Per MWh		Hornsdale Power Reserve	Dalian VFB Rongke Power	Average Single Level	Single Level Halved	Dalian VFB Rongke Power	Average Double Level	Extrapolated Size	Eastside Interim Solution 365 MW 2,394 MWh		Eastside Complete Solution 549 MW 5,500 MWh	
		Single Level			Double Level				Single	Double	Single	Double
	Acres	0.04	0.01	0.025	0.013	>0.01	0.01		58.87	21.22	135.25	48.76
	Sq. ft	1,669	473	1071	536	237	386		2,564,333	924,461	5,891,325	2,123,866
	Size compared to CenturyLink Stadium (1,500,000 Sq. Ft.)								171%	62%	393%	142%

System Life

The March 2015 Study modeled a 20-year system life with 2% per year cell degradation[89]. In other words, after 10 years, the system's energy discharge capacity would be 20% lower than at commercial operation date (although the power rating or maximum instantaneous discharge would

[86] Source: (http://www.lbds.info/civica/filebank/blobdload.asp?BlobID=6142)
[87] Assuming a four-hour system based on the 23MW/acre stated on website (http://www.uetechnologies.com/products/unisystem)
[88] Assuming a four-hour system based on the 46MW/acre stated on website (http://www.uetechnologies.com/products/unisystem)
[89] For comparison, the expected system life for the Energize Eastside poles & wires solution is approximately 40+ years.

remain the same). The life of an energy storage system depends on many factors including materials used, operating profile (e.g., depth of discharge and discharge rates), operating environment as well as calendar life.

While it is difficult to predict the life of any proposed solution for the Eastside system, recent deployments can inform what could be expected. The largest energy storage system in the world currently, the Hornsdale Power Reserve in South Australia, has a 15-year warranty.[90] Flow batteries, such as the ones proposed for the Rongke Power Energy Storage System, claim to have an operational life of approximately 15,000 cycles and a cycle and a design life of up to 20 years.[91]

The actual life of a system will vary based on operation. However, the option for 15-year warranties with some products and the potential for longer life for flow batteries mean that an investment in energy storage can be expected to provide a solution for beyond the 10 years expected for many earlier storage systems. This helps validate the assumption of no explicit cost for cell replacement during a 20-year system life.

[90] Source: (https://hornsdalepowerreserve.com.au/faqs/)
[91] Source: (http://www.uetechnologies.com/images/product/UET_UniSystem_Product_Sheet_reduced.pdf)

Commercial Developments

Since the publication of the March 2015 Study, there has been an increasing awareness of and development of programs utilizing battery storage as a multipurpose grid asset, including applications involving distribution and transmission reliability. Utilities in the western US and elsewhere around the world are frequently considering energy storage as part of a basket of resources being evaluated in their integrated resource planning processes, and all-source solicitations are more frequently being launched where storage is being considered amongst a basket of diverse resources for system capacity.

The most common uses of battery storage to date include providing grid ancillary services such as frequency regulation, energy arbitrage (time shift), renewables integration, providing system (generation) supply capacity and capacity firming, and customer electric bill management.

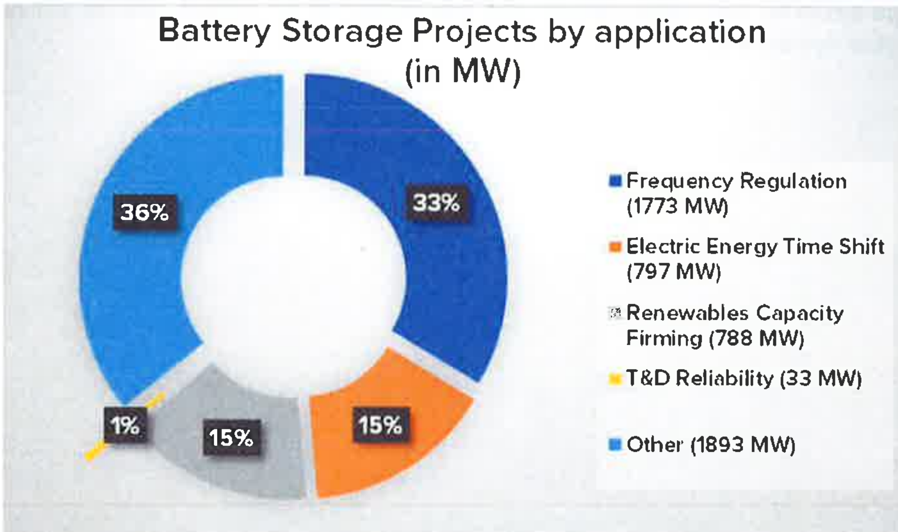

Figure 34: Battery Energy Storage Primary Applications

Source: US DOE Global Energy Storage Database, Accessed 17th of August 2018

Transmission or distribution reliability applications constituted a small portion of the overall total, with 32.8MW (0.62%) of all operational, under construction, proposed, offline, or decommissioned battery energy storage projects in the Global Energy Storage Database classifying T&D deferral as their primary application, with 2.0MW (0.06%) as transmission congestion relief, and 110kW (0.1 MW – 0.003%) as transmission support. It should be noted, however, that primary applications are self-reported in the DOE Global Energy Storage Database, and the above may not account for potential secondary applications. For example, while Tesla's Hornsdale Power Reserve plant is primarily a merchant plant earning revenues in Australia's wholesale market, it arguably is serving a reliability function in South Australia's grid. However, it is a fungible market asset rather than a transmission asset with location-dependent transmission delivery requirements.

DSD_011957

Table 14: Largest Battery Energy Storage Systems, Operational and Under Construction, by Power Rating

Project Name	Technology Type	Rated Power (MW)	Rated Energy (MWh)	Duration (hours)	Status	Primary Application
Dalian VFB - UET / Rongke Power	Vanadium Redox Flow Battery	200	800	4.0	Under Construction	Black Start
Alamitos Energy Center - AES	Lithium-ion Battery	100	400	4.0	Under Construction	Capacity and stability (combined with NG generation)
Hornsdale Power Reserve 100MW / 129MWh Tesla Battery	Lithium-ion Battery	100	129	1.29	Operational	Frequency Regulation
Kyushu Electric - Buzen Substation - Mitsubishi Electric / NGK Insulators	Sodium-sulfur Battery	50	300	6.0	Operational	Frequency Regulation
Nishi-Sendai Substation - Tohoku Electric / Toshiba	Lithium-ion Battery	40	20	0.50	Operational	Frequency Regulation
Minami-Soma Substation - Tohoku Electric / Toshiba	Lithium-ion Battery	40	40	1.0	Operational	Renewables Capacity Firming
Notrees Battery Storage Project - Duke Energy	Lithium-ion Battery	36	24	0.67	Operational	Electric Energy Time Shift
Rokkasho Village Wind Farm - Futamata Wind Development	Sodium-sulfur Battery	34	238	7.0	Operational	Electric Supply Reserve Capacity - Spinning
AES Laurel Mountain	Lithium-ion Battery	32	8	0.25	Operational	Frequency Regulation
Invenergy Grand Ridge Wind Project BESS	Lithium-Ion Titanate Battery	31.5	12	0.38	Operational	Frequency Regulation
Beech Ridge Wind Storage 31.5 MW	Lithium Iron Phosphate Battery	31.5	n/a	n/a	Operational	Frequency Regulation
Imperial Irrigation District BESS - GE	Lithium-ion Battery	30	20	0.67	Operational	Black Start
Escondido Energy Storage	Lithium-ion Battery	30	120	4.0	Operational	Electric Energy Time Shift
West-Ansung (Seo-Anseong) Substation ESS Pilot Project - 28 MW ESS - KEPCO / Kokam / LG Chem	Lithium-ion Battery	28	90	3.20	Operational	Frequency Regulation

Source: Strategen; US DOE Global Energy Storage Database, www.energystorageexchange.org, 17th of August 2018.

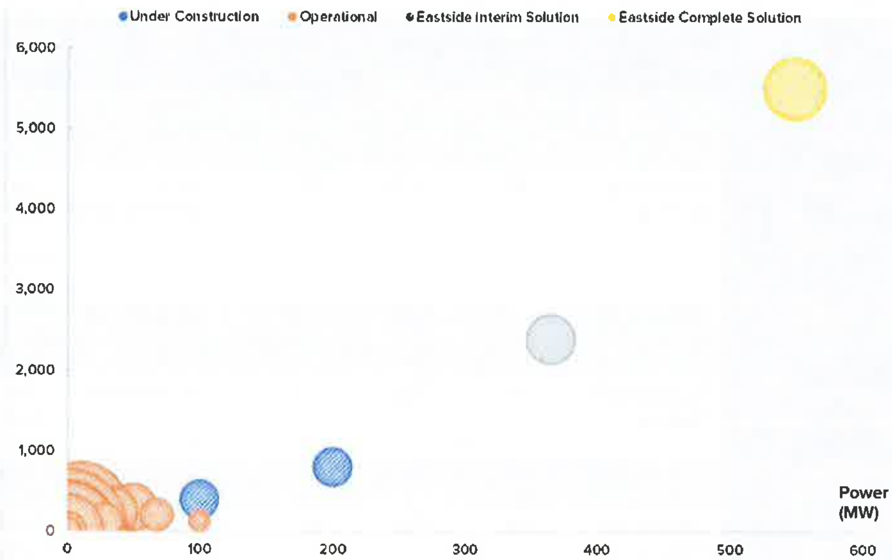

Figure 35: Visual representation of Eastside solutions versus storage projects that are operational or under construction. Size of bubble represents duration in hours. Source: US DOE Global Energy Storage Database, www.energystorageexchange.org, 5th of January 2018.

Recently, there have been some announcements of battery storage procurement for T&D reliability applications. For example, in its 2016 Energy Storage RFO, Pacific Gas & Electric Company ("PG&E") announced it was soliciting bids for a new 10MW/40MWh dual-use energy storage system ("ESS") that would enable PG&E to defer otherwise necessary investments at the Llagas Substation, to provide Resource Adequacy capacity credit and to participate in the CAISO Non-Generator Resource market.[92] This system will be entering operation in 2022 and is intended to serve a deferral need through 2031.

Consolidated Edison ("ConEd") in New York is another utility evaluating battery storage and other DER as non-wires solutions to traditional wires-based solutions. ConEd's activities began in earnest with the BQDM program, which was designed to reduce peak load in the affected area by 69MW, of which 52MW ended up being reduced by NWA investments on the customer- and utility-side of the meter and the remaining 17MW reduced through traditional wires-based solutions. ConEd has extended the BQDM to provide additional load reduction beyond the original scope of the pilot and has a number of other active solicitations for non-wires solutions. For example, the 42nd Street Load Transfer Project[93] seeks to achieve a peak load reduction of 42MW from 9 am to 7 pm from 2021 through 2026, implying a substantially higher need in terms of MWh, met through a basket of solutions (distributed generation, storage, advanced controls for demand response, etc.).

[92] Source: (https://www.pge.com/includes/docs/pdfs/b2b/wholesaleelectricsuppliersolicitation/Energy_Storage_2016/Information_Distribution_Deferral_ESS_Final.pdf)
[93] Source: (https://www.coned.com/-/media/files/coned/documents/business-partners/business-opportunities/non-wires/west-42-street-non-wires-solutions-soliciation.pdf?la=en)

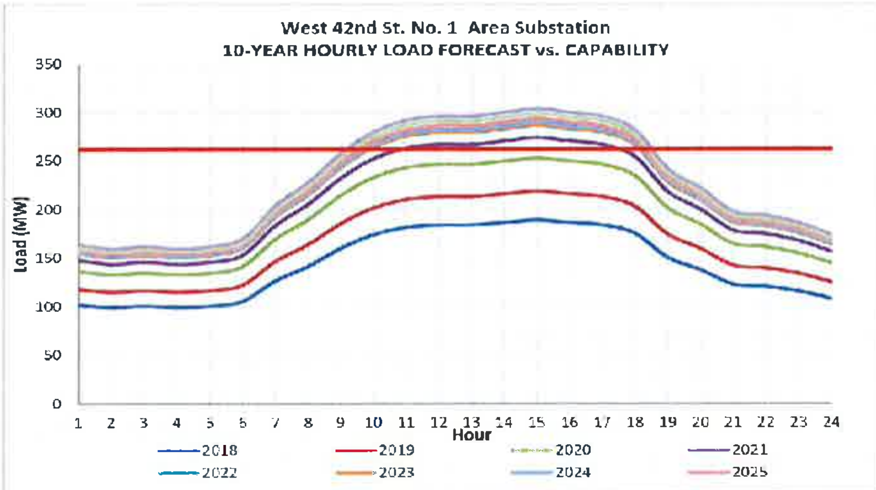

Figure 36: ConEd"s 42nd Street Transfer Project Overload Profiles (Source: ConEd)

Currently, operational projects providing demand reduction for transmission/distribution reliability are generally much smaller than those in the planning or solicitation stages, such as the ones mentioned above. The Village of Minster project, as shown in Table 15, is a large solar plus storage project that includes 4.2MW of solar PV, along with a 7MW/3MWh energy storage system that is expected to save the local municipal utility $350,000 in deferred T&D costs over the life of the project.

Table 15: Largest Battery Energy Storage Systems Used for Transmission/Distribution Reliability, Operational and Under Construction, by Power Rating

Project Name	Technology Type	Rated Power (MW)	Energy (MWh)	Duration (hours)	Status
Village of Minster - S&C Electric Company	Lithium-ion Battery	7.0	3	0.42	Operational
Smarter Network Storage	Lithium-ion Battery	6.0	10	1.67	Operational
Northern Powergrid CLNR EES1	Lithium-ion Battery	2.5	5	2.0	Operational
SCE Distributed Energy Storage Integration (DESI) Pilot 1	Lithium-ion Battery	2.4	3.9	1.62	Operational
Santa Rita Jail Smart Grid - Alameda County RDSI CERTS Microgrid Demonstration	Lithium Iron Phosphate Battery	2.0	4	2.0	Operational
Enel Puglia ESS	Lithium-ion Battery	2.0	1	0.50	Operational
Enel Dirillo Substation BESS Project	Lithium-ion Battery	2.0	1	0.50	Operational
Enel Chiaravalle Substation	Lithium-ion Battery	2.0	2	1.0	Operational
Powercor 2 MW Grid Scale Energy Storage - Kokam	Lithium-ion Battery	2.0	1	1.0	Operational

Source: Strategen; US DOE Global Energy Storage Database, www.energystorageexchange.org, 17th of August 2018.

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Virtual Power Plants

Since the original March 2015 Study, the installation of BTM energy storage systems that are coordinated and aggregated for grid benefits has become a new operating model. This is commonly referred to as a virtual power plant ("VPP") and has mostly been operated as a proof of concept trials, but in early 2018 a significant announcement in South Australia was made where a large number of BTM energy storage systems would be installed to reduce customer energy bills. South Australia is the most relevant market when considering VPP and the role they can play, and both AGL's[94] VPP trial and the recent announcement of the world's largest VPP, in partnership with Tesla, are discussed.

Australia – AGL's Virtual Power Plant Project

The South Australian power system is experiencing several complex challenges as the state progresses towards its clean energy goals and has experienced high-profile blackouts. As large, synchronous generators retire, intermittent, non-synchronous renewable generation comprises a larger share of the energy supply mix. South Australia has the highest level of rooftop solar PV per capita in the world, greater than 25% of customers.[95]

This high proportion of rooftop solar PV in the state's distribution network made it an ideal location to test the potential of a VPP. This VPP helps to stabilize the grid while delivering extra value to customers, the networks, and the retailer. The VPP is a centrally managed network of BTM battery storage systems that can be controlled to deliver multiple benefits to the household, the retailer, and the local network. The VPP is composed of 1,000 homes with existing rooftop solar PV, and BTM energy storage was installed through a shared funding arrangement. These systems aggregate to provide 5MW/7MWh of stored energy. The batteries are charged and discharged using sophisticated algorithms to maximize the benefits to the consumer while ensuring that the network and retailer can also gain value during specific network or wholesale events. Figure 33 shows a diagram of the VPP setup. The VPP can realize multiple benefit streams that can reduce the costs of the system to the customer and provide coordinated and efficient use of the distributed energy resources ("DERs") to support the power system and reduce energy charges for all ratepayers.

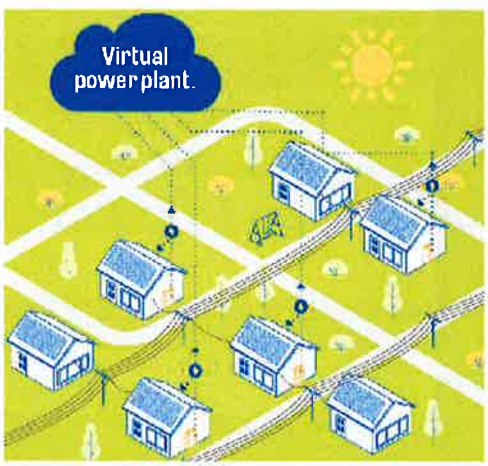

Figure 33: Diagram of the VPP utilizing dispersed PV coupled energy storage to provide aggregated grid benefits[96]

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[94] AGL is an energy retailer in Australia
[95] Source: (https://www.energycouncil.com.au/media/1318/2016-06-23_aec-renewables-fact-sheet.pdf)
[96] Source: (https://aglsolar.com.au/blog/virtual-power-plant-bringing-solar-energy-everyone/)

Given the expected increase in BTM battery storage and the reducing opportunities to gain value from exporting excess solar, VPPs represent an important opportunity to provide benefits to individual customers as well as the grid as a whole. The VPP can potentially provide a cost-effective medium-term solution to smooth intermittent renewable energy. In aggregated form, VPPs can add frequency response to the network and allow location-specific DER to be operated to avoid peak demand capacity investment. It also offers opportunities for customers to maximize the value of their existing solar PV systems. To effectively implement, a VPP needs to innovate in the way that technology is deployed and operated through appropriate commercial arrangements and balance the utilization of the batteries between grid and customer benefits.[97]

World's Largest Virtual Power Plant Announcement 2018

In early 2018, the State Government of South Australia unveiled a plan to roll out a network of at least 50,000 home solar and battery systems to form the world's largest VPP over the next four years. Beginning with a trial of 1,100 Housing Trust properties, a 5kW solar panel system and 13.5kWh Tesla Powerwall 2 battery will be in participating homes. For perspective, this trial that is being implemented over four years would meet approximately 28% of the Interim Solution and 13% of the Complete Solution for Eastside.

Following the pilot, which has now commenced, systems are set to be installed at a further 24,000 Housing Trust properties, and then a similar deal offered to all South Australian households, with a plan for at least 50,000 households to participate over the next four years.

Cost Trends

In the March 2015 Study, Strategen reviewed publicly available data on utility energy storage projects, as well as research reports identifying cost trends over time. These sources were evaluated to come up with a cost estimate for a generic multi-hour lithium-ion solution.

The key cost components for utility-scale energy storage projects include battery cells, balance of system, power electronics, building facilities, and interconnection, permitting, land and other indirect/soft costs.

At the time, cell pricing was approximately $600/kWh, and price forecasts suggested costs in the $200-$354/kWh range in the 2015-2020 timeframe. Balance-of-system costs at the time were estimated to be in the $400-$500/kWh range (although Strategen found that estimating this on a per kW basis to be a more accurate methodology). Strategen also evaluated the 100MW/400 MWh system developed by AES and recently procured by Southern California Edison ("SCE") and deemed it to be a reasonable cost comp, despite having a 2021 online date.

Strategen estimated the total cost and revenue requirements of storage alternatives, using cell costs of approximately $250/kWh and balance-of-system costs of approximately $500/kW, with land, permitting, and interconnection costs estimated by PSE. This resulted in a 20-year levelized cost of $218.60/kW-yr, of which approximately 57% was attributable to the cells, power electronics, and building structures, while 43% was attributable to the interconnection facilities, land, permitting, and contingency.

Recent case studies suggest Strategen's original assumptions remain accurate estimates of current pricing. Lazard's Levelized Cost of Storage v3.0 provided an Illustrative Value Snapshot of a 100MW/400MWh CAISO Peaker Replacement case study, assumed to be built in 2017, based on

[97] Source: (https://arena.gov.au/projects/virtual-power-plant/)

cost estimates developed with data from DOE, Enovation Partners, and Lazard's internal estimates, using storage module costs of $97.6 million ($244/kWh), and inverter/AC system, balance of system, and EPC costs of $72.9 million ($729/kW or $182/kWh, depending on the metric used),[98] while assumptions for interconnection facilities, land, and permitting were not explicitly detailed. Translated into a levelized cost, Lazard indicates that the range for such unsubsidized "peaker replacement" storage systems built in 2017 ranged from $395-$486/kW-yr, and Lazard estimates a median cost of $375/kW-yr[99] for projects built in 2018, assuming a 10-year useful life. Strategen's assumption of a 20-year useful life is the driving factor in the lower levelized cost assumption used in our March 2015 Study.

Utility capacity procurement efforts provide data points suggesting continued cost declines are likely. However, costs below the estimates provided in Strategen's March 2015 Study are unlikely until well beyond the timeframe needed to meet the Eastside reliability need (at least with respect to the Interim Solution). For example, in Xcel Energy's summary of the Public Service Company of Colorado's ("PSCo") 2017 All-Source Solicitation 30-Day Report published on December 28, 2017, RFP responses by technology were summarized. PSCo received bids for 21 different standalone battery storage projects totaling 1,614MW to meet a capacity need that begins in 2023. The median bid price was $11.30/kW-mo ($135.60/kW-yr).[100] Furthermore, Lazard indicates that "lithium-ion capital costs are expected to decline as much as 36% over the next five years." We therefore estimate capital cost for the incremental capacity necessary to build the Complete Solution to be 36% lower than capital cost for the Interim Solution.

[98] Lazard's Levelized Cost of Storage Analysis, Version 3.0, published November 2, 2017. https://www.lazard.com/perspective/levelized-cost-of-storage-2017/, p.35. We assume the balance-of-system cost also includes some estimate of cost for interconnection, land, etc., although these costs are not explicitly broken out in the analysis.
[99] Ibid., p.13.
[100] PSCo, 2017 All-Source Solicitation 30-Day Report, CPUC Proceeding No. 16A-0396E. https://www.documentcloud.org/documents/4340162-Xcel-Solicitation-Report.html, p.9.

Impact on Technical Readiness, Commercial Feasibility, and Cost-Effectiveness

The March 2015 Study did not identify any overt barriers to technical readiness, commercial feasibility or cost-effectiveness of energy storage to meet a generic transmission reliability need. However, the scale of projects deployed as of the date of the March 2015 Study was many orders of magnitude smaller than the identified Eastside transmission capacity deficiency, which indicated a higher commercial risk may exist than for technologies with a track record of deployments in similar circumstances.

Globally, there are no currently operational deployments of energy storage on a scale comparable to that necessary to meet the Eastside transmission capacity deficiency. The operational project with the closest scale is Tesla's 100MW/129MWh Hornsdale Power Reserve project in South Australia,[101] and the Dalian VFB 200MW/800MWh Vanadium Redox project currently under construction in China for Rongke Power[102] is the closest proposed project. In addition, there is limited operational history at that scale, and the largest *operational* project (as identified by the DOE's Global Energy Storage Database) *specifically intended to meet a distribution or transmission reliability need* as its primary purpose is the 7MW/3MWh Village of Minster project.[103]

Given that the current cost of storage appears consistent with the cost forecast contained in the March 2015 Study, and because the March 2015 Study indicated that certain storage configurations would already be potentially cost-effective in PSE's system, further assessment of the cost-effectiveness of energy storage was not completed as part of this update. The March 2015 Study showed energy storage within PSE's system (albeit a smaller system than is needed to meet the Eastside reliability need) had a positive benefit-cost ratio. This is because it could leverage its capacity to provide a variety of system services. With the market progressing there is no reason to suggest that energy storage (broadly speaking) within PSE's system would now no longer have a positive benefit-cost ratio.

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[101] Source: (https://energystorageexchange.org/projects/2271)
[102] Source: (https://energystorageexchange.org/projects/2169)
[103] Source: (https://energystorageexchange.org/projects/1976)

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