Newark-NRS HVDC Project
Project Sponsor Selection Report

March 21, 2023

California Independent System Operator Corporation

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LIST OF ATTACHMENTS

1. INTRODUCTION

This report describes the competitive solicitation process conducted by the California Independent System Operator Corporation (ISO) for the Newark-Northern Receiving Station (NRS) high voltage direct current (HVDC) project. The ISO conducted this competitive solicitation because, in its 2021-2022 transmission planning process, the ISO identified a reliability-driven need for this transmission project. As required by the ISO Tariff, the ISO undertook a comparative analysis to determine the degree to which each project sponsor and its proposal met the qualification criteria set forth in ISO Tariff Section 24.5.3.1 and the selection factors set forth in ISO Tariff Section 24.5.4 to determine the approved project sponsor to finance, construct, own, operate, and maintain the new Newark-NRS HVDC project and associated transmission facilities included in the project. The six different qualified proposals that the ISO reviewed from the four project sponsors for the Newark-NRS HVDC project were detailed and well supported. The ISO emphasizes that it considers all project sponsors to be qualified to finance, construct, own, operate, and maintain the Newark-NRS HVDC project. While conducting the comparative analysis, the ISO had to make detailed distinctions among the project sponsors' proposals in determining the approved project sponsor. The result of this competitive solicitation process is that the ISO has selected LS Power Grid California, LLC (LSPGC) as the approved project sponsor to finance, construct, own, operate, and maintain the Newark-NRS HVDC project.

2 BACKGROUND

2.1 The Newark-NRS HVDC Project and Competitive Solicitation Process

The ISO Tariff specifies that the ISO's transmission planning process must include a competitive solicitation process for new, stand-alone regional transmission facilities needed for reliability, economic, and/or public policy driven reasons. The ISO's 2021-2022 transmission plan identified a reliability-driven need for the Newark-NRS HVDC project to serve load in the San Jose area. The ISO governing board approved the Newark-NRS HVDC project on March 17, 2022.

Following approval of the transmission plan, the ISO opened a bid solicitation window on April 18, 2022, which provided project sponsors the opportunity to submit proposals to finance, construct, own, operate, and maintain the Newark-NRS HVDC project. Project sponsors had an opportunity to express interest in collaborating with another entity during the first ten business days after the bid window opened. No project sponsor requested collaboration. In accordance with ISO Tariff Section 24.5.1 and the posted 2021-2022 Transmission Planning Process Phase 3 Sequence Schedule, the bid solicitation window remained open through August 26, 2022.

The ISO Functional Specifications for this project are located in Appendix G of the 2021-2022 transmission plan, under the title *Description and Functional Specifications of Proposed Policy-Driven Newark-Northern Receiving Station HVDC Project* (ISO Functional Specifications).[1] As described in the ISO Functional Specifications, the Newark-NRS HVDC project is reliability-driven and is required to serve load in the San Jose area. In the ISO Functional Specifications, the project is described as follows:

- A new voltage-sourced converter (VSC) HVDC converter station connected to Newark 230 kV Substation. (Note: Newark Substation is owned by Pacific Gas and Electric Company (PG&E).)
- A new VSC HVDC converter station connected to Northern Receiving Station 230 kV Substation. (Note: Northern Receiving Station Substation is owned by Silicon Valley Power (SVP).)
- Installation by PG&E of a new transmission line segment from Newark 230 kV Substation bus to a dead end structure to be located within 100 feet of the substation property line. The line will be rated at 1000 MW. PG&E will own this new transmission line segment up to and including the dead end structure.
- A new 230 kV transmission line segment, rated 1000 MW, from the dead end structure installed by PG&E into the new HVDC converter station near Newark Substation.
- Installation by SVP of a new 230 kV transmission line segment, rated 500 MW, to a dead end structure within Northern Receiving Station Substation, all of which will be owned by SVP.
- A new 230 kV transmission line segment, rated 500 MW, from the dead end structure installed by SVP into the new HVDC converter station near Northern Receiving Station Substation.

[1] http://www.caiso.com/InitiativeDocuments/AppendixG-BoardApproved-2021-2022TransmissionPlan.pdf

- New +/- 320 kV DC bus work and termination equipment at both of the new converter stations.
- A new +/- 320 kV DC transmission line, rated 500 MW, interconnecting new Newark and Northern Receiving Station HVDC converter stations.

In the ISO Functional Specifications, the ISO provided estimates of costs for the entire project, but it did not break out the costs of the work between PG&E and the approved project sponsor. As stated in the ISO Functional Specifications, the ISO estimated the overall proposed project, both the components subject to competitive solicitation and the non-competitive components of the project, would cost approximately $325 to $510 million. The ISO also specified that the project must be in service no later than June 1, 2028. Upon completion of the project, the approved project sponsor will own the new Newark-NRS HVDC project, but it must turn the facilities over to ISO operational control.

The ISO also identified and on March 22, 2022 posted key selection factors for the Newark-NRS HVDC project.[2] After the ISO opened the bid solicitation window, the ISO hosted an informational call for interested parties on April 20, 2022 and provided a presentation describing the project and the competitive solicitation process, including the key selection factors.[3] These are the tariff criteria the ISO determined are the most important for selecting a project sponsor for this reliability-driven project. For purposes of this report, the ISO identified the following subsections of ISO Tariff 24.5.4 as the key selection factors:

- Section 24.5.4(a) – “the current and expected capabilities of the Project Sponsor and its team to finance, license, and construct the facility and operate and maintain it for the life of the solution;”
- Section 24.5.4(b) – “the Project Sponsor’s existing rights of way and substations that would contribute to the transmission solution in question;”
- Section 24.5.4(c) – “the experience of the Project Sponsor and its team in acquiring rights of way, if necessary, that would facilitate approval and construction, and in the case of a Project Sponsor with existing rights of way, whether the Project Sponsor would incur costs in connection with placing new or additional facilities associated with the transmission solution on such existing right of way;”
- Section 24.5.4(d) – “the proposed schedule for development and completion of the transmission solution and demonstrated ability to meet the schedule of the Project Sponsor and its team;”
- Section 24.5.4(e) – “the financial resources of the Project Sponsor and its team;”
- Section 24.5.4(f) – “the technical and engineering qualifications and experience of the Project Sponsor and its team;”
- Section 24.5.4(j) – “demonstrated cost containment capability of the Project Sponsor and its team, specifically, binding cost control measures the Project Sponsor agrees to accept, including any binding agreements by the Project Sponsor and its team to accept a cost cap that would preclude costs for the transmission solution above the cap from being recovered through the CAISO’s Transmission Access Charge, and, if none of the competing Project Sponsors

[2] http://www.caiso.com/InitiativeDocuments/Key-Selection-Factors-2021-2022-Transmission-Planning-Process.pdf
[3] http://www.caiso.com/InitiativeDocuments/Presentation-2021-2022TransmissionPlanningProcess-Phase3CompetitiveSolicitation-Apr202022.pdf

> proposes a binding cost cap, the authority of the selected siting authority to impose binding cost caps or cost containment measures on the Project Sponsor, and its history of imposing such measures."

The ISO described these key selection factors during its informational call for interested parties on April 20, 2022.[4]

The ISO evaluated six applications from four project sponsors – (1) Avangrid Networks, Inc. (Avangrid), a subsidiary of Avangrid Inc., which submitted two proposals, (2) Horizon West Transmission, LLC (HWT), an affiliate of NextEra Energy, Inc., which submitted two proposals, (3) LSPGC, a wholly-owned subsidiary of LS Power Associates, L.P., and (4) Starwood Energy Group Global Inc. (SEGG), which proposes to form a special purpose entity to own and operate the project. The ISO posted a list of validated project sponsor applications on October 17, 2022.[5] The ISO found that all six of the proposals provided sufficient information to meet the minimum validation criteria as set forth in Section 24.5.2.4 of the ISO Tariff. The ISO posted a list of qualified project sponsors and proposals on December 7, 2022.[6] The ISO found that all four project sponsors and their six validated proposals met the minimum qualification criteria as set forth in Section 24.5.3 of the ISO Tariff.

2.2 The ISO Transmission Planning Process and Competitive Solicitation Tariff Structure

In 2010, the Federal Energy Regulatory Commission (FERC) approved changes to the ISO's transmission planning process that included a competitive solicitation process for new, stand-alone transmission facilities needed for reliability, economic, and/or public policy driven reasons. Subsequently, in 2012 the ISO filed tariff amendments to comply with the requirements of FERC Order No. 1000 to further promote competition in the transmission planning process. The ISO conducted its first competitive solicitation process during the 2012-2013 transmission planning cycle. Based on the experience gained during the competitive selection process and discussions with stakeholders, the ISO identified improvements to clarify and provide more transparency to the process for participating transmission owners (PTOs) and other transmission developers. The ISO conducted a competitive transmission improvement initiative in late 2013, which concluded with ISO Tariff Section 24.5 and process changes.

The framework for the 2021-2022 transmission plan competitive solicitation process is set forth in ISO Tariff Section 24.5. In addition, the ISO posted the form of the project sponsor application (Attachment 1) on its website. Also, while the bid solicitation window was open, the ISO maintained and posted on its website a question-and-answer matrix detailing questions from prospective project sponsors and the ISO's responses thereto so that all interested parties would have access to the same clarifying information.[7] In

[4] http://www.caiso.com/InitiativeDocuments/Presentation-2021-2022TransmissionPlanningProcess-Phase3CompetitiveSolicitation-Apr202022.pdf
[5] http://www.caiso.com/InitiativeDocuments/ListofValidatedProjectSponsorApplications-Newark-%20NRSHVDCProject.pdf
[6] http://www.caiso.com/InitiativeDocuments/List-of-Qualified-Project-Sponsor-and-Proposals-Newark-North-Recieving-Station-HVDC-Project.pdf
[7] http://www.caiso.com/InitiativeDocuments/ISOResponsestoCommentsMatrix-2021-2022TranmissionPlanningProcessCompetitiveSolicitation.pdf

compliance with ISO Tariff Section 24.5.3.5, the ISO engaged two well-respected, international industry consulting firms to assist the ISO in its selection of the approved project sponsor. One firm primarily supports the ISO in the qualification and comparative analysis associated with the project schedule, rights-of-way acquisition, environmental permitting, design, construction, maintenance, and operating capabilities of the project sponsors. The other firm provides economic, financial, and rate expertise and provides cost of service analyses. Both firms have committed to remain unbiased and not participate with any project sponsor in the competitive solicitation process.

Each project sponsor completed the project application form, which included a series of questions and requirements in the following areas:

- Project Sponsor, Name, Organizational Structure, and Proposal Summary
- Project Qualifications
- Prior Projects and Experience
- Project Management and Schedule
- Cost Containment
- Financial
- Environment Permitting and Public Process
- Transmission or Substation Land Acquisition
- Substation Design and Engineering
- Transmission Line Design and Engineering
- Construction
- Maintenance
- Operations
- Miscellaneous
- Officer Certification
- Application Deposit Payment Instructions

The ISO provided the project sponsors opportunities to correct deficiencies in their applications. Following a project sponsor's submission of supplemental information, the ISO validated the project sponsor's application to determine if it contained sufficient information for the ISO to determine whether the project sponsor and its proposal were qualified. Once the ISO validated the applications, the ISO posted the list of validated project sponsor applications to its website on October 17, 2022 as described in Section 2.1 of this report. As also described in Section 2.1, the ISO validated all six of the applications.

Next, the ISO determined whether the project sponsors and their proposals were qualified pursuant to ISO Tariff Sections 24.5.3.1 and 24.5.3.2. The ISO evaluated the project sponsors based on the information submitted in response to the questions in the application corresponding to ISO Tariff Sections 24.5.2.1(a)-(i) to determine, in accordance with Section 24.5.3.1, whether the project sponsor had demonstrated that its team is physically, technically, and financially capable of:

(i) completing the needed transmission solution in a timely and competent manner; and
(ii) operating and maintaining the transmission solution in a manner that is consistent with good utility practice and applicable reliability criteria for the life of

the project, based on the qualification criteria as set forth in ISO Tariff Section 24.5.3.1(a)-(f).

In accordance with Section 24.5.3.2, the ISO evaluated the project sponsors' proposals based on the following criteria to determine whether the transmission solution proposed by the project sponsors would be qualified for consideration:

(a) "Whether the proposed design of the transmission solution is consistent with needs identified in the comprehensive Transmission Plan;"
(b) "Whether the proposed design of the transmission solution satisfies Applicable Reliability Criteria and CAISO Planning Standards."

As described in Section 2.1 of this report, the ISO posted the list of qualified project sponsors and their proposals to its website on December 7, 2022. The ISO found that all four project sponsors and their six validated proposals met the minimum qualification criteria as set forth in ISO Tariff Sections 24.5.3.1 and 24.5.3.2 for Newark-NRS HVDC project. Therefore, the ISO determined that no cure period was needed for the qualification phase pursuant to ISO Tariff Section 24.5.3.3. Section 3 of this report describes the ISO's selection process for this project.

3 SELECTION OF THE APPROVED PROJECT SPONSOR

3.1 Description of Project Sponsor Selection Process

Once the ISO has determined that two or more project sponsors are qualified, ISO Tariff Section 24.5.3.5 directs the ISO to select one approved project sponsor "based on a comparative analysis of the degree to which each project sponsor's proposal meets the qualification criteria set forth in section 24.5.3.1 and the selection factors set forth in 24.5.4." The selection factors specified in ISO Tariff Section 24.5.4 are:

(a) the current and expected capabilities of the Project Sponsor and its team to finance, license, and construct the facility and operate and maintain it for the life of the solution;
(b) the Project Sponsor's existing rights of way and substations that would contribute to the transmission solution in question;
(c) the experience of the Project Sponsor and its team in acquiring rights of way, if necessary, that would facilitate approval and construction, and in the case of a Project Sponsor with existing rights of way, whether the Project Sponsor would incur incremental costs in connection with placing new or additional facilities associated with the transmission solution on such existing right of way;
(d) the proposed schedule for development and completion of the transmission solution and demonstrated ability to meet that schedule of the Project Sponsor and its team;
(e) the financial resources of the Project Sponsor and its team;
(f) The technical and engineering qualifications and experience of the Project Sponsor and its team;
(g) if applicable, the previous record regarding construction and maintenance of transmission facilities, including facilities outside the CAISO Controlled Grid of the Project Sponsor and its team;
(h) demonstrated capability to adhere to standardized construction, maintenance and operating practices of the Project Sponsor and its team;
(i) demonstrated ability to assume liability for major losses resulting from failure of facilities of the Project Sponsor;
(j) demonstrated cost containment capability of the Project Sponsor and its team, specifically, binding cost control measures the Project Sponsor agrees to accept, including any binding agreement by the Project Sponsor and its team to accept a cost cap that would preclude costs for the transmission solution above the cap from being recovered through the CAISO's Transmission Access Charge, and, if none of the competing Project Sponsors proposes a binding cost cap, the authority of the selected siting authority to impose binding cost caps or cost containment measures on the Project Sponsor, and its history of imposing such measures; and
(k) any other strengths and advantages the Project Sponsor and its team may have to build and own the specific transmission solution, as well as any specific efficiencies or benefits demonstrated in their proposal.

In selecting the approved project sponsor, the ISO undertook a comparative analysis of the project sponsors' proposals regarding the qualification criteria described in ISO Tariff Section 24.5.3.1 and the selection factors in ISO Tariff Section 24.5.4. As part of the comparative analysis, the ISO has given particular consideration to the key selection factors for the Newark-NRS HVDC project as described in Section 2.1 of this report.

This report summarizes information provided by each project sponsor that was considered by the ISO to be important in analyzing their proposals regarding each of the qualification criteria and selection factors. At the beginning of each subsection of this Section 3, commencing with Section 3.4, of this report, the ISO has provided a listing of the sections of the project sponsor's application that the ISO particularly considered in undertaking its comparative analysis for that qualification criterion or selection factor. In addition, in the ISO's summaries in this report describing the information provided by each project sponsor, the ISO has provided a reference to the particular sections of the project sponsor's application that served as the source for that summary. Because this report is a summary, it does not repeat all of the information provided by the project sponsors. However, the ISO reviewed and considered all of the information provided by the project sponsors, and the ISO's failure to reference any specific information provided by a project sponsor does not indicate lack of consideration of such information.

3.2 Description of Project Sponsors for the Newark-NRS HVDC Project

The ISO evaluated six validated and qualified project sponsor applications for the Newark-NRS HVDC project submitted by four project sponsors:

- Avangrid, which submitted two proposals – referred to as proposal 1 and proposal 2
- HWT, which submitted two proposals – referred to as bay crossing and inland route
- LSPGC
- SEGG

All four entities are qualified and submitted strong, competitive applications supporting their proposals. As a result, the ISO had to make detailed distinctions among the four project sponsors and their six validated and qualified proposals in the comparative analysis process in selecting the approved project sponsor.

<u>Avangrid</u>

According to its proposal, Avangrid is a wholly owned subsidiary of Avangrid, Inc. and owns and operates 8,613 miles of transmission lines, 819 substations, 63,058 miles of overhead distribution lines, and 8,415 miles of underground distribution lines through its four regulated electric utilities in the United States. Avangrid indicated that Avangrid, Inc. is 18.5% publicly traded under the ticker symbol AGR and 81.5% owned by Iberdrola, S.A.

Avangrid indicated that it proposes to create a limited liability company for the purpose of building, owning, and operating this transmission asset if selected as the approved project sponsor for the project. Avangrid indicated that the limited liability company would be a subsidiary wholly owned by Avangrid, which would provide all financing and guarantees for the limited liability company for the duration of the project's useful life. (A-5, F-5)

Avangrid Access to Affiliate Financial Support

Avangrid indicated that it proposes to create a limited liability company and use either corporate or project financing for the construction of the project. Under the corporate financing approach, Avangrid indicated that it would rely on its parent company Avangrid, Inc. for all financing. Avangrid indicated that if the project finance approach is used, Avangrid would arrange for funding for construction from banks. (F-1)

Avangrid provided a letter from Avangrid, Inc. indicating Avangrid, Inc.'s financial assurance for the project and availability of financial resources from its ultimate parent company Iberdrola. (F-2.1)

<u>HWT</u>

According to its proposal, HWT is a Delaware limited liability company formed in 2014 that is a wholly owned subsidiary of NextEra Energy Transmission, LLC (NEET) and an indirect subsidiary of NextEra Energy, Inc. (NextEra). HWT indicated that HWT would own this project and other assets in the ISO region as a portfolio and is not intended to be a stand-alone project company for this project. (Executive Summary, A-5, F-1)

HWT indicated that NextEra, HWT's ultimate parent, and its wholly owned subsidiary NEET are headquartered in Juno Beach, Florida, and NextEra's principal subsidiaries are Florida Power & Light Company (FPL) and NextEra Energy Resources, LLC (NEER). HWT indicated that another key entity in the NextEra organization is NextEra Energy Capital Holdings, Inc. (NEECH), which is a wholly owned subsidiary of NextEra and owns and provides funding for NextEra's operating subsidiaries, including NEET and HWT. (A-5)

HWT indicated that its immediate parent, NEET, was formed by NextEra in 2007 to leverage NextEra's experience and resources in developing, designing, constructing, owning, and operating transmission facilities across the United States and Canada and that NEET's assets include operating transmission facilities in California (the Suncrest static VAR compensator (SVC) facility and the Trans Bay Cable, LLC (TBC) high voltage direct current (HVDC) facility), Nevada, Texas, New Hampshire, Illinois and Kentucky, Kansas and Oklahoma, and Ontario. HWT indicated that it also has projects in pre-construction development in a number of states and numerous other projects in earlier stages of development throughout the United States. (Executive Summary, A-5)

HWT Access to Affiliate Financial Support

HWT indicated that during development and construction of the project it would source equity funding from its parent company NEET and debt funding from its ultimate parent company, NextEra, through NextEra's financing affiliate NEECH. Upon commercial operations and throughout the life of the project, HWT indicated that it anticipates using project-level financing from NEECH and may consider third-party project financing in the future. (F-1)

HWT provided a letter from NextEra indicating that NEECH would provide appropriate funding and needed guarantees to HWT and that those would in turn be guaranteed by NextEra as provided for through a blanket guarantee arrangement between NEECH and NextEra. (F-2, F-2a, F-2c)

LSPGC

According to its proposal, LSPGC is a Delaware limited liability company established to own transmission projects in California, including the instant project. LSPGC indicated that, through intermediate holding companies (LS Power Grid California Holdings, LLC, LSP Transmission Holdings, LLC, and LSP Generation IV, LLC), it is a wholly owned subsidiary of LS Power Associates, L.P., which, together with its subsidiaries and affiliates, is generally known as LS Power. LSPGC indicated that a similar ownership and organization structure has been used by LS Power for its past projects, including all of its transmission projects. (A-5)

LSPGC indicated that it would utilize LS Power personnel to perform or manage all aspects of the project. LSPGC also identified six affiliates as particularly relevant to its proposal: (i) Cross Texas Transmission, LLC (Cross Texas Transmission), a transmission service provider in Texas, (ii) DesertLink, LLC (DesertLink), the owner of the Harry Allen-Eldorado 500 kV transmission line competitively selected by the ISO in 2016, (iii) Great Basin Transmission South, LLC, owner of a 75% interest in the One Nevada Transmission Line facilities in Nevada, (iv) Republic Transmission, LLC, the owner of the Duff to Coleman 345 kV transmission line in Indiana competitively awarded by MISO in 2016, (v) Silver Run Electric, LLC (Silver Run), the owner of the Silver Run 230 kV Substation and Silver Run-Hope Creek 230 kV transmission line competitively awarded by PJM in 2014, and (vi) LS Power Grid New York Corporation I (LSPGNY), the owner of the Gordon Road and Princetown 345 kV gas-insulated switchgear (GIS) substations and 345 kV transmission line in New York competitively awarded by NYISO in 2019. (A-5)

LSPGC Access to Affiliate Financial Support

LSPGC indicated that it is relying on its parent LS Power to satisfy the financial criterion for this project. LSPGC provided evidence of LS Power's financial assurances to LSPGC in the form of a written guarantee. (F-2, F-2A)

LSPGC also provided an equity financing commitment from LS Power's majority owner management company indicating the majority owner's commitment to provide funding to LS Power for the project. (Attachment F-2B)

SEGG

According to its proposal, SEGG is a Delaware corporation and an affiliate of private real estate investment firm Starwood Capital Group Global L.P. SEGG indicated that it and certain affiliates specialize in deploying equity capital in energy infrastructure investment in North America, with a focus on the transmission, renewable power generation, energy storage, biofuels, and natural gas sectors. (A-1)

SEGG indicated that it would create a special purpose entity as an affiliate for purposes of developing the project. SEGG indicated that the special purpose entity would be managed by SEGG through Starwood Energy Infrastructure Fund (SEIF III) and affiliated investment vehicles specifically to finance, construct, own, maintain, and operate the project. (A-5, F-5)

SEGG Access to Affiliate Financial Support

SEGG indicated that SEIF III and affiliated investment vehicles have sufficient uncommitted capital to support the development, construction, maintenance, and operation of the project. (F-3.2)

SEGG provided a written parent guarantee providing financial assurance that SEIF III, as the direct parent of the special purpose entity that would be formed specifically for this project, would provide customary credit support and has adequate financial resources to provide the financial support for the project repairs and permitting of the project. (F-2.1)

3.3 Selection Factor 24.5.4(a): Overall Capability to Finance, License, Construct, Operate, and Maintain the Facility

The ISO notes that the first selection factor is a broad factor that generally encompasses several subsequent narrower selection factors. As discussed in Section 2.1, the ISO has identified this selection factor as a key selection factor because the capabilities that comprise this factor will be critical given the specific nature, scope, and challenges presented by this project. These challenges include, *inter alia*, a tight schedule, significant project cost, submarine transmission, and unique land rights and sitting challenges. A proposal that best satisfies this factor will contribute significantly to ensuring that the project sponsor selected will develop the project in an efficient, cost-effective, and timely manner, which is particularly important for this project, because the timing of this project is critical to ensure reliable service of load in the San Jose area. The ISO will address satisfaction of this more general factor in its discussion of the applicable, more specific selection factors. The ISO will not duplicate here (1) the information provided by the project sponsors for purposes of demonstrating their capabilities and experience regarding each of the encompassed selection factors, or (2) the ISO's comparative analysis of the project sponsors' proposals in this regard, as set forth in the following sections of this report. The ISO will discuss the comparative analysis for selection factor 24.5.4(a) in Section 3.14 of this report after the discussion of the other selection factors.

3.4 Selection Factor 24.5.4(b): Existing Rights-of-Way and Substations that Would Contribute to the Project

(Executive Summary, A-4, P-4, L-1, L-2, L-5)

The second selection factor is "the Project Sponsor's existing rights of way and substations that would contribute to the transmission solution in question." As discussed in Section 2.1, the ISO has identified this selection factor as a key selection factor because the availability of existing rights-of-way can contribute to lower project cost, reduced rights-of-way acquisition efforts, and reduction in the overall time needed to complete the project. This project also presents unique land rights acquisition challenges, including challenges due to its proximity to the Don Edwards National Wildlife Refuge. A proposal that best satisfies this factor will contribute significantly to ensuring that the project sponsor selected will develop the project in an efficient, cost-effective, and timely manner, which is particularly important for this project, because the timing of this project is critical to ensure reliable service of load in the San Jose area.

For the consideration of this factor, the ISO has concluded that there is no significant difference between the two proposals submitted by Avangrid. Consequently, references to Avangrid and its proposal in this section apply equally to both Avangrid's proposal 1 and Avangrid's proposal 2.

3.4.1 Information Provided by Avangrid for Proposals 1 and 2

Avangrid indicated it does not have existing land rights along the project route. (L-1, L-5)

Avangrid indicated that it has been in contact with the City of San Jose concerning its parcel near Northern Receiving Station Substation for the south converter station. Avangrid further indicated that the city has not committed to this location, but indicated it was acceptable.

In addition, Avangrid indicated that it would be seeking franchise agreements to construct the transmission line along public roads from the following entities:

- City of Fremont
- City of Milpitas
- City of San Jose
- City of Santa Clara
- County of Alameda
- County of Santa Clara

Avangrid indicated that it would require permits or easements from the following entities:

- City of Santa Clara
- City of San Jose
- Santa Clara Valley Water District
- Alameda County Flood Control District
- City of Fremont
- State of California
- Union Sanitary District Common Area Tract 7994 East Bay Dischargers Authority
- City of Milpitas
- PG&E
- Approximately 33 private landowners.

Avangrid indicated that the Don Edwards National Wildlife Refuge was considered a major constraint and affected route decisions as well as overhead and underground decisions. Avangrid indicated that building overhead lines near the Don Edwards National Wildlife Refuge raises concerns of increased bird predation because the structures provide perching habitat for raptors that hunt the endangered snowy plover and other threatened and endangered bird species in the area. Avangrid also indicated that overhead lines present bird strike concerns because this area attracts bird species, including federally protected species.

Avangrid indicated that building underground or overhead lines within the Don Edwards National Wildlife Refuge requires authorization from the Secretary of the Interior, acting through the U.S. Fish and Wildlife Service, and could potentially trigger litigation even if it is approved. Avangrid indicated that for this reason any routes within the Don Edwards National Wildlife Refuge were scrupulously avoided. (A-4, L-1, L-2, L-5)

3.4.2 Information Provided by HWT for Inland Route

HWT indicated it does not have existing land rights along the project route.

HWT provided copies of executed purchase option agreements with the private property owners at its proposed Newark and Northern Receiving Station converter site locations.

HWT indicated that it expects to acquire land rights agreements or permits from public landowners such as the California State Lands Commission and Don Edwards National Wildlife Refuge. (E-1)

HWT indicated that approximately 0.9 miles of transmission line is proposed to cross the Don Edwards National Wildlife Refuge.

HWT indicated that the balance of the transmission line route would be in public streets and require franchise agreements or encroachment permits from the following agencies:

- City of Fremont
- City of Milpitas
- City of San Jose
- City of Santa Clara
- City of Newark
- California Department of Transportation
- Santa Clara Valley Water District
- Alameda County Flood Control District
- Don Edwards National Wildlife Refuge (U.S. Fish and Wildlife Service) (special use permit) (L-1)

HWT indicated that it also anticipates four crossing agreements for the following:

- PG&E pipeline
- PG&E transmission line
- Union Pacific Railroad
- Santa Clara Valley Transit

(A-4, L-1, L-5)

3.4.3 Information Provided by HWT for Bay Crossing

HWT indicated it does not have existing land rights along the project route.

HWT provided copies of executed purchase option agreements with the private property owners at its proposed Newark and Northern Receiving Station converter site locations.

HWT indicated that it expects to acquire land rights agreements or permits from public landowners such as the California State Lands Commission and Don Edwards National Wildlife Refuge. (E-1)

HWT indicated that approximately 4.7 miles of transmission line is proposed to cross the Don Edwards National Wildlife Refuge.

HWT indicated that the transmission line route would require encroachment or special permits from the following agencies:

- City of Fremont
- City of San Jose
- City of Santa Clara
- California Department of Transportation
- Santa Clara Valley Water District
- Alameda County Flood Control District
- Don Edwards National Wildlife Refuge (U.S. Fish and Wildlife Service) (certificate of compatibility and right-of-way permits) (L-1)

HWT indicated that it also anticipates four crossing agreements for the following:

- PG&E pipeline
- PG&E transmission line
- Union Pacific Railroad
- Santa Clara Valley Transit

(A-4, L-1, L-5)

3.4.4 <u>Information Provided by LSPGC</u>

LSPGC indicated it does not have existing land rights along the project route.

LSPGC indicated it has started discussions with a private property owner where the proposed Newark converter station would be located, as well as the City of San Jose, where the proposed Northern Receiving Station converter station would be located. LSPGC also indicated that if selected as the approved project sponsor, it would reengage with both parties to acquire the properties.

LSPGC indicated that approximately 0.1, 0.7 and 5.1 miles of the proposed transmission line will be within the cities of Santa Clara, San Jose and Fremont, respectively.

LSPGC indicated that it anticipates the following crossings:

- PG&E pipelines - three crossings
- PG&E electric transmission lines - 19 crossings
- Union Pacific railroad - one crossing
- Santa Clara Valley Transit - one crossing
- California Department of Transportation – one crossing

LSPGC indicated that routes were identified and evaluated that cross the Don Edwards National Wildlife Refuge, as PG&E had existing transmission lines in the Don Edwards National Wildlife Refuge. LSPGC indicated that U.S. Fish and Wildlife Service regulations specify that fragmentation of habitat, which a new transmission corridor would cause, is not a compatible use of a national wildlife refuge. Additionally, LSPGC indicated that in 1998 PG&E filed an application with the California Public Utilities Commission (CPUC) to construct the Northeast San José Transmission Reinforcement Project and had to withdraw that application (A-98-07-007) because of the U.S. Fish and Wildlife Service's difficulty in finding a transmission line to be compatible with the purposes for which the Don Edwards National Wildlife Refuge was created. LSPGC indicated that routes that cross the Don Edwards National Wildlife Refuge were not selected as the preferred route for these reasons. (A-4, L-1, L-2, L-5)

3.4.5 Information Provided by SEGG

SEGG indicated that it does not have existing land rights along the project route. (L-1, L-5)

SEGG indicated that the north converter site near PG&E's Newark Substation has been identified and it has prepared a draft letter of intent.

SEGG indicated that the south converter station site is owned by the City of San Jose, which indicated it would work with the successful project sponsor to utilize the site as the converter station site.

In addition, SEGG indicated the following are potential landowners and agencies requiring land rights or permits for the project:

- Don Edwards National Wildlife Refuge
- San Francisco Bay Conservation and Development Commission
- U.S. Army Corps of Engineers
- U.S. Fish and Wildlife Service
- Private landowners
- City of Fremont
- City of Milpitas
- City of Newark
- City of San Jose
- County of Alameda
- County of Santa Clara

SEGG indicated approximately 2,400 feet of its transmission line is proposed to cross the Don Edwards National Wildlife Refuge. (A-4, P-4, L-1, L-5)

3.4.6 ISO Comparative Analysis

For purposes of the comparative analysis for this factor, the ISO has considered the representations by the project sponsors regarding the rights-of-way or other land rights they possess and are proposing to contribute to this project and the acquisition of land rights needed for the project. All six proposals of the four project sponsors indicated that they did not have existing land rights along the project route.

Regarding acquiring land rights needed for the project, the ISO has determined that HWT's two proposals are better than the two proposals of Avangrid, LSPGC's proposal, and SEGG's proposal because HWT has entered into purchase options agreements for its identified converter station sites.

Based on the foregoing considerations, in conjunction with all the other considerations included in the ISO's analysis for this factor, the ISO has determined that, based on the specific scope of this project, the proposals of HWT, for its bay crossing and inland route proposals, are better that the proposals of Avangrid, for its proposals 1 and 2, LSPGC, and SEGG, among which there is no material difference, regarding this factor.

3.5 Selection Factor 24.5.4(c): Experience in Acquiring Rights-of-Way

The third selection factor is "the experience of the Project Sponsor and its team in acquiring rights of way, if necessary, that would facilitate approval and construction, and in the case of a Project Sponsor with existing rights of way, whether the Project Sponsor would incur incremental costs in connection with placing new or additional facilities associated with the transmission solution on such existing right of way."

For the purpose of performing the comparative analysis for this factor, the ISO has initially considered the two components of the factor separately and then combined them into an overall comparative analysis for this factor. The two components are: (1) the experience of the project sponsor and its team in acquiring rights-of-way and (2) for the case of a project sponsor with existing rights-of-way, whether the project sponsor would incur incremental costs in connection with placing new or additional facilities associated with the transmission solution on such existing rights-of-way.

For the consideration of this factor, the ISO has concluded that there is no significant difference between the two proposals submitted by Avangrid or between the two proposals submitted by HWT. Consequently, references to Avangrid and its proposal in this section apply equally to both Avangrid's proposal 1 and Avangrid's proposal 2, and references to HWT and its proposal in this section apply equally to both HWT's bay crossing proposal and HWT's inland route proposal.

Experience in Acquiring Rights-of-Way

(Prior Projects and Experience Workbook, A-4, A-5, L-1, L-2, L-4)

3.5.1 <u>Information Provided by Avangrid for Proposals 1 and 2</u>

Avangrid provided information on prior projects and experience that showed its experience and the experience of its contractors with acquiring rights of way for projects. Regarding projects that operate at voltages above 200 kV, are ongoing or have been completed in the past ten years, and are located in the U.S., the information provided included 20 substation and transmission line projects, five in California. (Prior Projects and Experience Workbook) Avangrid did not indicate in its application that it would utilize the land acquisition contractor identified in the Prior Projects and Experience Workbook to acquire land rights for this project. In its application, Avangrid identified a different land acquisition services provider that it would seek to use if awarded the project. The application did not indicate if this land acquisition services provider has experience in California. (L-4).

Avangrid indicated that as a utility owner in the Northeast it has experience in acquiring rights of way for transmission projects. Avangrid indicated that in the past five years it has successfully secured two separate transmission corridors of more than 100 miles each in Maine with no use of its eminent domain authority. Avangrid indicated that its approach to land acquisition prioritizes acquisition speed, outreach to landowners to enhance cooperation, and agreements that are mutually beneficial to both parties of the transaction. (A-4)

3.5.2 Information Provided by HWT for Bay Crossing and Inland Route

HWT provided information on prior projects and experience that showed its experience and the experience of its contractors with acquiring rights of way for projects. Regarding projects that operate at voltages above 200 kV, are ongoing or have been completed in the past ten years, and are located in the U.S., the information provided included 79 substation and transmission line projects, seven in California. (Prior Projects and Experience Workbook)

HWT indicated that it, along with its affiliates, have considerable experience in obtaining site control from private landowners for major transmission projects throughout North America. HWT indicated that this experience includes options to purchase, options for easements, and access easements. (L-1)

3.5.3 Information Provided by LSPGC

LSPGC provided information on prior projects and experience that showed its experience and the experience of its contractors with acquiring rights of way for projects. Regarding projects that operate at voltages above 200 kV, are ongoing or have been completed in the past ten years, and are located in the U.S., the information provided included 27 substation and transmission line projects, four in California. (Prior Projects and Experience Workbook)

3.5.4 Information Provided by SEGG

SEGG provided a list of its experience and the experience of its contractors with acquiring rights of way for projects. Regarding projects that operate at voltages above 200 kV, are ongoing or have been completed in the past ten years, and are located in the U.S., the information provided included 25 substation and transmission line projects, three in California. (Prior Projects and Experience Workbook)

SEGG identified a local land acquisition services company that it would work with in connection with this project. (A-5)

Incremental Costs Associated with Use of Existing Rights-of-Way

(L-1, L-5)

3.5.5 Information Provided by Avangrid for Proposals 1 and 2

Avangrid indicated it does not have existing land rights along the project route, thus it would not incur additional costs. (L-1, L-5)

3.5.6 Information Provided by HWT for Bay Crossing and Inland Route

HWT indicated it does not have existing land rights along the project route, thus it would not incur additional costs. (L-1, L-5)

3.5.7 Information Provided by LSPGC

LSPGC indicated it does not have existing land rights along the project route, thus it would not incur additional costs. (L-1, L-5)

3.5.8 Information Provided by SEGG

SEGG indicated it does not have existing land rights along the project route, thus it would not incur additional costs. (L-1, L-5)

3.5.9 ISO Comparative Analysis

Comparative Analysis of Experience in Acquiring Rights-of-Way

For purposes of the comparative analysis for this component of the factor, the ISO has considered the representations by the project sponsors regarding the experience of both the project sponsor and its team members in acquiring rights-of-way, including but not limited to experience in the U.S. and California.

The ISO considers experience in acquiring rights-of-way in California to be a slight advantage over experience in rights-of-way acquisition in other jurisdictions because the project is located in California and such experience will facilitate the timely, efficient, and effective undertaking of the project.

All four project sponsors and their teams have experience in acquiring land rights and site control. The ISO considers the proposals of HWT, LSPGC, and SEGG and their teams to be slightly better than Avangrid's proposals because of the uncertainty in Avangrid's applications as to whether Avangrid would be utilizing a land acquisition services company with experience in California. Based on the foregoing considerations, in conjunction with all the other considerations included in the ISO's analysis for this component of the factor, the ISO has determined that, based on the specific scope of this project, there is no material difference among the proposals of HWT, for its bay crossing and inland route proposals, LSPGC, and SEGG, and they are slightly better than Avangrid's proposals 1 and 2, between which there is no material difference, regarding this component of the factor.

Comparative Analysis of Incremental Costs Associated with Use of Existing Rights-of Way

For purposes of the comparative analysis for this component of the factor, the ISO has considered the representations by the project sponsors regarding whether the project sponsor would incur incremental costs in connection with placing new or additional facilities associated with the project on existing rights-of-way.

None of the six proposals of the four project sponsors indicated that the project sponsor expects to incur any incremental costs as a result of any use of existing rights-of-way for this project. Consequently, the ISO has determined that there is no material difference among the six proposals of the four project sponsors regarding this component of the factor.

Overall Comparative Analysis

Because the proposals of HWT, LSPGC, and SEGG are slightly stronger than Avangrid's proposals regarding the first component of this factor, and there are no material differences among the six proposals of the four project sponsors regarding the second component of the factor, the ISO has determined that there is no material difference among the proposals of HWT, for its bay crossing and inland route proposals, LSPGC, and SEGG, and they are slightly stronger than Avangrid's proposals 1 and 2, between which there is no material difference, regarding this factor overall.

3.6 Selection Factor 24.5.4(d): Proposed Schedule and Demonstrated Ability to Meet Schedule

The fourth selection factor is "the proposed schedule for development and completion of the transmission solution and demonstrated ability to meet the schedule of the Project Sponsor and its team." As discussed in Section 2.1, the ISO has identified this selection factor as a key selection factor because of the need for this project by the latest in-service date specified in the ISO Functional Specifications, which is particularly important for this project because the timing of this project is critical to ensure reliable service of load in the San Jose area. A proposal that best satisfies this factor will contribute significantly to ensuring that the approved project sponsor selected will develop the project in an efficient, cost-effective, and timely manner. The ISO used the following considerations in its analysis for this component of the factor:

- Proposed schedules
- Scope of activities specified in the proposed schedules
- Amount of schedule float
- Experience of project sponsors
- Potential risks associated with project sponsor's proposal

For the purpose of performing the comparative analysis for this factor, the ISO has initially considered the two components of the factor separately and then combined them into an overall comparative analysis for this factor. The two components are: (1) the proposed schedule for development and completion of the project and (2) demonstrated ability of the project sponsor and its team to meet that schedule.

For the consideration of this factor, the ISO has concluded that there is no significant difference between the two proposals submitted by Avangrid or between the two proposals submitted by HWT. Consequently, references to Avangrid and its proposal in this section apply equally to both Avangrid's proposal 1 and Avangrid's proposal 2, and references to HWT and its proposal in this section apply equally to both HWT's bay crossing proposal and HWT's inland route proposal.

Proposed Schedule

(P-3)

3.6.1 Information Provided by Avangrid for Proposals 1 and 2

Avangrid's proposed project schedule included an in-service date of January 10, 2028, four months and 21 days in advance of the ISO's latest in-service date of June 1, 2028. In addition, Avangrid identified seven months of float in land acquisition, three months of float each in engineering services, converter engineering and manufacturing, and converter station construction, as well as seven months of float in transmission line construction. Avangrid also indicated that it could complete its proposed project by the latest in-service date in the ISO Functional Specifications if the start date were to be delayed by six months. (P-3)

Avangrid also identified steps to address a potential delay in land acquisition, permitting, and construction. This included a price escalation strategy and pursuing eminent domain in the event of a delay in land acquisition, outreach activities, and increasing headcount and working hours, and working on multiple segments of the transmission line in parallel, in the event of a delay in construction. (P-3)

3.6.2 Information Provided by HWT for Bay Crossing and Inland Route

HWT's proposed project schedule included an in-service date of May 30, 2028 with no schedule float in relation to the ISO's latest in-service date of June 1, 2028. HWT also indicated that it could complete its proposed project by the latest in-service date in the ISO Functional Specifications if the start date were to be delayed by six months. (P-3)

HWT also identified actions it is taking or would take to address a potential delay in land acquisition, permitting, and construction, such as obtaining priority status in production queues by leveraging its strong relationships with partner vendors and by starting the engineering and design work early in the process. (P-3)

3.6.3 Information Provided by LSPGC

LSPGC's proposed project schedule included an in-service date of April 19, 2028, one month and 11 days in advance of the ISO's latest in-service date of June 1, 2028. LSPGC also indicated that it could complete its proposed project by the latest in-service date in the ISO Functional Specifications if the start date were to be delayed by six months. (P-3)

LSPGC also provided measures that it could undertake to compress the engineering, procurement, and construction schedule to meet the required in-service date, such as releasing engineering and procurement activities earlier and using additional crews and extended hours during construction. (P-3)

3.6.4 Information Provided by SEGG

SEGG's proposed project schedule included a substantial completion date of December 1, 2027, six months in advance of the ISO's latest in-service date of June 1, 2028. SEGG indicated that there is six months of float in its schedule, which is the difference between the substantial completion date of December 1, 2027, and the latest in-service date of June 1, 2028. SEGG also indicated that it could complete its proposed project by the latest in-service date in the ISO Functional Specifications if the start date were to be delayed by six months. (P-3)

Ability to Meet Schedule

(Prior Projects and Experience Workbook, P-1, P-2, P-3, P-4)

3.6.5 Information Provided by Avangrid for Proposals 1 and 2

Past performance

Avangrid provided schedule performance information for 13 200 kV or above substation and transmission line projects that were completed in the past ten years in the U.S. and internationally, along with their planned and actual in-service dates. Avangrid indicated that nine of the 13 projects were completed on or before the planned in-service date. Avangrid indicated that two of the four delayed projects were delayed due to previously unforeseen upgrades that the host utility was required to make due to the retirement of a nuclear power plant, one project was delayed due to breakdown of contractor equipment, and another project was delayed due to a supplier's issue with cable manufacturing and installation. (Prior Projects and Experience Workbook)

Based on the schedule performance information provided by Avangrid for 200 kV or above substation and transmission line projects that were completed in the past ten years, the average delay in schedule when a project was delayed was 42 months. The reason for a lengthy average delay in the case of Avangrid was due to a 64-month delay associated with two projects that were delayed due to previously unforeseen upgrades the host utility was required to make due to the retirement of a nuclear power plant, and a 28-month delay associated with another project that was delayed due to a supplier's issue with cable manufacturing and installation.

Project Management and Team

Avangrid indicated that the project would be executed by its projects organization which is International Standards Organization 9001 and 14001 compliant and certified regarding quality management systems and environmental management systems. Avangrid indicated that the 295-person projects organization includes professional engineers, schedulers, certified project management professionals and construction managers in all disciplines necessary to successfully deliver substation and transmission line projects. (P-1)

Avangrid provided information on the key project management team members, as well as their responsibilities, including the project manager. Avangrid indicated that the project manager role would be filled by an individual with extensive experience in developing and constructing complex high voltage transmission line and substation projects. (P-2)

Avangrid indicated that it would draw on the resources of its parent companies governed by a newly executed service agreement. Avangrid indicated that it uses similar service agreements across several of its subsidiaries. Avangrid also provided a similar agreement that is being utilized to govern the use of affiliate services for a large transmission line project in the Northeast. Avangrid also indicated that it would establish a steering committee to provide strategic direction and ensure visibility and coordination on the project for Avangrid corporate leadership. (P-2)

Risk Management

Avangrid provided a list of the major schedule risks identified for the project, with actions to mitigate the likelihood and impact of the risks.

Site control and right of way acquisition: Avangrid indicated that it intends to mitigate any schedule risks associated with site control and right-of-way acquisition by engaging with key owners and municipalities early in the process, as well as considering alternate locations of converter stations and routing of transmission lines.

Project design: Avangrid indicated that it intends to mitigate any transmission line design risks by selecting routes near existing roads to minimize permitting risks, prioritizing underground construction where possible, and minimizing the number of crossings for existing utilities.

Siting and permitting: Avangrid indicated that it has identified several non-governmental organizations as potential stakeholders to be engaged to reduce the risk of opposition to the project during the permitting process.

Procurement: Avangrid indicated that it would utilize an aggressive payment schedule to secure a manufacturing slot for the converter station. Avangrid also indicated that it plans to issue a limited notice to proceed in order to secure a manufacturing slot one year before the expected receipt of approval of the CPUC certificate of public convenience and necessity (CPCN).

Construction risk: Avangrid indicated that it intends to perform a geotechnical probing program to identify depths to bedrock across the substation site, which would be used to further optimize the layout and design to reduce construction costs. (P-4)

Permitting risk: Avangrid indicated that building underground or overhead lines within the Don Edwards National Wildlife Refuge would require authorization from the Secretary of the Interior, acting through the U.S. Fish and Wildlife Service, and could potentially trigger litigation even if it is approved. Avangrid indicated that any routes within the Don Edwards National Wildlife Refuge were scrupulously avoided.

Avangrid indicated that In the event that it is awarded more than one project, the projects' in-service dates would remain the same.

3.6.6 Information Provided by HWT for Bay Crossing and Inland Route

Past performance

HWT provided schedule performance information for 76 200 kV or above substation and transmission line projects that were completed in the past ten years in the U.S. and internationally along with their planned and actual in-service dates. HWT indicated that 65 of the 76 projects were completed on or before the planned in-service date. HWT also indicated that 11 of the 76 projects were delayed. HWT indicated that the majority of the delays were due to permitting and other reasons, including delays due to interconnection, public service commission approval, equipment delivery or installation, and power purchase agreement execution. (Prior Projects and Experience Workbook)

Based on the schedule performance information provided by HWT for 200 kV or above substation and transmission line projects that were completed in the past ten years, the average delay in schedule when a project was delayed was determined to be four months. (Prior Projects and Experience Workbook)

Project Management and Team

HWT indicated that it has assembled a project management team that would provide a single point of accountability for day-to-day activities, oversee all project work stream leads and resources, and be responsible for reporting project progress to senior management. HWT provided a list of project management process steps and actions that it would take during its development and construction of the project, including project launch and scoping, master project schedule development, risk identification and mitigation, project cost estimation, and project execution plan. HWT also indicated that throughout the project execution phase, the schedule, budget, and risk logs for the project would be updated and optimized based on current information. HWT also indicated that the project team would produce a project dashboard to provide an up-to-date status of pertinent project metrics. (P-1)

HWT indicated that its core team of professionals and subject matter experts would draw upon the NextEra's matrixed organization of shared resources for the project execution. HWT also provided corporate support services agreements recently executed for other projects for procuring services from NextEra's matrixed organization. HWT indicated that the project director would provide a single point of accountability for day-to-day project activities and would report project progress to senior management. HWT also provided information on the various teams that would be involved with the project and the personnel belonging to each team and their resumes. (P-2)

Risk Management

HWT provided a comprehensive risk and issues log that identified the risks specific to the project, and, for each risk, category of risk, whether it affects cost or schedule, the probability of occurrence, the impact of the occurrence, whether it is a risk during development or construction, and planned or potential mitigation. In addition, this log also identified the mitigation plan work stream lead. HWT's risk and issues log identified more than 50 risks, which were grouped into three categories – allocated contingency, unallocated contingency and price contingency. (P-4)

As discussed in Sections 3.4.2 and 3.4.3, HWT indicated that its proposed transmission line route for both its bay crossing and inland route proposals would cross the Don Edwards National Wildlife Refuge, for which it would have to obtain land rights and permits. (E-1, L-1)

HWT indicated that that it and its affiliates would be able to successfully deliver this project, the Metcalf-San Jose B HVDC project, the Collinsville 500/230 kV Substation project, and the Manning 500/230 kV Substation project, if selected as the approved project sponsor for any combination of those projects, with no changes to HWT's proposed schedule and project completion date for each project.

Financial Incentive

HWT's proposal included a schedule completion financial incentive penalty for each month the project completion date is delayed beyond May 30, 2028. (P-3)

3.6.7 Information Provided by LSPGC

Past performance

LSPGC provided schedule performance information for 23 200 kV or above substation and transmission line projects that were completed in the past ten years in the U.S. along with their planned and actual in-service dates. LSPGC indicated that 21 of the 23 projects were completed on or before the planned in-service date. LSPGC also indicated that two of the 23 projects were delayed. LSPGC indicated that the reason for both these delays was a delay in the completion of the interconnection by the interconnecting transmission owner due to force majeure that it claimed. (Prior Project and Experience Workbook)

Based on the schedule performance information provided by LSPGC for 200 kV or above substation and transmission line projects that were completed in the past ten years, the average delay in schedule when a project was delayed was determined to be three months. (Prior Project and Experience Workbook)

Project Management and Team

LSPGC indicated that it has assembled a project team with relevant experience in all areas of project execution to provide certainty to the ISO that the project would be delivered on schedule and on budget. LSPGC provided information on its approach for risk management, schedule management, cost management, project communication, quality management, issue management, and safety management. (P-1)

LSPGC indicated that the project director would be the primary point of contact for the ISO, would be responsible for guiding LSPGC's day-to-day activities, and would oversee all deliverables from selection as the approved project sponsor until the beginning of operations. LSPGC indicated that the project director would be supported by a highly qualified team of managers and subject matter experts with responsibilities for project execution within key project areas. LSPGC also provided detailed information on the roles and responsibilities of key personnel involved in project development, engineering and procurement, and construction. (P-2)

Risk Management

LSPGC provided a risk register that included 88 risk items grouped into categories (procurement, engineering, construction etc.) with a rating system for risk likelihood, risk consequence, risk level to ISO and ratepayers, and risk level to LSPGC, as well as mitigation measures for each risk.

LSPGC also identified the following potential major project risks of schedule delay along with their mitigation measures.

Technology risk: LSPGC indicated that it has secured the technical expertise of three consultants to mitigate the design and engineering risks.

HVDC terminal site acquisition: LSPGC indicated that it has already initiated discussions with site representatives for its preferred site.

Supply chain manufacturing and shipping delays: LSPGC indicated that it already has confirmation from its HVDC terminal and underground cable vendors regarding their ability to manufacture the equipment and cable for LSPGC consistent with the project schedule.

Delay in CPUC approvals: LSPGC indicated that it would mitigate this risk by retaining a highly qualified permitting and legal team and including a float to account for potential delays.

Construction restrictions: LSPGC indicated that it worked with its construction contractor and engineers experienced in the region to identify likely construction restrictions, which were incorporated into the cost estimate and schedule for the project.

Route changes: LSPGC indicated that it performed a routing study, including field reconnaissance and a review of environmental and engineering design criteria to consider alternative routes and identify a preferred route for the project.

Delay of interconnection facilities: LSPGC indicated that it has incorporated more than sufficient time for PG&E to complete the interconnection facilities in the project schedule. (P-4)

Permitting risk: LSPGC indicated that a new transmission corridor would cause a fragmentation of the Don Edwards National Wildlife Refuge and would not be considered as a compatible use by the refuge manager. LSPGC further indicated that routes that cross the Don Edwards National Wildlife Refuge were not selected as the preferred route for these reasons.

LSPGC indicated that it would dedicate additional resources to support multiple project awards and that the project schedule would not change in the event of multiple project awards. (P-4)

Financial Incentive

LSPGC's proposal also included a schedule completion financial incentive consisting of a reduction in return on equity of 2.5 basis points for every month that the project is delayed beyond June 1, 2028 up to a total of 30 basis points of total potential reduction to project return on equity. (P-3)

3.6.8 Information Provided by SEGG

Past performance

SEGG provided schedule performance information for four 200 kV or above substation and transmission line projects that were completed in the past ten years in the U.S. along with their planned and actual in-service dates. SEGG indicated that two of the four projects were completed on or before the planned in-service date. SEGG also indicated that two of the four projects were delayed for two instances for an average of 27.5 months. SEGG did not provide a specific reason for these delays but indicated that the explanation had already been supplied to the ISO. (Prior Projects and Experience Workbook)

Project Management and Team

SEGG indicated that it is proposing a project management team with appropriate skill sets and experience in permitting, financing, engineering, siting, construction, and operating high voltage substations and transmission lines. (P-1)

SEGG indicated that its chief executive officer would oversee the successful completion of the project. SEGG also provided the experience for individuals chosen for key positions such as the project manager, owner's representative and asset manager. SEGG also provided an organization chart that showed additional roles met by SEGG employees, as well as entities contracted to provide various services. SEGG indicated that all contractors would be directly engaged from the special purpose entity through service or supply contracts for their relevant scopes. (P-2)

Risk Management

SEGG identified the following major risks and obstacles to successful project completion on schedule:

SEGG indicated that the alternate transmission line routes that it considered would have passed through the Don Edwards National Wildlife Refuge lands, but new or expanded rights-of-way are no longer allowed by the refuge due to the National Wildlife Refuge Improvement Act enacted in 1997 and its required "compatibility" assessment. However, as discussed in Section 3.4.5, a portion of SEGG's proposed transmission line route would traverse the Don Edwards Nationals Wildlife Refuge. (A-4, P-4, L-2, L-5)

Environmental permitting and mitigation: SEGG indicated that an environmental impact report would be required for this project due to its potential for significant effects on biological and visual resources and that the project team has developed a set of application performance metric manuals, business process manuals, and a complete list of required permits that would support the CPUC's environmental impact report preparation, and the implementation of the suggested measures would minimize the potential for significant impacts. (P-4)

SEGG indicated that if selected as the approved project sponsor for both the Metcalf-San Jose B HVDC project and this project, it and its partners have the capability to complete both projects in accordance with the ISO's specifications and schedule. (P-5)

3.6.9 ISO Comparative Analysis

Comparative Analysis of Proposed Schedule

For purposes of the comparative analysis for this component of the factor, the ISO has considered the representations by the project sponsors regarding their proposed schedules for development of the project, including but not limited to the scope of activities specified in their schedules and the reasonableness of the timelines they have specified.

All six proposals of the four project sponsors included schedules that meet the latest in-service date of June 1, 2028 specified in the ISO Functional Specifications. Avangrid proposed a project schedule that would complete the project four months and 21 days ahead of the ISO's latest in-service date of June 1, 2028 for both of its proposals. HWT proposed a project schedule that would complete the project one day before the ISO's latest in-service date of June 1, 2028 for both of its proposals. LSPGC proposed a project schedule that would complete the project one month and 11 days ahead of the ISO's latest in-service date, and SEGG proposed a project schedule that included a substantial completion date six months in advance of the ISO's latest in-service date of June 1, 2028.

All four project sponsors for their six proposals indicated that that they could complete their proposed project by the latest in-service date in the ISO Functional Specifications if the start date were to be delayed by six months.

The ISO has determined that all six proposal schedules contain all the expected major activities for the project and contain potentially achievable associated timelines given the ISO's understanding of how long similar activities have taken on projects that have been completed in the recent past in California. In addition, the ISO considers the project sponsors' proposed schedule delay mitigation measures to be comparable.

For purposes of this comparative analysis, the ISO considers the potential benefits from an in-service date for this project in advance of the latest in-service date specified in the ISO Functional Specifications to be a small, but positive, benefit to the stakeholders based on the information currently available to the ISO. The ISO includes the consideration of a project sponsor completing the project ahead of the ISO's latest in-service date in the second component of the factor (demonstrated ability to meet that schedule). With this in mind, the ISO has chosen to evaluate the proposals as they relate to the latest in-service date specified in the ISO Functional Specifications for this component of the factor.

If the project can be placed into service earlier and the interconnection facilities necessary to accommodate the project can be completed sooner than the ISO's specified latest in-service date of June 1, 2028, the ISO reserves the option to negotiate an earlier in-service date with the approved project sponsor when the ISO has better information regarding the potential benefits of achieving an earlier in-service date.

The ISO has determined that, although there are differences in the details in the schedules proposed by each project sponsor, each proposed project schedule includes activities that show that the project sponsors understand the risks they would need to mitigate in order to complete the project by the latest in-service date of June 1, 2028, specified in the ISO Functional Specifications.

Based on the foregoing considerations, in conjunction with all the other considerations included in the ISO's analysis for this component of the factor, the ISO has determined that, based on the specific scope of this project, there is no material difference among the six proposals of the four project sponsors regarding this component of the factor.

Comparative Analysis of Ability to Meet Schedule

The ISO's analysis for this component of the factor focused primarily on the ability of the project sponsors to complete the project by the latest in-service date specified in the ISO Functional Specifications and any potential risks associated with each project sponsor's proposal that might affect completion of the project in a timely manner. However, as discussed in the prior component of the factor, the ISO considers completing the project ahead of schedule would provide small benefits to ratepayers. For purposes of the comparative analysis for this component of the factor, the ISO has considered the representations by the project sponsors regarding their experience, including but not limited to the information in their proposed schedules and their past experience in constructing projects on schedule, accounting for risk management, and performing project management, the potential for completing the project ahead of schedule, as well as any other factors that might impact the date of completion.

Previous Experience

The project sponsors and their teams have different levels of experience with completing previous transmission line and substation projects. HWT provided project experience information for both of its proposals that included 76 substation and transmission line projects that were at voltage levels 200 kV or above and completed in the past ten years. LSPGC provided information for 23 projects, Avangrid provided information for both of its proposals that included 13 projects, and SEGG provided information for four projects that were substation and transmission line projects at voltage levels 200 kV or above and completed in the past ten years.

Regarding completing projects on schedule, the ISO considers the proposals of HWT and LSPGC to have demonstrated a reasonable degree of success in meeting previous project schedules, slightly better than Avangrid's proposals. The schedule performance information provided for the five proposals of these three project sponsors showed that Avangrid, HWT, and LSPGC and their teams have completed a significant number of projects and that 69% of Avangrid's projects, 86% of HWT's projects, and 91% of LSPGC's projects were completed on or ahead of schedule. SEGG's schedule performance showed that it has had relatively less recent experience and success in meeting project schedules. For the schedule performance information provided by SEGG, two projects out of four or 50% were completed on schedule.

Regarding the amount of schedule delay for projects not completed on schedule, information provided by Avangrid showed an average delay of 42 months for its four projects that were not completed on schedule. The schedule performance information provided by HWT showed an average delay of four months, and the schedule performance information provided by LSPGC showed an average delay of three months. The schedule performance information provided by SEGG showed an average delay of 27.5 months for two of its four projects. SEGG did not provide a specific reason for the project delays but indicated that the explanation had already been supplied to the ISO.

Based on the foregoing, the ISO has determined that there is no material difference among the experience in the proposals of HWT and LSPGC regarding completing previous projects on schedule and considers their experience to be slightly better than the experience in Avangrid's proposals, which is better than the experience in SEGG's proposal.

Project Management and Team

All six proposals of the four project sponsors described a reasonable approach to professional project management. All six proposals laid out detailed project management programs, as well as identified the teams that would be working on each task of the project.

The project managers that were identified in each proposal have at least twenty years of experience, which the ISO considers sufficient.

Based on the foregoing analysis, the ISO determined that regarding project management and team there is no material difference among the six proposals of the four project sponsors.

Project Risk and Mitigation

All six proposals of the four project sponsors included a thorough approach to identifying risks to the project schedule and possible mitigations for those risks. All six proposals confirmed the project sponsors' ability to work on two projects simultaneously, if selected as the approved project sponsor for both. All four project sponsors indicate that they have taken steps to reduce risk for their proposals.

Regarding project risks and mitigation related to permitting and land rights acquisition, the ISO has determined that the two proposals of Avangrid and LSPGC's proposal are better than the two proposals of HWT and SEGG's proposal primarily because HWT and SEGG propose to route their transmission line through the Don Edwards National Wildlife Refuge. The two proposed routes of Avangrid, and the proposed route of LSPGC indicated that they avoided the Don Edwards National Wildlife Refuge and as a result they do not have the uncertainty whether the refuge manager would support their project routes.

Financial Incentive

Regarding financial incentive to complete the project by the latest in-service date in the ISO Functional Specifications, both of HWT's proposals and LSPGC's proposal include an on-time completion financial incentive.

HWT's proposals were based on completion by May 30, 2028, two days in advance of the ISO's latest in-service date of June 1, 2028. LSPGC's financial incentive proposal was based on project completion by the latest ISO in-service date of June 1, 2028. The other project sponsors did not offer any type of on-time completion financial incentive.

Regarding an on-time completion financial incentive (project completion on or before the latest ISO in-service date), the ISO has determined that the two proposals of HWT and the proposal of LSPGC are better than the two proposals of Avangrid and the proposal of SEGG because HWT and LSPGC included a schedule completion financial incentive tied to the latest ISO in-service date and Avangrid and SEGG did not include any form of an on-time completion financial incentive. The ISO compares the relative advantages of the two financial incentive proposals in the next subsection.

Completing the Project Ahead of Schedule

Regarding the potential for completing the project ahead of schedule, the ISO considers both the project sponsor's proposed schedule and the project sponsor's schedule completion incentive. As indicated above, there is a small benefit to completing the project earlier than the latest in-service date in the ISO Functional Specifications. The ISO recognizes no project sponsor can guarantee the project will be completed by a date certain, and factors such as permitting delays, supply chain issues, and interconnecting facility delays can affect a project's in-service date.

Avangrid proposed a schedule with an in-service date four months and 21 days in advance of the ISO's latest in-service date for both of its proposals; however, it did not provide any schedule completion incentive. HWT proposed a schedule with an in-service date two days ahead of the ISO's latest in-service date and a proposed schedule completion incentive that is tied to its proposed in-service date for both of its proposals. LSPGC proposed a schedule with an in-service date one month and 11 days ahead of the ISO's latest in-service date; with its proposed schedule completion incentive tied to the latest ISO in-service date. SEGG proposed an earlier in-service date that is six months ahead of the ISO's latest in-service date but did not provide a schedule completion incentive.

Regarding completing the project ahead of schedule, the ISO has determined that there is no material difference among the six proposals of the four project sponsors. Although HWT's two proposals include a schedule completion incentive based on its proposed in-service date, its proposed in-service date is only two days ahead of the ISO's latest in-service date. LSPGC has an earlier proposed in-service date, but its schedule completion incentive is based on the ISO's latest in-service date and not its proposed in-service date. The proposals of Avangrid and SEGG do not have any financial incentive to complete the project ahead of the latest ISO in-service date.

Overall Component

The ISO has determined that the proposals of HWT and LSPGC are slightly better than the proposals of Avangrid, which are better than the proposal of SEGG regarding the timely completion of construction of transmission line and substation projects over the past ten years.

The ISO has determined that there is no material difference among the six proposals of the four project sponsors regarding project management and team.

The ISO has determined that regarding project risk and mitigation, the two proposals of Avangrid and LSPGC's proposal are better than the two proposals of HWT and SEGG's proposal and there are no material differences among the Avangrid and LSPGC proposals and no material difference among the HWT and SEGG proposals.

The ISO has determined that, regarding offering a schedule completion incentive, there is no material difference among the proposals of HWT and LSPGC, and their proposals are better than the proposals of Avangrid and SEGG, between which there is no material difference.

The ISO has determined that, regarding completing the project prior to the latest ISO in-service date, there is no material difference among the six proposals of the four project sponsors.

Based on the foregoing considerations, in conjunction with all the other considerations included in the ISO's analysis for this component of the factor, the ISO has determined that, based on the specific scope of this project, LSPGC's proposal is slightly better than the two proposals of HWT, between which there is no material difference, which are slightly better than the two proposals of Avangrid, between which there is no material difference, and those five proposals are better than SEGG's proposal.

Overall Comparative Analysis

The ISO considers the two components of this factor to be of roughly equal importance in the selection process for this project. As discussed above, the ISO has determined that there is no material difference among the six proposals of the four project sponsors regarding the first component of this factor (proposed schedule).

Regarding the second component (demonstrated ability to meet the proposed schedule), based on the foregoing analysis, the ISO has determined that LSPGC's proposal is slightly better than HWT's bay crossing and inland route proposals, between which there is no material difference, which are slightly better than Avangrid's proposals 1 and 2, between which there is no material difference, and those five proposals are better than SEGG's proposal.

Based on the foregoing considerations, in conjunction with all the other considerations included in the ISO's analysis for this factor, the ISO has determined that, based on the specific scope of this project, LSPGC's proposal is slightly better than HWT's bay crossing and inland route proposals, between which there is no material difference, which are slightly better than Avangrid's proposals 1 and 2, between which there is no material difference, and those five proposals are better than SEGG's proposal, regarding this factor overall.

3.7 Selection Factor 24.5.4(e): The Financial Resources of the Project Sponsor and Its Team

(Prior Projects and Experience Workbook, A-5, F-1 through F-13)

The fifth selection factor is the "financial resources of the Project Sponsor and its team."

The ISO notes that the project sponsors provided substantial information regarding their finances in their applications; however, the ISO has only incorporated relatively limited and general financial information from the project sponsors' proposals in the summaries below due to the sensitive nature of some of the financial information provided.

As discussed in Section 2.1, the ISO has identified this selection factor as a key selection factor because the Newark-NRS HVDC project will cost hundreds of millions of dollars and require significant financial resources. It is among the costliest projects the ISO has opened for competitive solicitation.

Project sponsors provided information regarding their experience in developing and financing similar projects, annual financial results including key financial metrics, credit ratings, proposed financing sources, and other financial-oriented information requested by the ISO. In performing the comparative analysis, the ISO has considered all of the financial information provided by the project sponsors. The ISO has also utilized two metrics – tangible net worth and Moody's Analytics Estimated Default Frequency ("EDF")[8] – based on information provided in the project sponsors' annual reports. Moody's Analytics EDF has an associated equivalent rating, also provided by Moody's Analytics as part of its EDF calculation, that provides the ISO another metric similar to the agency credit ratings.

Although a company's net worth is sometimes used in financial analysis, it can be misleading because asset and liability values may change dramatically over time. For instance, derivative assets have the potential of changing daily. In addition, there is no prescribed way to value intangible assets. To compensate for these limitations, where possible, the ISO relies on tangible net worth[9], which removes certain assets and liabilities from the net worth calculation. For the purpose of evaluating the financial resources of the project sponsors and their teams for this project, the ISO considers tangible net worth to be more meaningful because it better represents assets that are more immediately available for project funding.

Likewise, the ISO considers that agency credit ratings can have important but limited usefulness in financial analysis because they are largely based on historical performance. In the general course of its business, the ISO has recognized the limitation of credit ratings and has begun to rely on EDF as a more forward-looking measure of a company's financial health. It produces a forward-looking default probability by combining financial statement and equity market information into a highly predictive measurement of stand-alone credit risk. EDF provides the ISO an additional metric in assessing a project sponsor's ability to see the project through to the end. In addition, the equivalent rating associated with the EDF provides another metric similar to the agency credit ratings. The ISO has utilized both of these additional measures of financial health in its comparative analysis of the financial resources of the project sponsors and their teams for this project.

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[8] Estimated Default Frequency is a proprietary scoring model developed by Moody's Analytics, Inc., a subsidiary of Moody's Corporation (NYSE: MCO).

[9] The ISO Tariff defines "Tangible Net Worth" as total assets minus assets (net of any matching liabilities, assuming the result is a positive value) the CAISO reasonably believes to be restricted or potentially unavailable to settle a claim in the event of a default (examples include restricted assets and Affiliate assets) minus intangible assets (*i.e.*, those assets not having a physical existence such as patents, trademarks, franchises, intellectual property, and goodwill) minus derivative assets (net of any matching liabilities, assuming the result is a positive value) minus total liabilities.

For the purpose of performing the comparative analysis for this factor, the ISO has considered the following components of the factor:

- Project financing experience
- Project financing proposal
- Financial resources
- Credit ratings
- Financial ratio analysis

The ISO has initially considered these components separately and then developed an overall comparative analysis for financial resources and creditworthiness.

For the consideration of this factor, the ISO has determined that there is no significant difference between the two proposals submitted by Avangrid or between the two proposals submitted by HWT. Consequently, references to Avangrid and its proposal in this section apply equally to both Avangrid's proposal 1 and Avangrid's proposal 2, and references to HWT and its proposal in this section apply equally to both HWT's bay crossing proposal and HWT's inland route proposal.

3.7.1 <u>Information Provided by Avangrid for Proposals 1 and 2</u>

Project Financing Experience

Avangrid provided a list of several transmission and substation projects that it financed in the past ten years. (Prior Projects and Experience Workbook) Avangrid provided information regarding financing of representative projects that were similar in type and cost or larger than this project. Avangrid indicated that the representative projects were financed using either a corporate or project financing approach. Under the corporate financing approach, Avangrid indicated that all construction financing was provided by its parent, Avangrid, Inc., with the intent to place debt capital after completion. Under the project financing approach, Avangrid indicated that construction financing was provided by financial institutions and converted to long-term debt after completion. (F-1, F-11)

Project Financing Proposal

Avangrid indicated that it proposes to create a limited liability company and use either corporate or project financing for the construction of the project. Under the corporate financing approach, Avangrid indicated that it would rely on its parent company Avangrid, Inc. for all financing. Avangrid indicated that at project completion, the project would issue third party debt and use the proceeds to reimburse Avangrid for a portion of the capital contributed during construction. Avangrid indicated that if the project finance approach is used, Avangrid would arrange for funding for construction from banks. Avangrid indicated that at completion, the construction debt would be converted to permanent debt. (F-1)

Avangrid also indicated that it is investigating the possibility of securing project financing through Western Area Power Administration's (WAPA) Transmission Infrastructure Program. Avangrid provided a letter of interest and support confirming WAPA's interest in leading a financing to support the project, but the letter of interest and support is clear that it is not a commitment to fund the project. (F-1)

Avangrid indicated that it anticipates using a corporate financing approach during project construction and would execute an intercompany loan agreement as an alternative to sourcing financing from capital markets. Avangrid indicated that this approach would ensure that the company to be formed for the purpose of this project would be able to benefit from the financial strength of Avangrid, Inc.'s capitalization and access to the equity and debt markets. Avangrid also indicated that this approach would provide benefits to ISO ratepayers by ensuring immediate access to required funding at highly competitive rates. (F-13)

Financial Resources

Avangrid, provided a letter from Avangrid, Inc. signed by an officer of Avangrid, Inc. indicating Avangrid, Inc.'s financial assurance for the project and availability of financial resources from its ultimate parent company Iberdrola. (F-2.1)

Avangrid provided Avangrid Inc.'s annual audited financial statements for 2017-2021 and quarterly unaudited financial statements for 2022. (F-3, F-4) Avangrid provided the following information from Avangrid Inc.'s latest audited financial statements:

Total assets
Total liabilities
Net worth

Credit Ratings

Avangrid indicated that Avangrid, Inc. is a public company and has been rated investment grade by all three credit rating agencies for the past five years. Avangrid provided the following credit ratings and associated credit rating reports for Avangrid Inc.: (F-6)

Moody's: Baa3
S&P: BBB+
Fitch: BBB+

Financial Ratio Analysis

Avangrid provided the following financial ratios based on Avangrid Inc.'s audited financial statements: (F-9, F-10)

Funds from operations (FFO)/interest coverage
FFO/total debt
Total debt/total capital
Total assets/total projected project cost

3.7.2 Information Provided by HWT for Bay Crossing and Inland Route

Project Financing Experience

HWT provided a list of several transmission and substation projects that its parent company, NextEra, financed in the past ten years. (Prior Projects and Experience

Workbook) HWT provided information regarding NextEra's financing of representative projects that were similar in type but less costly than this project. (F-11A) HWT indicated that the representative projects were financed using limited-recourse term and senior secured variable rate term loans. HWT indicated that debt sources included commercial banks. (F-11)

Project Financing Proposal

HWT indicated that during the development and construction of the project it would source equity funding from its parent company NEET and debt funding from HWT's ultimate company parent, NextEra, through NextEra's financing affiliate NEECH. Upon commercial operations and throughout the life of the project, HWT indicated that it anticipates using project-level financing from NEECH and may consider third-party project financing in the future. (F-1)

HWT provided a letter from NextEra indicating that NEECH would provide appropriate funding and needed guarantees to HWT and that those would in turn be guaranteed by NextEra as provided for through a blanket guarantee arrangement between NEECH and NextEra. HWT indicated that execution of a guaranty would be dependent on the ISO selecting HWT as the approved project sponsor and the execution of a mutually agreeable Approved Project Sponsor Agreement with the ISO. (F-2, F-2a, F-2c)

HWT indicated that the project would be supported 100% through corporate parent debt and equity funding. HWT indicated that ratepayers would receive the benefit of a project constructed with strong equity support, without any risk of project-level leverage. HWT indicated that corporate parent funding would benefit ratepayers by avoiding unnecessary and costly third-party transaction costs and providing the flexibility to complete the project under a range of possible scenarios (*e.g.*, construction delays, regulatory interventions, etc.). (F-13)

Financial Resources

HWT provided a letter from NextEra, signed by an officer of NextEra, indicating NextEra's financial assurance by guaranteeing the financial obligations of the project. (F-2a)

HWT provided NextEra's annual audited financial statements for 2017-2021 and quarterly unaudited financial statements for 2022. (F-3, F-4) HWT provided the following information from NextEra's latest audited financial statements:

Total assets
Total liabilities
Net worth

Credit Ratings

HWT indicated that NextEra is a public company and has been rated investment grade by all three credit rating agencies for the past five years. HWT provided the following credit ratings and associated credit rating reports for NextEra: (F-6)

Moody's: Baa1
S&P: A-
Fitch: A-

Financial Ratio Analysis

HWT provided the following financial ratios based on NextEra's audited financial statements: (F-9, F-10)

FFO/interest coverage
FFO/total debt
Total debt/total capital
Total assets/total projected project cost

3.7.3 <u>Information Provided by LSPGC</u>

Project Financing Experience

LSPGC provided a list of several transmission and substation projects that its parent, LS Power, financed in the past ten years. (Prior Projects and Experience Workbook) LSPGC provided information showing that LS Power has financed some similar types of transmission facilities, but all less in cost than the expected cost of this project. LSPGC indicated that the representative projects were financed with equity-to-debt contributions using a variety of debt sources, including project-specific financing through a number of commercial banks. (F-11) LSPGC also provided information regarding prior LS Power debt financings and a history of its ability and experience in utilizing the debt markets to consistently raise increasing amounts of capital for financing projects. (F-6)

Project Financing Proposal

LSPGC indicated it is relying on its parent LS Power to satisfy the financial criterion for this project. LSPGC indicated that LS Power intends to access the debt markets to lead placement of limited-recourse financing at LSPGC to support the construction and long-term operation of the project. LSPGC indicated that it will own the assets of the project, will be responsible for arranging the debt associated with construction of the project, and will service the debt after placing the project into service. (F-1)

LSPGC indicated that under the terms of the limited-recourse financing, LSPGC's lenders would not have recourse to LSPCG's parent company, LS Power, but lenders would have access to LSPCG's specific assets, and under an irrevocable equity commitment they would have recourse to LSPGC's committed equity. LSPGC indicated that LS Power intends to make a financial commitment to the lenders upon financial closing in the form of a letter of credit or other credit support deemed satisfactory by the lenders to support the equity requirements of the project. LSPGC indicated that this equity commitment to lenders would be irrevocable, thereby providing assurances that capital is sufficient to complete all phases of the construction program account upfront. (F-2) LSPGC indicated that it would convert debt used during development and construction or issue new long-term financing to support operations. (F-5)

LSPGC provided evidence of LS Power's financial assurances to LSPGC in the form of a written guarantee. (F-2A)

To provide further evidence of financial support for the project, LSPGC provided letters of support from two commercial banks. The letters state that they are non-binding and should not be construed as a commitment to finance the project. (F-6)

Financial Resources

LSPGC provided a written financial guarantee from LS Power, signed by an officer of LS Power's general partner, indicating LS Power's financial assurance for the project. (F-2A)

LSPGC provided an equity financing commitment letter, signed by an officer of LS Power's majority owner management company, indicating the majority owner's commitment to provide funding to LS Power for the project. (F-2B)

LSPGC provided LS Power's annual audited financial statements for 2017-2021 and quarterly unaudited financial statements for 2022. (F-3, F-4) LSPGC provided the following information from LS Power's latest annual audited financial statements:

Total assets
Total liabilities
Net worth

Credit Ratings

LSPGC indicated that LSPGC and LS Power are privately held companies that are not rated by credit rating agencies. (F-6)

Financial Ratio Analysis

LSPGC provided the following financial ratios based on LS Power's audited financial statements: (F-9, F-10)

FFO/interest coverage
FFO/total debt
Total debt/total capital
Total assets/total projected project cost

3.7.4 Information Provided by SEGG

Project Financing Experience

SEGG provided a list of transmission and substation projects that its affiliate, SEIF III, has financed in the past ten years. (Prior Projects and Experience Workbook) SEGG provided information regarding SEIF III's financing for representative projects that were similar in type to this project. SEGG provided information showing financing for two projects; however, both were not as costly as this project. SEGG indicated that the representative projects were financed using project-specific non-recourse construction and permanent debt sourced from institutions. (F-11, Prior Projects and Experience Workbook)

Project Financing Proposal

SEGG indicated that the project would be funded using a combination of debt and equity and that different banks have expressed interest in providing debt financing for the project. (A-5) SEGG indicated that it would create a special purpose entity as an affiliate for purposes of developing the project. SEGG indicated that the special purpose entity would be managed by SEGG through SEIF III and affiliated investment vehicles specifically to finance, construct, own, maintain, and operate the project. (F-5)

SEGG indicated that the financial structure for construction and working capital would rely on SEIF III and debt financing through private placement in the capital market. (F-12)

As an alternative to sourcing financing from capital markets, SEGG indicated that it is investigating the possibility of securing project financing through WAPA's Transmission Infrastructure Program. (F-13) SEGG indicated that it has received a letter of interest and support confirming WAPA's interest in leading a financing to support the project, but the letter of interest and support is clear that it is not a commitment to fund the project. (F-13)

To provide further evidence of financial support for the project, SEGG provided letters of support from two commercial banks. The letters are clear that they are non-binding and should not be construed as a commitment to finance the project. (F-1) SEGG also provided a parent guarantee letter for financial backing of the project. (F-2)

Financial Resources

SEGG indicated it would rely on existing funds or affiliated investment vehicles for financial backing of the project. SEGG indicated that the funds of SEIF III and other affiliated investment vehicles are available to support the construction of the project. (F-1)

SEGG provided a written parent guarantee, signed by an officer, providing financial assurance that SEIF III, as the direct parent of the special purpose entity that would be formed specifically for this project, would provide customary credit support and has adequate financial resources to provide the financial support for the project repairs and permitting of the project. (F-2.1)

SEGG indicated that it would have limited-recourse debt and plans to support the project once it goes into service. Although lenders would not have financial recourse to SEGG, SEGG indicated that SEIF III has sufficient uncommitted capital to support the construction of the project and any potential liabilities. (F-2)

SEGG provided the following information for SEIF III based on quarterly unaudited financial information for 2022 within a letter in lieu of financial statements for 2022: (F-3.2)

Total assets
Total liabilities
Net worth

Credit Ratings

SEGG indicated that SEIF III does not have a credit rating. (F-6)

Financial Ratio Analysis

SEGG did not provide audited financial statements or financial ratios. SEGG provided a letter in lieu of financial statements, which SEGG asserted demonstrates that SEIF III could meet the financial requirements of the project. (F-3.2)

The ISO calculated the following financial ratio based on the letter in lieu of financial statements provided by SEGG:

Total assets/total projected project cost

3.7.5 ISO Comparative Analysis

For the purpose of performing the comparative analysis for this factor, the ISO has considered the following components of the factor:

- Project financing experience
- Project financing proposal
- Financial resources
- Credit ratings
- Financial ratio analysis

The ISO has initially considered these components separately and then developed an overall comparative analysis for financial resources.

The ISO's analysis of the financial resources of the project sponsor and its team has focused primarily on whether each project sponsor has adequate financial resources and creditworthiness to finance the project and whether constructing, operating, and maintaining the facilities would significantly impair the project sponsor's creditworthiness or financial condition.

For purposes of the comparative analysis for this factor, the ISO has largely considered the project sponsors' representations. In addition, the ISO has considered each project sponsor's audited financial statements as well as credit ratings and associated ratings reports from one or more of the credit rating agencies. In instances where a project sponsor is looking to an affiliated entity (e.g., a corporate parent) for financial support on the project, the ISO has used financial statements and credit ratings of the affiliated entity if the affiliated entity provided a letter of assurance, signed by an officer of the company, stating that it would provide unconditional financial support to the project.

Although there are slight differences between project sponsors regarding some of the components considered, including the financial strength of the company ultimately backing the project and that company's credit ratings, the ISO does not consider these differences significant enough to materially affect any one project sponsor's ability to complete this project and considering the project cost estimates. Consequently, this comparative analysis relies in large part on minor degrees of difference.

Project Financing Experience

Based on the information provided and representations by the project sponsors, the ISO has determined that over the past ten years, HWT identified considerably more transmission project and project financing experience than Avangrid, LSPGC, and SEGG. Although Avangrid and LSPGC identified less transmission project financing experience than HWT, their financing experience exceeded the experience of SEGG during the past ten years. Avangrid provided information showing financing of multiple projects of similar type and cost to, or exceeding the expected cost of, this project. HWT provided information showing financing of transmission projects of similar type but less costly than this project. SEGG provided information showing the financing of two transmission projects that were not as costly as this project. LSPGC provided information showing financing of some similar types of transmission projects, but all less in cost than the expected cost of this project. LSPGC indicated that it has raised significant debt to support its business activities, including several individual financings that exceed the estimated debt for all four transmission projects that the ISO has opened for competitive solicitation in this cycle, as specified in the ISO's 2021-2022 transmission plan.

Although HWT demonstrated more transmission project financing experience than Avangrid, LSPGC, and SEGG in the past ten years, and Avangrid and LSPGC demonstrated more transmission project financing experience than SEGG during this period in the past ten years, the ISO has concluded that Avangrid, LSPGC, and SEGG sufficiently demonstrated their ability to secure project financing for this project. Consequently, the ISO considers the project financing experience of all four project sponsors for their six proposals to be sufficient such that there is no material difference among them regarding the extent to which their project financing experience has a bearing on their ability to finance this particular project.

Project Financing Proposal

Based on the financial proposals provided by each of the project sponsors, the project will be financed using a combination of both equity and debt. Equity for the project will be provided by the parent or an affiliate company of the project sponsor. Debt will be provided directly through the existing capital and/or credit facilities of the parent or through capital markets or financial institutions by either the project sponsor or the parent company. Debt provided during construction by the parent company may be converted into long-term debt once the project goes into operation. Some project sponsors intend to use limited-recourse debt financing with lenders. The project sponsors' capital structures are generally within a close range of each other regarding debt and equity.

Each of the project sponsors provided either a letter of financial assurance or guarantee from its parent company or affiliate for the financial obligations of the project.

As an alternative to sourcing financing from the capital markets, Avangrid and SEGG indicated they are investigating the possibility of securing project financing through WAPA's Transmission Infrastructure Program. Avangrid and SEGG have both received a letter of interest and support confirming WAPA's interest in leading a financing to support bids by both companies for the projects, but the letters of interest and support are clear that they are not a commitment to fund the project.

Based on all four project sponsors' reliance on parent funding and access to the capital markets, the ISO finds no material difference in their funding proposals.

Financial Resources

Each project sponsor has access to a parent or an affiliate and the capital markets and financial institutions for financing this project. All of the parent or affiliate companies of the project sponsors will provide equity for the project based on equity to total capital ratios that are in accordance with industry practice. Some of the project sponsors have debt financing experience with the capital markets or financial institutions, and all of the project sponsors have access to parent or affiliate funding to fulfill the balance of debt required to cover the cost of the project. The parent or affiliate companies of the project sponsors also provided either a letter of guarantee or financial assurance to support the financial obligations of the project.

Regarding particular measures of financial resources, based on the most recent financial information provided about the parent or affiliate companies of the project sponsors, all of the parent or affiliate companies have total assets that exceed the projected cost of the project and in some cases total assets to cover the projected project cost multiple times. Based on the information provided by the project sponsors, the ISO has determined that HWT's parent company, NextEra, and Avangrid's parent company, Avangrid, Inc., are strongest regarding this particular measure, followed by LSPGC's parent company, LS Power, which is stronger than SEGG's affiliate company, SEIF III. Strength in this factor can help minimize the financial risk that a project may not be completed.

The ISO also calculated a tangible net worth for the parent companies of three of the project sponsors and has concluded that the parents of Avangrid and HWT have shown higher tangible net worth than LSPGC's parent company over the past five years. SEGG did not provide sufficient information for the ISO to calculate a tangible net worth for SEGG's affiliate; thus, the ISO was unable to compare SEGG to the other project sponsors regarding this measure of financial strength.

Having the financial capacity to continue to bid on, win, and finance projects, although dependent in part on the financial resources of a company, also depends on the breadth and strength of a company's partners and banking relationships. The ISO has concluded that he two proposals of Avangrid and the two proposals of HWT are the strongest in this regard, followed by LSPGC's proposal and then SEGG's proposal. Both LSPGC and SEGG have developed banking relationships as evidenced by various banks providing support for this project. Consequently, the ISO considers LSPGC and SEGG, for their proposals, to have sufficient financial resources to complete this project, although Avangrid and HWT, for their proposals, are stronger with regard to this consideration. Given the cost of this project, including SEGG's higher cost estimates, considering the analysis discussed above, and given the inability of the ISO to calculate a tangible net worth for SEGG and its affiliate, the ISO considers LSPGC and its proposal to be stronger than SEGG and its proposal regarding this particular measure of financial strength.

Credit Ratings and Estimated Default Frequency

Public companies are typically rated by three major credit rating agencies, Moody's, S&P, and Fitch. Credit ratings are opinions about a company's relative creditworthiness. They provide a common standard for lenders to determine whether or not a company will pay its debts on time and in full.

Of the four project sponsors, two of their parent or affiliate companies are public and two are private. Both of the public companies had investment grade ratings from each of the credit agencies for the past five years. Investment grade ratings are an indication that the company is at low risk of default for creditworthiness purposes.

Avangrid and HWT are backed by independently rated, investment grade companies. Although their individual ratings vary somewhat, the ISO does not consider these differences to be material for purposes of assessing the ability of these companies to obtain sufficient funding to construct this project. LSPGC's parent, LS Power, and SEGG's affiliate companies are not independently rated by any of the three major credit rating agencies. The lack of a credit rating is not unusual, and the ISO has not considered it an adverse factor in this analysis or prior analyses.

In addition to available credit ratings, the ISO also used Moody's Analytics Estimated Default Frequency (EDF) report and equivalent credit ratings to assess whether a company is likely to default on its loan payments over a given period where the assets of a company go below its outstanding debt obligations that need to be paid. EDF reports were available for three of the four parent or affiliate companies of the project sponsors, for each of the past five years.

The EDF scores and equivalent ratings of the parent companies of HWT and Avangrid were lower than LSPGC's parent company's EDF scores and equivalent ratings for each of the five years. SEGG did not provide sufficient information to generate the EDF report for SEGG's affiliate company; thus, the ISO was unable to compare SEGG to the other project sponsors regarding this measure of financial strength.

Additionally, each of the project sponsors declared that neither it nor its parent or affiliate company had a history of payment default or bankruptcy in the past five years.

Given the information provided and based on the Moody's Analytics EDF report and the resulting Moody's Analytics equivalent rating for the past five years, the ISO considers the two proposals of Avangrid and the two proposals of HWT to be stronger than the proposal of LSPGC. The ISO relies on the EDF report and equivalent ratings as an additional financial metric to assess the probability that a company will default on its payments within a specified period of time. None of the EDF scores and equivalent ratings were unacceptable, but there were differences in the EDF scores and equivalent ratings of Avangrid and HWT compared to LSPGC, as discussed above. As noted, the ISO was unable to compare SEGG to the other project sponsors regarding this consideration.

Financial Ratio Analysis

Avangrid, HWT, and LSPGC provided audited financial statements for the past five years for their parent companies. Based on this information, Avangrid, HWT, and

LSPGC provided interest and debt coverage, debt to capital, and total assets to costs of the project ratios in their proposals. These financial ratios provide insight into the operational trends of the parent companies of those three project sponsors over the past five years.

Financial ratios provide the ISO insight into a project sponsor's ability to pay interest and service debt out of funds from its operating activities as well as how leveraged a company is in terms of its total debt obligations. The interest and debt coverage ratios are an indicator of how many times interest and debt are covered by the parent company's operating income in each of the past five years.

The coverage ratios vary depending on industry and the capital-intensity of a company's operations. Based on the prior project and financing experience and other information provided in the project proposals of Avangrid, HWT, and LSPGC, their parents are involved with large infrastructure projects, and the timing of cash flows of certain projects may be unpredictable and thus should not by itself affect their ability to finance the project.

The total debt to capital ratio of each of Avangrid's, HWT's, and LSPGC's parent companies for each of the past five years indicated no risk of extensive financial leverage because the company's debt obligations do not exceed its capital balance.

Based on a comparison of the project sponsors' financial ratios, the ISO considers the interest and debt coverage ratios and debt to capital ratios of Avangrid and HWT to be better than LSPGC's financial ratios for those measures. SEGG did not provide information on which the ISO could base a determination of all of the financial ratios that the ISO typically uses to evaluate the financial strength of a project sponsor. The ISO was unable to calculate financial ratios other than total assets to total project cost for SEGG; thus the ISO was unable to compare SEGG to the other project sponsors regarding this measure of financial strength.

As discussed above, Avangrid and HWT have better financial ratios than LSPGC, and the ISO was unable to calculate financial ratios for SEGG. As a result, the ISO considers the two proposals of Avangrid and the two proposals of HWT to be stronger than the proposal of LSPGC, and the ISO is unable to compare these proposals to SEGG's proposal, regarding this consideration.

Overall Analysis

In performing the comparative analysis for this factor, the ISO considered all of the financial information provided by the project sponsors as well as the additional information developed by the ISO described above. The ISO's assessment of the financial resources of the project sponsors and their teams is necessary for the ISO to determine which of the project sponsors can bring the strongest financial resources to bear in order to fully finance the project over its life span at a competitive cost and to complete the project under a range of possible scenarios (*e.g.*, construction delays, cost escalation, regulatory interventions, etc.). This comparative analysis relies in large part on minor degrees of difference.

Based on the information provided by the project sponsors, the ISO has concluded that each project sponsor has sufficiently demonstrated the experience and financial resources to undertake a project of this scope and cost. Also, as discussed above, the ISO considers there to be no material differences among the project sponsors and their proposals regarding project financing experience and project financing proposals, especially when compared to the other differences among the project sponsors and their proposals. As discussed in detail above, the ISO considers Avangrid and HWT to have an advantage over LSPGC and SEGG in the area of financial resources and considers LSPGC to have an advantage over SEGG in this area. The ISO also considers Avangrid and HWT to have an advantage over LSPGC in the area of credit ratings and EDF and the area of financial ratio analysis. The ISO is unable to compare SEGG to the other project sponsors regarding credit ratings and EDF and regarding financial ratio analysis.

Based on the foregoing, in conjunction with all the other considerations included in the ISO's analysis for this factor, the ISO has determined that, based on the scope of this particular project, there is no material difference among Avangrid and HWT and each of their two proposals, and they are better than LSPGC and its proposal, which is slightly better than SEGG and its proposal, regarding this factor.

3.8 Selection Factor 24.5.4(f): Technical (Environmental Permitting) and Engineering Qualifications and Experience

The sixth selection factor is "the technical and engineering qualifications and experience of the Project Sponsor and its team."

For the purpose of performing the comparative analysis for this factor, the ISO has initially considered the two components of the factor separately and then combined them into an overall comparative analysis for this factor. The two components are: (1) the technical (environmental permitting) qualifications and experience of the project sponsor and its team and (2) the engineering qualifications and experience of the project sponsor and its team.

Technical (Environmental Permitting) Qualifications and Experience

(Prior Projects and Experience Workbook, E-1, E-2, E-3, E-4)

3.8.1 <u>Information Provided by Avangrid for Proposals 1 and 2</u>

Avangrid indicated it and its team would submit an application for a CPCN and Proponent's Environmental Assessment with the CPUC.

In addition, Avangrid indicated the following permits would be required for this project:

- U.S. Army Corps of Engineers Clean Water Act Section 404 and Section 408 permits
- U.S. Fish and Wildlife Service and National Marine Fisheries Service Endangered Species Act Section 7 consultation
- State Historic Preservation Office National Historic Preservation Act Section 106 consultation
- Regional Water Quality Control Board Clean Water Act Section 401 water quality certification permit

- California Department of Fish and Wildlife Section 1600 streambed alteration agreement and Section 2081 incidental take permit
- Bay Conservation and Development Commission minor permit.
- California Department of Transportation highway encroachment permit
- City of Fremont street encroachment permit
- City of Milpitas street encroachment permit
- City of San Jose street encroachment permit and grading and building permits
- City of Santa Clara street encroachment permit
- Santa Clara Valley Water District encroachment permit

Avangrid indicated that the Don Edwards National Wildlife Refuge was considered a major constraint and affected route decisions as well as overhead and underground decisions. Avangrid indicated that building overhead lines near the Don Edwards National Wildlife Refuge raises concerns of increased bird predation because the structures provide perching habitat for raptors that hunt the endangered snowy plover and other threatened and endangered bird species in the area. Avangrid indicated that, additionally, overhead lines present bird strike concerns since this area attracts bird species, including federally protected species. Avangrid also indicated that building underground or overhead lines within the Don Edwards National Wildlife Refuge requires authorization from the Secretary of the Interior, acting through the U.S. Fish and Wildlife Service, and could potentially trigger litigation even if it is approved. Avangrid indicated that, as a result, any routes within the Don Edwards National Wildlife Refuge were scrupulously avoided. (E-1 to E-4)

Avangrid provided information on prior projects and experience that showed its experience and the experience of its contractors with obtaining permits for projects. Regarding projects that operate at voltages above 200 kV, are ongoing or have been completed in the past ten years, and are located in the U.S., the information provided included 19 substation and transmission line projects, eight in California. (Prior Projects and Experience Workbook)

3.8.2 Information Provided by HWT for Bay Crossing and Inland Route

HWT indicated it and its team would submit an application for a CPCN and Proponent's Environmental Assessment with the CPUC.

In addition, HWT indicated the following permits would be required for both HWT's bay crossing proposal and its inland route proposal:

- Don Edwards National Wildlife Refuge special use permit or certificate of compatibility and right of way permit
- U.S. Army Corps of Engineers Clean Water Act Section 404 permit
- U.S. Fish and Wildlife Service and National Marine Fisheries Service Endangered Species Act Section 7 consultation
- State Historic Preservation Office National Historic Preservation Act Section 106 consultation
- Federal Aviation Administration determination of no hazard to air navigation
- Regional Water Quality Control Board Clean Water Act Section 401 water quality certification permit
- California Department of Fish and Wildlife Section 1600 Streambed Alteration Agreement and Section 2081 incidental take permit

- Bay Conservation and Development Commission major permit
- California Department of Transportation highway encroachment permit
- California State Lands Commission lease
- California State Water Resources Control Board construction general permit
- Bay Area Air Quality Management District authority to construct and permit to operate.

HWT indicated that a small section of transmission line for its inland route proposal and approximately 4.7 miles of transmission line for its bay crossing proposal route are proposed to cross the Don Edwards National Wildlife Refuge. HWT provided a list of its experience and the experience of its contractors with obtaining permits for projects. (E-1 to E-4)

HWT provided information on prior projects and experience that showed its experience and the experience of its contractors with obtaining permits for projects. Regarding projects that operate at voltages above 200 kV, are ongoing or have been completed in the past ten years, and are located in the U.S., the information provided included 103 substation and transmission line projects, 21 in California. (Prior Projects and Experience Workbook)

3.8.3 Information Provided by LSPGC

LSPGC indicated it and its team would submit an application for a CPCN and Proponent's Environmental Assessment with the CPUC. LSPGC indicated it performed a routing study and assessment of its preferred and alternative sites along with an overview of a number federal, state, and local agencies having discretionary and ministerial authority over this project. LSPGC also provided a CPUC CPCN and California Environmental Quality Act process flow chart.

In addition, LSPGC indicated that permits would be required for the project from the following entities:

- City of San José
- City of Milpitas
- City of Fremont
- City of Santa Clara
- Santa Clara Valley Water District
- California State Lands Commission
- Santa Clara Valley Transportation Authority
- California Department of Transportation
- San Francisco Public Utilities Commission

LSPGC indicated that routes were identified and evaluated that cross the Don Edwards National Wildlife Refuge, as PG&E has existing transmission lines in the Don Edwards National Wildlife Refuge. LSPGC indicated that U.S. Fish and Wildlife Service regulations specify that fragmentation of habitat, which a new transmission corridor would cause, is not a compatible use of a national wildlife refuge. LSPGC further indicated that in 1998, PG&E filed an application with the CPUC to construct the Northeast San José Transmission Reinforcement Project and had to withdraw that application (A-98-07-007) because of the U.S. Fish and Wildlife Service’s difficulty in finding a transmission line to be "compatible" with the purposes for which the Don Edwards National Wildlife Refuge was created. (E-1 to E-4)

LSPGC indicated that routes that cross the Don Edwards National Wildlife Refuge were not selected as the preferred route for these reasons. (L-2)

LSPGC provided information on prior projects and experience that showed its experience and the experience of its contractors with obtaining permits for projects. Regarding projects that operate at voltages above 200 kV, are ongoing or have been completed in the past ten years, and are located in the U.S., the information provided included 22 substation and transmission line projects, two in California. (Prior Projects and Experience Workbook)

3.8.4 <u>Information Provided by SEGG</u>

SEGG indicated it and its team would submit an application for a CPCN and Proponent's Environmental Assessment with the CPUC.

In addition, SEGG indicated that the following permits would be required for this project:

- Don Edwards National Wildlife Refuge special use permit
- U.S. Army Corps of Engineers Clean Water Act Section 404 permit and Rivers and Harbors Act Section 10 permit
- U.S. Fish and Wildlife Service and National Marine Fisheries Service Endangered Species Act Section 7 consultation
- San Francisco Bay Regional Water Quality Control Board Clean Water Act Section 401 Water Quality Certification permit
- California Department of Fish and Wildlife Section 1600 Streambed Alteration Agreement and Section 2081 incidental take permit
- Bay Conservation and Development Commission major permit
- California State Lands Commission lease
- Bay Area Air Quality Management District authority to construct and permit to operate
- Counties of Alameda and Santa Clara, Cities of Newark, Milpitas, Fremont and San Jose conditional use permits and general plan amendment

(E-1 to E-4)

SEGG indicated approximately 2,400 feet of its transmission line is proposed to cross the Don Edwards National Wildlife Refuge. (P-4) SEGG indicated that that the alternate transmission line routes that it considered would have passed through the Don Edwards National Wildlife Refuge lands, and new or expanded rights-of-way are no longer allowed by the refuge due to the National Wildlife Refuge Improvement Act enacted in 1997 and its required "compatibility" assessment. (A-4, L-2, L-5, P-4)

SEGG provided information on prior projects and experience that showed its experience and the experience of its contractors with obtaining permits for projects. Regarding projects that operate at voltages above 200 kV, are ongoing or have been completed in the past ten years, and are located in the U.S., the information provided included 25 substation and transmission line projects, 14 in California. (Prior Projects and Experience Workbook)

Engineering Qualifications and Experience

(Prior Projects and Experience Workbook, QP-1, P-4, P-5, S-1 through S-8, T-1 through T-8)

3.8.5 Information Provided by Avangrid for Proposal 1

Avangrid provided information on prior projects and experience that showed its experience and the experience of its contractors with designing substation and transmission line projects. The information included 25 substation and transmission line design projects that operate at voltages above 200 kV and are ongoing or have been completed in the past ten years. Three of the identified substation and transmission line design projects were located in the U.S., including one in California. Of the 25 total projects, none were underground projects and 17 included an HVDC component (*i.e.*, transmission line or converter station). (Prior Projects and Experience Workbook)

Based upon information provided in the application, Avangrid identified engineering contractors that have significant experience in California in the design of substations and transmission lines. (A-5)

Avangrid indicated that the project has been designed in accordance with the ISO Functional Specifications. (QP-1) Avangrid indicated that the project would comply with all applicable reliability criteria and ISO planning standards. (QP-2) Avangrid indicated that it has mitigated the risks for transmission line design by evaluating multiple routing alternatives, routes near existing roads, transmission line crossings, and the length of routes. (P-4) Avangrid indicated that it would leverage its experience with the design and engineering of systems utilizing VSC to mitigate risks. Avangrid indicated that permitting may require design modification and that cable installation and horizontal direct drilling are a unique challenge. (P-5)

Avangrid provided detailed design criteria and identified a list of standards and requirements that it would use in the design of the DC converter station and the AC and DC overhead and underground transmission lines, including California and local requirements. Avangrid provided a description of the major electrical equipment, protection, relays, supervisory control and data acquisition (SCADA) system, transmission conductor and cables, ampacity, and impedances. (S-1 to S-8, T-1 to T-8)

Avangrid indicated that it is currently developing the 1200 MW ±320 kV HVDC New England Clean Energy Connect, a 145-mile transmission line and VSC HVDC converter station in Maine designed to bring hydropower from Quebec to the New England energy market. Avangrid indicated that through this development process, it has gained valuable experience in the intricacies of bringing an HVDC project from the design and engineering phase to construction, all while dealing with limited global supply chains for VSC HVDC technology. (Application Introduction)

3.8.6 Information Provided by Avangrid for Proposal 2

Avangrid provided information on prior projects and experience that showed its experience and the experience of its contractors with designing substation and transmission line projects. The information included 20 substation and transmission line design projects that operate at voltages above 200 kV and are ongoing or have been completed in the past ten years, of which three projects were located in the U.S., with one in California. Of the 20 total projects, none were underground projects and 12 included an HVDC component (i.e., transmission line or converter station). (Prior Projects and Experience Workbook)

Based upon information provided in the application, Avangrid identified engineering contractors that have significant experience in California in the design of substations and transmission lines. (A-5)

Avangrid indicated that the project has been designed in accordance with the ISO Functional Specifications. (QP-1) Avangrid indicated that proposed complies with all applicable reliability criteria and California ISO planning standards. (QP-2)

Avangrid indicated that the project would comply with all applicable reliability criteria and ISO planning standards. (QP-2) Avangrid indicated that it has mitigated the risks for transmission lines design by evaluating multiple routing alternatives, routes near existing roads, transmission line crossings, and the length of routes. (P-4) Avangrid indicated that it would leverage its experience with the design and engineering of systems utilizing VSC to mitigate risks. Avangrid indicated that permitting may require design modification and that cable installation and horizontal direct drilling are a unique challenge. (P-5)

Avangrid provided detailed design criteria and identified a list of standards and requirements that it would use in the design of the DC converter station and the AC and DC overhead and underground transmission lines, including California and local requirements. Avangrid provided a description of the major electrical equipment, protection, relays, SCADA, transmission conductor and cables, ampacity, and impedances. (S-1 to S-8, T-1 to T-8)

Avangrid indicated that it is currently developing the 1200 MW ±320 kV HVDC New England Clean Energy Connect, a 145-mile transmission line and VSC HVDC converter station in Maine designed to bring hydropower from Quebec to the New England energy market. Avangrid indicated that through this development process, it has gained valuable experience in the intricacies of bringing an HVDC project from the design and engineering phase to construction, all while dealing with limited global supply chains for VSC HVDC technology. (Application Introduction, A-4)

3.8.7 Information Provided by HWT for Bay Crossing and Inland Route

HWT provided information on prior projects and experience that showed its experience and the experience of its contractors with designing substation and transmission line projects. The information included 129 substation and transmission line design projects that operate at voltages above 200 kV and are ongoing or have been completed in the past ten years, of which 104 were located in the U.S., including eight in California. Of the 104 U.S. projects, nine were underground projects. Of the 129 total projects, 23 included an HVDC component (*i.e.,* transmission line or converter station). (Prior Projects and Experience Workbook)

HWT indicated that its proposal meets or exceeds all ISO Functional Specifications and is able to accommodate all anticipated future expansion of the Newark Substation, including potential new series reactor additions. (QP-1) HWT indicated that its proposal fully satisfies the ISO's identified transmission needs and satisfies all reliability standards and ISO transmission planning standards. (QP-2) HWT identified the risks specific to the project. HWT indicated that it and its affiliates have sufficient financial, technical, and human resources to successfully work on and deliver multiple, large-scale projects at the same time. (P-4) HWT indicated that it and its NextEra affiliates have a vast range of experience in completing transmission line and substation projects, and that these projects were designed throughout the U.S., with a broad variety of climate, siting, and technical requirements. (P-5)

HWT provided detailed design criteria and identified a list of standards and requirements that it would use in the design of the DC converter station and the AC and DC overhead and underground transmission lines, including California and local requirements. HWT provided a description of the major electrical equipment, protection, relays, SCADA, transmission conductor and cables, ampacity, and impedances. (S-1 to S-8, T-1 to T-8)

3.8.8 <u>Information Provided by LSPGC</u>

LSPGC provided information on prior projects and experience that showed its experience and the experience of its contractors with designing substation and transmission line projects. The information included 23 substation and transmission line design projects that operate at voltages above 200 kV and are ongoing or have been completed in the past ten years, of which 18 were located in the U.S., including seven in California. Of the 18 U.S. projects, three were underground projects. Of the 23 total projects, six included an HVDC component (*i.e.*, transmission line or converter station). (Prior Projects and Experience Workbook)

LSPGC indicated that it designed the proposal to meet or exceed the needs identified in the ISO transmission plan, including the ISO Functional Specifications and all applicable standards, and provided tables that showed the design values exceed the minimum requirements. (QP-1) LSPGC indicated that its proposal design satisfies all applicable reliability criteria and ISO planning standards including the ISO Functional Specifications for the project. LSPGC has incorporated design decisions to enhance reliability of the project beyond the minimum. (QP-2) LSPGC provided a list of potential project risks that included site acquisition, delay in approvals, construction restriction, transmission line changes, and delay of interconnection facilities. (P-4) LSPGC indicated that it has demonstrated experience successfully managing the designing and engineering risks and challenges presented by the project. (P-5)

LSPGC provided detailed design criteria and identified a list of standards and requirements that it would use in the design of the DC converter station and the AC and DC overhead and underground transmission lines, including California and local requirements. LSPGC provided a description of the major electrical equipment, protection, relays, SCADA, transmission conductor and cables, ampacity, and impedances. (S-1 to S-8, T-1 to T-8)

3.8.9 <u>Information Provided by SEGG</u>

SEGG provided information on prior projects and experience that showed its experience and the experience of its contractors with designing substation and transmission line projects. The information included 41 substation and transmission line design projects that operate at voltages above 200 kV and are ongoing or have been completed in the past ten years, 18 of which were located in the U.S., with five in California. Of the 18

U.S. projects, two were underground projects. Of the 41 total projects, none included an HVDC project. (Prior Projects and Experience Workbook) In its proposals, SEGG identified engineering and design firms as part of its team that have experience in California. (A-5)

SEGG indicated that the design for converter stations and transmission line meets the criteria set forth in the ISO Functional Specifications. SEGG also indicated that the substation general arrangement satisfies requirements of the ultimate layout by providing adequate additional land to accommodate the substation ultimate arrangement. (QP-1) SEGG indicated that the proposed project design has considered ISO Tariff requirements and the ISO planning standards. (QP-2) SEGG identified risks pertaining to potential design changes because key system data (harmonic impedance sectors and background harmonic measurements) were not available at the time of submittal of its proposal. SEGG identified engineering risks and challenges associated with the underground transmission lines with identifying an engineering corridor that facilitates the project requirements. SEGG provided general information on mitigation measures. (P-5)

SEGG provided detailed design criteria and identified a list of standards and requirements that it would use in the design of the DC converter station and the AC and DC overhead and underground transmission lines, including California and local requirements. SEGG provided a description of the major electrical equipment, protection, relays, SCADA, transmission conductor and cables, ampacity, and impedances for the project. (S-1 to S-8, T-1 to T-8)

3.8.10 ISO Comparative Analysis

Comparative Analysis of Technical (Environmental Permitting) Qualifications and Experience

For purposes of the comparative analysis for this component of the factor, the ISO has considered the representations by the project sponsors regarding the qualifications and experience of both the project sponsor and its team members in obtaining and complying with environmental permits for a transmission project, including but not limited to (1) the permitting experience of the project sponsor and its team for projects it has developed, (2) how much of the experience of the project sponsor and its team is in the U.S. and in California and (3) the permits needed to complete the sponsor's proposed projects.

U.S. environmental permitting laws, rules, regulations, and processes are unique to the U.S., and California environmental permitting laws, rules, regulations, and processes are unique to the state of California. For example, the process that must be followed in California to comply with the California Environmental Quality Act is particularly unique to the state of California.

The ISO considers experience in the U.S. and California to be an advantage over experience in environmental permitting in other jurisdictions because the project will be located in California and there are special aspects of environmental regulation and processes in the U.S. and California for which experience is an advantage.

All six project sponsors' teams have experience permitting projects in the U.S. and in California, including experience with the environmental permitting process for transmission lines and substations in California, although the amount of experience varied among the project sponsors and their proposed teams.
Regarding its analysis of this component of the factor, the ISO considers the environmental permitting contractors identified by the project sponsors as part of their teams to be qualified and fully capable of handling the environmental permitting work associated with this project.

Regarding the permitting experience of the project sponsors and their teams including experience in California, in conjunction with all the other considerations included in the ISO's analysis for this component of the factor, the ISO has determined that there is no material difference among the six proposals.

Based on the foregoing considerations, in conjunction with all the other considerations included in the ISO's analysis for this component of the factor, the ISO has determined that, based on the specific scope of this project, there are no material differences among Avangrid's proposal 1, Avangrid's proposal 2, HWT's bay crossing and inland route proposals, LSPGC's proposal, and SEGG's proposal regarding this component of the factor.

The ISO notes that some of the proposals create greater permitting-related uncertainty than others. For example, HWT's proposals and SEGG's proposal propose to route their transmission line through the Don Edwards National Wildlife Refuge where the refuge manager has previously indicated an overhead transmission line may be incompatible with the habitat. This is discussed in Sections 3.8.1 and 3.8.3 as the basis for Avangrid and LSPGC avoiding a route through the refuge, including a reference to a PG&E project that was withdrawn due to incompatibility with the purposes of the refuge. As a result, it is uncertain that the refuge manager would support a project with a route through the refuge. The ISO discusses this and other siting-related risks in Section 3.12 regarding their implications for cost containment and in Section 3.6 regarding their implications for potential schedule delay.

Comparative Analysis of Engineering Qualifications and Experience

For purposes of the comparative analysis for this component of the factor, the ISO has considered the representations by the project sponsors regarding the qualifications and experience of both the project sponsor and its team members in engineering and designing transmission line and substation projects, including but not limited to (1) the engineering experience for similar projects of the project sponsor and its team member or members who have been designated as having responsibility for project engineering, and (2) and how much of the experience of the project sponsor and its team is in the U.S. and in California.

The ISO considers experience in the U.S. and California to be an advantage over substation engineering and design experience in other countries because the project will be located in California and there are special aspects of engineering and design codes and regulations in the U.S. and California for which this experience is an advantage.

U.S. engineering and design codes and regulations are unique to the U.S., and California engineering and design laws, rules, regulations, and processes are unique to the state of California. For example, projects developed in the United States must adhere to the National Electrical Safety Code (NESC) published by the Institute of Electrical and Electronics Engineers (IEEE). In addition, the process that must be followed for engineering and design of transmission line, substations and reactive stations in California includes adherence to requirements of the California Building Standards Commission, the California Energy Commission, the California Environmental Protection Agency, California Occupational Safety and Health Administration (OSHA), California High Voltage Electrical Safety Orders, California Building Code Title 24, and county and city planning and permitting requirements.

The ISO considered the engineering and design qualifications and experience of each project sponsor and its team. The ISO considers the engineering and design contractors identified by Avangrid, HWT, LSPGC, and SEGG as part of their teams to be highly qualified. They all have experience with the engineering and design of substation and transmission line projects in the U.S. and California, including experience with underground transmission line design. Avangrid, HWT, and LSPGC also provided information showing that their teams have substantial experience with the design of HVDC transmission projects. However, SEGG provided information that indicated that its HVDC team had limited experience and did not have experience designing HVDC transmission projects greater than 200 kV.

Based on the foregoing considerations, in conjunction with all the other considerations included in the ISO's analysis of this component of the factor, the ISO has determined that there is no material difference among the proposals of Avangrid, for its proposals 1 and 2, HWT, for its bay crossing and inland route proposals, and LSPGC, and that, based primarily on the limited experience of SEGG's HVDC team, these proposals are better than SEGG's proposal regarding this component of the factor.

Overall Comparative Analysis

The ISO considers the two components of this factor to be of roughly equal importance in the selection process for this project

The ISO has determined that, regarding the first component of the factor (environmental permitting experience including experience in California), there is no material difference among the proposals of Avangrid, for its proposals 1 and 2, HWT, for its bay crossing and inland route proposals, LSPGC, and SEGG.

The ISO has determined that, regarding the second component (engineering experience), there is no material difference among the proposals of Avangrid, for its proposals 1 and 2, HWT, for its bay crossing and inland route proposals, and LSPGC, and they are better than SEGG's proposal.

Based on the foregoing considerations, in conjunction with all the other considerations included in the ISO's analysis for this factor, the ISO has determined that, based on the specific scope of this project, there is no material difference among the proposals of Avangrid, for its proposals 1 and 2, HWT, for its bay crossing and inland route proposals, and LSPGC, and they are better than SEGG's proposal regarding this factor overall.

3.9 Selection Factor 24.5.4(g): Previous Record Regarding Construction and Maintenance of Transmission Facilities

The seventh selection factor is "if applicable, the previous record regarding construction and maintenance of transmission facilities, including facilities outside the ISO Controlled Grid of the Project Sponsor and its team."

For the purpose of performing the comparative analysis for this factor, the ISO has initially considered the two components of the factor separately and then combined them into an overall comparative analysis for this factor. The two components are: (1) the previous record regarding construction including facilities outside the ISO controlled grid of the project sponsor and its team and (2) the previous record regarding maintenance including facilities outside the ISO controlled grid of the project sponsor and its team.

For the consideration of this factor, the ISO has determined that there is no significant difference between the two proposals submitted by HWT. Consequently references to HWT and its proposal in this section apply equally to both HWT's bay crossing proposal and HWT's inland route proposal.

Construction Record

(Prior Projects and Experience Workbook; P-5, C-8)

3.9.1 Information Provided by Avangrid for Proposals 1 and 2

Avangrid provided its experience and the experience of its contractors with constructing substation and transmission line projects. For both its proposal 1 and its proposal 2, the information included 28 substation and transmission line construction projects that operate at voltages above 200 kV and are ongoing or have been completed in the past ten years, 26 of which were located in the U.S., including nine in California. Of the 26 U.S. projects, three were underground projects. Of the 28 total projects, two included an HVDC component. (Prior Projects and Experience Workbook)

Avangrid provided examples of construction problems that Avangrid and its team have previously faced that are comparable to the risks and challenges with this project, and how they were addressed. (P-5)

Avangrid provided information for two fines related to permitting that occurred during project construction. (C-8)

3.9.2 Information Provided by HWT for Bay Crossing and Inland Route

HWT provided its experience and the experience of its contractors with constructing substation and transmission line projects. The information included 100 substation and transmission line construction projects that operate at voltages above 200 kV and are ongoing or have been completed in the past ten years, 78 of which were located in the U.S., including six in California. Of the 78 U.S. projects, seven were underground projects. Of the 100 total projects, 17 included an HVDC component. (Prior Projects and Experience Workbook)

HWT indicated that its capabilities managing the unique design requirements and correctly defining construction methods associated with transmission facilities would be leveraged from their company's experience. (P-5) HWT indicated that neither it nor any of its affiliates has been subject to any violations or fines in the past ten years. (C-8)

3.9.3 Information Provided by LSPGC

LSPGC provided its experience and the experience of its contractors with constructing substation and transmission line projects. The information included 24 substation and transmission line construction projects that operate at voltages above 200 kV and are ongoing or have been completed in the past ten years, 21 of which were located in the U.S., including four in California. Of the 21 U.S. projects, three were underground projects. Of the 24 total projects, four included an HVDC component. (Prior Projects and Experience Workbook)

LSPGC indicated that its contractors have successfully completed multiple underground construction projects in California that involved crossings of existing utilities/buried infrastructure and have extensive experience in constructing substations of similar scope to the project. (P-5) LSPGC indicated that neither it nor any of its affiliates has been subject to any violations or fines in the past ten years. (C-8)

3.9.4 Information Provided by SEGG

SEGG provided its experience and the experience of its contractors with constructing substation and transmission line projects. The information included 47 substation and transmission line construction projects that operate at voltages above 200 kV and are ongoing or have been completed in the past ten years, 26 of which were located in the U.S., including six in California. Of the 26 U.S. projects, none were underground projects. Of the 47 total projects, none included an HVDC component. (Prior Projects and Experience Workbook)

SEGG provided examples of previous projects that represent the risks and challenges of construction of substation and transmission lines. (P-5) SEGG indicated that neither it nor any of its affiliates has been subject to any violations or fines in the past ten years. (C-8)

Maintenance Record

(Prior Projects and Experience Workbook; P-5, M-1, M-4, M-5, M-6, M-7)

3.9.5 Information Provided by Avangrid for Proposals 1 and 2

Avangrid provided its experience and the experience of its contractors with maintaining substation and transmission line projects.

For Avangrid's proposal 1, the information included 28 substation and transmission line maintenance projects that operate at voltages above 200 kV and are ongoing or have been completed in the past ten years, seven of which were located in the U.S., including none in California. Of the seven U.S. projects, one was an underground project. Of the 28 total projects, 11 included an HVDC component. (Prior Projects and Experience Workbook)

For Avangrid's proposal 2, the information included 19 substation and transmission line maintenance projects that operate at voltages above 200 kV and are ongoing or have been completed in the past ten years, seven of which were located in the U.S., including none in California. Of the seven U.S. projects, one was an underground project. Of the 19 total projects, six included an HVDC component. (Prior Projects and Experience Workbook)

Avangrid indicated that maintenance activities for the project would be led by Avangrid through a combination of in-house maintenance personnel, contractors, and its HVDC equipment supplier. (M-1)

Avangrid indicated that it owns, operates, and maintains 8,613 miles of transmission lines, 819 substations, 63,058 miles of overhead distribution lines, and 8,415 miles of underground distribution lines through four regulated electric utilities in the United States.

Avangrid indicated that it prefers to employ the services of its maintenance contractor for maintenance of the transmission lines for the project, including vegetation management within the project rights-of-way, but would employ other contractors as prudent for the benefit of ratepayers. (M-5)

Avangrid indicated that in terms of HVDC system maintenance and compliance experience, Avangrid has the support of its ultimate parent company, Iberdrola, including Iberdrola's global HVDC organization, and in particular, its sister company within the Iberdrola group, SP Transmission, which operates and maintains the 2.2 GW Western HVDC Link system in the United Kingdom. (M-6)

3.9.6 Information Provided by HWT for Bay Crossing and Inland Route

HWT provided its experience and the experience of its contractors with maintaining substation and transmission line projects. The information included 86 substation and transmission line maintenance projects that operate at voltages above 200 kV and are ongoing or have been completed in the past ten years, 79 of which were located in the U.S., including seven in California. Of the 79 U.S. projects, five were underground projects. Of the 86 total projects, six included an HVDC component. (Prior Projects and Experience Workbook)

HWT indicated the project's maintenance would be undertaken for HWT by its NextEra affiliate TBC. HWT indicated that the TBC VSC HVDC maintenance team is an in-house owner-operator staff, based in the San Francisco Bay Area, with exceptional experience, tools, and capability to attend to all matters pertaining to VSC HVDC system maintenance and repair. (M-1)

HWT indicated that NextEra has been managing vegetation around its power lines since December of 1925 and that NextEra is currently managing the maintenance of around 80,000 miles of transmission, distribution, and gen-tie lines across North America. (M-5)

HWT indicated that it and its affiliated transmission businesses have well-established, reasonable practices and procedures for complying with standards of maintenance, inspection, repair, and replacement of its facilities. HWT indicated that its proposed project operator, its affiliate TBC, has more than ten years operational experience in accordance with the ISO maintenance procedures. (M-6)

HWT indicated that it and its affiliates have experience with addressing stringent environmental regulations in the project area (both land and water), including managing land use restrictions. (P-5)

3.9.7 Information Provided by LSPGC

LSPGC provided its experience and the experience of its contractors with maintaining substation and transmission line substation projects. The information included 14 substation and transmission line maintenance projects that operate at voltages above 200 kV and are ongoing or have been completed in the past ten years, 13 of which were located in the U.S., with two in California. Of the 14 total projects, one included an HVDC component. Of the 13 U.S. projects, one was an underground project. (Prior Projects and Experience Workbook)

LSPGC indicated that LS Power would hire one technician to be located in close proximity to the project to perform routine substation maintenance and inspections, transmission line inspections, perform minor repairs, and oversee the outside contractors for the project. LSPGC indicated that the California-based technicians would be supported by the existing LS Power maintenance staff located in Texas, as well as asset management and engineering staff located in Texas and Missouri. (M-1)

LSPGC indicated that the project would be incorporated into LS Power's existing maintenance policies and procedures that are successfully utilized for maintaining highly reliable transmission systems across the country. (M-4)

LSPGC indicated that the project's above-ground facilities would be integrated into LS Power's transmission vegetation management plan based on experience maintaining hundreds of miles of 230 kV, 345 kV, and 500 kV transmission lines across multiple regions. (M-5)

LSPGC indicated that as required by NERC, LS Power has participated in the NERC auditing process since the inception of affiliate Cross Texas Transmission's assets, which includes an audit at least once every three years. (M-6)

LSPGC indicated that its operations and maintenance (O&M) personnel and its contractors currently operate and maintain similar equipment at its Cross Texas Transmission, Silver Run, and LSPGNY utilities with high reliability. By the time the project is energized, LS Power indicated that it would also be operating and maintaining similar equipment at LSPGC's Orchard static synchronous compensator (STATCOM) and Fern Road GIS/STATCOM project facilities. (P-5)

3.9.8 Information Provided by SEGG

SEGG provided its experience and the experience of its contractors with maintaining substation and transmission line projects. The information included seven substation and transmission line maintenance projects that operate at voltages above 200 kV and are ongoing or have been completed in the past ten years, all seven of which were located in the U.S., including two in California. Of the seven total projects, none included an HVDC component. Of the seven U.S. projects, none were underground projects. (Prior Projects and Experience Workbook)

SEGG indicated that its O&M contractor would be providing all maintenance services for the projects either directly or through additional subcontractors that it would hire. SEGG also indicated that it would have a service agreement with its HVDC supplier (M-1)

SEGG indicated that its O&M contractor experience with implementation and compliance with standards for inspection, maintenance, repair and replacement of similar facilities include proven programs and scalable processes (operations, management, inspection, maintenance and repair, compliance and subcontractor services) that enable successful O&M services on high-voltage transmission line segments associated with its O&M contractor-operated power plants. SEGG indicated that its O&M contractor's successful experience thus far with transmission and distribution system projects demonstrates that these core capabilities translate across various types of electric power projects. (M-6)

SEGG indicated that its O&M contractor would apply the same overarching strategic and tactical approaches when performing O&M services for this project that it has applied to the power generation facilities and transmission lines for which it has provided similar services. SEGG listed 21 generation projects totaling 6622 MW and approximately 55 miles of transmission lines for which its O&M contractor is currently responsible for O&M services. (M-6)

3.9.9 <u>ISO Comparative Analysis</u>

Comparative Analysis of Construction Record

For purposes of the comparative analysis for this component of the factor, the ISO has considered the representations by the project sponsors regarding the record and experience of both the project sponsor and its team members in constructing transmission projects, including substations, and how much of the experience of the project sponsor and its team is in the U.S. and in California. The ISO considers experience in the U.S. and California to be an advantage over transmission line and substation construction experience in other jurisdictions because the project will be located in California and there are special aspects of construction codes and regulations in the U.S. and California for which this experience is an advantage.

U.S. construction laws, rules, regulations, and processes are unique to the U.S., and California construction laws, rules, regulations, and processes are unique to the state of California. For example, the process that must be followed in California includes adherence to requirements of California OSHA, the California Air Resources Board, the California Office of Historic Preservation, Title 22 regarding hazardous waste, and city and county codes. U.S. laws, rules, regulations, and processes applicable to construction include federal OSHA, NEPA, Storm Water Pollution Prevention Plan, and U.S. Fish and Wildlife Service requirements, Fair Labor Standards Act regulations, and National Electric Code standards.

In the ISO's analysis for this component of the factor, the ISO additionally considered the combined experience of the project sponsor and its team constructing underground transmission facilities, because all project sponsors' proposals include an underground element, and experience constructing projects with an HVDC transmission component, because the project includes HVDC transmission elements.

Regarding its analysis of this component of the factor, the ISO considers the construction contractors identified by Avangrid, HWT, LSPGC, and SEGG as part of their teams to be highly qualified, experienced, and fully capable of handling the construction work associated with this project. Although the number of transmission facilities constructed varies among the proposed project sponsors' teams, all four project sponsors' teams have established experience in the construction of transmission line and substation projects. The proposals from Avangrid, HWT, and LSPGC identified specific underground electrical transmission line projects their teams had constructed, while SEGG did not indicate in its proposal any previous construction experience with underground electrical transmission lines. The proposals of Avangrid, HWT, and LSPGC also identified specific experience with HVDC transmission construction, while SEGG did not indicate in its proposal any HVDC construction experience for projects 200 kV or greater within the past ten years.[10] All proposals included projects in California.

Based on the foregoing considerations, and considering the specific nature and scope of the construction involved with this project, in conjunction with all the other considerations included in the ISO's analysis for this component of the factor, the ISO has determined that there is no material difference among the proposals of Avangrid, for its proposals 1 and 2, HWT, for its bay crossing and inland route proposals, and LSPGC, and they are better than the proposal of SEGG regarding this component of the factor, primarily because Avangrid, HWT, and LSPGC identified specific experience performing underground electrical transmission line construction and HVDC transmission construction, while SEGG did not.

Comparative Analysis of Maintenance Record

For purposes of the comparative analysis for this component of the factor, the ISO has considered the representations by the project sponsors regarding the record and experience of both the project sponsor and its team members in maintaining transmission projects, including but not limited to experience with compliance with NERC standards.

The ISO has determined that all of the project sponsors and their proposed teams have the basic capability to manage the maintenance of the project; however, the amount of past experience with extra high voltage (EHV) transmission facilities, underground transmission facilities, and HVDC transmission facilities varied among the project sponsors' proposed teams.

In particular, Avangrid, HWT, and LSPGC all indicated specific experience maintaining underground electrical transmission lines and HVDC transmission facilities and experience maintaining more transmission facilities than SEGG. The information provided by SEGG did not identify any specific maintenance experience with

[10] The ISO notes that although some project sponsors propose to use the same vendors or contractors, their applications in some cases list different experience numbers and projects for such vendors or contractors.

underground electrical transmission lines or HVDC facilities. Avangrid, HWT and LSPGC indicated that their teams have experience maintaining HVDC transmission facilities above 200 kV in the past ten years, while SEGG did not.[11]

Based on the foregoing considerations, in conjunction with all the other considerations included in the ISO's analysis for this component of the factor, the ISO has determined that, based on the specific scope of this project, there is no material difference among the proposals of Avangrid, for its proposals 1 and 2, HWT, for its bay crossing and inland route proposals, and LSPGC, and they are better than SEGG's proposal regarding this component of the factor.

Overall Comparative Analysis

The ISO considers the two components of this factor to be of roughly equal importance in the selection process for this project.

Regarding the first component of this factor (previous record regarding construction of transmission facilities), the ISO has determined that there is no material difference among Avangrid's proposals 1 and 2, HWT's bay crossing and inland route proposals, and LSPGC's proposal, and they are better than SEGG's proposal.

Regarding the second component of the factor (previous record regarding maintenance) the ISO has determined that there is no material difference among the proposals of Avangrid, for its proposals 1 and 2, HWT, for its bay crossing and inland route proposals, and LSPCG, and they are better than SEGG's proposal.

Based on the foregoing considerations, in conjunction with all the other considerations included in the ISO's analysis for this factor, the ISO has determined that, based on the specific scope of this project, there is no material difference among Avangrid's proposals 1 and 2, HWT's bay crossing and inland route proposals, and LSPGC's proposal, and they are better than SEGG's proposal regarding this factor overall.

3.10 Selection Factor 24.5.4(h): Adherence to Standardized Construction, Maintenance, and Operating Practices

The eighth selection factor is "demonstrated capability to adhere to standardized construction, maintenance and operating practices of the Project Sponsor and its team."

For the purpose of performing the comparative analysis for this factor, the ISO has initially considered the three components of this factor separately and then combined them into an overall comparative analysis for this factor. The three components are:
(1) demonstrated capability to adhere to standardized construction practices,
(2) demonstrated capability to adhere to standardized maintenance practices, and
(3) demonstrated capability to adhere to standardized operating practices.

[11] The ISO notes that although some project sponsors propose to use the same vendors or contractors, their applications in some cases list different experience numbers and projects for such vendors or contractors.

For the consideration of this factor, the ISO has determined that there is no significant difference between the two proposals submitted by Avangrid or between the two proposals submitted by HWT. Consequently, references to Avangrid and its proposal in this section apply equally to both Avangrid's proposal 1 and Avangrid's proposal 2, and references to HWT and its proposal in this section apply equally to both HWT's bay crossing proposal and HWT's inland route proposal.

Construction Practices

(P-5, S-1, T-1, C-1, C-2, C-3, C-4, C-5, C-6, C-7)

3.10.1 Information Provided by Avangrid for Proposals 1 and 2

Avangrid stated that it and its parent companies have extensive experience managing the construction of complex transmission projects (P-5)

Avangrid indicated that it would assemble a construction management team that would manage and monitor the work of all contractors, and would be responsible for the field management, execution, and monitoring of work progress and schedule, quality, health and safety. (C-1) Avangrid indicated that contractors would be responsible for obtaining property to establish laydown and storage yards, and once materials are received, they would be stored to ensure protection from the elements. (C-2) Avangrid indicated that it would work with its construction contractor to schedule any outages required. (C-3) Avangrid indicated that its project team would review drawing sets, technical specifications, and lists of materials and quantities to ensure the documents reflect the entirety of the project scope. Avangrid indicated that the constructability review would occur when the drawings and specifications are at a 90% design level and prior to being issued for bid. (C-4) Avangrid indicated that as the project is in an early stage of development, no easements, orders of possession, permits, or pre-construction permit mitigation measures are in place. (C-5)

Avangrid indicated that its schedule development would be based on: (1) past project experience, (2) utilization of subject matter experts for each division, and (3) input from the contractors and suppliers for the project. (C-6) Avangrid indicated that it would use conventional cut-and-cover trenching operations, as well as trenchless methods, such as horizontal directional drilling, splice chamber of precast concrete construction, and microtunnelling. (C-7)

3.10.2 Information Provided by HWT for Bay Crossing and Inland Route

HWT indicated that its capabilities managing the unique design requirements and correctly defining construction methods associated with transmission facilities would be leveraged from its experience (P-5)

HWT indicated that it would perform construction inspections addressing necessary inspections, witness points, confirmations, and verification of documentation and drawings. HWT indicated that it and each contractor would be responsible for daily and weekly inspection and construction quality control. (C-1) HWT indicated that the site civil contractor would establish material yards close to the converter stations, providing access to the converter stations and transmission line, and that each contractor would be responsible for scheduling and coordinating delivery of its equipment. (C-2) HWT indicated that it would develop an outage plan to establish a procedure required for outages, as well as the necessary steps to restore the equipment to service. (C-3) HWT indicated that it would coordinate design review that would encompass all aspects of the design, including single-line and three-line diagrams, general arrangements, material specifications, and construction specifications, and the project management team would be responsible for assuring that all project stakeholders have the most current version of documents and drawings. (C-4) HWT indicated that it would develop a consolidated environmental compliance matrix to provide a comprehensive list of all permitting requirements, conditions, and mitigation measures associated with the project. (C-5) HWT indicated that it has responsibility for the overall project schedule and has developed a preliminary project schedule that would meet the ISO's requirements for the project. (C-6) HWT indicated that for the construction of the underground transmission lines it would utilize common construction techniques including jack and bore and horizontal directional drilling. (C-7)

3.10.3 Information Provided by LSPGC

LSPGC indicated that its contractors have successfully completed multiple underground construction projects in California that involved crossings of existing utilities and buried infrastructure and have extensive experience constructing substations of similar scope to the project. (P-5)

LSPGC indicated that it has assembled a skilled and experienced team to complete and oversee construction activities for the project, develop a quality assurance and quality control plan that would detail the inspection program, and provide a detailed list of the items to be inspected. (C-1) LSPGC indicated that it would directly purchase the major material for the DC terminals, major equipment, the cable, splices and termination hardware, and underground construction materials. LSPGC indicated that subcontractors would use inventory management programs to track the receipt, location within the material yards, and delivery of all materials for construction. (C-2) LSPGC indicated that its preliminary design for the project incorporates clearance requirements and crossing techniques to cross underneath the existing underground and overhead transmission lines and that it would coordinate with the line owner. (C-3) LSPGC indicated that the design documents and construction specifications would be reviewed by LSPGC and its engineering contractor and that an independent review would be completed by the LSPGC directors. LSPGC indicated that any changes would require review and approval by the LSPGC team. (C-4) LSPGC indicated that it would maintain a comprehensive master project schedule that would incorporate all project tasks, and that schedules would be reviewed during the kick-off, weekly, and monthly meetings. (C-6) LSPGC indicated that the project would require trenchless construction of underground cable, a special construction technique, in locations where typical duct bank construction cannot be implemented. LSPGC also indicated that the preferred route for the project would require six trenchless cable installations consisting of one jack and bore for a railroad crossing and five horizontal directional drilling sites along water ways and provided a detailed description of the jack and bore procedure. (C-7)

3.10.4 Information Provided by SEGG

SEGG indicated that its quality control manager would conduct daily field inspections of the construction operations, including those by subcontractors, and would perform tests on materials for self-performed work. SEGG indicated that soil and concrete testing would be performed by a third-party vendor and that it would perform factory and on-site visual inspections of the equipment and materials. (C-1) SEGG indicated that an area co-located within the converter station would be utilized for material staging and temporary contractor offices, and that a manufacturing schedule would be issued each week listing current information on materials processed, the delivery schedule, and the schedule for remaining items. (C-2) SEGG indicated that it would coordinate with the ISO and PG&E regarding all outages or crossings. (C-3) SEGG indicated that the construction, environmental, and land teams would participate in the engineering design reviews at the 30, 60, and 90 percent and issued for construction design milestones. (C-4) SEGG indicated that it has not executed any easements, permits, or agreements. (C-5) SEGG indicated that it would use the pre-construction phase to build up the schedule with the full complement of activities for each segment and would be updated and provided to ISO on a monthly basis. SEGG indicated that each week, a three week look ahead schedule would be updated. (C-6) SEGG indicated that it has a goal to keep as much of the scope of construction as conventional as possible. (C-7)

Maintenance Practices

(CC-3, CC-5, M-1 through M-10)

3.10.5 <u>Information Provided by Avangrid for Proposals 1 and 2</u>

Avangrid indicated that it would lead the maintenance activities for the project through a combination of in-house maintenance personnel and contractors, with operations performed by its operations contractor. Avangrid indicated that it has selected a contractor to perform maintenance of the transmission lines of the project, as well as specific converter station maintenance activities. Avangrid indicated that the converter station maintenance would be executed by a combination of its original equipment manufacturer (OEM), maintenance contractor, and itself in a two-stage approach, with adjustments made to the structure of the project’s maintenance organization at the beginning of year six of the project’s commercial operation. Avangrid indicated that this maintenance approach is based on the services offered by its converter station OEM for converter station maintenance. (M-1)

Avangrid indicated that, as the entity responsible for maintenance execution, its O&M contractor would be responsible for hiring the project manager who would perform and oversee maintenance activities for the project, as well as the five direct reports to the project manager.

Avangrid indicated that its O&M contractor’s project manager would be responsible for directing all operations and maintenance activities at the facility and assuring that the facility is operated in compliance with applicable safety, environmental, and power grid requirements. Avangrid indicated that the project manager position would require a technical degree or equivalent work experience, ten years of high voltage transmission or substation maintenance experience or similar experience and at least three years of supervising technical, supervisory and administrative personnel. Avangrid also indicated that previous experience in HVDC operations and maintenance would be a considerable advantage for the project manager for this project but would not be required given the limited number of these types of facilities in the U.S.

Avangrid indicated that additional requirements for the position would include experience preparing budgets, knowledge of transmission line and substation operations and maintenance, compliance with safety policies and procedures, compliance awareness

(NERC and environmental requirements), outage management experience, strong team leadership skills, and strong verbal and written communications skills.

Avangrid indicated that its project manager would incorporate a team composed of field operations specialists, both for primary plant and control, with all necessary authorizations to safely operate and maintain the system. Avangrid indicated that apprentices would also be regularly included in the team to ensure development of skills and capabilities.

Avangrid indicated that tasks not directly performed by the project team would be subcontracted to its OEM and maintenance contractor or another entity as appropriate. Avangrid indicated that when hiring contractors, it would enter into a contracting qualification process that would include both a technical and safety evaluation to determine if the contractor is qualified to perform the work.

Avangrid indicated that in order to ensure individuals performing work for the project are qualified, it intends to hire union qualified electrical workers to perform work. Avangrid indicated that the individuals provided by the union would be assessed via work history review prior to beginning work, would complete a comprehensive apprenticeship program, and would be evaluated on a daily basis in the field by operations management and safety departments.

Avangrid indicated that the dedicated OEM maintenance personnel deployed at the HVDC converter stations would have both a broad understanding of HVDC technology as well as important local knowledge of the system, enabling them to rapidly diagnose and rectify any issues. (M-2)

Avangrid indicated that its OEM O&M team would provide all necessary personnel required to ensure competence of operating and maintaining the system during the warranty period as well as necessary activities required under the O&M services contract. Avangrid provided an overview of its OEM training plan for converter station operations and maintenance personnel.

Avangrid indicated that as part of the engineering, procurement, and construction contractual obligation and scope of supply, its OEM would provide training for its operations contractor personnel, Avangrid's key personnel, and maintenance contractor personnel prior to the start of operation of the project. Avangrid provided a list of topics to be covered in the training.

Avangrid indicated that its OEM would provide a training program to effectively train Avangrid's operations and maintenance staff for the operation and configuration of the entire HVDC converter stations and also for future maintenance needs. Avangrid indicated that the training programs would include classroom instructions on VSC converters, HVDC transformers, control and protection, cooling system, and other converter station equipment.

Avangrid indicated that it plans to utilize an apprentice program for converter station maintenance personnel to ensure continuity in the converter station maintenance workforce in light of anticipated personnel turnover throughout the 50-year life of the converter station.

Avangrid indicated that maintenance contractor employees working on the project would be required to complete the prescribed training and service program in addition to those required, if applicable, by the apprenticeship program prior to performing more sophisticated and technical jobs. (M-3)

Avangrid indicated that it would leverage its experience owning, operating, and maintaining both overhead and underground transmission lines in the service territories of its electric utility subsidiaries in the Northeast to develop and execute a maintenance plan that is compliant with the requirements listed in Section 5.2.2 of the ISO Transmission Control Agreement (TCA) as well as all other applicable standards and regulations. Avangrid indicated that it owns and operates eight regulated utilities in the Northeast, with four electric utilities in both ISO-New England and New York ISO territories. Avangrid indicated that it owns, operates, and maintains 8,613 miles of transmission lines, 819 substations, 63,058 miles of overhead distribution lines, and 8,415 miles of underground distribution lines through these four regulated electric utilities in the United States.

Avangrid indicated that its standard operating procedures for the maintenance of electrical equipment adequately address the elements listed in TCA Appendix C Sections 5.2.1 (transmission line circuit maintenance) and 5.2.2 (station maintenance), including transmission line patrol and inspection, maintenance of underground transmission lines, right-of-way maintenance, and the maintenance of all major equipment and attributes of stations.

Avangrid described its plans and procedures for the prevention of HVDC transmission line faults and DC line insulator maintenance. (M-4)

Avangrid indicated that it is worth noting that the underground portions of the proposed transmission line route for the project would not require vegetation management and that the majority of the overhead portion of the proposed transmission line route would be in an urban setting and would require relatively minimal vegetation management compared to the overhead lines Avangrid owns and operates in densely forested areas through its electric utility subsidiaries.

Avangrid indicated that it has selected its O&M contractor to perform vegetation management within the project rights-of-way and in access and service roads.

Avangrid indicated that it prefers to employ the services of its maintenance contractor for maintenance of the transmission lines for the project, including vegetation management within the project rights-of-way, but would employ other contractors as prudent for the benefit of ratepayers. Avangrid indicated that it and its selected contractor for the maintenance of the transmission lines for the project would work together to develop a comprehensive integrated vegetation management plan to minimize interference with the flow of electricity, to proactively address potential safety issues, and to facilitate O&M activities. Avangrid indicated that the project's vegetation management program would comply with the National Electric Safety Code, ANSI A300 Part 7: American Operations Integrated Vegetation Management and Electric Utility Rights-of-Way, and the International Society of Arboriculture best management practices. Avangrid indicated that, additionally, the project would comply with vegetation management standards required by the NERC and WECC vegetation management guidelines, FAC-003, and that failure to comply with these requirements can result in substantial financial penalties. Avangrid indicated that its O&M contractors' policy document ensures compliance with this standard.

Avangrid indicated that objectives of integrated vegetation management on utility rights-of-way are to establish sustainable plant communities that are compatible with the electric facilities. Avangrid indicated that the vegetation management plan has a series of control methods used to achieve the aforementioned objectives and listed those control methods. (M-5)

Avangrid indicated that each of Avangrid's four electric utility subsidiaries in the Northeast undergoes regular operations and planning compliance audits by the Northeast Power Coordinating Council. Avangrid indicated that Maine Electric Power Company, a joint venture between Avangrid and Versant Power that owns and operates a 182-mile 345 kV transmission line connecting Maine to New Brunswick, is also subject to these regular audits. Avangrid indicated that the audits primarily focus on compliance with standards associated with operations, but also investigate vegetation management as well as maintenance and testing of protection and control systems. Avangrid indicated that all of Avangrid's subsidiaries subject to these audits were found to be in compliance with all applicable reliability standards with zero areas of concern and zero recommendations during their most recent audits. Avangrid provided copies of several audits.

Avangrid indicated that in terms of HVDC system maintenance and compliance practices, Avangrid has the support of its ultimate parent company, Iberdrola, including Iberdrola's global HVDC organization, and in particular, its sister company within the Iberdrola group, SP Transmission, which operates and maintains the 2.2 GW Western HVDC Link system in the United Kingdom. Avangrid provided information regarding an inspection and maintenance plan and an audit report for that HVDC system. (M-6)

Avangrid indicated that its O&M contractor regularly reports on availability measures for its clients and that its current system, GenSuite, is capable of capturing the necessary information to report on availability measures as described in TCA Appendix C, Section 4.3. Avangrid indicated that in accordance with Section 4.3, its O&M contractor would generate and submit to Avangrid, or others as necessary, an annual report, which would be transmitted to the ISO within 90 days of the end of the calendar year. Avangrid indicated that the report would describe the project's availability measures performance which would include all forced outage records including the date, start time, end time, affected transmission facility and the problem cause of the outage. Avangrid indicated that this data is tracked utilizing its operations contractor's data historian, utilizing a capture rate of two- to six-second intervals. (M-7)

Avangrid indicated that it does not anticipate any major changes or exceptions to the TCA to integrate the project into the ISO controlled grid but reserves the right to raise items for discussion with the ISO regarding the TCA at the time of final contract execution. (M-8)

Avangrid indicated that, generally speaking, its operations contractor would coordinate communication of necessary outage information to each applicable party, including the ISO, adjacent transmission owners and transmission operators, and non-participating generators through the ISO outage management system or other communication channels, such as phone calls if necessary. Avangrid provided information describing specifically how the project would comply with the requirements of TCA Section 7. (M-9)

Avangrid indicated that its O&M team would be composed of an O&M manager, two primary plant authorized maintenance personnel, two authorized control systems personnel, and one apprentice, and would be based in one of the project's converter stations during normal business hours. Avangrid indicated that this would constitute the center of operations for all maintenance activities for the transmission lines and converter stations.

Avangrid indicated that the OEM maintenance team that would be performing maintenance activities for the converter stations for the first five years of the project's operations would be located in the vicinity of the project in the San Jose area, which would minimize the response time for any emergency work or corrective maintenance during this time. Avangrid indicated that this maintenance team would have access to remote 24/7 technical support from the OEM's regional team in the U.S. and globally from its OEM's worldwide team, as necessary. Avangrid indicated that additional OEM maintenance personnel responsible for conducting annual scheduled off-line maintenance during and after this five-year warranty maintenance period would be located offsite and would be brought to the project site annually for approximately one to two weeks of scheduled off-line maintenance.

Avangrid indicated that its maintenance contractor's maintenance personnel would be located within reasonable distance of the project at its offices in Vacaville, which would ensure an estimated response time of four hours to conduct emergency maintenance or restoration work as needed. Avangrid indicated that if alternative contractors are selected for emergency response services and for the maintenance of the transmission lines for the project, it would ensure that they are located in the vicinity of the project location in the San Jose area. Avangrid indicated that it would seek to contractually ensure required response times with its maintenance contractor, or alternative emergency response providers at the time that the service contract is negotiated, prior to the project's in-service date. (M-10)

3.10.6 <u>Information Provided by HWT for Bay Crossing and Inland Route</u>

HWT provided maintenance information related to the following:

- VSC-HVDC converter equipment
- AC substation equipment
- Protection system - NERC PRC-005 compliance
- Transmission line, cable, right of way, and vegetation maintenance
- Environmental and wildfire

HWT indicated that the project would leverage existing real-time monitoring tools (protection systems) to detect impending problems immediately. HWT indicated that the protection systems would monitor phase currents, circuit breaker auxiliary contacts, and the substation DC battery voltage, and compare it with data from the manufacturer and notify the maintenance team when a set of parameters exceeds preset thresholds. HWT also indicated that the real time monitoring information together with results from annual substation condition assessments and routine infrared inspections would be used to optimize the scheduling of de-energized, invasive maintenance tasks.

For transformer monitoring, HWT indicated that it would leverage the NextEra existing suite of monitoring methods optimized by FPL.

HWT provided a list of VSC HVDC converter maintenance activities, along with their frequencies. HWT also provided the frequency of protection system maintenance and vegetation management activities.

HWT indicated that during the operational phase, the project's field maintenance lead would manage all environmental and wildfire plan obligations, including the requirements of local governments, county, state, and federal agencies, and other authorities. HWT indicated that it would compile and maintain these plans and submit them annually to the relevant agencies for review. (CC-3)

HWT indicated that the project's maintenance operations would be undertaken for HWT by its NextEra affiliate TBC. HWT indicated that the TBC VSC HVDC maintenance team is an in-house owner-operator staff, based in the San Francisco Bay Area, with experience, tools, and capability to attend to all matters pertaining to VSC HVDC system maintenance and repair. HWT indicated that the team's experience and capability ensure it does not rely on expensive annual maintenance agreements with HVDC's OEM. HWT indicated that the maintenance base would be at the project's Newark VSC location and supported by the existing TBC VSC HVDC team from its facility in Pittsburg. HWT indicated that undertaking the project maintenance by an existing ISO PTO and California based team bolsters HWT operational consistency and alignment with the operational jurisdictions, agencies, and authorities in the state. HWT indicated that TBC has a strong track record of maintaining VSC HVDC transmission assets in accordance with the ISO maintenance procedures and the interconnection protocols of Bay Area utilities, including PG&E, for almost 12 years.

HWT provided information on its proposed maintenance organization and its roles, responsibilities, and coordination with stakeholders. The information provided included maintenance management, compliance oversight, technical support, training, and field technicians.

HWT described the functional structure and reporting relationship of the maintenance organization and the jurisdictions as they relate to the project. HWT provided resumes of its team members. (CC-5, M-1)

HWT indicated that it and its operating affiliate TBC follow established human resources policies, processes, and procedures to assure that only persons who are appropriately qualified, skilled, and experienced in their respective trades or occupations are employed in maintenance functions. HWT indicated that it uses a state-of-the-art online recruiting program that compares skills, experience, education, and preferences with job openings companywide. HWT indicated that successful applicants for transmission and substation positions must meet minimum requirements and demonstrate the necessary experience for a given position as determined by HWT. HWT indicated that in addition to basic entry qualifications and experience, HWT and its affiliates require all personnel to undertake company compliance and ethics training, along with specialized training dependent on job role and responsibilities.

HWT described the qualifications, certifications, and experience requirements for the project maintenance personnel. HWT indicated that maintenance team members all maintain certification to perform all high voltage switching and clearance activities. HWT described its continuous switching training.

HWT indicated that to ensure the project sponsor's VSC HVDC maintenance staff would be qualified, skilled, and experienced to undertake maintenance, staff would be required to pass specific tests and be interviewed in all areas by the TBC operations manager. HWT indicated that this would come after completing the formal series of VSC HVDC training modules.

HWT also provided information on vegetation maintenance personnel qualifications, maintenance support vendor personnel qualifications, and transmission lineman experience, qualifications, and expertise.

HWT indicated that to assure that contractors' employees are appropriately qualified, skilled, and experienced in their respective trades or occupations, HWT evaluation of a contractor's quality, environmental, health and safety, and training programs' past performance would involve an assessment process to determine the current state of elements of these programs. HWT provided a copy of the contractor questionnaire used in the evaluation process. (M-2)

HWT indicated that it has a rigorous system maintenance personnel training program and continuous education requirements. HWT indicated that delivery method options for training include classroom training, self-study, field trips, observation in the TBC control center, and simulator scenarios.

HWT indicated that the HWT training coordinator would be responsible for the operations and maintenance personnel training programs, including providing and delivering classes and modules for the field maintenance personnel. HWT indicated that the training coordinator's qualifications would include:

- NERC-certified reliability coordinator certification
- 25+ years' experience in the electrical utility industry; transmission, distribution, and market operations; and
- Member of NERC reliability coordinator operations working groups.

HWT indicated that to facilitate this training, NextEra Energy University, NextEra's continuing education department, offers an array of business and technical courses specifically selected to meet the changing demands of the business environment and the needs of all employees.

HWT indicated that the O&M staff training program would consist of the following general categories:

- Core training,
- NERC compliance,
- Safety, and
- Environmental.

HWT provided a list describing training courses required by the HWT maintenance personnel responsible for substation maintenance, switching, protection and control, entry level, and transmission lines. (M-3)

HWT indicated that the project sponsor's training program for VSC HVDC maintenance staff would include online and hands-on training to ensure staff reach and maintain the qualified skills and experience to undertake maintenance. HWT indicated that VSC HVDC maintenance staff would be required to pass specific tests and be interviewed in all areas by the TBC operations manager.

HWT provided details of the individual VSC HVDC training tasks.

HWT indicated that the maintenance staff would have access to the TBC training lab, which includes a complete submodule training tower set-up on which its team would practice replacing sub-module capacitors and power modules. HWT indicated that the training lab would also provide the team with tools to examine bypassed or failed modules to support OEM root cause analyses. (M-3)

HWT indicated that the following representations by HWT demonstrate that HWT would have the capability and experience to comply with TCA Appendix C and the ISO transmission maintenance procedures.

- HWT and its project operator, TBC, are both ISO PTOs.
- HWT and TBC have transmission line circuit and substation maintenance practices that are consistent with ISO transmission maintenance standards, and each has been approved by the ISO.
- HWT and TBC maintenance practices address substations, underground cable, VSC HVDC facilities, and flexible AC transmission systems. The project's substation maintenance would be based on the existing ISO approved VSC HVDC facility maintenance practices utilized by TBC. HWT indicated that cable maintenance would be based on the existing ISO approved maintenance practices of HWT and TBC. HWT provided copies of those practices.
- All the elements listed in TCA Appendix C, Sections 5.2.1 (transmission line circuit maintenance) and 5.2.2 (station maintenance) are addressed in HWT and TBC maintenance practices except for overhead line elements. Neither HWT's nor TBC's facilities currently utilize overhead line elements. These would be added to the HWT line maintenance practices and implemented by the project's maintenance team.
- HWT would amend its maintenance practices in accordance with ISO maintenance standards to include new substation and transmission line elements relating to the project.
- For more than ten years for TBC and more recently for HWT, both have demonstrated adherence to TCA Appendix C transmission maintenance standards and have been assessed annually by the ISO grid assets team, consistent with ISO maintenance procedures.
- Representatives of HWT and TBC have been regular participants at the ISO transmission maintenance coordinating committee. HWT and TBC equipment maintenance practices address substations, transmission lines, HVDC facilities, and flexible AC transmission systems.
- For more than ten years, TBC and more recently HWT have demonstrated the effectiveness of their maintenance practices gauged through the ISO's

availability monitoring systems. This includes adherence to TCA Appendix C, consistent with ISO maintenance procedures.

HWT indicated that it and its affiliates bring further significant O&M capabilities pursuant to the representations by HWT below:

- HWT and its affiliates' existing O&M organization is responsible for power lines up to 500 kV across all NERC jurisdictions in the United States. These facilities are operated and maintained in compliance with NERC Transmission Owner and Transmission Operator standard requirements. The existing NextEra O&M organization has a program of maintenance standards providing the capability to manage compliance with the provisions of the TCA and the ISO transmission maintenance standards.
- HWT and its affiliates have well-established practices and procedures for transmission system operations and maintenance of its transmission and substation facilities, which are derived from FPL's O&M practices.
- HWT's field maintenance team members have experience maintaining substations and lines up to 500 kV, and varying equipment types, including VSC HVDC facilities, SVCs, STATCOMs, MSCs, series compensators, and synchronous condensers.
- Well-established O&M practices and standardized processes are already being used across NextEra's transmission and substation fleet operating EHV transmission facilities.
- HWT has access to over 700 power system professionals, including technicians and other staff, with expertise in all aspects of transmission and substation equipment installation, maintenance, and repair.
- HWT and its affiliates have experience operating and maintaining power delivery assets in all NERC jurisdictions at voltages up to 500 kV.

HWT described its plans and procedures for the prevention of HVDC transmission line faults and DC transmission line insulator maintenance. (M-4)

HWT indicated that vegetation and line patrols would occur twice a year, in the spring and fall. HWT indicated that ahead of severe storms and fire season, the HWT field operations lead would make plans to engage the necessary inspection resources to evaluate the status of the transmission line and route once the storm or fire event has passed. HWT indicated that the method of transmission line and vegetation patrol would include aerial inspection and ground patrol and that the tools to support the patrol would include infrared, high-resolution photography, LiDAR, and unmanned aircraft systems and drones.

HWT indicated that NextEra has been managing vegetation around its power lines since December of 1925 and that NextEra is currently managing around 80,000 miles of transmission, distribution, and gen-tie lines across North America. HWT indicated that the proposed project would be added to the existing NextEra vegetation management program.

HWT indicated that both external contractors and internal vegetation management personnel would be utilized to execute vegetation management work. HWT indicated that a large majority of the work would be bid out or assigned to vendors after receiving "not to exceed" quotes. HWT indicated that for the proposed project tree trimming and mowing work would be added to NextEra's existing contract with both vendors.

HWT described the vegetation management duties and responsibilities for the internal team.

HWT indicated policies and procedures for periodic vegetation management are found in the vegetation management operations manual, a copy of which it provided. (M-5)

HWT indicated that it and its affiliates' transmission businesses have well-established, reasonable practices and procedures for complying with standards of maintenance, inspection, repair, and replacement of its facilities as evidenced by the following processes HWT indicated it already has in place:

- The HWT project operator, its affiliate TBC, has more than ten years of operational experience in accordance with the ISO maintenance procedures: standard maintenance reporting; ISO maintenance review; and preparing, submitting, and amending maintenance practices;
- Annual maintenance audit reports of HWT and TBC maintenance practices by the ISO;
- Reporting amendments to TBC maintenance practices;
- HWT and TBC experience reporting actual and planned maintenance data in accordance with the ISO standard maintenance reporting system for the period 2011 to 2022;
- Experience creating and reporting wildfire mitigation plans for HWT and TBC; and
- HWT and TBC annual SF6 status reporting to the state of California.

HWT indicated that it follows the above procedures and guidelines to assure that component parts and equipment are installed, inspected, and tested in strict accordance with applicable reliability requirements, plans, procedures, specifications, standards, and codes and that support vendors are required to have their own quality plans and controls. (M-6)

HWT indicated that its proposed project operator, TBC, has for more than ten years provided the ISO with availability measures in accordance with TCA Appendix C, Section 4.3 and the ISO maintenance procedures.

HWT indicated that it would utilize the TBC procedure that describes how it would track operational performance and availability of facilities to adequately report the facilities' performance to the ISO and other stakeholders. HWT provided a copy of this procedure.

HWT indicated that it utilizes its affiliate FPL's power delivery assurance procedures and processes that provide guidance on how to document unplanned events whether initiated by the transmission line facilities (*e.g.*, lighting outage) or initiated by the interconnecting utilities' equipment (*e.g.,* substation breaker failure). HWT indicated that these processes support HWT's facility reporting obligations, which are documented in internal procedures, reviewed on a routine basis, and form part of its procedure refresher programs. HWT indicated that the reporting criteria used by it and its affiliates aligns with the current availability reporting obligations indicated in TCA Appendix C, Section 4.3 for forced outages. (M-7)

HWT indicated that adding the project to the ISO controlled grid is not expected to require any changes or exceptions to the provisions of the TCA. (M-8)

HWT indicated that it and its affiliate TBC, the project operator, are both ISO PTOs operating in accordance with TCA Section 7. HWT indicated that for TCA Section 7.1: reporting and audits, HWT and TBC each annually submit scheduled maintenance reports and availability reports and have successfully passed the ISO's annual maintenance audits.

HWT indicated that neither HWT nor TBC exercises any contractual rights in accordance with TCA Section 7.2. (M-9)

HWT indicated that the project sponsor's maintenance team would consist of three dedicated field maintenance personnel located in the vicinity of the project and supported by the existing TBC maintenance team already based in Pittsburg.

HWT indicated that it and its affiliates have a team of approximately 150 technical staff in California and that almost a quarter of this team are about an hour's drive from the project. HWT indicated that the project's proposed maintenance team has seven trained VSC HVDC maintenance staff already based in Pittsburg., within an hour's drive from the project. HWT indicated that three new VSC HVDC maintenance staff would be added to this team, dedicated to the project VSC HVDC maintenance and field operations tasks, with two based at the project's VSC HVDC facilities. HWT indicated that, in total, the project would have a team of ten VSC HVDC maintenance, repair, and operations staff, supported by a further 23 NextEra technical staff based at NextEra's Livermore facility, a 45 minute drive from the proposed project.

HWT indicated that it and its affiliates have approximately 150 technical staff in California. HWT indicated that all have access to all the specialized tools, resources, and equipment needed to successfully perform and support maintenance and inspection and respond to any emergency repairs on a 24/7 basis.

HWT indicated that the project's field operations leader, supported by the project's lead high voltage technician, would have full responsibility for leading on all matters pertaining to maintenance at the project facilities and that HWT and its affiliates have support service arrangements with several vendors for specialized services, including substation and transmission line maintenance, inspection, and emergency support. HWT indicated that for new projects, HWT's preferred arrangement is to use its affiliate's in-house VSC HVDC maintenance team, which includes personnel who have the capability and experience to perform all of the project's maintenance. HWT indicated that it would put in place selective support contracts with the contractors used to construct the project.

HWT indicated that an example of OEM strategic support agreements is HWT's agreements with two large multi-national OEM companies that maintain a complete staff of trained field engineers and technicians who are available to provide advisory assistance, installation, inspection, commissioning, testing, troubleshooting, start up, engineering studies, and maintenance and repair services of electrical apparatus. HWT provided copies of negotiated field service agreements with these two companies.

HWT indicated that it has engaged a contractor based in the project area and that contractor has provided a letter offering substation and transmission line maintenance, inspection, and emergency support services. (M-10)

3.10.7 Information Provided by LSPGC

LSPGC indicated that maintenance activities would be performed by LS Power through a combination of internal resources and outside contractors. LSPGC indicated that it would contract with LS Power through an affiliate service agreement and reimburse LS Power based on its actual costs to operate and maintain the project. LSPGC further indicated that LS Power is able to provide operations and maintenance services for the project primarily utilizing its existing personnel and equipment providing significant efficiencies.

LSPGC provided a list of maintenance activities and their frequency.

LSPGC indicated that it would contract for specialized maintenance services conducted on an as needed or periodic basis such as emergency response, vegetative management, helicopter services, specialized divers, or equipment inspection and testing.

LSPGC indicated that LS Power would be responsible for completing all maintenance activities for the project and that internal personnel would perform planned and routine inspection and maintenance activities and third-party contractors would be utilized for unplanned, larger scope, or specialized maintenance activities. LSPGC indicated that at all times LS Power personnel would be onsite to manage and oversee all maintenance activities performed by contractors.

LSPGC indicated that LS Power would hire one technician to be located in close proximity to the project to perform routine substation maintenance and inspections, transmission line inspections, perform minor repairs, and oversee the outside contractors for the project. LSPGC indicated that LS Power would also have at least two technicians located in California to support maintenance of the Orchard STATCOM and Fern Road GIS/STATCOM projects that would be leveraged to support the project. LSPGC indicated that the California-based technicians would be supported by the existing LS Power maintenance staff located in Texas as well as asset management and engineering staff located in Texas and Missouri. LSPGC provided an organization chart showing the individuals within LS Power directly responsible for managing maintenance of the project.

LSPGC indicated that it would contract with its OEM to conduct annual maintenance, support forced outage response, complete major facility rebuilds for the HVDC converters, and provide technical support during emergency response events. In addition, LS Power indicated that it has identified three additional contractors to support forced outage response, perform emergency repair, and complete major facility rebuilds of the project facilities. LSPGC listed the three additional contractors.

LSPGC indicated that its OEM would serve as the primary contractor for large scale maintenance tasks for the HVDC terminals.

LSPGC indicated that first of its three additional contractors would serve as the primary emergency response and maintenance contractor for the project's HVDC terminals. LSPGC indicated that this contractor has over 200 qualified employees at three California offices, including project coordinators, safety personnel, foremen, linemen, electricians, and operators. LSPGC provided a copy of an executed emergency response and field service agreement with its emergency response contractor and a summary of its tools, vehicles, and equipment.

LSPGC indicated that the second of its three additional contractors would serve as the primary emergency response and maintenance contractor for the underground transmission lines. LSPGC indicated that this contractor's affiliates are highly qualified in underground construction and have considerable resources available in the region capable of providing emergency response and maintenance services for the project.

LSPGC indicated that the third of its three additional contractors would serve as the secondary emergency response and maintenance contractor for the project. LSPGC indicated that this contractor has three California offices, two in Rancho Cordova and one in Murrieta. LSPGC provided a summary of the secondary emergency response contractor's local staff, tools, vehicles, and equipment and a copy of an executed emergency response and field service agreement. (CC-5, M-1)

LSPGC indicated that LS Power employs staff with prior demonstrated qualifications, skills, and experience necessary to maintain its assets.

LSPGC indicated that LS Power would require maintenance position applicants to possess:

- Completion of a technical or vocational training program as a technician, relay technician, or lineman;
- Five to ten years of relevant experience with an electrical utility, utility contractor, or testing services contractor;
- Superior knowledge and understanding of maintenance work performed by contract personnel involving substation equipment (including transformers, circuit breakers and switches) and/or transmission lines (overhead and underground);
- A basic understanding of protective relaying, communication, metering, and SCADA systems;
- Familiarity with specialized technical software and test equipment utilized for maintenance activities;
- Completion of training programs for qualified electrical workers including OSHA safety training; and
- LSPGC indicated that references are checked to confirm past work history and performance, and employee background checks are conducted.

LSPGC indicated that LS Power requires all contractor personnel to be duly qualified, licensed, trained, and experienced to perform maintenance and/or emergency response activities on its facilities. LSPGC indicated that contractors are responsible for training their employees to perform the anticipated activities with LS Power providing information specific to the project. LSPGC indicated that LS Power assesses all contractors to ensure their personnel have the appropriate training and expertise for the work before authorizing any work order and that contractors are required to perform a pre-task analysis and have developed a job briefing checklist prior to performing work.

LSPGC indicated that LS Power's contractor selection methods include:

- Evaluating the contractor's expertise, past experience, staff and equipment detailed in resumes, proposals, and statement of qualifications;
- Understanding past and current experience working with the contractor and its staff;
- Soliciting industry referrals; and
- Reviewing the contractor's safety record.

LSPGC indicated that LS Power maintains a substation access procedure (copy provided) to ensure only qualified and trained personnel have access to LS Power transmission facilities. LSPGC indicated that only authorized, qualified, and trained personnel may enter a LS Power substation or control house without an escort. LSPGC indicated that NERC Critical Infrastructure Protection (CIP) security awareness training, a background check, and approval are also required for substations containing NERC CIP medium impact cyber assets. LSPGC indicated that to facilitate this procedure, LS Power maintains lists of qualified personnel, including individual contractor staff, allowed station access. (M-2)

LSPGC indicated that LS Power utilizes internal and external training courses to ensure it has qualified, skilled, and experienced field maintenance personnel and that internal employee orientation training is performed upon hire. LSPGC indicated that this new employee training includes, but is not limited to, topics such as: emergency action plans, fall protection, hazard communications, CIP, code of conduct, and switching. LSPGC indicated that further training is provided based on job classification and that annual evaluations of the training program are completed to identify continuous improvements.

LSPGC indicated that LS Power uses quality training database to build training plans, track initial and ongoing training, and track reliability related tasks to ensure all members of LS Power's operations group are fully trained.

LSPGC indicated that LS Power substation maintenance personnel have obtained or are pursuing substation maintenance technician certification through a well-known training institute. LSPGC indicated that LS Power substation maintenance personnel must obtain substation maintenance technician certification within three years of hire.

LSPGC indicated that LS Power maintenance personnel must also perform continuing education in order to maintain their substation maintenance technician certification. LSPGC indicated that LS Power's technicians would receive training from the OEM at a remote HVDC station through side-by-side instruction with trained and certified technicians prior to LS Power energizing the project. LSPGC indicated that after assuming operations, LS Power would integrate HVDC technology into continuing education requirements for technicians.

LSPGC indicated that LS Power has an approved apprenticeship program with the Department of Labor that is recommended for transmission line technicians. LSPGC indicated that technicians are trained in LS Power's iOS-based think power solutions transmission line maintenance tool and the computerized maintenance management system (CMMS or Maximo). LSPGC indicated that technicians also complete annual continuing education on maintenance procedures, inspection practices, NERC requirements, and current construction practices.

LSPGC indicated that maintenance personnel may be required to perform switching and that LS Power uses the International Electrical Testing Association standard for certification of electrical testing technicians to establish minimum requirements for qualification to perform switching. LSPGC indicated that an individual must be a level 3 certified technician to be considered by LS Power to perform switching and that this includes at least five years of full-time experience in the electrical testing industry; 72 hours of safety training; 400 hours of training in electrical testing, component testing, or systems and commissioning; and passing a level 3 examination. LSPGC indicated that in addition, a qualified switchman must have sufficient knowledge of the equipment and complete training specific to LS Power procedures for switching procedures, lockout/tagout, etc.

LSPGC indicated that all vegetation management personnel are required to complete and maintain annual training necessary to be certified vegetation management technicians. LSPGC indicated that this would include training specific to the project such as environmental issues impacting the right-of-way, landowner considerations, and compliance with applicable ISO and NERC standards and requirements.

LSPGC indicated that all LS Power field personnel receive continual safety training throughout the year which in addition to typical OSHA, fall protection, personal protective equipment, and first aid training requirements, field personnel complete transmission specific safety training covering items like induced current, grounding, clearance procedures, and transmission specific equipment.

LSPGC indicated that LS Power's environmental training program includes required initial and annual training to ensure awareness of and compliance with all applicable environmental laws and regulations. LSPGC indicated that training is performed by LS Power environmental staff. (M-3)

LSPGC indicated that it would comply with the provisions of TCA Appendix C Sections 5.2.1 and 5.2.2 through its existing maintenance policies and procedures and by leveraging the experience of its affiliate, DesertLink. LSPGC indicated that DesertLink currently complies with the provisions of TCA Appendix C Sections 5.2.1 and 5.2.2 and that DesertLink's transmission maintenance and inspection plan (copy provided) was approved by ISO in 2020.

LSPGC indicated that the project would be incorporated into LS Power's existing maintenance policies and procedures that are successfully utilized for maintaining highly reliable transmission systems across the country. LSPGC indicated that the maintenance policies and procedures include the elements listed in TCA Appendix C Sections 5.2.1 and 5.2.2.

LSPGC indicated that LS Power's transmission maintenance plan, protection system maintenance program, and HVDC-specific maintenance plan developed based on OEM recommendations address the elements listed in TCA Appendix C Sections 5.2.1 and 5.2.2 (copies provided). LSPGC indicated that LS Power's plans contains specific maintenance and testing procedures for applicable protection system component types in compliance with NERC standard PRC-005-6, as well as internal LS Power standards related to system protection. LSPGC indicated that LS Power utilizes Maximo to produce notices and work orders to complete each task.

LSPGC described its plans and procedures for the prevention of HVDC line faults and DC line insulator maintenance.

LSPGC indicated that LS Power would incorporate the project into its maintenance plans (including HVDC-specific maintenance plans) to fully comply with the maintenance standards described in Appendix C of the TCA. (M-4)

LSPGC indicated that while that vegetation management for the project would be limited given that the project would not include any overhead transmission lines, the project would be integrated into LS Power's transmission vegetation management plan (copy provided) based on experience maintaining hundreds of miles of 230 kV, 345 kV, and 500 kV transmission lines across multiple regions.

LSPGC indicated that the transmission vegetation management plan is a preventative and corrective program that utilizes regularly scheduled inspections, chemical treatments, mowing, and trimming with corrective measures as identified by the inspections. LSPGC indicated that additional ground patrol and drone inspections would be performed in response to specific circumstances as they arise (e.g., weather event, landowner feedback).

LSPGC described various tasks and their frequency and indicated that LS Power's transmission vegetation management plan would be amended to accommodate specific vegetation management requirements for the project. (M-5)

LSPGC indicated that LS Power currently complies with ISO standards for inspection, maintenance, repair, and replacement set forth in TCA Appendix C. LSPGC indicated that DesertLink maintains an ISO approved maintenance plan per the TCA and provides maintenance reports to the ISO in compliance with TCA Appendix C Section 6. LSPGC provided a recent maintenance report submitted to the ISO by DesertLink.

LSPGC indicated that as required by NERC, LS Power has participated in the NERC auditing process since the inception of affiliate Cross Texas Transmission's assets, which includes an audit at least once every three years. LSPGC indicated that in 2016, the Texas Reliability Entity performed an audit finding LS Power confirmed a commitment to promote a healthy compliance culture within its organization. LSPGC indicated that vegetation management and maintenance plans and procedures were submitted to NERC during the audit process. The audit report indicated that based on the results of this audit, no findings were noted for the standards and applicable requirements that were included in the scope of the engagement. The audit included standards in the following areas of NERC standards: EOP, FAC, PER, and PRC. (M-6)

LSPGC indicated that LS Power would have extensive real-time monitoring capabilities for the project via its control centers. LSPGC indicated that all outages would receive a time stamp, cause code, and reason and would be stored in a database and this data would serve as the basis for complying with the requirements of TCA Appendix C Section 4.3 and for more detailed root cause analyses completed to continuously improve reliability. LSPGC indicated that LS Power currently complies with the requirements of TCA Appendix C Section 4.3. LSPGC provided DesertLink's 2021 availability measures report, which had a 100% availability. LSPGC indicated that it would submit similar reports to the ISO for the Orchard STATCOM, Fern Road GIS/STATCOM, and the project. (M-7)

LSPGC indicated that it believes the addition of the project to the ISO controlled grid would require amendment to Appendix A to identify the project as under ISO control. (M-8)

LSPGC indicated that upon award of the project, LS Power would incorporate the project into its maintenance plans and other maintenance policies and procedures.

LSPGC indicated that LS Power would incorporate the project into its existing outage coordination program and included a copy of the Cross Texas Transmission transmission outage coordination procedure. LSPGC indicated that LS Power currently performs planned outage coordination for the transmission lines, substations, and associated facilities it operates.

LSPGC indicated that to the extent LSPGC has contractual rights to do so, LSPGC would coordinate maintenance outages with non-participating generators and require maintenance by non-participating generators as the ISO approves or requests to comply with TCA Section 7. (M-9)

LSPGC indicated that the primary emergency response and maintenance contractor and the secondary emergency response and maintenance contractor each have resources in multiple locations in California.

LSPGC indicated that LS Power's technician located in the project area would be able to respond to the project within one hour and that the maintenance contractors would be able to respond to the project within a few hours. (M-10)

3.10.8 Information Provided by SEGG

SEGG described the scope and frequency of its proposed maintenance work. (CC-4)

SEGG indicated that one full-time equivalent employee would be engaged in maintenance services on an annual basis. (CC-5)

SEGG indicated that its O&M contractor, would be providing all maintenance services for the project either directly or through additional subcontractors that it would hire. SEGG indicated that O&M services would be managed by the project manager, who would report to the senior operations director, and interact with the transmission operator and SEGG. SEGG listed the roles and responsibilities of its O&M contractor and its operations contractor. SEGG indicated that it is currently engaged in numerous contracts with its O&M contractor for other projects and would create a custom contract for this project with its O&M contractor if selected as the approved project sponsor.

SEGG described the O&M roles and responsibilities of its O&M contractor.

SEGG indicated that its O&M contractor would subcontract with qualified vendors and the selected manufacturers of substation equipment for parts and with other qualified vendors for field maintenance on the transmission line and substation. SEGG indicated that its O&M contractor uses third party vendors for some aspects of maintenance, parts, testing, and miscellaneous facility services. SEGG indicated that in general, third-party vendors would perform services that require specialized equipment and knowledge, and which are conducted on an infrequent basis, such as aerial inspections of transmission lines, transmission line maintenance, switchyard major maintenance, and maintenance of specific controls equipment.

SEGG identified two vendors that its O&M contractor would subcontract with for this project. SEGG indicated that its O&M contractor has a preferred vendor agreement with a specific subcontractor and indicated its proposed maintenance role. SEGG indicated that its O&M contractor has a strategic partnership with another specific subcontractor and indicated what that subcontractor's proposed maintenance role would be. SEGG indicated that it would have a service agreement with its HVDC equipment manufacturer and provided a description of the maintenance plan proposed for the HVDC system. (M-1)

SEGG indicated that the project manager would be responsible for directing all operations and maintenance activities at the facility and assuring that the facility is operated in compliance with applicable safety, environmental, and power grid requirements. SEGG indicated that the project manager position would require a technical degree or equivalent work experience, ten years of power generation or similar experience, and at least three years of supervising technical, supervisory, and administrative personnel.

SEGG indicated that to become a qualified operator (both initially and bi-annually thereafter), an employee must complete the qualifications standard for the applicable operator position (e.g., control room operator and assistant plant operator). SEGG indicated that the employee must also complete a comprehensive written examination followed by an oral examination. SEGG indicated that the written examination focuses on the technical aspects of plant design and operation and the oral examination focuses on the employee's overall understanding of plant dynamics and how to handle unusual or emergency situations. SEGG indicated that in addition to the above, all plant workers are responsible for completing an initial qualification standard, which addresses the plant's safety rules and administrative policies.

SEGG indicated that the desired qualifications for field personnel include:

- Transmission, WECC power grid and substation technical and leadership experience with a work history that demonstrates a pattern of accomplishments and advancement.
- Bachelor of Science degree in electrical engineering or equivalent desired.
- SEGG provided a general list of skillsets required for field personnel. (M-2)

SEGG indicated that its O&M contractor's training program encompasses all aspects of training, including management, operations, maintenance, environmental considerations, safety programs, and administration. SEGG indicated that the training program applies to all employees and that the senior operations director and project manager have overall responsibility for ensuring that the training program is successful.

SEGG described the following requirements of its O&M contractor's training program:

- Employee Qualification: Initial qualification applies to all plant employees to ensure that each employee is familiar with the administration, operations, and maintenance programs used at the facility. It also ensures that new employees are trained on specific portions of the plant safety program.

- Training Qualification: The qualification process includes hands-on training as well as classroom and self-study training. SEGG's O&M contractor would ensure that every O&M technician is qualified to operate the facility by the time the facility commences commercial operations. The O&M technicians would have completed the respective portion of the sign-off sheet prior to operating any particular piece of equipment.
- Project Manager Training: The project manager typically undergoes a two to three-week training program at SEGG's O&M contractor's headquarters and spends approximately one week at a plant operated by its O&M contractor. Training focuses on corporate philosophy and the review of contracts, agreements, and facility-design information.
- Operations Training: Pre-commercial engineering, procurement, and construction contractor training provides plant personnel with a sound understanding of the plant's design and the methodologies of component and equipment operation, including an understanding of the integrated and dynamic plant operations in normal and off-normal situations. Such training makes use of the O&M procedures developed for the plant, which are a key element on which the training is based.
- Safety Training: The project manager, or his or her designee, would cover aspects of the safety program training that includes general safety practices, personnel protective equipment, emergency response/evacuation plans, lockout/tagout procedures, fire protection plan, confined space entry procedures, hazardous materials procedures, electrical and welding safety, respirator protection, and hearing conservation.
- Computer Training: SEGG's O&M contractor provides training to select staff members on the use of its O&M contractor's accounting (Saige) and maintenance management (Maximo) software.
- Other Training: SEGG's O&M contractor arranges for training from outside organizations on first aid/CPR training, basic firefighting, and forklift operations. (M-3)

SEGG indicated that the maintenance practices employed address the major areas as listed in TCA Appendix C, Sections 5.2.1 and 5.2.2 and described processes for transmission line circuit maintenance and station maintenance. (M-4)

SEGG described its plans and procedures for the prevention of HVDC line faults and DC line insulator maintenance.

SEGG provided a copy of its OEM's HVDC maintenance plan which indicated that during the warranty periods (40 years), any maintenance work must be carried out exclusively by its OEM service personnel. The plan indicated that after the warranty period, maintenance work may only be carried out by qualified personnel. (M-4)

SEGG indicated that the project entity would manage vegetation within its rights-of-way (and in access and service roads to minimize interference with the flow of electricity, to address safety issues, and to facilitate O&M activities.

SEGG indicated that the vegetation management complies with the National Electric Safety Code, ANSI A300 Part 7 and the International Society of Arboriculture best management practices. SEGG indicated that additionally, the project entity would comply with vegetation management standards required by the NERC and WECC vegetation management guidelines and that failure to comply with these requirements can result in substantial financial penalties.

SEGG indicated that objectives of integrated vegetation management on utility rights-of-way are to establish sustainable plant communities that are compatible with the electric facilities. SEGG indicated that integrated vegetation management has a series of control methods used to achieve the aforementioned objectives. SEGG provided a list of the control methods. (M-5)

SEGG indicated that, as a third party provider, its O&M contractor is unable to share any audit reports or regulatory filings for similar projects, as they are confidentiality protected. SEGG indicated that its O&M contractor has an outstanding compliance history with NERC and other regulatory agencies. SEGG indicated that in the past ten years of NERC mandatory standards, neither its O&M contractor nor its clients have received a penalty.

SEGG indicated that its O&M contractor's experience with implementation and compliance with standards for inspection, maintenance, repair, and replacement of similar facilities includes proven programs and scalable processes (operations, management, inspection, maintenance and repair, compliance and subcontractor services) that enable successful O&M services on high-voltage transmission line segments associated with its O&M contractor-operated power plants. SEGG indicated that its O&M contractor's successful experience thus far with transmission and distribution system projects demonstrates that these core capabilities translate across various types of electric power projects.

SEGG indicated that although its O&M contractor does not have audit reports or regulatory filings for similar facilities, it has included several assessment document templates that it uses to ensure compliance with its standards for implementation, inspection, maintenance, repair, and replacement.

SEGG indicated its O&M contractor would apply the same overarching strategic and tactical approaches when performing O&M services for this project that it has applied to the power generation facilities and transmission lines for which it has provided similar services. SEGG listed 21 generation projects totaling 6622 MW and approximately 55 miles of transmission lines for which its O&M contractor is currently responsible for O&M services. (M-6)

SEGG indicated its O&M contractor would submit an annual report to the ISO within 90 days of the end of the calendar year that would describe the project's availability measures performance, which would include all forced outage records, including the date, start time, end time, affected transmission facility and the problem cause of the outage. SEGG listed sample availability measures that are currently being provided to various clients and entities by its operations contractor and its O&M contractor subsidiary, as contractually and legally required.

SEGG provided sample availability and forced outage rate information on its O&M contractor operated generators. (M-7)

SEGG indicated that at this time, it does not anticipate any changes or exceptions to the provisions of the TCA to be required. (M-8)

SEGG listed actions that its O&M contractor would take including:

- Operate the transmission facilities in compliance with the ISO Tariff, ISO protocols, the operating procedures (including emergency procedures in the event of communications failure), and the ISO's operating orders unless the health and safety of operating personnel or the public would be endangered.
- Obtain approval from the ISO pursuant to the ISO Tariff before taking out of service and returning to service any facility, except in cases involving immediate hazard to the safety of personnel or the public or imminent damage to facilities. In the case of a forced outage, the ISO would be promptly notified.
- After a system emergency or forced outage, the O&M contractor would restore service of the transmission facilities under the ISO's operational control as soon as possible and in the priority, order determined by the ISO.
- Provide the ISO with a written report describing the circumstances and the reasons for any forced outage.
- Forecast and coordinate maintenance outage plans in accordance with Section 9 of the ISO Tariff.
- Coordinate maintenance outages with non-participating generators (as necessary), including exercising contractual rights to require maintenance by those generators in such manner as the ISO approves or requests.
- Notify the ISO of any faults on the ISO controlled grid or any actual or anticipated forced outages as soon as aware of them.
- Take all steps necessary to prevent forced outages.
- Return to operation, as soon as possible, any facility under the ISO's operational control that is subject to a forced outage. (M-9)

SEGG indicated that its O&M contractor and any qualified vendors would have personnel within a two-hour radius of the project location. SEGG indicated that its O&M contractor has operations and maintenance personnel in Tracy, California and that its operations contractor's control center is in Houston, Texas. SEGG indicated that SEGG has personnel in Sacramento, California. (M-10)

Operating Practices

(Prior Projects and Experience Workbook; P-5, CC-3, CC-4, CC-5, O-1 through O-18)

3.10.9 Information Provided by Avangrid for Proposals 1 and 2

Avangrid provided its experience and the experience of its contractors with operating substation and transmission line projects. The information included 15 substation and transmission line operation projects that operate at voltages above 200 kV and are ongoing or have been completed in the past ten years, seven of which were located in the U.S., none in California. Of the seven U.S. projects, one was an underground project. Of the 15 total projects, one included an HVDC component. (Prior Projects and Experience Workbook)

Avangrid indicated that it has signed a memorandum of understanding with its O&M contractor as its operations partner for this project, with a full contract to be executed upon project award. Avangrid indicated that day-to-day transmission operator functions would be performed by an operations contractor as documented in a delegation of responsibilities matrix that identifies roles and responsibilities for each applicable NERC reliability standard, with oversight and support from the Avangrid operations group.

The responsibility matrix provided by Avangrid lists the responsibilities for the O&M contractor, the operations contractor and Avangrid.

Avangrid indicated that operations contractor maintains its primary control center in downtown Houston, Texas. Avangrid indicated that the primary control center has stringent security controls including on-site security, cameras and physical access control managed by the building and the operations contractor. Avangrid indicated that the primary control center is connected to building power, an uninterruptible power supply and an on-site generator in addition to having separate environmental controls. Avangrid indicated that additionally its operations contractor maintains a back-up control center located about 40 minutes west of downtown Houston. Avangrid indicated that the back-up control center has stringent physical security controls including on-site security, cameras, and physical access controls managed by the building and the operations contractor. Avangrid indicated that the operations contractor’s primary and backup control centers comply with all applicable NERC standards, including but not limited to physical and cyber security standards.

Avangrid indicated that no changes to its current organization are expected to be required to accommodate the operation of the project. Avangrid indicated that its O&M contractor would communicate regularly with Avangrid’s compliance manager to ensure situational awareness and compliance with NERC, ISO, and Avangrid policies and procedures.

Avangrid indicated that its O&M contractor and its operations contractor and Avangrid would work together to perform operations for the project, with its operations contractor carrying out day-to-day operations activities. Avangrid indicated that the three entities have developed a detailed matrix of roles and responsibilities to ensure that all required activities and functions are accounted for and assigned. (O-1)

Avangrid indicated that as the entity responsible for maintenance execution, O&M contractor would be responsible for hiring the project manager who would perform and oversee operations activities for the project.

Avangrid indicated its operations activities would be performed at the operations contractor’s primary up control center by its team of NERC certified system operators.

Avangrid indicated that its operations contractor maintains a highly qualified group of NERC reliability coordinator certified system operators that perform transmission operator functions on behalf of its client base. Avangrid indicated that this group of personnel are also required to maintain their reliability coordinator and transmission operator certifications to ensure the highest level of the electric grid reliability is maintained. Avangrid indicated that its operations contractor has a training coordinator that tracks and ensures all on-going continuing education requirements are met and testing is repeated, as necessary. Avangrid indicated that in addition, the training coordinator manages the operations contractor’s learning management system to provide project by project customized training to all operations personnel.

Avangrid indicated that while the converter stations would be remotely operated and dispatched by its operations contractor's NERC certified transmission operators, Avangrid plans to hire a project manager, two on-site converter station control technicians, two converter station primary plant technicians and one apprentice in accordance with the maintenance staffing plan.

Avangrid indicated that it intends to only hire converter station control and primary plant technicians who are certified general electricians in the state of California and that it plans to require that all converter station control and primary plant technicians have at least one year of prior experience with high voltage power systems, preferably with high voltage substations above 200 kV. Avangrid indicated that all field personnel would receive extensive converter station training from the OEM prior to the project's in-service date.

Avangrid indicated that it would continue to ensure that all field personnel throughout the entire operational life of the project would be properly qualified, skilled, and experienced and there would be a built-in degree of redundancy in the staffing requirements for the converter station. (O-2)

Avangrid indicated that its operations contractor would be supporting the transmission operator function and working with qualified transmission owner field personnel using NERC certified reliability coordinators or transmission operator system operators that would receive ongoing training in line with the requirements of the NERC PER-005 training program, its operations contractor's internal policies and procedures, and initial and ongoing HVDC operator training requirements as identified by its OEM.

Avangrid indicated that its operations contractor is a registered balancing authority and transmission operator subject to NERC Reliability Standard PER-005 requirements to maintain a risk-based training program for the initial and ongoing training of NERC certified system operators. Avangrid indicated that its operations contractor has deployed its systematic approach to identifying training needs, including minimum areas of competency per NERC Reliability Standard PER-003, PER-005 requirements and internal training requirements.

Avangrid indicated that its operations contractor's system operators are required to complete initial training program requirements, which encompasses meeting the minimum system operator NERC certification requirements, *i.e.*, NERC reliability coordinator or NERC transmission operator in combination with its operations contractor required transmission certification requirements, and minimum competency training activities designed to ensure that all required job tasks can be independently performed. Avangrid indicated that its operations contractor leverages training content internally developed and issued via its learning management system, training from outside sources, and on-the-job training. Avangrid indicated that its operations contractor system operators are required to participate in required training on an on-going basis to meet at least the minimum required continuing education units to maintain minimum certification levels for supporting the transmission operator function, and annually participate in EOP-011 emergency and EOP-005 restoration drills. Avangrid indicated that if there is a new real-time reliability task any operation contractor's system operator would perform; the system operator is required to participate in training activities related to the task to verify it can perform such a task independently within established timelines. Avangrid indicated that several persons coordinate to track and monitor upcoming training requirements for the individual system operators.

Avangrid indicated that as the entity responsible for the execution of maintenance activities, its construction contractor would be responsible for ensuring that all field personnel are properly trained and certified for the training of operations field personnel, such as substation and transmission linemen.

Avangrid indicated that in addition to the rigorous apprenticeship training that transmission and substation lineman must complete to become journeyman, its construction contractor requires all employees to undergo extensive ongoing training to ensure that they are qualified to safely and effectively perform all tasks required by their position. Avangrid indicated that all employees are required to comply with the construction contractor's company policies and safe work practices, business unit specific policies/procedures, and customer's procedures and guidelines.

Avangrid indicated that its construction contractor's employees responsible for field O&M activities would be required to complete initial and ongoing trainings in line with the requirements of the OSHA Electrical Transmission & Distribution Partnership.

Avangrid indicated that its construction contractor provides its employees ongoing trainings and assessments starting on the first day of their employment. Avangrid provided a copy of the construction contractor's health, safety, and environmental handbook.

Avangrid indicated that the HVDC training program for control room operators would be provided by its OEM during the development of the project and would be completed by all operators. Avangrid indicated that the operator training program would thoroughly familiarize all operating personnel with the various facets of the HVDC converter stations, so that at the completion of the training they would be able to operate the HVDC converter stations completely and properly without OEM assistance. Avangrid indicated that this program includes both initial and ongoing training for:

- Converter start/stop and de-block/block sequences of the HVDC system;
- Power, current, and voltage order setting;
- Local and remote operation; and
- Alarm, monitoring and reporting system simulator configuration and operation. (O-3)

Avangrid indicated that it does not anticipate major changes or exceptions to the provisions of the TCA regarding operations to integrate the project into the ISO controlled grid. Avangrid indicated that it reserves the right to raise items for discussion with ISO regarding the TCA at the time of final contract execution. (O-4)

Avangrid indicated that it intends to register for the NERC functions of Transmission Owner, Transmission Operator, and Transmission Planner as related to this project. (O-5)

Avangrid indicated that it has contracted with an operations contractor that is part of the O&M contractor's family of companies to provide operations support for the project, including performance of all applicable NERC functions.

Avangrid indicated that in order to ensure compliance with the reliability standards and requirements associated with these functions, it would take a number of steps to clarify responsibilities, assess the O&M contractor and the operations contractor's policies and procedures to ensure compliance with relevant reliability standards, and integrate oversight of the contractor into Avangrid's existing internal NERC compliance programs. Avangrid indicated that it would:

1. Ensure that a division of responsibilities matrix is included as an appendix for the final service contract. During contract negotiations, Avangrid indicated that it would review the matrix with the two contractors to ensure it is clear and agreed upon which is responsible for each NERC standard and requirement.
2. Require the two contractors to provide process and procedure documentation, as well as evidence of compliance prior to energization, for each standard as appropriate.
3. Track and require evidence of compliance from the two contractors for those requirements that have periodic actions.
4. Conduct periodic assessments of compliance, conducted by Avangrid's reliability assurance or internal audit organizations, or by a third-party.

Avangrid indicated that these periodic assessments would be conducted in accordance with Avangrid's internal compliance program. (O-6)

Avangrid indicated that O&M services would be overseen by an Avangrid senior director of system operations who would report to Avangrid's vice president of electrical operations and interact with the transmission operator and external maintenance contractors. Avangrid indicated that the senior director of system operations would provide oversight for the execution of maintenance activities for the project's converter stations, transmission lines, rights-of-way, and other related facilities in compliance with all applicable NERC requirements, state and federal regulations, OEM recommendations, and Avangrid policies and procedures. Avangrid indicated that the senior director of system operations would serve as the business area lead responsible for interfacing with Avangrid's reliability assurance group to ensure compliance with all NERC reliability standards applicable for developing, owning, and operating this project and any other projects awarded in this and/or future solicitations in line with Avangrid's NERC compliance program. (O-7)

Avangrid indicated that it owns, operates, and maintains over 8,000 miles of transmission and 191 substations in accordance with NERC and ISO reliability standards across its six regulated electric utilities in Maine, Connecticut, and New York. Avangrid provided a breakdown of these assets by voltage which included 1389 miles of 345 kV and 230 kV transmission lines and 28 345 kV and 230 kV substations. Avangrid provided 2018 NERC and Northeast Power Coordinating Council compliance audit results for Central Maine Power Company and United Illuminating Company, which reports indicated that no findings were noted for the applicable requirements in scope for this engagement.

Avangrid indicated that its O&M contractor is a registered transmission operator through its subsidiary operations contractor and that its operations contractor has not had a transmission operations audit related violation and has passed certification reviews by SERC and PJM. Avangrid indicated that in addition, as a registered generator owner and generator operator, its O&M contractor has been subject to nearly 200 audits across its registrations with no audit discovered violations since 2012.

Avangrid listed the transmission lines for which its O&M contractor has current or past experience maintaining. (O-8)

Avangrid indicated that it expects to divide responsibility for NERC reliability standards between itself and the ISO consistent with previously negotiated coordinated functional registration agreements between the ISO and PTOs.

Avangrid indicated that it and its O&M contractor have created a preliminary division of responsibilities matrix that assigns responsibility for various NERC functions to Avangrid as the project sponsor, to its O&M contractor as the maintenance execution lead, to its operation contractor as the operations execution lead, or to the ISO. Avangrid indicated that it expects to refine this matrix to reflect the final coordinated functional registration agreement. (O-9)

Avangrid indicated that as an experienced transmission owner and operator in Maine, New York, and Connecticut, Avangrid regularly enters into agreements with customers and other market participants to ensure that reliability of the system is maintained and all necessary activities are performed. Avangrid indicated that it is ready to execute any of these agreements with market participants in the ISO. (O-10)

Avangrid indicated that its operations contractor has two remote data centers that are "hot-hot" to ensure no loss of data could occur. (O-11)

Avangrid indicated that it as the project sponsor and its O&M contractor as its operations partner are experienced in the physical operation and maintenance of transmission facilities. Avangrid indicated that it operates over 4,500 miles of transmission lines, over 350 circuits, and 188 substations at 100 kV and above across its six utilities in New York and New England, plus an additional 4,000-plus miles and 500-plus circuits at lower voltages. Avangrid indicated that these facilities are operated and maintained by Avangrid in accordance with applicable laws, relevant independent system operator policies and procedures and good utility practice to ensure the safety and reliability of the system.

Avangrid indicated that its O&M contractor and its subsidiary operations contractor, with oversight from Avangrid, would operate the project in compliance with TCA Section 6.1 and Section 6.3. (O-12)

Avangrid indicated that it would register the special purpose entity formed for the purpose of developing, owning, and operating the project as a NERC certified Transmission Operator (TOP). Avangrid indicated that as a transmission operator in the ISO operated system, the special purpose entity would develop and submit an operating plan to be reviewed by the reliability coordinator RC West to mitigate transmission system emergencies and extreme weather emergencies in the area and notify the RC West operator in real time when a transmission system emergency occurs in line with RC West procedures for system emergencies. Avangrid indicated that it develops similar emergency operating plans for its utilities in the New York and New England. Avangrid provided an example of the New York State Electric & Gas Company and Rochester Gas & Electric Company emergency response plans.

Avangrid indicated that the operations contractor's control center would manage all communications with the ISO during an emergency, coordinating with Avangrid and field personnel, as necessary. Avangrid indicated that the operations contractor data historian would capture data on the emergency and be used to generate reports as described in TCA Section 9.3.

Avangrid indicated that its construction contractor would perform maintenance activities for the project, including emergency response. Avangrid indicated that its construction contractor would ensure compliance with the ISO's system operations emergency plan and system emergencies reliability coordinator procedure.

Avangrid indicated that as a transmission owner and operator in the Northeast, Avangrid is currently a member of the North Atlantic Mutual Assistance Group, a regional consortium in the Northeast U.S. and Canada that provides mutual aid to its members during restoration events. Avangrid indicated that it would seek to join the Western Region Mutual Assistance Group, which performs a similar function for California utilities, if awarded one or more projects in this solicitation. (O-13)

Avangrid indicated that it does not anticipate the project being subject to any encumbrances as defined in Appendix A of the ISO Tariff. Avangrid indicated that it reserves the right to identify encumbrances as may arise in the development of the project. (O-14)

Avangrid indicated that it has worked with suppliers to develop a plan to replace major failed equipment in a timely manner that balances project costs and risks from outages in accordance with good utility practice. Avangrid indicated that the actual range of response and repair times for each piece of major equipment would be finalized in Avangrid's contract with its maintenance contractor. Avangrid indicated that it plans to have spare equipment and parts available based on company policy, manufacturer's recommendations, and utility best practice to allow replacements and repairs to be made in a timely manner to reduce the likelihood and extent of unplanned outages.

Avangrid indicated that it plans to have all spare equipment for the project stored in a warehouse at the Northern Receiving Station converter station. Avangrid indicated that the Northern Receiving Station converter station was identified as the optimal site because of its central location relative to other proposed converter stations, which would help to ensure timely access to spare parts and consumables and minimize the response time to repair and replace failed equipment.

Avangrid indicated that a comprehensive spare parts package would be available at the time the HVDC converter stations commence commercial operation. Avangrid indicated that spare parts would properly be stored in accordance with the environment conditions required for their storage, easy to identify, ready for use at any time required.

Avangrid indicated that it would have a single-phase transformer in each substation available in case any major failure happens to any transformer.

Avangrid listed the equipment it plans to have in its substation and warehouse available in case of any major failure. Avangrid described the expected response and restoration times for various types of failures. (O-15)

Avangrid indicated that its O&M contractor and its operations contractor, as a NERC-certified Transmission Owner (TO) or TOP, have not had any violations of NERC reliability standards in the past ten years.

Avangrid indicated that it maintains a rigorous NERC compliance program and regularly identifies and mitigates issues that may result in impacts to the operation of the bulk power system. Avangrid provided a list of violations that resulted in a notice of penalty in the past ten years. The list included eight violations of the TOP-1 standard in the NPCC, mostly related to energy management system functions. (O-16)

Avangrid indicated that its O&M contractor and its operations contractor have not incurred any operations related tariff violations or FERC rules violations in the past ten years.

Avangrid indicated that it has not had any operations related tariff violations or FERC rule violations in the past ten years. (O-17)

Avangrid indicated that its O&M contractor and its operations contractor have not incurred any violations of operations-related laws, statues, rules, or regulations not discussed elsewhere.

Avangrid also provided a summary of other Avangrid violations and penalties. Avangrid indicated that these relate to electric operation-related laws, statutes, rules, and regulations. Avangrid indicated that in Connecticut, all utilities are subject to notices of potential violation. Avangrid indicated that most of the penalties for its subsidiary were in proceedings where the other investor-owned utility in the state was also assessed penalties. Avangrid indicated that the larger penalty amounts relate to storm restoration, which are not unusual given the weather and tree density in Connecticut. (O-18)

3.10.10 Information Provided by HWT for Bay Crossing and Inland Route

HWT provided its experience and the experience of its contractors with operating substation and transmission line projects. The information included 86 substation and transmission line operation projects that operate at voltages above 200 kV and are ongoing or have been completed in the past ten years, 79 of which were located in the U.S., including seven in California. Of the 79 U.S. projects, five were underground projects. Of the 86 total projects, six included an HVDC component. (Prior Projects and Experience Workbook)

HWT indicated that the project’s operations would be undertaken for HWT by its NextEra affiliate TBC. HWT indicated that the TBC HVDC operations team is an in-house owner-operator staff, based in the San Francisco Bay Area, with exceptional experience, tools, and capability to attend to all matters pertaining to VSC HVDC facilities. HWT indicated that the team’s experience and capability ensure it does not rely on expensive annual operating agreements with the HVDC line’s OEM. HWT indicated that the project’s 24/7 system control center would be the existing TBC main and back up control centers located at the TBC HVDC facility in Pittsburg. HWT indicated that TBC would undertake project operations. HWT indicated that the TBC owner-operations team has almost 12 years’ experience owning and operating a VSC HVDC facility, in accordance with the ISO and PG&E operating procedures and NERC and WECC reliability standards. HWT indicated that TBC is an existing ISO PTO and a WECC certified TOP and its local based team bolsters HWT operational consistency and alignment with the operational jurisdictions, agencies, and authorities in California. HWT indicated that TBC has a strong record of operating transmission assets under the ISO Tariff and interconnection protocols with PG&E.

HWT indicated that the HWT corporate services agreement delineates the services provided to HWT by its NextEra affiliates and that HWT would revise its corporate services agreement to include TBC operations services for this project.

HWT provided information on its proposed organization responsible for the project's system operations. The information provided included the control center team responsible for the project's 24/7 operation, ISO single point of contact and coordination with operational stakeholders, and operations management, compliance oversight, technical support, training, and field operators. (CC-4, CC-5, O-1)

HWT indicated that it and its operating affiliate TBC follow established human resources policies, processes, and procedures to assure that only persons who are appropriately qualified, skilled, and experienced in their respective trades or occupations are employed in operations functions. HWT indicated that it uses state-of-the-art online recruiting program which compares skills, experience, education, and preferences with job openings companywide. HWT indicated that successful applicants for transmission and substation positions must meet minimum requirements and demonstrate the necessary experience for a given position as determined by HWT. HWT indicated that in addition to basic entry qualifications and experience, HWT and its affiliates requires all personnel to undertake company compliance and ethics training, along with specialized training dependent on job role and responsibilities.

HWT indicated that its system operator hiring philosophy is to hire experienced operations personnel that have previously obtained the necessary NERC certifications. HWT indicated that the project operator TBC's system operators are experienced with analysis and problem solving, integrity and compliance, process and project management, leadership communication and other professional skills.

HWT indicated that all HWT system operators for the project, undertaken by its affiliate TBC, are NERC certified TOP operators.

HWT indicated that the system and field operations team maintains certification to perform all high voltage switching and clearance activities, which includes annual training. (O-2)

HWT indicated that its training coordinator is responsible for the operations and maintenance personnel training programs, including providing and delivering classes and modules for the system operators. HWT indicated that the training coordinator holds NERC certified reliability coordinator certification and is a member of the NERC reliability coordinator operations working group.

HWT described NextEra's training program including NextEra University.

HWT indicated that the training program for HWT and its affiliates covers initial and continuing education requirements for maintaining qualifications for classifications with operational responsibilities. HWT described the training and certification requirements for operations personnel. HWT indicated that new hires with transmission system operational duties are required to take NextEra on-boarding training and certification training applicable to their roles. HWT indicated that in addition to basic entry qualifications and experience, NextEra requires all personnel to undertake company compliance and ethics training and specialized training depending on staff roles and responsibilities. HWT indicated that for continuing education, HWT would apply NextEra's formal program of skills re-certification to the project. HWT indicated that this program applies to HWT and its affiliates in the areas of high voltage specialists, control and protection, control center dispatchers, engineering, switching, and safety, as well as general systems training. HWT indicated that training is focused on skill refreshing and re-certification and many courses include an exit test. HWT indicated that the courses are delivered by a variety of training aids including classroom sessions, online reference materials, training documentation, job aids, exercise drills, hands-on instruction, training videos, refreshers on new work techniques, and online learning. HWT indicated that training progress and records are tracked by NextEra's corporate learning management system.

HWT indicated that TBC's owner-operator VSC HVDC training program provided for the converter station covers all topics related to VSC HVDC transmission technology.

HWT indicated that in addition to the comprehensive library of training materials, TBC has its own in-house VSC HVDC control simulator that is used for both new and ongoing operator training. HWT indicated that TBC is the only operator in North America with a VSC HVDC control simulator. HWT indicated that it consists of hardware and software that enables TBC to develop, test and run new software, software upgrades, and software patches for its control and protection systems on a separate system, off-line, before implementation on the production control and protection systems.

HWT provided copies of its core training and operations training programs. (O-3)

HWT indicated that it does not anticipate the addition of the project to the ISO controlled grid to require any changes or exceptions to the provisions of the TCA regarding operations. (O-4)

HWT indicated that the NERC functions applicable to the project are the NERC Transmission Owner (TO), Transmission Planner (TP), and Transmission Operator (TOP).

HWT indicated that in February 2020 HWT registered as a NERC TO and NERC TP in WECC in connection with the Suncrest SVC project commencing commercial operations. HWT indicated that HWT's NERC TO and NERC TP registrations would also cover the proposed project.

HWT indicated that in 2010 TBC registered as a NERC TO and TOP and that TBC is a certified TOP in WECC.

HWT indicated that for the proposed project, HWT would perform the TO and TP function under its registration. HWT indicated that HWT affiliate and certified NERC TOP TBC would undertake the project's TOP role for HWT. HWT indicated that HWT would coordinate with WECC to seek agreement that the project's NERC TOP function can be performed by TBC under TBC's existing NERC TOP registration and that this plan would also be agreed with the ISO. (O-5)

HWT indicated that it would contract with its affiliate TBC for NERC TOP services for the project.

HWT indicated that NextEra's compliance and responsibility organization is a centralized group of reliability standard subject matter experts who oversee control and audit the NextEra registered entities' compliance programs. HWT indicated that the NextEra compliance and responsibility organization would monitor HWT and TBC execution of their NERC functional programs to ensure compliance with the reliability standards or requirements associated with the project. (O-6)

HWT indicated that it would ensure acceptable reliability levels are maintained by periodic internal auditing of compliance, continuous training of staff, increased automation of processes, and utilization technology to enhance accuracy of compliance function and reporting.

HWT indicated that it would follow NextEra's documented NERC reliability standards internal compliance program. HWT provided a copy of NextEra's NERC compliance manual and indicated that a copy is provided to every employee who works directly on NERC reliability standards compliance. HWT indicated that the compliance and responsibility organization has responsibility for the internal oversight of compliance with NERC standards.

HWT provided a list of applicable NERC standards and listed existing procedures intended to address those standards.

HWT indicated that prior to energization, the compliance and responsibility organization would conduct a formal review of the project for applicable compliance requirements and evidence of compliance to determine the readiness of HWT system control operations, operated by TBC, to comply with NERC reliability standards in accordance with its readiness review process.

HWT indicated that it does not foresee any applicable reliability criteria for which transmission owners are responsible that would require temporary waivers under TCA Section 5.1.6. (O-7)

HWT indicated that it has had no violations relating to these standards. HWT provided the results of NERC audits for the project operator TBC for the past ten years. The results indicated that there were no findings for any of the standards that were audited.

HWT indicated that TBC has 53 miles of transmission lines and three substations subject to NERC compliance. HWT indicated that it has 91 miles of transmission line and ten substations in California subject to NERC compliance. HWT also indicated that NextEra has many miles of transmission line and many substations subject to NERC compliance. HWT indicated that for NextEra most of its potential violations have been the subject of self-reports submitted to the applicable regional entities. HWT provided a listing of NERC violations from 2007 to present for NextEra affiliates. (O-8)

HWT indicated that its operations team members have been instrumental in establishing two coordinated functional registration agreements with the ISO.

HWT indicated that it and its affiliate operator TBC would work with the ISO to develop a coordinated functional registration agreement that would include defining roles and responsibilities related to complying with all applicable NERC TOP reliability standards requirements. (O-9)

HWT listed the types of applicable agreements that would define the project transmission operator's responsibilities and authority regarding other NERC functional entities. HWT described the purpose and scope and the project stakeholders and interfacing parties for each agreement type. (O-10)

HWT indicated that the project would be integrated into HWT's and TBC's existing control center infrastructure and that TBC would perform the system operations function for the project. HWT provided a copy of its back-up operations plan. HWT indicated that the project would adopt TBC's existing procedures and processes for supplying real-time operational data and system modeling data to PG&E, the ISO, and the reliability coordinator and provided a copy of its operational information sharing procedure. HWT indicated that this functionality would support the data collection requirements of TCA Appendix C Section 4.3. (O-11)

HWT indicated that its affiliates are responsible for the operation and maintenance for over 8,700 circuit miles of the bulk electric system and that all circuits and associated facilities have operational processes, procedures, and maintenance practices that comply with applicable reliability criteria and NERC's operation and planning reliability standards.

HWT indicated that it and the project's operator TBC are both signatories to the TCA in connection with the Suncrest SVC project and the TBC HVDC project and that both have programs in compliance with TCA Sections 6.1 and 6.3. HWT described its capability to comply with each of the activities required by TCA Section 6.1.

HWT indicated that the operations team has been involved in several upgrades to the VSC HVDC system.

HWT indicated that as existing PTOs both HWT and TBC have experience and established capability managing availability measures and reporting described in TCA Section 14 and the ISO maintenance procedures. (O-12)

HWT indicated that TBC existing procedures describe the obligation of project operations to comply with both ISO and PG&E procedures and demonstrate the project operating teams' experience in complying with TCA Section 9.2 regarding management of emergencies and communications during an emergency.

Regarding TCA Section 9.3 pertaining to system emergency reports, HWT indicated that TBC's existing experience and procedures describe the process for planning, coordination, notification, and scheduling of outages for maintenance, repair, and construction of new facilities. HWT indicated that it also provides the guidelines to follow when forced outages occur on facilities. HWT indicated that TBC's event reporting procedure provides the operating plans and protocols for the notification, reporting, investigation, and analysis of reportable events. HWT provided copies of TBC's outage planning and notifications and event reporting procedures.

HWT indicated that the project system operator (the TBC control center) would keep the ISO and the interconnecting utilities informed of the status of the forced outage or emergency condition and manage any coordination requirements. HWT indicated that the project field operator's lead would act as the incident commander for all recovery efforts needed to rectify the forced outage or emergency condition issue.

HWT indicated that project field operations team members based at the project facilities would be the first responders, responding within 30 minutes, supported by the TBC Pittsburg team members, who would be available to be on-site within 60 minutes of being notified. HWT indicated that additional support, if needed, would be available from the TBC Pittsburg team with further support available from NextEra staff based at its Livermore facility, a 40-minute drive from the project substation and specialized vendors.

HWT indicated that outside of the project sponsor's team, HWT affiliates have approximately 150 technical staff in California and have access to all the specialized tools, resources and equipment needed to successfully respond to any forced outage or emergency condition or emergency repair on a 24/7 basis.

HWT indicated that the NextEra emergency preparedness business unit ensures organizational readiness across all threats and hazards to the NextEra enterprise and HWT. HWT indicated that emergency preparedness and response is managed and institutionalized through the corporate emergency management plan framework. HWT provided a copy of the plan, which it indicated was intended to provide a framework by which NextEra and FPL can respond effectively to all threats and hazards.

HWT provided a list of TBC emergency plans and a copy of the TBC extreme weather earthquake procedure. (O-13)

HWT indicated that the project would not be subject to any encumbrance. (O-14)

HWT indicated that the project would be built to FPL equipment design standards to the extent possible so that the project can be incorporated into the larger NextEra spare parts management program.

HWT provided a preliminary list of spare parts for each 500 MW VSC HVDC converter station. HWT indicated that this list would be finalized by the VSC HVDC OEM following a reliability, availability, maintainability, and performance study on the final design. HWT indicated that modeling would be used by the OEM to simulate the VSC HVDC configuration, operation, failure, repair, and maintenance of components.

HWT indicated that it would hold selected strategic spares at the project site, including circuit breakers, disconnect switches, bus insulators, surge arresters, CCVTs and VTs. HWT indicated that the project design includes a spare single-phase transformer at both converter sites. HWT indicated that it would also have access to its affiliate company-wide spares sharing program, specifically FPL spares, and strategic support of equipment suppliers. HWT indicated that NextEra is one of the biggest North American customers of the project OEM and that this would help bolster HWT's position in its relationship with the OEM.

HWT indicated that it has created a transmission line restoration plan to be implemented in response to an outage or other emergency conditions that would be encountered over the life of the project resulting in damages requiring structure, wire, or hardware replacement. HWT provided the detailed draft plan. HWT indicated that it would develop a plan to replace one mile of line and structures and return the line to service in seven days.

HWT indicated that to determine its line spares requirements it would perform a series of failure containment studies based on the expanded residual static load concept discussed in ASCE MOP 74 to assess the impact of a single event failure mode on the final line structure design. HWT indicated that it would maintain a spare stock of critical transmission line components, hardware, wire, and structures to ensure expedient recovery in the event of an emergency. (O-15)

HWT indicated that regarding servicing and maintaining the underground portion of the project's transmission system, the project's operator, TBC, possesses substantial resources, experience, and capability that would be utilized to support operational needs of the project.

HWT listed the spare stock of cable components, cable, and joints that it would maintain to ensure two full repairs and expedient recovery in the event of an emergency. (O-15)

HWT provided a listing of NERC violations from 2007 to present that identifies and describes NextEra and the project sponsor's team violations in all NERC regions, including WECC. The listing indicated that of the violations in the WECC, all were self-reports, and all had been settled.

HWT indicated that it has had no violations and that for the project's operator TBC, and most NextEra entities in California, potential violations have been the subject of self-reports submitted to WECC. (O-16)

HWT indicated that neither it nor any of its affiliates have been found in violation of any operations-related tariff FERC rules violations in the past ten years. (O-17)

HWT indicated that neither it nor any of its affiliates have been found in violation of any operations-related laws, statutes, rules, or regulations by any court or agency in the past ten years that have not been previously discussed elsewhere in this proposal. (O-18)

3.10.11 Information Provided by LSPGC

LSPGC provided its experience and the experience of its contractors with operating substation and transmission line projects. The information included 13 substation and transmission line operation projects that operate at voltages above 200 kV, are ongoing or have been completed in the past ten years. All of the identified substation and transmission line operation projects were located in the U.S., with two in California. Of the 13 U.S. projects, one was an underground project. Of the 13 total projects referenced earlier, none of those projects included an HVDC component. (Prior Projects and Experience Workbook)

LSPGC indicated that its operations and maintenance personnel and its contractors currently operate and maintain similar equipment at its Cross Texas Transmission, Silver Run, and LSPGNY utilities with high reliability. LSPGC further indicated that by the time the project is energized, LS Power would also be operating and maintaining similar equipment at LSPGC's Orchard STATCOM and Fern Road GIS/STATCOM project facilities. (P-5)

LSPGC indicated that the project would be operated by LS Power using its existing control centers that operate high voltage transmission facilities in multiple jurisdictions across the United States. LSPGC indicated that LS Power currently has four control centers (two primary and two backup) that operate, or would operate, facilities in ERCOT (Texas), PJM (New Jersey, Delaware), NYISO (New York), and the ISO. LSPGC indicated that in California, the LS Power control centers would be integrated with the ISO's systems to operate the Orchard STATCOM and Fern Road GIS/STATCOM projects that are planned to be placed in service by 2024. LSPGC indicated that as a result, LSPGC would register with NERC/WECC as a Transmission Owner (TO), Transmission Operator (TOP), and Transmission Planner (TP) and the same registrations and control centers used to operate the Orchard STATCOM and Fern Road GIS/STATCOM projects would be utilized for the project.

LSPGC indicated that LS Power would use experienced and highly qualified internal staff to perform all operations and compliance activities for the project. LSPGC indicated provided and organization chart showing the individuals directly responsible for operating the project.

LSPGC indicated that LS Power plans to operate the project from its control centers (primary and backup) located in Austin, Texas. LSPGC indicated that all transmission system operators and operations management that would serve as the single point of contact for ISO would be located in Austin. LSPGC indicated that the LS Power facilities are NERC certified high impact rating control centers (per CIP-002-5) that currently operate EHV transmission lines and substations and meet all of the physical and cyber security requirements necessary to operate the project. LSPGC indicated that LS Power's control centers would be integrated into the ISO's systems by 2024 to operate the Orchard STATCOM and Fern Road GIS/STATCOM projects.

LSPGC indicated that technicians who would perform switching operations would be located in California with additional technicians and switching management located in Texas.

LSPGC indicated that LS Power would hire one additional technician to accommodate the integration of the project and LS Power plans to add three transmission system operators and two technicians in 2023 to accommodate the integration and operation of the Orchard STATCOM and Fern Road GIS/STATCOM projects in the ISO controlled grid, which should be sufficient to operate the project.

LSPGC indicated that LS Power would use internal staff and existing facilities to perform operations and compliance activities for the project. LSPGC indicated that LS Power trains and credentials local contractors to perform field operations at LS Power facilities to supplement its internal resources as may be necessary from time to time. LSPGC indicated that LS Power does not use contractors for transmission system operator positions. (CC-3, CC-4, CC-5, O-1)

LSPGC indicated that LS Power's employment practices provide the foundation for ensuring qualified, skilled, and experienced personnel operate its facilities and that candidates for employment must demonstrate that they have the qualifications, skills, and experience necessary to operate the assets. LSPGC indicated that extensive efforts are made to identify top candidates, to confirm work history and performance, and to perform background checks.

LSPGC indicated that LS Power requires that all transmission system operators hold: (1) Transmission Operator NERC certification; or (2) Reliability Coordinator NERC certification. LSPGC indicated that, in addition, transmission system operators are required to complete recurring situational awareness training and ISO training. LSPGC indicated that prospective team members interested in becoming a transmission system operator that have not obtained NERC certification are required to successfully demonstrate qualifications, skills, and experience to begin training to become a transmission system operator. LSPGC indicated that while in training, the candidate is required to work under direct supervision of a NERC certified transmission system operator and obtain NERC certification within six months.

LSPGC indicated that LS Power requires that technicians (operations field personnel) obtain a substation maintenance technician certification through the AVO Training Institute and obtain certification through the International Electrical Testing Association. LSPGC indicated that any technician performing switching must be a level 3 certified technician or above and have at least five years of experience. LSPGC indicated that in addition, a qualified switchman must demonstrate knowledge of the equipment and complete training specific to LS Power procedures for switching, lockout/tagout, and communication. (O-2)

LSPGC indicated that LS Power uses a system to build training plans, track initial and ongoing training, and track reliability related tasks to ensure all members of LS Power's operations group are fully trained. LSPGC indicated that each quarter, training meetings are conducted to discuss recent operations-related events, conditions on the system, changes in procedures and/or tools, and other training issues. LSPGC indicated that annual evaluations of the training program are completed to identify continuous improvements.

LSPGC indicated that LS Power utilizes NERC's system operator certification and continuing education database to review and archive transmission system operator continuing education hours. LSPGC indicated that the transmission system operator shift schedule is designed with training weeks built-in to ensure each transmission system operator receives required training throughout the year. LSPGC indicated that this includes computer-based training, instructor-led courses, formal on-the-job training, simulations, drills, and exercises. LSPGC indicated that each transmission system operator is also provided a minimum of 32 hours annually of emergency operations training including system emergency drills, system restoration exercises, system restoration scenarios, and system restoration table-top exercises. LSPGC indicated that transmission system operators are required to pursue ongoing education to maintain their NERC certified System Operator – reliability certifications, which are renewed every three years.

LSPGC indicated that to facilitate regular operating training, LS Power's SCADA and energy management system has an operator training simulator.

LSPGC indicated that field personnel are required to complete an annual training program and whenever there is a change in job responsibilities or policy/procedures. LSPGC indicated that this training includes a number of topics such as: emergency action plans, fall protection, hazard communications, CIP, code of conduct, switching, and environmental training. LSPGC indicated that LS Power staff must perform continuing education in order to maintain their substation maintenance technician certification. LSPGC indicated that personnel are required to complete annual coursework for satisfying continuing education requirements associated with their certifications.

LSPGC indicated that transmission system operators would receive training from the OEM at a remote HVDC station through side-by-side instruction with trained and certified operators prior to LS Power energizing the project. LSPGC indicated that after assuming operations, LS Power would integrate HVDC technology into continuing education requirements for technicians.

LSPGC indicated that LS Power requires all contractor personnel to be duly qualified, licensed, trained, and experienced to perform maintenance activities on its facilities. LSPGC indicated that contractors are responsible for training their employees to perform the anticipated activities with LS Power providing information specific to the project. LSPGC indicated that LS Power assesses all contractors to ensure that their personnel have the appropriate training and expertise for the work before authorizing any work order. (O-3)

LSPGC indicated that it believes the addition of the project to the ISO controlled grid would require amendment to TCA Appendix A to identify the project as under ISO control. (O-4)

LSPGC indicated that it would be registered with NERC as a TO, TOP, and TP for the Orchard STATCOM and Fern Road GIS/STATCOM projects by 2024. LSPGC indicated that it does not plan any additional NERC registrations to accommodate the project beyond the TO, TOP, and TP registrations. (O-5)

LSPGC indicated that LS Power would perform all NERC functions for the project or for each project in the event LSPGC has multiple project awards. (O-6)

LSPGC indicated that the project would be integrated in LS Power's NERC internal compliance program leveraging its existing policies and procedures. LSPGC indicated that LS Power has a strong culture of compliance with a dedicated and experienced compliance team to ensure all applicable reliability standards are met. LSPGC indicated that all LS Power operations personnel have compliance obligations and responsibilities with experience across multiple operating jurisdictions including ISO.

LSPGC provided a copy of that LS Power's NERC compliance plan and indicated that it is intended to provide a functional framework that outlines the guiding principles, governance structure, and internal compliance management activities implemented at LS Power entities in support of its commitment to the secure and reliable operation of the bulk electric system and compliance with the NERC reliability standards.

LSPGC described LS Power's enterprise compliance management program. LSPGC indicated that LS Power's strong governance program is sustained by clearly defining roles and responsibilities, followed by assignment of ownership in oversight, execution, and support accountabilities throughout the organization. LSPGC provided information on LS Power's NERC compliance organization structure, which is headed by a steering committee and chief compliance officer that is the NERC senior manager responsible for all NERC compliance for LS Power's transmission facilities and is the ultimate owner and approver for the enterprise compliance program and implementation. The information provided also describes the roles and responsibilities of the organization structure.

LSPGC indicated that it does not require any waivers under TCA Section 5.1.6. (O-7)

LSPGC indicated that LS Power's affiliates currently own transmission facilities in six states. LSPGC indicated that:

- LS Power affiliate Cross Texas Transmission currently owns approximately 300 miles of 345 kV transmission lines, three 345 kV switching stations and one 345 kV series compensation station located in Texas.
- LS Power affiliate Great Basin Transmission South, LLC owns 75% of 231 miles of 500 kV single circuit transmission lines, one 500 kV substation, eight miles of 345 kV single circuit transmission lines, and two 345 kV series capacitors located in Nevada.
- LS Power affiliate DesertLink owns 60 miles of 500 kV single circuit transmission lines and one series compensation station located in Nevada.
- LS Power affiliate Silver Run owns six miles of 230 kV transmission lines and one 230 kV substation located in Delaware and New Jersey.
- LS Power affiliate Republic Transmission, LLC owns approximately 31 miles of single circuit 345 kV transmission lines located in Indiana.
- LS Power affiliate LSPGNY owns approximately ten miles of 345 kV single-circuit transmission lines.
- LS Power currently operates the transmission facilities located in Texas, Delaware, New Jersey, and New York.

LSPGC provided a 2016 Texas reliability entity compliance audit report that concluded that based on the results of this audit, no findings were noted for the standards and applicable requirements that were included in the scope of this engagement. (O-8)

LSPGC indicated that it would rely on the coordinated functional registration that would be in place with the ISO by 2024 for the Orchard STATCOM and Fern Road GIS/STATCOM projects to divide responsibility for NERC reliability standards on this project. (O-9)

LSPGC indicated that the responsibilities and authority regarding the transmission operator and adjacent transmission operator(s) functions would be defined in an interconnection agreement with each respective adjacent transmission operator.

LSPGC indicated that in the event future generation is connected to the project, the division of responsibility and authority between LSPGC and any generation owner(s) or generation operator(s) would be defined in an interconnection agreement with any generation owner. (O-10)

LSPGC indicated that all of LS Power's existing facilities have fully functioning data acquisition equipment connected to fully redundant communication circuits and terminal equipment at each monitored node. LSPGC indicated that LS Power has an existing communications procedure (copy provided) documenting how it provides adequate and reliable telecommunications facilities to maintain the reliability of the bulk electric system. LSPGC indicated that similar equipment would be installed for the project to ensure adequate, reliable, and redundant data transmission and acquisition capabilities. LSPGC indicated that the communication infrastructure utilized for the project would provide reliable and secure multi-path links between the primary and backup controls centers, ISO, and the project.

LSPGC indicated that LS Power's Austin, Texas control centers (fully functioning primary and live backup location) were constructed to operate, monitor, and control LS Power-owned EHV transmission lines and substations and are equipped with modern and advanced energy management and SCADA systems. LSPGC indicated that these facilities are NERC certified high impact control centers (per CIP-002-5) that currently operate EHV substations and meet all of the physical and cyber security requirements necessary to operate the project.

LSPGC indicated that LS Power affiliate DesertLink currently complies with the requirements of TCA Appendix C Section 4.3. LSPGC indicated that it would submit similar reports to the ISO for the Orchard STATCOM, Fern Road GIS/STATCOM, and this project upon energization. (O-11)

LSPGC indicated that LS Power demonstrates its capability to comply with TCA Sections 6.1 and 6.3 through its existing operations. (O-12)

LSPGC indicated that LS Power's operations and maintenance group has experience managing emergency responses for wildfires, snow and ice storms, thunderstorms, hurricanes, and tornados.

LSPGC indicated that LS Power's transmission system operating, and support personnel are trained regularly on emergency operations procedures and are familiar with the various reporting requirements associated with system emergencies. LSPGC indicated that the project would be incorporated into the emergency response plans of LS Power leveraging its experience, labor, equipment, and processes. LSPGC provided copies of LS Power's emergency operations plan, emergency response plan and system restoration plan.

LSPGC indicated that LS Power maintains master service agreements with transmission line contractors, vegetation management contractors, helicopter services, equipment suppliers, and material suppliers to supplement its staff and resources as may be necessary. LSPGC indicated that these contracted resources, can be quickly mobilized to the project in the event of an emergency.

LSPGC indicated that LS Power maintains communication and coordination with ISO/RTOs throughout the emergency repair process, maintains records of the event, and submits reports to the ISO/RTO in accordance with ISO/RTO agreements. (O-13)

LSPGC indicated that the project would not be subject to any encumbrance on the ISO's operational control. (O-14)

LSPGC indicated that LS Power has the internal resources to manage major rebuilds with its maintenance contractor and its emergency response contractor available to perform work pursuant to the master services agreement for emergency response and field services.

LSPGC indicated that while LS Power does not anticipate the need for major rebuilds over the life of the project, a financial strategy would be maintained that would be crafted specifically for major rebuilds associated with adverse weather or other emergency events that be encountered by the project. LSPGC indicated that this strategy involves maintaining cash reserves to complete maintenance and LSPGC's existing working capital revolver of $20 million.

LSPGC indicated that the project would be designed to accomplish high availability in part through installed and stored spares. LSPGC indicated that LS Power's project design includes advanced monitoring capabilities allowing maintenance personnel to remotely monitor the condition of major equipment.

LSPGC indicated that it would maintain critical spare parts and materials required to repair system facilities, including HVDC valves, control panels, protection panels, cooling system, medium voltage equipment, and AC/DC equipment. LSPGC indicated that the spare parts inventory would be in addition to the more than 3% redundant HVDC valve submodules that would be included as installed spares. LSPGC indicated that the onsite spare parts would be available to replace fully damaged submodules or a failed control system in the event of a failure, ensuring the downtime associated with a forced outage in minimized. LSPGC indicated that a spare transformer and phase reactor would be stored on each HVDC terminal site and would be shared between the three transformers and six reactors, respectively. LSPGC indicated that adequate cooling system components would be provided and stored on-site to conduct ongoing maintenance as required.

LSPGC indicated that LS Power has access to the equipment necessary to replace or rebuild the facilities utilizing owned equipment and through existing agreements with major contractors. (O-15)

LSPGC indicated that the Texas reliability entity conducted a CIP audit of Cross Texas Transmission in 2019 that identified compliance violations of five standards. LSPGC indicated that following the audit findings, Cross Texas Transmission conducted a deep-dive compliance oversight review and self-reported seven additional standard violations.

LSPGC listed each compliance standard violation and indicated that each has been properly mitigated and the enterprise compliance program has been fortified to prevent the re-occurrence of similar violations. LSPGC indicated that this is further supported by the Texas reliability entity's disposal of all but one standard violation as a compliance exceptions. (O-8, O-16)

LSPGC indicated that an LS Power affiliate, Cross Texas Transmission, self-reported one violation of ERCOT nodal protocols. LSPGC indicated that Cross Texas

Transmission discovered it did not revoke a user's digital certificate within three days of the user resigning from Cross Texas Transmission and that the certificate in question was installed on a laptop that was returned when the individual's employment ended. LSPGC indicated that although the certificate was not revoked within three business days, the former employee had no access to the laptop or certificate to gain access. LSPGC indicated that as a result of this event, Cross Texas Transmission created an event driven task in its compliance tracking tool that triggers a task upon receiving an employee termination notification to revoke any issued digital certificates.

LSPGC indicated that neither LSPGC nor any LS Power affiliates have been found in violation of any operations-related tariff or FERC rules violations in the past ten years. (O-17)

LSPGC indicated that neither LSPGC nor any LS Power affiliates have been found in violation of any operations-related laws, statutes, rules, or regulations by any court or agency in the past ten years that have not been previously discussed. (O-18)

3.10.12 Information Provided by SEGG

SEGG provided its experience and the experience of its contractors with operating substation and transmission line projects. The information included nine substation and transmission line operation projects that operate at voltages above 200 kV and are ongoing or have been completed in the past ten years, all nine of which were located in the U.S., including three in California. Of the nine U.S. projects, two were underground projects. Of the nine total projects, none included an HVDC component. (Prior Projects and Experience Workbook)

SEGG indicated that it is currently engaged in numerous contracts with its O&M contractor for other projects and would create a custom contract for this project with its O&M contractor, if selected as the approved project sponsor for this project.

SEGG indicated that its O&M contractor would register as the Transmission Operator (TOP), via its operations contractor (its O&M contractor affiliate).

SEGG indicated that major O&M activities, in coordination with its O&M subcontractors, would include:

- Maintain operations switching support clearances for construction and scheduled and unscheduled maintenance of the facilities, and conduct switching as required.
- Maintain operations switching support clearances for operations, including with other applicable operating entities indicated by good utility practices and conduct switching as required.
- Responsible for station power availability and quality.
- Responsible for total load dispatch.
- SEGG's operations contractor would conduct all aspects of 24x7 transmission operations as defined in a separate transmission operator services agreement. (CC-3, CC-5, O-1)

SEGG indicated that its O&M contractor strives to obtain the best qualified applicant for each job opening while complying with all federal, state, and local employment regulations.

- SEGG indicated that requirements for field personnel include:
- Transmission, WECC power grid and substation technical and leadership experience with a work history that demonstrates a pattern of accomplishments and advancement.
- Bachelor of Science degree in electrical engineering or equivalent desired.

SEGG indicated that desired skillsets include:
- Budget preparation
- Transmission operations and maintenance
- Substation operations and maintenance
- Safety policies and procedures
- Compliance awareness (NERC, environmental)
- Outage management
- Team leadership
- Verbal and written communications

SEGG indicated that its operations contractor’s transmission operators are all NERC certified System Operators at the Reliability Coordinator level and that they have all passed the following four exams:
- The Reliability Examination;
- The Balancing, Interchange, and Transmission Examination;
- The Transmission Examination; and
- The Balancing Examination

SEGG indicated that in addition, these personnel maintain their System Operator certifications by completing all necessary continuing education requirements on a three-year cycle. SEGG indicated that these personnel also maintain a PJM transmission and PJM generation certifications and maintain these licenses by completing the necessary CEHs every five years. (O-2)

SEGG indicated that its O&M contractor training program encompasses all aspects of training, including management, operations, maintenance, environmental considerations, safety programs, and administration. SEGG indicated that the training program applies to all employees, and the senior operations director and project manager have overall responsibility for ensuring that the training program is successful.

SEGG indicated that the qualification process includes hands-on training as well as classroom and self-study training. SEGG indicated that its O&M contractor ensures that every O&M technician is qualified to operate the facility by the time the facility commences commercial operations. SEGG indicated that the O&M technicians would have completed the respective portion of the sign-off sheet prior to operating any particular piece of equipment.

SEGG indicated that for operations training, pre-commercial engineering, procurement, and construction contractor training provides plant personnel with a sound understanding of the plant's design and the methodologies of component and equipment operation, including an understanding of the integrated and dynamic plant operations in normal and off-normal situations. SEGG indicated that such training makes use of the

O&M procedures developed for the plant, which are a key element on which the training is based.

SEGG indicated that all Transmission Operator certifications are maintained as required by both NERC and PJM. SEGG indicated that the electrician and lineman qualifications would be maintained per utility best practice and would be required of any and all subcontractors utilized by its O&M contractor in the performance of these duties. (O-3)

SEGG indicated that at this time it does not anticipate any changes or exceptions to the provisions of the TCA to be required. (O-4)

SEGG indicated that its operations contractor would be the registered Transmission Operator (TOP) and the project sponsor would be the registered Transmission Owner (TO) and Transmission Planner (TP) for the project. SEGG indicated that a Balancing Authority registration is assumed to be unnecessary for this project, however, its operations contractor is also a registered Balancing Authority and would take on this responsibility should it become necessary. (O-5)

SEGG indicated that its O&M contractor would perform all NERC activities for this project. SEGG indicated that its O&M contractor would perform these services internally from the resources and expertise of its headquarters-based NERC department and would not contract out NERC services. (O-6)

SEGG indicated that the mobilization and commercial operations periods would be overseen by the senior operations director. SEGG indicated that the operations director is tasked with coordinating and completing all mobilization services and is the primary point person for coordinating all its O&M contractor’s home office support for the project and during the commercial operations periods.

SEGG indicated that the operations director would be responsible for managing and directing the on-site project manager to achieve client and its O&M contractor’s objectives, including meeting contractual requirements and performance standards through implementing its O&M contractor’s policies, programs, and processes. SEGG indicated that on a continuing basis, the operations director would evaluate O&M performance to identify and implement appropriate follow-up actions that would ensure the required objectives are met.

SEGG indicated that O&M services would be managed by the project manager, who would report to the senior operations director and interact with the transmission operator and SEGG. SEGG indicated that the project manager would manage the project substations, transmission line, aerial portion of the overhead/underground transition assets, right-of-way, and other related project facilities.

SEGG indicated that NERC enforceable reliability standards often include requirements to complete an activity in the future on an established schedule, such as an obligation to review a procedure annually or obtain approval of a procedure annually (compliance milestone). SEGG indicated that these requirements must be used as the minimum input internal to its operations contractor timelines.

SEGG described its operations contractor’s milestone management process, which consist of meetings with involved parties to manage compliance milestones.

SEGG indicated that there are no applicable reliability criteria for which the project sponsor is responsible that require temporary waivers under TCA Section 5.1.6 at this time. (O-7)

SEGG indicated that its O&M contractor has significant experience as a registered Generator Owner and Generator Operator. SEGG indicated that it has been through nearly 200 audits across its registrations with no audit discovered violations since 2012. SEGG indicated that in addition, it is a registered Transmission Operator through its O&M contractor's affiliate, which would be its operations contractor. SEGG indicated that its operations contractor has not had a Transmission Operations audit related violation and has passed certification reviews by SERC and PJM.

SEGG indicated that its O&M contractor is a leader in NERC reliability and CIP compliance with an in-house and highly experienced and proven team of over 20 NERC professionals that includes auditors, industry experts, and NERC and CIP reliability specialists. SEGG indicated that it provides services to over 150 power generation facilities, including facilities for which its O&M contractor is registered as the Generator Operator or Transmission Operator.

SEGG provided a list showing its O&M contractor's experience with generation facilities subject to NERC compliance, which showed no violations since 2012. (O-8)

SEGG indicated that its O&M contractor and its subsidiary that would serve as its operations contractor would provide technical leadership and program coordination in NERC reliability program compliance, and it would work in coordination with the project proponent and ISO. SEGG indicated that its O&M contractor would enter into a coordinated functional registration agreement with the ISO similar to the existing agreements posted on the ISO website. (O-9)

SEGG indicated that its O&M contractor would create and execute necessary agreements with interconnected or neighboring generating facility owners and operators, transmission facility owners and operators, and balancing authorities. SEGG indicated that it recognizes that, in general, many of these functions are led or supported by the ISO, and its O&M contractor would become a party to the ISO TCA. SEGG indicated that for the functions that are not led or supported by the ISO, its O&M contractor would utilize existing or create new agreements with each counterparty. (O-10)

SEGG indicated that its operations contractor, its O&M contractor affiliate, would conduct all aspects of 24x7 transmission operations that includes a control center based in Texas and backup control center facilities. SEGG indicated that in addition, its operations contractor has two remote data centers that are "hot-hot" to ensure no loss of data could occur.

SEGG indicated that its operations contractor would submit an annual report to the ISO within 90 days after the end of each calendar year describing the project's availability measures performance. SEGG indicated that this annual report would be based on forced outage records, which would include the date, start time, end time, affected transmission facility, and the problem cause. (O-11)

SEGG indicated that its O&M contractor and its operations contractor have extensive experience in managing and operating the activities required by TCA Sections 6.1 and 6.3. (O-12)

SEGG indicated that its O&M contractor maintains emergency operating or “casualty” procedures that contain the actions to be followed in response to critical conditions on the system, such as trips, fire, loss of AC power, etc.

SEGG indicated that immediate actions are performed quickly to place the system in a safe condition and that supplementary actions are performed to further stabilize the system and/or to restore the system to normal operations. SEGG indicated that supplementary actions would be reviewed prior to being performed, and some may be performed simultaneously due to the various probable causes for a particular casualty situation. SEGG provided a sample emergency operating procedure regarding major fire response.

SEGG indicated that its O&M contractor would either directly, through mutual assistance agreements, or through subcontractors, maintain the necessary human resources to respond to a major problem associated with the project within four hours of its occurrence irrespective of the nature of the problem. SEGG indicated that its O&M contractor, through its operations contractor, would be monitoring the project in real time and would make call notifications as necessary to mobilize appropriate personnel to address the specific problem identified. (O-13)

SEGG indicated that it is not aware of any encumbrances to the project at this time. (O-14)

SEGG indicated that in the proposed solution, efficient repair and/or replacement of the main equipment is ensured using both adequate design measures and effective service and maintenance execution capabilities during the O&M phase of the asset.

SEGG indicated that its O&M contractor’s predictive and preventative maintenance programs are meant to provide real-time condition assessments of the operating equipment and that major equipment replacement would be based primarily on periodic condition assessments and appropriate capital funds would be made to replace equipment, as necessary. SEGG indicated that the project would maintain adequate spares to ensure replacement on an emergency basis to prudent equipment. SEGG indicated that in addition, built in redundancy should ensure that any singular failure would not result in significant down time.

SEGG indicated that consistent with the objective of maximizing operational availability of equipment when doing so would be cost effective, at the appropriate time, adequate spare parts supplies would be procured and maintained to satisfy preventive maintenance and probable corrective maintenance requirements. SEGG indicated that purchases of spare parts would be based upon an evaluation of criticality, availability, lead time, and cost, and the spare parts and spare equipment strategy would be documented and regularly evaluated. SEGG indicated that per TPL-001-5.1 requirements, all spare equipment that cannot be replaced within one year of equipment failure would be evaluated in an annual planning assessment to determine impacts to the transmission system associated with the potential for long-term outages of such equipment and the results of this analysis would be used to refine and update the spare parts and spare equipment strategy used. SEGG indicated that all spare parts, including consumables and materials, would be received, maintained, and stored at the project site. SEGG indicated that, as feasible, potential alliances with nearby utilities or manufacturers would also be pursued to seek opportunities for the option to utilize spare off-site equipment such as replacement transmission transformers if ever needed.

SEGG listed its proposed spare parts.

SEGG indicated that additional spares would be identified during the procurement process that are either longer lead time durations or determined critical in nature, would be procured for the project, and would be based upon the system needs. (O-15)

SEGG indicated that its O&M contractor, and its subsidiary that would serve as its operations contractor, as a registered TO or TOP has not had any violations of NERC reliability standards in the past ten years.

SEGG indicated that there have been some NERC non-compliance issues at SEGG-owned projects; however, all of these have been minor, and none has resulted in NERC violations or penalties. (O-16)

SEGG indicated that its O&M contractor, and its subsidiary that would serve as its operations contractor, has not received an operations related tariff violation or FERC rules violation in the past ten years.

SEGG indicated that SEGG is not aware of any operations related tariff violations or FERC rules violations in the past ten years. (O-17)

SEGG indicated that its O&M contractor, and its subsidiary that would serve as its operations contractor, have not incurred any violations of operations-related laws, statues, rules, or regulations not discussed elsewhere in its proposal.

SEGG indicated that there have been some NERC non-compliance issues at SEGG-owned projects; however, SEGG asserted that all of these have been minor, and none has resulted in NERC violations or penalties. SEGG indicated that some SEGG-owned projects have had environmental permit non-compliance issues, but SEGG asserted that none of them were considered to be material issues. SEGG indicated that the Pennsylvania Reasonably Available Control Technology (RACT) rule II notice of violation for air emissions was settled with the Pennsylvania Department of Environmental Protection. (O-18)

SEGG indicated that its O&M contractor does not have any operations risks and challenges that it has previously faced that would be comparable to the risks and challenges associated with this project. (P-5)

3.10.13 ISO Comparative Analysis

Comparative Analysis of Construction Practices

For purposes of the comparative analysis for this component of the factor, the ISO has considered the representations by the project sponsors regarding the construction practices they propose for this project, including but not limited to their proposed design criteria and constructability review process.

All of the project sponsors provided a detailed design criteria and constructability review processes that demonstrate that their respective projects would adhere to standardized construction standards.

Based on these considerations, in conjunction with all the other considerations included in the ISO's analysis for this component of the factor, the ISO has determined that there is no material difference among the six proposals of the four project sponsors regarding to this component of the factor.

Comparative Analysis of Maintenance Practices

The ISO has determined that all the project sponsors and their proposed teams have the basic capability to adhere to standardized maintenance practices. Some of the project sponsors and their teams have more well-established organizations and processes related to the maintenance of EHV and HVDC transmission facilities.

Both HWT and its team and LSPGC and its team have experience maintaining facilities under, and complying with, the ISO's transmission maintenance standards under the TCA. In particular, for many years HWT and its team have maintained the TBC HVDC line in the San Francisco Bay Area. HWT and its team have well-established HVDC transmission maintenance practices and maintenance staff and facilities in the San Francisco Bay Area.

LSPGC will incorporate the project into its existing maintenance policies and procedures that it utilizes for maintaining other transmission facilities across the country. LSPGC will have an in-house technician in the immediate vicinity of the project, and it has retained several maintenance contractors with extensive bulk transmission experience, including experience maintaining underground transmission lines and extensive experience with bulk transmission, within reasonable driving distance of the project. LSPGC has also retained an HVDC transmission OEM with specialized HVDC transmission experience. LSPGC has also retained a services provider to provide specialized maintenance and technical support for the HVDC terminals.

The ISO has determined that HWT's proposals and LSPGC's proposal are better than the proposals of Avangrid and SEGG in this regard. Neither Avangrid and its team nor SEGG and its team has experience actually maintaining facilities under the TCA maintenance provisions. Avangrid, however, owns and operates eight regulated utilities in the Northeast, with four electric utilities in both ISO-NE and NYISO territories, and has standard operating procedures that apply to the maintenance of the transmission and distribution facilities. For maintenance activities, Avangrid will utilize in-house personnel, a maintenance contractor in the San Francisco Bay Area with underground transmission experience, and its specified HVDC transmission OEM for HVDC transmission maintenance. SEGG identified a general maintenance contractor, two specialty subcontractors, and its HVDC transmission OEM for maintenance activities. SEGG and its team have less overall experience developing and complying with applicable maintenance standards and practices than Avangrid and its team, in particular standards and practices for underground transmission lines.

Based on the foregoing considerations, in conjunction with all the other considerations included in the ISO's analysis for this component of the factor, the ISO has determined that, based on the specific scope of this project, there is no material difference between HWT's bay crossing and inland route proposals, and they are slightly better than LSPGC's proposal, which is slightly better than Avangrid's proposals 1 and 2, between which there is no material difference, which are slightly better than the proposal of SEGG, regarding this component of the factor.

Comparative Analysis of Operating Practices

The ISO has determined that all the project sponsors and their proposed teams have the basic capability to adhere to standardized operating practices, NERC standards, the TCA, operating agreements, and applicable tariff provisions. Some of the project sponsors have more well-established organizations and processes related to the operation of EHV and HVDC transmission facilities.

HWT and its team and LSPGC and its team operate transmission facilities under the ISO's operational control that are required to comply with NERC standards, the TCA, and the ISO Tariff. HWT operates the TBC HVDC line in the San Francisco Bay Area under the ISO's operational control. HWT and LSPGC and their teams also have transmission facilities in other parts of the country that are required to operate in compliance with NERC and ISO/RTO standards; however, LSPGC does not operate any HVDC transmission facilities. Neither Avangrid nor SEGG has transmission facilities operating under the ISO's operational control that are subject to the TCA and the ISO Tariff. Avangrid and its team have successfully operated extensive bulk electric transmission facilities subject to the NERC reliability standards and ISO/RTO tariffs and operating agreements. SEGG's team has less experience operating bulk electric transmission facilities under ISO/RTO tariffs and the NERC standards, but SEGG operates an HVDC transmission line in the NYISO. An Avangrid affiliate operates HVDC transmission facilities in the United Kingdom. The ISO considers LSPGC's experience operating facilities under the ISO's operational control and the experience of Avangrid's and SEGG's teams operating HVDC facilities in other jurisdictions to be equally important regarding their potential contribution to success in operating this project.

The ISO has determined there are no material differences in the emergency response capabilities of the project sponsors and their teams.

Based on the foregoing considerations, in conjunction with all the other considerations included in the ISO's analysis for this component of the factor, the ISO has determined that, based on the specific scope of this project, there is no material difference between HWT's bay crossing and inland route proposals, and they are slightly better than Avangrid's proposals 1 and 2, LSPGC's proposal, and SEGG's proposal, among which there is no material difference, based on the various factors considered regarding this component of the factor, some of which were offsetting.

Overall Comparative Analysis

The ISO considers the three components of this factor to be of roughly equal importance in the selection process for this project.

Regarding the first component of this factor (demonstrated capability to adhere to standardized construction practices), the ISO has determined that there is no material difference among the proposals of Avangrid, for its proposals 1 and 2, HWT, for its bay crossing and inland route proposals, LSPGC, and SEGG.

Regarding the second component of this factor (demonstrated capability to adhere to standardized maintenance practices), the ISO has determined that there is no material difference between HWT's bay crossing and inland route proposals, which are slightly better than LSPGC's proposal, which is slightly better than Avangrid's proposals 1 and 2, between which there is no material difference, which are slightly better than SEGG's proposal.

Regarding the third component of this factor (demonstrated capability to adhere to standardized operating practices), the ISO has determined that there is no material difference between HWT's bay crossing and inland route proposals, which are slightly better than Avangrid's proposals 1 and 2, LSPGC's proposal, and SEGG's proposal, which the ISO has determined to be comparable after accounting for certain offsetting considerations.

Based on the combination of the foregoing comparisons for the three components of this factor, the ISO has determined that there is no material difference between HWT's bay crossing and inland route proposals, and they are slightly better than LSPGC's proposal, which is slightly better than Avangrid's proposals 1 and 2, between which there is no material difference, which are slightly better than SEGG's proposal, regarding this factor overall.

3.11 Selection Factor 24.5.4(i): Ability to Assume Liability for Major Losses

(F-14, F-15, O-15)

The ninth selection factor is "demonstrated ability to assume liability for major losses resulting from failure of facilities of the Project Sponsor."

For the consideration of this factor, the ISO has determined that there is no significant difference between the two proposals submitted by Avangrid or between the two proposals submitted by HWT. Consequently, references to Avangrid and its proposal in this section apply equally to both Avangrid's proposal 1 and Avangrid's proposal 2, and references to HWT and its proposal in this section apply equally to both HWT's bay crossing proposal and HWT's inland route proposal.

3.11.1 <u>Information Provided by Avangrid for Proposals 1 and 2</u>

Avangrid indicated that the project would likely be self-financing once operating, but Avangrid would provide contributions of equity or debt financing using the intercompany revolving loan agreement if necessary. (F-15)

Avangrid indicated that it owns and operates eight electric and natural gas utilities with $11.7 billion in rate base. Avangrid indicated that the utilities frequently cover increased costs due to equipment failures. Over the past three years, Avangrid indicated that it has spent $5.7 billion in capital expenditures to upgrade and expand electricity and natural gas transmission and distribution infrastructure. Avangrid indicated that the cost to replace equipment would be covered by cash available on hand, debt issuance, equity infusions, or a combination of these options. (F-15)

Avangrid described a comprehensive program of insurance coverage it would provide during the different phases of the project, including builders all risk and construction all-risk property insurance during the construction phase, and general liability and property insurance (with the exception of poles and overhead and underground conductor) during the operations phase. Avangrid indicated that all contractors would be required to maintain insurance coverage prior to their engagement. (F-14)

Avangrid indicated that it has worked with suppliers to develop a plan to replace major failed equipment in a timely manner that balances project costs and risks from outages in accordance with good utility practice. (O-15)

Avangrid indicated that it would have available one operational spare converter station transformer of each type at each site available in case any major failure happens to any transformer. Avangrid also provided a list of other spare equipment that it plans to have available for the project. (O-15)

3.11.2 Information Provided by HWT for Bay Crossing and Inland Route

HWT indicated that it is well-capitalized and would rely on its internal financial resources, including operating revenues from its projects, as well as its NEECH debt facility, to fund unexpected repairs during the project's expected 60-year useful life. In addition, HWT indicated that it would have access to additional equity funding, additional credit facilities, and a robust insurance program to finance unexpected repairs both during construction and over the life of the project. HWT indicated that access to additional parent equity and debt funding is backed by NextEra, which has access to and regularly secures financing in the public debt and equity markets. (F-15)

HWT indicated that it is covered by NextEra's property all-risk insurance program that would cover the project from "all risks" of direct physical loss or damage, including but not limited to mechanical and electrical breakdown, flood, earthquake, wind storm, and terrorism. HWT indicated that it maintains and would maintain a commercial general liability insurance program with industry leading insurance carriers with limits commensurate with industry standards that provides protection against liability claims for bodily injury and property damage. HWT indicated that the insured values during construction and over the operational life of the project facilities would not be less than the full replacement cost of the facility and would include the entire extent of failure of project facilities during the operation of the project. HWT indicated that during construction and operations, it would also maintain California fire related liability coverage. (F-14)

HWT indicated that the project design includes a spare converter station transformer in each converter location. HWT indicated that it would also have access to its affiliate company-wide spares sharing program, specifically FPL spares and strategic support of equipment suppliers. HWT indicated that it has plans in place for transformer replacement, circuit breaker replacement, and restoration of transmission line facilities. (O-15)

HWT indicated the project would be built to FPL equipment design standards to the extent possible so that the project can be incorporated into the larger NextEra spare parts management program, thus improving access to critical spares. (O-15)

HWT indicated that its project operator, TBC, possesses substantial experience, and capability, which would be utilized to support operational and maintenance needs of the project. (O-15)

HWT indicated that it would maintain a spare stock of OEM converter station spare parts, underground cable spare parts, and spares for the AC yard equipment. (O-15)

3.11.3 Information Provided by LSPGC

LSPGC indicated that major capital replacements and rebuilds necessary over the life of the project would be financed through retained earnings, owner cash reserves, revolving lines of credit, and insurance proceeds. LSPGC indicated it would maintain cash operating reserves and a line of credit to cover unexpected capital replacements, as well as insurance coverage for catastrophic events. (F-15)

Throughout the construction period and operational life of the project, LSPGC indicated that it would maintain substantial insurance coverage with companies rated “A-” or better with a minimum financial size classification of “X,” by A.M. Best (or an equivalent rating). LSPGC indicated that, through LS Power, it currently maintains liability insurance that would include the project. During construction, LSPGC indicated it would be protected by builder’s all-risk insurance coverage that would provide coverage for the project on an “all risk basis” on a completed value form inclusive of earthquake, flood, windstorm, collapse, sinkhole, subsidence, testing, commissioning, riot, and civil commotion coverage, on a no coinsurance basis. Once operational, LSPGC indicated the project would be included in LS Power’s property all-risk insurance program, which is planned to cover full replacement value of the project based upon customary and currently available coverage.

In addition, LSPGC indicated that it plans to require contractors and subcontractors to have an appropriate level of insurance for the scope of work to be performed.

In the event of multiple project awards, LSPGC indicated it would maintain the insurance coverage types described above with coverage amounts for property all-risk insurance and builder’s all-risk insurance being adjusted for each project award. (F-14)

LSPGC indicated it would maintain critical spare parts and materials required to repair system facilities including HVDC valves, control panels, protection panels, cooling systems, medium voltage equipment, and AC/DC yard equipment. LSPGC indicated a spare converter station transformer and phase reactor would be stored at each HVDC terminal site. LSPGC indicated adequate cooling system components would be provided and stored on site. (O-15)

LS Power indicated it has access to the equipment necessary to replace or rebuild the facilities utilizing owned equipment and through existing agreements with major contractors. (O-15)

3.11.4 Information Provided by SEGG

SEGG indicated that the project sponsor would have sufficient access to financing to cover the project cost and potential cost overruns. SEGG indicated that its team has successfully dealt with equipment failures at prior projects. (F-15)

To address the possibility of major losses resulting from facilities failures, SEGG indicated that it would rely on:

(1) Insurance,
(2) Long term parts and services agreements where risks are transferred to service or equipment providers,
(3) Working capital facilities available under project debt,
(4) Project cash, and
(5) Equity contribution.

(F-15)

SEGG indicated that it plans to maintain insurance for the project that is typical of industry standards and required for debt financing. SEGG indicated that this would include coverage based on replacement value, as well as business interruption and general liability. (F-14)

SEGG provided maintenance procedures for the major components of its project, e.g. transformers, circuit breakers, etc. SEGG indicated that its proposed design includes a spare transformer at each converter station. (O-15)

3.11.5 ISO Comparative Analysis

For purposes of the comparative analysis for this factor, the ISO has considered the representations by the project sponsors regarding their resources and plans for assuming responsibility for losses resulting from failure of project facilities, including but not limited to their financial resources, proposed insurance, and other plans for mitigation of equipment failures.

Financial Resources

As discussed above and in Section 3.7 of this report, the financial resources of the project sponsors vary, and their proposals vary as to how they would finance emergency repairs. Nevertheless, the ISO has determined that all four project sponsors have the financial resources to finance or otherwise assume liability for major losses resulting from failure of project facilities.

Insurance

The ISO has determined that all four project sponsors have identified comparable insurance coverage for their proposals, including coverage during the operation of the project up to replacement value.

Mitigation of Equipment Failures

All four project sponsors identified reasonable approaches to maintaining spare parts for use in the event of a major equipment failure. One of the largest potential failures for the project from a financial risk perspective would be a catastrophic failure of a converter station transformer. There would be a significant capital expenditure to replace the failed transformer, as well as a reliability risk to the system until a replacement transformer could be placed into service. All project sponsors included spare replacement transformers as part of their proposals. All proposals also included a set of spare parts, or a plan for procuring spare parts, in addition to the spare transformer.

Overall Analysis

The ISO has concluded that all four project sponsors have sufficient financial resources, insurance coverage, and operational arrangements for their six proposals to make necessary repairs and return the facilities to service in a reasonable period of time. Based on the foregoing considerations, in conjunction with all the other considerations included in the ISO's analysis for this factor, the ISO has determined that, based on the specific scope of this project, there is no material difference among Avangrid, HWT, LSPGC, and SEGG and their six proposals regarding this factor.

3.12 Selection Factor 24.5.4(j): Cost Containment Capability, Binding Cost Cap and Siting Authority Cost Cap Authority

The tenth selection factor is "demonstrated cost containment capability of the Project Sponsor and its team, specifically, binding cost control measures the Project Sponsor agrees to accept, including any binding agreement by the Project Sponsor and its team to accept a cost cap that would preclude costs for the transmission solution above the cap from being recovered through the ISO's Transmission Access Charge, and, if none of the competing Project Sponsors proposes a binding cost cap, the authority of the selected siting authority to impose binding cost caps or cost containment measures on the Project Sponsor, and its history of imposing such measures." As discussed in Section 2.1 of this report, the ISO identified this selection factor as a key selection factor for this project because under ISO Tariff Section 24.5.1, binding cost containment commitments are a key selection factor in every ISO competitive solicitation.

For the purpose of performing the comparative analysis for this factor, the ISO has initially considered the two components of the factor separately and then combined them into an overall comparative analysis for this factor. The two components are:
(1) demonstrated cost containment capability of the project sponsor and its team, including any binding agreement by the project sponsor and its team to accept a cost cap that would preclude project costs above the cap from being recovered through the ISO's transmission access charge, and (2) if none of the competing project sponsors propose a binding cost cap, the authority of the selected siting authority to impose binding cost caps or cost containment measures on the project sponsor and its history of imposing such measures.

All four project sponsors provided binding capital cost containment proposals for their six proposals. The proposals had various provisions regarding cost escalation. The ISO retained a well-respected expert consulting firm to assist, *inter alia,* in evaluating the project sponsors' cost containment proposals and conducting cost of service and revenue requirement studies. The studies and analyses conducted by the consulting firm were extensive, including numerous sensitivity analyses. In addition to evaluating the proposals regarding their binding cost containment measures, the ISO evaluated each project sponsor's proposal regarding the following factors relating to cost containment:

- Cost containment performance for past projects
- Project management capabilities
- Project risks and mitigation of risks

Cost Containment Capability Including Binding Cost Cap

(Prior Projects and Experience Workbook, Cost and Cost Containment Workbook; P-1, P-2, P-4, CC-1 through CC-15, S-1)

3.12.1 Information Provided by Avangrid for Proposals 1 and 2

Cost Containment

Avangrid proposed the following cost containment measures for its proposal 1:

- A capital cost cap;
- A cap on the return on equity;
- A cap on the percentage of equity in the project; and
- An annual revenue requirement cap for a limited period of time

(CC-1; Cost and Cost Containment Workbook)

Avangrid indicated that it identified a number of opportunities for cost savings if awarded more than one HVDC project. (A-4)

Avangrid proposed specified exclusions from its cost caps and rate treatment for any incurred costs associated with such exclusions. (CC-7-CC-15)

Avangrid proposed the following cost containment measures for its proposal 2:

- A capital cost cap;
- A cap on the return on equity;
- A cap on the percentage of equity in the project; and
- An annual revenue requirement cap for a limited period of time.

(CC-1; Cost and Cost Containment Workbook)

Avangrid indicated that it identified a number of opportunities for cost savings if awarded more than one HVDC project. (A-4)

Avangrid proposed specified exclusions from its cost caps and rate treatment for any incurred costs associated with such exclusions. (CC-7-CC-15)

Cost Containment Performance for Past Projects

Avangrid provided a list of project experience for its substation and transmission line projects that included its actual cost versus budget performance. Avangrid provided budget and actual cost information on a project-by-project basis, and, if applicable, identified major issues or challenges faced on a particular project.

Regarding substation projects operating at voltages above 200 kV that are ongoing or have been completed in the past ten years and are located in the U.S., the Information provided included three projects. Of these three substation projects, one substation project was completed above budget by 55% because the project was delayed due to previously unforeseen upgrades that the host utility was required to make due to the retirement of a nuclear power plant. The remaining two substation projects were completed below budget. One substation with an original budget greater than $1 billion was completed 1.8% below budget and the other with an original budget of less than $100 million was completed 7.6% below budget.

Regarding transmission line projects operating at voltages above 200 kV that are ongoing or have been completed in the past ten years and are located in the U.S., the Information provided included three projects. Of these three transmission line projects, one project was above budget by 55% because the project was delayed due to previously unforeseen upgrades that the host utility was required to make due to the retirement of a nuclear power plant. The remaining two transmission line projects were completed below budget. One transmission line project with an original budget greater than $1 billion was completed 1.8% below budget and the other with an original budget of nearly $100 million was completed 33% below budget. (Prior Projects and Experience Workbook)

Project Management Capabilities

Avangrid indicated that the project would be executed by its projects organization, which is International Standards Organization 9001 and 14001 compliant and certified regarding quality management systems and environmental management systems. Avangrid indicated that the 295-person projects organization includes professional engineers, schedulers, certified project management professionals and construction managers in all disciplines necessary to successfully deliver substation and transmission projects. (P-1)

Avangrid provided information on the key project management team members, as well as their responsibilities, including the project manager. Avangrid indicated that the project manager role would be filled by an individual with extensive experience developing and constructing complex high voltage transmission line and substation projects. (P-2)

Avangrid indicated that it would draw on the resources of its parent companies governed by a newly executed service agreement. Avangrid also indicated that it would establish a steering committee to provide strategic direction and ensure visibility and coordination on the project for Avangrid corporate leadership. (P-2)

Project Risks and Mitigation of Risks

Avangrid indicated that it has developed a proven methodology to identify and mitigate project risks that is being employed for this project. Avangrid indicated that this methodology follows a risk management cycle as found in the project management body of knowledge where risks are identified and analyzed.

Avangrid indicated that this analysis results in the cost impacts of the risks being identified, with mitigation strategies created to contain cost impacts for the project. Avangrid further indicated that this process would be done throughout the course of the project as new risks are identified and other risks subside. (P-1)

Avangrid provided a list of the major cost risks identified for the project, with actions to mitigate the likelihood and impact of the risks.

Site control and right of way acquisition: Avangrid indicated that it intends to mitigate any risks associated with site control and right of way acquisition by engaging with key owners and municipalities early in the process, as well as considering alternate locations of converter stations and routing of transmission line.

Project design: Avangrid indicated that it intends to mitigate any transmission line design risks by selecting routes near existing roads to minimize permitting risks, prioritizing underground construction where possible and minimizing the number of crossings for existing utilities.

Siting and permitting: Avangrid indicated that it has identified several non-governmental organizations as potential stakeholders to be engaged to reduce the risk of opposition to the project during the permitting process.

Procurement: Avangrid indicated that it would utilize an aggressive payment schedule to secure a manufacturing slot for the converter station. Avangrid also indicated that it plans to issue a limited notice to proceed in order to secure a manufacturing slot one year before the expected receipt of the CPCN approval.

Construction Risk: Avangrid indicated that it intends to perform a geotechnical probing program to identify depths to bedrock across the substation site which would be used to further optimize the layout and design to reduce construction costs. (P-4)

Avangrid indicated that its OEMs for proposals 1 and 2 have identified the potential for cost savings due to synergies in project management and engineering for the manufacture of four converter stations if this project and the Metcalf-San Jose B HVDC project were to be staggered by four to six months. Avangrid indicated that, if selected as the approved project sponsor for both projects, it would collaborate with the ISO to determine the best approach to realizing these savings, balancing cost and schedule considerations. (A-4)

3.12.2 <u>Information Provided by HWT for Bay Crossing and Inland Route</u>

Cost Containment

HWT proposed the following cost containment measures for its inland route proposal:

- A capital cost cap;
- A cap on the project's return on equity;
- A cap on the project's equity percentage for a limited period of time;
- An annual revenue requirement cap for a limited period of time;
- A combined capital cost cap for both this project and the Metcalf-San Jose B HVDC project;
- A combined cap on annual revenue requirement for both this project and the Metcalf-San Jose B HVDC project;
- A financial schedule incentive for meeting the project completion date of May 30, 2028.

(CC-1; Cost and Cost Containment Workbook)

HWT also proposed specified exclusions to its proposed cost caps.

(CC-7-CC-15)

HWT proposed the following cost containment measures for its bay crossing proposal:

- A capital cost cap;
- A cap on the project's return on equity;
- A cap on the project's equity percentage for a limited period of time;
- An annual revenue requirement cap for a limited period of time;
- A combined capital cost cap for both this project and the Metcalf-San Jose B HVDC project;
- A combined cap on annual revenue requirement for both this project and the Metcalf-San Jose B HVDC project;
- A financial schedule incentive for meeting the project completion date of April 4, 2028.

(CC-1; Cost and Cost Containment Workbook)

HWT also proposed specified exclusions to its proposed cost caps.

(CC-7-CC-15)

Cost Containment Performance for Past Projects

HWT provided a list of project experience for its substation and transmission line projects regarding its actual cost versus budget performance. HWT provided budget and actual cost information on a project-by-project basis, and, if applicable, it identified major issues or challenges faced on a particular project.

Regarding substation projects operating at voltages above 200 kV, that are ongoing or have been completed in the past ten years and are located in the U.S., the information provided included 55 projects. Of these 55 substation projects, 19 projects ranging in value from around $1 million to $1 billion were above budget by 3.1% on average. The remaining 36 substation projects ranging in value from around $30 million to $2 billion were either on budget or below budget by an average of 4.1%.

Regarding transmission projects that operate at voltages above 200 kV, are ongoing or have been completed in the past ten years and are located in the U.S., the information provided included 22 projects. Of these 22 transmission projects, eight projects ranging in value from $150 million to $1 billion were above budget by an average of 5.3%. Fourteen transmission projects ranging in value from around $100 million to $2 billion were below budget by an average of 3.3%. (Prior Projects and Experience Workbook)

Project Management Capabilities

HWT indicated that it has assembled a project management team that would provide a single point of accountability for day-to-day activities, oversee all project work stream leads and resources, and be responsible for reporting project progress to senior management. HWT provided a list of project management process steps and actions that it would take during its development and construction of the project, including project launch and scoping, master project schedule development, risk identification and mitigation, project cost estimation, and project execution plan. HWT also indicated that throughout the project execution phase, the schedule, budget, and risk logs for the project would be updated and optimized based on current information. HWT also indicated that the project team would produce a project dashboard to provide an up-to-date status of pertinent project metrics. (P-1)

HWT indicated that its core team of professionals and subject matter experts would draw upon the NextEra's matrixed organization of shared resources for the project execution. HWT also provided corporate support services agreements recently executed for other projects for procuring services from NextEra's matrixed organization.
HWT indicated that the project director would provide a single point of accountability for day-to-day project activities and would report project progress to senior management. HWT also provided information on the various teams that would be involved with the project and the personnel belonging to each team and their resumes. (P-2)

Project Risks and Mitigation of Risks

HWT provided a comprehensive risk and issues log that identified the risks specific to the project, and, for each risk, category of risk, whether it affects cost or schedule, the probability of occurrence, the impact of the occurrence, whether it is a risk during development or construction, and planned or potential mitigation. In addition, this log also identified the mitigation plan. HWT's risk and issues log identified more than 50 risks, which were grouped into three categories – allocated contingency, unallocated contingency and price contingency. (P-4)

As discussed in Sections 3.4.2 and 3.4.3, HWT indicated that its proposed transmission line route for both its bay crossing and inland route proposals would cross the Don Edwards National Wildlife Refuge, for which it would have to obtain land rights and permits. (E-1, L-1)

3.12.3 <u>Information Provided by LSPGC</u>

Cost Containment

LSPGC proposed an annual revenue requirement cap for 40 years (ARR Cap Proposal). Under the ARR Cap Proposal, the cap during year 1 would be $102.07 million and would decline to $41.12 million in year 40. LSPGC would not seek recovery of construction work in progress.

The following describes the ARR Cap Proposal as indicated by LSPGC in its proposal. Under the ARR Cap Proposal, if LSPGC's revenue requirement exceeds the cap, LSPGC would only recover revenues in that year up to the cap. The unrecovered difference between the calculated revenue requirement and the calculated cap would be tracked by way of a deferred recovery account. Costs in the deferred recovery account would not earn interest and could only be recovered in future years if LSPGC's revenue requirement is below the annual cap. The amount of any unrecovered costs remaining in the deferred recovery account at the end of the 40-year period would be forfeited, and LSGC would be unable to recover them in rates. If LSPGC's revenue requirement is below the annual cap in a certain year and there is no balance in the deferred recovery account, only actual costs for that year would be recovered.

LSPGC indicated that if FERC does not approve the ARR Cap Proposal, LSPGC would seek an alternative annual revenue requirement cap that would include the same costs as the ARR Cap Proposal but would eliminate the deferred recovery account. Under this alternative proposal, LSPGC indicated that the annual revenue requirement cap in year 1 would be $103.09 million and would decline to $41.53 million in year 40. LSPGC indicated that if its revenue requirement exceeds the annual cap in any year, it would only seek to recover revenues in that year up to the cap, and any excess, unless related to costs specifically excluded from the cost cap (Excluded Costs), would be forfeited. If LSPGC's revenue requirement in any year is below the annual cap, such difference would be added to the cap in the following year, resulting in a revised cap. (CC-1; Cost and Cost Containment Workbook)

Regarding costs excluded from its annual revenue requirement cap, LSPGC indicated that its cap would capture all project costs other than incremental costs that result from (1) a change in the ISO project requirements or the ISO Functional Specifications or a change in LSPGC's design caused by the interconnection agreement or interconnecting PTO, (2) the issuance, enactment, or material change in the enforcement, interpretation, or application of any statute, rule, regulation, or other applicable law that becomes effective after the submission date of LSPGC's proposal, (3) force majeure type events, including but not limited to Uncontrollable Force (as defined in the ISO Tariff), uninsured losses (for example, damage due to an earthquake that requires additional project investment greater than the insurance coverage), a delay in the receipt of permits necessary to construct the project not caused by LSPGC, or impacts from environmental contamination or damage not caused by LSPGC or its contractors, (4) costs associated with capitalized expenditures incurred after the project is placed in service, (5) a requirement to place underground any transmission line identified as an overhead line in its proposal, or (6) additional impositions by a governmental authority. (CC-1)

LSPGC indicated that excluded costs would include additional impositions by a governmental authority. LSPGC identified the following scenarios as constituting additional impositions of a governmental authority. If a siting or permitting authority requires relocation of the proposed site for the project and such relocation results in incremental costs incurred, such incremental costs would be considered Excluded Costs. (CC-9) If a siting or permitting authority requires changes to the proposed structures, equipment, or transmission lines for the project, and such change results in incremental costs incurred, such incremental costs would be considered Excluded Costs. (CC-10)

LSPGC indicated that a decision by the siting authority to require an increase in the amount of environmental mitigation beyond that assumed in LSPGC's binding cap proposal would not be a basis for LSPGC to claim relief from the binding cost cap, except to the extent associated with environmental contamination or damage not caused by LSPGC or its contractor. (CC-11)

LSPGC indicated that a requirement for overhead construction instead of underground would not affect the proposed cost containment measures. LSPGC proposes to include within the definition of Excluded costs incremental costs incurred by the approved project sponsor associated with a requirement to place underground any transmission line identified as an overhead transmission line in its proposal. (CC-12)

LSPGC indicated that a delay attributable to matters beyond LSPGC's control that would impact the date of the schedule incentive and the incremental costs associated with the delay would be considered Excluded Costs. (CC-13) LSPGC also indicated that such a delay could affect the in-service date in its schedule completion incentive. LSPGC proposes to include the following schedule completion incentive language: "…if the Project is not energized on or before June 1, 2028, and such delay is not attributable to matters beyond the Approved Project Sponsor's control, its Project-specific return on equity will be reduced by 2.5 basis points for every full calendar month that the Project's energization is delayed beyond (June 1, 2028) up to a total of 30 basis points." (CC-13)

In addition to the exclusions from its cost cap described above, LSPGC indicated that excluded costs would include: (1) incremental costs incurred by LSPGC associated with (a) a change in the ISO requirements for the project facilities set forth in the Approved Project Sponsor Agreement or (b) a change in the requirements of an interconnection agreement or interconnecting transmission owner; and (2) costs incurred by LSPGC associated with studying, designing, procuring, installing, and commissioning transmission interconnection facilities, transmission interconnection service, network upgrades, distribution upgrades, affected system upgrades, mitigation for synchronous resonance or harmonics, and project studies and design modifications required by (or delays caused by) any interconnecting transmission owner, affected system, or generator, including metering and system protection requirements. LSPGC indicated that such costs would include incremental costs associated with rerouting transmission tie lines to accommodate requirements of the interconnecting transmission owner. (CC-14)

LSPGC indicated that a failure by one of LSPGC's preferred vendors to meet LSPGC's requirements would not be the basis for LSPGC to claim relief from the binding cost cap. (CC-15)

Cost Containment Performance for Past Projects

LSPGC provided a list of project experience for its substation and transmission line projects, including actual cost versus budget performance. LSPGC provided budget and actual cost information on a project-by-project basis, and, if applicable, identified major issues or challenges faced on a particular project.

Regarding substation projects operating at voltages above 200 kV that are ongoing or have been completed in the past ten years and are located in the U.S., the information provided included 12 projects. Of these 12 substation projects, one project with a budget of less than $25 million was above budget by 13% due to the change in scope requested by the interconnecting utility. The remaining eleven substation projects ranging in value from around $2 million to $90 million were on budget or below budget by an average of 5.6%.

Regarding transmission line projects operating at voltages above 200 kV that are ongoing or have been completed in the past ten years and are located in the U.S., the information provided included 11 projects. Of these 11 transmission line projects, none were above budget. Eleven transmission line projects ranging in value from around $5 million to $500 million were either on budget or below budget by an average of 6%. (Prior Projects and Experience Workbook)

Project Management Capabilities

LSPGC indicated that it has assembled a project team with relevant experience in all areas of project execution to provide certainty to the ISO that the project would be delivered on budget. LSPGC provided information on its approach for risk management, schedule management, cost management, project communication, quality management, issue management, and safety management.

Risk Management: LSPGC indicated that the project director would be directly responsible for risk oversight with every member of the project team being responsible for recognizing and reporting risks. LSPGC indicated that when a risk is identified, it would be logged in a risk register and provided a score based on potential consequences and the probability of occurrence.

Schedule Management: LSPGC indicated that it conducted extensive due diligence and incorporated California-specific experience and knowledge to ensure the initial schedule is well conceived and realistic. LSPGC indicated that the project director is responsible for maintaining the master schedule throughout project implementation. LSPGC also indicated that the members of the project team would meet regularly to provide schedule updates, review the master schedule, and determine if tasks need to be accelerated or decelerated.

Cost Management: LSPGC indicated that the project director would be responsible for managing the detailed budget, which would be updated and re-forecasted on a monthly basis. LSPGC indicated that the project team would actively manage contractors to ensure they are adhering to budget, and typical contracts would include firm, not-to-exceed pricing for all authorized work. (P-1)

LSPGC indicated that the project director would be the primary point of contact for the ISO, would be responsible for guiding LSPGC's day-to-day activities, and would oversee all deliverables from selection as the approved project sponsor until the beginning of operations. LSPGC indicated that the project director would be supported by a highly qualified team of managers and subject matter experts with responsibilities for project execution within key project areas. LSPGC also provided detailed information on the roles and responsibilities of key personnel involved in project development, engineering and procurement, and construction. (P-2)

Project Risks and Mitigation of Risks

LSPGC provided a risk register that included 88 risk items grouped into categories (procurement, engineering, construction etc.) with a rating system for risk likelihood, risk consequence, risk level to ISO and ratepayers, and risk level to LSPGC, as well as mitigation measures for each risk.

LSPGC also identified the following potential major project risks to budget along with their mitigation measures.

Technology risk: LSPGC indicated that it has secured the technical expertise of three consultants to mitigate the design and engineering risks.

HVDC terminal site acquisition: LSPGC indicated that it has already initiated discussions with site representatives for its preferred site.

Supply chain manufacturing and shipping delays: LSPGC indicated that it already has confirmation from its HVDC terminal and underground cable vendors regarding their ability to manufacture the equipment and cable for LSPGC consistent with the project schedule.

Delay in CPUC approvals: LSPGC indicated that it is mitigating this risk by retaining a highly qualified permitting and legal team and including a float to account for potential delays.

Construction restrictions: LSPGC indicated that it worked with its construction contractor and engineers experienced in the region to identify likely construction restrictions, which were incorporated into the cost estimate for the project.

Route changes: LSPGC stated that it performed a routing study including field reconnaissance and a review of environmental and engineering design criteria to consider alternative routes and identify a preferred route for the project.

Delay of interconnection facilities: LSPGC indicated that it has incorporated more than sufficient time for PG&E to complete the interconnection facilities in the project schedule. (P-4)

LSPGC indicated that it would dedicate additional resources to support multiple project awards and that the project schedule would not change in the event of multiple project awards. (P-4)

3.12.4 <u>Information Provided by SEGG</u>

Cost Containment

SEGG proposed the following cost containment measures:

- A capital cost cap; and
- A return on equity cap.

(CC-1; Cost and Cost Containment Workbook)

SEGG proposed specified exceptions to its proposed capital cost cap and agreed to certain cost containment measures if such exceptions are triggered. (CC-7-CC-15; Cost and Cost Containment Workbook)

Cost Containment Performance for Past Projects

SEGG provided a list of project experience for its substation and transmission line projects, including actual cost versus budget performance. SEGG provided budget information on a project-by-project basis, and, if applicable, identified major issues or challenges faced on a particular project.

Regarding substation projects operating at voltages above 200 kV that are ongoing or have been completed in the past ten years and are located in the U.S., the information provided included two projects. SEGG did not provide budget information for these two projects since these projects were not yet completed.

Regarding transmission line projects operating at voltages above 200 kV that are ongoing or have been completed in the past ten years and are located in the U.S., the information provided included four projects. SEGG did not provide budget information for these four projects. (Prior Projects and Experience Workbook)

Project Management Capabilities

SEGG indicated that it is proposing a project management team with appropriate skill sets and experience in permitting, financing, engineering, siting, construction, and operating high voltage substations and transmission lines. (P-1)

SEGG indicated that its project team has developed a high-level schedule for this project showing the most relevant tasks, including the following:

- Preconstruction
- PG&E coordination
- FERC filings
- Public outreach plan
- Land acquisition
- Environmental and permitting
- Engineering
- Procurement
- Construction management and contract plan (P-1)

SEGG indicated that its chief executive officer would oversee the successful completion of the project. SEGG also provided the experience for individuals chosen for key positions such as the project manager, owner's representative, and asset manager. SEGG also provided an organization chart that showed additional roles met by SEGG employees, as well as entities contracted to provide various services. SEGG indicated that all contractors would be directly engaged from the special purpose entity through service or supply contracts for their relevant scopes. (P-2)

Project Risks and Mitigation of Risks

SEGG identified the following major risks and obstacles to successful project completion within budget:

Siting and land acquisition: SEGG indicated that during route selection the project team reviewed geographic information system data from the City of San Jose to consider vulnerable populations and high congestion areas. SEGG indicated that communication with the City of San Jose would continue through the project to mitigate adverse effects to sensitive areas and vulnerable populations.

Environmental permitting and mitigation: SEGG also indicated that the project team has developed a set of application performance metric manuals, business process manuals and a complete list of required permits that would support the CPUC's environmental impact report preparation, and the implementation of the suggested measures would minimize the potential for significant impacts. (P-4) SEGG indicated approximately 2,400 feet of its transmission line is proposed to cross the Don Edwards National Wildlife Refuge. (P-4,) SEGG indicated that that the alternate transmission line routes that it considered would have passed through the Don Edwards National Wildlife Refuge lands, and new or expanded rights-of-way are no longer allowed by the refuge due to the National Wildlife Refuge Improvement Act enacted in 1997 and its required "compatibility" assessment. (P-4, A-4, L-2, L-5)

SEGG identified risks pertaining to potential design changes because key system data (harmonic impedance sectors and background harmonic measurements) were not available at the time of submittal of its proposal. SEGG identified engineering risks and challenges associated with the underground transmission lines with identifying an engineering corridor that facilitates the project requirements. SEGG provided general information on mitigation measures. (P-5)

SEGG indicated that if selected as the approved project sponsor for this project and any of the other projects for which the ISO is conducting a competitive solicitation, SEGG would be able to use economies of scale and effectively manage some of the costs of the multiple projects. (P-5)

Authority to Impose Binding Cost Caps

(CC-16)

3.12.5 Information Provided by Avangrid for Proposals 1 and 2

Avangrid indicated that this provision is inapplicable because it is proposing a binding cost cap. (CC-16)

3.12.6 Information Provided by HWT for Bay Crossing and Inland Route

HWT indicated that its transmission rates are regulated by FERC and the binding cost containment measures it is proposing would be enforced by FERC. (CC-16.)

3.12.7 Information Provided by LSPGC

LSPGC indicated that this is inapplicable because LSPGC is proposing binding cost containment measures. (CC-16)

3.12.8 Information Provided by SEGG

SEGG indicated it would be seeking siting approval from the CPUC and asserted that the CPUC's authority over costs is preempted by federal law in this context. SEGG indicated that it is proposing binding cost containment measures. (CC-16)

3.12.9 ISO Comparative Analysis

Comparative Analysis of Cost Containment Capability Including Cost Cap Agreement

For purposes of the comparative analysis for this component of the factor, the ISO's analysis considered the expected effectiveness of the project sponsor's overall cost containment capabilities, including but not limited to cost containment performance on prior projects, project management and scheduling organizations and capabilities, experience of key individuals, the project risk and mitigation that each project sponsor identified, factors affecting cost, and proposed cost containment plans and proposed binding cost caps. The ISO also considered the effect of the project sponsors' proposals on PG&E's interconnection costs and determined that there is no significant difference among the project sponsors' proposals in their effect on PG&E's interconnection costs.

In addition, for purposes of this comparative analysis, the ISO considers the potential benefits from an in-service date for this project in advance of the latest in-service date specified in the ISO Functional Specifications to be small based on the information currently available to the ISO and considers the proposed schedules in combination with the schedule completion financial incentives to provide only a small likelihood that a particular project sponsor would be able to complete the project significantly earlier than the latest in-service date in the ISO Functional Specifications. With this in mind, the ISO has chosen to evaluate the project based on the latest in-service date specified in the ISO Functional Specifications. In the event the project can be placed into service earlier, the ISO will reserve the option to negotiate an earlier in-service date with the approved project sponsor when the ISO has better information regarding the potential benefits (and risks) of achieving an earlier in-service date.

Cost Estimates

The project sponsors provided a range of cost estimates for capital costs and operations and maintenance costs. The differences in cost estimates are reflected in the binding cost caps proposed by each project sponsor. The ISO discusses below potential site and route-related risks associated with particular projects.

Binding Cost Containment Measures and Cost Containment Exclusions

All four project sponsors committed to some form of binding cost containment measures subject to certain specified exclusions and conditions for adjustment. However, the robustness of the cost containment measures varied greatly. Consistent with the practice the ISO implemented in connection with the competitive solicitation for the Harry Allen-El Dorado Transmission Line project and to respect confidentiality concerns, the ISO only specifies in this section the specific, detailed cost containment measures and conditions of the approved project sponsor. The cost containment measures and conditions proposed by the other project sponsors are described only in very general terms.

LSPGC proposed a 40-year annual revenue requirement cap with a deferred cost recovery mechanism. In addition, the ISO evaluated the alternative cost recovery model proposed by LSPGC in the event FERC were to reject LSPGC's proposed cost recovery mechanism. Under both approaches, LSPGC's proposed annual revenue requirement caps are for a much longer period than the annual revenue requirement caps proposed by Avangrid, in its proposals 1 and 2, and HWT in its bay crossing and inland route proposals. Also, LSPGC's annual revenue requirement during the period when the Avangrid and HWT revenue caps are in place is lower in each year of that period. In addition, LSPGC's proposal has a lower evaluated net present value of projected revenue requirements than Avangrid's proposals 1 and 2, HWT's bay crossing and inland route proposals, and SEGG's proposal. Thus, both LSPGC's proposed cost recovery approach and its alternative cost recovery approach provide significantly greater cost certainty and lower projected overall costs than the cost containment proposals of the other project sponsors. The ISO considers LSPGC's proposal to provide the most overall cost certainty and stability and the lowest net present value of projected revenue requirements even when compared to HWT's proposed cost containment measures if selected as the approved project for both this project and the Metcalf-San Jose B HVDC project.

Regarding the proposed cost containment measures of the other three project sponsors for their five proposals, Avangrid's proposal 2 had the lowest capital cost cap, even after accounting for certain excluded costs, followed by HWT's bay crossing proposal, followed by Avangrid's proposal 1, after accounting for certain excluded costs, HWT's inland route proposal, and then SEGG's proposal. Avangrid's proposals 1 and 2 and HWT's bay crossing and inland route proposals had comparable return on equity caps, and their caps were lower than SEGG's return on equity cap. HWT, for its bay crossing and inland route proposals, proposed a slightly lower equity percentage cap than Avangrid, in its proposals 1 and 2, but it was for a significantly shorter period of time than Avangrid's equity percentage caps in its proposals 1 and 2. SEGG did not propose an equity percentage cap. Avangrid's annual revenue requirement caps in its proposals 1 and 2 were for a longer period of time than HWT's annual revenue requirement caps in its bay crossing and inland route proposals. During the period the annual revenue requirement caps overlap, HWT's bay crossing annual revenue requirement cap proposal is very slightly lower than the annual revenue requirement cap in Avangrid's proposal 2, after accounting for certain excluded costs, followed by the annual revenue requirement cap in Avangrid's proposal 1, after accounting for certain excluded costs, and then the annual revenue requirement cap in HWT's inland route proposal. SEGG did not propose an annual revenue requirement cap. HWT was the only project sponsor that proposed a separate combined capital cost cap and annual revenue requirement cap for being selected as the approved project sponsor for both this project and the Metcalf-San Jose B HVDC project. Excluding consideration of any siting-related exclusions from the various cost containment measures or any project risk considerations, and accounting for the shorter terms of HWT's equity percentage and annual revenue requirement caps, the ISO has determined that LSPGC has the strongest cost containment proposal, followed by Avangrid's proposal 2, HWT's bay crossing proposal, Avangrid's proposal 1, HWT's inland route proposal, and then SEGG's proposal.

The proposals of all the project sponsors included numerous siting-related costs that would be excluded from their binding cost caps. Many of these siting-related cost cap exclusion items were common across all of the project sponsors' proposals. HWT's bay crossing and inland route proposals and LSPGC's proposal included fewer siting-related cost cap exclusions than Avangrid, in its proposals 1 and 2, and SEGG in its proposal. Regarding a comparison of LSPGC's proposed cost cap exclusions and those of HWT, under LSPGC's proposal, any siting authority decision requiring a change to the proposed structures, equipment, and transmission lines associated with the project would not serve as the basis for LSPGC to seek relief from the proposed binding cost caps, provided such changes are not inconsistent with the description of the project facilities in the Approved Project Sponsor Agreement. This is not included among HWT's proposed cost cap exclusions. However, HWT's two proposals included a cost cap exclusion not included in LSPGC's proposal, and HWT's inland route proposal did not include another cost cap exclusion that was included in both its bay crossing proposal and in LSPGC's proposal. Thus, HWT's inland route proposal had fewer siting-related cost cap exclusions than HWT's bay crossing proposal and LSPGC's proposal, and the ISO considers the cost cap exclusion differences between HWT's bay crossing proposal and LSPGC's proposal effectively to offset each other. All three proposals were stronger from a siting-related cost cap exclusion perspective than Avangrid's proposals 1 and 2 and SEGG's proposal, which were comparable.

Avangrid, in its proposals 1 and 2, and SEGG propose cost containment measures to mitigate the cost impacts of certain specified cost cap exclusions. The mitigation measures in Avangrid's two proposals are different from the mitigation measures in SEGG's proposal. SEGG's mitigation measures are stronger than Avangrid's to the extent the amount of excluded costs are on the low end; Avangrid's mitigation measures are stronger than SEGG's to the extent the amount of excluded costs is more significant. HWT's and LSPGC's proposals contains no special cost containment measures to mitigate the impacts of any costs incurred due to cost cap exclusions. Nevertheless, the ISO does not consider the mitigation measures proposed by Avangrid and SEGG to offset the stronger cost cap exclusion proposals by HWT and LSPGC.

The ISO has determined that the project sponsors' proposed cost cap exclusions cannot be fully compared and evaluated in isolation. They must be considered in the context of the specific risks each project presents, the likelihood that specific cost cap exclusions might be triggered, and the potential magnitude of impact of any triggered cost cap exclusion. The ISO discusses each project's risk profile in the project risks and mitigation subsection below and then provides a more holistic comparative analysis of the binding cost containment measures, cost cap exclusions, risk profiles, and likelihood of triggering cost cap exclusions in the overall assessment subsection below.

Cost Containment Performance for Past Projects

Regarding completing past projects within the project budget, Avangrid, HWT, and LSPGC demonstrated a reasonable degree of success in completing projects within or under budget, recognizing that the number of completed projects varied among the three project sponsors. SEGG did not provide actual cost information for any of its substation or transmission line projects.

Consequently, the ISO has determined there to be no material difference among the recent experience of Avangrid, HWT, and LSPGC in completing projects within or under budget, and it considers their experience as represented in their proposals to be better than the experience described by SEGG, which provided no cost data. In any event, given that all project sponsors proposed specific cost containment measures, those measures would have the most direct bearing on cost containment for this project.

Project Management Capabilities

The ISO determined that all four project sponsors provided a reasonable approach to professional project management for their proposals and, as result, it has determined them to be comparable regarding project management capabilities. Given that all project sponsors proposed cost containment measures, those measures have the most direct bearing on cost containment for this project.

Project Risks and Mitigation of Risks

All four project sponsors provided a description of a thorough and professional approach to identifying risks to the completion of the project within the project budget and possible mitigations for those risks for their proposals. All four project sponsors confirmed their ability to work on two projects simultaneously, if awarded both. All four project sponsors have taken steps to reduce risk.

The ISO considers HWT's bay crossing proposal to present a very high siting risk given its extensive route through the Don Edwards National Wildlife Refuge. A prior PG&E project through the area had to be withdrawn due to the challenges of siting a project there. HWT's inland route poses less risk than its bay crossing proposal, but there are small, discrete sections of the project that potentially could be rerouted because they cross the Don Edwards National Wildlife Refuge. Sections of SEGG's proposed transmission line also traverse the Don Edwards National Wildlife Refuge, as well as other potentially environmentally sensitive areas.

Avangrid's proposals 1 and 2 and LSPGC's proposal contain both overhead and underground components. LSPGC's proposal has fewer miles of overhead lines. The ISO considers there to be a small-to-moderate risk that Avangrid and LSPGC would be required to underground their proposed overhead transmission lines. Their overhead routes generally traverse industrial and commercial areas and open space and undeveloped areas, although a segment of Avangrid's route goes through a slightly more congested area. The ISO notes, however, that there are existing overhead transmission lines in the vicinity of their projects, and their projects do not pass through the Don Edwards National Wildlife Refuge.

Based on the foregoing analysis, the ISO has determined that LSPGC's proposal and Avangrid's proposals 1 and 2 pose the least risk, followed by HWT's inland route proposal, then SEGG's proposal, and then HWT's bay crossing proposal.

Overall Assessment

For purposes of the comparative analysis for this component of the factor, the ISO's analysis considered the expected effectiveness of the project sponsor's overall cost containment capabilities, including but not limited to cost containment performance on prior projects, project management and scheduling organizations and capabilities, experience of key individuals, the project risk and mitigation that each project sponsor identified, factors affecting cost, and proposed cost containment plans and proposed binding cost caps.

As discussed above and in Section 2.1, the ISO has identified this selection factor as a key selection factor because under ISO Tariff Section 24.5.1 binding cost containment commitments are a key selection factor in every ISO competitive solicitation, and the ISO considers commitment to robust, binding cost containment measures to be the most effective way in which the ISO can ensure that a project is developed in an efficient and cost-effective manner. Consequently, the ISO considers the binding cost containment measures proposed by project sponsors to be the most significant inputs into the comparative analysis for this component of the factor.

As discussed above, the ISO has determined that the proposals of the four project sponsors are comparable regarding project management capabilities and that the proposals of Avangrid, HWT, and LSPGC are better than SEGG's proposal regarding cost containment performance on prior projects. The ISO addresses the comparison of project risks and mitigation in conjunction with the analysis of cost containment below.

Considering the project sponsors' proposed cost containment measures, cost cap exclusions (siting and non-siting related), and project-specific risks in conjunction, the ISO has determined that LSPGC's proposal presents the most robust cost containment proposal, followed by Avangrid's proposal 2, Avangrid's proposal 1, HWT's inland route proposal, SEGG's proposal, and then HWT's bay crossing proposal. LSPGC's 40-year annual revenue requirement cap, in conjunction with its low risk profile and limited proposed cost cap exclusions, makes LSPGC's cost containment proposal much stronger than Avangrid's proposals 1 and 2, HWT's bay crossing and inland route proposals, and SEGG's proposal. The net present value of the projected revenue requirements of LSPGC's proposal is lower than the net present value of the projected revenue requirements of all of the other proposals. Also, the ISO does not consider the risk that a siting authority would require LSPGC to underground its entire HVDC transmission line to be significant given the specific conditions where the line would be located, the existing overhead transmission lines in the vicinity, and the fact that the project does not traverse the Don Edwards National Wildlife Refuge. In any event, the ISO does not consider there to be a material risk of significant cost escalation that would cause LSPGC's proposal ultimately to exceed the costs of any other sponsor's proposal. LSPGC proposes only a few miles of overhead lines, fewer than Avangrid in its proposals 1 and 2 and SEGG, and its projected costs are significantly lower than the projected costs of HWT's inland route proposal, which could face some potential rerouting issues, and HWT's revenue requirement cap is for a much shorter period of time. Finally, not only does HWT's bay crossing proposal have higher projected costs than LSPGC's proposal, it poses a significant risk of being rejected or rerouted, which would trigger cap exclusions without any mitigation measures.

Avangrid's proposal 2 is projected as a much lower cost solution than Avangrid's proposal 1, and Avangrid proposes similar types of cost containment and cost cap exclusion measures for each. Both proposals share a similar risk profile. Thus, Avangrid's proposal 2 is stronger from a cost containment perspective than Avangrid's proposal 1.

Comparing Avangrid's proposals 1 and 2 to HWT's inland route proposal, based solely on the proposed cost caps, and accounting for certain excluded costs, Avangrid's proposals are projected to be lower in cost than HWT's inland route proposal, particularly Avangrid's proposal 2. Avangrid's proposal 2 is projected to be much less costly than Avangrid's proposal 1 and can better absorb cost escalation due to the triggering of any cap exclusions. The ISO does not consider there to be a high risk that a siting authority would require Avangrid to underground its entire HVDC transmission line given the specific conditions where the line would be located and the fact there are existing overhead transmission lines in the vicinity. There is a possible risk the segment of the HVDC line that traverses a slightly more congested area could be undergrounded. Avangrid's proposals 1 and 2 do not traverse the Don Edwards National Wildlife Refuge. Given its significantly lower projected costs and considering HWT's shorter-term annual revenue requirement cap and equity percentage cap, and Avangrid's proposed cost mitigation measures for excluded costs, the ISO considers Avangrid's proposal 2 to be stronger from a cost containment perspective than HWT's inland route proposal, which also faces the risk of partial relocation. However, the ISO considers HWT's inland route proposal to be stronger from a cost containment perspective than Avangrid's proposal 1 given the greater cost certainty it provides from a risk exposure perspective and accounting for the fact that the projected cost of Avangrid's proposal 1 is much higher than the projected cost of Avangrid's proposal 2 and closer in cost to HWT's inland route proposal. The projected cost differences between Avangrid's proposal 1 and HWT's inland route proposal, are close, but the ISO considers HWT's inland route proposal to have a slight advantage regarding cost containment given HWT's proposed use of significantly less overhead transmission.

The ISO considers Avangrid's proposals 1 and 2 and HWT's inland route proposal to be stronger than SEGG's proposal and HWT's bay crossing proposal. SEGG's proposal has the least robust cost containment measures of any proposal, has the highest net present value of projected revenue requirements, and has a large number of cost cap exclusions. SEGG also faces a high risk of triggering cost cap exclusions because its proposal is for overhead transmission, some of which traverses the Don Edwards National Wildlife Refuge. The ISO anticipates that SEGG's proposed mitigation measures for cost cap exclusions under these circumstances would only have a minimal effect. HWT's bay crossing proposal has the second lowest projected costs of the submitted proposals. However, it poses a significant siting and permitting risk that could cause the proposal to be rejected or completely overhauled, triggering multiple cost cap exclusions. The ISO presumes that HWT would fall back to its inland route proposal, which poses less risk of significant modification and which the ISO considers to be stronger from an overall cost containment and permitting risk perspective than its bay crossing proposal. For these reasons, the ISO considers SEGG's proposal to be stronger than HWT's bay crossing proposal regarding cost containment.

As a result, after applying all of the foregoing considerations included in the ISO's analysis for this component of the factor, the ISO has determined that LSPGC's proposal is better than the five proposals of the other three project sponsors regarding this component, followed in order by Avangrid's proposal 2, HWT's inland route proposal, Avangrid's proposal 1, SEGG's proposal, and then HWT's bay crossing proposal. LSPGC proposed the most robust overall cost containment measures, particularly with its 40-year annual revenue requirement cap, for the lowest projected total revenue requirements and considering its low risk profile and limited cost cap exclusions.

Comparative Analysis of the Authority to Impose Binding Cost Caps

Because all four project sponsors have proposed binding cost caps for their proposals, in accordance with the provisions of this component of the factor, the ISO has not considered this component of the factor in the comparative analysis.

Overall Comparative Analysis

The ISO considers the first component of this factor (cost containment and cost caps) more important than the second (siting authority imposing a cost cap). Given that all four project sponsors offered a binding cost cap for each of their proposals, the first component is the only basis for the comparative analysis of this factor.

Based on the ISO's analysis for the first component of this factor discussed above, the ISO has determined that LSPGC's proposal is better than the five proposals of the other three project sponsors regarding this factor overall, followed in order by Avangrid's proposal 2, HWT's inland route proposal, Avangrid's proposal 1, SEGG's proposal, and then HWT's bay crossing proposal.

3.13 Selection Factor 24.5.4(k): Additional Strengths or Advantages

(Introduction, A-4, A-5, QP-1, QP-2, Z-1)

The eleventh selection factor is "any other strengths and advantages the project sponsor and its team may have to build and own the specific transmission solution, as well as any specific efficiencies or benefits demonstrated in their proposal."

For the consideration of this factor, the ISO has concluded that there is no significant difference between the two proposals submitted by Avangrid. Consequently, references to Avangrid and its proposal in this section apply equally to both Avangrid's proposal 1 and Avangrid's proposal 2.

3.13.1 Information Provided by Avangrid for Proposals 1 and 2

Avangrid indicated that its project would consist of the construction of two new 500 MW ±320 kV VSC stations connected by a 320 kV HVDC circuit, interconnecting into the existing Newark 230 kV and Northern Receiving Station 230 kV substations. Avangrid indicated that the converter stations would be designed using an international HVDC equipment supplier's HVDC VSC technology. Avangrid indicated that the northern converter station would be located 0.4 miles from Newark Substation and would connect to Newark Substation via a new 230 kV AC circuit, with overhead and underground sections. Avangrid indicated that, due to space constraints in the vicinity of Northern Receiving Station Substation, the southern converter station would be located 1.0 miles from Los Esteros Substation and connected to Northern Receiving Station Substation through a 3.5-mile 230 kV AC circuit with overhead and underground sections. Avangrid indicated that the HVDC transmission line would be comprised of 7.3 miles of overhead and 0.7 miles of underground construction. (QP-1)

Avangrid indicated that the project would be expandable to accommodate the ISO's Stage 2 ultimate plan described in Appendix G of the ISO's 2021-2022 transmission plan without additional expansion of the converter stations connected to Newark and Northern Receiving Station substations, and would only require additional converter reactors, bank transformers, and some minor auxiliary equipment. Avangrid indicated that this would result in significant cost savings for future expansion.

Calculations included by Avangrid identified an availability of at least 97.5%, which exceeds the ISO Functional Specifications value of 97.0%. (QP-1)

3.13.2 <u>Information Provided by HWT for Bay Crossing</u>

HWT indicated that its proposal would consist of: (1) a 500 MW ±320 kV HVDC VSC station, located approximately 0.5 miles from PG&E's Newark Substation, with a symmetrical monopole configuration, (2) a 230 kV AC switchyard designed as a gas-insulated, enclosed substation and located on the same parcel as the Newark converter station and comprising two breaker-and-a-half bays for the ultimate arrangement, (3) a 1,000 MW, 230 kV AC line from the Newark converter AC switchyard to the dead-end structure, which new line would be approximately one mile and would be overhead, (4) a 500 MW, ±320 kV HVDC VSC station, located approximately one mile from SVP's Northern Receiving Station Substation, with a symmetrical monopole configuration, (5) a 230 kV AC switchyard designed as a gas-insulated, enclosed substation and located on the same parcel as the Northern Receiving Station converter and comprising two breaker-and-a-half bays for the ultimate arrangement; one bay of which would be developed in the current project scope, (6) a 500 MW, 230 kV AC line from the Northern Receiving Station converter AC switchyard to the dead-end structure within the existing Northern Receiving Station Substation, which new line would run approximately one mile underground, and (7) a 500 MW, ±320 kV DC line from the DC yard located within the Newark converter to the DC yard located within the Northern Receiving Station converter, which new line would be approximately eight miles in length, approximately two-thirds overhead across the bay and approximately one-third underground. (QP-1)

HWT indicated that operations and maintenance activities for the project would be undertaken primarily by NextEra affiliate TBC. HWT indicated that TBC has demonstrated a strong track record of maintaining HVDC transmission assets under the ISO Tariff and the interconnection protocols of PG&E. HWT indicated that TBC's 5-year average availability is at 99.86%, with a 5-year switching accuracy of 99.98%. HWT indicated that TBC's extensive experience and expertise with HVDC systems has been and would continue to be leveraged for the design, engineering, execution, operation, and maintenance of the project, along with the experience and expertise across the entire NextEra family of companies. HWT indicated that TBC has reliably operated the only HVDC project in the San Francisco Bay Area for over 12 years. (A-5)

HWT submitted calculations indicating that the calculated availability of its proposed project is 97.89%, which exceeds the ISO Functional Specifications value of at least 97.0%. (QP-1)

3.13.3 Information Provided by HWT for Inland Route

HWT indicated that its proposal would consist of: (1) a 500 MW, ±320 kV HVDC VSC station, located approximately 0.5 miles from PG&E's Newark Substation, with a symmetrical monopole configuration, (2) a 230 kV AC switchyard designed as a gas-insulated, enclosed substation and located on the same parcel as the Newark converter and comprising two breaker-and-a-half bays for the ultimate arrangement, (3) a 1,000 MW, 230 kV AC line from the Newark converter AC switchyard to the dead-end structure, which new line would be approximately one mile and would be overhead, (4) a 500 MW, ±320 kV HVDC VSC station, located approximately one mile from SVP's Northern Receiving Station Substation, with a symmetrical monopole configuration, (5) a 230 kV AC switchyard designed as a gas-insulated, enclosed substation and located on the same parcel as the converter and comprising two breaker-and-a-half bays for the ultimate arrangement, one bay of which would be developed in the current project scope, (6) a 500 MW, 230 kV AC line from the converter AC switchyard to the dead-end structure within the existing substation, which new line would run approximately one mile underground, and (7) a 500 MW, ±320 kV DC line from the DC yard located within the Newark converter to the DC yard located within the Northern Receiving Station converter station, which new line would be approximately 12 miles in length and would be underground. (QP-1)

HWT indicated that operations and maintenance activities for the project would be undertaken primarily by NextEra affiliate TBC. HWT indicated that TBC has demonstrated a strong track record of maintaining HVDC transmission assets under the ISO Tariff and the interconnection protocols of PG&E. HWT indicated that TBC's 5-year average availability is at 99.86%, with a 5-year switching accuracy of 99.98%. HWT indicated that TBC's extensive experience and expertise with HVDC systems has been and would continue to be leveraged for the design, engineering, execution, operation, and maintenance of the project, along with the experience and expertise across the entire NextEra family of companies. HWT indicated that TBC has reliably operated the only HVDC project in the San Francisco Bay Area for over 12 years. (A-5)

HWT submitted calculations indicating that the calculated availability of its proposed project is 97.89%, which exceeds the ISO Functional Specification value of at least 97.0% (QP-1)

3.13.4 Information Provided by LSPGC

LSPGC indicated it proposes to construct the project with an initial capacity of 593 MVA, with the HVDC terminals rated at 1,044 MVA, between Newark 230 kV Substation and the Northern Receiving Station 230 kV Substation.

LSPGC indicated that its project would include a new Newark HVDC terminal interconnected to Newark 230 kV Substation through an approximately 0.1-mile 230 kV transmission line, a new Northern Receiving Station HVDC terminal interconnected to Northern Receiving Station 230 kV Substation through an approximately 3.5-mile 230 kV transmission line, and an approximately 8.0 mile ±320 kV HVDC transmission line connecting the Newark HVDC terminal to the Northern Receiving Station HVDC terminal. LSPGC indicated that it would use VSC HVDC equipment and enclosed GIS in a breaker-and-a-half configuration. LSPGC indicated that the project would include redundancy with a spare duct for all of the underground transmission and spare parts for the HVDC terminals, including insulated-gate bipolar transistor modules, reactors, and a transformer.

LSPGC indicated that it designed the project to significantly exceed the requirements of the ISO Functional Specifications and provide expanded operational flexibility for the ISO in both its initial configuration and ultimate plan, including multi-terminal operation. LSPGC indicated that the project would be capable of delivering up to 593 MW measured at Northern Receiving Station 230 kV Substation, even during future multi-terminal operation, in excess of the 500 MW required by the ISO Functional Specifications. LSPGC indicated that the project would similarly be capable of providing significantly more reactive support and would be easily expandable for multi-terminal operation, only requiring new DC switchgear. LSPGC indicated that it would also maintain critical spare parts onsite (e.g., transformer, reactor, redundant HVDC valve submodules) to provide high availability and high reliability. (A-4)

LSPGC indicated that it has designed the Newark HVDC terminal and Northern Receiving Station HVDC terminal with an initial capacity of 1,044 MVA to accommodate the ultimate HVDC development plan. In addition, LSPGC indicated that the Newark-Northern Receiving Station ±320 kV DC transmission line would be designed to transfer 1,000 MW to accommodate increased delivery to Northern Receiving Station Substation. (A-4)

LSPGC calculated project availability at 98.94%, which exceeds the ISO Functional Specifications value of at least 97.0%. (Table QP-1a)

3.13.5 Information Provided by SEGG

SEGG indicated that its proposed transmission solution would consist of a 230 kV AC single-circuit underground transmission line traversing 3.25 miles from 100 feet outside PG&E’s 230 kV Newark Substation to its proposed 500 MW Newark converter station. SEGG indicated that the proposed project would then interconnect via a 320 kV HVDC transmission line to its proposed 500 MW Northern Receiving Station converter station. SEGG indicated that the 320 kV HVDC line would consist of approximately 11.25 miles of overhead or underground transmission line. SEGG indicated that from the Northern Receiving Station converter station, the transmission solution would route an overhead single-circuit 230 kV AC transmission line approximately three miles, and then interconnect and share a double circuit structure with PG&E for approximately one mile to connect to SVP’s existing Northern Receiving Station Substation. (A-4)

SEGG’s proposal included a “full-bridge” submodule design as part of its proposed HVDC project. SEGG indicated its proposed HVDC system would be a VSC system unit composed of a three-phase modular multilevel converter circuit. SEGG indicated that the modular multilevel converter valve would be composed of series-connected full-bridge submodules. SEGG asserted that a full-bridge submodule design would have the potential to provide additional advantages compared to a half-bridge design. (S-1)

SEGG indicated that its selected Northern Receiving Station converter station site is close to the Los Esteros Substation, which would provide ease for the construction of the

ISO's ultimate HVDC configuration, which ties the Northern Receiving Station converter station into PG&E's Los Esteros Substation. (A-4)

3.13.6 ISO Comparative Analysis

For purposes of the comparative analysis for this factor, the ISO has reviewed the six proposals from the four project sponsors to determine if there are other advantages the project sponsor or its team have for building the project that were not addressed in other parts of the selection process. This comparative analysis will consider both the proposed project design as well as other possible advantages.

Because there were some project design differences among the submitted proposals, the ISO undertook an analysis to determine whether any of those designs offered additional advantages or benefits over any of the other project designs.

The ISO has determined that all proposals meet the minimum requirements set forth in the ISO Functional Specifications. However, LSPGC's proposal allows for greater real and reactive power flows than the minimum requirements specified in the ISO Functional Specifications. The ISO has determined that LSPGC's proposal is better than the proposals of Avangrid, HWT, and SEGG because of this increased real and reactive capability. The ISO considers the value of these capabilities to be a significant additional advantage beyond the requirements of the ISO Functional Specifications.

Regarding the advantages claimed by some project sponsors for potential cost savings for the future expansion of the project to facilitate implementation of the ISO's ultimate plan associated with this project, including aspects of facility design and proximity to PG&E's Los Esteros Substation, the ISO could not identify significant enough benefits regarding those aspects of the proposals to attribute a significant additional advantage to any of the proposals in relation to the ISO Functional Specifications or to each other.

SEGG proposed a "full-bridge" submodule design as part of its HVDC project. The use of full-bridge submodule design has the potential to offer additional advantages over a half-bridge submodule design. In the near term, the full-bridge design can potentially perform better than a half-bridge design during temporary faults on an overhead HVDC transmission line segment of a project.

The ISO first notes that a fast transmission line restoration time following a fault on an HVDC transmission line is not required in the ISO Functional Specifications for this project nor is it required to meet NERC planning standards. Thus, any advantages of a full-bridge design would be additional to those that are required by standards or specifications.

There are other longer term potential advantages of a full-bridge design that are related to future expansion of the ISO transmission system; however, because the ISO cannot predict the need for and the type of system expansion, the ISO cannot predict the long-term potential advantages. Consequently, the ISO does not consider the full bridge proposal to provide SEGG with any significant advantage.

The ISO has determined that none of the project sponsors' proposals provides relevant information or identifies any particular other advantage to the ISO and transmission ratepayers that the ISO has not already considered and addressed in the foregoing analysis or in its analysis of the more specific selection factors.

The ISO has determined that LSPGC's proposal offers an additional advantage over the other four proposals of the other three project sponsors primarily because it provides added capacity, while still being the least cost solution.

Based on the foregoing considerations, in conjunction with all the other considerations included in the ISO's analysis for this factor, the ISO has determined that, based on the specific scope of this project, LSPGC's proposal is slightly better than the proposals of Avangrid, for its proposals 1 and 2, HWT, for its bay crossing and inland route proposals, and SEGG, among which there is no material difference, regarding this factor.

3.14 Selection Factor 24.5.4(a): Capability to Finance, License, Construct, Operate, and Maintain the Facility

In this section, the ISO provides the comparative analysis of this selection factor, as discussed in Section 3.3 of this report. This selection factor is a comparative analysis of "the current and expected capabilities of the project sponsor and its team to finance, license, and construct the facility and operate and maintain it for the life of the solution." As noted in Section 3.3, this factor encompasses several more specific selection factors, which are discussed in Sections 3.7, 3.8, 3.9, and 3.10 of this report.

What follows is an overall comparative analysis for this factor based upon the discussion of the other factors or factor components encompassed by this factor. As stated in Section 3.3, the ISO will not repeat all of the information provided by the project sponsors for these more specific selection factors and the comparative analysis for each.

In addition to the general project information provided in the project sponsors' proposals, the other selection factors (or components of a factor) considered in the comparative analysis for this factor are as follows:

> 24.5.4(e): the financial resources of the project sponsor and its team;
>
> 24.5.4(f): the technical [environmental permitting] qualifications and experience of the project sponsor and its team (component of 24.5.4(f));
>
> 24.5.4(g): the previous record regarding construction and maintenance of transmission facilities, including facilities outside the ISO controlled grid, of the project sponsor and its team; and
>
> 24.5.4(h): demonstrated capability to adhere to standardized construction, maintenance, and operating practices of the project sponsor and its team.

3.14.1 <u>ISO Comparative Analysis</u>

The ISO's comparative analysis has considered the results of the analysis of the four selection factors or factor components listed above. As an initial matter, the ISO notes that all of the project sponsors and their teams are capable of satisfying these selection factors regarding this project.

The ISO has determined that there is no material difference between HWT's bay crossing and inland route proposals, and they are slightly better than the four proposals of the other three project sponsors regarding this factor because, as discussed regarding each of the relevant individual selection factors or factor components, they are slightly better than Avangrid's proposals 1 and 2 regarding the fourth selection factor (demonstrated capability to adhere to standardized construction, maintenance, and operating practices), they are better than LSPGC's proposal regarding first selection factor (financial resources) and slightly better regarding the fourth selection factor, and they are better or slightly better than SEGG's proposal regarding the first selection factor, the third selection factor (construction and maintenance record), and the fourth selection factor, and there is no material difference among HWT's bay crossing and inland route proposals and the four proposals of the other three project sponsors regarding the other relevant selection factors or factor components.

The ISO has determined that there is no material difference between Avangrid's proposals 1 and 2, and they are slightly better than LSPGC's proposal regarding this factor because, as discussed regarding each of the relevant individual selection factors or factor components, there is no material difference between Avangrid's proposals 1 and 2, and they are better than LSPGC's proposal regarding first selection factor, and LSPGC's proposal is slightly better than Avangrid's proposals 1 and 2, between which there is no material difference, regarding the fourth selection factor, which the ISO considers to result in a slight advantage for Avangrid's proposals 1 and 2, and there is no material difference among Avangrid's proposals 1 and 2 and LSPGC's proposal regarding the other relevant selection factors or factor components.

The ISO has determined that the proposals of Avangrid, for its proposals 1 and 2, and LSPGC are better than SEGG's proposal regarding this factor because, as discussed regarding each of the relevant individual selection factors or factor components, all three are better or slightly better than SEGG's proposal regarding the first selection factor, the third selection factor, and the fourth selection factor, and there is no material difference among the four proposals regarding the other relevant selection factors or factor components.

Based on a detailed review of the proposals of the project sponsors regarding these individual selection factors and factor components, the ISO has determined that there is no material difference between HWT's bay crossing and inland route proposals, and they are slightly better than Avangrid's proposals 1 and 2, between which there is no material difference, which are slightly better than LSPGC's proposal, which is better than SEGG's proposal, regarding this factor overall.

3.15 Qualification Criterion 24.5.3.1(a): Manpower, Equipment, and Knowledge to Design, Construct, Operate, and Maintain the Project

The first qualification criterion is "whether the Project Sponsor has demonstrated that it has assembled, or has a plan to assemble, a sufficiently-sized team with the manpower, equipment, knowledge and skill required to undertake the design, construction, operation and maintenance of the transmission solution."

The first qualification criterion is a broad criterion that encompasses three specific selection factors that are discussed in Sections 3.8, 3.9, and 3.10 of this report. The ISO will not repeat here the information provided by the project sponsors for these more specific selection factors or the comparative analysis for each. What follows is an overall comparative analysis for this criterion based upon the comparative analyses for the selection factors encompassed by this criterion.

3.15.1 ISO Comparative Analysis

The ISO previously determined and posted notice on its website that the four project sponsors submitted six proposals that meet the minimum requirements to qualify for evaluation in the selection process. Pursuant to ISO Tariff Section 24.5.4, the ISO has further reviewed the proposals regarding the project sponsor qualification criteria in its comparative analysis for purposes of selecting the approved project sponsor.

This qualification criterion considers several factors addressed by the selection factors previously discussed. For this reason, the ISO bases its comparative analysis for this criterion on the results of the comparative analysis for the selection factors addressed above. The selection factors or factor components considered in the comparative analysis for this criterion are as follows:

- 24.5.4(f): the engineering qualifications and experience of the project sponsor and its team (a component of 24.5.4(f));
- 24.5.4(g): the previous record regarding construction and maintenance of transmission facilities, including facilities outside the ISO controlled grid, of the project sponsor and its team; and
- 24.5.4(h): demonstrated capability to adhere to standardized construction, maintenance, and operating practices, of the project sponsor and its team.

The ISO's comparative analysis has considered the results of the analysis of the three selection factors or factor components listed above. As an initial matter, the ISO notes that all of the project sponsors and their teams are capable of satisfying these factors regarding this project.

The ISO has determined that there is no material difference between HWT's bay crossing and inland route proposals, and they are slightly better than the four proposals of the other three project sponsors regarding this criterion because, as discussed regarding each of the relevant individual selection factors or factor components, they are slightly better than Avangrid's proposals 1 and 2 and LSPGC's proposal regarding the third selection factor (demonstrated capability to adhere to standardized construction, maintenance, and operating practices), and they are better or slightly better than SEGG's proposal regarding the first selection factor component (engineering qualifications and experience of the project sponsor and its team), the second selection factor (construction and maintenance record), and the third selection factor, and there is no material difference among HWT's bay crossing and inland route proposals and the four proposals of the other three project sponsors regarding the other relevant selection factors or factor components.

The ISO has determined that LSPGC's proposal is slightly better than Avangrid's proposals 1 and 2, between which there is no material difference, regarding this criterion because, as discussed regarding each of the relevant individual selection factors or factor components, LSPGC's proposal is slightly better than Avangrid's proposals 1 and 2, between which there is no material difference, regarding the third selection factor, and there is no material difference among Avangrid's proposals 1 and 2 and LSPGC's proposal regarding the other relevant selection factors or factor components.

The ISO has determined that the proposals of Avangrid, for its proposals 1 and 2, and LSPGC are better than SEGG's proposal regarding this criterion because, as discussed regarding each of the relevant individual selection factors or factor components, all three are better or slightly better than SEGG's proposal regarding the first selection factor component, the second selection factor, and the third selection factor, and there is no material difference among the four proposals regarding the other relevant selection factors or factor components.

Based on a detailed review of the proposals of the project sponsors regarding these individual selection factors and factor components, the ISO has determined that there is no material difference between HWT's bay crossing and inland route proposals, and they are slightly better than LSPGC's proposal, which is slightly better than Avangrid's proposals 1 and 2, between which there is no material difference, which are better than SEGG's proposal, regarding this criterion overall.

3.16 Qualification Criterion 24.5.3.1(b): Financial Resources

The second qualification criterion is "whether the Project Sponsor and its team have demonstrated that they have sufficient financial resources, by providing information including, but not limited to, satisfactory credit ratings, audited financial statements, or other financial indicators."

3.16.1 <u>ISO Comparative Analysis</u>

The ISO previously determined and posted notice on its website that the four project sponsors submitted six proposals that meet the minimum requirements to qualify for evaluation in the selection process. Pursuant to ISO Tariff Section 24.5.4, the ISO has further reviewed the six proposals regarding the project sponsor qualification criteria in its comparative analysis for purposes of selecting the approved project sponsor.

This qualification criterion essentially duplicates the factors addressed by selection factor 24.5.4(e) (the financial resources of the project sponsor and its team) discussed in Section 3.7 above. For this reason, the ISO bases its comparative analysis for this criterion on the results of the comparative analysis for the selection factor above. As discussed above regarding selection factor 24.5.4(e), the ISO has determined that there are no material differences among Avangrid and its proposals 1 and 2 and HWT and its bay crossing and inland route proposals, and they are better than LSPGC and its proposal, which is slightly better than SEGG and its proposal, regarding this criterion.

3.17 Qualification Criterion 24.5.3.1(c): Ability to Assume Liability for Losses

The third qualification criterion is “whether the Project Sponsor and its team have demonstrated the ability to assume liability for major losses resulting from failure of any part of the facilities associated with the transmission solution by providing information such as letters of credit, letters of interest from financial institutions regarding financial commitment to support the Project Sponsor, insurance policies or the ability to obtain insurance to cover such losses, the use of account set asides or accumulated funds, the revenues earned from the transmission solution, sufficient credit ratings, contingency financing, or other evidence showing sufficient financial ability to cover these losses in the normal course of business.”

3.17.1 <u>ISO Comparative Analysis</u>

The ISO previously determined and posted notice on its website that the four project sponsors submitted six proposals that meet the minimum requirements to qualify for evaluation in the selection process. Pursuant to ISO Tariff Section 24.5.4, the ISO has further reviewed the six proposals regarding the project sponsor qualification criteria in its comparative analysis for purposes of selecting the approved project sponsor.

This qualification criterion essentially duplicates the factors addressed by selection factor 24.5.4(i) (demonstrated ability to assume liability for major losses resulting from failure of facilities of the project sponsor) discussed in Section 3.11 above. For this reason, the ISO bases its comparative analysis for this criterion on the results of the comparative analysis for the selection factor above. As discussed above regarding selection factor 24.5.4(i), the ISO has determined that that there is no material difference among Avangrid and its proposals 1 and 2, HWT and its bay crossing proposal and its inland route proposal, LSPGC and its proposal, and SEGG and its proposal regarding this criterion.

3.18 Qualification Criterion 24.5.3.1(d): Proposed Schedule and Ability to Meet Schedule

The fourth qualification criterion is “whether the Project Sponsor has (1) proposed a schedule for development and completion of the transmission solution consistent with need date identified by the ISO; and (2) has the ability to meet that schedule.”

3.18.1 <u>ISO Comparative Analysis</u>

The ISO previously determined and posted notice on its website that the four project sponsors submitted six proposals that meet the minimum requirements to qualify for evaluation in the selection process. Pursuant to ISO Tariff Section 24.5.4, the ISO has further reviewed the six proposals regarding the project sponsor qualification criteria in its comparative analysis for purposes of selecting the approved project sponsor.

This qualification criterion essentially duplicates the factors addressed by selection factor 24.5.4(d) (the proposed schedule for development and completion of the transmission solution and demonstrated ability to meet that schedule of the project sponsor and its team) discussed in Section 3.6 above. For this reason, the ISO bases its comparative analysis for this criterion on the results of the comparative analysis for the selection factor above. As discussed above regarding selection factor 24.5.4(d), the ISO has determined that LSPGC's proposal is slightly better than HWT's bay crossing and inland route proposals, between which there is no material difference, which are slightly better than Avangrid's proposals 1 and 2, between which there is no material difference, and those five proposals are better than SEGG's proposal, regarding this criterion.

3.19 Qualification Criterion 24.5.3.1(e): Technical and Engineering Qualifications and Experience

The fifth qualification criterion is "whether the Project Sponsor and its team have the necessary technical and engineering qualifications and experience to undertake the design, construction, operation and maintenance of the transmission solution."

3.19.1 <u>ISO Comparative Analysis</u>

The ISO previously determined and posted notice on its website that the four project sponsors submitted six proposals that meet the minimum requirements to qualify for evaluation in the selection process. Pursuant to ISO Tariff Section 24.5.4, the ISO has further reviewed the six proposals regarding the project sponsor qualification criteria in its comparative analysis for purposes of selecting the approved project sponsor.

This qualification criterion considers several factors addressed by the selection factors previously discussed in Sections 3.8, 3.9, and 3.10 above. For this reason, the ISO bases its comparative analysis for this criterion on the results of the comparative analysis for the selection factors addressed above. The selection factors considered in the comparative analysis for this criterion are as follows:

> 24.5.4(f): the technical [environmental permitting] and engineering qualifications and experience of the project sponsor and its team;
>
> 24.5.4(g): the previous record regarding construction and maintenance of transmission facilities, including facilities outside the ISO controlled grid, of the project sponsor and its team; and
>
> 24.5.4(h): demonstrated capability to adhere to standardized construction, maintenance, and operating practices of the project sponsor and its team.

The ISO's comparative analysis has considered the results of the analysis of the three selection factors listed above. As an initial matter, the ISO notes that all of the project sponsors and their teams are capable of satisfying these selection factors regarding this project.

The ISO has determined that there is no material difference between HWT's bay crossing and inland route proposals, and they are slightly better than the four proposals of the other three project sponsors regarding this criterion because, as discussed regarding each of the relevant individual selection factors, they are slightly better than Avangrid's proposals 1 and 2 and LSPGC's proposal regarding the third selection factor (demonstrated capability to adhere to standardized construction, maintenance, and operating practices), and they are better or slightly better than SEGG's proposal regarding the first selection factor (technical [environmental permitting] and engineering qualifications and experience of the project sponsor and its team), the second selection factor (construction and maintenance record), and the third selection factor, and there is no material difference among HWT's bay crossing and inland route proposals and the four proposals of the other three project sponsors regarding the other relevant selection factors.

The ISO has determined that LSPGC's proposal is slightly better than Avangrid's proposals 1 and 2, between which there is no material difference, regarding this criterion because, as discussed regarding each of the relevant individual selection factors, LSPGC's proposal is slightly better than Avangrid's proposals 1 and 2, between which there is no material difference, regarding the third selection factor, and there is no material difference among Avangrid's proposals 1 and 2 and LSPGC's proposal regarding the other relevant selection factors.

The ISO has determined that the proposals of Avangrid, for its proposals 1 and 2, and LSPGC are better than SEGG's proposal regarding this criterion because, as discussed regarding each of the relevant individual selection factors, all three are better or slightly better than SEGG's proposal regarding the first selection factor, the second selection factor, and the third selection factor, and there is no material difference among the four proposals regarding the other relevant selection factors.

Based on a detailed review of the proposals of the project sponsors regarding these individual selection factors, the ISO has determined that there is no material difference between HWT's bay crossing and inland route proposals, and they are slightly better than LSPGC's proposal, which is slightly better than Avangrid's proposals 1 and 2, between which there is no material difference, which are better than SEGG's proposal, regarding this criterion overall.

3.20 Qualification Criterion 24.5.3.1(f): Commitment to Enter Into TCA and Adhere to Applicable Reliability Criteria

(A-6)

The sixth qualification criterion is "whether the Project Sponsor makes a commitment to become a Participating TO for the purpose of turning the Regional Transmission Facility that the Project Sponsor is selected to construct and own as a result of the competitive solicitation process over to the ISO's Operational Control, to enter into the Transmission Control Agreement with respect to the transmission solution, to adhere to all Applicable Reliability Criteria and to comply with NERC registration requirements and NERC and WECC standards, where applicable."

3.20.1 Information Provided by Avangrid for Proposals 1 and 2

Avangrid indicated that it commits to becoming a PTO for the purpose of turning the transmission element that the project sponsor is selected to construct and own as a result of the competitive solicitation process over to the ISO's operational control, to enter into the TCA regarding the transmission element, to adhere to all applicable reliability criteria, and to comply with NERC registration requirements and NERC and WECC standards, where applicable. (A-6)

3.20.2 Information Provided by HWT for Bay Crossing and Inland Route

HWT, which is already a PTO through the Suncrest SVC project, indicated that if selected by the ISO as the approved project sponsor to construct and own the Newark-NRS HVDC project, HWT would commit to turn over the transmission element to the ISO's operational control, to enter into the TCA regarding the transmission element, to adhere to all applicable reliability criteria, and to comply with NERC registration requirements and NERC and WECC standards, where applicable. (A-6)

3.20.3 Information Provided by LSPGC

LSPGC indicated that it would become a PTO in 2024 in connection with the Orchard STATCOM and Fern Road GIS/STATCOM projects. LSPGC indicated that, if selected as the approved project sponsor for this project, LSPGC would turn the project over to the ISO's operational control and work with the ISO to amend the existing TCA. LSPGC indicated that it would adhere to all applicable reliability criteria and comply with applicable NERC registration requirements and NERC and WECC standards. (A-6)

3.20.4 Information Provided by SEGG

SEGG indicated that it would commit as follows:

1. That the special purpose entity that would be incorporated for this project would become a PTO with the ISO for the purpose of turning the project over to the ISO's operational control;
2. That the special purpose entity would negotiate, execute, and abide by the Approved Project Sponsor Agreement with the ISO and would support the filing of this document with FERC, if necessary;
3. That the special purpose entity would negotiate, execute, and abide by the TCA and any provisions of the ISO Tariff that pertain to a PTO; and
4. That the special purpose entity would adhere to all applicable reliability criteria and comply with NERC registration requirements and NERC and WECC standards, where applicable. (A-6)

3.20.5 ISO Comparative Analysis

All four project sponsors have committed to becoming a PTO, turning over operational control of the project to the ISO, abiding by the terms of the TCA, and adhering to all applicable reliability criteria for their proposals. Consequently, the ISO has determined there is no material difference among the six proposals of the four project sponsors regarding this criterion.

3.21 ISO Overall Comparative Analysis for Approved Project Sponsor Selection

Under ISO Tariff Section 24.5.4, the ISO conducts a comparative analysis to select an approved project sponsor. In accordance with Section 24.5.4, the purpose of the comparative analysis is to take into account all transmission solutions being proposed by competing project sponsors and to select a qualified project sponsor that is best able to design, finance, license, construct, maintain, and operate the particular transmission facility in a cost-effective, efficient, prudent, reliable, and capable manner over the lifetime of the facility, while maximizing the overall benefits and minimizing the risk of untimely project completion, project abandonment, and future reliability, operational, and other relevant problems, consistent with good utility practice, applicable reliability criteria, and ISO documents. In conducting the comparative analysis, the ISO applies the qualification criteria described in ISO Tariff Section 24.5.3.1 and the selection factors specified in Section 24.5.4.

As discussed above, the ISO has conducted this competitive solicitation because, in its 2021-2022 transmission planning process, the ISO identified a reliability-driven need for the Newark-NRS HVDC project. As required by the ISO Tariff, the ISO undertook a comparative analysis to determine the degree to which each project sponsor and its proposal met the applicable tariff selection factors and qualification criteria to determine the approved project sponsor to finance, construct, own, operate, and maintain this project.

The ISO's analysis determined that there are either no material differences or only slight differences among the project sponsors and their proposals regarding many of the selection factors and qualification criteria. One of the key selection factors for which the ISO identified material differences among the project sponsors' proposals is the cost containment factor, particularly the project sponsors' commitment to binding cost containment measures. As discussed above, this factor is one of the seven key selection factors identified by the ISO at the outset of this procurement process. LSPGC proposed the most robust cost containment proposal -- a forty year annual revenue requirement cap. Its proposal provides significantly greater cost certainty and lower projected costs than the other project sponsors' proposals whether FERC accepts LSPGC's proposed rate approach or instead requires LSPGC to implement an approach without a deferred cost recovery mechanism.

A second key selection factor is the current and expected capabilities of the project sponsor and its team to finance, license, and construct the facility and operate and maintain it for the life of the solution. HWT's two proposals were better than LSPGC's proposal regarding this factor, due largely to the stronger financial capabilities of HWT and its affiliates, which are also considered in a separate, stand-alone key selection factor, and its experience with the TBC project, an existing HVDC line in the ISO controlled grid. However, LSPGC demonstrated that it is capable of successfully financing, licensing, constructing, operating, and maintaining both this project and the Metcalf-San Jose B HVDC project. Although LSPGC does not currently own or operate any HVDC transmission line, LSPGC's team has successfully financed, permitted, designed, constructed, maintained, and operated high voltage transmission facilities, and they have experience operating under the TCA and ISO Tariff. LSPGC's team also has experience designing, constructing, and maintaining HVDC facilities. In the overall analysis, the advantage of HWT's proposal regarding this selection factor does not offset the significant advantage of LSPGC's proposal regarding cost containment. Also regarding this key selection factor, Avangrid's two proposals were stronger than LSPGC's proposal regarding the financial resources component. Although LSPGC's proposal was slightly stronger than Avangrid's two proposals regarding maintenance and operations practices, the ISO considers the two proposals of Avangrid to be slightly better than LSPGC's proposal regarding this selection factor, as discussed in Section 3.14 above.

A third key selection factor is the project sponsor's existing rights of way and substations that would contribute to the transmission solution in question. No project sponsor has existing land rights along the proposed route or for the proposed converter station sites. However, as discussed above, HWT has an option to purchase in place for both converter station sites, putting its two proposals ahead of the proposals of LSPGC and the other project sponsors in this regard. For this reason, HWT has the strongest proposals regarding this key selection factor.

A fourth key selection factor is the proposed schedule for development and completion of the transmission solution and demonstrated ability to meet the schedule of the project sponsor and its team. The ISO determined that LSPGC's proposal is slightly stronger than HWT's two proposals because it is subject to less risk of siting-related delays, included a very similar incentive penalty for failing to complete construction of the project earlier than the latest in-service date in the ISO Functional Specifications, and is comparable with respect to schedule in all other regards. LSPGC's incentive penalty was tied to completing construction of the project by June 1, 2028 – the latest in-service date in the ISO Functional Specifications, while HWT's incentive penalty was tied to a date only two days earlier. HWT's and LSPGC's proposals are better than the proposals of Avangrid and SEGG because neither Avangrid nor SEGG proposed a schedule completion incentive. There is a small benefit to completing the project before the latest in-service date in the ISO Functional Specifications, but the ISO recognizes that no project sponsor can guarantee completion of the project before that date. Because the incentive penalties proposed by HWT and LSPGC are tied to proposed in-service dates that aren't significantly earlier than the latest in-service date in the ISO Functional Specifications, and because Avangrid and SEGG do not propose a financial incentive to complete their projects prior to this date, the ISO considers none of the proposals to have an advantage in these circumstances. In addition to having the strongest proposal overall regarding this factor, LSPGC's proposal showed that it has a solid track record in timely completing projects, and it proposed an in-service date one month and 11 days before the latest in-service date in the ISO Functional Specifications, supported by a schedule completion financial incentive. These features of LSPGC's proposal, and LSPGC's detailed implementation schedule, project management plan, and track record in timely completing projects, indicate an intent and ability to complete this project by the latest in-service date in the ISO Functional Specifications.

The fifth key selection factor is the financial resources of the project sponsor and its team. The ISO's analysis showed that Avangrid and HWT have better financial metrics than LSPGC. However, LSPGC's proposal demonstrated it has sufficient financing experience, financial resources, and financial backing to finance both this project and the Metcalf-San-Jose B HVDC project. Avangrid's and HWT's advantage regarding this selection factor does not offset the significant advantage of LSPGC's cost containment proposal.

The sixth key selection factor is ability to acquire rights-of-way. LSPGC, HWT, and SEGG have the strongest proposals regarding this factor based on their identified teams having experience in California regarding rights-of-way acquisition.

The seventh key selection factor is technical (environmental permitting) and engineering experience. The ISO considers all project sponsors to be equal regarding this factor. LSPGC has proposed a strong team with strong qualifications and significant experience to handle permitting and engineering matters, including HVDC project design.

Regarding the non-key selection factors, LSPGC's proposal was either as strong as or better than the proposals of the other project sponsors, with the lone exception of the advantage associated with HWT's proposal regarding its adherence to standardized construction, maintenance, and operating practices. HWT's advantage regarding this selection factor arises from its relationship with TBC, which has an HVDC line already operating as part of the ISO controlled grid. However, LSPGC's proposal was the strongest of all the project sponsors' proposals regarding the non-key selection factor of other strengths or advantages, offsetting HWT's advantage regarding adherence to standardized construction, maintenance, and operating standards. HWT's advantage regarding one non-key selection factor, which is offset by LSPGC's advantage regarding another non-key selection factor, does not offset the advantages of LSPGC's strong cost containment proposal. In addition in this regard, LSPGC's team has experience constructing and maintaining HVDC lines, and LSPGC has experience operating facilities under the TCA. .

For the foregoing reasons, the ISO has determined that LSPGC and its team are qualified, experienced, and have the financial resources to capably, cost-effectively, and reliably license, finance, construct, operate, and maintain this particular project at the lowest cost and by the specified in-service date. Based on the ISO's review of the proposals and a comparative analysis regarding all of the selection factors and qualification criteria, the ISO has determined that LSPGC's proposal is better than the proposals of Avangrid, for its proposals 1 and 2, HWT, for its bay crossing and inland route proposals, and SEGG regarding this project. The result of this competitive solicitation is that the ISO has selected LSPGC as the approved project sponsor to finance, construct, own, operate, and maintain the Newark-NRS HVDC project.[12]

[12] Selection of LSPGC as the approved project sponsor does not preclude the ISO from taking positions on specific rate proposals contained in LSPGC's rate filing at FERC regarding its proposal.

Attachment 1

Competitive Solicitation Transmission Project Sponsor Application

Transmission Project Sponsor Proposal –Competitive Solicitation Application

Contents

Introduction and General Instructions

In accordance with ISO Tariff Section 24.5 (Transmission Planning Process Phase 3), the ISO will initiate a period of at least ten (10) weeks that will provide an opportunity for project sponsors to submit specific transmission project proposals to finance, construct, own, operate, and maintain certain transmission elements identified in the ISO's comprehensive transmission plan, or those approved by ISO management in advance of the issuance of the transmission plan if the capital cost of the project is less than or equal to $50 million. Such project proposals must include plan of service details and supporting information as set forth in the Business Practice Manual for the Transmission Planning Process (BPM-TPP) sufficient to enable the ISO to determine whether the proposal meets the criteria specified in ISO Tariff Sections 24.5.3 and 24.5.4. This competitive solicitation application form describes the details that must be provided regarding project sponsor proposals.

Projects included in this process will become part of the ISO controlled grid, and approved project sponsors will become participating transmission owners (PTOs) and will sign the Transmission Control Agreement (TCA) and enter into a Coordinated Functional Registration (CFR) agreement with the ISO. The ISO also anticipates that the project sponsor or its contracted representative(s) will be registered with the North American Electric Reliability Corporation (NERC) in the NERC categories of Transmission Owner and other functions as applicable.

This section sets forth requirements for the formatting and general contents of the project sponsor's application. The application submitted to the ISO shall not include any substantive information in response to this section. In particular, in Section 1 of the application, the project sponsor shall provide a summary of the most significant aspects of the project as proposed by the project sponsor. The ISO will refer to the information provided in Section 1, rather than any information provided in a transmittal letter for an introduction to and overview of the project. The information to be included in the application will be used by the ISO to determine whether the proposal meets the qualification criteria set forth in ISO Tariff section 24.5.3 and, if so, to compare each project sponsor and its proposal with other qualified project sponsors and proposals for the same approved transmission element pursuant to ISO Tariff section 24.5.4. To facilitate this assessment and comparison, project sponsors must provide information that reflects a thorough understanding of the requirements, processes, and activities needed to accomplish project completion and continuing operation and maintenance.

The project sponsor must submit three documents in connection with its proposal:

1. this Competitive Solicitation Application form;
2. the Cost and Cost Containment Workbook;
3. the Prior Projects and Experience Workbook.

The first document, Competitive Solicitation Application, is a completed form of this Microsoft Word document. The second document, Cost and Cost Containment Workbook, is in the form of an Excel spreadsheet. The spreadsheet documents the project sponsor's proposed capital and operations and maintenance (O&M) expenses, and also any proposed cost containment measures. The third document, Prior Projects and Experience Workbook, is in the form of a separate Excel spreadsheet. The spreadsheet documents the project sponsor's listing of prior projects and experience relevant to its capability to develop the current project.

This application form is separated into specific sections. Each section specifies information to be provided and is assigned a unique identifier for each item of information required, for example, QP–1 for Project Qualification, E-1 for Environmental Permitting and Public Processes items, S-1 for items related to Substation Design and Engineering, and so on. Project sponsors must provide responses to each of the items in the space provided after the specification of the information required and clearly note in the response the unique item identifier in each part of the response.

If the project sponsor believes that any item of the application is not applicable to its project proposal, it may indicate "N/A" but must provide a brief reason why it believes it is not applicable.

If supporting documentation is provided to supplement specific responses to application items, the project sponsor must include a specific reference to the item number and to the page numbers and paragraphs of the supporting documentation that are responsive to the application item, along with a brief explanation of how the referenced material is responsive. Information that responds directly to the information requests in the application shall be incorporated directly into the application and not be submitted as separate attachments merely referenced in the application response.

If a project sponsor provides attachments as part of the response, the project sponsor shall specify the file name of the attachment in the space provided for the response. In addition, the project sponsor shall name the attached files using the following naming convention – the file name shall include the unique identifier for the application item to which the information responds (e.g., A-5) and a description of the contents (e.g., A-5 Resumes of Key Individuals). All responses must be in readable electronic format and include the name of the project sponsor and description of the project. When submitting attachments, do **NOT** create any subdirectories. The ISO's filing system cannot process subdirectories and their use may cause important information to be lost. Also, do not use any of the following (special) characters when naming attachment files: [(~ # % & * { } \ / : < > ?)]. Use of any of these special characters is not compatible with the ISO's filing system and will cause important information to be lost. In addition, the project sponsor shall include in its cover letter a table or index in Microsoft Word format that contains a list of documents and attachments provided. The table or index must include the file name, contents, and a description of the application section(s) and items to which it corresponds. The project sponsor must provide a copy of the application in Microsoft Word format. The project sponsor must provide all responses and attached material in English or the ISO will disregard the information submitted.

The following instructions in italics pertain to the submission of geographic information:

When submitting geographic information, e.g., the proposed route for a transmission line or the location of a proposed new substation, or reactive support or series compensation station, the *project sponsor shall provide the information both in a PDF file or files, and also in shapefiles. In order to provide for the greatest support and exchangeability, shapefiles are chosen as the GIS format for submittal. There shall be one shapefile for each proposed transmission project, and no shapefile submitted shall contain more than one proposed transmission project. The proposed transmission projects are to be defined as **line** shapes. The attribute table of the shapefile shall include a **"NAME" text field** that contains the name of the transmission project. This submittal shall include, at a minimum, the following four files: **name.shp**, **name.shx**, **name.dbf** and **name.prj**. The file name shall be the name of the transmission project with any spaces and special characters replaced by underscores or other regular characters. Abbreviating and shortening of the names are acceptable and encouraged. All of the files that make up the shapefile shall be zipped together in a single "zip" file with the same name as the shapefile.*

If the project sponsor proposes to contract with others to perform duties related to the proposed project, the project sponsor's responses to the items in the application must reflect the roles, responsibilities, processes, and procedures to be used by the organization that will perform those duties, and the management controls that will be used by the project sponsor to assure that the work is done in accordance with applicable agreements, contracts, and regulatory and reliability requirements. In addition, the project sponsor shall complete the Excel spreadsheet entitled Prior Projects and Experience Workbook by which the project sponsor is to provide information regarding relevant prior projects and experience of the project sponsor and its contractors.

For each item in the application, if the project sponsor is proposing to finance, construct, own, operate, and maintain multiple transmission elements, the project sponsor shall also indicate how its response would change depending on how many of its proposals are approved by the ISO. For example, in P-4 of Section 4 (Project Management and Schedule) the project sponsor shall describe how the projected in-service date of a project would be affected if two or more of the project sponsor's proposals are approved.

Please note that the ISO will consider only ONE proposal per application submitted. The project sponsor may identify alternate proposals that it has considered, but shall clearly identify the single proposal that it wishes the ISO to evaluate.

This application form includes an officer certification form (Section 15) that must be signed by an officer of the authorized representative of the applicant project sponsor. The ISO will not consider any application that does not include a completed officer certification form.

To the extent a project sponsor considers any of the information submitted with its application to be confidential or proprietary, the project sponsor must clearly identify the confidential or proprietary information and must include an explanation as to why the information should be treated by the ISO as confidential. The ISO will not treat the identity of a project sponsor and basic information about the project sponsor's proposed project as confidential information. A project sponsor must separately request confidential treatment for each response to an individual application information request and explain the need for confidential treatment. Project sponsors shall not make general designations of large sections of the application as confidential or proprietary.

Project sponsors should note that the maximum size of an e-mail submitted to the ISO must not exceed 20 MB or the ISO's e-mail system may not be able to process it. An application that includes files or attachments larger than 20 MB must be compressed to files of a size less than 20 MB. Project sponsors shall submit their information via CD or DVD medium. Please provide 3 complete sets of CDs or DVDs and clearly label each with project name and sponsor name. The ISO prefers that project sponsors submit the initial application (consisting of the Microsoft Word document and associated attachments, and the Excel spreadsheets) on CDs or DVDs.

If a project sponsor wishes to apply for more than one project eligible for the ISO's transmission procurement process, the project sponsor must submit a separate application for each project. Again, the ISO will consider only one proposal per application.

Please note that there are several tables in this application form for use in providing responses. Project sponsors may add rows to the tables if the number of entries exceeds the number of rows initially provided in the tables.

The ISO requires a deposit of $75,000 for each submitted application. The ISO will not consider applications if the project sponsor fails to include the deposit on or before the date the bid window closes. Payment instructions and a project sponsor deposit form can be found in Section 16 of this application form.

While the competitive bid window is open, a project sponsor may submit questions to the ISO for clarification. Questions must be submitted via e-mail to the following address: transmissioncompetitivesolicitation@caiso.com. The ISO will attempt to answer these questions in a timely manner. The answers will be made available in a table that the ISO will post to its website on the "Transmission Planning" page. Note that the ISO will not include the identity of the project sponsor in the table. In general, the ISO will update this table on a weekly basis or as needed.

• Project Sponsor Name, Organizational Structure, and Proposal Summary

A-1 Project Sponsor Name:

Response: (Enter Project Sponsor Company Name)

A-2 Proposal Name:

Response: (Enter Proposal Name)

A-3

Submittal Date:

Response: (Enter Submittal Date)

A-4 Provide a brief summary of the project sponsor's proposal:

Response:

A-5 Provide an organizational chart depicting the project team and areas of responsibility, including the responsibilities of all contractors. In addition, provide a corporate organizational chart of the project sponsor and any parent companies and affiliates. Attach resumes of all key management and lead personnel of the project sponsor, affiliates, and contractors who will be used for the project, including a resume for each lead individual of the project sponsor and its contractors in each area of responsibility for the project. Identify any parent organization or affiliate personnel responsible for a specific project listed in the Prior Projects and Experience Workbook who will be part of the project sponsor's team for the instant project. For project sponsor and affiliated personnel and for contractor personnel, relate each resume to a position on the organization chart provided. The project sponsor should be aware that if it is selected as the approved project sponsor, the ISO will require that any change in the personnel and contractors proposed to be used for the project must be approved by the ISO. Describe the legal and financial structure of the project sponsor and its team, including type of corporation if a corporation, or type of entity if it is a special purpose entity (e.g. project financed LLC) created explicitly for the proposed project. Describe the legal and financial relationship of the entity listed as the project sponsor to all other entities that are referred to in the application to include but not limited to all parent or holding company organizational entities, equity investors and any entity that will finance or otherwise financially support or provide guarantees for part or all of the project if different from the project sponsor. This description shall include the entity or entities that will own the assets of the project (whether through a special purpose entity or as part of a portfolio of assets or other mechanism) during the construction period and during the operating period.

Response:

A-6 State that the project sponsor is making a commitment to become a participating transmission owner for the purpose of turning the transmission element that the project sponsor is selected to construct and own as a result of the competitive solicitation process over to the ISO's operational control, to enter into the Transmission Control Agreement with respect to the transmission element, to adhere to all applicable reliability criteria, and to comply with NERC registration requirements and NERC and Western Electricity Coordinating Council (WECC) standards, where applicable.

Response:

* ## Project Qualification

Project Sponsor and Project Qualifications:

The ISO will review each project sponsor's proposal to assess the qualifications of the project sponsor and its project proposal based on the qualification criteria set forth in ISO Tariff section 24.5.3. The ISO will evaluate the information submitted by each project sponsor in response to the application items pertaining to sections 24.5.3.1(a)-(e) to determine whether the project sponsor has demonstrated that its team is physically, technically, and financially capable of (i) completing the needed transmission solution in a timely and competent manner and (ii) operating and maintaining the transmission solution in a manner that is consistent with good utility practice and applicable reliability criteria for the life of the project.

In addition, the ISO will determine whether the transmission solution proposed by a project sponsor is qualified for consideration, based on the qualification criteria contained in ISO Tariff sections 24.5.3.2(a) and (b). Please demonstrate that the proposed project meets the proposal qualification criteria for the needed transmission element by providing responses to the following two items (QP-1, QP-2) that relate to the qualification of the proposed project. When providing these responses, the project sponsor shall refer to information that has been provided in other sections of its application for additional information and support. The following two responses shall provide a complete demonstration or qualification – through the two responses directly and by including references in the two responses to material provided in responses to other items in the application.

Describe and demonstrate how:

QP-1. The proposed design of the transmission solution is consistent with needs identified in the comprehensive ISO transmission plan.

Response:

QP-2. The proposed design of the transmission solution satisfies applicable reliability criteria and ISO planning standards.

Response:

- **Prior Projects and Experience**

In the accompanying Excel spreadsheet entitled Prior Projects and Experience Workbook, the project sponsor shall provide a description of all relevant prior projects and experience of the project sponsor on the Project Sponsor experience tab and its proposed contractors on the Contractor experience tab as it relates to this project. The lists of projects should include those with voltages greater than 200 kV completed in the past ten years. If the project sponsor or its proposed contractors do not have experience constructing facilities with voltages greater than 200 kV, but do have experience constructing lower voltage facilities, this experience may be included. Detailed explanations of schedule and budget variances may be supplied in a separate document if necessary as noted in the spreadsheet and shall include a description of major issues confronted and resolved during the project.

The Contractor experience tab of the Prior Projects and Experience Workbook shall be used to list the prior project experience of all contractors that the project sponsor proposes to use for this project, including but not limited to land acquisition, environmental permitting, design and engineering, construction, maintenance, and operations contractors. If the project sponsor proposes to but has not retained a contractor for any of the foregoing functions, the project sponsor shall provide a realistic short list of contractors under consideration. Any change to these contractors will require approval by the ISO. The evaluation will consider the qualifications of each submitted contractor. The experience list shall include any work performed by the contractor for the project sponsor. For environmental permitting contractors, the project sponsor must indicate in the spreadsheet, for each prior project listed for that contractor, the federal and state permits acquired as well as associated environmental processes, including federal NEPA or state environmental review determinations.

- **Project Management and Schedule**

P - 1. Provide a general description of the proposed approach to project management and scheduling for the transmission element.

Response:

P - 2. Provide the proposed management structure, organization, authority levels, and resources committed to project management and scheduling for the full scope of the project, including relevant experience and capability for the proposed project manager and other relevant decision-makers for the project. If the sponsor does not have a team in place, provide your plan to meet these requirements.

Response:

P - 3. Provide a proposed schedule for project development through release for operation that includes, at a minimum, key critical path items such as:
- Develop contracts for project work;
- Regulatory approval; permitting; rights of way and land acquisition;
- Engineering and design;
- Material and equipment procurement;
- Facility construction;
- Agreements (interconnection, operating, scheduling, etc.) with other entities;
- Pre-operations testing;
– Any amount of "float" incorporated into the schedule;
- Project in-service date;
- Other items identified by the project sponsor.

Provide a list of measures that the project sponsor would take to meet its schedule if the project sponsor encounters unanticipated delays in its schedule for land acquisition, permitting, or construction of up to 6 months. If the project sponsor proposes any financial or other incentives to ensure completion of the project on schedule, provide a description of those financial or other incentives.

Response:

P - 4. For the proposed project, identify the major risks and obstacles to successful project completion within cost budget while meeting schedule and identify proposed mitigations to minimize the risks. Describe all actions that the project sponsor will take to keep the project within budget while meeting schedule in light of the major risks identified.

If the project sponsor is sponsoring more than one project, the project sponsor shall also describe how the projected in-service date of this project (as reflected in the proposed schedule) would be affected if two or more of the project sponsor's proposals are selected.

Response:

P - 5. For the transmission line and substation projects included in the Prior Projects and Experience Workbook, provide the following:
(a) Any environmental permitting risks and challenges that the project sponsor and its team have previously faced that are comparable to the risks and challenges it will face in connection with this project.
(b) Any transmission line or substation design or engineering risks and challenges that the project sponsor and its team have previously faced that are comparable to the risks and challenges it will face in connection with this project.
(c) Any transmission line or substation construction risks and challenges that the project sponsor and its team have previously faced that are comparable to the risks and challenges it will face in connection with this project.
(d) Any maintenance risks and challenges that the project sponsor and its team have previously faced that are comparable to the risks and challenges it will face in connection with this project.
(e) Any operations risks and challenges that the project sponsor and its team have previously faced that are comparable to the risks and challenges it will face in connection with this project.
(f) Other specific materials that reflect project management skills for an actual project.

Response:

• Cost Assumptions and Containment

Provide all the information regarding cost containment for the proposed project in the Cost and Cost Containment Workbook. In addition, provide the information regarding the cost containment proposal in response to the following requests. Ensure the information provided in this application is consistent with the information provided in the Cost and Cost Containment Workbook.

CC-1 Fully describe in detail all of your proposed cost containment measures.

Response:

CC-2 Explain in detail and provide all bases, assumptions, reasons, support, and documentation as to why your estimated cost of debt constitutes a reasonable representation and expectation of the debt cost you expect to incur in connection with the project.

Response:

CC-3 Describe each proposed maintenance activity and its frequency planned over the life of the project facilities. Explain in detail and provide all bases, assumptions, reasons, and support as to why your estimated O&M costs (and Administrative and General (A&G) costs) constitutes a reasonable representation and expectation of the O&M costs you expect to incur in connection with the project. To the maximum extent practicable, provide this analysis for each individual component of total O&M costs as reflected in the Cost and Cost Containment Workbook.

Response:

CC-4 Identify by job category the number of full-time equivalent employees (FTE) the project sponsor intends to employ from its company to perform operations activities and the number of FTEs the project sponsor intends to employ from its company to perform maintenance activities. Also provide the number of FTEs that will be allocated to Administrative and General activities. Describe the specific role and functions each FTE will serve. Describe in detail the basis for and assumptions underlying these FTE estimates and the cost associated with the FTEs.

Response:

CC-5 Indicate whether the project sponsor intends to contract for O&M services.

a. If so, provide the name of the counterparty and attach any agreements that provide the terms of the relationship.
b. If the project sponsor intends to rely on O&M services from a regulated utility, identify the utility and describe in detail how the utility intends to support the project. Attach any agreements that provide the terms of the relationship.

c. Provide the specific roles and functions the contractors will provide for the project.

d. Provide in detail the justification for cost estimates associated with contracted O&M services.

e. For contracted O&M services, provide: (1) the number of FTEs- (on an annual basis) that would be conducting maintenance activities; (2) the number of FTEs- that would be providing operations services; and (3) the number of FTEs- that would be allocated to Administrative and General activities.

Response:

CC-6 Provide all details, assumptions, reasons, and supporting documentation (including manufacturers' guidelines) underlying the project sponsor's useful life projections for the project.

Response:

CC-7 Describe in detail all exclusions to any cost cap and cost containment measures the project sponsor proposes.

Response:

CC-8 If the project sponsor is proposing an exclusion for *force majeure* events, how exactly does the project sponsor propose to define *force majeure* for purposes of limiting exclusions from or increases to any cost cap and other cost containment measures?

Response:

CC-9 If a siting or permitting authority were to require relocation of the project sponsor's proposed site for the project, how exactly would that affect the project sponsor's proposed cost cap and other cost containment measures?

Response:

CC-10 If a siting or permitting authority were to require changes to the proposed structures, equipment, or transmission lines associated with the project sponsor's project, how would that affect the proposed cost cap and other cost containment measures?

Response:

CC-11 If a siting or permitting authority were to require an increase in the amount of environmental mitigation beyond that assumed in the project sponsor's proposal, how would that affect the proposed cost cap and other cost containment measures?

Response:

CC-12 If a siting or permitting authority were to require undergrounding of the project sponsor's proposed transmission facilities, or require overhead construction if the project sponsor has proposed undergrounding, how would that affect the proposed cost cap and other cost containment measures?

Response:

CC-13 If there were to be a delay in the receipt of any of the project sponsor's siting or permit authorizations, how exactly would that affect the proposed cost cap and other cost containment measures?

Response:

CC-14 If there were to be a delay in the schedule of the participating transmission owner for constructing its interconnection facility for the project, or if changes in project scope or location were to be required or caused by the interconnecting PTO, how would that affect the proposed cost cap and other cost containment measures?

Response:

CC-15 If one of the project sponsor's approved contractors was not able to meet its requirements, and the project sponsor were to propose and the ISO approve an alternate contractor, what impact would this have on the proposed cost cap and other cost containment measures?

Response:

CC-16 Indicate the authority of any agency with jurisdiction over the project to impose binding cost control measures or cost caps on the project, if the project sponsor is not proposing a cost cap.

Response:

- ## Financial

The project sponsor (or the project sponsor's parent or other affiliated entity in the event the project sponsor must rely on either to meet this financial criteria) must demonstrate it has sufficient financial resources, including, but not limited to, satisfactory credit ratings and other financial indicators as well as the demonstrated ability to assume liability for major losses resulting from failure of any part of the facilities associated with the transmission solution. The ISO will consider the parent's or affiliated entity's financial statements, credit ratings, and other statements in this section if the parent or affiliated entity provides financial assurances acceptable to the ISO as described in F-2 below.

General

F - 1. Provide a list of equity holders, equity contribution by each investor, and the amount of debt over the entire life of the project.

Response:

F - 2. If the project sponsor is relying on a parent or another affiliated entity to satisfy the financial criterion of its application, (1) describe the entity's relationship to the project sponsor in the form of a corporate hierarchy and (2) provide a letter signed by an officer of the parent or affiliated entity indicating that the parent or affiliated entity provides financial assurances for the project. In addition, provide details of the parent's or affiliated entity's plan for providing for credit, investment, or financing arrangements for financial backing of the project. If financial recourse is limited, describe under what conditions recourse is available to the parent or affiliated entity's financial resources. Describe how these arrangements comply with all legal and regulatory requirements related to affiliate transactions.

Response:

Financial Strength and Creditworthiness

For the entity that has the financial resources to meet the financial strength and creditworthiness criteria and is required to provide financial assurances for the project, provide the information requested in F-3 through F-10.

F - 3. Provide annual, audited financial statements or equivalent (e.g., FERC Form 1) that at a minimum, includes an Auditors Statement, Management Statement, Balance Sheet, Income Statement, Statement of Cash Flows and Notes to the Financial Statements, for the most recent year and previous four years (five years total). If audited financial statements are not available, the project sponsor may provide other documentation demonstrating financial capability. In either case, the documentation **must be accompanied by a letter signed and attested to by an officer of the company** providing financial assurances that the documents are a fair representation of the financial condition of the company in accordance with generally accepted accounting practices. If this information is available electronically, it is acceptable for the project sponsor to provide links to the appropriate documents. NOTE: All financial statements must be provided in English.

Response:

F - 4. Provide quarterly, unaudited financial statements or equivalent (e.g. FERC Form 3-Q) published since the last annual, audited financial statement. If not available, the project sponsor may provide other documentation demonstrating financial capability. In either case, such documentation **must be accompanied by a letter signed and attested to by an officer of the company** providing financial assurances that the documents are a fair representation of the financial condition of the company in accordance with generally accepted accounting practices. If this information is available electronically, it is acceptable for the project sponsor to provide links to the appropriate documents. NOTE: All financial statements must be provided in English.

Response:

F - 5. If the creation of a special purpose entity (SPE) is being proposed for this project, describe the funding source(s) for the SPE for the duration of the project's useful life and how it fits into the corporate hierarchy. Explain how the capabilities and resources of the parent organization(s) of the SPE can be attributed to and will serve the SPE.

Response:

F - 6. Provide current credit ratings <u>and</u> rating agency reports from Moody's Investor Services, Standard & Poor's Ratings Services and/or Fitch Ratings, or another rating agency designated by the U.S. Securities and Exchange Commission as a Nationally Recognized Statistical Rating Organization. If credit ratings are unavailable, the project sponsor may provide other supporting information.

Response:

F - 7. Provide a report of any failure to make debt service payments on time during the previous five years. If the project sponsor is an SPE, report any such failures by its parent or other affiliated entities, including any predecessor SPEs.

Response:

F - 8. Provide a summary of any history of bankruptcy, dissolution, merger, or acquisition for the current calendar year and the five prior calendar years. If the project sponsor is an SPE, report any such events by its parent or other affiliated entities, including any predecessor SPEs.

Response:

F - 9. Based upon the most recent audited financial statements, provide a ratio of total assets to the total projected capital costs of the project, and show the calculation including any encumbrances.

Response:

F - 10. For each of the five years for which audited financial statements were provided according to F – 3 above, provide the following financial ratios, and show the calculation for each:

a. Funds from operations to interest coverage
b. Funds from operations to total debt
c. Total debt to total capital

Response:

Project Financing

F - 11. Describe the financing used on up to five projects listed in the Prior Projects and Experience Workbook that are similar in type and size to (or larger than) the transmission element and/or substation proposed in the application. Include the following in your response and use the table provided below:

1) Project description,
2) Financing structure (e.g., LLC vs. corporate),
3) Equity and debt contribution,
4) Debt sources,
5) Bank(s) involved,
6) Other important information.

F-11 (1)Project Description	(2)Financing Structure	(3)Equity and Debt Contribution	(4)Debt Sources	(5)Banks Involved	(6)Other Important Information

F - 12. Describe the proposed financing sources of funds and instruments for construction and working capital for this project by completing the following table:

Entity Providing Debt Financing	Loan Amount	Interest Rate	Repayment Period	Grace Period During Construction	Equity Provided by Project Sponsor

F - 13. For financing sources other than the capital markets, describe the benefits to ratepayers and others of your proposed financing source(s). This shall include the projected cost of the financing sources.

Response:

Project Liability Protection and Project Replacement and Repairs

F - 14. Provide the project sponsor's planned insurance coverage, including types of coverage and insured values during the construction period and over the operational life of the project facilities, including but not limited to covering negligent performance. Also include the types of losses to be covered during the construction and operation of the project, including specifying the extent of failure of project facilities to be covered by the planned insurance during the operation of the project.

Response:

F - 15. Describe your ability to finance unexpected repairs (*e.g.*, replacement of a series of towers) or replacement construction during the estimated useful life, *i.e.*, the operating period for the transmission element(s). For example, capabilities can include, but are not limited to, the following: use of account set-asides or accumulated funds, parent organization guarantees, letters of credit, letters of intent from financial institutions to support the project sponsor, insurance, or other means of ensuring that these increased costs can be covered in a timely manner and thus not delay the return of the project to normal operation.

Describe any actual events where the project sponsor had to cover increased costs due to equipment failures, including the nature of the event, costs incurred, and how these costs were funded by the project sponsor.

Response:

• Environmental Permitting and Public Processes

E - 1. Provide an overview of the various project activities that the project sponsor believes are needed to achieve siting approval, obtain all necessary permits, and any other necessary public processes required to construct the project. Provide a list of steps or flow chart for these project activities and processes. If the project is located within more than one state, provide a response for each state as applicable.

Response:

E - 2. Using your best estimate, indicate whether any federal discretionary permit(s) will be required. For each discretionary permit anticipated, identify the agency and applicable governing rule or statute. Describe these in detail, e.g., Clean Water Act Section 401- 404, U.S. Fish and Wildlife Service biological opinion.

Response:

E - 3. Using your best estimate, indicate whether any state discretionary permit(s) will be required and the type of permit to be filed (e.g., endangered species incidental take permit, water quality Section 401).

Response:

E - 4. Indicate if any federal land (for example, Forest Service, BLM) is proposed to be crossed, and if a NEPA (National Environmental Policy Act) environmental process is required.

Response:

E - 5. For projects within the State of California:

a. Indicate which agency is the expected California Environmental Quality Act (CEQA) lead agency. Explain why that agency was chosen and indicate whether that agency has agreed to be the lead agency for this project.

Response:

b. Provide a list of Best Management Practices[13] and project sponsor standing policies, related to siting and permit processes, that all employees are required to observe, including how are they implemented and how are they reported, that would be applicable for the proposed project.

[13] BMPs, which are environmental industry standard terminology, are the project sponsor's standards that would be common to all projects, i.e., not specific to any particular project. For example, this could consist of company training policies that relate to required safety training, environmental sensitivity training, accident and injury reporting, or community involvement programs involving both the local elected officials and the immediate community that will be impacted by the proposed project.

Response:

c. Provide a list of Applicant Proposed Measures that would be applicable for the proposed project. These are project sponsor mitigation measures that would be applied to reduce the potential environmental impact for a particular construction activity to ensure the impact is reduced below the level of a significant unavoidable impact. These are normally related to the CEQA checklist.

Response:

d. Indicate if you expect to perform any public outreach (e.g., open houses, project hotline number, project update mailings) and describe the planned outreach program.

Response:

E - 6. Provide information related only to transmission line, reactive support, series compensation, and substation siting and permits for projects developed by the project sponsor or its team in the past ten years. If the project sponsor is an SPE, provide information on the parent organization(s) for similar projects. Provide:

a. A description of any project siting or permitting notice of violation (NOV).

Response:

b. Siting or permitting fines levied by the project approval authority or any other agency with discretionary or ministerial authority over the project.

Response:

c. Remediation actions taken to avoid future violations.

Response:

d. A summary of siting or permitting law violations by the project sponsor or its team found by federal or state courts, federal regulatory agencies, state public utility commissions, other regulatory agencies, or in any other legal proceeding.

Response:

e. Any notice of violations that were remediated to the satisfaction of the issuing agency or authority.

Response:

f. A summary of any instances in which the project sponsor or its team is currently under investigation or is a defendant in any legal proceeding for violation of any siting or permitting law.

Response:

• Transmission or Substation Land Acquisition

L - 1. Provide an overview of the various project activities that the project sponsor believes are needed to obtain rights-of-way (ROW) or other land acquisition for the project. Provide a list of steps or flow chart for these project activities and processes. If the project is located within more than one state, provide a response for each state as applicable.

Response:

L - 2. Provide a general description of the land siting and acquisition needed for the proposed project and a map of the proposed project alignment and/or substation site on a suitable map base and scale - USGS quadrangle 1:24000 at a minimum. The map should show the study area for routing the project as well as any alternate routes, existing transmission lines, California Natural Diversity Data Base (CNDDB) information within the project area, and avoidance areas (such as parks, airports, military installations, and areas of local, state or national interest and any other major exclusion areas). Provide estimated acreages required. Include construction access, permanent access roads, laydown yards, and landing zones, if required. Show alternatives evaluated, those dismissed, and the justification for the preferred site.

Response:

L - 3. Provide a copy of the standard grant of easement anticipated and any temporary construction easement documents necessary for the project construction and a description of your proposed strategy for crop loss and or business loss compensation.

Response:

L - 4. Provide an indication of whether the project sponsor has eminent domain authority. If the project sponsor does not have eminent domain authority and does not plan to obtain eminent domain authority, describe the strategy for acquisition of necessary land rights.

Response:

L - 5. Indicate whether the project sponsor has any existing ROW or substations on which all or a portion of the transmission element can be built. For any such ROW describe how it would be used as part of the proposed project. Also, for any such ROW describe any incremental costs and risks associated with using the existing ROW (for example, negotiating additional land rights or the potential of "overburdening" existing easements). Does the project sponsor make a binding commitment to seek to use such existing ROW or substations for the project, and to use such existing ROW or substations unless the applicable siting authority or other regulatory agency determines otherwise, approves a different route, or the project sponsor is prevented from doing so by *force majeure* type events?

Response:

Substation Design and Engineering

The items listed below should only be completed if the proposed transmission solution contains a substation or facilities similar to a substation (e.g., synchronous condenser, STATCOM).

S - 1. For each substation or reactive control element that is included as part of your proposed project, provide the location, interconnection with new or existing transmission facilities, bus and breaker arrangement, typical structure types and materials that will be used, and any other unique aspects of the substation that the project sponsor proposes.

Response:

S –2. For each proposed substation, reactive support, or series compensation installation, provide the substation siting criteria that will be used on the project (e.g., future area plans, constructability, earthquake activity, flood plain and mudslide considerations).

Response:

S – 3. For each proposed substation, reactive support, or series compensation installation, provide the basic parameters for the installation - primary and secondary voltage, BIL[14], initial design power capacity, and final design power capacity (if developed in stages).

Response:

S – 4. For each proposed substation, reactive support, or series compensation installation, provide a preliminary design criteria document that specifies the criteria that will be used in the design of the facility. Also provide a list of standards and requirements that will be used in its design - e.g., IEEE 142. Provide a complete list of state specific requirements for each U.S. state in which the project will be located (e.g., California and other state specific requirements if part of the project or the entire project is located outside California).

Response:

S – 5. For each proposed substation, reactive support, or series compensation installation, provide a single line diagram and general arrangement plan, which includes:

i. bus and breaker arrangement,
ii. transformer arrangement,
iii. automatic tap changer, if any,
iv. power factor correction equipment if any,
v. voltage regulator, if any,
vi. ground fault limiting resistor or reactor, if any,
vii. line terminations for existing or proposed transmission lines,

[14] A design voltage level for electrical apparatus that refers to a short duration (1.2 x 50 microsecond) crest voltage and is used to measure the ability of an insulation system to withstand high surge voltage.

viii. bus type and rating,
ix. high voltage switch types and ratings,
x. switchgear type and ratings,
xi. battery system arrangements,
xii. substation, reactive support, or series compensation facility layout with equipment location, fencing, grounding, control/relay building, etc.

Response:

S – 6. For each proposed substation, reactive support, or series compensation installation, describe the protection system criteria and specific components included in the design for primary and back-up protection. Identify any special protection considerations for the substation.

Response:

S – 7. For each proposed substation, reactive support, or series compensation installation, describe the SCADA incorporated in the design. Include the project sponsor’s commitment to meet operational data requirements and a specific description of the communications strategy.

Response:

S – 8. For each proposed substation, reactive support, or series compensation installation, describe the physical security criteria and specific security measures that will be incorporated in the final facility design.

Response:

- ## Transmission Line Design and Engineering

The items listed below should only be completed if there is a transmission line included in the proposed transmission solution.

T - 1. Provide a general overview and description of the transmission line that the project sponsor proposes, including the following items. Use the table provided below for your responses:

a. The starting and ending points including length of preferred route. If the route is in more than one state, provide the information for each state.
b. proposed conductor size, bundling and type,
c. intervening substations, switching stations, or series compensation facilities,
d. typical span lengths,
e. any other unique aspects of the line that the project sponsor proposes that has not previously been provided for the overhead portions of the line.

If any underground transmission is proposed, include a general description of the following items:

f. the underground conductor size and type and length of segment(s),
g. the proposed termination facilities, and
h. any other unique aspects of the underground portion of the line not previously provided.

T-1 Item	Response
a	
b	
c	
d	
e	
f	
g	
h	

T - 2. Provide the transmission line siting criteria that will be used for any overhead section of the proposed transmission line and any underground sections of the proposed transmission line.

Response:

T - 3. Provide a listing of all existing or permitted transmission lines, including voltage, structure type, and separation, located adjacent to or in the same corridor as the proposed project. Provide the criteria used to establish the separation between the proposed transmission line and existing transmission and distribution facilities.

Response:

T - 4. Provide the preliminary design criteria document for any overhead section of the proposed transmission line and any underground section of the proposed transmission line.

Response:

T - 5. Provide a list of standards and requirements that will be used in the transmission line design for both overhead and underground, e.g., IEEE 951, ASCE Manual No. 72, GO 95, with an emphasis on providing a complete list of state specific requirements and the requirements of other states where the proposed project will be located. Also provide any interconnection standards for interconnection of the project to existing utility system(s).

Response:

T - 6. Provide a single line diagram and a general arrangement plan of the entire proposed transmission line, including transmission line crossings by the new project line. For crossings, provide a list by voltage and type of construction of lines crossed (either over or under) by the proposed project. Include isolation devices to be installed for operations and maintenance purposes.

Response:

T - 7. For any proposed overhead transmission line, provide the following additional information not included in response to T-1 in the table provided below:

a. Basic parameters of the transmission line(s) - Design voltage, BIL (design or adjacent substation criteria), initial design power capacity and final design power capacity (if developed in stages).

Support Structures

For any support structures including wood poles, tubular poles, and lattice steel structures, provide:

b. a description of the proposed support structures and conductor geometry,
c. structure foundations as appropriate and grounding criteria and implementation,
d. insulation level, insulator types,
e. lightning protection,
f. estimated right of way widths for each different segment of the project with drawings for each and the basis of determining each right of way width.

Line Ratings and Impedance

g. Provide the estimated per mile line impedances for each different line section proposed in the project, suitable for use in power flow, system stability, and system protection studies. Also provide an estimate of the completed line overall impedance in per unit on a 100 MVA base.
h. Provide NESC and/or GO 95 Grade of Construction.
i. Provide NESC and/or GO 95 Loading Corridor Separation.

T-7 Item	Response
a	
b	
c	
d	
e	
f	
g	
h	
i	

T - 8. For any proposed overhead section and any underground section of the transmission line, provide the ampacity rating methodology including maximum conductor temperature that will be used to determine the normal and emergency ratings of the overhead line for summer and winter. Provide the actual ampacity for the line under normal conditions and emergency operations (specify time limit for emergency operations) for summer and winter operating conditions.

Response:

T - 9. For any proposed underground transmission sections, provide the following additional information not included in response to T-1 in the table provided below:

a. Type of transmission cable, including splicing and cable grounding,
b. Substructures, conduits and duct banks, and splicing enclosures,
c. Termination facilities and structures,
d. Description of the type of transmission cable, including splicing and cable grounding,
e. Provide the estimated per mile line impedances for each different line section proposed in the project. All line impedances shall be provided on a per unit 100 MVA base. Also provide an estimate of the completed line overall impedance.
f. lightning protection,
g. estimated right of way widths for each different segment of the project with drawings for each and the basis of determining each right of way width.

T-9 Item	Response
a	
b	
c	
d	
e	

f	
g	

T - 10. For each substation that the proposed transmission line would terminate in that will not be the responsibility of the project sponsor to modify in order to interconnect the line, provide the following information in the table below:

a. Name of the substation where the interconnection will take place.
b. A description of the demarcation point that identifies the point in the interconnection where responsibility for implementation (e.g., design, construction, testing) changes from the project sponsor to the substation owner.
c. List of agreements that must be reached with the substation owner or others to interconnect and operate the proposed line to the substation (e.g., interconnection agreement, schedule agreement).
d. A description of the project sponsor’s approach to determining if any environmental permitting will be required to terminate the proposed line at the substation
e. A description of the approach the project sponsor’s will use to determine the cost to implement changes at the substation or other locations that are associated with the interconnection of the proposed project at the substation and of those costs which will paid for by the project sponsor.

T-10 Item	**Response**
a	
b	
c	
d	
e	

Construction

Provide an overview and description of the construction plan and management practices that the project sponsor proposes to follow in response to the questions below:

C-1 Description of inspection of construction activities, including substations, reactive support, series compensation installations, overhead transmission lines, and underground transmission lines if part of the project.

Response:

C-2 Description of the method of establishing material yards, sequencing and receiving material, providing material to contractors, material quality control methods, and material expediting processes.

Response:

C-3 Description of the method of coordination of the duration and timing of any clearances of existing circuits necessary during construction.

Response:

C-4 Description of the plans for a constructability review including completeness of engineering drawings, construction specifications, material orders, and tracking and providing changes.

Response:

C-5 Description of the status of easements orders of possession, permits, and compliance with pre-construction permit conditions and mitigation measures.

Response:

C-6 Description of the method for detail scheduling showing sequence of work, environmental restrictions, clearances requirements, progress reports, and actions taken to maintain schedule.

Response:

C-7 Description of any unique or special construction techniques proposed for any aspect of the proposed project, including ROW clearing, construction and permanent access road construction, and expected helicopter work.

Response:

C-8 Provide information related only to transmission line, reactive support, series compensation, and substation construction for projects developed by the project sponsor or its team for projects completed during the past ten years. If the project sponsor is an SPE, provide the information for the parent organization(s). Provide

a. A description of any project construction-related notice of violation (NOV).

Response:

b. Construction-related fines levied by the project approval authority or any other agency with discretionary or ministerial authority over the project.

Response:

c. Remediation actions taken to avoid future violations.

Response:

d. A summary of construction-related law violations by the project sponsor or its team found by federal or state courts, federal regulatory agencies, state public utility commissions, other regulatory agencies, or in any other legal proceeding.

Response:

e. Any notice of violations that were remediated to the satisfaction of the issuing agency or authority.

Response:

f. A summary of any instances in which the project sponsor or its team is currently under investigation or is a defendant in any legal proceeding for violation of any construction-related law.

Response:

Maintenance

M-1 Describe the roles and responsibilities of the project sponsor’s maintenance organizations. Describe any organizational changes to the project sponsor’s current organization that are planned to accommodate maintenance of the proposed project. Provide any contract you have with a third party to provide maintenance services for the project. Describe what specific maintenance activities will be handled by project sponsor staff and which activities will be handled by contractors or vendors.

Response:

M-2 Describe the project sponsor’s policies, processes, and procedures for assuring that only persons who are appropriately qualified, skilled, and experienced in their respective trades or occupations are employed. Include qualifications, certifications, and experience requirements for maintenance and field personnel.

Response:

M-3 Describe the project sponsor’s training program for maintenance personnel. Include initial and continuing education requirements for maintaining qualifications for classifications with maintenance responsibilities (e.g., what are the training and certification requirements for linemen and substation electricians?). Identify training resources used.

Response:

M-4 Describe the project sponsor’s capabilities that will enable it to comply with the maintenance standards described in Appendix C of the TCA. Indicate whether or not the project sponsor’s standards include the elements listed in TCA Appendix C Sections 5.2.1 (Transmission Line Circuit Maintenance) and 5.2.2 (Station Maintenance). (Note: Each PTO will prepare its own maintenance practices that shall be consistent with the requirements of the ISO Transmission Maintenance Standards. The effectiveness of each PTO’s maintenance practices will be gauged through the ISO’s availability performance monitoring system. Each PTO’s adherence to its maintenance practices will be assessed through an ISO review pursuant to TCA Appendix C Maintenance Procedure 4).

Response:

M-5 Describe the project sponsor’s vegetation management plan as it applies to the proposed project. Provide the project sponsor’s preexisting procedures and historical practices for managing ROW for transmission facilities.

Response:

M-6 Provide information, notices, or reports regarding the project sponsor's compliance with its standards for inspection, maintenance, repair, and replacement of similar facilities. Include audit reports or regulatory filings.

Response:

M-7 Describe the project sponsor's capabilities that will enable it to provide its Availability Measures in accordance with TCA Appendix C Section 4.3 as applicable. Provide sample availability measures, or similar measures, for other facilities owned by the project sponsor to demonstrate the project sponsor's capability.

Response:

M-8 Would adding the project to the ISO controlled grid require any changes or exceptions to the provisions of the TCA? If "yes", describe.

Response:

M-9 Describe the project sponsor's (its team or planned team) capabilities that will enable it to comply with the activities required by TCA Section 7 (Operations and Maintenance [including Scheduled Maintenance, Exercise of Contractual Rights, and Unscheduled Maintenance]).

Response:

M-10 Specify where the project's maintenance team (including any project sponsor staff and contractors) will be located. Specify the estimated response time of any assigned project sponsor staff, maintenance contractor, or emergency response provider.

Response:

- ## Operations

O-1 Describe the roles and responsibilities of the operations organizations, including operating jurisdictions as they relate to the proposed project. Identify the planned location of those responsible for operation of the project, including the location of the control center that will serve as the single point of contact for the ISO. Describe any organizational changes to the project sponsor's current operations organization that are planned to accommodate the proposed project. Provide any contract you have with a third party to provide operation services for the project. Describe what specific operations activities will be handled by project sponsor staff and what activities will be handled by contractors or vendors.

Response:

O-2 Describe the project sponsor's policies, processes, and procedures for assuring that only persons who are appropriately qualified, skilled, and experienced in their respective trades or occupations are employed. Include qualifications, certifications, and experience requirements for operators and field personnel.

Response:

O-3 Describe the project sponsor's training program for operations personnel. Include initial and continuing education requirements for maintaining qualifications for classifications with operation responsibilities (e.g., what are the training and certification requirements for operators, linemen, and substation electricians?). Identify training resources used.

Response:

O-4 Would adding the project to the ISO controlled grid require any changes or exceptions to the provisions of the TCA regarding operations? If "yes", describe.

Response:

O-5 Identify the NERC functions for which the project sponsor has registered or intends to become registered related to the proposed project.

Response:

O-6 If the project sponsor plans to contract for services to perform the NERC functions, identify the contractor and the NERC functions for which it is registered or intends to become registered. If you plan to use a contractor and have not selected one yet, provide the requested information for the contractors you are considering. Describe how the project sponsor will ensure compliance with the reliability standards or requirements associated with these functions. Provide any contract you have with a third-party to perform NERC functions.

Response:

O-7 Describe the approach the project sponsor will use to assure compliance with Applicable Reliability Standards. Include descriptions of organizational responsibility, processes, and procedures for assuring compliance. Identify any Applicable Reliability Criteria for which transmission owners are responsible that require temporary waivers under TCA Section 5.1.6. Explain any.

Response:

O-8 Provide information demonstrating that the project sponsor, or its intended contractor or contractors as identified in O-1, has been in compliance with the Applicable Reliability Standards for all transmission facilities that it owns, operates, or maintains. This could include information for facilities outside the ISO controlled grid and shall include available NERC compliance audit results. Provide information describing the amount of transmission facilities subject to NERC compliance by listing the number of miles of transmission lines by voltage class and the number of substations by voltage class. If the project sponsor does not have experience with transmission facilities subject to NERC reliability standards, provide information demonstrating compliance with standards that do apply to those facilities and the amount of facilities subject to such compliance.

Response:

O-9 Describe in general how the project sponsor proposes to divide responsibility for NERC reliability standards between the project sponsor and the ISO in the Coordinated Functional Registration agreement. Compare your response with existing agreements between the ISO and other PTOs, and describe expected differences, if any. Existing agreements are available on the ISO website.

Response:

O-10 Describe the applicable agreements that will define the responsibilities of the Transmission Operator as defined in NERC reliability standards and authority with respect to NERC reliability standards categories of Generator Owner(s), Generator Operator(s), Planning Authority(ies), Distribution Provider(s), Transmission Owner(s), Transmission Service Provider(s), Balancing Authority(ies), Transmission Planner(s), and adjacent Transmission Operator(s).

Response:

O-11 Describe how the project sponsor will meet the NERC reliability standards requirement that a Transmission Operator have adequate and reliable data acquisition facilities for its Transmission Operator Area and with others for operating information necessary to maintain reliability. Include back-up control center plans if any. Also include provisions for providing the availability data required by TCA Appendix C Section 4.3.

Response:

O-12 Describe the project sponsor’s (its team or planned team) capability that will enable it to comply with the activities required by TCA Section 6.1 (Physical Operation of Facilities [including

Operation, ISO Operating Orders, Duty of Care, Outages, Return to Service, and Written Report]) and TCA Section 6.3 (Other Responsibilities).

Response:

O-13 Describe the project sponsor's capability (for its team or its planned team) that will enable it to comply with the activities required by TCA Section 9.2 (Management of Emergencies by Participating TOs) and TCA Section 9.3 (System Emergency Reports: TO Obligations). Identify resources available to respond to major problems on the proposed project. Include resources available through mutual assistance agreements and describe expected response times. Provide samples of emergency operating plans.

Response:

O-14 Will the project be subject to any encumbrance? If so, provide a statement of any Encumbrances to which any of the transmission lines and associated facilities to be placed under ISO Operational Control are subject, together with any documents creating such Encumbrances and any instructions on how to implement Encumbrances and Entitlements in accordance with TCA Section 6.4.2.

Response:

O-15 Identify the plans or provisions to be implemented by the project sponsor to replace major failed equipment, e.g., a substation transformer, circuit breaker, or a group of towers (including dead end structures).

Response:

O-16 Identify and describe any violations of NERC reliability standards or other reliability standards the project sponsor or its team has incurred in the past ten years.

Response:

O-17 Identify and describe any operations-related tariff violations or FERC rules violations the project sponsor or its team has incurred in the past ten years.

Response:

O-18 Identify and describe any violations of operations-related laws, statutes, rules, or regulations the project sponsor or its team has incurred in the past ten years that are not discussed elsewhere in the application.

Response:

- ## Miscellaneous:

Z-1: Provide any additional evidence or support that the project sponsor believes supports its selection as an approved project sponsor. This can include, but is not limited to, other benefits the project sponsor's proposal provides, specific advantages that the project sponsor or its team have, or any efficiencies to be gained by selecting the project sponsor's proposal or additional information that was not requested in the other sections that supports the selection of the sponsor's proposal. Do not include information that is already included in other sections of the application.

Response:

- **Officer Certification**

OFFICER CERTIFICATION FORM

Project Sponsor Name:

I, ____, an officer of the entity identified above as the Project Sponsor or affiliate of the Project Sponsor, understanding that the ISO is relying on the information set forth in the foregoing application, including associated worksheets, to select an Approved Project Sponsor for the transmission element that is the subject of the application, hereby certify that I have full authority to represent the Project Sponsor or affiliate of the Project Sponsor, as described below. I further certify that:

1. I am the _________________________(title) of _______________________ (Project Sponsor).

2. I have prepared, or have reviewed, all of the information contained in the foregoing application, including associated worksheets, which is being submitted into the ISO's competitive selection process for the:

   ____(name of transmission element).

3. On behalf of the Project Sponsor, I agree that any dispute between the ISO and the Project Sponsor regarding any aspect of the competitive selection process, including the ISO's selection report, will be resolved in accordance with ISO Tariff Section 13 ("Dispute Resolution").

I acknowledge that I understand the relevant provisions of Section 24.5 of the ISO Tariff and the Business Practice Manual for Transmission Planning applicable to the Project Sponsor's application, including, but not limited to, those provisions describing the information that will be used by the ISO to determine the Project Sponsor's qualifications to participate in the competitive selection process and the criteria that the ISO will apply in the comparative evaluation for purposes of Selecting an Approved Project Sponsor. I certify, after due investigation, that the information provided in the application, including associated worksheets, is true and accurate to the best of my belief and knowledge and there are no material omissions. In addition, by signing this certification, I acknowledge the potential consequences of making incomplete or false statements in this certification, which may include exclusion from the current and subsequent competitive selection processes.

____
(Signature)

Print Name: _____________________________

Title: ______________________________

Date: ______________________________

- ## Application Deposit Payment Instructions

Please complete this entire form.

Project Sponsor Deposit Information

1. **Name of Phase 3 Project:** _____

2. **Name, address, telephone number, and e-mail address of the Customer's contact person (primary person who will be contacted):**

Name:	_____
Title:	_____
Company Name:	_____
Street Address:	_____
City, State:	_____
Zip Code:	_____
Phone Number:	_____
Fax Number:	_____
Email Address:	_____

3. **Alternate contact:**

Name:	_____
Title:	_____
Company Name:	_____
Street Address:	_____
City, State:	_____
Zip Code:	_____
Phone Number:	_____
Fax Number:	_____
Email Address:	_____

4. **Any deposit paid by check shall be submitted to the CAISO representative indicated below: Note – the check may be included with applications submitted on CDs or DVDs. Checks shall be made payable to the CAISO.**

	Overnight Address
California ISO	California ISO
Attn: Julie Balch	Attn: Julie Balch
Grid Assets	Grid Assets
P.O. Box 639014	250 Outcropping Way
Folsom, CA 95763-9014	Folsom, CA 95630

5. **Project Sponsor Deposit is submitted by:**

Legal name of the Customer: _____
By (signature): ____
Name (type or print): _____
Title: _____
Date: _____

**Required Deposit: $75,000 USD (note: Wires originating from outside the U.S. are subject to currency conversion rates and/or additional bank fees).

**Your application will not be considered received if the deposit is not received prior to the bid window close date.

Wire Information

California ISO - Remit to Addresses
Beneficiary Bank Name
Beneficiary Bank Address
Wells Fargo Bank, NA
420 Montgomery St.
San Francisco, CA 94104

LGIP/SGIP
Wells Fargo Bank, NA
ABA # 121000248
Account # 4122041825
Account name: CAISO LGIP

Approval History

Approval Date:	March 22, 2021
Effective Date:	March 22, 2021
Application Owner:	Stephen Rutty
Application Owner's Title:	Director, Grid Assets

Revision History

Version	Date	Description
7	3/22/2021	Revised Version Released - General update and simplification
6	4/17/2019	General update
5	5/10/2016	General update and revised to address stakeholder comments.
4	4/7/2014	Revised to align with updated tariff.
3	4/4/2013	Revised Version Released – Add Version Control, Approval History, and Revision History Sections
2	4/1/2013	Revised Version Released - General clarification modifications and clean-up for 2012-2013 TPP Phase 3 Bid Window Opening
1	12/19/2012	Initial Version Released