



California ISO  
Shaping a Renewed Future

# Delaney-Colorado River Transmission Line Project Project Sponsor Selection Report

July 10, 2015

California Independent System Operator Corporation

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**LIST OF ATTACHMENTS**

Attachment 1 – Competitive Solicitation Transmission Project Sponsor Application dated 04/08/14 Version 4.

## **1. INTRODUCTION**

This report describes the competitive solicitation process conducted by the California Independent System Operator Corporation (ISO) for the Delaney-Colorado River transmission line project, including a new 500 kV transmission line and associated series compensation between Delaney Substation and Colorado River Substation. The ISO has conducted this competitive solicitation because, in its 2013-2014 transmission planning process, the ISO identified an economically-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 Delaney-Colorado River project. The proposals that the ISO reviewed from the five project sponsors for the Delaney-Colorado River project were detailed and well-supported. The ISO would like to emphasize that it considers all project sponsors to be qualified to finance, construct, own, operate, and maintain the Delaney-Colorado River 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 DCR Transmission, LLC (DCRT), a joint venture company owned by Abengoa Transmission & Infrastructure, LLC and an affiliate of Starwood Energy Group Global, Inc., as the approved project sponsor to finance, construct, own, operate, and maintain the Delaney-Colorado River project.

## 2. BACKGROUND

### 2.1 The Delaney-Colorado River 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 2013-2014 transmission plan identified an economically-driven need for a 500 kV transmission line with associated series compensation between the 500 kV Colorado River Substation and the 500 kV Delaney Substation. The ISO governing board approved the Delaney-Colorado River project on July 15, 2014 subsequent to its approval of the 2013-2014 transmission plan.

Following the approval of the transmission project, the ISO opened a bid solicitation window on August 19, 2014, which provided project sponsors the opportunity to submit proposals to finance, construct, own, operate, and maintain the Delaney-Colorado River project. In accordance with ISO Tariff Section 24.5.1 and the posted 2013-2014 Transmission Planning Process Phase 3 Sequence Schedule, the bid solicitation window remained open through November 19, 2014.

At the time the ISO opened the bid solicitation window, the ISO posted a paper on its website entitled *Delaney-Colorado River 500 kV Transmission Line Project Description, Key Selection Factors, and Functional Specifications for Competitive Solicitation* (ISO Functional Specifications) describing the Delaney-Colorado River project.<sup>1</sup> As described in the ISO Functional Specifications for the Delaney-Colorado River project, the new transmission line is justified on economic grounds, *i.e.*, on the basis that the ISO expects that its benefits will exceed its costs. The Delaney-Colorado River project includes a new 500 kV transmission line between the Delaney Substation and Colorado River Substation, plus associated series compensation. The ISO Functional Specifications indicate that the series compensation level is to be approximately 35%, and the series capacitors may be located either in the middle of the transmission line or near the line termination stations. The ISO Functional Specifications also indicate that the ISO prefers the transmission line to be located with sufficient spatial diversity from other transmission lines in order to avoid a common mode contingency. Only the 500 kV transmission line and series compensation were eligible for competitive solicitation. The facilities necessary at Delaney Substation and Colorado River Substation to interconnect with the project, including anticipated shunt reactors, were not eligible for competitive solicitation under the ISO Tariff. As indicated in the ISO Functional Specifications, the ISO estimates the cost of the portion of the proposed Delaney-Colorado River project subject to competitive solicitation to be \$300 million in 2014 dollars. The ISO Functional Specifications specify that the latest in-service date for the Delaney-Colorado River project is May 1, 2020. Upon completion of the Delaney-Colorado River project, the facility or facilities must be turned over to ISO operational control.

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<sup>1</sup>[http://www.caiso.com/Documents/DelaneyColoradoRiverFunctionalSpecifications\\_KeySelectionFactors.pdf](http://www.caiso.com/Documents/DelaneyColoradoRiverFunctionalSpecifications_KeySelectionFactors.pdf)

The ISO identified and posted key selection factors for the Delaney-Colorado River project.<sup>2</sup> These are the tariff criteria that the ISO determined are the most important for selecting a project sponsor for this economic project. For purposes of this project, the ISO identified the following subsections of ISO Tariff Sections 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(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.”
- 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 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 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.”

The ISO described these key selection factors during a stakeholder information conference call on September 3, 2014.<sup>3</sup>

Subject to the collaboration process described in Section 2.2, the ISO evaluated applications of five project sponsors – (1) California Transmission Development, LLC (CTD) , a wholly-owned subsidiary of LS Power Associates, L.P., (2) DCR Transmission, LLC (DCRT), a joint venture company owned by Abengoa Transmission & Infrastructure, LLC and an affiliate of Starwood Energy Group Global, Inc., (3) Duke-American Transmission Company in conjunction with Western Area Power Administration Desert Southwest Region and Citizens Energy Corporation (DATC), (4) NextEra Energy Transmission West, LLC (NEET West), an affiliate of NextEra Energy, Inc., and (5) TransCanyon DCR, LLC in collaboration with Southern California Edison Company (TC/SCE). The ISO posted a final list of validated project sponsor applications on March 19, 2015<sup>4</sup> and posted a list of qualified project sponsors and proposals on April 15, 2015.<sup>5</sup>

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<sup>2</sup>

[http://www.caiso.com/Documents/DelaneyColoradoRiverFunctionalSpecifications\\_KeySelectionFactors.pdf](http://www.caiso.com/Documents/DelaneyColoradoRiverFunctionalSpecifications_KeySelectionFactors.pdf)

<sup>3</sup><http://www.caiso.com/Documents/Delaney-ColoradoRiverCompetitiveSolicitationCall9314.htm>

<sup>4</sup><http://www.caiso.com/Documents/AdditionalValidatedProjectSponsorApplicationfortheDelaneytoColoradoRiverTransmissionProject.htm>

<sup>5</sup> <http://www.caiso.com/Documents/QualifiedProjectSponsors-Proposals-Delaney-ColoradoRiver500kVTransmissionLine.htm>

## 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 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 2013-2014 competitive solicitation process is set forth in the 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 a question and answer matrix detailing questions from prospective project sponsors and the ISO's responses so that all interested parties would have access to the same clarifying information.<sup>6</sup> In compliance with ISO Tariff Section 24.5.3.5, the ISO engaged two well-respected international industry consulting firms to assist with the 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 and Qualifications
- Past Projects, Project Management and Cost Containment
- Financial
- Environment and Public Process
- Substation
- Transmission Line
- Construction
- Operation and Maintenance
- Miscellaneous
- Officer Certification
- Payment Instructions

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<sup>6</sup> <http://www.caiso.com/Documents/DelaneyToColoradoRiverQuestionAndAnswerLog.pdf>

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, as described in Section 2.1 of this report. The collaboration period opened on January 13, 2015 and closed on February 26, 2015. Two project sponsors requested collaboration. In accordance with ISO Tariff Section 24.5.2.3, the ISO provided these two project sponsors the opportunity to submit a single revised project sponsor application. On February 26, 2015, these two project sponsors submitted a single revised application.

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."

The ISO found that all project sponsors and their proposals met the minimum qualification criteria as set forth in ISO Tariff Sections 24.5.3.1 and 24.5.3.2 for the Delaney-Colorado River project. Therefore, the ISO determined that no cure period was needed for the qualification phase. 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 April 15, 2015. 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 has undertaken a comparative analysis of the project sponsors’ proposals with regard to 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 Delaney-Colorado River 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 with respect to each of the qualification criteria and selection factors. At the beginning of each subsection of Section 3.3 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 section 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 Delaney-Colorado River Project**

Subject to the collaboration process, the ISO received project sponsor applications for the Delaney-Colorado River project on behalf of five project sponsors:

- California Transmission Development, LLC (CTD), a wholly-owned subsidiary of LS Power Associates, L.P.
- DCR Transmission, LLC (DCRT), a joint venture company owned by Abengoa Transmission & Infrastructure, LLC and an affiliate of Starwood Energy Group Global, Inc.
- Duke-American Transmission Company in conjunction with Western Area Power Administration Desert Southwest Region and Citizens Energy Corporation (DATC)
- NextEra Energy Transmission West, LLC (NEET West), an affiliate of NextEra Energy, Inc.
- TransCanyon DCR, LLC in collaboration with Southern California Edison Company (TC/SCE)

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

#### **CTD**

According to its proposal, CTD is a Delaware limited liability company established on August 15, 2008 to develop, own, and operate transmission within the area operated by the ISO. CTD indicated that, through intermediate holding companies, it is a wholly-owned subsidiary of LS Power Associates, L.P. (LS Power). CTD indicated that its ownership and the ownership of each holding company up to LS Power is 100%, making CTD a wholly-owned subsidiary of LS Power. CTD indicated that this ownership structure is the same as is used by LS Power for all of its development projects, including development of past transmission projects.

CTD indicated that it does not currently have any material assets or responsibility for other projects and that the Delaney-Colorado River project would be CTD's first operating asset; CTD indicated that its lenders insist that CTD not conduct any business unrelated to the project and project-related activities.

CTD indicated that LS Power would be the equity provider and would provide corporate support services, including project management, during development, construction, and operation of the project. CTD indicated that LS Power has significant experience financing debt and equity for large energy projects and has raised over \$29 billion in the past 10 years. CTD indicated that the total investment in the project represents a small fraction of the total assets of LS Power as of December 31, 2013 and is expected to be a smaller fraction of total assets at the time of project execution. CTD stated that LS Power is an incumbent transmission service provider in the Electric Reliability Council of Texas (ERCOT). CTD indicated that LS Power would draw on its significant recent experience developing, constructing, and operating generation.

### **CTD Access to Affiliate Financial Support**

CTD indicated that it is relying on its parent, LS Power to satisfy the financial criteria required of the project sponsor and that the development of the project would be financed by LS Power with equity. CTD indicated that LS Power's primary plan for construction financing is to finance the project through the Western Area Power Administration's Transmission Infrastructure Program, which is authorized for up to \$3.2 billion of transmission system investment. In the event Transmission Infrastructure Program funding is not available, CTD indicated that LS Power has excellent access to the bank and bond markets for non-recourse project financing. CTD provided a support letter for financial assurances from LS Power.

### **DCRT**

According to its proposal, DCRT would be a joint venture between Abengoa Transmission & Infrastructure, LLC (ATI) and an affiliate of Starwood Energy Group Global, Inc. (Starwood Energy). DCRT indicated that ATI is a Delaware limited liability company, registered as a foreign LLC in Arizona and California, and that Starwood Energy is a Delaware corporation.

If selected as the approved project sponsor, DCRT stated that it would be incorporated as a specific purpose entity specifically to finance, construct, own, maintain, and operate the Delaney-Colorado River project. DCRT indicated that it would be owned 25% by ATI and 75% by Starwood Energy.

DCRT indicated that ATI is a wholly-owned subsidiary of Abengoa S.A., a company established and organized under the laws of Spain (Abengoa). DCRT indicated that Abengoa works in the energy and environment sectors, generating electricity from renewable resources, converting biomass into biofuels, and producing drinking water from sea water. In addition to the transmission elements ATI has constructed in the United States, DCRT indicated that Abengoa also has extensive international experience.

DCRT indicated that Starwood Energy is an affiliate of private real estate investment firm Starwood Capital Group and specializes in energy infrastructure investment, with focus on the transmission, renewable power generation, and natural gas sectors. DCRT indicated that, through Starwood Energy's general opportunity funds Starwood Energy Infrastructure I and II, and other affiliated investment vehicles, Starwood Energy manages total equity commitments in excess of \$2 billion and has executed transactions totaling more than \$4 billion in enterprise value.

DCRT indicated that it would service the debt associated with the design, procurement, construction, and operation of the Delaney-Colorado River project. DCRT indicated that it would be funded by means of project financing for the debt portion. DCRT provided a letter of support from a large multinational banking and financial services company along with two other banks. DCRT also stated that it would consider Western Area Power Administration Transmission Infrastructure Program financing if it provides a more expedient and cost-effective option.

DCRT stated that, once the project is placed in service, Abengoa would provide support for operational needs and provided a guarantee to that effect.

#### **DCRT Access to Affiliate Financial Support**

DCRT indicated that Starwood Energy has significant remaining commitments available, including access to additional discretionary equity capital. DCRT provided parent guarantee letters from Abengoa and Starwood Energy.

### **DATC in conjunction with Western Area Power Administration Desert Southwest Region and Citizens Energy Corporation**

According to the proposal, the project sponsor is DATC in conjunction with Western Area Power Administration Desert Southwest Region (Western DSW) and Citizens Energy Corporation (Citizens Energy). DATC indicated that it would fund 100% of the costs of the project, that Western DSW would permit, obtain rights of way, and maintain the project and would hold title to the physical facilities, and that DATC would own the transmission service rights. DATC indicated that Citizens Energy would acquire, through a lease or otherwise, 25% of the transmission service rights post construction.

DATC indicated that it is a limited liability company that was formed in April 2011 and is a 50/50 joint-venture between Duke Energy Corporation (Duke Energy), through its wholly-owned subsidiary Duke Energy Transmission Holding Company, LLC (DETHCo), and American Transmission Company LLC (ATC). DATC indicated that it draws on the resources and expertise of the two parent companies and is managed by a board of managers with two representatives each from Duke Energy and ATC.

DATC indicated that Western Area Power Administration is a federal power marketing agency within the United States Department of Energy, established in 1977 as part of the Department of Energy Organization Act. DATC indicated that Western Area Power Administration currently operates over 17,000 miles of transmission in the western United States. DATC indicated that Western Area Power Administration is participating in this project with DATC through Western DSW for all aspects other than potential financing, which would be done through Western Area Power Administration's Transmission Infrastructure Program.

DATC indicated that Citizens Energy is a 501(c)4 non-profit energy corporation dedicated to pursuing for-profit ventures and using the profits to help low-income households meet their basic needs. DATC indicated that Citizens Energy has been engaged in developing high-voltage transmission in California since 2005. DATC indicated that Citizens Energy's role in transmission is to assist with the development and permitting, finance a portion of a project's transfer capability once completed, become an ISO participating transmission owner (PTO), and dedicate its profits to assist low-income energy consumers in the project.

If selected as the project sponsor, DATC stated that it plans to create a special purpose entity, DATC West Energy, which would be a project-financed limited liability company, wholly owned by DATC. DATC indicated that it would finance 50% of the cost of the project with debt, consistent with anticipated FERC ratemaking policy. DATC indicated that it plans to use Western Area Power Administration's Transmission Infrastructure Program financing or standard commercial lending to provide a combination of construction and long-term financing. DATC stated that it has had numerous discussions with the Western Area Power Administration Transmission Infrastructure Program office regarding the program. DATC stated that it has also had discussions with commercial lenders and has received strong interest in financing the project.

#### **DATC in conjunction with Western DSW and Citizens Energy Access to Affiliate Financial Support**

DATC stated that, based upon its discussions with commercial lenders, the relationships of Duke Energy and ATC in the commercial lending market, and the potential to use Western Area Power Administration Transmission Infrastructure Program financing, it is confident that it can obtain competitive debt financing for the project. DATC indicated that the Western Area Power Administration Transmission Infrastructure Program office accepted the project into the program on October 23, 2014. DATC indicated that it sought and received a letter of interest from a large financing entity indicating that the project could be financed through commercial lenders. DATC also provided letters from Duke Energy and ATC stating that they had the resources and capabilities to provide written guarantees or other financial assurances on behalf of DATC.

DATC indicated that it would make a final determination of the source and structure of the debt financing after the selection of the project sponsor is completed.

#### **NEET West**

According to its proposal, NEET West is a Delaware limited liability company formed in 2014, is a wholly-owned subsidiary of NextEra Energy Transmission, LLC (NEET), and is an indirect subsidiary of NextEra Energy, Inc. (NextEra). NEET West's proposal indicated that it was created to own the proposed Delaney–Colorado River project and other assets in the ISO region as a portfolio, and according to the proposal is not intended to be a stand-alone project company for the Delaney–Colorado River project. NEET West stated that it would draw 100% of its financial requirements from its ultimate corporate parent NextEra and provided appropriate documentation from NextEra reflecting this guarantee.

NEET West indicated that its ultimate parent NextEra is a company with revenues of approximately \$15 billion and 13,900 employees as of December 31, 2013 and that NextEra, and its wholly owned subsidiaries, NEET and NEET West, are headquartered in Juno Beach, Florida. NEET West indicated that NextEra's principal subsidiaries are Florida Power & Light Company (FPL) and NextEra Energy Resources, LLC (NEER). NEET West indicated that another key entity in the NextEra organization is NextEra Energy Capital Holdings (NEECH), which owns and provides funding for NextEra's operating subsidiaries, other than FPL and its subsidiaries.

NEET West indicated that its immediate parent, NEET, was formed by NextEra in 2007 to apply NextEra's experience and resources in developing, owning, and operating transmission facilities to projects across the United States and Canada. NEET West stated that it intends to own 100% of the project from development through operations, for the life of the project.

NEET West stated that it is an indirect, wholly owned subsidiary of NEECH and would rely upon NEECH for financial backing of this project. NEET West indicated that it plans to finance the project from development through commercial operation with corporate parent funding provided by NEECH, which will ultimately be guaranteed by NextEra.

NEET West stated that it would have ultimate responsibility for siting, permitting, engineering, procurement, construction, and placing the project into operation. NEET West indicated that it would draw from expertise across the entire NextEra organization, as well as engage a selected suite of consulting firms specifically in the areas of engineering design, construction, environmental permitting, land management, and legal and regulatory support to bring the project to successful completion. NEET West indicated that it has assembled a leadership team consisting of a project director and team leads from within NextEra who would select experienced, qualified engineers, technicians, and other staff from within NextEra or third party consultants to support the project.

### **NEET West Access to Affiliate Financial Support**

NEET West provided evidence that NextEra maintains a blanket guarantee of certain obligations of NEECH, pursuant to a Guarantee Agreement between FPL Group, Inc. and FPL Group Capital Inc., dated as of October 14, 1998 (the Guarantee Agreement). NEET West further demonstrated that guarantee obligations by NEECH to NEET West would, in turn, be guaranteed by NextEra pursuant to the aforementioned Guarantee Agreement. NEET West indicated that each and every obligation of NEET West to the ISO would be backstopped by mutually agreed upon support obligations between NEET West and its affiliates.

### **TC/SCE**

According to the proposal, TransCanyon DCR, LLC (TransCanyon) is the project sponsor in collaboration with Southern California Edison Company (SCE). As discussed in the proposal, TransCanyon and SCE have agreed to a commercial arrangement whereby TransCanyon would be the sole party to the agreements necessary to develop the project, and SCE as a collaborator will provide development support and has the option to purchase an undivided 33-1/3% ownership interest in the project shortly before its commercial operation date. TC/SCE indicated that this arrangement is enabled by an

option agreement dated February 25, 2015. TC/SCE indicated that, if SCE does not exercise its option, TransCanyon is committed to successfully delivering the project as the 100% owner consistent with its obligations as a signatory to an approved project sponsor agreement with the ISO and ultimately the Transmission Control Agreement (TCA).

TC/SCE indicated that TransCanyon is a single member limited liability company owned by TransCanyon, LLC formed on November 4, 2014 solely for the purpose of developing, siting, permitting, designing, financing, constructing, owning, operating, and maintaining the Delaney-Colorado River project. TC/SCE indicated that TransCanyon, LLC is a joint venture entity whose membership interests are equally and indirectly held by its two parent companies – Pinnacle West Capital Corporation (PNW) and Berkshire Hathaway Energy Company (BHE). TC/SCE indicated that TransCanyon, LLC was formed on July 29, 2014 for the purpose of developing, acquiring, siting, permitting, designing, financing, constructing, owning, operating, and maintaining independent transmission assets in the western interconnection.

TC/SCE indicated that PNW is an energy holding company headquartered in Phoenix and incorporated in the State of Arizona. TC/SCE indicated that, through its principal subsidiary, Arizona Public Service Company (APS), PNW provides retail electricity service to approximately 1.2 million Arizona homes and businesses and has approximately 5,900 line miles of transmission assets in Arizona and New Mexico. TC/SCE indicated that PNW currently has an equity market capitalization of \$7.4 billion and an enterprise value of \$10.9 billion.

TC/SCE indicated that BHE, through its subsidiaries, owns approximately 32,600 miles of electric transmission lines. TC/SCE indicated that BHE's United States electric power generating, transmission and distribution, and natural gas transmission assets are owned directly or indirectly by the following entities: PacifiCorp, MidAmerican Energy Company, NV Energy, Inc., Northern Natural Gas Company, Kern River Gas Transmission Company, BHE U.S. Transmission, LLC (BHT) (named MidAmerican Transmission, LLC prior to January 2015), and MidAmerican Renewables, LLC. TC/SCE indicated that BHE also has a joint-transmission ownership footprint in the Southwest Power Pool and ERCOT areas totaling over 1,100 miles. TC/SCE indicated that BHE has total assets of \$74.0 billion and book equity value of \$20.8 billion (as of September 30, 2014).

TC/SCE also described additional subsidiaries between PNW and BHE in the proposal, including Bright Canyon Transmission, LLC and Bright Canyon Energy Corporation (under PNW) and MTL Canton Holding, LLC (under BHE).

TC/SCE indicated that SCE is an investor-owned public utility primarily engaged in supplying and delivering electricity. TC/SCE indicated that, as a California corporation, SCE is a wholly owned subsidiary of parent company Edison International. TC/SCE indicated that SCE has been providing electric service in the southern California region for more than 125 years serving nearly five million customer accounts and 14 million residents in its 50,000 square-mile service territory. TC/SCE indicated that SCE owns, operates, and maintains over 12,800 miles of transmission and sub-transmission lines.

If selected as the project sponsor, TC/SCE stated that TransCanyon would lead the work to develop, site, permit, design, finance, construct, own, operate, and maintain the

project. Accordingly, TC/SCE stated that TransCanyon would execute an approved project sponsor agreement with the ISO, execute the TCA, become a PTO, and transfer the project capacity to the operational control of the ISO.

TC/SCE stated that it would explore multiple financing sources; the financing plan currently anticipates that TransCanyon would service the debt associated during the construction phase and that TransCanyon and SCE would service the debt associated with their respective interests during the commercial operation phases.

### **TC/SCE Access to Affiliate Financial Support**

TC/SCE stated that it currently plans to seek authorization for a capital structure from FERC targeting a capital structure of 50% debt and 50% equity during construction and a target capital structure of 50% equity once the project is placed in service. At present, TC/SCE stated that TransCanyon is 100% equity capitalized and that as of December 31, 2014 PNW and BHE each had contributed equal amounts of equity to TransCanyon. TC/SCE stated that TransCanyon's future equity needs would be funded by pro rata contributions from PNW and BHE consistent with their ownership shares of TransCanyon LLC.

TC/SCE stated that it is relying on TransCanyon's two parent entities – PNW and BHE – to satisfy the financial criteria of the application and provided parental guarantees to support it.

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

The first 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 project.” As discussed in Section 2.1, the ISO has identified this selection factor as a key selection factor because the overall capability to finance, license, construct, operate, and maintain this project is critical to ensuring that the project will be completed and will remain the major component in the ISO's bulk transmission system that the ISO expects it to be. 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.

The ISO notes that the first selection factor is a broad factor that encompasses several of the subsequent more narrow selection factors. The ISO will therefore 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 with respect to each of the encompassed selection factors, or (2) the ISO's comparative analysis of the project sponsors 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) after the discussion of the other selection factors in Section 3.14 of this report.



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

(Section 3 - General Project Information, QS-1, QS-4, E-10, E-13)

The second selection factor is “the Project Sponsor’s existing rights of way and substations that would contribute to the project in question.”

#### **3.4.1 Information Provided by CTD**

CTD indicated that it does not have any existing rights-of-way that would contribute to its project. (QS-1, QS-4, E-10, E-13)

#### **3.4.2 Information Provided by DCRT**

DCRT indicated that it does not have any existing rights-of-way that would contribute to its project. (QS-1, QS-4, E-10, E-13)

#### **3.4.3 Information Provided by DATC**

DATC indicated that it does not have any existing rights-of-way that would contribute to this project. (QS-1, QS-4, E-10, E-13)

#### **3.4.4 Information Provided by NEET West**

NEET West indicated that it does not have any existing rights-of-way to use for this project. NEET West indicated that it has negotiated an exclusive agreement with the Colorado River Indian Tribes to lease rights-of-way across Colorado River Indian Tribes lands. NEET West also indicated that it plans to use SCE’s unused DPV #2 500 kV rights-of-way for this project. If unable to use these rights-of-way, NEET West indicated that it would acquire new rights-of-way from BLM, USFWS, etc. (QS-1, QS-4, E-10, E-13)

#### **3.4.5 Information Provided by TC/SCE**

TC/SCE indicated that its affiliate APS is the majority owner of Delaney Substation and that its collaborator SCE owns Colorado River Substation and the DPV #1 and #2 rights-of-way. TC/SCE indicated that it might seek to expand the existing DPV #1 rights-of-way where parallel to TC/SCE’s proposed route. If unable to use the existing rights-of-way, TC/SCE indicated that it would acquire its own rights-of-way for this project. TC/SCE also proposed to install the series capacitors within the confines of Delaney Substation, but it indicated that it will pay all costs for the installation and maintenance of the series capacitors to be installed in Delaney Substation. (QS-1, QS-4, E-10, E-13)

#### **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.

CTD, DCRT, DATC, and NEET West do not have any existing rights-of-way that they propose to contribute to this project. Although TC/SCE's affiliate and collaborator own Delaney Substation and rights-of-way closely related to TC/SCE's proposal for this project, TC/SCE has not made a definitive proposal to contribute existing rights-of-way to the project. TC/SCE's proposal to lease space and pay all costs for the installation and maintenance of the series capacitors to be installed in Delaney Substation does not result in any significant financial advantage. Consequently, the ISO has determined that there is no material difference among the proposals of the five project sponsors with regard to 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.

#### **Experience in Acquiring Rights-of-Way**

(Section 3 - General Project Information, QS-1, QS-4, P-1, P-9, P-10, E-1, E-2, E-3, E-4, E-7, E-8, E-9c, E-10, E-11, E-12, E-14a, E-14b, E-15a, E-15b, E-16a, E-16b, E-16c, E-16d, E-16e, E-16f, S-1, S-5, T-1)

##### **3.5.1 Information Provided by CTD**

CTD indicated that its staff would utilize a land acquisition contractor with significant utility rights-of-way experience if awarded the project. CTD provided information for three potential rights of way acquisition contractors with experience in Arizona or California. (QS-1, E-2, E-3, E-4, E-7, E-8, E-9c, E-10, E-11, E-12, E-13, E-14a, E-14b, E-15a, E-15b, and E-16)

##### **3.5.2 Information Provided by DCRT**

DCRT indicated that it has contracted with a land acquisition company to perform rights-of-way acquisition services for this project. DCRT indicated that the company has experience in acquiring rights-of-way for electric transmission lines throughout the Midwest and beyond. DCRT indicated that the company's Arizona and California land acquisition experience is limited to an existing natural gas pipeline system upgrade in southern California. (QS-1, E-2, E-3, E-4, E-7, E-8, E-9c, E-10, E-11, E-12, E-13, E-14a, E-14b, E-15a, E-15b, and E-16)

### **3.5.3 Information Provided by DATC**

DATC indicated that its associate Western DSW would lead the land acquisition process for this project. DATC indicated that Western DSW has significant acquisition experience in Arizona and California. (QS-1, E-2, E-3, E-4, E-7, E-8, E-9c, E-10, E-11, E-12, E-13, E-14a, E-14b, E-15a, E-15b, and E-16)

### **3.5.4 Information Provided by NEET West**

NEET West indicated that its affiliate's staff has significant acquisition experience in Arizona and California. In addition, NEET West indicated that it expects to contract with land acquisition companies to assist in the acquisition process. (QS-1, E-2, E-3, E-4, E-7, E-8, E-9c, E-10, E-11, E-12, E-13, E-14a, E-14b, E-15a, E-15b, and E-16)

### **3.5.5 Information Provided by TC/SCE**

TC/SCE indicated that it plans to utilize the staff of its affiliate APS and its collaborator SCE to lead the rights-of-way acquisition effort. TC/SCE indicated that these staff members have significant land acquisition experience in Arizona and California. However, TC/SCE indicated that it might also contract with a land acquisition company to assist the APS and SCE staff members. TC/SCE provided information on four potential companies TC/SCE might use. (QS-1, E-2, E-3, E-4, E-7, E-8, E-9c, E-10, E-11, E-12, E-13, E-14a, E-14b, E-15a, E-15b, and E-16)

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

(Section 3 - General Project Information, E-13)

### **3.5.6 Information Provided by CTD**

CTD indicated that it does not propose to use any of its existing rights-of-way, so it does not expect to incur incremental costs due to placing new or additional facilities on existing rights-of-way. (E-13)

### **3.5.7 Information Provided by DCRT**

DCRT indicated that it does not have any existing rights-of-way to use for the project and does not expect to incur incremental costs due to placing new or additional facilities on existing rights-of-way. (E-13)

### **3.5.8 Information Provided by DATC**

DATC indicated that it does not propose to use any of its existing rights-of-way for this project. DATC indicated that it does not anticipate incurring any incremental costs due to placing new or additional facilities on existing rights-of-way. (E-13)

### **3.5.9 Information Provided by NEET West**

NEET West indicated that it does not propose to use any of its existing rights-of-way for this project. NEET West indicated that it does not anticipate incurring any incremental costs due to placing new or additional facilities on existing rights-of-way. (E-13)

### **3.5.10 Information Provided by TC/SCE**

TC/SCE indicated that its affiliate APS owns Delaney Substation and its collaborator SCE owns Colorado River Substation and the DPV #1 and #2 500 kV transmission line rights-of-way. TC/SCE indicated that it might seek to expand the existing rights-of-way where parallel to TC/SCE's proposed route. If unable to use the existing rights-of-way, TC/SCE indicated that it would acquire its own rights-of-way for this project.

TC/SCE indicated that it does not anticipate incurring any incremental costs due to placing additional or new facilities on its existing rights-of-way. (E-13)

### **3.5.11 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 Arizona and California to be a slight advantage over experience in rights-of-way acquisition in other jurisdictions because the project is located in Arizona and California and such experience will facilitate the timely, efficient, and effective undertaking of the project.

All of the project sponsors and their teams have extensive experience acquiring utility rights-of-way. CTD, DATC, NEET West, and TC/SCE identified staff, an affiliate, an associate, or a collaborator with substantial experience acquiring utility rights-of-way in Arizona and California. DCRT's team has less experience in acquiring utility rights-of-way in Arizona and California. 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 proposals of CTD, DATC, NEET West, and TC/SCE, and that their proposals are slightly better than the proposal of DCRT, with regard to this component of the factor.

## **Comparative Analysis 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.

All five project sponsors have indicated that they do not expect any additional incremental costs as a result of any use of existing rights-of-way for this project. Therefore, the ISO has determined that there is no material difference among the proposals of the five project sponsors with regard to this component of the factor.

## **Overall Comparative Analysis**

Because there is no material difference among the proposals of the five project sponsors with regard to the second component of this factor (incremental costs for use of existing rights-of-way), the ISO's analysis for this factor overall is based on the analysis for the first component (experience in acquiring rights-of-way).

As discussed above, the ISO has determined that there is no material difference among the proposals of CTD, DATC, NEET West, and TC/SCE with regard to the first component of this factor and that their proposals are slightly better than DCRT's proposal with regard to the first component of this factor. Consequently, the ISO has determined that there is no material difference among the proposals of CTD, DATC, NEET West, and TC/SCE with regard to this factor overall and that their proposals are slightly better than DCRT's proposal with regard to 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 project and demonstrated ability to meet that 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 the economic benefits to ratepayers may decrease if the project goes into service later than the targeted in-service date of May 1, 2020, as specified in the ISO Functional Specifications. 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

A proposal that best satisfies this factor will contribute significantly to ensuring that the project sponsor selected will develop the project in a prudent, efficient, cost-effective, and timely manner.

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.

## **Proposed Schedule**

(Section 3 - General Project Information, QS-1, QS-4, QS-3, P-9, E-1, E-2, E-3, E-4, E-7, E-14a, E-14b, E-14c, E-14di, E-14dii, E-14diii, E-15a, E-15b, E-15c, E-15di, E-15dii, E-15diii, S-2, S-3, S-4, T-2, T-3, T-4)

### **3.6.1 Information Provided by CTD**

CTD stated that, although many of its assumptions, including its cost estimates, assume the project would be completed by May 2020, CTD estimates that the project could be in service as early as April 2019, a year ahead of the latest in-service date of May 1, 2020 specified in the ISO Functional Specifications. In its proposed schedule, CTD allocated 26 months for the regulatory and siting processes. CTD stated that it has assembled a team of companies with local expertise in all elements of transmission development, including route development, design, and construction. CTD indicated that it developed its timeline in consultation with these experts and that it supports CTD's commitment to meet the latest in-service date of May 1, 2020 specified in the ISO Functional Specifications. CTD stated that it has a high degree of confidence as to the timeline's completeness and reasonableness.

CTD stated that, in the event the project permitting were to be delayed more than 12 months, it could undertake additional activities to compress the estimated construction schedule to meet the required in-service date. (P-9)

### **3.6.2 Information Provided by DCRT**

DCRT provided a proposed schedule for the project that showed an in-service date for the project of March 25, 2020, about two months ahead of the latest in-service date of May 1, 2020 specified in the ISO Functional Specifications. In its proposed schedule, DCRT allocated 28 months for the regulatory and siting processes. DCRT indicated that there is about three months of float in its schedule. DCRT also provided an adjusted schedule with construction acceleration, addressing a possible six-month delay in the start of the project. The adjusted schedule shortens the original project schedule by about three months. (P-9)

### **3.6.3 Information Provided by DATC**

DATC provided a proposed schedule for the project that would complete the project on January 11, 2020, about four months ahead of the latest in-service date of May 1, 2020 specified in the ISO Functional Specifications. In its proposed schedule, DATC allocated 39 months for the regulatory and siting processes. DATC stated that its schedule provides for about four months of float to meet the ISO's latest in-service date.

DATC stated that to further mitigate the effects of any delays and ensure the latest in-service date specified by the ISO, its project team would also explore accelerating the design, construction, and procurement processes. DATC asserted that it would have more flexibility than any other project sponsor to alter the timing of certain activities due to the regulatory certainty afforded by Western DSW's participation. DATC indicated that its team would not have to acquire as many permits from Arizona and California as other project sponsors would have to acquire. In addition, DATC indicated that Western DSW would not require state approvals to begin many activities.

DATC identified additional measures that it would take, if necessary, to ensure timely delivery of the project. (P-9)

### **3.6.4 Information Provided by NEET West**

NEET West provided a proposed schedule for the project that showed an in-service date for the project of May 1, 2020, meeting the latest in-service date of May 1, 2020 specified in the ISO Functional Specifications. In its proposed schedule, NEET West allocated 31 months for the regulatory and siting processes. NEET West indicated that there is about four months of float in its schedule associated with preliminary engineering and permitting and regulatory work. NEET West stated that there is also a potential of two additional months of float associated with project construction.

NEET West stated that a six-month start delay would have a modest impact compared to the overall project timeline. To meet the latest project in-service date with a delay in the start of the project of six months, NEET West indicated that it would use the four months of float in its schedule and identified activities in permitting, land acquisition, procurement, and construction to shorten the schedule by an additional two months. (P-9)

### **3.6.5 Information Provided by TC/SCE**

TC/SCE provided a proposed schedule for the project that would achieve the latest in-service date of May 1, 2020 specified in the ISO Functional Specifications. In its proposed schedule, TC/SCE allocated 44 months for the regulatory and siting processes. TC/SCE stated that the schedule includes two months of schedule contingency between the end of construction and start of commissioning. TC/SCE indicated that it has prepared its schedule on the basis that the preferred route, in combination with one or both of the proposed alternatives, would be the final route approved by the regulatory agencies. TC/SCE indicated that any material variation from these routes could affect the final project schedule but would not affect its binding cost containment proposal.

TC/SCE stated that it has confirmed California's preference for a concurrent environmental review process under the National Environmental Policy Act (NEPA) and the California Environmental Quality Act (CEQA), which it asserted has the potential to reduce the permitting schedule by at least several months. TC/SCE stated that it believes it could expedite the schedule by completing an administrative draft proponent's environmental assessment and submitting it to the California Public Utilities Commission (CPUC) for review as soon as possible after ISO selection of an approved project sponsor.

If the start date were to be delayed six months, or if any combination of delays up to six months were to impact the project, TC/SCE indicated that it would use schedule compression to meet the latest in-service date of May 1, 2020 specified in the ISO Functional Specifications. TC/SCE stated that these schedule mitigation measures would only be possible because TC/SCE is going to commence preliminary permitting work in advance of ISO selection of an approved project sponsor and because it has worked closely with its construction contractor to develop alternate construction plans in the event needed. (P-9)

## **Ability to Meet Schedule**

(Section 3 - General Project Information, QS-1, QS-3, QS-4, P-1, P-6, P-7, P-8, P-9, P-10, E-1, E-2, E-3, E-4, E-14a, E-14b, E-14c, E-14di, E-14dii, E-14diii, E-15a, E-15b, E-15c, E-15di, E-15dii, E-15diii, S-2, S-3, S-4, T-2, T-3, T-4)

### **3.6.6 Information Provided by CTD**

As discussed above, CTD estimated that the project may be in service as early as April 2019, a year ahead of the latest in-service date of May 1, 2020 specified in the ISO Functional Specifications. (P-9)

CTD provided a description of LS Power transmission line and substation projects completed in the last five years, summarized as follows:

CTD described five transmission line projects (>100 kV) total; three at 500 kV or 345 kV; full range of responsibilities (finance, design, site, construct, operate, and maintain) for four of these projects; all the projects were in the U.S., including one in Arizona with a short section of 500 kV line and one in California not involving 345 kV or 500 kV. CTD also indicated that some of its team members had siting or construction roles in four of the projects. (P-1)

CTD described five substation projects (>100 kV) total; four at 500 kV or 345 kV and one involving series compensation; full range of responsibilities (finance, design, site, construct, operate, and maintain) for four of these projects; all of the projects were in the U.S., including one in Arizona involving 500 kV and one in California not involving 345 kV or 500 kV. CTD also indicated that some of its team members had siting, design, and construction roles in four of the projects. (P-1)

CTD provided a description of project schedule and budget performance for transmission line and substation projects completed in the past five years. CTD described five transmission line projects completed in the past five years, four of which were completed on or before the initial scheduled completion date and one of which was one year behind schedule due to technical issues that arose during construction. (P-6)

CTD described five substation projects completed in the past five years, four of which were completed on or before the initial scheduled completion date and one of which was slightly late. (P-6)

CTD indicated that LS Power employs a detail-oriented and hands-on philosophy to all of its development, construction, and asset management activities. CTD indicated that LS Power employees directly oversee all project development activities, including siting, permitting, community relations, government relations, labor relations, regulatory, real estate acquisition, engineering, and contracting. CTD indicated that LS Power performs a considerable amount of the development activities itself, while managing consulting firms for portions of the work that are specialized (e.g., surveying, environmental studies). (P-7)

CTD provided an organization chart that is specific for this project. The organization chart indicates that the project director would report to senior management and have the primary decision making authority for project execution on a day-to-day basis within the project schedule and budget, which would be approved by the overall project



management. CTD indicated that changes to the schedule and budget and expenditures not included in the project budget would also require management review and approval. CTD provided a resume for the CTD project director that indicates that he has 23 years of utility experience. CTD stated that contractors on this project would work under the supervision and direction of LS Power personnel. (P-8)

CTD stated that LS Power has identified several major risks to the schedule for the project as well as mitigation measures related to each risk. CTD indicated that generally a developer that understands the need to obtain social license for a project would best mitigate the risks it has identified; CTD described social license as obtaining acceptance or approval of a project not just in the formal regulatory processes but also with stakeholders and the public generally. CTD stated that early, thorough public outreach starting with elected public officials, local officials, and other local leaders is a key first step in the path toward public acceptance. (P-10)

CTD stated that LS Power believes the most significant risks to the successful completion of the project are related to public acceptance: establishing need at the Arizona Corporation Commission (ACC), obtaining private easements, and mitigation of impacts to sensitive species. CTD discussed various aspects of these issues and its approach to mitigation of these risks. (P-10)

### **3.6.7 Information Provided by DCRT**

As discussed above, DCRT provided a proposed schedule that showed an in-service date for the project of March 25, 2020, about two months ahead of the latest in-service date of May 1, 2020 specified in the ISO Functional Specifications, and provided an adjusted schedule with construction acceleration, addressing a possible six-month delay in the start of the project. (P-9)

DCRT provided a description of past transmission line and substation projects for ATI and Starwood Energy) and also for other Abengoa entities (Abengoa Brazil and Inabensa). DCRT indicated that it would be a new entity, so it has not completed any transmission line or substation projects. DCRT described projects completed by its team and affiliates in the past five years as follows:

#### **Transmission Lines**

ATI - three projects (greater than 100 kV) total, all below 500 kV; responsible for project design, siting, and construction; two projects in California and one in Arizona.  
Starwood Energy - one project, at 500 kV; responsible for project finance and operations; the project was not in California or Arizona.

Abengoa Brazil and Inabensa - numerous transmission line projects outside the U.S., six at 400 kV or 500 kV and eight below 500 kV. (P-1)

#### **Substations**

ATI - three projects (>100 kV) total, all below 500 kV and none involving series capacitors; responsible for project design, siting, and construction; one in California and one in Arizona.

Starwood Energy - DCRT did not identify any Starwood Energy substation projects.

Abengoa Brazil and Inabensa – numerous substations outside the U.S., eight at 400 kV or 500 kV, one below 500 kV. (P-1)

DCRT provided a description of project schedule and budget performance for transmission line and substation projects completed in the past five years, summarized as follows

DCRT described 12 transmission projects completed in the past five years; three of these were in the U.S.; delays ranged from one to three months; of the nine non-U.S. projects, two were completed on or before the initial scheduled completion date. Others were delayed due to the remote primitive conditions (jungle, mountainous terrain, heavy snow conditions).

DCRT described 13 substation projects completed in the past five years; two of the projects were in the U.S.; delays ranged from one to four months; of the 11 non-U.S. projects, eight were completed on or before the initial scheduled completion date. (P-6)

DCRT stated that ATI, as its engineering, procurement, and construction (EPC) contractor, would assemble a project management team comprised of personnel with the appropriate skill sets, necessary knowledge, and experience in construction of transmission lines. During the project execution, DCRT indicated that it would also hire several contractors with specific experience in their field for the successful completion of the project. DCRT indicated that, prior to the start of the project, it would lay out a management structure for the project through a series of meetings and would develop plans prior to execution, including a project management system, engineering records system, environmental management, labor relations, procurement, logistics, health and safety, and construction managing and contract. DCRT indicated that each of these would consist of a team led by experienced personnel who would be reporting the weekly progress to the assigned head of the project. (P-7)

DCRT indicated that scheduling plays a key role in completing the project on time and on budget. DCRT indicated that each of the teams involved in the project would have a scheduler to track the progress of the team and report to the head scheduler, who would in turn determine whether the project is on schedule. DCRT indicated that the head scheduler would take necessary actions and initiatives to speed up a project in order to avoid penalties and comply with the client's timeline requirements. DCRT stated its team approach to project scheduling is based on the use of Gantt charts. DCRT indicated that ATI would also use a similar approach for the EPC contract. (P-7)

DCRT provided an organization chart for the project showing the project director reporting to a four-member board from ATI and Starwood Energy. The organization chart also reflects the reporting relationship of the various sub-contractors that DCRT would use for the project. DCRT provided a resume for the DCRT project director that shows 16 years of experience. DCRT provided a resume for the lead over the EPC contract that shows 15 years of experience. (P-8)

DCRT indicated that the top five risks for the project would be (1) obtaining rights-of-way, permits, and environmental authorizations; (2) unavailability of manpower and equipment to build the transmission line and substation; (3) raw material volatility; (4)

site risk, latent conditions, and access; and (5) interest rates before construction. DCRT discussed its mitigation measures for project risks, which consist primarily of relying on the experience of its sub-contractors or indicating that the EPC contractor would accept the risk. (P-10)

DCRT also discussed regulatory approval as a risk for the project. DCRT stated it believes all the project sponsors face the same regulatory risk for project approval. DCRT indicated that it has sited generation and interconnection projects in California and Arizona and that its team has years of experience in obtaining the required regulatory approvals and working with regulators in California and Arizona. (P-10)

### **3.6.8 Information Provided by DATC**

As discussed above, DATC provided a proposed schedule that would complete the project on January 11, 2020, about four months ahead of the latest in-service date of May 1, 2020 specified in the ISO Functional Specifications, and identified additional measures it would take, if necessary, to ensure timely delivery of the project. As also discussed above, DATC also asserted that it would have more flexibility than any other project sponsor to alter the timing of certain activities due to the regulatory certainty afforded by Western DSW's participation, because it would not have to acquire as many permits from Arizona and California as other project sponsors and because Western DSW would not require state approvals to begin many activities. (P-9)

DATC provided a description of DATC team members' transmission line and substation projects completed in the last five years, summarized as follows:

#### **Transmission Lines**

ATC - nine projects (>100 kV) total; none at 500 kV and four at 345 kV; full range of responsibilities (finance, design, site, construct, operate, and maintain) for these projects; all the projects were in the U.S., none in Arizona or California.

Western DSW - ten projects (>100 kV) total; one at 500 kV (involved structure repair only); none at 345 kV; full range of responsibilities for these projects; all but one of the projects were in Arizona or California.

Duke Energy – seven projects (>100 kV) total; none at 500 kV or 345 kV; full range of responsibilities for these projects; all the projects were in the U.S., with none in Arizona or California.

Engineering and design contractor – five projects (>100 kV) total; all at 345 kV or greater; had at least design, site, and construct responsibilities for all the projects and had the full range of responsibilities for one of the projects; one of the projects was in the U.S., but not in Arizona or California.

Construction contractor - ten projects (>100 kV) total; three at 500 kV and three at 345 kV; responsible for construction only; nine of the projects were in the U.S., including two in California.

Citizens Energy – one project at 500 kV; responsible for financing only; the project is in California. (P-1)

## **Substations**

ATC – four projects (>100 kV) total; none at 500 kV or 345 kV, all involved capacitors (likely shunt); full range of responsibilities (finance, design, site, construct, operate, and maintain) for these projects; all of the projects were in the U.S., but none was in Arizona or California.

Western DSW - nineteen projects (>100 kV) total; none at 500 kV and three at 345 kV; none involved capacitors and two were listed as a transformer purchase (including one of the 345 kV projects); full range of responsibilities for all but two of these projects; all the projects were in Arizona or California.

Duke Energy - seven projects (>100 kV) total; one at 500 kV and none at 345 kV, one project involved a static VAR compensator, two projects involved series reactors (including the one 500 kV project); full range of responsibilities for these projects; all of the projects were in the U.S. but none were in Arizona or California.

Engineering and design contractor – ten projects (>100 kV) total; five at 345 kV or higher, one project with four substations that included a series capacitor at each substation; responsibilities varied from the full range to design only for these projects; seven of these projects were in the U.S., but none in Arizona or California.

Construction contractor – four projects (>100 kV) total, two at 500 kV, one of which included a series capacitor; responsible for construction only for all of these projects; all the projects were in the U.S., including three in California. (P-1)

DATC provided a description of project schedule performance for transmission line and substation projects completed in the past five years, summarized as follows:

## **Transmission Lines**

ATC – ten projects completed in the past five years; seven projects were completed on or before the initial scheduled completion date; two projects were slightly late; schedule information was not provided for one project.

Duke Energy – all seven projects were completed on or before the initial scheduled completion date.

Engineering and design contractor – five projects completed in the past five years. DATC did not provide sufficient detail to allow determination of the schedule or cost performance for these projects.

Construction contractor –initial and final schedule information provided for two projects. Both projects experienced delays – one was delayed for two years and one was delayed for three months. DATC described the circumstances and problems that led to these schedule delays. DATC did not provide sufficient schedule information to allow determination of the schedule performance for the other projects. (P-6)

## **Substations**

ATC – seven projects completed in the past five years; five projects were completed on or before the initial scheduled completion date; one project was slightly late, and one project was four months behind schedule.

Duke Energy – seven projects completed in the past five years; six projects were completed on or before the initial scheduled completion date; schedule information for one project was not available.

Engineering and design contractor – ten projects completed in the past five years. DATC did not provide sufficient detail to allow determination of the schedule or cost performance for these projects.

Construction contractor – one project completed in the past five years. DATC did not provide sufficient detail to allow determination of the schedule performance for this project. (P-6)

DATC described major issues for each project and provided a typical management progress report.

DATC stated that, as a federal agency, Western DSW cannot release project-specific information involving joint customer projects. (P-6)

DATC stated that its project manager's focus would be on front-end-loaded scope development and management, schedule adherence, recovery plans (if necessary), cost and risk management through the use of Primavera software for schedules, internal processes and procedures, and employing internal and external functional support throughout the project. DATC provided additional information from its proposed project management manual, including the life cycle, baseline scheduling, constructability, and other proprietary management processes. (P-7)

DATC stated that it and Western DSW would form a project management executive committee staffed by senior officials from Western DSW, DATC, and Citizens Energy with authority to make significant decisions. DATC indicated that the executive committee would provide oversight of the program management office, which would be staffed by experienced professionals from DATC and Western DSW and led by the project manager from ATC. DATC indicated that the project manager would report to the executive committee and have reasonable authority to make decisions commensurate with this type of project. DATC identified a proposed project manager with about 25 years of utility experience and who has been involved with leading project teams for about 13 years. DATC stated that any contractors hired to work on the project would be fully assimilated into the project team; the contractors would be involved in team meetings and site visits and would have an on-site presence, as needed. (P-8)

DATC indicated that decision-making would be performed within the project team and that in situations in which the decision would be beyond the scope or risk level of the team, the team would elevate the issue to the program management organization, led by the project manager. Should further escalation of the issue be required, DATC indicated that the program management organization would escalate the issue to the executive committee.

DATC stated that a contractor would be in a support role as owner's engineer and would also support the project director. (P-8)

DATC provided a detailed risk register as part of its project plan to assist in the determination of an appropriate amount of contingency. DATC identified thirty-three potential risks, including a dollar assessment of the cost impact and a brief review of possible mitigation actions. DATC discussed in more detail several of the risks in its risk register. DATC stated that the primary risk to successful completion of the project on time and within budget is route risk. DATC indicated that its chosen route is the shortest route reasonably available; therefore, any alteration in the route would increase cost. DATC indicated that it could mitigate the schedule impact of route changes by increasing staffing and accelerating construction activities. (P-10)

DATC stated that utility crossings represent another risk to the project. DATC indicated that foundation characteristics and quantity are another risk. DATC stated that permitting represents a material risk to both cost and schedule for the project because inability to acquire permits on time would extend the schedule and delays would affect costs. (P-10)

DATC indicated that it is also important to note risks that are not present for the DATC team. DATC stated that other project sponsors would require some state approvals and permits that Western DSW would not. DATC indicated that this is a significant advantage to DATC because Western DSW would acquire rights-of-way and provide for construction of the facilities under its own authority and jurisdiction. (P-10)

### **3.6.9 Information Provided by NEET West**

As discussed above, NEET West (1) provided a proposed schedule that showed an in-service date for the project of May 1, 2020, meeting the latest in-service date of May 1, 2020 specified in the ISO Functional Specifications, and (2) stated that a six-month start delay would have a modest impact compared to the overall project timeline. NEET West stated that a key and unique cost and scheduling risk mitigation for its project is the exclusive agreement NEET West has executed with the Colorado River Indian Tribes, which would enable NEET West to construct a portion of the project on Colorado River Indian Tribes reservation lands in Copper Bottom Pass. NEET West stated that it is prepared to stand behind its schedule by proposing an in-service date incentive such that NEET West would agree to forego the return of, and associated return on, a specified amount of its total cost to construct the project if it did not meet the latest in-service date of May 1, 2020. NEET West indicated that this incentive would only be applicable if it were to receive all approvals required by the CPUC, ACC, and NEPA processes by July 1, 2018. (P-9)

NEET West stated that it was created in mid-2014 solely to own the project and other future assets in the ISO region as a portfolio. Therefore, NEET West indicated that none of the projects described in its proposal were developed, constructed, owned, and operated by NEET West. NEET West provided a description of NextEra's transmission line and substation projects completed in the last five years. NEET West stated that the description of these projects only includes information for NextEra affiliates and does not include information regarding non-NextEra firms that are or may become part of the NEET West team in developing, siting, and constructing the project. (P-1)

NEET West's description of projects completed by NextEra in the last five years is summarized as follows:

NEET West described 29 transmission line projects (>100 kV) total; none at 500 kV and seven projects at 345 kV; 25 of the 29 projects were in the U.S., including three in California and one in Arizona. (P-1)

NEET West described 51 substation projects (>100 kV) total, two at 500 kV and fourteen at 345 kV; 44 of the projects were in the U.S., including five in California and one in Arizona; three of the new 345 kV substations included series capacitor installations. (P-1)

NEET West indicated that NextEra typically had the full range of project responsibilities – finance, design, site, construct, maintain, and operate – for the transmission and substation projects described. (P-1)

NEET West provided high-level summaries of project schedule and cost performance for 95 NextEra projects with a transmission element completed since 2003. NEET West stated that 86% of the 95 NextEra major capital projects were completed on time and all three of the stand-alone transmission projects were completed on time. The other projects described by NEET West involved wind, solar, or gas-fired generation with a transmission element. NEET West stated that the vast majority of projects that did not meet originally planned schedules failed to do so because of interconnection delays with the local utility. (P-6)

NEET West also provided descriptions of project cost and schedule performance for individual transmission line and substation projects. For the seven 345 kV transmission line projects completed in the past five years, NEET West indicated that six were completed on or ahead of schedule; the one late project was not materially late (16 days). (P-6)

NEET West described two 500 kV and fourteen 345 kV substations completed in the past five years. For the 500 kV substations, NEET West indicated that one project was two months late and did not provide schedule details for the other project. For the fourteen 345 kV substation projects completed in the past five years, NEET West indicated that 13 were completed on or ahead of schedule and one was 16 days late. (P-6)

NEET West stated that it would apply to its execution of the project the same project management approach NextEra has employed for the previous projects described in its proposal. NEET West indicated that its approach would consist of active management of all aspects of the project by an experienced and skilled project team of professionals and subject-matter experts who would take personal responsibility and accountability for all phases of the project's execution. (P-7)

NEET West stated that it would take the following project management process steps and actions during its development and construction of the project, based on the model used by other NextEra companies: project launch and scoping, master project schedule, risks identification and mitigation, comprehensive project cost estimate/budget, project execution plan, monitor and control project schedule, cost and risks, and track and

report on project performance. NEET West provided an explanation of its intended actions in each of the project management steps. NEET West also stated that its project director would hold monthly senior management project status update meetings. (P-7)

NEET West indicated that it would break the project execution period into project development and construction phases. During the development phase, NEET West stated that it would develop the project execution plan, complete land acquisition, and begin permitting and seeking regulatory approvals. In the construction phase, NEET West indicated that it would implement the project execution plan and that the project would be constructed and ultimately placed into service. (P-8)

NEET West indicated that it would assemble a team of professionals and subject-matter experts to make up the core project team that would draw upon the NextEra's matrixed organization of shared resources for the project execution. NEET West indicated that its senior management would direct the core team and that reporting to NEET senior management would be the project director for the project who would provide a single point of accountability for day-to-day project activities, oversee all project work stream leads and resources, and be responsible for reporting project progress to senior management. (P-8)

NEET West provided separate organization charts for the NEET West teams for the development phase, the construction phase, and the operations phase of the project. NEET West also provided summaries of the experience of individuals with key roles in the project management teams. NEET West indicated that it proposed overall project director has 30 years of utility experience and that its proposed development, engineering, and construction leads have 16, 20, and 40 years of experience, respectively. (P-8)

NEET West provided a table listing 63 risks that it considers as major risks and obstacles to the successful completion of the project on schedule and within budget. NEET West identified the specific 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 and/or construction, and the planned or potential mitigation. NEET West indicated that it considers 28 of the risks listed as having a high impact on the project cost and/or schedule. Of these, NEET West indicated that it considers five of these risks likely to occur; these issues involve delays in regulatory processes and data requests, litigation for the rights-of-way through the Kofa National Wildlife Refuge, and weather impacting scheduled work. NEET West identified early reach-out and process initiation and conservative schedule time allocations as general mitigations for these high impact risks it considers likely to occur. (P-10)

NEET West stated that it is applying to develop multiple projects under the ISO's competitive transmission process. NEET West stated that it would be able to execute multiple projects in parallel due to the extensive experience and capabilities of the NextEra companies at project execution. (P-10)

### **3.6.10 Information Provided by TC/SCE**

As discussed above, TC/SCE provided a proposed schedule that would achieve the latest in-service date of May 1, 2020 specified in the ISO Functional Specifications and stated that, if the start date were to be delayed six months, or if any combination of



delays up to six months were to impact the project, it would use schedule compression to meet the latest in-service date of May 1, 2020 specified in the ISO Functional Specifications. (P-9)

TC/SCE stated that it has not completed any projects to date but that its team members, its joint venture members and their affiliates, and its collaborator have completed a significant number of projects. TC/SCE provided a detailed description of past projects for its affiliates, team members, and collaborator APS, BHT, and SCE. TC/SCE provided a description of team members' past transmission line and substation projects completed in the last five years, summarized as follows:

### **Transmission Lines**

APS - six projects (>100 kV) total; five at 500 kV (two were very short taps); full range of responsibilities (finance, design, site, construct, operate, and maintain) for these projects; all the projects in Arizona.

BHT - four projects total; all at 345 kV; full range of responsibilities for two of the projects and finance only for two projects; all the projects were in the U.S., with none in California or Arizona.

SCE - seven projects (>100 kV) total; four at 500 kV; full range of responsibilities for these projects; all the projects were in California. (P-1)

### **Substations**

APS – six projects total; all at 500 kV, four involved series capacitors; full range of responsibilities (finance, design, site, construct, operate, and maintain) for these projects; all of the projects were in Arizona.

BHT – eight projects total; three at 345 kV, two involving series capacitors; full range of responsibilities for all but two of these projects; all the projects were in the U.S., with none in Arizona or California.

SCE - eight projects (>100 kV) total; four at 500 kV, none involving series capacitors (TC/SCE stated that SCE owns eighteen 500 kV series capacitors); full range of responsibilities for these projects; all of the projects were in California. (P-1)

TC/SCE provided a description of project schedule performance for transmission line and substation projects completed in the past five years, summarized as follows:

### **Transmission Lines**

APS – seven projects completed in the past five years; all seven projects were completed on or before the initial scheduled completion date.

BHT – four projects completed in the past five years; all four projects were completed on or before the initial scheduled completion date.

SCE – seven projects completed in the past five years; two of the projects were completed on or before the initial scheduled completion date; for four of the late projects, the delay ranged from four to eight months. TC/SCE provided explanations of these

delays, primarily that they were due to conditions beyond SCE's control. TC/SCE explained that one project was delayed by 3.5 years due to interconnection agreement delays.

### **Substations**

APS – three projects completed in the past five years; all three projects were completed on or before the initial scheduled completion date.

BHT – eight projects completed in the past five years; seven of the projects were completed on or before the initial scheduled completion date; one project was delayed for 10 months as the project was re-scoped.

SCE – eight projects completed in the past five years; three of the projects were completed on or before the initial scheduled completion date; the delays in five of the projects ranged from six months to three and a half years. TC/SCE provided explanations of these delays, primarily that they were due to conditions beyond SCE's control, such as permitting or customer delays. (P-6)

TC/SCE stated that it has assembled a project management team comprised of individuals from BHT and PNW, as well as California-specific permitting and licensing expertise from its collaborator SCE. TC/SCE indicated that its approach to the overall project would be one of development and long-term ownership. TC/SCE indicated that its aim would be to provide a quality installation to minimize operational and maintenance costs and to provide long-term reliable service. TC/SCE stated that it would accomplish this through effective project management. (P-7)

TC/SCE stated that its project manager would be responsible for oversight of three major project work streams: (1) permitting and siting, (2) engineering and design, and (3) construction delivery. TC/SCE indicated that it would coordinate all activities with the ISO during all phases of the project and comply with all reporting requirements of the ISO. (P-7)

TC/SCE indicated that its overall approach to project management during construction would be governed by the project execution plan, which would be developed with its construction contractor. TC/SCE indicated that the project execution plan would describe the processes, roles, and responsibilities for each phase of the project. TC/SCE provided additional project management discussion in the areas of the application, permitting, project development, construction and commissioning, and operations, including actions it has already taken for the project. TC/SCE also discussed in detail its approach to scheduling. TC/SCE stated that it would use an interactive planning approach to scheduling the project, taking all inputs (scope, estimates, engineering, maintenance, operations, etc.) into account when developing the initial schedule. TC/SCE stated it would use Primavera software for the project schedule. TC/SCE indicated that it would update the schedule with any approved changes to the project and report the impact (if any) in terms of potential schedule delays or improvement. TC/SCE indicated that it would also use the schedule for a critical path analysis and the development of "what-if" scenarios to evaluate various execution options throughout the project. (P-7)

TC/SCE provided an organization chart for the project showing the project manager reporting to an executive at TransCanyon; the project manager would be responsible for permitting and siting, engineering and design, and construction delivery. The organization chart also reflects other project-related activities, including FERC, system planning, operations and maintenance (O&M), and compliance; these activities would report to other TransCanyon executives. The organization chart also reflects the reporting relationship of the various contractors that TC/SCE would use for the project. TC/SCE provided a table with the experience of key project leads identified; TC/SCE identified a proposed project manager who has 16 years of experience. (P-8)

TC/SCE stated that it has focused on understanding risks specific to the project and developing strategies to mitigate those risks as a part of developing its cost estimate and cost containment proposal. TC/SCE indicated that it employed a six-step approach to identifying and evaluating risk to maximize the likelihood of delivering the project on budget and on schedule. TC/SCE indicated that it developed a risk register that catalogues 18 risks, including risk category, description, impact, and mitigation. TC/SCE also provided additional risk discussion related to schedule, environment, and line route, including actions it has or would take prior to the completion of the ISO selection process to reduce the risks. (P-10)

TC/SCE stated that BHT is currently developing the Gates-Gregg transmission project with its partners but that the commercial operation date of this project will not be impacted by BHT's development of the Gates-Gregg transmission project, and vice versa. (P-10)

### **3.6.11 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 five project sponsors have proposed schedules that meet the latest in-service date specified in the ISO Functional Specifications. CTD proposes a project schedule that would complete its project one year ahead of the latest in-service date of May 1, 2020 specified in the ISO Functional Specifications. The other four project sponsors propose schedules that would complete the project at or somewhat earlier than the latest in-service date (up to four months early). All five project sponsors indicate that they could complete the project by the latest in-service date specified in the ISO Functional Specifications if the start date were to be delayed by six months.

The ISO has determined that all five project sponsors' 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 amount of float and schedule delay mitigation actions proposed by the project sponsors to be comparable.

The ISO has determined that there are no economic benefits to completing this project ahead of the latest in-service date of May 1, 2020 specified in the ISO Functional Specifications because other transmission projects must be completed in order for this project to yield economic benefits. In addition, the ISO has documented in the transmission plan containing this project that the benefits of the project are largest in the first year of operation and decrease over time. Consequently, realization of the maximum economic benefit of the project is sensitive to completing the project on time.

The ISO has determined that, although there are differences in the details in the schedules as proposed by each project sponsor, each proposed project schedule includes activities that show that the project could be completed by the required date. Thus the ISO has not identified any advantage for any project sponsor for this component of factor. Therefore, the ISO has determined that there is no material difference among the proposals of the five project sponsors with regard to this component of the factor.

### **Comparative Analysis of Ability to Meet Schedule**

The ISO's analysis for this component for 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. 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 with projects comparable to this project in meeting schedules, including but not limited to the information in their proposed schedules as well as their past experience in constructing projects on schedule, accounting for risk management, and performing project management, as well as any other indicated factors that might impact the date of completion (either favorably or unfavorably).

As discussed above, the ISO has determined that there are no economic benefits to completing this project ahead of the ISO required date because other transmission projects must be completed in order for this project to yield economic benefits and that the benefits of the project are largest in the first year of operation and decrease over time. Consequently, realization of the maximum economic benefit of the project is sensitive to completing the project on time.

### **Proposed Schedule**

As discussed above, all five project sponsors propose schedules that meet the latest in-service date of May 1, 2020 specified in the ISO Functional Specifications. CTD proposes a schedule that completes its project one year ahead of that latest in-service date, while the other four project sponsors propose schedules that complete the project somewhat later than CTD's proposed schedule. All five project sponsors indicate that they could still complete the project by the latest in-service date if the start date were to be delayed by six months.

### **Financial Incentive**

NEET West has offered an "in-service date incentive" whereby it would forego a portion of its return if its project were to be completed after the latest in-service date of May 1,

2020 specified in the ISO Functional Specifications, subject to certain conditions. This incentive is an advantage relative to the proposals of the other project sponsors, which include no additional financial incentive to complete the project on schedule.

### **Previous Experience**

All the project sponsors and their team members have demonstrated experience with previous transmission line and substation projects. TC/SCE, however, has a slight advantage relative to the other four project sponsors given its extensive previous experience with extra high voltage (EHV) and series compensation projects, in addition to having most of its past projects completed in Arizona and California. Although there are variations in the previous project experience for CTD, DATC, and NEET West regarding EHV and series compensation work in Arizona and California, the ISO has determined that these variations in experience are not significant enough to result in an advantage for any of these three project sponsors relative to the others. DCRT's affiliates have significant international experience with large scale transmission line and substation projects that is comparable to the experience of other project sponsors and their affiliates. However, DCRT's EPC contractor ATI -- the U.S. subsidiary of Abengoa - is a relatively new entity and thus has less experience than the other four project sponsors with respect to EHV and series compensation facilities.

In terms of completing past projects on schedule, all project sponsors and their teams have had a reasonable degree of success in meeting project schedules, generally only experiencing minor delays, and they provided reasonable explanations for the delays.

### **Project Management and Risk**

All five project sponsors have provided a reasonable approach to professional project management. The project managers identified by each project sponsor have at least 15 years of experience, which the ISO considers sufficient.

All five project sponsors have provided a thorough approach to identifying risks to the project schedule and possible mitigations for those risks. DATC asserts that it does not face the risk to the project schedule that other four project sponsors face because DATC will not require some state approvals and permits as a result of Western DSW acquiring rights-of-way and providing for construction of the facilities under its own authority and jurisdiction. The ISO considers the efficiencies gained by using a single siting and permitting authority to be a slight advantage for DATC relative to the other four project sponsors as a factor in completing the project on schedule.

Also, the project sponsors that are applying for more than one ISO project appear to have the capability to complete multiple projects without negatively affecting the schedule for this project.

### **Overall Analysis**

Based on consideration of all of the aspects of the ability of the project sponsors to meet their proposed schedules, the ISO has identified differences among the proposals of the five project sponsors. CTD's schedule has the most float; however, it allocated the least time of all the project sponsors' schedules to completing the necessary regulatory and siting processes and offered no explanation as to why its permitting process could be

completed faster than those of the other project sponsors. DATC proposes to bypass state regulatory processes, which could avoid possible delays, resulting in less risk that DATC might not meet the latest in-service date specified in the ISO Functional Specifications. NEET West has voluntarily offered a financial completion incentive, whereby it would forego the opportunity to recover a portion of the project costs under certain conditions if its project is late. TC/SCE identified the most relevant recent experience with projects similar to this project in California and Arizona, and TC/SCE's experience would contribute to meeting the latest in-service date. Although these and other aspects of the project sponsors' proposals offer different advantages regarding the ability to complete the project on time, the ISO considers the proposals of DATC, NEET West, and TC/SCE to be comparable to each other for different reasons with regard to the project sponsors' ability to meet the latest in-service date as discussed above. The ISO considers the proposals of DATC, NEET West, and TC/SCE to be slightly better than CTD's proposal because CTD's proposal does not contain any of the foregoing specific advantages of the proposals of DATC, NEET West, and TC/SCE, and there is otherwise no indication that CTD's proposal would offer greater certainty of meeting the latest in-service date specified in the ISO Functional Specifications. The ISO considers the proposals of CTD, DATC, NEET West, and TC/SCE to be slightly better than DCRT's proposal because of their Arizona and California experience and other factors discussed above.

Based on consideration of all of the aspects of the ability of the project sponsors to meet the latest in-service date of May 1, 2020 specified in the ISO Functional Specifications, the ISO has determined that there is no material difference among the proposals of DATC, NEET West, and TC/SCE, that their proposals are slightly better than CTD's proposal, and that these four project sponsors' proposals are slightly better than DCRT's proposal, with regard to 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. Because the ISO has determined that there is no material difference among the proposals of the project sponsors with regard to the first component of this factor (proposed schedule), and the ISO has determined that there is no material difference among the proposals of DATC, NEET West, and TC/SCE, that they are slightly better than CTD's proposal, and that these four project sponsors' proposals are slightly better than DCRT's proposal with regard to the second component of this factor (ability to meet schedule), the ISO has determined that there is no material difference among the proposals of DATC, NEET West, and TC/SCE with regard to this factor overall, that they are slightly better than CTD's proposal, and that these four proposals are slightly better than DCRT's proposal with regard to this factor overall.

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

(Section 3 - General Project Information, QS-2, P-1, P-5, F-1, F-2, F-3, F-4, F-5, F-6, F-7, F-8, F-9, F-10, F-11, F-12, F-13, F-14, F-15)

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.

Project sponsors provided information related to 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")<sup>7</sup> – 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, the ISO relies on tangible net worth<sup>8</sup>, 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 one 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.

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

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<sup>7</sup> Estimated Default Frequency is a proprietary scoring model developed by Moody's Analytics, Inc., a subsidiary of Moody's Corporation (NYSE: MCO).

<sup>8</sup> 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 ISO 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.

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

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

### **3.7.1 Information Provided by CTD**

#### **Project Financing Experience**

CTD provided a list of five transmission line and five substation projects that it or its ultimate parent, LS Power, have financed in the past five years, of which one 230 kV transmission line project of 1.4 miles was located in California. CTD indicated that its other California experience was a substation project that was part of the transmission project listed above. CTD provided information regarding its and/or LS Power's debt contribution for the five transmission line projects and indicated that it or LS Power financed the projects through multiple types of debt instruments structured and facilitated through third parties. (P-1, F-11)

#### **Project Financing Proposal**

CTD indicated that it plans to finance the overall project with 50% equity and 50% debt. CTD indicated that it plans to have LS Power provide the equity financing for the development of the project and to obtain construction financing through Western Area Power Administration's Transmission Infrastructure Program. CTD provided a memorandum of understanding showing Western Area Power Administration's support, but not a financial commitment, for CTD to continue its review and evaluation of the project. By at least partially funding through Western Area Power Administration's Transmission Infrastructure Program, CTD indicated that it would anticipate realizing similar benefits that ratepayers received from another affiliate's projects, *i.e.*, reduced interest expense during construction and a 30-year term that eliminates the need to refinance and exposure to interest rate risk, resulting in savings to ratepayers on the rate base and providing significant annual revenue requirement savings.

CTD indicated that, in the event CTD were to fail to secure Western Area Power Administration Transmission Infrastructure Program funding, it would have excellent access to the bank and bond markets for non-recourse project financing. CTD indicated that, although the lower interest rate of Western Area Power Administration Transmission Infrastructure Program financing would have a direct benefit to ratepayers, failure to secure such financing and the need to secure potentially higher interest rate financing would not change CTD's proposal. (F-2, F-12, F-14)

#### **Financial Resources**

CTD indicated that it would rely on LS Power for capital funding for this project. CTD provided a letter from LS Power indicating its financial support for the project. CTD provided LS Power's annual audited and quarterly unaudited financial statements for



2009-2013. CTD provided the following information from LS Power’s latest annual audited financial statements:

Total assets  
Total liabilities  
Net worth

The ISO calculated a tangible net worth for LS Power. LS Power’s quarterly unaudited financial statements did not show any material adverse change to LS Power’s financial condition. (F-3, F-4)

### **Credit Ratings**

LS Power is not rated by any of the three major credit rating agencies.

The ISO calculated a Moody’s Analytics equivalent rating for LS Power based on LS Power’s 2013 audited financial statements. (F-6)

### **Financial Ratio Analysis**

CTD provided the following financial ratios based on LS Power’s 2013 audited financial statements: (F-9, F-10)

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

## **3.7.2 Information Provided by DCRT**

### **Project Financing Experience**

DCRT provided a list of 13 transmission projects that Abengoa has financed in the past five years, none of which was in the U.S. DCRT cited three projects in the U.S. that it had not financed for which it had design, siting, and construction experience, two of which were in California.

DCRT provided a list of three additional transmission projects financed by Starwood Energy, one of which was a combined 458-mile 500 kV line that was built in the 1990s and at least in part extended through California.

DCRT provided no substation financing experience.

DCRT provided information regarding Abengoa’s and Starwood Energy’s combined debt contribution for what DCRT considered comparably sized projects, using principally bonds and subordinated and institutional debt. DCRT only indicated relationships with a handful of foreign banks for these projects. In spite of the potential lack of relationships with U.S. banks, DCRT did provide letters of support for this project from five banks, one of which is California based. Although these letters indicated the banks’ support for this project, none offered a commitment to fund it. (P-1, F-11, F-13)

## **Project Financing Proposal**

DCRT indicated that it would rely on its parent and Starwood Energy to provide the capital needed to fund this project. DCRT provided a letter from Abengoa indicating that it would provide financial backing for the project.

DCRT indicated that the financial structure would incorporate a special purpose vehicle tranche of debt at the project level, reflecting a 50%/50% debt-to-equity ratio at the special purpose vehicle, which DCRT believes would be highly likely to be approved by FERC as a deemed capital structure.

DCRT provided information regarding the debt financing requirement for the project and indicated that the equity commitment would be structured as senior secured bonds placed with institutional investors. DCRT indicated that the special purpose vehicle financing would be structured as a traditional project financing with the objective of achieving a mid-investment grade rating.

DCRT asserted that its proposed capital structure (long term bond permanent financing and equity injections) would allow it to require a comparatively reduced return on equity, which would ultimately benefit all ratepayers by reducing and optimizing the transmission rates to be paid by ratepayers. DCRT indicated that this financing structure has been executed in the past for similar transmission assets and that most investors showed strong interest in the special purpose vehicle debt. (F-2, F-12, F-14)

DCRT also stated that it has filed an application for project development assistance with Western Area Power Administration through its Transmission Infrastructure Program and will consider this source of financing if it provides a more expedient and cost-effective option. (Section 3 – General Project Information)

## **Financial Resources**

DCRT provided letters from Abengoa and Starwood Energy indicating their financial support for the project.

DCRT provided Abengoa’s annual audited and quarterly unaudited financial statements for 2009-2013. DCRT provided the following information from Abengoa’s latest annual audited financial statements:

Total assets  
Total liabilities  
Net worth

The ISO calculated a tangible net worth for Abengoa. Abengoa’s quarterly unaudited financial statements did not show any material adverse change to Abengoa’s financial condition.

DCRT did not provide financial statements for Starwood Energy. DCRT described Starwood Energy as a private equity investment firm that makes energy infrastructure investments through its existing general opportunity funds, including SEIF II, and affiliated investment vehicles. DCRT provided information regarding SEIF II’s

uncommitted direct equity capital and its access to additional discretionary equity capital to invest in infrastructure projects. (F-3, F-4)

### **Credit Ratings**

DCRT provided the following credit ratings and associated credit rating reports for Abengoa:

Moody's: B2  
S&P: B

The ISO calculated a Moody's Analytics equivalent rating for Abengoa based on Abengoa's 2013 audited financial statements.

DCRT indicated that Starwood Energy's SEIF II is not rated by any of the three major credit rating agencies. Because of the nature of the fund, financial statements were unavailable. Therefore, the ISO was not able to calculate a Moody's Analytics equivalent rating for SEIF II. (F-6)

### **Financial Ratio Analysis**

DCRT provided the following financial ratios based on Abengoa's 2013 audited financial statements: (F-9, F-10)

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

DCRT did not provide similar ratios for Starwood Energy, and these ratios would not be relevant anyway given SEIF II's nature as a general opportunity investment fund.

### **3.7.3 Information Provided by DATC**

#### **Project Financing Experience**

DATC provided a list of nine transmission projects that ATC has financed in the past five years, none of which was in California. DATC listed two additional projects that occurred outside the five-year window of experience requested.

DATC provided additional transmission project financing experience among the team members that DATC has proposed to be part of this project; however, they are not involved in the direct financing of the project.

DATC did not provide any transmission project financing experience for Duke Energy. DATC also did not provide any substation project financing experience, stating that substations are outside the scope of this project.

DATC did not provide any debt contribution history for comparably sized projects. DATC did note that three projects financed through private placement had a 45.5%/54.5% equity-to-debt ratio placed with large U.S. commercial and investment banks. DATC

indicated that two other projects had a 50%/50% equity-to-debt ratio using a combination of revolving credit and bonds using what DATC characterized as a variety of top tier banking partners. DATC provided a letter of support from one bank that stated that, although the bank supported the project, the letter should not be construed as a commitment by the bank or any of its affiliates to lend to or arrange funds for the project. (P-1, F-11)

### **Project Financing Proposal**

DATC indicated that DATC West Energy would be a special purpose limited liability company that would be a wholly-owned subsidiary of DATC, which is ultimately owned by Duke Energy and ATC. DATC indicated that Duke and ATC would provide the 50% equity funding via DATC for DATC West Energy.

DATC indicated that it plans to use Western Area Power Administration's Transmission Infrastructure Program and/or commercial bank financing to provide construction and long-term financing for the remaining 50% of the project's capital costs. DATC indicated that it anticipates that DATC West Energy would be able to obtain the necessary letters of credit to meet the necessary ISO guarantees for financial backing of the project due to significant interest in the project by commercial banks. As noted above, DATC provided one such letter of support from one commercial bank.

DATC asserted that it has applied to and met the initial criteria for the Western Area Power Administration Transmission Infrastructure Program. DATC provided a memorandum of understanding showing Western Area Power Administration's support, but not a financial commitment, for DATC to continue its review and evaluation of the project. DATC asserted that participating in the Western Area Power Administration Transmission Infrastructure Program would include the opportunity to utilize financing provided by Western Area Power Administration at lower costs and rates than commercial financing. DATC indicated that, upon award as the approved project sponsor, it would continue the process within the Western Area Power Administration Transmission Infrastructure Program to complete the loan application and evaluate the costs of Western Area Power Administration Transmission Infrastructure Program financing compared to commercial financing to ensure the lowest cost financing is utilized for the project, thus providing a direct benefit to ratepayers. (F-1, F-2, F-12, F-14)

### **Financial Resources**

DATC indicated that it would rely on its ultimate parents, Duke Energy and ATC, for capital funding for this project. DATC provided letters from both Duke Energy and ATC indicating their financial support for the project.

DATC provided Duke Energy's and ATC's annual audited and quarterly unaudited financial statements for 2009-2013. DATC provided the following information from each company's latest annual audited financial statements:

Duke Energy  
Total assets  
Total liabilities  
Net worth

The ISO calculated a tangible net worth for Duke Energy.

ATC

Total assets  
Total liabilities  
Net worth

The ISO calculated a tangible net worth for ATC.  
Neither company's quarterly unaudited financial statements showed any material adverse change to that company's financial condition.

DATC indicated that Western DSW would operate and maintain the project upon completion. (F-3, F-4, F-13)

**Credit Ratings**

DATC provided the following credit ratings and associated credit rating reports: (F-6)

Duke Energy

Moody's: A3  
S&P: BBB+

The ISO calculated a Moody's Analytics equivalent rating for Duke Energy based on Duke Energy's 2013 audited financial statements.

ATC

Moody's: A1  
S&P: A+

The ISO calculated a Moody's Analytics equivalent rating for ATC based on ATC's 2013 audited financial statements.

**Financial Ratio Analysis**

DATC provided the following financial ratios based on Duke Energy's and ATC's 2013 audited financial statements: (F-9; F-10)

Duke Energy

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

ATC

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

### **3.7.4 Information Provided by NEET West**

#### **Project Financing Experience**

NEET West provided a list of 31 transmission and 54 substation projects financed in the past five years, of which four of the transmission projects were in California. NEET West provided many more examples of each outside the requested five-year window.

NEET West provided information regarding its and/or NextEra's debt contribution for five representative projects of limited-recourse senior secured variable rate term loans and letters of credit for which the loans were secured by all borrower's assets and a pledge of ownership interest in the borrower. (P-1, F-11)

#### **Project Financing Proposal**

NEET West indicated that it would draw 100% of its funding requirements from its corporate parent, which would consist of both equity and debt. NEET West indicated that it would receive funding from NEECH, the financing arm of NextEra for all of NextEra's subsidiaries. NEET West indicated that NEECH would provide needed guarantees to NEET West and that those would in turn be guaranteed by NextEra as provided for through a blanket guarantee arrangement between NEECH and NextEra. NEET West indicated that execution of a guaranty would be dependent on NEET West being selected and the execution of a mutually agreeable approved project sponsor agreement.

NEET West indicated that it would be targeting a debt-to-equity ratio of 50%/50%. During development and construction, NEET West indicated that NEECH would contribute equity and provide access to debt financing at commercially attractive rates. On or around the in-service date for the project, NEET West indicated that it intends to convert the debt to long-term debt at commercially attractive rates, provided by NEECH.

During development, permitting, and construction and operation, NEET West indicated that the project would be supported 100% through corporate parent funding, which would consist of both equity and debt. NEET West indicated that ratepayers would receive the benefit of a project constructed with strong equity support, without any risk of project-level leverage. NEET West 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.). Further, as was noted previously, NEET West indicated that it has voluntarily decided to forego specified pre-bid development costs and would not seek recovery for these funds, which NEET West indicated would be a direct benefit to ratepayers. NEET West indicated that the project might further benefit from a portfolio financing post-construction that could include a series of multiple fixed rate debt issuances that would align with the forecasted depreciable net book value of the project assets, when viewed as a diversified portfolio. NEET West indicated that such a structure would allow ratepayers to benefit from a portfolio of debt terms and rates that would minimize the overall financing cost. (F-1, F-2, F-12, F-14)

## **Financial Resources**

NEET West provided a letter from its ultimate parent, NextEra, assuring NextEra's financial support of this project.

NEET West provided NextEra's annual audited and quarterly unaudited financial statements for 2009-2013. NEET West provided the following information from NextEra's latest annual audited financial statements:

Total assets  
Total liabilities  
Net worth

The ISO calculated a tangible net worth for NextEra. NextEra's quarterly unaudited financial statements did not show any material adverse change to NextEra's financial condition. (F-3, F-4)

## **Credit Ratings**

NEET West provided the following credit ratings and associated credit rating reports for NextEra: (F-6)

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

The ISO calculated a Moody's Analytics equivalent rating for NextEra based on 2013 audited financial statements.

## **Financial Ratio Analysis**

NEET West provided the following financial ratios based on NextEra's 2013 audited financial statements: (F-9, F-10)

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

### **3.7.5 Information Provided by TC/SCE**

#### **Project Financing Experience**

TC/SCE provided a list of 24 transmission and 24 substation projects it and/or its affiliates or collaborator have financed in the past five years, of which eight of the transmission projects were in California. TC/SCE provided information regarding debt contributions for two of the five projects listed as representative examples of TC/SCE's financing experience of long-term debt issuances and revolving credit facilities. TC/SCE listed three additional projects as having used corporate debt facilitated by up to six banking partners. (P-1, F-11)

## **Project Financing Proposal**

TC/SCE indicated that TransCanyon is relying on its two parent entities – PNW and BHE – to satisfy the financial criteria for this project and provided a parental guarantee in favor of the ISO to support this. TC/SCE indicated that SCE would provide specific non-financial support to the project in exchange for the right but not the obligation of exercising an option to acquire a part of the completed project. Because SCE is not providing financial support for this project, the ISO has not considered SCE's financial information and credit ratings relevant in assessing the financial capabilities of TC/SCE and TransCanyon.

TC/SCE indicated that TransCanyon's equity would be funded entirely by contributions from BHE and PNW. TC/SCE indicated that TransCanyon expects to be able to issue non-recourse debt for its remaining capital needs.

TC/SCE indicated that, during the pre-commercial-operation stages (e.g., permitting, construction), TransCanyon would finance 100% of the project, save for in-kind contributions from SCE internal resources, which costs SCE would bear and contribute to the project upon affirmative option election. TC/SCE indicated that, once the project became operational, TransCanyon and SCE would independently finance their respective interests in the project as is common in a tenants-in-common structure.

TC/SCE indicated that it has strong financial backing and does not plan to access capital markets to fund equity for a project of this size. TC/SCE indicated that this would facilitate immediate commencement of development and construction activities and benefit ratepayers by minimizing financing and transaction fees. TC/SCE indicated that both PNW and BHE have significant operating cash accessible to fund equity and would be able to draw from existing and available credit facilities if needed.

For longer-term construction and permanent financing, TC/SCE indicated that it expects to rely on traditional bank and/or capital market transactions to arrange the necessary financing and would not employ any overly complex financing structures or use extreme amounts of leverage that could increase the financial risk of the project. (F-2, F-12, F-14)

## **Financial Resources**

TC/SCE provided letters of financial support for the project from PNW, BHE, and SCE. TC/SCE provided five years of audited financial statements for PNW and BHE. TC/SCE also provided financials for SCE. The ISO notes that there is no plan for SCE to be involved in project financing, and it is uncertain at this time whether SCE will even participate in the project, so the ISO has not included the information provided by TC/SCE for SCE in this report. The following information is from each company's 2013 financial statements:

### PNW

Total assets  
Total liabilities  
Net worth

The ISO calculated a tangible net worth for PNW.



**BHE**

Total assets  
Total liabilities  
Net worth

The ISO calculated a tangible net worth for BHE.

No company's quarterly unaudited financial statements showed any material adverse change to its financial condition. (F-3, F-4)

**Credit Ratings**

TC/SCE provided the following credit ratings and associated credit reports (as noted above, the ISO has not provided SCE's credit ratings): (F-6)

**PNW**

Moody's: Baa1  
S&P: A-

The ISO calculated a Moody's Analytics equivalent rating for PNW based on 2013 audited financial statements.

**BHE**

Moody's: A3  
S&P: BBB+

The ISO calculated a Moody's Analytics equivalent rating for BHE based on 2013 audited financial statements.

**Financial Ratio Analysis**

TC/SCE provided the following financial ratios based on PNW's and BHE's 2013 audited financial statements (as noted above, the ISO has not provided SCE's financial ratios): (F-9, F-10)

**PNW**

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

**BHE**

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

**3.7.6 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., an ultimate 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.

Generally speaking, although there are differences in financial and legal structure for each project sponsor, 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. Consequently, this comparative analysis relies in large part on minor degrees of difference.

### **Project Financing Experience**

Based upon the information provided and representations by the project sponsors, the ISO has determined that all five project sponsors have sufficient experience financing and completing a significant number of projects, including some projects significantly larger than this one. NEET West and TC/SCE have considerably more transmission project and project financing experience than the other project sponsors based on the number of projects they identified over the past five years. DCRT, although benefitting from Abengoa having considerable transmission project and project financing experience, provided no examples of U.S. transmission project experience during the past five years. DCRT did provide five bank letters of support for the project. Although these letters do not represent a commitment to fund or facilitate funding for the project, they do indicate that DCRT, through Abengoa, has developed strong banking relationships that may allow it to secure financing for the project. In addition, DCRT's majority partner, Starwood Energy, has sufficient uncommitted capital available to fund this project.

Similarly, CTD and DATC, although identifying less transmission project financing experience during the past five years, have demonstrated that they have project

financing experience and have established the necessary banking relationships to secure financing for this project.

Although some project sponsors clearly have more experience in transmission project financing than others, the ISO has concluded that each project sponsor has sufficient transmission financing experience and access to capital. Consequently, with respect to this particular project, the ISO has determined that there is no material difference among the project sponsors and their proposals in this regard.

### **Project Financing Proposal**

Each project sponsor proposes to rely to some extent on its ultimate parent for financing and/or access to the capital markets. As required, all provided letters of financial support for the project from their ultimate parents. Each project sponsor's funding target is 50% equity to 50% debt.

Two project sponsors, CTD and DATC, propose to finance the debt portion of the project using Western Area Power Administration's Transmission Infrastructure Program, and each provided a memorandum of understanding showing Western Area Power Administration's support for each company to continue its review and evaluation of the project. The memorandum of understanding is clear that it is not a commitment to fund the project. In the event that Western Area Power Administration Transmission Infrastructure Program funding of the project is unavailable, both CTD and DATC indicated that they would pursue alternative financing of the project through the capital markets. CTD indicated that pursuit of funding through the capital markets would not materially affect its proposal due to its proposed cost containment measures.

The other three project sponsors would use non-recourse debt to fund the remaining capital needs of the project, although DCRT also stated that it will consider Western Area Power Administration Transmission Infrastructure Program financing if it provides a more expedient and cost-effective option.

Each project sponsor has given thoughtful consideration to project financing. Based on their representations, all of the sponsors appear capable of financing the project.

### **Financial Resources**

Based on the project sponsors' 2013 annual financial statements and their 2014 quarterly financial reports, all five project sponsors exhibit sufficient financial strength and resources to complete this project. DATC, NEET West, and TC/SCE have shown higher net worth and tangible net worth than CTD and DCRT over the past five years. Having the financial capacity to continue to bid on, win, and finance projects, although dependent on the financial resources of a company, also depends on the breadth and strength of a company's partner and banking relationships. Recent and past project financing experience indicate that both CTD and DCRT have strong partner and banking relationships as evidenced by their support for this project. Consequently, the ISO has determined that there is no material difference among the five project sponsors in this regard.

## **Credit Ratings**

DATC, NEET West, and TC/SCE are all backed by highly-rated, investment grade companies. Although their individual ratings vary somewhat, the ISO does not consider these differences to be material for purposes of this analysis. DCRT's parent Abengoa is rated non-investment grade. CTD's parent LS Power is not 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.

Based on the ISO's calculation of Moody's Analytics estimated default frequency and the resulting Moody's Analytics equivalent rating for the past five years, the ISO considers DATC, NEET West, and TC/SCE comparable and slightly stronger than DCRT and considers DCRT, through Abengoa's relationship with Starwood Energy, slightly stronger than CTD with regard to this measure of financial resources.

## **Financial Ratio Analysis**

DATC, NEET West, and TC/SCE have better financial ratios than CTD and DCRT. As a result, the ISO has determined that there is no material difference among DATC, NEET West, and TC/SCE with regard to this measure of financial resources, that they are slightly stronger than DCRT in this regard, and that DCRT, through Abengoa's relationship with Starwood Energy, has a slight advantage over CTD in this regard.

## **Overall Analysis**

In performing the comparative analysis for this factor, the ISO has 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.

DATC, NEET West, and TC/SCE rate higher than CTD and DCRT in several of the financial metrics used by the ISO to assess each project sponsor's financial capabilities. CTD and DCRT have enhanced their financial capability through their partnerships and banking relationships, and their partners and affiliates have successfully financed large utility-scale projects in the past. The ISO notes that DATC also relies in part on similar partner and banking relations to those of CTD and DCRT. The difference is the higher ratings of DATC's financial backers.

Based on the information provided by the project sponsors, the foregoing review of their current financial resources, and the relative strength of the financial metrics used in this analysis, the ISO has determined that, although each project sponsor has demonstrated the experience and access to financial resources to undertake a project of this size, DATC, NEET West, and TC/SCE have stronger financial metrics than CTD and DCRT. Consequently, the ISO has determined that there is no material difference among the proposals of DATC, NEET West, and TC/SCE with regard to this factor and that they are better than the proposals of CTD and DCRT, between which there is no material

difference, with regard to this factor. Although DCRT has a slight advantage over CTD with regard to certain measures of financial resources, the ISO does not consider these advantages to be material in the context of the overall analysis of CTD's and DCRT's financial resources.

### **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**

(Section 3 - General Project Information, QS-1, QS-4, P-1, P-6, P-8, P-9, P-10, E-1, E-2, E-3, E-4, E-5, E-6, E-7, E-8, E-9 a, E-9 b, E-9bi, E-9bii, E-9c, E-10, E-14a, E-14c, E-14di, E-14dii, E-14diii, E-15a, E-15c, E-15di, E-15dii, E-15diii, E-16a, E-16b, E-16c, E-16d, E-16e, E-16f, S-1, S-2, S-5, T-1)

##### **3.8.1 Information Provided by CTD**

CTD indicated that its team has experience in permitting 12 electric transmission line projects in Arizona and California in the last five years. CTD indicated that neither it nor its affiliates have received notices of violation of permit requirements in the last five years.

CTD indicated it would seek project approval from the CPUC and ACC.  
(QS-1, QS-4, P-1, P-6, P-8, P-9, P-10, E-1, E-2, E-3, E-4, E-5, E-6, E-7, E-8, E-9 a, E-9 b, E-9bi, E-9bii, E-9c, E-10, E-14a, E-14c, E-14di, E-14dii, E-14diii, E-15a, E-15c, E-15di, E-15dii, E-15diii, E-16a, E-16b, E-16c, E-16d, E-16e, E-16f, S-1, S-2, S-5, T-1)

##### **3.8.2 Information Provided by DCRT**

DCRT indicated that its team has experience in permitting six electric transmission line projects in Arizona and California in the last five years. DCRT indicated that neither it nor its affiliates have received notices of violation of permit requirements in the last five years.

DCRT indicated that, because the project is subject to review by multiple siting authorities and the California portion of the project lies primarily in Riverside County, Riverside County may have discretionary permitting authority over the portion of the project in California, and DCRT may seek siting approvals either from Riverside County or from the CPUC.

(QS-1, QS-4, P-1, P-6, P-8, P-9, P-10, E-1, E-2, E-3, E-4, E-5, E-6, E-7, E-8, E-9 a, E-9 b, E-9bi, E-9bii, E-9c, E-10, E-14a, E-14c, E-14di, E-14dii, E-14diii, E-15a, E-15c, E-15di, E-15dii, E-15diii, E-16a, E-16b, E-16c, E-16d, E-16e, E-16f, S-1, S-2, S-5, T-1)

### **3.8.3 Information Provided by DATC**

DATC indicated that its team has experience in permitting 29 electric transmission line projects in Arizona and California in the last five years. DATC indicated that neither it nor its affiliates have received notices of violation of permit requirements in the last five years.

DATC indicated that its associate Western DSW, as a federal agency, is exempt from seeking project approval from the CPUC and ACC.

(QS-1, QS-4, P-1, P-6, P-8, P-9, P-10, E-1, E-2, E-3, E-4, E-5, E-6, E-7, E-8, E-9 a, E-9 b, E-9bi, E-9bii, E-9c, E-10, E-14a, E-14c, E-14di, E-14dii, E-14diii, E-15a, E-15c, E-15di, E-15dii, E-15diii, E-16a, E-16b, E-16c, E-16d, E-16e, E-16f, S-1, S-2, S-5, T-1)

### **3.8.4 Information Provided by NEET West**

NEET West indicated that its team has experience in permitting 24 electric transmission line projects in Arizona and California in the last five years. NEET West indicated that neither it nor its affiliates have received notices of violation of permit requirements in the last five years.

NEET West indicated it would seek project approval from the CPUC and ACC.

(QS-1, QS-4, P-1, P-6, P-8, P-9, P-10, E-1, E-2, E-3, E-4, E-5, E-6, E-7, E-8, E-9 a, E-9 b, E-9bi, E-9bii, E-9c, E-10, E-14a, E-14c, E-14di, E-14dii, E-14diii, E-15a, E-15c, E-15di, E-15dii, E-15diii, E-16a, E-16b, E-16c, E-16d, E-16e, E-16f, S-1, S-2, S-5, T-1)

### **3.8.5 Information Provided by TC/SCE**

TC/SCE indicated that its team has experience in permitting 11 electric transmission line projects, including approximately 1050 miles of transmission line projects, in Arizona and California in the last five years. In the last five years, TC/SCE indicated that its collaborator SCE received a notice of violation of permit requirements with regard to fugitive dust, paid a fine of \$1,100 and remediated the issue to the satisfaction of the South Coast Air Quality Management District.

TC/SCE indicated it would seek project approval from the CPUC and ACC.

(QS-1, QS-4, P-1, P-6, P-8, P-9, P-10, E-1, E-2, E-3, E-4, E-5, E-6, E-7, E-8, E-9 a, E-9 b, E-9bi, E-9bii, E-9c, E-10, E-14a, E-14c, E-14di, E-14dii, E-14diii, E-15a, E-15c, E-15di, E-15dii, E-15diii, E-16a, E-16b, E-16c, E-16d, E-16e, E-16f, S-1, S-2, S-5, T-1)

## **Engineering Qualifications and Experience**

(Section 3 - General Project Information, QS-1, QS-4, P-1, P-6, S-2, S-3, S-4, S-6, S-7, S-8, S-9, S-10, T-2, T-3, T-4, T-6, T-7, T-8, T-9 (T items as appropriate to the proposed project))

### **3.8.6 Information Provided by CTD**

CTD indicated that it has not completed the design of any transmission line or substation projects as a developer, and CTD did not identify any internal staff with design experience. CTD indicated that an engineering firm would design the series compensation pursuant to an EPC contract with the series compensation equipment supplied and installed by the manufacturer and that the same firm would design the transmission line. CTD reserved its right to identify an alternative contractor (S-2, T-2).

CTD provided an extensive list of substation projects designed by its EPC contractor in the past five years. The list of projects included modifications to existing substations, including an addition to an existing 138 kV capacitor bank and work on two additional capacitor banks. The list included three minor projects in California, and no projects in Arizona (S-3). CTD provided resumes for key EPC firm personnel (S-2).

CTD provided a list of five transmission projects completed in the past five years for its affiliate LS Power, including one 500 kV project in Nevada and one in Arizona, one 230 kV project in California, and two other transmission line projects in the U.S. (P-1). CTD indicated that in the past five years LS Power has completed five substation projects that included a 500 kV project in Arizona, a 230 kV project in California, and three EHV projects in Texas. CTD indicated that one of these projects included a series compensation station that was designed by CTD's series capacitor EPC firm (P-1). CTD provided an extensive list of transmission line projects completed in the past five years by its design firm, including five 500 kV projects with two in California and none in Arizona (T-3).

CTD provided design criteria and identified a list of standards and requirements that it would use in the design of the project's series capacitors and transmission line. The design criteria did not include some CPUC General Order (GO) 95 specific design requirements that may influence transmission line design, such as anti-cascading. CTD indicated that it would design for CPUC GO 95 Grade B, no broken phase, except for Grade A at crossings.

CTD identified a route that provides a 250-foot corridor to meet the ISO Functional Specifications reliability criteria (S-6, S-7, S-8, S-9, S-10, T-6, T-7, T-8, T-9).

CTD indicated that LS Power has prior experience with its proposed transmission line and substation design firm (S-4, T-4).

CTD provided a list of California and Arizona specific permits, rules, and regulations that could affect the design of the transmission line and substation (E-1, E-6, C-5).

### **3.8.7 Information Provided by DCRT**

DCRT indicated that it has not completed the design of any transmission line or substation project as a developer, and DCRT did not identify any internal staff with design experience.

DCRT indicated that a major design firm would design the series capacitor substation (S-2) and provided an extensive list of substation projects, including seven high voltage series capacitor projects, that the design firm has completed in the U.S. and Arizona in the past five years (S-3). DCRT provided resumes for key DCRT and design firm personnel (S-2). DCRT identified substation projects that ATI has completed in the past five years, including five substations, one with series capacitors, in the U.S., California, and Arizona (P-1).

DCRT provided a list of transmission line projects that ATI has completed in the U.S. in the past five years, including one project in California, one in Arizona, and a list of transmission line projects that Abengoa has completed outside the U.S. (P-1).

DCRT indicated that it has retained a major engineering firm for the design of the transmission line (T-2) and provided a list of transmission line projects the design firm has completed in the past five years that included two 345 kV projects, but no transmission line projects in California or Arizona (T-3).

DCRT indicated that its substation design firm has experience with the design of 500 kV series capacitors and projects in Arizona (S-3). DCRT provided detailed design criteria and identified a list of standards and requirements that it would use in the design of the project's series capacitors and transmission line, including California, Arizona, and local requirements.

DCRT identified a 250-foot corridor separation to meet the ISO Functional Specifications reliability criteria (S-6, S-7, S-8, S-9, S-10, T-6, T-7, T-8, T-9). DCRT indicated that it does not have previous experience with its transmission line design firm (T-4), but that Abengoa does have previous experience with its substation design firm (S-4).

DCRT provided a list of California and Arizona specific permits, rules, and regulations that could affect the design of the transmission line and substation (E-1, E-6).

### **3.8.8 Information Provided by DATC**

DATC indicated that it has not completed the design of any transmission line or substation projects as a developer. DATC indicated that representatives from Duke Energy, ATC, Western DSW, and Citizens Energy would be responsible for the design of the project. DATC also indicated that Duke Energy and ATC have not completed the design of any transmission line projects in California or Arizona and have not completed the design of any substation projects in Arizona. DATC indicated that Western DSW's participation in the project would not include design of the substation or transmission line.

DATC indicated that it intends to provide the design of the series compensation by an experienced company through a turnkey contract held by DATC (S-2). DATC identified two firms for the design of the series capacitor substation (S-2) and provided a list of



their projects, including projects in Arizona (S-3), and indicated that it has worked with these firms in the past, but not on a project in Arizona (S-4).

DATC indicated that it has pre-approved contracts for transmission line design with three major firms that could design the transmission line portion of the project (T-2) and provided information on projects they have completed in the past five years, including EHV projects in California and Arizona (T-3), but did not identify past experience (T-4) with these firms. DATC provided a list of projects for its owner's engineer that will provide design oversight services, which included transmission line design projects in the U.S. (T-3).

DATC provided detailed design criteria and identified a list of standards and requirements that it would use in the design of the project's series capacitors and transmission line. The design criteria did not include some CPUC GO 95 specific design requirements that may influence transmission line design, such as anti-cascading.

DATC indicated that its corridor separation criteria would be less than 250 feet and that its team considers the adjacent DPV #1 line to meet the 30-year mean failure rate test to satisfy the ISO Functional Specifications corridor separation criteria. DATC proposed to have the ISO determine if the DATC separation criteria meet the ISO Functional Specifications. (S-6, S-7, S-8, S-9, S-10, T-6, T-7, T-8, T-9).

DATC provided a list of California and Arizona specific permits, rules, and regulations that could affect the design of the transmission line and substation (E-1, E-6).

### **3.8.9 Information Provided by NEET West**

NEET West indicated that it has not completed the design of any transmission line or substation projects as a developer but did identify internal staff with design experience.

NEET West provided a list of numerous substation projects that NextEra has completed in the past five years, including eight with series capacitors, two of which were EHV projects in Texas, and one of which was in Arizona. NEET West identified four design firms and provided a list of projects completed in the past five years that included projects with series capacitors and projects in Arizona (P-1, S-2, S-3).

NEET West identified transmission line projects completed in the past five years for NextEra that included seven transmission line projects, including three projects in California and EHV projects in Texas. NEET West identified an expansive list of transmission line projects completed in the past five years for four design firms that included 500 kV projects in both California and Arizona (P-1, T-2, T-3).

NEET West provided detailed design criteria and identified a list of standards and requirements that would be used in the design of the series capacitors and transmission line, including California, Arizona, and local requirements.

NEET West identified a 250-foot corridor separation to meet the ISO Functional Specifications reliability criteria (S-6, S-7, S-8, S-9, S-10, T-6, T-7, T-8, T-9).

### **3.8.10 Information Provided by TC/SCE**

TC/SCE indicated that it has not completed the design of a transmission line or substation project as a developer. TC/SCE indicated that BHT would be responsible for the overall engineering and design of the project and has not completed the engineering and design of any transmission line or substation projects in Arizona or California. TC/SCE identified internal staff for BHT who have experience with the development of transmission line and substation projects in the U.S., but not in California or Arizona.

TC/SCE indicated that it would contract with APS for the engineering and design of the series compensation facility, which it proposes to locate inside APS's Delaney Substation. TC/SCE identified key APS personnel with experience in the engineering and design of series capacitors in Arizona. TC/SCE also identified two potential firms for design and a firm for supply of series capacitors (S-2). TC/SCE provided a list of series capacitor projects completed in the past five years by the two potential design firms that included six series capacitor projects by one of the design firms, including 500 kV projects in Arizona, and three substation design projects for the second design firm (S-3).

TC/SCE identified a separate large engineering and design firm as responsible for detail design of the transmission line (T-2). TC/SCE provided a list of transmission line projects designed in the past five years or still under construction that were designed by its affiliate APS, including two 500 kV projects. TC/SCE indicated that APS's participation in the project would not include any aspect of the design of the transmission line. TC/SCE identified three projects designed by BHT for a subsidiary of BHE, which is not a participant in this project, and five projects designed by its transmission line engineering and design firm, including one 230 kV and one 500 kV project in California (T-3).

TC/SCE provided detailed design criteria and identified a list of standards and requirements that it would use in the design of the series capacitors and transmission line, including California, Arizona, and local requirements. TC/SCE indicated that BHT has prior experience with the firm responsible for the detail design of the transmission line (T-4) and that affiliate APS has prior experience with all of the substation design firms identified for series capacitors to be installed by APS (S-4).

TC/SCE identified a 250-foot corridor separation to meet the ISO Functional Specifications reliability criteria. (S-6, S-7, S-8, S-9, S-10, T-6, T-7, T-8, T-9)

### **3.8.11 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) the permitting experience for similar projects of the project sponsor's team member or members that have been designated as having responsibility for project

permitting, and (3) how much of the experience of the project sponsor and its team is in the U.S. and in Arizona and California.

The ISO considers environmental permitting experience in the U.S., Arizona, and California to be an advantage over experience in environmental permitting in other jurisdictions because the project will be located in Arizona and California and there are special aspects of environmental regulation and processes in the U.S., Arizona, and California for which experience is an advantage. U.S. and Arizona environmental permitting laws, rules, regulations, and processes are unique to the U.S. and Arizona, and the environmental permitting laws, rules, regulations, and processes are especially unique in the state of California. For example, the process in California to comply with the California Environmental Quality Act (CEQA) is particularly unique to the state of California.

All five project sponsors' teams have substantial experience permitting projects in the U.S. and in Arizona and California. CTD, NEET West, and TC/SCE plan to seek environmental permitting approvals from the CPUC and ACC. DATC's associate, Western DSW, is a federal agency not subject to CPUC or ACC environmental permitting authority. DCRT indicates that Riverside County may have discretionary permitting authority over the portion of the project in California, and it may seek siting approvals either from Riverside County or from the CPUC. As discussed above, the ISO has determined that there are no economic benefits to completing this project ahead of the latest in-service date of May 1, 2020 specified in the ISO Functional Specifications because other transmission projects must be completed in order for this project to yield economic benefits. In addition, the ISO has documented in the transmission plan containing this project that the benefits of the project are largest in the first year of operation and decrease over time. Consequently, realization of the maximum economic benefit of the project is sensitive to completing the project on time.

The ISO has determined that the one notice of violation received by TC/SCE's collaborator SCE for the release of fugitive dust beyond the property line of the emissions source was minor and not a significant issue in view of the number of transmission lines and substations SCE has developed, operated, and maintained over the past five years.

Based on the substantial and comparable environmental permitting experience of the project sponsors' teams, 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 the project sponsors with regard to this component of this factor. The firms retained by the project sponsors are all capable of completing the environmental permitting for the project.

## **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 and substation projects, including but not limited to (1) the engineering experience of the project sponsor for projects it has developed, (2) the engineering experience for similar projects of the project sponsor's team member or

members who have been designated as having responsibility for project engineering, and (3) how much of the experience of the project sponsor and its team is in the U.S. and in California and Arizona. The ISO considers experience in the U.S., Arizona, and California to be an advantage over substation and transmission line engineering and design experience in other countries because the project would be located in California and Arizona and there are special aspects of engineering and design codes and regulations in the U.S., Arizona, and California for which this experience is an advantage.

U.S. engineering and design codes and regulations are unique to the U.S., and Arizona and California engineering and design laws, rules, regulations, and processes are unique to the states of Arizona and California. These codes, regulations, laws, rules, and processes apply to both transmission lines and substations. For example, transmission lines and substation projects developed in the United States and Arizona 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 lines and substations in California includes adherence to requirements of the California Building Standards Commission, the California Energy Commission, the California Environmental Protection Agency, Cal-OSHA, California High Voltage Electrical Safety Orders, California Building Code Title 24, and county and city planning and permitting requirements. In Arizona, the process that must be followed for engineering and design of transmission lines and substations includes adherence to the requirements of the ACC, Arizona Department of Transportation, Arizona Department of Environmental Quality, Arizona Department of Agriculture, and county and city planning and permitting requirements. All five of the project sponsors provided information on the U.S., California, and Arizona specific rules, regulations, and laws that might affect the design of transmission lines and substations in California and Arizona.

**Experience of the project sponsor.**

None of the project sponsors, acting as developers, has completed the engineering or design of any substation or transmission line project.

**Experience of the project sponsor's team with the design of series capacitor substation projects.**

CTD, DCRT, DATC, NEET West, and TC/SCE affiliates and design firms have completed the engineering and design of substation projects, including series capacitors and EHV projects, in the U.S. and Arizona.

**Experience of the project sponsor's team with the design of transmission line projects.**

CTD, DATC, NEET West, and their affiliates and design firms have completed the engineering and design of transmission line projects in the U.S., California, and Arizona, including EHV projects. DCRT and TC/SCE and their affiliates and design firms have similar experience to that of CTD, DATC, and NEET West and their affiliates and design firms except that DCRT's design firm has limited experience with the design of EHV transmission lines and limited experience in California or Arizona, and TC/SCE's affiliate BHT, which is responsible for the overall engineering and design of the transmission

line, has not provided examples of engineering or design of a transmission line in California or Arizona.

**Experience with U.S. design codes and regulations and Arizona and California engineering and design laws, rules, and regulations.**

All of the project sponsors identified U.S. codes and regulations and California and Arizona specific laws, rules, and regulations and provided design criteria and industry design standards. However, the design criteria for CTD and DATC did not include certain CPUC GO 95 specific design requirements that influence transmission line design, such as anti-cascading.

**Overall Analysis**

With regard to its analysis of this component of the factor, the ISO first wants to point out that it considers the engineering and design contractors identified by the project sponsors as part of their teams to be qualified and fully capable of handling the engineering work associated with this project. As a result, the ISO's analysis identifies only the slightest of advantages for any project sponsor over any other with these engineering and design firms on its team.

Based on the experience of the teams of CTD, DATC, and NEET West in the design of transmission lines and substations, particularly EHV projects, and their experience in both California and Arizona, in conjunction with all the other considerations included in the ISO's analysis for this component of the factor, the ISO has determined that, for this particular component of the factor, there is no material difference among the proposals of CTD, DATC, and NEET West and that their proposals are slightly better than the proposals of DCRT and TC/SCE, between which there is no material difference, with regard to this component of the factor. The DCRT and TC/SCE teams have limited experience with the design of EHV transmission lines and limited EHV transmission line design experience in Arizona and California.

**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. Because the ISO has determined that there is no material difference among the proposals of the five project sponsors with regard to the first component of this factor (environmental permitting experience), the overall comparative analysis for this factor is based on the second component of the factor (engineering experience). As discussed above, the ISO has determined that there is no material difference among the proposals of CTD, DATC, and NEET West, and that they are slightly better than the proposals of DCRT and TC/SCE, between which there is no material difference, with regard to the second component of this factor. Consequently, the ISO has determined that there is no material difference among the proposals of CTD, DATC, and NEET West with regard to this factor overall, that their proposals are slightly better than the proposals of DCRT and TC/SCE, between which there is no material difference, with regard to 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.

#### **Construction Record**

(Section 3 - General Project Information, QS-1, QS-4, P-1, P-2, P-6, P-7, E-14a, E-14b, E-14c, E-14di, E-14dii, E-14diii, E-15a, E-15b, E-15c, E-15di, E-15dii, E-15diii, E-16a, E-16b, E-16c, E-16d, E-16e, E-16f, S-2,S-3, S-4,T-2,T-3,T-4)

#### **3.9.1 Information Provided by CTD**

CTD indicated that its transmission line construction firm has completed numerous projects in the past five years, none of which was in California or Arizona. (P-1, T-3)

CTD indicated that its substation construction firm has completed the construction of numerous substation projects in the past five years, including one series compensation station in Texas but no projects in Arizona. (P-1, S-2, S-3)

CTD provided a list of projects that LS Power has completed in the past five years, including transmission line projects in Nevada and Arizona and a 230 kV project in California and substation projects, one in Arizona and a 230 kV project in California. (P-1)

CTD indicated that LS Power has prior experience with the transmission line and substation construction firms. (P-1, S-4, T-4)

CTD provided a list of California and Arizona specific permits, rules, and regulations that could affect the design and construction of the transmission line and substation. (E-1, E-6, C-5)

#### **3.9.2 Information Provided by DCRT**

DCRT indicated that its transmission line construction firm has completed the construction of seven projects in the past five years, including projects in California and Arizona. (Section 3 – General Project Information)

DCRT indicated that its substation construction firm has completed the construction of numerous substation projects in the past five years, including projects in Arizona. (S-3)

DCRT indicated that Abengoa has prior experience with the substation construction firm and that the transmission line construction firm is ATI. (S-4)

DCRT provided a list of California and Arizona specific permits, rules, and regulations that could affect the design and construction of the transmission line and substation. (E-1, E-6, S-6, S-7, S-8, S-9, S-10, T-6, T-7, T-8, T-10)

### **3.9.3 Information Provided by DATC**

DATC provided information describing the experience of the firm that would provide transmission line construction services; the information included construction projects in the U.S. and California. DATC indicated that it has prior experience working with the firm that will provide construction services. (T-2, T-3, T-4)

DATC indicated that it intends to provide the construction of the series capacitor substation by an experienced company through a turnkey contract held by DATC. DATC identified two firms for the construction of the series capacitors, provided a list of previous projects, including projects in Arizona, and indicated that it has worked with them in the past. (S-2, S-3, S-4)

DATC identified a list of standards and requirements that it would use in the construction of the substation and transmission line, including California, Arizona, and local requirements. (E-1, E-6, S-6, S-7, S-8, S-9, S-10, T-6, T-7, T-8, T-10)

### **3.9.4 Information Provided by NEET West**

NEET West identified five firms for construction of the substation and four firms for the construction of the transmission line. (S-2, T-2)

NEET West provided a list of numerous projects that NextEra has completed in the past five years, including eight substation projects with series capacitors and several transmission line projects, including three projects in California. (S-3, T-3)

NEET West provided a list of substation projects for the five substation firms, including projects in Arizona, and a list of projects for the four firms for construction of the transmission line, including projects in both California and Arizona. (S-3, T-3)

NEET West indicated that NextEra has prior experience with all of the transmission line and substation construction firms that it identified. (T-4, S-4)

NEET West identified a list of standards and requirements that it would use in the construction of the substation and transmission line including California, Arizona, and local requirements. (E-6, S-6, S-7, S-8, S-9, S-10, T-6, T-7, T-8, T-10)

### **3.9.5 Information Provided by TC/SCE**

TC/SCE identified a construction firm for the transmission line that in the past five years has completed three projects in Arizona and two projects in Utah. (T-2) TC/SCE provided information on transmission line projects that APS has constructed or is constructing. TC/SCE indicated that APS's participation in the project does not include construction of the transmission line. (T-2, T-3)

TC/SCE identified three firms for construction of the series capacitors inside Delaney Substation and provided a list of 23 projects that they have completed in the past five years, including projects in Arizona. (S-2, S-3)

TC/SCE indicated that APS has prior experience with the substation and transmission line construction firms. (S-4, S-5)

TC/SCE identified a list of standards and requirements that it would use in the construction of the substation and transmission line, including California, Arizona, and local requirements. (E-6, S-6, S-7, S-8, S-9, S-10, T-6, T-7, T-8, T-10)

## **Maintenance Record**

(Section 3 - General Project Information, QS-1, QS-4, P-1, O-2, O-3, O-4, O-5, O-6, O-7, O-9, O-11, O-14)

### **3.9.6 Information Provided by CTD**

CTD stated that it has assembled a team of companies with local expertise in all areas of transmission development, including maintenance. The organization chart provided by CTD shows a specialty contractor to be responsible for construction and maintenance. (Sections 1 and 3 - General Project Information)

CTD stated that its specialty contractor has the necessary technical and engineering qualifications to undertake the maintenance of facilities for utilities all across the United States, including in the project area. (QS-1) CTD indicated that its affiliates are responsible for O&M of one longer EHV transmission line and several short ones and four substations. (P-1)

CTD indicated that the O&M director for its affiliate Cross Texas Transmission (Cross Texas) or someone with similar credentials would be responsible for O&M of the project. CTD also provided resumes for several key personnel of its proposed maintenance contractor, which indicated many years of experience with transmission projects up to 500 kV and included series capacitors. (O-2)

CTD stated that its affiliate Cross Texas operates and maintains 240 miles of 345 kV double circuit transmission lines, two 345 kV switching stations, and a 345 kV series compensation station and that its team members have additional experience managing operations for other transmission utilities. CTD stated that its proposed maintenance contractor has provided transmission and distribution services through master services agreements with utility clients nationwide for repair, construction, and maintenance of systems and that it would provide maintenance services through its Phoenix, Arizona operating group. (O-3) CTD stated that its maintenance contractor and LS Power have established programs and experience for recruiting and training maintenance personnel. (O-4, O-5)

CTD stated that LS Power has experienced personnel as well as policies and procedures that would ensure compliance with the ISO's maintenance standards. (O-6, O-7) CTD stated that Cross Texas submits transmission availability data system (TADS) reports to the North American Electric Reliability Corporation (NERC) and that, although having only a relatively short history, Cross Texas has had excellent reliability



performance, with no material outages. (O-9) CTD stated that Cross Texas is registered with NERC as a Transmission Planner, a Transmission Owner, and a Transmission Operator. (O-11) CTD stated that it does not currently own, operate, or maintain any transmission facilities but indicated that its affiliates have facilities subject to NERC compliance with good compliance records. (O-14)

### **3.9.7 Information Provided by DCRT**

DCRT stated that it has entered into an agreement with Valley Electric Association, Inc. (VEA). DCRT stated that VEA is a PTO with the ISO, has executed the TCA with the ISO, and is registered with NERC and the Western Electricity Coordinating Council (WECC) as a Transmission Operator. DCRT stated that VEA would perform operation and maintenance and NERC compliance for the project. (Section 3 - General Project Information) (QS-1)

DCRT stated that Abengoa, as part of its team, operates and maintains thousands of miles of transmission lines around the world, including more than 5,000 kilometers of high voltage lines in Brazil. DCRT stated that personnel from Abengoa's subsidiary ASI Operation, LLC, a company that serves as the operations and maintenance company for the 250 MW Solana power plant (Solana project), a solar generating facility, is registered with WECC and NERC and would interact with VEA for O&M and NERC compliance needs for the line. DCRT stated that ASI Operation, LLC already operates the Solana project's 20-mile 230 kV generation tie-line in Arizona. (QS-4) DCRT stated that Abengoa does not operate or maintain any lines in the U.S. and that Starwood Energy operates but does not maintain 500 kV lines in New Jersey, New York, California, Nevada, and Arizona totaling over 500 miles. DCRT did not identify any projects operated and maintained by VEA. (P-1)

DCRT provided resumes for VEA and Abengoa personnel. The information provided indicated that the person who would be responsible for field operation, maintenance, inspection, and emergency response has been in the position since 2014 and has eight years of utility experience. DCRT stated that the line superintendent has 30 years' experience. DCRT indicated that the Abengoa O&M transmissions lines general director has 36 years of utility experience and is currently responsible for O&M of 10 power line concessions totaling 5,000 kilometers of power lines, 20 substations, and 130 employees. (O-2)

DCRT stated that its O&M contractor, VEA, currently has a transmission maintenance agreement with the ISO, which would be expanded to include this project. DCRT indicated that this current program covers inspection and maintenance of VEA's 164 miles of 230 kV and 191 miles of 138 kV transmission lines. DCRT indicated that VEA does not currently operate or maintain series capacitors within its bulk electric system. DCRT stated that VEA intends to contract with the series capacitors manufacturer for anything other than first response troubleshooting and routine maintenance. (O-3) DCRT stated that VEA and Abengoa have established programs and experience for recruiting and training maintenance personnel. (O-4, O-5)

DCRT indicated that VEA is a PTO with the ISO and has executed the TCA with the ISO and that VEA has an ISO-approved transmission line maintenance plan and vegetation management plan, which it would apply to this project. (O-6, O-7) DCRT stated that VEA collects data and reports on availability measures annually to the ISO as required

under the TCA. (O-9) DCRT stated that Abengoa would contract with VEA to perform NERC functions. DCRT indicated that VEA is currently registered with NERC as a Distribution Provider, Load Serving Entity, Purchasing-Selling Entity, Transmission Owner, and Transmission Operator. (O-11) DCRT stated that VEA's NERC Transmission Operator registration began on January 2013 and that it has performed an internal self-audit and certification in 2014 and self-reported minor violations. DCRT indicated that Abengoa also has experience registering and complying with NERC reliability standards through its affiliate, Arizona Solar One, LLC (for the Solana project). (O-14)

### **3.9.8 Information Provided by DATC**

DATC stated that DATC and Western DSW would enter into definitive agreements governing project development, construction, and operation. DATC stated that Western DSW expects to use a combination of its in-house staff headquartered in Phoenix, Arizona, and contractors, utilizing the same practices and procedures in use to maintain its current transmission system. (Section 3 - General Project Information) DATC stated that Western Area Power Administration currently operates more than 17,000 miles of transmission in the western United States. DATC stated that the project would be geographically located in Western DSW's service territory, where Western DSW has existing operations, experience, and knowledge. (QS-1)

DATC stated that Western Area Power Administration brings experience and expertise from designing, constructing, and maintaining more than 17,000 miles of transmission, including 500 kV transmission currently under the operational control of the ISO. DATC stated that Western DSW has an established maintenance organization with 500 kV capabilities as well as the ability to draw on Western Area Power Administration's larger organizational capabilities. DATC stated that Duke Energy, ATC, and Western DSW would be able to share best practices and that since DATC's purchase of the Path 15 upgrade transmission facilities, DATC's maintenance representatives have collaborated with Western Area Power Administration personnel to share best practices in the maintenance of high-voltage facilities. (QS-4) DATC listed projects for which its team members have been responsible, but the list of projects does not appear to include all lines and series capacitor banks operated and maintained by Western DSW in the past five years. (P-1)

DATC stated that Western DSW is the operations manager of the Mead-Phoenix Project and is responsible for all operation and maintenance from Perkins Substation through Mead Substation and on to Marketplace Substation. DATC indicated that Western DSW has performed these responsibilities for the Mead-Phoenix Project for approximately the last 20 years. DATC stated that Western DSW personnel are employees of the federal government and, in accordance with federal employment policies, it is unable to provide resumes of these federal employees. DATC stated that Western DSW personnel are qualified and have sufficient experience to perform their assigned duties. DATC stated that the ISO could rely on the fact that it would be a violation of federal law to employ personnel not qualified for a specific position. DATC stated further that Western DSW personnel also maintain elements that are part of the ISO system. (O-2)

DATC stated that Western DSW would maintain the facilities for the project and that other DATC team members would be involved in management and maintenance oversight, including the sharing of best practices. DATC stated that its O&M contractor

Western DSW has been a transmission owner and operator since 1978. DATC stated that Western DSW operates and maintains more than 1,700 miles of lines in Arizona, southern California, and southern Nevada. DATC stated that Western DSW has operated and maintained series capacitors for more than 45 years as part of the Western DSW system. (O-3) DATC stated that Western Area Power Administration fills all positions through policies and processes established by the U.S. Office of Personnel Management and that Western Area Power Administration's practice is to fill positions with journeymen. DATC indicated that Western Area Power Administration has craft in training/apprenticeship programs to develop less experienced personnel when appropriate. (O-4) DATC stated that Western DSW trains to the journeyman level and has required annual training for all apprentices and journeymen. (O-5)

DATC indicated that Western DSW utilizes a Maximo asset database to document the interval and maintenance records, including required scheduling dates (due dates) for maintenance, in order to maintain required compliance with the NERC standards. DATC stated that Western DSW's maintenance standards include the elements listed in the TCA. (O-6) DATC stated that Western DSW has established a "WAPA Order," which covers transmission vegetation management. DATC indicated that in October of 2014 a WECC on-site audit found Western DSW to be compliant with NERC standard FAC-003. (O-7) DATC indicated that Western Area Power Administration has a proven success rate of limiting accountable outages with only 16 accountable outages across Western Area Power Administration's fifteen state area identified in Western Area Power Administration's 2012 annual report. DATC indicated that to monitor the availability of the project, Western DSW would use industry standard monitoring and communications equipment and that availability would be monitored by the ISO and by Western DSW's control center. (O-9) DATC stated that Western DSW is registered with NERC as a Balancing Authority, Load Serving Entity, Purchasing-Selling Entity, Transmission Owner, Transmission Operator, Transmission Planner, Transmission Service Provider, and Planning Authority. (O-11) DATC indicated that Western DSW would be the responsible DATC team member for all applicable reliability standards. The report of Western DSW compliance with NERC reliability standards referenced by DATC indicated only one possible violation for the period October 24, 2008 to October 14, 2011. DATC listed its team members' transmission facilities that are subject to NERC compliance, but the list does not appear to include all lines and series capacitor banks operated and maintained by Western DSW in the past five years. (O-14)

### **3.9.9 Information Provided by NEET West**

NEET West stated that it would draw from a wide range of corporate support services. NEET West stated that through this model FPL, NEER, and NEET employ experienced operation and support service personnel that would be available to assist NEET West. NEET West stated that its construction and O&M teams have already developed a successful model working with APS and SCE, which would be beneficial to the project. (Introduction - General Project Information) NEET West stated that it would operate the project and would draw from NextEra's existing pool of high-voltage technicians and existing field support resources already located in California and Arizona to support existing NEER power generation and transmission assets. NEET West stated that these personnel would be responsible for providing 24/7 on-call response, site switching and safety, routine inspection and maintenance, and general site care duties. NEET West stated that it has an extensive operations and maintenance team at NextEra and that NEET West would leverage both internal and contractor resources for the safe, reliable,

and efficient operation and maintenance of the project. NEET West stated that it has experience with owning, operating, and maintaining reactive power support equipment and their associated control systems, including 3,400 MVAR of series compensation. (QS-1)

NEET West indicated that key individuals who would be involved in the project include professionals who have collaborated in the development, design, construction, and operation of numerous prior transmission, substation, and other major infrastructure projects. (QS-4) NEET West provided a list of 31 transmission line projects and 53 substation projects that NextEra affiliates have completed in the past five years. None was a 500 kV line and two were 500 kV substations. NEET West indicated that its affiliates were responsible for operation and maintenance of nearly all of the projects it listed. (P-1)

NEET West stated that its proposed operations lead is currently director of operations at NEET and as such is responsible for directing the safe, reliable, and cost-effective operations of NEET assets across North America to ensure operational excellence via the comprehensive application of processes, procedures, and standards for transmission operations. NEET West indicated that its proposed operations lead has responsibility for control center operations, as well as for transmission line and substation field asset operations, installation, and maintenance for current NEET assets, such as those of New Hampshire Transmission, LLC in New England and Lone Star Transmission, LLC (Lone Star Transmission) in Texas. NEET West stated that the NEET technical support manager is responsible for providing operations and maintenance technical support for the five Lone Star Transmission substations, including four 345 kV series capacitor units and associated transmission assets and New Hampshire Transmission assets. (O-2)

NEET West stated that the NEER director of operations has direct operations and maintenance responsibility for existing transmission assets and that he also has direct maintenance responsibility for many wind generation facilities. (O-3) NEET West stated that it would follow NextEra's established programs and experience for recruiting and training maintenance personnel. (O-4, O-5)

NEET West stated that 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's transmission maintenance standards. NEET West indicated that this capability is supported by NextEra O&M team members' past experience with the TCA requirements and ISO transmission maintenance standards. (O-6) NEET West stated that the NextEra transmission vegetation management program meets all NERC compliance requirements and that NextEra has constructed, operated, and maintained 150 miles of transmission facilities in California. (O-7) NEET West indicated that NextEra continuously logs the availability of its major transmission elements. (O-9) NEET West stated that it would register as a Transmission Owner, Transmission Operator and/or Transmission Planner with NERC as applicable based on NERC's reliability functional model and WECC's entity registration requirements. (O-11) NEET West stated that NextEra and its affiliates operate in all eight NERC regions and that NextEra affiliates are registered for all NERC functions. NEET West indicated that the majority of NextEra's potential violations have been the result of self-reports submitted to the applicable regional entities. NEET West summarized the transmission and substation facilities owned by NextEra that are subject to NERC compliance in each NERC region. The summary indicated that NextEra has 7,918 miles of transmission

lines 138 kV and above subject to NERC compliance, 6,647 miles of which are in NERC's Florida Regional Reliability Coordinator region. (O-14)

### **3.9.10 Information Provided by TC/SCE**

TC/SCE indicated that APS would have lead responsibility for operation of the project and that TransCanyon would have an oversight role. TC/SCE stated that, given the proximity of the project to the existing service territory of APS, TC/SCE believes there is a natural synergy in retaining APS to provide line operations and maintenance services. (Section 3 - General Project Information) TC/SCE stated that TransCanyon has contracted with APS to provide operations and maintenance services, including vegetation management, for the project. TC/SCE stated that APS currently operates and maintains more than 5,000 miles of transmission/sub-transmission lines and serves as path operator for five WECC-rated paths spanning the Southwest region. TC/SCE stated that as an interconnecting neighbor system with the ISO, APS has extensive experience coordinating operations with the ISO. TC/SCE stated that TransCanyon and APS have executed an agreement for operation and maintenance of a transmission line that, among other topics addressed, sets forth APS's responsibility to provide maintenance on the series capacitor bank located within Delaney Substation. (QS-1)

TC/SCE stated that APS has recently added operators, which increases the company's capacity for switching and situational awareness, and has planned for future expansion of responsibilities, including support of TC/SCE and the project. (QS-4) TC/SCE listed transmission lines rated at 230 kV or higher totaling 2,906 miles (completed/under construction: 1,399 miles / planned: 1,507 miles) and indicated that the project team responsibilities for those lines include operation and maintenance. TC/SCE listed more than a dozen substation projects with facilities rated 230 kV and higher for which the team has operation and maintenance responsibility. TC/SCE stated four of APS's substation projects listed contain series capacitors and that two BHT projects listed contain series capacitors. TC/SCE stated that its collaborator SCE owns and operates 18 500 kV series capacitors within its transmission system. (P-1)

TC/SCE described the roles and responsibilities of the APS O&M team members and indicated that they have many years of experience. (O-2) TC/SCE stated that APS has extensive experience operating and maintaining a large and complex transmission system, that the company has served Arizona for 124 years, and that it has operated EHV transmission lines since the early 1960s. (O-3) TC/SCE stated that all grid operators at APS hold current NERC reliability coordinator certifications, which NERC has granted based on its comprehensive knowledge assessments of these personnel. TC/SCE indicated that field personnel at APS are qualified journeymen linemen or electricians and are required to complete a comprehensive, state-sanctioned apprentice program, as well as on-going annual training to retain their journeyman skill set. (O-4) TC/SCE stated that APS's operations training has received approved provider status from NERC. TC/SCE described APS's apprenticeship programs for linemen and electricians. (O-5)

TC/SCE stated that APS's maintenance standards meet or exceed the maintenance standards described in Appendix C of the TCA. TC/SCE indicated that APS has extensive experience in installing and maintaining series capacitor banks, that most of APS's 345 kV and 500 kV lines are equipped with series capacitors, and that APS has been installing or replacing an average of one series capacitor bank each year over last

10 years. (O-6) TC/SCE provided the most recent update of the APS transmission vegetation management plan and indicated that this document provides a roadmap describing how APS's forestry and special programs department meets the current NERC vegetation standard FAC-003-3 (NERC, 2013). (O-7) TC/SCE stated that APS is familiar with control chart methodology described in the TCA and has monitored availability performance of its 500 kV and 345 kV transmission lines using this process for more than 10 years in the past. (O-9) TC/SCE stated that TransCanyon intends to register with NERC for the Transmission Owner and Transmission Operator functions and would in turn contract with APS to perform these NERC Transmission Owner and Transmission Operator functions. TC/SCE indicated that APS is currently registered with NERC and has the capabilities to serve as a Balancing Authority, Distribution Provider, Generator Operator, Generator Owner, Load-Serving Entity, Planning Authority, Purchasing-Selling Entity, Resource Planner, Transmission Operator, Transmission Owner, Transmission Planner, and Transmission Service Provider. (O-11) TC/SCE stated that NERC last audited APS in 2013 and that it found no operations or planning violations. TC/SCE stated that APS has not had any non-compliance findings since that audit. TC/SCE stated that APS operates and maintains 2,810 miles of transmission lines that are subject to NERC compliance, including 1,302 miles of 500 kV transmission and 578 miles of 345 kV transmission. (O-14)

### **3.9.11 ISO Comparative Analysis**

#### **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 construction of transmission facilities and how much of the experience of the project sponsor and its team is in the U.S. and in Arizona and California. The ISO considers experience in the U.S., Arizona, and California to be an advantage over experience in other countries because the project would be located in California and Arizona and there are special aspects of engineering and design codes and regulations in the U.S., Arizona, and California for which this experience is an advantage.

U.S. construction codes and regulations are unique to the U.S., and Arizona and California laws, rules, regulations, and processes are unique to those states. For example, U.S. laws, rules, regulations, and processes applicable to construction of transmission lines and substations include federal OSHA, NEPA, Storm Water Pollution Prevention Plan, and USFWS requirements, Fair Labor Standards Act regulations, and National Electric Code standards. Also, transmission line and substation projects developed in the United States and Arizona must adhere to the National Electrical Safety Code (NESC) published by the Institute of Electrical and Electronics Engineers (IEEE), and transmission line projects developed in California must adhere to CPUC GO 95. In addition, the process that must be used in California includes adherence to requirements of the California Building Standards Commission, the California Energy Commission, the California Environmental Protection Agency, Cal-OSHA, California High Voltage Electrical Safety Orders, California Building Code Title 24, the California Air Resources Board, the California Office of Historic Preservation, Title 22 regarding hazardous waste, and county and city planning and permitting requirements. In Arizona, the process that must be followed for transmission lines and substations includes adherence to the requirements of the ACC, Arizona Department of Transportation, Arizona Department of Environmental Quality, Arizona Department of Agriculture, and county and city planning

and permitting requirements. All of the project sponsors provided information on the California and Arizona specific rules, regulations, and laws that might affect the construction of transmission lines and substations in California and Arizona.

Based on the extensive experience of all five project sponsors' teams in the construction of transmission line projects in California and Arizona and substation projects, including projects in Arizona, and their prior experience working with their potential construction firms, 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 CTD, DCRT, DATC, NEET West, and TC/SCE with regard to this component of the factor.

## **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.

All five project sponsors have established records and experience regarding maintenance of transmission facilities in compliance with NERC standards. However the amount of experience varies among the project sponsors' teams. The TC/SCE team has the greatest amount of experience maintaining similar facilities in the vicinity of the proposed project location. DATC's team also has experience maintaining similar facilities in the area but not as much as the TC/SCE team. NEET West's team has experience with a large number of similar facilities but most are outside of the WECC region. CTD's proposed team has some experience with facilities similar to those of the proposed project, but such experience is less than that of the teams of DATC and NEET West. DCRT's affiliates have significant experience with similar facilities; however, that experience is mostly international. DCRT's proposed contractor has less experience with similar facilities.

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 TC/SCE's proposal is better than the proposals of the other four project sponsors with regard to this component of the factor and that there is no material difference between the proposals of DATC and NEET West and that their proposals are slightly better than those of CTD and DCRT, between which there is no material difference, with regard to 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. Because the ISO has determined that there is no material difference among the proposals of the five project sponsors with regard to the first component of this factor (construction record), the overall comparative analysis for this factor is based on the second component of the factor (maintenance record). As discussed above, the ISO has determined that TC/SCE's proposal is better than the proposals of the other four project sponsors with regard to the second component of the factor and that there is no material difference between the proposals of DATC and NEET

West and that their proposals are slightly better than those of CTD and DCRT, between which there is no material difference, with regard to the second component of the factor. Consequently, the ISO has determined that TC/SCE's proposal is better than the proposals of the other four project sponsors with regard to this factor overall and that there is no material difference between the proposals of DATC and NEET West and that their proposals are slightly better than those of CTD and DCRT, between which there is no material difference, with regard to 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.

#### **Construction Practices**

(Section 3 - General Project Information, QS-1, QS-4, P-1, E-16a, E-16b, E-16c, E-16d, E-16e, E-16f, S-3, S-7, T-3, T-6, C-1, C-2, C-3, C-4, C-5, C-6, C-7)

##### **3.10.1 Information Provided by CTD**

CTD provided detailed design criteria (S-7, T-6), indicated that it would have a comprehensive team of field inspectors to ensure quality of every phase of construction (C-1), indicated that material yards, receiving, and management would be performed by the construction contractor (C-2), and indicated that transmission lines to be crossed would be done under clearances (C-3). CTD indicated that its constructability review would involve design engineers, engineers with experience in transmission line construction, and construction contractors (C-4) and stated its commitment to ensure compliance with all requirements (C-5). CTD indicated that it would have a detailed project schedule and would maintain a three-week look-ahead schedule.

CTD did not identify any clearance requirements (C-6).

CTD indicated that it has recent experience with guyed structures, including development of several innovative construction methods, and indicated the possible use of helicopters (C-7).

##### **3.10.2 Information Provided by DCRT**

DCRT provided detailed design criteria (S-7, T-6), indicated that it would perform testing of equipment, and provided a copy of its procedure for inspection during construction (C-1).



DCRT indicated that it would install a store yard and enclosed storage units for materials and that incoming material would be inspected on receipt, logged into a database, and dispatched to the field as needed (C-2).

DCRT described the process to obtain clearances from the ISO (C-3) and identified a constructability plan that identifies obstacles and potential risks during pre-construction (C-4). DCRT identified compliance with rights-of-way easements, mitigation measures, and permits (C-5).

DCRT indicated that it would implement a method of detailed scheduling that would ensure that all project activities are coordinated and managed according to their critical path dependencies (C-6) and that it may need to utilize special construction techniques, including helicopters and dust control. (C-7)

### **3.10.3 Information Provided by DATC**

DATC provided detailed design criteria (S-6, T-7), would have a physical presence on the construction site by placing a construction inspector with each construction crew (C-1), indicated that a material yard would be centrally located, and described the duties of a logistics manager who would be responsible for all material management activities (C-2).

DATC identified four transmission crossings that would require clearances, described its process for obtaining clearances (C-3), and indicated that it would establish a team for an ongoing constructability review of construction plans, design, and specifications ((C-4).

DATC indicated that its project team would secure the necessary permits to construct the project and would develop a real estate record for identifying land ownership rights (C-5).

DATC indicated that it would develop three-day, three-week, and ninety-day look-ahead schedules and generate reports to track progress and identified methods to maintain schedule (C-6).

DATC indicated that it does not anticipate any unique or special construction techniques except where DATC's route is located in extremely rough terrain north of the DPV #1 line in Copper Bottom Pass, where DATC indicated that helicopter erection of structures, landing pads, and special foundations would be required (C-7).

### **3.10.4 Information Provided by NEET West**

NEET West provided detailed design criteria (S-6, T-7) and indicated that its construction management and inspection team would be active through all phases of construction and that quality assurance/quality control personnel have extensive experience in proper construction methods (C-1).

NEET West proposed one large (50 acres) material yard and 26 (10 acres each) staging yards (C-2).

NEET West also identified the transmission lines that would be crossed, identified a process to work with the line owners to develop schedule, work procedures, and durations (C-3), and indicated that it would schedule several constructability reviews with the design engineers and contractors for both the transmission line and series compensation station (C-4).

NEET West indicated that it would develop a consolidated environmental compliance matrix to provide a comprehensive list of all permitting requirements, conditions, and mitigation measures (C-5).

NEET West indicated that it would develop a detailed project schedule and that it would hold weekly schedule meetings and provided a list of actions that it would take to maintain schedule (C-6).

NEET West indicated that special construction techniques may be required, including, but not limited to, blasting, micropile systems, implosive sleeves for conductor splicing, and helicopter construction (C-7).

### **3.10.5 Information Provided by TC/SCE**

TC/SCE provided detailed design criteria (S-6, T-7) and indicated that inspectors would be onsite and available to inspect any ongoing aspect of construction (C-1). TC/SCE indicated that an environmental scientist would oversee the environmental inspection process; however, the scientist identified by TC/SCE is an employee of TC/SCE's proposed construction contractor (C-1).

TC/SCE proposed three material yards of about 30 acres each (C-2), identified transmission line crossings, and indicated that a total of twelve one-day clearances may be required for the crossings of the DPV #1 line (C-3).

TC/SCE indicated that its constructability review would include review of engineering drawings and construction specifications. TC/SCE indicated that it would also have constructability review of the series compensation being installed inside Delaney Substation (C-4).

TC/SCE provided a management plan for key elements of the easement, permitting, and mitigation processes (C-5).

TC/SCE indicated that its approach to scheduling would incorporate inputs based on the project scope, environmental restrictions, seasonal restrictions, and permitting requirements and that it would submit weekly progress reports (C-6).

TC/SCE indicated that it might use screw or helical pile foundations and helicopter aided constructed as needed, and would use helicopters for pulling sock line (C-7).

## **Maintenance Practices**

(Section 3 - General Project Information, QS-1, QS-4, P-1, O-1, O-2, O-3, O-4, O-5, O-6, O-7, O-8, O-9, O-10, O-11, O-12, O-13, O-14, O-17, O-19)

### **3.10.6 Information Provided by CTD**

CTD stated that although it would be a new PTO with the ISO, LS Power is not a new entrant in transmission but is an incumbent transmission service provider in the ERCOT system. (QS-1) CTD stated that Cross Texas has the necessary technical and engineering qualifications to undertake the operations of its facilities and that its specialty contractor has the necessary technical and engineering qualifications to undertake the maintenance of facilities for utilities all across the United States, including in the project area. (QS-4) CTD indicated that its affiliates are responsible for O&M of one longer EHV transmission line and several short ones and four substations. (P-1)

CTD indicated that it would hire a limited number of employees who would reside locally to maintain the system with the support of the maintenance provider. CTD stated that its local office would be in the project area west of Phoenix, Arizona and that its proposed maintenance provider has an existing office in Phoenix, Arizona. CTD stated that the maintenance organization and field staff would be responsible for all field activities, including line and series compensation inspection, patrols, vegetation management, materials and inventory management, field services, field switching, and emergency response. (O-1) CTD indicated that its proposed director of operations and maintenance is currently responsible for operation and maintenance of the Cross Texas Transmission project, a 240-mile 345 kV double circuit transmission line. CTD indicated that the Cross Texas O&M director or someone with similar credentials would be responsible for O&M of the project. (O-2) CTD stated that its proposed maintenance contractor has provided transmission and distribution services through master services agreements with utility clients nationwide for repair, construction, and maintenance of systems and that it would provide maintenance services through its Phoenix, Arizona operating group. (O-3) CTD stated that its maintenance contractor and LS Power have programs and experience for recruiting and training maintenance personnel. (O-4, O-5)

CTD stated that its maintenance program would include the elements in the TCA related to transmission line and station maintenance requirements. CTD indicated that LS Power utilizes a Maximo asset management system. (O-6, O-7) To demonstrate compliance with its maintenance standards, CTD provided sample inspection, maintenance, and operations reports from Cross Texas but no independent audit reports. (O-8) To demonstrate its capability and experience that would enable it to provide availability measures required by the TCA, CTD stated that Cross Texas submits transmission availability data system (TADS) reports to NERC. (O-9) CTD identified no substantive changes needed to the TCA. (O-10)

CTD stated that it would register with NERC as a Transmission Owner. CTD indicated that it plans to contract for services to provide transmission operations with Cross Texas. CTD stated that Cross Texas is registered with NERC as a Transmission Planner, a Transmission Owner, and a Transmission Operator. (O-11, O-12) CTD stated that it would develop policies and procedures that would ensure it is compliant with the applicable reliability standards and that its compliance manager would have an independent line of reporting to the general manager. CTD stated that it would not require any waivers under TCA Section 5.1.6. (O-13) CTD stated that it does not

currently own, operate, or maintain any transmission facilities but indicated that its affiliates have facilities subject to NERC compliance with good compliance records. (O-14)

CTD indicated that all outage data would be tracked and maintained by operators on staff in a secure, archived data storage file. (O-17) CTD stated that it would maintain critical spare parts and materials required to repair system facilities. CTD stated that for the series compensation equipment, a long-term service agreement with the vendor might be the most efficient way to ensure prompt repair. (O-19)

### **3.10.7 Information Provided by DCRT**

DCRT stated that it has entered into an agreement with VEA. DCRT stated that VEA is a PTO with the ISO, has executed the TCA with the ISO, and is registered with NERC and WECC as a Transmission Operator. (Section 3 - General Project Information) DCRT stated that it would contract with VEA, which has extensive experience in O&M in the region. (QS-1, QS-4) DCRT stated that Abengoa does not operate or maintain any lines in the U.S. and that Starwood Energy operates but does not maintain 500 kV lines in New Jersey, New York, California, Nevada, and Arizona totaling over 500 miles. DCRT did not identify projects operated and maintained by VEA. (P-1)

DCRT indicated that VEA would provide and be responsible for all O&M and NERC services for the line. DCRT indicated that the equipment supplier would be under contract to provide the commissioning, troubleshooting, repair, and maintenance on its power electronics equipment associated with the series compensation under the direction of Abengoa and VEA. DCRT stated that existing Abengoa personnel are trained and certified in transmission O&M and NERC compliance needs and that these personnel would interface with VEA. (O-1) DCRT stated that Abengoa specializes in operation and maintenance of transmission lines ranging from high to extra high voltages and that it operates and maintains several lines around the world, including Brazil where it maintains more than 5,000 kilometers of high to extra high voltage lines. DCRT stated that its O&M contractor, VEA, currently has a transmission maintenance agreement with the ISO, which would be expanded to include this project. (O-3) DCRT stated that VEA and Abengoa have established programs and experience for recruiting and training maintenance personnel. (O 4, O 5)

DCRT indicated that VEA has an ISO-approved transmission line maintenance plan and vegetation management plan. (O-6, O-7) DCRT provided a copy of its 2014 ISO standard maintenance reporting system planning document, which has a section on overhead line vegetation/right of way maintenance and the corresponding corrective actions. (O-8) DCRT stated that VEA collects data and reports on availability measures annually to the ISO as required under the TCA. (O-9) DCRT stated that Abengoa and VEA are not aware of any required changes or exceptions to the provisions of the TCA if DCRT were to add this project to the ISO controlled grid. (O-10)

DCRT stated that Abengoa would contract with VEA to perform NERC functions. DCRT indicated that VEA is currently registered with NERC as a Distribution Provider, Load Serving Entity, Purchasing-Selling Entity, Transmission Owner, and Transmission Operator. (O-11) DCRT stated that Abengoa's compliance coordinator reporting to the O&M manager would ensure functions contracted to VEA would be accomplished. DCRT stated that it has on staff personnel who have experience with NERC compliance

who would closely monitor and coordinate VEA's performance. (O-12) DCRT described VEA's processes and procedures for assuring compliance with NERC standards. DCRT did not identify any applicable reliability criteria for which transmission owners are responsible that would require temporary waivers under TCA Section 5.1.6. (O-13) DCRT stated that VEA's NERC Transmission Operator registration began on January 2013 and that it performed an internal self-audit and certification in 2014 and self-reported minor violations. DCRT indicated that Abengoa also has experience registering and complying with NERC reliability standards through Abengoa's affiliate, Arizona Solar One, LLC (for the Solana project). (O-14)

DCRT stated that VEA has existing reliable data acquisition facilities for its bulk electric facilities as well as contract facilities at the Nevada National Security Site. DCRT indicated that VEA's manager of engineering would provide annual availability reports to the ISO in accordance with the TCA. (O-17) DCRT stated that Abengoa would have spare tower structures available for use to repair the proposed line, along with additional replacement parts deemed prudent. DCRT stated that it has considered spare parts in its proposal and that it would have in stock near the project substation spare parts such as motors, coils for circuit breakers and disconnect switches, capacitors, and control parts, all to minimize the outage time in the case where they become needed. DCRT stated that the recommended spare parts would be available in quantities to support the series capacitor. DCRT stated that, during the recommended scheduled maintenance intervention, its personnel would be able to identify parts that would need to be replaced at the next planned outage and would validate their availability prior to the planned outage. (O-19)

### **3.10.8 Information Provided by DATC**

DATC stated that Western DSW would permit, obtain rights-of-way, and maintain the project. DATC stated that Western Area Power Administration is a federal power marketing agency within the United States Department of Energy, established in 1977 and that Western Area Power Administration currently operates more than 17,000 miles of transmission in the western United States. DATC stated that for maintenance of the project Western DSW expects to use a combination of its in-house staff headquartered in Phoenix, Arizona, and contractors, utilizing the same practices and procedures in use to maintain its current transmission system. (Section 3 - General Project Information) DATC stated that the project is geographically located in Western DSW's service territory, where Western DSW has existing operations, experience, and knowledge. (QS-1) DATC stated that Western DSW has an established maintenance organization with 500 kV capabilities, as well as the ability to draw on Western Area Power Administration's larger organizational capabilities. DATC stated that Duke Energy, ATC, and Western DSW would be able to share best practices and that, since DATC's purchase of the Path 15 upgrade transmission facilities, DATC's maintenance representatives have collaborated with Western Area Power Administration personnel to share best practices in the maintenance of high-voltage facilities. (QS-4) DATC listed projects for which its team members have been responsible, but the list of projects does not appear to include all lines and series capacitor banks operated and maintained by Western DSW in the past five years. (P-1)

DATC provided organization charts for Western DSW's maintenance division. DATC stated that Western DSW would maintain this project and that Western DSW's senior managers are the reliability standard owners who would be assigned the responsibility

for ensuring the compliance program work. (O-1) DATC stated that Western DSW is the operations manager of the Mead-Phoenix Project and is responsible for all operation and maintenance from Perkins Substation through Mead Substation and on to Marketplace Substation. DATC indicated that Western DSW has performed these responsibilities for the Mead-Phoenix Project for approximately the last 20 years. (O-2) DATC stated that its O&M contractor Western DSW has been a transmission owner and operator since 1978. DATC stated that Western DSW operates and maintains more than 1,700 miles of lines in Arizona, southern California, and southern Nevada. DATC stated that Western DSW has operated and maintained series capacitors for more than 45 years as part of the Western DSW system. (O-3) DATC stated that Western Area Power Administration fills all positions through policies and processes established by the U.S. Office of Personnel Management and that Western Area Power Administration's practice is to fill positions with journeymen. DATC indicated that Western Area Power Administration has craft in training/apprenticeship programs to develop less experienced personnel when appropriate. (O-4) DATC stated that Western DSW trains to the journeyman level and has required annual training for all apprentices and journeymen. (O-5)

DATC indicated that Western DSW utilizes a Maximo asset database to document the interval and maintenance records, including required scheduling dates (due dates) for maintenance, in order to maintain required compliance with NERC standards. DATC stated that Western DSW's maintenance standards include the elements listed in the TCA. (O-6) DATC indicated that Western DSW has established a "WAPA Order," which covers transmission vegetation management. DATC indicated that in October of 2014 a WECC on-site audit found Western DSW to be compliant with NERC standard FAC-003. (O-7) DATC stated that NERC audits are a good example of Western DSW's implementation and compliance and provided copies of standard maintenance reports for the Path 15 upgrade transmission facilities indicating that maintenance objectives had been met. (O-8) DATC indicated that Western Area Power Administration has a proven success rate of limiting accountable outages with only 16 accountable outages across Western Area Power Administration's fifteen-state area identified in Western Area Power Administration's 2012 annual report. DATC indicated that to monitor the availability of the project, Western DSW would use industry standard monitoring and communications equipment and that availability would be monitored by the ISO and by Western DSW's control center. (O-9) DATC indicated that no changes to the TCA would be required for this project. (O-10)

DATC stated that Western DSW is registered with NERC as Balancing Authority, Load Serving Entity, Purchasing-Selling Entity, Transmission Owner, Transmission Operator, Transmission Planner, Transmission Service Provider, and Planning Authority. (O-11) DATC stated that Western DSW would perform all of the NERC compliance and would not contract out its compliance work for the NERC reliability standards or requirements. DATC stated that it would periodically review Western DSW's NERC compliance practices and procedures and share best practices used by Duke Energy and ATC. (O-12) DATC stated that Western DSW has a comprehensive compliance program and maintains continuous compliance with all applicable NERC standards. DATC provided a copy of the maintenance practices used by Western Area Power Administration for the Path 15 upgrade transmission facilities, which are under ISO operational control. DATC stated that Western DSW would not be seeking a waiver under TCA Section 5.1.6. (O-13) DATC indicated that Western DSW would be the responsible DATC team member for all applicable reliability standards. The report of Western DSW compliance

with NERC reliability standards referenced by DATC indicated only one possible violation for the period October 24, 2008 to October 14, 2011. (O-14)

DATC stated that Western DSW complies with NERC standards EOP-005 and EOP-008, including operating an emergency control center. DATC indicated that NERC's reliability coordinator for the relevant NERC region reviews, coordinates, and approves Western DSW's restoration and black-start plans annually. DATC stated that Western DSW has data acquisition facilities that that would be capable of meeting the requirement that a transmission operator have adequate and reliable data acquisition facilities for its transmission operator area and data acquisition facilities with others sufficient to provide operating information necessary to maintain reliability and to provide the availability data required by TCA Appendix C Section 4.3 (O-17)

DATC stated that Western DSW maintains a trained and qualified workforce (on call and prepared to respond), tools, equipment, a fleet of service vehicles, aircraft, and spare parts (structures, conductors, connectors, insulators, breakers). (O-19)

### **3.10.9 Information Provided by NEET West**

NEET West stated that its construction and O&M teams have already developed a successful model working with APS and SCE, which would be beneficial to the project. (Section 3 - General Project Information) NEET West stated that it would operate the project and would draw from NextEra's existing pool of high-voltage technicians and existing field support resources already located in California and Arizona to support existing NEER power generation and transmission assets. NEET West stated that these personnel would be responsible for providing 24/7 on-call response, site switching and safety, routine inspection and maintenance, and general site care duties. (QS-1) NEET West stated that NextEra and its key management personnel have a history of successfully working on major capital projects involving billions of dollars in investment. NEET West indicated that key individuals who would be involved in the project include professionals who have collaborated in the development, design, construction, and operation of numerous prior transmission, substation, and other major infrastructure projects. (QS-4) NEET West provided a list of 31 transmission line projects and 53 substation projects that NextEra affiliates have completed in the past five years. None was a 500 kV line and two were 500 kV substations. NEET West indicated that its affiliates were responsible for operation and maintenance of nearly all of the projects listed. (P-1)

NEET West stated that it would staff and manage site requirements, including high-voltage technician activities, from NextEra's local repair yard near Blythe, California. NEET West stated that the daily project O&M obligations, including site walk-downs and 24/7 out-of-hours response, would be performed by NextEra's Blythe high-voltage technicians. (O-1) NEET West indicated that its proposed operations lead is currently director of operations at NEET and as such is responsible for directing the safe, reliable, and cost-effective operations of NEET assets across North America to ensure operational excellence via the comprehensive application of processes, procedures, and standards for transmission operations. NEET West indicated that its proposed operations lead has responsibility for control center operations, as well as transmission line and substation field asset operations, installation, and maintenance for current NEET assets, such as those of New Hampshire Transmission, LLC in New England and Lone Star Transmission in Texas. NEET West stated that NextEra's compliance support

lead was previously a voting member of the ISO's transmission maintenance coordination committee. (O-2) NEET West stated that the NEET operations director has overall responsibility for the operations and maintenance of five Lone Star Transmission substations and associated transmission assets and New Hampshire Transmission assets and that in his prior role he had overall O&M financial responsibility for all FPL substation and transmission assets. NEET West stated that the NEET technical support manager is responsible for providing operations and maintenance technical support for the five Lone Star Transmission substations, including four 345 kV series capacitor units, and associated transmission assets and New Hampshire Transmission assets and that, in his prior role, he provided O&M predictive maintenance technology integration support for all FPL substation and transmission assets. (O-3) NEET West stated that it would follow NextEra's established programs and experience for recruiting and training maintenance personnel. (O-4, O-5)

NEET West stated that 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's transmission maintenance standards. NEET West indicated that this capability is supported by NextEra O&M team members' experience with the TCA requirements and ISO transmission maintenance standards. NEET West stated that NextEra inspection and maintenance practices cover all elements in TCA Appendix C Sections 5.2.1 and 5.2.2 for operating voltages 69-500 kV. (O-6) NEET West stated that the NextEra transmission vegetation management program meets all NERC compliance requirements and that NextEra has constructed, operated, and maintained 150 miles of transmission facilities in California. NEET West stated that it would operate and maintain all facilities to California codes and NERC standard requirements for vegetation. NEET West indicated that the program would ensure that the project is compliant with all governmental vegetation related regulations and restrictions, in particular NERC standards FAC-003-1 and FAC-003-2. NEET West stated that the vegetation management work for the project would likely be performed under NEET West's supervision, by a contractor, under a contract with NEER. (O-7) NEET West provided a copy of FPL's annual March filing to the Florida Public Service Commission, defining its maintenance inspection and follow-up programs, the focus of which is on storm preparedness initiatives. (O-8) NEET West describe NextEra's current capability to meet its obligation to comply with TCA Appendix C Section 4.5 measures. (O-9) NEET West stated that no changes or exceptions would be required to the provisions of the TCA. (O-10)

NEET West stated that it would register as a Transmission Owner, Transmission Operator, and/or Transmission Planner with NERC as applicable based on NERC's reliability functional model and WECC's entity registration requirements. NEET West indicated that it does not plan to contract for services to perform the NERC functions. (O-11, O-12) NEET West stated that NextEra's compliance and responsibility organization is a centralized group of reliability standard subject matter experts who manage, report, control, and audit the NextEra registered entities' compliance programs. NEET West stated that the NextEra compliance and responsibility organization would work with NEET West to establish the required agreements, processes, and procedures for assuring compliance. NEET West stated that its compliance support lead would perform the NERC compliance support role for NEET West and that this effort would include the identification of all applicable and non-applicable NERC reliability standards requirements. NEET West stated that it would create project specific procedures and processes for each applicable NERC requirement to address all NEET West obligations.



NEET West stated 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-13) NEET West stated that NextEra and its affiliates operate in all eight NERC regions and that NextEra affiliates are registered for all NERC functions. NEET West indicated that the majority of NextEra's potential violations of NERC reliability standards have been the result of self-reports submitted to the applicable regional entities. NEET West summarized the transmission and substation facilities owned by NextEra that are subject to NERC compliance in each NERC region. The summary indicated that NextEra has 7,918 miles of transmission lines 138 kV and above subject to NERC compliance, 6,647 miles of which are in NERC's Florida Regional Reliability Coordinator region. (O-14)

NEET West stated that NextEra's supervisory control and data acquisition (SCADA) schemes are used to gather power delivery equipment availability data and that equipment operating times are synchronized to allow for the capture of outages. NEET West indicated that this functionality would support the data collection requirements of TCA Appendix C Section 4.3. (O-17) NEET West stated that NextEra has inventory and spare parts strategies for routine maintenance requirements and breakdown events for all its facilities. NEET West stated that NextEra's practices include spare parts management, storage plans for spares, spare parts identification and records, periodic inventory of spare parts, usage of spare parts, and replenishment of inventory. NEET West stated that NextEra has service level agreements in place with experienced vendors for its facilities in the ISO region. NEET West stated that these agreements provide necessary consumable spares for all types of line, substation, protection and control, vegetation management, and environmental needs. NEET West stated that it would implement a specific spare equipment and parts strategy for the project based on system needs that are known at the time the transmission facilities become operational. (O-19)

### **3.10.10 Information Provided by TC/SCE**

TC/SCE indicated that APS would have lead responsibility for operation of the project and that TransCanyon would have an oversight role. (Section 3 - General Project Information) TC/SCE stated that APS currently operates and maintains more than 5,000 miles of transmission/sub-transmission lines. TC/SCE stated that APS has an award-winning predictive maintenance program and an industry-leading vegetation management program. (QS-1) TC/SCE stated that APS operates and maintains the fifth largest service territory in the country and that APS is well equipped to manage the operations and maintenance responsibilities of the project. (QS-4) TC/SCE listed transmission lines rated at 230 kV or higher totaling 2,906 miles (completed/under construction: 1,399 miles / planned: 1,507 miles) and indicated that the project team responsibilities for those lines would include operation and maintenance. TC/SCE listed more than a dozen substation projects with facilities rated 230 kV and higher for which the team has operation and maintenance responsibility. TC/SCE stated that four of the APS substation projects listed contain series capacitors and that two of the BHT projects listed contain series capacitors. TC/SCE stated that its collaborator SCE owns and operates 18 500 kV series capacitors within its transmission system. (P-1)

TC/SCE stated that, by using APS to provide O&M services, it would have the advantage of integrating the project into APS's existing infrastructure with compliance policies already in place, award-winning systems, and highly trained, qualified staff.

TC/SCE described APS's existing maintenance organization that would be responsible for the project. (O-1) TC/SCE described the roles and responsibilities of the APS O&M team members and indicated that they had many years of experience. (O-2) TC/SCE stated that APS has extensive experience operating and maintaining a large and complex transmission system, that the company has served Arizona for 124 years, and that it has operated EHV transmission lines since the early 1960s. (O-3) TC/SCE indicated that field personnel at APS are qualified journeymen linemen or electricians and are required to complete a comprehensive, state-sanctioned apprentice program, as well as on-going annual training to retain their journeyman skill set. (O-4) TC/SCE described APS's apprenticeship programs for linemen and electricians. (O-5)

TC/SCE stated that APS's maintenance standards meet or exceed the maintenance standards described in Appendix C of the TCA. TC/SCE indicated that APS has extensive experience in installing and maintaining series capacitor banks, that most of APS's 345 kV and 500 kV lines are equipped with series capacitors, and that APS has been installing or replacing an average of one series capacitor bank each year over last 10 years. (O-6) TC/SCE provided the most recent update of the APS transmission vegetation management plan and indicated that this document provides a roadmap describing how APS forestry and special programs department meets the current NERC vegetation standard FAC-003-3 (NERC, 2013). (O-7) TC/SCE stated that APS tracks its annual transmission and substation maintenance requirements using a monthly transmission and distribution performance indices scoreboard to record both predictive and preventive measures. TC/SCE provided several sample reports. (O-8) TC/SCE stated that APS is familiar with control chart methodology described in the TCA and has monitored availability performance of its 500 kV and 345 kV transmission lines using this process for more than 10 years. (O-9) TC/SCE stated that adding the project to the ISO controlled grid would not require any changes or exceptions to the provisions of the TCA. (O-10)

TC/SCE stated that TransCanyon intends to register with NERC for the Transmission Owner and Transmission Operator functions and would in turn contract with APS to perform these NERC Transmission Owner and Transmission Operator functions. TC/SCE indicated that APS is currently registered and has the capabilities to serve as a Balancing Authority, Distribution Provider, Generator Operator, Generator Owner, Load-Serving Entity, Planning Authority, Purchasing-Selling Entity, Resource Planner, Transmission Operator, Transmission Owner, Transmission Planner, and Transmission Service Provider. TC/SCE indicated that it and APS would continually review the programs in place that assure ongoing compliance. (O-11, O-12) TC/SCE indicated that it would assure seamless integration with APS systems already subject to and in compliance with NERC reliability standards. TC/SCE indicated that TransCanyon would also have an officer on the APS executive reliability and security committee, the purpose of which would be to provide oversight of and executive level decision-making for ongoing compliance by APS and TransCanyon with FERC-approved NERC reliability standards and FERC-approved WECC reliability standards. (O-13) TC/SCE stated that NERC last audited APS in 2013 and that it found no operations or planning violations. TC/SCE stated that APS has not had any non-compliance findings since that audit. TC/SCE stated that APS operates and maintains 2,810 miles of transmission lines that are subject to NERC compliance, including 1,302 miles of 500 kV transmission and 578 miles of 345 kV transmission. (O-14)

TC/SCE stated that the APS transmission system SCADA and EMS systems are designed to meet or exceed any and all NERC availability, reliability, security, and performance standards and metrics. TC/SCR stated that it would ensure that adequate data acquisition would be available to the APS transmission operators to compute availability metrics based on control chart methodology described in TCA Appendix C Section 4.3. (O-17) TC/SCE stated that it would maintain stock levels for critical materials needed during unplanned events separately from other maintenance stock. TC/SCE stated that warehouse and hauling personnel would be available 24 hours a day, 365 days per year, to move materials. TC/SCE stated that APS's supply chain organization maintains agreements and contacts with manufacturers, vendors, and neighboring utilities to supply excess inventory on demand. TC/SCE stated that the O&M services agreement between APS and TransCanyon would provide for shared spare parts and material for the project, including the series capacitor bank, which would be constructed with similar equipment as APS existing series capacitor banks. (O-19)

## **Operating Practices**

(Section 3 - General Project Information, QS-1, QS-4, P-1, O-1, O-2, O-3, O-4, O-5, O-11, O-12, O-13, O-14, O-15, O-16, O-17, O-18, O-19, O-20)

### **3.10.11 Information Provided by CTD**

CTD stated that, although it would be a new PTO with the ISO, LS Power is not a new entrant in transmission but is an incumbent transmission service provider in ERCOT. CTD stated that, in addition, LS Power would draw on its significant recent experience developing, constructing, and operating generation in the project area. (QS-1) CTD stated that Cross Texas has the necessary technical and engineering qualifications to undertake the operations of its facilities. (QS-4) CTD indicated that its affiliates are responsible for O&M of one longer EHV transmission line and several short ones and four substations. (P-1)

CTD stated that real-time monitoring of the series compensation, remote switching, and other transmission operations activities, including compliance, would be the responsibility of an affiliate under a services contract. (O-1) CTD stated that its proposed director of operations and maintenance for the project is currently responsible for operation and maintenance of the Cross Texas Transmission project, a 240-mile 345 kV double circuit transmission line. CTD indicated that the Cross Texas Transmission project includes a control center. CTD indicated that Cross Texas will be the operator of the project (O-17). CTD indicated that the Cross Texas O&M director or someone with similar credentials would be responsible for O&M of this project. (O-2) CTD stated that its affiliate Cross Texas's team members also have experience managing operations for other transmission utilities. CTD stated that its proposed maintenance contractor would provide 24-hour emergency dispatching and has numerous vehicles and equipment immediately available to mobilize to a storm site within 48-hours. (O-3) CTD stated that LS Power has programs and experience for recruiting and training operations personnel. CTD stated that all control room operators would be NERC certified and that Cross Texas, through its compliance policies and procedures, would ensure that all required certifications would be maintained. (O-4, O-5)

CTD indicated that it plans to contract with Cross Texas for services to provide transmission operations. CTD stated that Cross Texas is registered with NERC as a Transmission Planner, a Transmission Owner, and a Transmission Operator. CTD

stated that it would have full audit rights of services provided by Cross Texas and that Cross Texas would provide CTD with necessary compliance documentation as required. (O-11, O-12) CTD stated that LS Power has a culture of compliance and that all project personnel, from senior management to the project director to all operating and maintenance personnel, would have compliance obligations and responsibilities. CTD stated that it would develop policies and procedures that would ensure it is compliant with the applicable reliability standards. CTD stated that it does not require any waivers under TCA Section 5.1.6. (O-13) CTD stated that it does not currently own, operate, or maintain any transmission facilities but indicated that its affiliates have facilities subject to NERC compliance with good compliance records. (O 14)

CTD stated that LS Power has experience with reliability standards agreements, as Cross Texas and ERCOT have a similar coordinated functional registration agreement. CTD indicated that it expects a similar division of responsibility for NERC reliability standards with the ISO as with other recently accepted independent PTOs. (O-15) CTD described the applicable agreements that would define the transmission operator responsibilities and authority with respect to other entities. (O-16) CTD stated that it would meet the requirements for adequate and reliable data acquisition facilities through data acquisition equipment design in accordance with project requirements and NERC standards, adequate communications systems, and systems at the control facilities of its affiliate, Cross Texas. CTD stated that Cross Texas has recently completed construction of both primary and backup control center facilities that utilize the latest software and systems to ensure reliable data acquisition and control. (O-17) CTD stated that Cross Texas currently operates systems consistent with TCA requirements and has experience working with regional entities (ERCOT) and following their operating orders. (O-18)

CTD stated that it would also enter into mutual assistance agreements with neighboring utilities to leverage material and equipment and/or labor that might be mutually beneficial. CTD stated that its specialty contractor has resources local to the project area available for emergency response and provides such services for area utilities. CTD stated that from a real-time system monitoring perspective, Cross Texas has emergency operating procedures and that it would develop specific procedures for operation of the project. CTD provided a copy of the current emergency operations plan Cross Texas would use in operating the series compensation station. CTD stated that it estimates typical emergency response times to the line and series capacitors to be less than two hours. (O-19) CTD stated that the project would not be subject to any encumbrance on the ISO's operational control. (O-20)

### **3.10.12 Information Provided by DCRT**

DCRT stated that it would be responsible for the operation and maintenance of the project and that VEA would perform operation and maintenance and NERC compliance for DCRT. (Section 3 - General Project Information) DCRT stated that it would contract with VEA, which has extensive experience in O&M in the region, and that the operations group at VEA is a certified operator and PTO with the ISO. (QS-1, QS-4) DCRT stated that Abengoa does not operate or maintain any lines in the U.S. and that Starwood Energy operates but does not maintain 500 kV lines in New Jersey, New York, California, Nevada, and Arizona totaling over 500 miles. DCRT did not identify specific projects operated and maintained by VEA. (P-1)

DCRT stated that VEA's manager of engineering would be responsible for control center operations associated with the proposed line, including outage scheduling. DCRT stated that VEA would operate and manage the line from VEA's primary control center located in Pahrump, NV. DCRT stated that Abengoa personnel are trained and certified in transmission O&M and NERC compliance needs and that these personnel would interface with VEA. (O-1) DCRT indicated that the VEA operations manager, who would be responsible for field operation, maintenance, inspection, and emergency response, has been in the position since 2014 and has eight years of utility experience, primarily in distribution. DCRT indicated that the VEA assistant manager of operations has nearly 30 years of utility experience, is a NERC certified operator, and is a member of the ISO's transmission maintenance coordination committee. DCRT stated that the VEA assistant manager of operations has experience with operation and maintenance of systems up to 345 kV. DCRT indicated that the Abengoa O&M transmissions lines general director has 36 years of utility experience and is currently responsible for O&M of 10 power line concessions totaling 5,000 kilometers of power lines, 20 substations and 130 employees. (O-2) DCRT stated that Abengoa specializes in operation and maintenance of transmission lines ranging from high to extra high voltages and that it operates and maintains several lines around the world, including Brazil where it maintains more than 5,000 kilometers of high to extra high voltage lines. DCRT stated that its O&M contractor, VEA currently has a transmission maintenance agreement with the ISO, which would be expanded to include this project. DCRT indicated that this current program covers inspection and maintenance of VEA's 164 miles of 230 kV and 191 miles of 138 kV transmission lines. DCRT indicated that VEA does not currently operate or maintain series capacitors within its bulk electric system but that VEA does operate and maintain an 8.4 MVAR shunt capacitor at its 138 kV Valley Switch Station and that key VEA employees have experience operating series capacitors in other systems. DCRT stated that Abengoa operates and maintains series capacitors in South America. (O-3) DCRT stated that Abengoa and VEA have programs and experience for recruiting and training operations personnel. DCRT stated that all VEA control room operators are NERC certified and indicated that VEA employs a lead power system controller who would be responsible for certification training and NERC compliance requirements for all dispatchers. (O-4, O-5)

DCRT stated that Abengoa would contract with VEA to perform NERC functions. DCRT indicated that VEA is currently registered with NERC as a Distribution Provider, Load Serving Entity, Purchasing-Selling Entity, Transmission Owner, and Transmission Operator. (O-11) DCRT stated that Abengoa's compliance coordinator reporting to the O&M manager would ensure that VEA accomplished functions contracted to it. DCRT stated that it has on staff personnel who have experience with NERC compliance who would closely monitor and coordinate VEA's performance. (O-12) DCRT described VEA's processes and procedures for assuring compliance with NERC standards. DCRT did not identify any applicable reliability criteria for which transmission owners are responsible that would require temporary waivers under TCA Section 5.1.6. (O-13) DCRT stated that VEA's NERC Transmission Operator registration began on January 2013 and that it performed an internal self-audit and certification in 2014 and self-reported minor violations. DCRT indicated that Abengoa also has experience registering and complying with NERC reliability standards for Abengoa's affiliate, Arizona Solar One, LLC. (O-14)

DCRT stated that VEA has a coordinated functional registration agreement with the ISO and that this is the mechanism through which VEA and the ISO divide responsibility for

reliability standards. DCRT indicated that VEA would enter into a similar agreement with the ISO to address NERC and WECC reliability standards and requirements for transmission operator functions for the project. (O-15) DCRT stated that it would coordinate multi-party agreements with the ISO and neighboring balancing authorities and transmission owners similar to what VEA has done for its 230 kV and 138 kV facilities. (O-16) DCRT stated that VEA has existing reliable data acquisition facilities for its bulk electric facilities, as well as contract facilities at the Nevada National Security Site. DCRT indicated that it would procure secure communications services to the Delaney-Colorado River 500 kV facilities and that VEA would have visibility of the real-time data, which it would provide in real-time to the ISO through inter-control center communications protocol. DCRT stated that VEA maintains a primary and backup control center and maintains historical system data and outage information. (O-17) DCRT stated that VEA currently complies with the requirements of TCA Section 6.1 for its own bulk electric system facilities and would do the same for the proposed 500 kV transmission line. (O-18)

DCRT stated that as a registered Transmission Operator and member of the ISO, VEA currently complies with the requirements of TCA Sections 9.2 and 9.3 while operating its own bulk electric system facilities. DCRT stated that VEA would have personnel on-call to respond to emergencies on the proposed 500 kV line, that they would be capable of performing inspections and initial troubleshooting, and that the response time for these employees would be five hours or less. DCRT stated that VEA could contract with one or more qualified transmission line construction and maintenance companies if needed and that the contract would include a service level agreement that would guarantee crews and equipment on site within a specified period of time to perform any necessary repairs to the proposed line, up to and including full structure replacement. DCRT stated that VEA has emergency operating procedures in place in accordance with NERC requirements and that the procedures are coordinated with the ISO and neighboring utilities. DCRT stated that VEA currently has mutual assistance agreements with other utilities, and could execute additional mutual assistance agreements if needed, to support the repair and rebuild of the line. (O-19) DCRT stated that neither Abengoa nor VEA are aware of any encumbrances to the project at this time. (O-20)

### **3.10.13 Information Provided by DATC**

DATC stated that Western DSW would permit, obtain rights-of-way, and maintain the project. DATC stated that Western Area Power Administration is a federal power marketing agency within the United States Department of Energy, established in 1977 and that Western Area Power Administration currently operates over 17,000 miles of transmission in the western United States. (Section 3 - General Project Information) DATC stated that the project is geographically located in Western DSW's service territory, where Western DSW has existing operations, experience, and knowledge. (QS-1, QS-4) DATC listed projects for which its team members have been responsible, but the list does not appear to include all lines and series capacitor banks operated and maintained by Western DSW in the past five years. (P-1)

DATC stated that the ISO would be the operator of the transmission line and that the Western DSW control center operator(s) at its main control center located in Phoenix, Arizona would be the main point of contact for the ISO. DATC did not provide a description of roles and responsibilities of its proposed operating organization. (O-1) DATC stated that Western DSW is the operations manager of the Mead-Phoenix Project

and is responsible for all operation and maintenance from Perkins Substation through Mead Substation and on to Marketplace Substation. DATC indicated that Western DSW has performed these responsibilities for the Mead-Phoenix Project for approximately the last 20 years. DATC stated that Western DSW personnel are employees of the federal government and, in accordance with federal employment policies, it is unable to provide resumes of these federal employees. DATC stated that Western DSW personnel are qualified and have sufficient experience to perform their assigned duties. DATC stated that the ISO could rely on the fact that it would be a violation of federal law to employ personnel not qualified for a specific position. DATC stated further that Western DSW personnel also maintain elements that are part of the ISO system. (O-2) DATC stated that its O&M contractor Western DSW has been a transmission owner and operator since 1978. DATC stated that Western DSW operates and maintains more than 1,700 miles of lines in Arizona, southern California, and southern Nevada. (O-3) DATC stated that all Western Area Power Administration positions are filled through policies and processes established by the U.S. Office of Personnel Management and that Western Area Power Administration's practice is to fill positions with journeymen. DATC indicated, however, that Western Area Power Administration has craft in training/apprenticeship programs to develop less experienced personnel when appropriate. (O-4) DATC stated that Western DSW trains to the journeyman level and has required annual training for all apprentices and journeymen for a one or two-week period. DATC provided a copy of the Western Area Power Administration training plan that indicates that the training staff is responsible for analyzing, designing, developing, implementing, and evaluating the training provided to each of the system operators to meet each individual's needs and to comply with the NERC continuing education program and NERC standards. DATC indicated that power system operators-in-training would be supervised by a regionally qualified power system operator at all times and that, prior to assuming full duties of an assigned position, a power system operator would, among other things, need to acquire a valid NERC system operator certification. (O-5)

DATC stated that Western DSW is registered with NERC as Balancing Authority, Load Serving Entity, Purchasing-Selling Entity, Transmission Owner, Transmission Operator, Transmission Planner, Transmission Service Provider, and Planning Authority. (O-11) DATC stated that Western DSW performs all of the NERC compliance activities and does not contract out its compliance work for the reliability standards or requirements. DATC stated that it would periodically review Western DSW's NERC compliance practices and procedures and share best practices used by Duke Energy and ATC. (O-12) DATC stated that Western DSW has a comprehensive compliance program and maintains continuous compliance with all applicable NERC standards. DATC indicated that the NERC compliance group would be integrated within the operations and maintenance functional area. DATC indicated that this project would represent an incremental increase in its compliance responsibilities. (O-13) DATC indicated that Western DSW would be the responsible DATC team member for all applicable reliability standards. The report of Western DSW compliance with NERC reliability standards referenced by DATC indicated only one possible violation for the period October 24, 2008 to October 14, 2011. (O-14)

DATC stated that Western DSW proposes to divide responsibility for NERC standards applicable to Transmission Operators in the same way as responsibility is divided between the ISO and Western Area Power Administration for the Path 15 upgrade transmission facilities. DATC stated that it expects its reliability standards agreement for

the project to be the same as the agreement between the ISO and Trans Bay Cable. (O-15) DATC stated that the applicable agreements to define the transmission operator responsibilities would be (i) the TCA, to be executed by Western DSW, and (ii) a coordinated operation and interconnection agreement(s) among DATC, Western DSW, SCE, and APS. (O-16) DATC stated that Western DSW complies with NERC standards EOP-005 and EOP-008, including operating an emergency control center. DATC indicated that NERC's reliability coordinator for the relevant NERC region reviews, coordinates, and approves Western DSW's restoration and black-start plans annually. DATC stated that Western DSW has data acquisition facilities that that would be capable of meeting the requirement that a transmission operator have adequate and reliable data acquisition facilities for its transmission operator area and data acquisition facilities with others sufficient to provide operating information necessary to maintain reliability and to provide the availability data required by TCA Appendix C Section 4.3. DATC provided a sample availability report for the Path 15 upgrade transmission facilities indicating that there were no forced outages in 2013. (O-17) DATC indicated that Western DSW has the personnel, facilities, experience, and capability, including physical presence, to respond to the ISO's operating orders. DATC stated that Western DSW has the capability and experience that would enable it to comply with the activities required by TCA Sections 6.1, 6.3, and 7. (O-18)

DATC stated that Western DSW maintains a trained and qualified workforce (on call and prepared to respond), tools, equipment, a fleet of service vehicles, aircraft, and spare parts (structures, conductors, connectors, insulators, breakers), that would allow it to respond 24x7 to maintenance emergencies and to comply with the activities required by TCA Section 9.2 (management of emergencies by PTOs) and TCA Section 9.3 (system emergency reports: TO obligations). DATC stated that, in addition, Western DSW maintains agreements with neighboring utilities and contractors to provide additional support, as necessary, for large-scale emergencies. DATC stated that, although response time for more common emergencies would be measured in hours, response times for mutual assistance events would depend on how widespread the emergency condition became (i.e., wildfires, earthquakes, hurricanes, tornados). (O-19) DATC stated that no encumbrances would be placed on the facilities. (O-20)

#### **3.10.14 Information Provided by NEET West**

NEET West stated that it would draw from a wide range of corporate support services. NEET West stated that, through this model, FPL, NEER, and NEET employ experienced operation and support service personnel that would be available to assist NEET West. NEET West stated that its construction and O&M teams have already developed a successful model working with APS and SCE, which would be beneficial to the project. (Section 3 - General Project Information) NEET West stated that it would operate the project and would draw from NextEra's existing pool of high-voltage technicians and existing field support resources already located in California and Arizona to support existing NEER power generation and transmission assets. NEET West stated that these personnel would be responsible for providing 24/7 on-call response, site switching and safety, routine inspection and maintenance, and general site care duties. NEET West stated that, in addition, NEET's existing in-house transmission operations team, located in Austin, Texas, would monitor and control the project's operations. NEET West stated that compliance and accounting activities would be undertaken by NEET's existing operations and finance teams. (QS-1) NEET West indicated that key individuals who would be involved in the project include professionals who have collaborated in the



development, design, construction, and operation of numerous prior transmission, substation, and other major infrastructure projects. NEET West stated that it plans to draw on the capabilities and collaborative effort of these key individuals and their existing relationships to deliver the project successfully. (QS-4) NEET West provided a list of 31 transmission line projects and 53 substation projects that NextEra affiliates have completed in the past five years. None was a 500 kV line and two were 500 kV substations. NEET West indicated that its affiliates were responsible for operation and maintenance of nearly all of the projects listed. (P-1)

NEET West stated that NextEra's existing organization includes operations, maintenance, and compliance management groups. NEET West stated that its proposed system operations lead is currently the director of operations for Lone Star Transmission in Austin, Texas. NEET West indicated that at Lone Star Transmission the proposed system operation lead is responsible for the transmission operations organization, which includes transmission operator system operations, energy grid management systems, field operations and maintenance, capital budget, compliance with regulatory requirements, and maintaining business continuity. (O-1, O-2) NEET West described the roles and responsibilities of key management personnel, which included operation and compliance activities for NextEra transmission assets in Texas and New Hampshire and for wind generation facilities. (O-2, O-3) NEET West stated that it would follow NextEra's established programs and experience for recruiting and training maintenance personnel. (O-4, O-5)

NEET West stated that it would register as a Transmission Owner, Transmission Operator, and/or Transmission Planner with NERC as applicable based on NERC's reliability functional model and WECC's entity registration requirements. NEET West indicated that it does not plan to contract for services to perform the NERC functions. (O-11, O-12) NEET West stated that NextEra's compliance and responsibility organization is a centralized group of reliability standard subject matter experts who manage, report, control, and audit the NextEra registered entities' compliance programs. NEET West stated that the compliance and responsibility organization would work with NEET West to establish the required agreements, processes, and procedures for assuring compliance. NEET West stated that its compliance support lead would perform the NERC compliance support role for NEET West and that this effort would include the identification of all applicable and non-applicable NERC reliability standards requirements. NEET West stated that, for each applicable NERC requirement, it would create project-specific procedures and processes to address all NEET West obligations. NEET West stated 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-13) NEET West stated that NextEra and its affiliates operate in all eight NERC regions and that NextEra affiliates are registered for all NERC functions. NEET West indicated that the majority of NextEra's potential violations have been the result of self-reports submitted to the applicable regional entities. NEET West summarized the transmission and substation facilities owned by NextEra that are subject to NERC compliance in each NERC region. The summary indicated that NextEra has 7,918 miles of transmission lines 138 kV and above subject to NERC compliance, 6,647 miles of which are in NERC's Florida Regional Reliability Coordinator region. (O-14)

NEET West stated that it would work with the ISO to develop an operational agreement that would include defining roles and responsibilities related to complying with all applicable NERC reliability standards requirements. NEET West indicated that the

foregoing approach would align with existing agreements and the approach taken by PG&E and the Trans Bay Cable in establishing their project-related reliability standards agreement with the ISO. (O-15) NEET West listed the applicable agreements that would define the project transmission operator's responsibilities and authority with respect to other NERC functional entities. (O-16) NEET West stated that, for the proposed project, NEET West anticipates using similar data acquisition architecture as used for the Lone Star Transmission system. NEET West provided a sample of the back-up control center plan developed for the Lone Star Transmission control center. The plan provided by NEET West states that the purpose of this procedure is to set forth the backup control center plan for the Lone Star Transmission system operations. The plan references related NERC requirements. (O-17) NEET West stated that NextEra subsidiaries are responsible for operation and maintenance for over 8,000 circuit miles of the bulk electric system and that all of these circuits and associated facilities have operational processes, procedures, and maintenance practices that comply with their applicable reliability criteria and NERC's operation and planning reliability standards. NEET West described its capability and experience to meet each of the referenced sections of the TCA and provided several examples. (O-18)

NEET West stated that it would rely on transmission operations personnel both in the project area and in support functions throughout the NextEra affiliate company organizations to ensure availability in response to emergency operating conditions. NEET West stated that, in addition to proven event response processes, NEET West would also establish a comprehensive emergency operations plan, which would outline individual roles and responsibilities. NEET West stated that the emergency operations plan would also address applicable NERC and U.S. Department of Energy compliance requirements, including, as applicable, black start coordination and critical asset recovery plans. NEET West stated that the proposed local reporting center for the project would be the NextEra Blythe, California facility. NEET West indicated that this location is thirty minutes from Colorado River Substation, fifty minutes from the proposed series compensation site, and approximately ninety minutes from Delaney Substation. NEET West estimated that the NEET West's high-voltage technicians could respond to trouble at the most remote points on the line within two hours and to the series compensation station in less than an hour. NEET West indicated that, to support its first responders, additional NextEra high-voltage technicians would be located in Palm Springs, California, a 90-minute drive west of Colorado River Substation. NEET West also indicated that NextEra has an agreement with a service provider to provide transmission resources and material support in California and Arizona. NEET West stated that the service provider is located in El Cajon, California, three hours from Blythe. NEET West indicated that NextEra also has an existing support agreement with a manufacturing company that provides temporary transmission line emergency restoration systems and is located in Azusa, California, three hours west of Colorado River Substation. (O-19) NEET West indicated that the project would not be subject to any encumbrances. (O-20)

### **3.10.15 Information Provided by TC/SCE**

TC/SCE indicated that APS would have lead responsibility for operation of the project and that TransCanyon would have an oversight role. TC/SCE stated that, given the proximity of the project to the existing service territory of APS, TC/SCE believes there is a natural synergy in retaining APS to provide line operations and maintenance services. (Section 3 - General Project Information) TC/SCE stated that TransCanyon has

contracted with APS to provide operations and maintenance services for the project. TC/SCE stated that APS currently operates and maintains more than 5,000 miles of transmission/sub-transmission lines and serves as path operator for five WECC-rated paths spanning the Southwest region. TC/SCE stated that, as an interconnecting neighbor system with the ISO, APS has extensive experience coordinating operations with the ISO. (QS-1) TC/SCE stated that APS has recently added operators, which increases the company's capacity for switching and situational awareness, and has planned for future expansion of responsibilities, including support of TC/SCE and the project. (QS-4) TC/SCE listed transmission lines rated at 230 kV or higher totaling 2,906 miles (completed/under construction: 1,399 miles/planned: 1,507 miles) and indicated that the project team responsibilities for those lines include operation and maintenance. TC/SCE listed more than a dozen substation projects with facilities rated 230 kV and higher for which the team has operation and maintenance responsibility. TC/SCE stated that four of the APS substation projects listed contain series capacitors and that two of the BHT projects listed contain series capacitors. TC/SCE stated that its collaborator SCE owns and operates 18 500 kV series capacitors within its transmission system. (P-1)

TC/SCE stated that the personnel that would be responsible for field operations and maintenance of the project, including the series capacitor bank in Delaney Substation, are located Phoenix, Arizona approximately 10 miles north of the downtown Phoenix area. TC/SCE stated that the typical response time to address trouble with the series capacitor bank at Delaney Substation would be less than one hour and the typical response time to address trouble with the transmission line that the ISO deems high priority would be less than two hours. (O-1) TC/SCE described the roles and responsibilities of the APS O&M team members and indicated that they have many years of experience. (O-2) TC/SCE stated that APS has extensive experience operating and maintaining a large and complex transmission system, that the company has served Arizona for 124 years, and that it has operated EHV transmission lines since the early 1960s. TC/SCE stated that most of APS's 345 kV and 500 kV lines are equipped with series capacitors. (O-3) TC/SCE stated that all grid operators at APS hold current NERC reliability coordinator certifications, which NERC has granted based on its comprehensive knowledge assessments of these personnel. TC/SCE indicated that field personnel at APS are qualified journeymen linemen or electricians and are required to complete a comprehensive, state-sanctioned apprentice program, as well as on-going annual training, to retain their journeyman skill set. (O-4) TC/SCE stated that APS's operations training has received approved provider status from NERC. TC/SCE described APS's apprenticeship programs for linemen and electricians. (O-5).

TC/SCE stated that TransCanyon intends to register with NERC for the Transmission Owner and Transmission Operator functions and would in turn contract with APS to perform these NERC Transmission Owner and Transmission Operator functions. TC/SCE indicated that APS is currently registered with NERC and has the capabilities to serve as a Balancing Authority, Distribution Provider, Generator Operator, Generator Owner, Load-Serving Entity, Planning Authority, Purchasing-Selling Entity, Resource Planner, Transmission Operator, Transmission Owner, Transmission Planner, and Transmission Service Provider. TC/SCE indicated that it and APS would continually review the programs in place that assure ongoing compliance. (O-11, O-12) TC/SCE indicated that TransCanyon would assure seamless integration with APS systems already subject to and in compliance with NERC reliability standards. TC/SCE indicated that TransCanyon would also have an officer on the APS executive reliability and

security committee, the purpose of which would be to provide oversight of and executive level decision-making for ongoing compliance by APS and TransCanyon with FERC-approved NERC reliability standards and FERC-approved WECC reliability standards. (O-13) TC/SCE stated that NERC last audited APS in 2013 and that it found no operations or planning violations. TC/SCE stated that APS has not had any non-compliance findings since that audit. TC/SCE stated that APS operates and maintains 2,810 miles of transmission lines that are subject to NERC compliance, including 1,302 miles of 500 kV transmission and 578 miles of 345 kV transmission. (O-14)

TC/SCE indicated that TransCanyon would be solely responsible for complying with the NERC Transmission Owner requirements where applicable. TC/SCE indicated that, for the NERC Transmission Operator function, TC/SCE would employ the NERC-coordinated functional registration to allocate and assign compliance responsibility between TransCanyon and the ISO. TC/SCE indicated that it is comfortable with the PTO reliability standards agreement executed between Trans Bay Cable and the ISO and would be willing to enter into a similar agreement or negotiate different terms if preferred by the ISO. (O-15) TC/SCE stated that NERC reliability standards that are applicable to the coordinated functional registration would inform all applicable agreements with any reliability entities that interconnect to the project. Also, TC/SCE indicated that FERC pro forma generator interconnection agreements would be employed for any generator interconnections. TC/SCE stated that transmission interconnections would be defined by an executed interconnection agreement and that the ISO agreements would inform the reliability relationship between the ISO and TransCanyon. TC/SCE described various types of agreements indicating how TransCanyon would fulfill the NERC Transmission Operator responsibilities for the project. (O-16) TC/SCE stated that the APS transmission system SCADA and EMS systems are designed to meet or exceed any and all NERC availability, reliability, security, and performance standards and metrics. TC/SCE indicated that it intends to work with SCE and APS in facilitating the interconnection of the project into Colorado River and Delaney Substations and would ensure that adequate data acquisition would be available to the APS transmission operators to compute availability metrics based on control chart methodology described in TCA Appendix C Section 4.3. TC/SCE stated that the primary and backup energy control centers, located at two geographically separate locations approximately 20 miles apart, would both have full SCADA functionality. TC/SCE indicated that the backup control center would be fully operational at all times and that the APS operations business resumption procedure includes both a backup control center procedure and a procedure for transferring primary communications to the backup control center. TC/SCE provided a copy of APS's backup control center procedure. (O-17) TC/SCE stated that APS, acting as TransCanyon's designated contractor for O&M services, has repeatedly demonstrated its ability to comply at a minimum with the activities and responsibilities required by TCA Sections 6.1, 6.3, and 7. TC/SCE described APS's capabilities and experience relevant to each TCA section. (O-18)

TC/SCE stated that APS's transmission operators would coordinate with the ISO to develop a strategy to mitigate EHV emergencies that might affect the project, as well as the WECC bulk electric system. TC/SCE stated that, since APS already operates Delaney Substation, the eastern termination of the project, the company has developed an operating guideline for mitigating planned and forced outages on Path 49, which is the path for the project. TC/SCE stated that APS, acting as TransCanyon's designated contractor for O&M services, has repeatedly demonstrated the capability and experience

to comply with the emergency management and emergency reporting obligations described in TCA Sections 9.2 and 9.3. TC/SCE stated that APS's operations center monitors the APS transmission system and that APS's operations engineering group provides on-call support 24 hours a day, 365 days a year to support transmission operations. TC/SCE stated that other emergency response personnel would be available in real-time and on-call to analyze fault data and provide real-time guidance. TC/SCE stated that when APS anticipates that conditions may approach emergency or disaster proportions, APS would activate its transmission, distribution, and customer incident command center, and, if necessary, APS would activate its corporate emergency operations center to support the command center. TC/SCE stated that the command center would be staffed by selected emergency staff as dictated by the situation and that APS maintains business resumption, load curtailment, and black start plans, which would be implemented for critical emergencies. TC/SCE stated that APS's robust emergency response plan includes access to restoration personnel, materials, and resources and that this plan includes mutual assistance agreements for both generation and transmission capacity with neighboring utilities to assist with immediate needs. TC/SCE stated that emergency crews would be able to call upon APS's fleet of 20 EHV Lindsey towers for emergency tower restoration and that this fleet includes the "Condor," the largest bucket truck in the western United States, whose height and wingspan make it ideally suited to emergency repairs of transmission lines and towers. (O-19) TC/SCE stated that the project, as proposed by TC/SCE, would not be subject to any encumbrances and that the entire capacity of the line would be placed under the operational control of the ISO through the TCA. (O-20)

### **3.10.16 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 five project sponsors provided 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 proposals of CTD, DCRT, DATC, NEET West, and TC/SCE with regard to this component of the factor

#### **Comparative Analysis of Maintenance 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 maintenance practices they propose for this project, including but not limited to their proposed plans for compliance with NERC requirements for transmission owners and operators, the TCA, and the ISO's transmission maintenance standards.

All five project sponsors have established records and experience demonstrating the capability to adhere to standardized maintenance practices. However, the amount of experience varies widely among the proposed sponsors' teams. Each project sponsor's

O&M organization includes the necessary operations, maintenance, and compliance functions. All of the project sponsors have transmission facilities subject to NERC compliance requirements, and each provided some information on compliance audit results. All project sponsors included provisions for spare parts.

TC/SCE's O&M contractor has a large O&M organization servicing similar facilities in the vicinity of the project, including series capacitors, and its staff has many years of experience operating in the region. DATC's proposed O&M organization, Western DSW, operates similar but fewer facilities in the area than TC/SCE's O&M contractor, and DATC personnel have had experience operating and maintaining similar facilities, including some under ISO operational control. NEET West operates and maintains transmission facilities in the vicinity, but they are generally smaller and less complex than those serviced by the O&M organizations of TC/SCE or DATC; however, NEET West can draw on the expertise of its affiliates that have experience in other parts of the country with complex systems, including series capacitors. CTD, NEET West, and TC/SCE provided resumes of team members with many years of transmission system operation and maintenance experience. The CTD O&M team has experience with similar facilities in other parts of the region but currently maintains and operates fewer facilities similar to the proposed project. Although DCRT's proposed O&M contractor does not maintain any 500 kV facilities or series capacitors and would need to develop training programs for this purpose, DCRT's affiliate Abengoa has significant experience with transmission system operation and maintenance outside of the U.S., and DCRT's maintenance contractor has been successfully operating as an ISO PTO, adhering to the ISO's maintenance standards, and complying with NERC standards.

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 made the following determinations. The ISO has determined that TC/SCE's proposal is slightly better than the proposals of the other four project sponsors with regard to this component of the factor because TC/SCE has the greatest amount of resources in the area and the greatest amount of experience with similar facilities in the area. The ISO has determined that DATC's proposal is slightly better than the proposals of CTD, DCRT, and NEET West with regard to this component of the factor because DATC's team has more resources and experience in the area and because CTD and DCRT have fewer facilities subject to NERC compliance.

The ISO has determined that NEET West's proposal is slightly better than the proposals of CTD and DCRT with regard to this component of the factor because NEET West has more experience with similar facilities and can draw on the expertise of its affiliates that have experience in other parts of the country with complex systems. The ISO has determined that there is no material difference between CTD's proposal and DCRT's proposal with regard to this component of the factor because the greater EHV maintenance resources of CTD's maintenance contractor is offset by the fact that DCRT's maintenance contractor currently has a full set of maintenance practices filed with and accepted by the ISO and has successfully complied with these standards.

## **Comparative Analysis of Operating 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 operating practices they propose for this project, including but not limited to their proposed emergency plans

and other plans for compliance with NERC requirements for transmission owners and operators and the ISO's standards.

Although all five project sponsors have established records and experience demonstrating the capability to adhere to standardized operating practices, the amount of experience varies among the proposed sponsors' teams. Each project sponsor's O&M organization includes the necessary operations, maintenance, and compliance functions. All of the project sponsors have transmission facilities subject to NERC compliance, and each provided some information on compliance audit results. All project sponsors described emergency operations processes.

TC/SCE's O&M contractor has a large O&M organization servicing similar facilities in the vicinity of the project, including series capacitors, and serves as path operator for five WECC-rated paths spanning the Southwest region. APS's O&M organizations are currently in place and staffed to operate and maintain similar facilities in the vicinity of the project. APS also has many facilities subject to NERC compliance and an acceptable compliance record. The APS emergency response plans included in TC/SCE's proposal appear to be the most robust of all the emergency response plans included in the project sponsors' proposals. DATC's proposed O&M organization, Western DSW, also operates similar but fewer facilities in the area. NEET West operates and maintains transmission facilities in the vicinity as well, but they are generally smaller and less complex than those of TC/SCE and DATC. However, NEET West is able to draw on the expertise of its affiliates that have experience in other parts of the country with complex systems, including series capacitors. CTD's team has experience with similar facilities in other parts of the region but currently maintains and operates fewer facilities similar to the proposed project. DCRT's O&M contractor does not currently operate or maintain any 500 kV facilities or series capacitors.

CTD, NEET West, and TC/SCE provided resumes of team members with many years of transmission system operation and maintenance experience. DATC indicated that its personnel had experience operating and maintaining similar facilities, including some under ISO control. DCRT's proposed O&M contractor's team members have less experience with 500 kV transmission, O&M, and series capacitors than the other sponsors. VEA would be supported by Abengoa, but most of Abengoa's experience is from outside of North America. Thus VEA would need to develop training programs to cover those topics. DCRT also indicated that its response times to emergencies would be longer than those of the other 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 made the following determinations. The ISO has determined that TC/SCE's proposal is better than the proposals of the other four project sponsors with regard to this component of the factor because its O&M contractor APS operates many similar facilities in the region, is a WECC rated path operator, and has the most robust emergency response capability and because it operates more similar facilities in the region than the other project sponsors and more facilities subject to NERC regulation and therefore has more exposure and experience. The ISO has determined that there is no material difference between the proposals of DATC and NEET West and that their proposals are slightly better than CTD's proposal with regard to this component of the factor because CTD currently operates fewer facilities similar to the proposed project. The ISO determined that the proposals of the other four project sponsors are slightly better than DCRT's proposal

with regard to this component of the factor because DCRT’s team has less experience with 500 kV facilities in the U.S. and its proposal includes the longest response times to emergencies.

## **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.

Because the ISO has not identified any material difference among the proposals of the five project sponsors with regard to the first component of this factor (ability to adhere to standardized construction practices), the comparative analysis for this factor is based on the analysis for the second and third components (ability to adhere to standardized maintenance and operating practices). As discussed above, the ISO has determined that TC/SCE’s proposal is slightly better than the proposals of the other four project sponsors with regard to this factor overall because it is slightly better with regard to the second component and better with regard to the third component of the factor. The ISO has determined that DATC’s proposal is slightly better than the proposals of CTD, DCRT, and NEET West with regard to this factor overall because it is slightly better with regard to the second component and is comparable to NEET West’s proposal and slightly better than the proposals of CTD and DCRT with regard to the third component. The ISO has determined that NEET West’s proposal is slightly better than the proposals of CTD and DCRT with regard to this factor overall because it is slightly better with regard to both the second and third components. The ISO has determined that CTD’s proposal is slightly better than DCRT’s proposal with regard to this factor overall because it is slightly better with regard to the third component and comparable with regard to the second component of this factor.

### **3.11 Selection Factor 24.5.4(i): Ability to Assume Liability for Major Losses**

(Section 3 - General Project Information , QS-1, QS-2, QS-4, P-5, F-1, F-2, F-3, F-4, F-5, F-6, F-7, F-8, F-9, F-10, F-11, F-12, F-13, F-14, F-15, F-16, O-19)

The ninth selection factor is “demonstrated ability to assume liability for major losses resulting from failure of facilities of the Project Sponsor.”

#### **3.11.1 Information Provided by CTD**

Regarding preparations to reduce the need for financing equipment to repair or replace failed facilities, CTD stated that it would maintain critical spare parts and materials required to repair system facilities. CTD stated that the project capital cost includes an allowance for initial capitalized spare parts along with a storage facility. CTD stated that it would also enter into mutual assistance agreements with neighboring utilities to leverage material and equipment and/or labor that may be mutually beneficial. (O-19)

CTD stated that, prior to the commencement of construction and throughout the construction and operations period, it would maintain insurance with companies rated “A-” or better and with a minimum financial size classification of “X,” by A.M. Best (or an equivalent rating). CTD described the insurance coverage it would consider.



In addition, CTD stated that it would include a requirement for contractors to have an appropriate level of insurance for the scope of work to be performed. CTD provided examples of the insurance coverage that the primary construction contractor would be required to have. (P-5)

CTD stated that it would finance unexpected repairs or replacement construction during the operating period through retained earnings, lines of credit, and insurance proceeds. CTD indicated that the details of whether CTD's working capital would be in the form of a letter of credit, cash reserves, or other funds would be negotiated with CTD's lenders. CTD provided one example of funding increased costs due to equipment failure, and that was accomplished within the original budget for the project. (F-13)

### **3.11.2 Information Provided by DCRT**

Regarding preparations to reduce the need for financing equipment to repair or replace failed facilities, DCRT stated that Abengoa would have spare tower structures available for use to repair the proposed line, along with additional replacement parts deemed prudent. DCRT stated that Abengoa has included this cost in its operational plan. DCRT stated that Abengoa anticipates having twelve different types of spare towers available for future use, in addition to needed hardware associated with these structures. DCRT stated that spare parts have been considered in the proposal; it would have in stock spare parts such as motors, coils for circuit breakers and disconnect switches, capacitors, and control parts. DCRT stated that the recommended spare parts would be available in quantities to support the series capacitors. (O-19)

DCRT stated that it would team with the best companies in the insurance marketplace in placing any required coverage. DCRT stated that its insurance partners are preparing and refining several coverage options and that the coverage levels would be specifically tailored to the needs of the project, once the scope is definitively agreed.

DCRT indicated that it would likely consider additional performance-related coverage specific to the project and that the coverage levels would not be less than its base policies. DCRT also stated that it would obtain any additional and different insurance coverage and amounts that are required under the ISO and APS tariffs to accommodate transmission interconnection service for the project. (P-5)

DCRT stated that it has received letters of support from five financial institutions, including a California financial institution at this stage. DCRT stated that other financial institutions have also expressed interest in supporting Abengoa and Starwood Energy to finance project costs and potential cost overruns. DCRT stated that its corporate parent, Abengoa would provide enough support to cover any unexpected repairs or replacement during construction and during the operating period. DCRT indicated that construction insurance costs have also been included in its estimate of total project costs. DCRT did not address any previous examples of funding increased costs due to equipment failures. (F-13)

### **3.11.3 Information Provided by DATC**

Regarding preparations to reduce the need for financing equipment to repair or replace failed facilities, DATC stated that Western DSW would maintain spare parts and be prepared to respond to maintenance emergencies, in accordance with its call-out

procedures. DATC stated that Western DSW maintains a trained and qualified workforce (on call and prepared to respond), tools, equipment, a fleet of service vehicles, aircraft, and spare parts (structures, conductors, connectors, insulators, breakers), that allow it to respond 24x7 to maintenance emergencies. DATC stated that, in addition, Western DSW maintains agreements with neighboring utilities and contractors to provide additional support, as necessary, for large-scale emergencies. DATC stated it would use the same policies and procedures that are currently used by Western DSW for transmission lines, substations, and existing series capacitor banks for the project, including the new series capacitor bank. (O-19)

DATC stated that, during the construction period, insured values would be in the care, custody, and control of the construction contractor. DATC indicated that the contractor would provide property coverage while in the construction phase and described the insurance coverage it would be required to carry.

Once the project is in commercial operation, DATC stated that it would obtain a commercial general liability policy in various layers. DATC indicated that it does not anticipate carrying property coverage for the wires and poles, as DATC stated that very few, if any, in the industry carry this coverage because it is not cost effective since the coverage cannot be obtained at a commercially viable level. (P-5)

DATC stated that it is confident that the special purpose entity that it would establish to own the project would have the ability to finance any unforeseen events related to the project. As part of the financing process, DATC stated it would maintain a major maintenance reserve account to be utilized in the event of unanticipated equipment failures, the amount of which would in part be determined by an independent engineer. DATC stated that the special purpose entity that it would establish to own the project would also have insurance in line with normal utility practices, which would ensure sufficient funds in the event of an insurable event.

DATC indicated that it had experienced a failure-related event in 2014 associated with erosion issues that resulted in significant costs in comparison to its annual O&M budget. DATC indicated that it recovered the costs from project cash flows; however, DATC indicated that it stood by with a revolving letter of credit (already in place) and that both ATC and Duke Energy were prepared for necessary equity contributions. (F-13)

#### **3.11.4 Information Provided by NEET West**

Regarding preparations to reduce the need for financing equipment to repair or replace failed facilities, NEET West stated that NextEra has existing overhead line, substation, and environmental service level agreements for its assets located in the vicinity of the project. NEET West stated that NextEra has inventory and spare strategies for routine maintenance requirements and breakdown events for all its facilities. NEET West stated that NextEra's practices include spare parts management, storage plans for spares, spare parts identification and records, periodic inventory of spare parts, usage of spare parts, and replenishment of inventory. NEET West stated that NextEra has service level agreements in place with experienced vendors for its facilities in the ISO region. NEET West stated that these agreements provide necessary consumable spares for all types of line, substation, protection and control, vegetation management, and environmental needs. NEET West stated that it would implement a specific spare equipment and parts strategy for the project based on system needs that are known at the time the

transmission facilities become operational. NEET West also indicated that NextEra has an agreement with a service provider to provide transmission resources and material support in California and Arizona. NEET West indicated that NextEra also has an existing support agreement with a manufacturing company that provides temporary transmission line emergency restoration systems. (O-19)

NEET West stated that NextEra, and/or its affiliated, subsidiary, and associated companies and/or corporations, which would include NEET West, maintain a property all-risk insurance program that covers insurable assets from “all risks” of direct physical loss or damage. NEET West indicated that the limits, sub-limits, deductibles, terms, and conditions of coverage would be commensurate with industry practice and with leading insurance carriers. However, NEET West indicated that the transmission line specifically would be self-insured, consistent with industry practice.

NEET West stated that it would maintain a commercial general liability insurance program with industry leading insurance carriers, with limits commensurate with industry standards.

NEET West indicated that there would be no commercial insured values during construction. NEET West indicated that it would fully self-insure this project given the spread of risk geographically, which is consistent with its corporate policies and programs. (P-5)

NEET West stated that the project over its useful life would be an affiliate of and supported by the resources of NextEra, a well-capitalized entity with over \$69 billion in total assets, access to significant financial resources, and investment grade credit ratings. NEET West stated that NextEra is committed to supporting NEET West and consequently NEET West has the financial capacity to finance, develop, construct, operate, and maintain the project over the long-term. NEET West also stated that NextEra’s team has a proven history of meeting operating budgets which can be reallocated, if necessary, to meet financial commitments.

NEET West also described three insurable events associated with equipment failures ranging from \$1.7 to \$6.3 million; the events all involved affiliate substation equipment. (F-13)

### **3.11.5 Information Provided by TC/SCE**

Regarding preparations to reduce the need for financing equipment to repair or replace failed facilities, TC/SCE stated that APS’s emergency response plan includes access to restoration personnel, materials, and other resources. TC/SCE stated that it would maintain stock levels for critical materials needed during unplanned events separately from other maintenance stock. TC/SCE stated that APS’s supply chain organization maintains agreements and contacts with manufacturers, vendors, and neighboring utilities to supply excess inventory on demand. TC/SCE stated that the O&M services agreement between APS and TransCanyon would provide for shared spare parts and material for the project including the series capacitor bank, which would be constructed with equipment similar to the existing APS series capacitor banks. (O-19)

TC/SCE stated that it based its insurance coverage on what its parent companies have used on similar projects.

TC/SCE indicated that, during the construction phase, the procurement and construction contract and by extension the insurance carried by the contractor would cover the project until final acceptance by TC/SCE. TC/SCE described the insurance coverage that it has arranged for its contractor to carry. TC/SCE also identified the potential for additional coverage once due diligence has been performed and the need is identified.

Upon final acceptance, TC/SCE stated that it would carry insurance directly to cover the project. TC/SCE indicated that property insurance coverage would only apply to series compensation at Delaney Substation and not to the transmission line. TC/SCE described the insurance coverage, consistent with good utility practice, that it intends to carry as the asset owner. (P-5)

TC/SCE stated that PNW, BHE, and its collaborator SCE have routinely financed the repair and replacement of transmission equipment due to any number of unforeseen events during their normal course of business and that these expenditures have typically been financed from operating cash flows or the capital markets. TC/SCE indicated that TransCanyon and SCE would finance repairs and replacements consistent with their then-respective pro-rata interests.

TC/SCE stated that TransCanyon is backed by utility holding companies; BHE owns assets totaling \$74 billion and PNW owns assets totaling \$14 billion. TC/SCE stated that SCE, contingent upon exercise of its option, would provide its resources to support the continued operation of the project and that SCE owns electric assets totaling \$49 billion.

TC/SCE stated that TransCanyon and SCE would hold insurance commensurate with industry standards and seek compensation for any financing needs where recourse under the insurance agreement applies. Beyond this, TC/SCE indicated that TransCanyon and SCE would finance unexpected repairs with a combination of internally generated cash, indebtedness, and/or equity infusions from their respective parent entities. In addition, TC/SCE indicated that TransCanyon may supplement its long-term debt facility with a short-term revolving facility to finance unexpected repair or replacement costs and general working capital needs.

TC/SCE stated that, given access to existing capital and ongoing earnings by which PNW, BHE, and SCE may fund any additional equity, continued revenue recovery from project, and the overall strength of the owners' balance sheets, TC/SCE should be able to routinely handle unexpected repair or replacement costs and that these are not expected to pose financial difficulty or unnecessarily delay the repair or replacement of the damaged facility.

TC/SCE provided one example of financing unexpected repairs involving hurricane levels winds affecting the SCE system requiring \$40 million of repairs. (F-13)

### **3.11.6 ISO Comparative Analysis**

This factor looks at financial ability to cover losses. 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 financing emergency repairs.

Failures of project facilities would likely represent only a portion of the investment in the project, e.g., a number of towers, a limited number of spans of wire, damaged insulators, the series capacitor bank, etc. The financial resources of the project sponsors vary, and their proposals vary as to how they will finance emergency repairs, including retained earnings, lines of credit, maintenance reserves, insurance, and contributions from parent companies. All the project sponsors, except DCRT, provided examples (primarily for parent companies) of previous experience in covering increased costs due to equipment failures.

The ISO has determined that all five project sponsors have the resources to finance or otherwise assume liability for major losses resulting from failure of facilities. In addition, all five project sponsors have identified reasonable insurance coverage, including coverage during the operation of the project. Also, although there are differences in the emergency response capabilities of each project sponsor, all five project sponsors have identified reasonable approaches to maintaining spare parts for use in the event of a major equipment failure. Consequently, the ISO has concluded that all five project sponsors have sufficient financial resources, insurance coverage, and operational incentives 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 there is no material difference among the proposals of CTD, DCRT, DATC, NEET West, and TC/SCE with regard to 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 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.” As discussed in Section 2.1, the ISO has identified this selection factor as a key selection factor because the justification for this project is solely based on economic benefits to ratepayers, and the ISO considers commitment to a robust binding cost cap to be the most effective way in which the ISO can ensure that a project is developed in an efficient and cost-effective manner. A proposal that best satisfies this factor will contribute significantly to ensuring that the project sponsor selected will develop the project in an efficient and cost-effective manner.

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.

Four of the five project sponsors provided binding capital cost containment proposals with provisions for escalation of costs. The ISO retained a well-respected expert consulting firm to assist, *inter alia*, in evaluating 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 sensitivity analyses. In addition to evaluating the proposals with respect to binding cost containment measures, the ISO evaluated each project sponsor's proposal with respect to the following factors relating to cost containment:

- O&M cost containment
- Project risks and mitigation of risks
- Project management capabilities
- Cost containment performance for past projects

### **Cost Containment Capability Including Binding Cost Cap**

(Section 3 - General Project Information, QS-1, QS-4, P-2, P-3, P-4, P-6, P-7, P-10, P-11, P-12, P-13, F-15, F-16)

#### **3.12.1 Information Provided by CTD**

CTD provided a capital cost estimate in 2015 dollars, with transmission line and series compensation station costs separated, that included contingency funds and allowance for funds used during construction (AFUDC). (P-2)

CTD provided a binding capital cost containment proposal. (P-12) CTD stated that the cost containment limits in its proposal would be increased under certain specified conditions. The bases for increases identified by CTD included a change in the scope of the project due to changes to the ISO project requirements as contained in the ISO Functional Specifications, a change in scope required by law or a regulatory agency, force majeure not covered by the project insurance, or a change in law related to taxes.

CTD indicated that an increase to its cost containment limits based upon its proposed cost escalation conditions is very unlikely to occur because CTD's cost containment limits would not be increased for route changes, cost escalation, or need for additional environmental mitigation not initially anticipated. (P-12)

CTD provided a detailed description of its development of the cost estimate for each category (e.g., project management, permits, engineering, real estate, materials, etc.) in its cost estimate, including assumptions. (P-3)

CTD provided an estimate of the average annual operating and maintenance cost in 2015 dollars, broken down by third party O&M, staff, consultation and legal, audit/financials, and insurance. CTD stated that other expenses not included in its cost containment proposal are administrative and general (A&G) costs and property taxes. (P-4)

CTD provided a description of project schedule and budget performance for transmission line and substation projects completed by its affiliates in the past five years. CTD described five transmission line projects completed in the past five years, four of which were completed at or below the initial project budget and one of which had a small cost overrun. (P-6)

CTD described five substation projects completed by its affiliates in the past five years, four of which were completed at or below the initial project budget and one of which had a cost overrun (\$3 million (14%)) due to scope changes. (P-6)

CTD indicated that LS Power employs a detail-oriented and hands-on philosophy to all of its development, construction, and asset management activities. CTD indicated that LS Power employees directly oversee all project development activities including siting, permitting, community relations, government relations, labor relations, regulatory, real estate acquisition, engineering, and contracting. CTD indicated that LS Power performs a considerable amount of the development activities itself, while managing consulting firms for portions of the work that are specialized (e.g., surveying, environmental studies). (P-7)

CTD stated it would have an established governance structure under which decision making is carried out; the project director would be the primary point of contact for the ISO and be responsible for guiding CTD's day-to-day activities and overseeing all deliverables. CTD indicated that the project director would receive direction from and report to the CTD senior management and would be supported by a team of subject-matter experts with responsibilities for project execution within key project areas. (P-7)

CTD stated that the LS Power approach to managing cost and schedule is to initiate planning and scheduling as early as practical to increase certainty and use governance and project controls to ensure budgets and schedules remain in accordance with the plan. CTD indicated that the project director would execute the project plan in accordance with an approved project budget and project schedule. CTD indicated that, subsequent to budget approval, management would track all costs and report budget variances and that any non-budgeted items would require additional approval. CTD stated that LS Power has used this process to bring its projects into service at or under budget. (P-7)

To ensure compliance with the schedule, CTD stated that it would foster strong cooperation and communication between team members and stakeholders to ensure all requirements, including milestones, and expectations related to the project schedule. CTD indicated that it would include mitigation processes and immediate remedies in the project delivery program to address any real or perceived issues in schedule slippage. (P-7)

CTD stated that LS Power has identified several major risks to the schedule for the project, as well as mitigation measures related to each risk. CTD indicated that generally the risks it has identified would be best mitigated by a developer that understands the need to obtain social license for a project; CTD described social license as obtaining acceptance or approval of a project not just in the formal regulatory processes but with stakeholders and the public generally. CTD stated that early, thorough public outreach starting with elected public officials, local officials, and other local leaders is a key first step in the path toward public acceptance. (P-10)

CTD stated that LS Power believes the most significant risks to the successful completion of the project are related to public acceptance: establishing need at the ACC, obtaining private easements, and mitigation of impacts to sensitive species. CTD discussed various aspects of these issues and its approach to mitigation of these risks. (P-10)

CTD asserted that LS Power has a proven ability to translate its low-cost approach to transmission. CTD provided a table comparing various 345 kV and 500 kV transmission projects on a cost-per-mile basis. According to CTD's proposal, Cross Texas had the lowest per-mile transmission line construction cost comparing various transmission developers of 345 kV double circuit projects in the Texas Competitive Renewable Energy Zone, and ON Line (an LS Power project in Nevada) had the lowest per-mile construction cost comparing various recent 500 kV projects in that region. (P-11)

CTD stated that LS Power achieves this low-cost approach by keeping a focus on costs at all steps of project implementation, while ensuring compliance with all requirements and regulations without sacrificing quality. CTD stated that LS Power's project director has responsibility for schedule and budget compliance, with the support of managers of individual aspects of the project such as a permitting and construction. CTD stated that a key component in LS Power's cost control success is the ability to identify and allocate risk. For the project, CTD stated that it has already assembled a multi-disciplined team. CTD indicated that it would allocate risk to each team member best able to manage the risk through a process of: identify, assess, measure, manage, mitigate, and report. CTD provided some examples of how this approach has been applied previously in transmission line projects in Texas and Nevada. (P-11)

CTD stated that it has not yet determined if construction would be on a turn-key engineering, procurement, and construction (EPC) contract or through a combination of several contracts with suppliers and the construction contractors. CTD indicated that the construction contractor as well as material suppliers would provide specific guarantees. CTD indicated that specific security would also be required to support the contractor's obligations. (P-11)

CTD stated that overall budget responsibility during operations would rest with the asset manager identified with regard to O&M. CTD indicated that certain elements of O&M would be performed through contracts with suppliers and that, in each case, the contracts would have protections to ensure performance as well as control costs. (P-11)

CTD stated that it would seek siting approval for the transmission line and series compensation station from the BLM, Bureau of Reclamation, ACC, and CPUC. CTD stated that these siting authorities would not have jurisdiction over CTD's rates and therefore would not have a direct mechanism to enforce CTD's cost containment proposal. CTD stated that its rates would be set by FERC and that the FERC rate setting process would be the proper jurisdiction for its binding cost containment measures. (P-13)

CTD stated that it would incorporate its commitment to the ISO related to its cost containment proposal into the approved project sponsor agreement with the ISO and that the ISO would be able to terminate the approved project sponsor agreement for cause in the event CTD attempted to violate the cost containment proposal. (P-13)



### **3.12.2 Information Provided by DCRT**

DCRT provided a capital cost estimate in 2015 dollars, with transmission line and series compensation station costs separated, that included contingency funds and AFUDC. (P-2)

DCRT offered a binding capital cost containment proposal for the project and stated that the cost containment limits in its proposal include EPC construction costs, development costs, DCRT general costs, AFUDC, and financing fees. DCRT indicated that all costs associated with the transmission solution are included in its cost containment limits. DCRT also indicated that it would seek to recover only its actual costs should these be less than the proposed cost containment limits. DCRT stated that it has proposed different route alternatives and that it would be able to choose the route that minimizes the overall project schedule, with no impact to its cost containment proposal. (P-12)

DCRT stated that the binding cost containment limits in its proposal do not include costs to comply with changes in law, such as new NERC compliance requirements. DCRT stated that, if a regulatory agency were to impose a change to the three route options that DCRT identified, DCRT would bear all incremental costs resulting from such route change up to a specified amount and not increase the cost containment limits it has proposed. If the cumulative cost increase associated with the route change were to exceed the specified amount, DCRT would seek to recover the increment above that specified amount. DCRT also clarified that, insofar as a “change in law” is concerned, DCRT would only seek to include in its revenue requirement costs associated with a new law resulting in new costs to comply with new law. DCRT also stated that it would not seek a change in its cost containment proposal should FERC authorize a higher (or lower) return on equity (ROE) in a future filing. (P-11, P-12).

DCRT stated that FERC rules and regulations allow a developer to seek authorization to include certain “incentives” in its transmission revenue requirement and collect them in transmission rates. DCRT indicated that it would choose to impose deliberate cost containment measures and committed to the following with regard to available incentives: (1) no recovery of costs of construction work in progress (CWIP), (2) no ROE that includes a 100 basis point adder, (3) no use of accelerated depreciation, and (4) pursuit of tax incentives/reductions. (P-12)

DCRT included ROE within the cost containment limits in its proposal. (P-12)

DCRT provided its assumptions for its cost estimate regarding the schedule (development period, 26 months for construction, etc.), transmission line (route, rights-of-way, access, design, etc.), and labor rates. (P-3)

DCRT identified three different route alternatives associated with the Copper Bottom Pass section of the project and stated that it would pursue the route that minimizes overall project schedule, with no impact on its cost containment proposal. (P-3)

DCRT provided an estimate of the average annual O&M cost in 2015 dollars, broken down by dispatch, line operations, series compensation, compliance, and corporate services. (P-4)

DCRT provided a description of project schedule and budget performance for transmission line and substation projects completed in the past five years, summarized as follows:

DCRT described 12 transmission projects completed in the past five years; three of these were in the U.S.; none of the three U.S. projects was completed at or below the initial project budget; the overruns were small; of the nine non-U.S. projects, four were completed at or below the initial project budget; DCRT provided reasonable explanations for the overruns.

DCRT described 13 substation projects completed in the past five years; two of the projects were in the U.S.; neither of the two U.S. projects was completed at or below the initial project budget; the overruns were small; of the 11 non-U.S. projects, eight were completed at or below the initial project budget; DCRT provided reasonable explanations for the overruns. (P-6)

DCRT stated that ATI, as the EPC contractor, would assemble a project management team comprised of personnel with the appropriate skill sets, necessary knowledge, and experience in construction of transmission lines. During the project execution, DCRT indicated that it would also hire several contractors with specific experience in their field for the successful completion of the project. DCRT indicated that, prior to the start of the project, it would lay out a management structure for the project through a series of meetings and would develop plans prior to execution, including a project management system, engineering records system, environmental management, labor relations, procurement, logistics, health and safety, and construction managing and contract. DCRT indicated that each of these would consist of a team led by experienced personnel who would be reporting the weekly progress to the assigned head of the project. (P-7)

DCRT indicated that scheduling plays a key role in completing the project on time and on budget. DCRT indicated that each of the teams involved in the project would have a scheduler to track the progress of the team and report to the head scheduler, who would in turn determine whether the project is on schedule. DCRT indicated that the head scheduler would take necessary actions and initiatives to speed up a project in order to avoid penalties and comply with the client's timeline requirements. DCRT stated its team approach to project scheduling is based on the use of Gantt charts. DCRT indicated that ATI would also use a similar approach for the EPC contract. (P-7)

DCRT indicated that the top five risks for the project would be: (1) obtaining rights-of-way, permits, and environmental authorizations; (2) unavailability of manpower and equipment to build the transmission line and substation; (3) raw material volatility; (4) site risk, latent conditions, and access; and (5) interest rates before construction. DCRT discussed its mitigation measures for project risks, which consist primarily of relying on the experience of its sub-contractors or indicating that the EPC contractor would accept the risk. (P-10)

DCRT indicated that it has sited generation and interconnection projects in California and Arizona and that its team has years of experience in obtaining the required regulatory approvals and working with regulators in California and Arizona. (P-10)

DCRT discussed 11 general cost containment categories and actions it would take, such as risk analysis, project planning and scheduling, project staffing, quality assurance, cost reporting and tracking, etc. DCRT indicated that ATI has agreed to sign a lump sum, fixed-fee, turnkey EPC contract for the project construction. DCRT provided the term sheet for this contract, including provisions such as delay and performance liquidated damages, price and payments, and performance assurances. (P-11)

DCRT indicated that VEA would perform O&M work under contract, VEA would provide DCRT with an estimated annual charge for routine maintenance, and DCRT would advance the funds for routine maintenance each year. For major maintenance, DCRT indicated that VEA would provide DCRT with an estimate for approval and payment prior to VEA beginning work. For emergency maintenance, DCRT indicated that VEA would provide DCRT with a detailed invoice after it has completed the maintenance. (P-11)

DCRT indicated that it would evaluate the benefits of working with Western Area Power Administration under its Transmission Infrastructure Program to seek support for the permitting and financing aspects of the project. (P-13)

DCRT stated that it would seek any required new rights-of-way grants from the BLM for portions of the line on federal land. (P-13)

### **3.12.3 Information Provided by DATC**

DATC provided a capital cost estimate in 2015 dollars, with transmission line and series compensation station costs separated, that included contingency funds. DATC stated that it does not expect AFUDC costs for the project because it anticipates asking for and receiving authority from FERC to include CWIP in rate base. (P-2)

DATC did not offer a binding cost containment proposal, stating that firm cost containment limits expose the project sponsor to unlimited financial risks. DATC stated that it is confident that its cost estimate presented is a fair and accurate representation of the cost to deliver the project given the current stage of project development. (P-12)

DATC committed not to seek ROE adders other than that allowed for regional transmission organization membership. DATC indicated that this commitment would not include other incentives like recovery of CWIP or abandonment costs. (P-12)

DATC provided a listing of 14 assumptions used to develop its cost estimate, including items such as route and line design, start and duration of construction, basis for contingency funds, wage rates, 10-hour work days, six-day work weeks, and others. DATC also listed the items not included in the cost estimate, such as substations and terminations, removal of hazardous materials, work stoppages due to archeological/paleontological finds, and others. (P-3)

DATC provided an estimate of the average annual O&M cost in 2015 dollars, broken down by dispatch, line operations, series compensation, compliance, and corporate services. (P-4)

DATC stated that Western DSW has a long history of transmission construction projects and manages projects utilizing mature processes, procedures, and controls. (P-3)

DATC provided a table with estimates of the annual operating and maintenance cost for the project by year. The estimated O&M costs include items such as A&G, inspections, property tax, access maintenance, engineering support, outage coordination, etc. (P-4)

DATC provided a description of project budget performance for transmission line and substation projects completed in the past five years, summarized as follows:

### **Transmission Lines**

ATC – ten projects completed in the past five years; seven projects were completed at or below the initial project budget; one project had a small cost overrun; two projects had larger cost overruns of 5% and 16%.

Duke Energy – seven projects completed in the past five years; one project had a small cost overrun.

Engineering and design contractor – five projects completed in the past five years. DATC did not provide sufficient detail to allow determination of the schedule or cost performance for these projects.

Construction contractor – ten projects completed in the past five years; initial and final cost information provided for only three projects showing serious cost overruns – one overrun of 79%, one overrun of 25%, and one overrun of 33%. DATC described the circumstances and problems that led to these cost overruns.

### **Substations**

ATC – seven projects completed in the past five years; six of the projects were completed at or below the initial project budget; one project had a small cost overrun.

Duke Energy – seven projects completed in the past five years; four projects were completed at or below the initial project budget; three projects had small cost overruns.

Engineering and design contractor – ten projects completed in the past five years. DATC did not provide sufficient detail to allow determination of the schedule or cost performance for these projects.

Construction contractor – one project completed in the past five years; this project was completed on budget. (P-6)

DATC described major issues for each project and provided a typical management progress report.

DATC stated that, as a federal agency, Western DSW cannot release project-specific information involving joint customer projects. (P-6)

DATC stated that its project manager's focus would be on front-end-loaded scope development and management, schedule adherence, recovery plans (if necessary), cost and risk management through the use of Primavera software for schedules, internal processes and procedures, and employing internal and external functional support throughout the project. DATC provided additional information from its proposed project

management manual, including the life cycle, baseline scheduling, constructability, and other proprietary management processes. (P-7)

DATC provided a detailed risk register as part of its project plan to assist in the determination of an appropriate amount of contingency. DATC identified 33 potential risks, including a dollar assessment of the cost impact and a brief review of possible mitigation actions. DATC discussed in more detail several of the risks in its risk register. DATC stated that the primary risk to successful completion of the project on time and within budget is route risk. DATC indicated that its chosen route is the shortest route reasonably available; therefore, any alteration in the route would increase cost. DATC indicated that it could mitigate the schedule impact of route changes by increasing staffing and accelerating construction activities. (P-10)

DATC stated that utility crossings represent another risk to the project. DATC indicated that foundation characteristics and quantity are another risk. DATC stated that permitting represents a material risk to both cost and schedule for the project because inability to acquire permits on time would extend the schedule and delays would affect costs. (P-10)

DATC indicated that it is also important to note risks that are not present for the DATC team. DATC stated that other project sponsors would require some state approvals and permits that Western DSW would not. DATC indicated that this is a significant advantage to DATC because Western DSW would acquire rights-of-way and provide for construction of the facilities under its own authority and jurisdiction. (P-10)

DATC stated that it is not proposing to sponsor more than one project at this time. (P-10)

DATC stated that it would implement a management structure to ensure the appropriate planning and execution of the project. DATC indicated that the project manager would have overall ownership to ensure that risks were actively managed and mitigated and that a team member would be assigned as the owner for each risk. DATC stated that it would manage the engineering, procurement, and construction of the project rather than hire a contractor and that the following items would be covered in contracts to limit liability and control cost: compliance with laws, warranties, procurement, and construction. (P-11)

DATC stated that it plans to use a construction contractor for the project. DATC stated that, although specific techniques for controlling costs and ensuring supplier performance would be negotiated and agreed upon at the time of contract execution, the following cost control techniques are frequently used by DATC's supply chain team: lump sum fixed price contracts or open book target price contracts with shared incentives, owner-supplied major equipment, equipment and labor rate increases tied to specific independent indices, stringent change order approval process, milestone payments based on completed and inspected work, and other items. (P-11)

DATC stated that it would not use contractors for O&M of the project, as Western DSW would perform the O&M. DATC indicated that it would provide oversight of O&M in an equal capacity with Western DSW by creation of, and participation in, a maintenance management committee. DATC indicated that Western DSW would prepare an O&M work plan and budget for the following fiscal year, as approved by DATC. (P-11)

DATC stated that Western DSW would secure all rights-of-way and permits required to site and construct the project and that Western DSW would act under its own authority and jurisdiction to secure rights-of-way and provide for completion of the project. As a result, DATC asserted that its team would not need siting approval from any state agency. (P-13)

DATC asserted that no authorized government body would have the ability to impose a cost cap or cost containment measures related to the project nor would the project bear the risk that a state siting agency would require changes to the project. (P-13)

### **3.12.4 Information Provided by NEET West**

NEET West provided a capital cost estimate in 2015 dollars, with transmission line and series compensation station costs separated, that included contingency funds and AFUDC. (P-2)

NEET West provided a multi-part cost containment proposal that includes binding capital cost containment limits, incentives for completing the project within budget and schedule, and O&M cost recovery waiver for a specified period of time. (P-12)

NEET West stated that its binding cost containment limits include all costs associated with the construction period, including direct costs, allocated/overhead costs, and capital/AFUDC costs. NEET West stated that its binding cost containment limits would be subject to increase prior to the completion of construction to reflect any scope changes directed by the ISO, CPUC, ACC, or other governmental or regulatory body that impact project costs. NEET West indicated that changes to its proposed cost containment limits could also be triggered by the occurrence of any events that would qualify as an “Uncontrollable Force” as defined in the ISO Tariff. (P-12)

NEET West stated that the difference between its capital cost estimate and its binding capital cost containment limits reflects NEET West’s assessment of potential risk for the project. NEET West stated that it expects to be able to construct the project for an amount equal to its cost estimate but no higher than its binding cost containment limits. NEET West indicated that, if it were able to construct the project for a cost below its binding cost containment limits, it would seek to recover its actual costs. (P-12)

NEET West stated that it would agree to include a provision in the approved project sponsor agreement with the ISO reflecting its binding cost containment limits, subject to the cost escalation conditions described, and that NEET West would commit to file a rate recovery request with FERC consistent with the tiered ROE proposal discussed above. (P-12)

NEET West also proposed to forego cost recovery for all O&M and A&G expenses in their entirety (i.e., the project revenue requirement would incorporate zero dollars for O&M and A&G) for a specified number of years. NEET West indicated that it would request FERC approval to recover O&M and A&G following the end of the waiver period and on an annual basis going forward. (P-12)

In addition, NEET West proposed an in-service date guarantee such that NEET West would agree to forego the return of, and associated return on, a specified amount of its total cost to construct the project if it does not meet the latest in-service date of May 1,

2020 specified in the ISO Functional Specifications. NEET West indicated that this incentive would only be applicable if it were to receive all approvals required by the CPUC, ACC, and NEPA processes by July 1, 2018. (P-12)

NEET West provided a thorough discussion of the various assumptions it made to prepare the capital cost estimate, including the line route, structures and spans, and access. NEET West also provided a description of its assumptions, including items such as AFUDC, work schedule (five-day work week), weather (daylight-only work and limitations due to heat), planned outage grading, equipment costs, and environmental. (P-3)

NEET West provided an estimate of the average annual operating and maintenance cost in 2015 dollars, broken down by dispatch, maintenance of lines, structures, and equipment, rents, outside services, and insurance. (P-4)

As discussed above, NEET West stated that it would forego cost recovery for all O&M and A&G expenses in their entirety (i.e., the project revenue requirement would incorporate zero dollars for O&M and A&G) for a specified number of years. NEET West indicated that it would seek to recover actual annual operation and maintenance costs following the end of the waiver period. (P-4)

NEET West provided high-level summaries of project schedule and cost performance for 95 NextEra projects with a transmission element completed since 2003. NEET West stated that budget results for the 95 projects delivered since 2003 demonstrated a total positive variance of \$600 million (under budget) with total project capital costs of \$24.8 billion. NEET West indicated that the three stand-alone transmission projects showed a negative variance of \$100 million (over budget) with total project costs of \$1.2 billion. (P-6)

NEET West also provided descriptions of project cost and schedule performance for individual transmission line and substation projects. For the seven 345 kV transmission line projects completed in the past five years, NEET West indicated that five of these projects were completed at or below the project budget; one overrun was minor; and one overrun was major (43%) due to added land acquisition costs. (P-6)

NEET West described two 500 kV and fourteen 345 kV substations completed in the past five years. For the 500 kV substations, NEET West indicated that both were completed at or below the initial budget. For the fourteen 345 kV substations completed in the past five years, NEET West indicated that 12 of these projects were completed at or below the project budget, one was slightly above the budget, and NEET West did not provide budget details for one project. (P-6)

NEET West stated it would apply to its execution of the project the same project management approach NextEra has employed for the previous projects described in its proposal. NEET West indicated that its approach would consist of active management of all aspects of the project by an experienced and skilled project team of professionals and subject-matter experts who would take personal responsibility and accountability for all phases of the project's execution. (P-7)

NEET West stated that it would take the following project management process steps and actions during its development and construction of the project, based on the model

used by other NextEra companies: project launch and scoping, master project schedule, risks identification and mitigation, comprehensive project cost estimate/budget, project execution plan, monitor and control project schedule, cost and risks, and track and report on project performance. NEET West provided an explanation of its intended actions in each of the project management steps. NEET West also stated that its project director would hold monthly senior management project status update meetings. (P-7)

NEET West provided a table listing 63 risks that it considers as major risks and obstacles to the successful completion of the project on schedule and within budget. NEET West identified the specific 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 and/or construction, and the planned or potential mitigation. NEET West indicated that it considers 28 of the risks listed as having a high impact on the project cost and/or schedule. Of these, NEET West indicated that it considers five of these risks likely to occur; these issues involve delays in regulatory processes and data requests, litigation for the rights-of-way through the Kofa National Wildlife Refuge, and weather impacting scheduled work. NEET West identified early reach-out and process initiation and conservative schedule time allocations as general mitigations for these high impact risks it considers likely to occur. (P-10)

NEET West stated that it is applying to develop multiple projects under the ISO's competitive transmission process. NEET West stated that it would be able to execute multiple projects in parallel due to the extensive experience and capabilities of the NextEra companies at project execution. (P-10)

NEET West stated that it would use a two-part cost containment approach for the project, based on NextEra's established approach. In the first step, NEET West indicated that it would seek to eliminate project uncertainties as early in the project lifecycle as feasible by thoroughly identifying and understanding each project component. NEET West indicated that the second step in its cost containment process is related to uncertainties that cannot be eliminated. NEET West indicated that it would consider these project risks and seek to identify, categorize, and then mitigate these risks throughout project execution. (P-11)

NEET West stated that it would competitively bid the transmission line and series capacitor site civil/electrical construction. NEET West stated that it would prequalify bidders based on financial criteria and credit analysis prior to bidding work. NEET West indicated that each contract would be a performance contract with liquidated damages for late schedule or performance delivery. NEET West indicated that it would meet regularly to review contractor progress and schedules and that any slip in schedule would require a mitigation plan. NEET West indicated that, as an additional incentive to complete construction milestones, it would tie payments to actual progress and earned value as opposed to dates. (P-11)

For project uncertainties and risks, NEET West identified specific actions it would undertake to mitigate risks and contain the potential for costly project scope changes. NEET West grouped numerous actions by risk, including siting, environmental permitting, regulatory approval, engineering and design, and construction. (P-11)



NEET West stated that it would not outsource the bulk of its O&M activities. In terms of its O&M cost, NEET West described cost containment measures for its internally operated program.

NEET West stated that, although not directly considered a cost containment measure, it included a contingency amount in its project cost estimate derived from its assessment of project uncertainties and risks. (P-11)

NEET West stated that it would seek siting approval for the project in California from the CPUC, which has jurisdiction for approving the siting and construction of privately owned electric transmission lines in California that would become part of the ISO-controlled transmission system. NEET West indicated that it understands that the CPUC has imposed cost cap authority on other jurisdictional utilities in the past. However, NEET West stated that such a cost cap is non-binding on the project sponsor since cost recovery of transmission projects is under the jurisdiction of FERC. (P-13)

NEET West stated that it would also seek siting approval in Arizona from the ACC through the certificate of environmental compatibility process. NEET West indicated that Arizona statute ARS § 40-360.03 requires a utility to file an application for a certificate of environmental compatibility for the construction of any transmission lines in the state of 115 kV or higher. Apart from consideration of estimated costs in the siting process, NEET West stated that the ACC has not asserted jurisdiction over the wholesale rates of a merchant transmission line in Arizona due to federal preemption. NEET West indicated that there is no precedent or statutory provision to suggest that the ACC would establish a cost cap through the siting process. (P-13)

As part of its overall development of its proposal, NEET West stated that it reviewed the prior written record for the various attempts to develop and permit prior versions of this project and has met with CPUC staff and ACC commissioners and staff, as well as key stakeholders in both states. NEET West indicated that many officials raised the prospect that establishing a determination of a public interest benefit is not assured – both in California and in Arizona. NEET West discussed its strategy for achieving a determination of public interest benefit for the project. (P-13)

### **3.12.5 Information Provided by TC/SCE**

TC/SCE provided a capital cost estimate in 2015 dollars, with transmission line and series compensation station costs separated, that included contingency funds. TC/SCE stated that it does not expect AFUDC costs for the project because it anticipates asking for and receiving authority from FERC to include CWIP in rate base. TC/SCE provided an estimate of AFUDC that it would use if FERC did not approve CWIP recovery. (P-2)

TC/SCE provided a binding capital cost containment proposal. TC/SCE also stated that any savings realized by delivering the project at a cost below the cost containment limits in its proposal would result in direct savings for the ISO. TC/SCE also stated that it would not seek additional funding beyond the proposed cost containment limits for route changes imposed by regulatory agencies. (P-12)

TC/SCE stated that it has developed three additional features to its bid that address unique aspects of its proposal and the project with respect to schedule acceleration, environmental mitigation, and inflation adjustment. (P-12)

TC/SCE also provided a discussion of the various aspects of the rate proposal it would file at FERC, including capital structure, depreciation, recovery of CWIP, and no special FERC ROE incentives other than a 50-basis point adder for participation in a regional transmission organization. (P-12)

TC/SCE also discussed other cost containment aspects of its proposal, including locating the series compensation at Delaney Substation and the possible efficiencies for the interconnection work (outside the scope of the application) at Delaney and Colorado River Substations given its association with the parent companies. (P-12)

TC/SCE also stated that it would not seek additional funding beyond the proposed cost containment limits for route changes imposed by regulatory agencies. TC/SCE clarified that it has incorporated its route risk contingency (i.e., materials and labor costs resulting from a longer or shorter route imposed by a siting agency) within its cost containment limits. TC/SCE included an environmental exception to the proposed cost containment limits. If the environmental mitigation measures ordered by an agency cause TC/SCE to incur additional environmental mitigation costs above a specified amount assumed within its base bid, irrespective of the length of the final permitted route, then TC/SCE indicated that the cost containment limits would be increased by a specified amount. (P-11)

TC/SCE provided a detailed summary of the various assumptions it used to prepare its cost estimate. TC/SCE included its base assumptions for the line and series compensation. TC/SCE also included a discussion of other cost assumptions, including base case cost estimating, construction and materials, engineering, permitting, and series capacitors. TC/SCE also provided a detailed estimate of land costs. TC/SCE also discussed its assumption that it would be able to use CWIP recovery in lieu of AFUDC. (P-3)

TC/SCE provided an estimate of the average annual O&M cost in 2015 dollars. TC/SCE stated that this estimate is primarily the costs it expects under its agreement for O&M of the project with APS. TC/SCE indicated that it would incur other related costs of operating the project directly, such as regulatory costs, property taxes, insurance, and overhead support services. TC/SCE provided the various assumptions it used to develop its O&M cost estimate and stated that its O&M costs are not included in its cost containment proposal. (P-4)

TC/SCE indicated that personnel of APS, BHT, PacifiCorp, and its collaborator SCE involved with the project have completed or are in various stages of siting, permitting, and constructing approximately 3,000 miles of high-voltage (230 kV and above) lines, including 369 miles in Arizona and 677 miles in California, with the remainder in other states in the U.S.

TC/SCE stated that it has not completed any projects to date but that its team members, its joint venture members and their affiliates, and its collaborator have completed a significant number of projects. TC/SCE provided a description of project budget performance for transmission line and substation projects completed in the past five years, summarized as follows:

## **Transmission Lines**

APS – seven projects completed in the past five years; five projects were completed at or below the initial project budget; two projects had small cost overruns.

BHT – four projects completed in the past five years; all four projects were completed at or below the initial project budget.

SCE – seven projects completed in the past five years; three projects were completed at or below the initial project budget; the four project cost overruns ranged from \$6 to \$32 million. TC/SCE explained these overruns as primarily due to conditions beyond SCE's control.

## **Substations**

APS – three projects completed in the past five years; all three projects were completed at or below the initial project budget.

BHT – eight projects completed in the past five years; seven of the projects were completed at or below the initial project budget; one project had a small overrun.

SCE – eight projects completed in the past five years; five projects were completed at or below the initial project budget; the project cost overruns for three of the projects ranged from \$2 to \$22 million. TC/SCE explained these overruns as primarily due to conditions beyond SCE's control. (P-6)

TC/SCE stated that it has assembled a project management team comprised of individuals from BHT and PNW, as well as California-specific permitting and licensing expertise from its collaborator SCE. TC/SCE indicated that its approach to the overall project would be one of development and long-term ownership. TC/SCE indicated that its aim would be to provide a quality installation to minimize operational and maintenance costs and to provide long-term reliable service. TC/SCE stated that it would accomplish this through effective project management. (P-7)

TC/SCE stated that its project manager would be responsible for oversight of three major project work streams: (1) permitting and siting, (2) engineering and design, and (3) construction delivery. TC/SCE indicated that it would coordinate all activities with the ISO during all phases of the project and comply with all reporting requirements of the ISO. (P-7)

TC/SCE indicated that its overall approach to project management during construction would be governed by the project execution plan, which would be developed with its construction contractor. TC/SCE indicated that the project execution plan would describe the processes, roles, and responsibilities for each phase of the project. TC/SCE provided additional project management discussion in the areas of the application, permitting, project development, construction and commissioning, and operations, including actions it has already taken for the project. TC/SCE also discussed in detail its approach to scheduling. TC/SCE stated that it would use an interactive planning approach to scheduling the project, taking all inputs (scope, estimates, engineering, maintenance, operations, etc.) into account when developing the initial schedule. TC/SCE stated that it would use Primavera software for the project schedule. TC/SCE indicated that it would update the schedule with any approved

changes to the project and report the impact (if any) in terms of potential schedule delays or improvement. TC/SCE indicated that it would also use the schedule for a critical path analysis and the development of “what-if” scenarios to evaluate various execution options throughout the project. (P-7)

TC/SCE stated that it has focused on understanding risks specific to the project and developing strategies to mitigate those risks as a part of developing its cost estimate and cost containment proposal. TC/SCE indicated that it employed a six-step approach to identifying and evaluating risk to maximize the likelihood of delivering the project on budget and on schedule. TC/SCE indicated that it developed a risk register that catalogues 18 risks, including risk category, description, impact, and mitigation. TC/SCE also provided additional risk discussion related to schedule, environment, and line route, including actions it has taken or would take prior to the completion of the ISO selection process to reduce the risks. (P-10)

TC/SCE stated that BHT is currently developing the Gates-Gregg transmission project with its partners but that the commercial operation date of this project will not be impacted by BHT’s development of the Gates-Gregg transmission project, and vice versa. (P-10)

TC/SCE indicated that the schedule, environmental, and the route risks for the project would all be owned and managed by TC/SCE, supported by its consultant and construction contractor. TC/SCE discussed the various actions it has taken or would take to address these risks, including starting the proponent’s environmental assessment and route surveys early, developing its construction acceleration option, on-site visits to assess the line route, study of potential routes to achieve confidence that significant mileage would not be added to its route, and the inclusion of contingency in its cost estimate. (P-11)

TC/SCE summarized its cost containment measures and actions that have been or would be employed during all phases of the project—application, permitting, development, and construction – including risk mitigation, experience with permitting, project design, a combination of a fixed rate and fixed management-price contract for construction, and development of a project-specific risk register. (P-11)

TC/SCE stated that it considered using a turn-key approach for the project but decided that by assembling its team it would be in a position to deliver the most informed proposal that reduces the risks. TC/SCE indicated that, although a turn-key approach is not being used, it would implement provisions in the construction contract to contain construction costs. (P-11)

TC/SCE stated it would contract with APS through an agreement for operation and maintenance to provide O&M services for the project. TC/SCE indicated that it believes this arrangement would contain O&M costs by leveraging APS’s existing O&M personnel and infrastructure, including the primary and backup energy control centers. (P-11)

TC/SCE stated that the project, as it has proposed, would cross private, state, and federal lands located within Arizona as well as private and federal lands within California. As a result, TC/SCE indicated that it would need to seek siting approval from both the ACC and the CPUC. In addition, TC/SCE indicated that it would need to obtain rights-of-way over the federal and state lands that the project would cross. (P-13)

TC/SCE indicated that the ACC, which has siting authority with respect to the lands located within Arizona, does not have the authority to impose binding cost caps or cost containment measures as part of the siting approval process, nor does the BLM or other federal agencies that would be involved in the NEPA or permitting process. (P-13)

TC/SCE indicated that the CPUC, which has siting authority within California, also does not have the authority to impose binding cost caps or cost containment measures on applicants for transmission siting approval. TC/SCE stated that the CPUC has acknowledged that FERC has the authority to regulate transmission costs. (P-13)

## **Authority to Impose Binding Cost Caps**

(P-12, P-13)

### **3.12.6 Information Provided by CTD**

CTD provided a binding capital cost containment proposal. (P-12) CTD stated that its cost containment limits would be subject to increase in the event of a change in the scope of the project due to changes to the ISO project requirements, a change in scope required by law or a regulatory agency, force majeure not covered by the project insurance, or a change in law related to taxes. CTD indicated that an increase to its cost containment limits based upon its proposed cost escalation conditions is very unlikely to occur, since CTD's cost containment limits would not be increased for route changes, cost escalation, or need for additional environmental mitigation not initially anticipated. (P-12)

CTD stated that it would seek siting approval for the transmission line and series compensation station from the BLM, Bureau of Reclamation, ACC, and CPUC. CTD stated that these siting authorities would not have jurisdiction over CTD's rates and therefore would not have a direct mechanism to enforce CTD's cost containment proposal. CTD stated that its rates would be set by FERC and that the FERC rate setting process would be the proper jurisdiction for its binding cost containment measures. (P-13)

### **3.12.7 Information Provided by DCRT**

DCRT offered a binding capital cost containment proposal for the project and stated that the cost containment limits in its proposal include EPC construction costs, development costs, DCRT general costs, AFUDC, and financing fees. DCRT indicated that all costs associated with the transmission solution are included in its cost containment limits. DCRT also indicated it would seek to recover only its actual costs should these be less than the proposed cost containment limits. DCRT stated that it has proposed different route alternatives and that it would be able to choose the route that minimizes the overall project schedule, with no impact to its cost containment proposal. (P-12)

DCRT stated that the binding cost containment limits in its proposal do not include costs to comply with changes in law, such as new NERC compliance requirements. DCRT stated that, if a regulatory agency were to impose a deviation to the routes that DCRT has proposed, DCRT would bear all such costs up to a specified amount cumulatively and not increase the cost containment limits it has proposed. If the cumulative cost increase were to exceed the specified amount, DCRT stated that it would seek to

recover the increment above the specified amount. DCRT also clarified that, insofar as a “change in law” is concerned, DCRT would only seek to include in its revenue requirement costs associated with a new law resulting in new costs to comply with new law. DCRT also stated that it would not seek a change in its cost containment proposal should FERC authorize a higher (or lower) ROE in a future filing. (P-11, P-12)

DCRT stated that FERC rules and regulations allow a developer to seek authorization to include certain “incentives” in its transmission revenue requirement and collect them in transmission rates. DCRT indicated that it would choose to impose deliberate cost containment measures and committed to the following with regard to available incentives: (1) no recovery of CWIP, (2) no ROE that includes a 50 basis point adder, (3) no use of accelerated depreciation, and (4) pursuit of tax incentives/reductions. (P-12)

DCRT stated that it would seek approval for the project in California from the CPUC for authorization to build and operate a transmission line in California as well as for a CPUC certificate of public convenience and necessity, for “lead agency” approval under CEQA and any needed eminent domain orders. DCRT indicated that it does not anticipate that the CPUC would impose cost caps or cost containment measures for the project as long as the project sponsors offer cost caps. (P-13)

DCRT stated that it would seek approval to construct and operate the transmission line in Arizona and seek any related eminent domain order from the ACC. DCRT indicated that it is not aware of any authority of, and reason for, the ACC to impose cost caps or other cost containment measures for the project. (P-13)

### **3.12.8 Information Provided by DATC**

DATC stated that Western DSW would secure all rights-of-way and permits required to site and construct the project and that Western DSW would act under its own authority and jurisdiction to secure rights-of-way and provide for completion of the project. As a result, DATC asserted that its team would not need siting approval from any state agency. (P-13)

DATC asserted that no authorized government body would have the ability to impose a cost cap or cost containment measures related to the project nor would the project bear the risk that a state siting agency would require changes to the project. (P-13)

### **3.12.9 Information Provided by NEET West**

NEET West provided a multi-part cost containment proposal that includes binding capital cost containment limits, incentives for completing the project within budget and schedule, and O&M cost recovery waiver for a specified period of time. (P-12)

NEET West stated that its binding cost containment limits include all costs associated with the construction period, including direct costs, allocated/overhead costs, and capital/AFUDC costs. NEET West stated that its binding cost containment limits would be subject to increase prior to the completion of construction to reflect any scope changes directed by the ISO, CPUC, ACC, or other governmental or regulatory body that impact project costs. NEET West indicated that changes to its proposed cost

containment limits could also be triggered by the occurrence of any events that would qualify as an “Uncontrollable Force” as defined in the ISO Tariff. (P-12)

NEET West stated that, if it were able to construct the project for a cost below its binding cost containment limits, it would seek to recover its actual costs. (P-12)

NEET West stated that it would seek siting approval for the project in California from the CPUC, which has jurisdiction for approving the siting and construction of privately owned electric transmission lines in California that would become part of the ISO-controlled transmission system. NEET West indicated that it understands that the CPUC has imposed cost cap authority on other jurisdictional utilities in the past. (P-13)

NEET West stated that it would also seek siting approval in Arizona from the ACC through the certificate of environmental compatibility process. NEET West indicated that Arizona statute ARS § 40-360.03 requires a utility to file an application for a certificate of environmental compatibility for the construction of any transmission lines in the state of 115 kV or higher. Apart from consideration of estimated costs in the siting process, NEET West stated that the ACC has not asserted jurisdiction over the wholesale rates of a merchant transmission line in Arizona due to federal preemption. NEET West indicated that there is no precedent or statutory provision to suggest that the ACC would establish a cost cap through the siting process. (P-13)

### **3.12.10 Information Provided by TC/SCE**

TC/SCE provided a binding capital cost containment proposal. TC/SCE also stated that any savings realized by delivering the project at a cost below the cost containment limits in its proposal would result in direct savings for the ISO. TC/SCE also stated that it would not seek additional funding beyond the proposed cost containment limits for route changes imposed by regulatory agencies. (P-12)

TC/SCE indicated that the ACC, which has siting authority with respect to the lands located within Arizona, does not have the authority to impose binding cost caps or cost containment measures as part of the siting approval process, nor does the BLM or other federal agencies that would be involved in the NEPA or permitting process. (P-13)

TC/SCE indicated that the CPUC, which has siting authority within California, also does not have the authority to impose binding cost caps or cost containment measures on applicants for transmission siting approval. TC/SCE stated that the CPUC has acknowledged that FERC has the authority to regulate transmission costs. (P-13)

### **3.12.11 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 has considered the expected effectiveness of the project sponsors’ overall cost containment capabilities, including but not limited to experience of cost containment performance on previous projects, project management and scheduling organizations and capabilities, experience of key individuals, the project risks and mitigation that each

project sponsor identified, factors impacting cost, and proposed cost containment plans and proposed binding cost caps.

### **Cost Estimates**

The project sponsors provided different cost estimates for capital costs. The ISO has not identified any significant site-related risks, physical project features, or special construction techniques that would inherently or materially increase the costs of a particular project sponsor's project or pose a distinct cost or cost escalation risk.

### **Binding Capital Cost Containment Measures**

CTD, DCRT, NEET West, and TC/SCE have committed to binding capital cost containment measures for this project, subject to increase to the cost containment limits in their proposals under certain conditions as discussed below. The project sponsors that have offered binding cost containment measures have different approaches to how they would adjust their cost containment limits if there were to be unanticipated changes that increased the costs for the project.

The capital costs underlying CTD's cost containment proposal are significantly lower than the capital costs underlying NEET West's cost containment proposal, slightly lower than the capital costs underlying TC/SCE's cost containment proposal, and significantly higher than the capital costs underlying DCRT's cost containment proposal. CTD would increase its cost containment limits for project changes required by the ISO or a regulatory agency or for force majeure. CTD claims that an increase to its cost containment limits is very unlikely. CTD's cost containment limits would not change for route changes, cost escalation, environmental mitigation, etc. The ROE in CTD's cost containment proposal is slightly lower than the ROE in DCRT's cost containment proposal. No project sponsor other than CTD and DCRT proposed to include ROE within its cost containment proposal.

DCRT's capital cost containment proposal is based on its capital cost estimate, including contingency. The capital costs underlying DCRT's cost containment proposal are significantly below the capital costs underlying the cost containment proposals of CTD, NEET West, and TC/SCE. DCRT would absorb increased costs associated with changes to the routes identified by DCRT up to a certain amount. DCRT also proposes cost containment measures for its return on equity for the life of the project. As noted above, CTD's cost containment proposal is slightly better than DCRT's cost containment proposal with respect to ROE.

The capital costs underlying NEET West's cost containment proposal are equal to its capital cost estimate, including contingency, plus a risk margin added to its cost estimate. NEET West's proposal includes the highest cost containment limits. NEET West added a risk premium in developing its cost containment proposal and would increase the cost containment limits for scope changes by the ISO or a regulatory agency or for changes defined as "Uncontrollable Force" in the ISO Tariff; NEET West would not increase its cost containment limits for small changes if its general route alignment remains valid. NEET West did not propose to include ROE within its cost containment limits, but proposed to reduce its ROE under certain circumstances.



The capital costs underlying TC/SCE's cost containment proposal are equal to its estimate for capital costs, including contingency. The cost containment limits in TC/SCE's proposal are significantly higher than DCRT's cost containment limits, significantly lower than NEET West's cost containment limits, and slightly higher than CTD's cost containment limits. TC/SCE would absorb all costs associated with regulatory agency route changes and increase its cost containment limits by a specified amount only if there were incremental environmental related changes that exceeded the amount reflected in its cost estimate, up to an additional specified amount. TC/SCE's increased capital cost containment limits would be lower than the capital costs underlying CTD's cost containment proposal. TC/SCE did not propose to include ROE within its cost containment limits, but it agreed to forego ROE incentives except for the 50 basis-point-adder for participation in a regional transmission organization.

DATC did not offer a binding cost containment proposal. DATC agreed to forego ROE incentives.

Due to the complexity and diversity of the various binding cost containment measures and cost assumptions contained in the proposals, the ISO and its expert consulting firm conducted a comprehensive cost analysis and ran numerous studies and scenarios to calculate illustrative revenue requirements for each project sponsor's proposal and examined a host of sensitivities to compare costs effectively and assess the impacts of any cost escalation.

Due to the fact that the binding cost containment measures proposed by the project sponsors only addressed costs associated with capital, the ISO first considered the revenue requirements associated with capital items. The ISO then calculated illustrative revenue requirements associated with capital cost and other non-O&M items for each project sponsor's proposal, taking into account proposed cost containment limits and examining a large number of scenarios reflecting different assumptions. The ISO used this approach because the capital cost containment limits were clearly defined by all project sponsors that proposed binding cost containment measures. These analyses showed that DCRT's proposal has significantly lower projected revenue requirements than the proposals of any of the other project sponsors, followed by the proposals of CTD, TC/SCE, NEET West, and DATC, in that order.

The ISO recognizes that the capital cost escalation conditions proposed by CTD are the most secure (capital costs are least likely to increase) and is better than the cost escalation conditions proposed by the other project sponsors. As discussed above, DCRT would absorb route risk up to a specified amount above its cost containment limits. TC/SCE's cost containment limits are firm for route changes, but they allow for recovery of additional environmental mitigation costs (in excess of the amount reflected in TC/SCE's cost estimate) up to a specified level. The ISO and its expert consulting firm conducted a thorough review of the routes proposed by all project sponsors, with specific attention focused on DCRT's identified routes. This review concluded that the cost escalation risk associated with DCRT's proposal is low. The ISO also conducted extensive sensitivity analyses of the projected revenue requirements results, which demonstrated that the cost advantage of DCRT's proposal is very robust compared to the proposals of the other project sponsors, such that it could absorb a significant increase in route-risk-related or other costs and still be the lowest-cost project. Thus, the slightly better capital cost escalation conditions proposed by CTD and TC/SCE do not outweigh the significant cost differential that exists between their proposals and

DCRT's proposal. In addition, the absence of ROE from the cost containment proposals of DATC, NEET West, and TC/SCE poses additional risk.

Based on the foregoing analysis, the ISO has concluded with regard to this aspect of cost containment that DCRT's binding cost containment measures proposal is significantly better than the proposals of the other four project sponsors, that CTD's binding cost containment measures proposal is better than the proposals of DATC, NEET West, and TC/SCE, that TC/SCE's binding cost containment measures proposal is better than the proposals of DATC and NEET West and that NEET West's binding cost containment measures proposal is better than DATC's proposal both on the basis of projected revenue requirements and because DATC's proposal includes only non-binding cost estimates.

### **O&M Cost Containment**

None of the project sponsors provided a binding cost containment proposal for O&M expenses. NEET West proposes to forego cost recovery for all O&M and A&G expenses in their entirety for a specified period of time. None of the other project sponsors has offered any binding cost containment measures for its O&M costs. All the project sponsors would use contracted resources from existing utilities and/or contractors and internal resources. The ISO notes that the O&M cost estimates for TC/SCE, NEET West, and DATC are comparable to each other, and lower than those proposed by CTD and DCRT. The ISO considers it likely that TC/SCE, NEET West, and DATC would have lower O&M costs due to the proximity of affiliate resources in the general vicinity of the project. For example, TC/SCE states that it has an agreement with APS to provide O&M services at cost based on APS' regulatory agency-approved O&M costs. Although the ISO's and its expert consultant's analyses indicated that TC/SCE's proposal could have an overall cost advantage over the proposals of CTD, NEET West, and DATC, but not over DCRT's proposal, when O&M costs are taken into account, the ISO considers these potential O&M cost differences, under the specific circumstances presented here, to be too uncertain to be given significant weight, in part because the project sponsors are outsourcing their O&M services. This does not alter the ISO's conclusions regarding the effect of the project sponsors' commitments to binding capital cost containment measures. In any event, even assuming that TC/SCE's and the other project sponsors' actual O&M costs equal the estimates in their proposals, after taking the binding cost containment proposals into consideration, DCRT's proposal still results in the overall lowest projected revenue requirements.

### **Project Risks and Mitigation of Risks**

All five project sponsors have provided a thorough review of potential risks and mitigation actions they would consider. DATC asserts that it does not face the same risks to the project as the other four project sponsors because DATC will not require some state approvals and permits, as it proposes to have Western DSW acquire rights-of-way and provide for construction of the facilities under its own authority and jurisdiction. The ISO has determined that using one siting authority is a slight advantage for DATC relative to the other four project sponsors with regard to project development and regulatory/permitting efficiency.

### **Project Management Capabilities**

All five project sponsors have provided a reasonable approach to professional project management with experienced personnel identified as project managers.

The project sponsors have different approaches to using turn-key EPC contracts, contracts for portions of the work, and/or internal resources to manage/complete the project. All five project sponsors have identified contract provisions to manage costs with their contractors.

### **Cost Containment Performance for Past Projects**

In terms of completing past projects within the project budget, all five project sponsors and their teams have demonstrated a reasonable degree of success in meeting budgets; the ISO considers the cost overruns reported by the project sponsors either to be insignificant, or the project sponsors provided reasonable explanations of the circumstances that resulted in the overruns. All five project sponsors reference parent or affiliate companies' past projects in presenting their credentials in completing past work.

### **Overall Assessment**

For purposes of the comparative analysis for this component of the factor, the ISO's analysis has considered the expected effectiveness of the project sponsors' overall cost containment capabilities, including but not limited to experience of cost containment performance on previous projects, project management and scheduling organizations and capabilities, experience of key individuals, the project risks and mitigation that each project sponsor identified, factors impacting cost, and proposed cost containment plans.

As discussed above and in Section 2.1, the ISO has identified this selection factor as a key selection factor because the justification for this project is solely based on economic benefits to ratepayers, 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 cost containment measures proposed by the project sponsors to be the most significant inputs into the comparative analysis for this component of the factor.

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 DCRT's proposal is significantly better than the proposals of the other four project sponsors with regard to this component of the factor because the significant advantage of DCRT's proposal with regard to the materially lower project costs resulting from its binding cost containment measures outweighs any other slight advantages the other project sponsors may have with regard to other aspects of their cost containment proposals. The ISO notes that sensitivity studies show that this result would hold true even if the ISO were to take into account the projected O&M costs of the project sponsors. The ISO has determined that CTD's proposal is better than TC/SCE's proposal, and that they are better than the proposals of DATC and NEET West with regard to this component of the factor, because, in conjunction with all the other considerations included in the ISO's analysis for this component of the factor, the ISO has determined that CTD's proposal is better than TC/SCE's proposal, which is better than the proposals of DATC and NEET West, with regard to projected revenue

requirements, which outweighs any other slight advantages the other project sponsors may have with regard to other aspects of cost containment. The ISO has determined that NEET West's proposal is better than DATC's proposal with regard to this component of the factor because, in conjunction with all the other considerations included in the ISO's analysis for this component of the factor, NEET West's inclusion of binding cost containment measures in its proposal and DATC's lack of such measures in its proposal outweighs the lower project development and permitting risks resulting from DATC's proposal.

## **Comparative Analysis of the Authority to Impose Binding Cost Caps**

Because CTD, DCRT, NEET West, and TC/SCE have all proposed binding cost containment measures, 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 process.

## **Overall Comparative Analysis**

The ISO considers the first component of this factor (cost containment and cost cap) more important than the second (siting authority imposing a cost cap). Given that there was at least one binding cost containment proposal offered, the first component is the only basis for the comparative analysis of this factor.

As discussed above, the ISO has determined that DCRT's proposal is better than CTD's proposal, which is better than TC/SCE's proposal, which is better than NEET West's proposal, and which is better than DATC's proposal, with regard to the first component (cost containment and cost cap) of this factor. Consequently, the ISO has determined that DCRT's proposal is better than CTD's proposal, which is better than TC/SCE's proposal, which is better than NEET West's proposal, and which is better than DATC's proposal, with regard to this factor overall.

### **3.13 Selection Factor 24.5.4(k): Additional Strengths or Advantages**

(M-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."

#### **3.13.1 Information Provided by CTD**

CTD stated that LS Power has a proven least-cost approach to transmission with evidence of its ability to deliver transmission line infrastructure at a lower cost than comparable projects with similar design under construction at the same time and in the same region. (M-1)

### **3.13.2 Information Provided by DCRT**

DCRT stated that ATI is a subsidiary of Abengoa, which was recently identified by ENR magazine as the top #1 contractor in transmission and distribution worldwide.

DCRT indicated that it is proposing not to pursue certain rate items and rate incentives that are available to it through FERC. For example, because the special purpose entity that it would establish to develop the project would be a start-up transmission company, ROE adders of as much as 100 basis points would be available. DCRT committed not to pursue these ROE adders for the project, and has agreed to include ROE within its binding cost containment proposal. DCRT asserted that this lower ROE would provide benefits to the ISO and its ratepayers.

DCRT indicated that, by selecting its proposal, the ISO's ratepayers would get the following extra values:

- **Corporate social responsibility:** DCRT indicated that Abengoa is committed to responsible management to reduce the negative impacts of its activities, contribute to developing the communities where its projects are developed, and build trusted partnerships with stakeholders. As a result of this commitment, DCRT indicated that Abengoa has established a strategic corporate social responsibility plan and in 2013 invested more than \$11M in social actions through the Focus-Abengoa Foundation, 12.3% more than the year before.
- **Global footprint accountability:** DCRT indicated that Abengoa has developed a method for calculating the global footprint of its projects in order to provide means to educate and inform the market of the impact of consumption of resources and of Abengoa's activities, with the additional purpose of increasing its commitment to the United Nations Millennium Development Goals and to the sustainable development of communities.
- **Social communication program:** DCRT indicated that Abengoa has established a channel for the purpose of achieving fluid communication with the communities located near a project. DCRT indicated that, by means of a project-specific webpage, the community would be informed of any environmental action or any other initiatives that may be of interest to the communities in the location of where the transmission line project passes.
- **Health and safety:** DCRT indicated that it is important to Abengoa to highlight the constant preoccupation in its corporate culture for the safety of its teams and operations around the world and that Abengoa manages this through a strict system of quality and occupational health and safety at every level of the organization. (M-1)

### **3.13.3 Information Provided by DATC**

DATC stated that it has formed a team, including Citizens Energy, a unique non-profit energy company, that can develop transmission projects and deliver social benefits from those projects. According to DATC, its proposal provides significant benefits, including low income assistance programs in the project vicinity after commercial operation.

DATC stated that Western DSW, as a federal entity, holds federal eminent domain authority, which minimizes the legal hurdles to overcome before taking possession of rights-of-way and provides regulatory certainty because of its exemption from certain state level requirements. (M-1)

### **3.13.4 Information Provided by NEET West**

NEET West offered three additional and unique reasons that it believes differentiates its proposal.

1. NEET West indicated that it will be a new utility in California and Arizona but that it draws on the extensive and long-standing local presence of NextEra subsidiaries.
2. NEET West indicated that it will benefit from its affiliation with FPL, a leading utility in the U.S., and that the accomplishments of FPL, NEER, NEET, and other members of the NextEra family have led NextEra to be named No. 1 in its sector for an unprecedented eighth straight year on Fortune magazine's "Most Admired Companies" list. In addition to being named No. 1 overall in its sector in today's global rankings, NEET West indicated that NextEra also was named No. 1 in its sector for innovation, No. 1 in its sector for social responsibility, and No. 1 in its sector for quality of products/services.
3. NEET West indicated that, through NextEra's shared services model, NEET West would be able to draw on resources from throughout NextEra to provide the operation and corporate support services NEET West would require if selected to develop the project. NEET West indicated that, through this shared services model, FPL, NEER, and NEET employ experienced operation and support service personnel that would be available to assist NEET West and that these resources would give NEET West access to pools of specialized operation and support talent within the NextEra organization. (M-1)

### **3.13.5 Information Provided by TC/SCE**

TC/SCE stated that its team would leverage the combined strengths of three prominent energy leaders – PNW, BHE, and its collaborator SCE — to deliver the project on schedule, within its cost containment limits, and to the ISO's specifications.

TC/SCE also stated that it has begun significant work on siting, routing, and permitting preparation and has initiated interconnection requests with SCE and APS. (M-1)

### **3.13.6 ISO Comparative Analysis**

For purposes of the comparative analysis for this factor, the ISO has reviewed the proposals of the five 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.

Based on its consideration of the proposals of the five project sponsors, the ISO has determined that none of the proposals provide relevant information or identify any particular advantages to the ISO and transmission ratepayers that the ISO has not already considered and addressed in its analysis of the more specific selection factors.

Consequently, the ISO has determined that there is no material difference among the proposals of the five project sponsors with regard to 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 a number of the more specific selection factors discussed in this report. As discussed in Sections 2.1 and 3.3, the ISO has identified this selection factor as a key selection factor because the overall capability to finance, license, construct, operate, and maintain this project is critical to ensuring that the project will be completed and will remain the major component in the ISO’s bulk transmission system that the ISO expects it to be. 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.

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.

#### **3.14.1 ISO Comparative Analysis**

The ISO’s comparative analysis has considered the results of the analysis of the four 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 with respect to this project. The ISO has determined that TC/SCE’s proposal is slightly better than the proposals of the other four project sponsors with regard to this factor because, as discussed regarding each of the relevant individual selection factors, TC/SCE’s proposal is better than the proposals of the other four project sponsors with regard to the third selection factor (construction and maintenance record) and slightly better with regard to the fourth selection factor (demonstrated capability to adhere to standardized construction, maintenance, and operating practices) and is comparable to or better than the proposals of the other four project sponsors with regard to the other two selection

factors. The ISO has determined that DATC's proposal is slightly better than the proposals of CTD, DCRT, and NEET West with regard to this factor because, as discussed regarding each of the relevant individual selection factors, DATC's proposal is slightly better with regard to the fourth selection factor (demonstrated capability to adhere to standardized construction, maintenance, and operating practices) and is comparable to or better than the proposals of CTD, DCRT, and NEET West with regard to the other three selection factors. The ISO has determined that NEET West's proposal is slightly better than the proposals of CTD and DCRT with regard to this factor because, as discussed regarding each of the relevant individual selection factors, NEET West's proposal is better or slightly better than the proposals of CTD and DCRT with regard to the first, third, and fourth selection factors (financial resources, construction and maintenance record, and demonstrated capability to adhere to standardized construction, maintenance, and operating practices) and is comparable to the proposals of CTD and DCRT with regard to the second selection factor. The ISO has determined that CTD's proposal is slightly better than DCRT's proposal with regard to this factor because, as discussed regarding each of the relevant individual selection factors, CTD's proposal is slightly better than DCRT's proposal with regard to the fourth selection factor (demonstrated capability to adhere to standardized construction, maintenance, and operating practices) and is comparable to DCRT's proposal with regard to the other three selection factors.

### **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 other sections 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 all five project sponsors submitted 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 with regard to the project sponsor qualification criteria in its comparative analysis for purposes of selection of the approved project sponsor.

This qualification criterion considers a number of 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 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 factors with regard to this project. Based on a detailed review of the proposals of the project sponsors with respect to these factors, the ISO has determined that TC/SCE's proposal is slightly better than the proposals of the other four project sponsors with regard to this criterion because, as discussed regarding each of the relevant individual selection factors, TC/SCE's proposal is better than the proposals of the other four project sponsors with regard to construction and maintenance record and is slightly better with regard to demonstrated capability to adhere to standardized construction, maintenance, and operating practices, which outweighs the slightly better proposals of three of the four other project sponsors with regard to environmental permitting and engineering experience. The ISO has determined that DATC's proposal is slightly better than the proposals of CTD, DCRT, and NEET West with regard to this criterion because, as discussed regarding each of the relevant individual selection factors, DATC's proposal is slightly better than the proposals of CTD, DCRT, and NEET West with regard to demonstrated capability to adhere to standardized construction, maintenance, and operating practices and is comparable to NEET West's proposal and comparable to or slightly better than the proposals of CTD and DCRT with regard to environmental permitting and engineering experience and construction and maintenance record. The ISO has determined that NEET West's proposal is slightly better than the proposals of CTD and DCRT with regard to this criterion because, as discussed regarding each of the relevant individual selection factors, NEET West's proposal is slightly better than the proposals of CTD and DCRT with regard to construction and maintenance record and demonstrated capability to adhere to standardized construction, maintenance, and operating practices and is comparable to or slightly better than the proposals of CTD and DCRT with regard to environmental permitting and engineering experience. The ISO has determined that CTD's proposal is slightly better than DCRT's proposal with regard to this criterion because, as discussed regarding each of the relevant individual selection factors, CTD's proposal is slightly better than DCRT's proposal with regard to environmental permitting and engineering experience and demonstrated capability to adhere to standardized construction, maintenance, and operating practices and is comparable to DCRT's proposal with regard to construction and maintenance record.

### **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 ISO Comparative Analysis**

The ISO previously determined and posted notice on its website that all five project sponsors submitted 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 with regard to the project sponsor qualification criteria in its comparative analysis for purposes of selection of 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 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 with regard to selection factor 24.5.4(e), the ISO has determined that there is no material difference among the proposals of DATC, NEET West, and TC/SCE with regard to this criterion and that they are slightly better than the proposals of CTD and DCRT, between which there is no material difference, with regard to this criterion. However, all of the project sponsors are capable of financing this project, and each project sponsor has demonstrated the experience and access to financial resources to undertake a project of this size.

### **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 ISO Comparative Analysis**

The ISO previously determined and posted notice on its website that all five project sponsors submitted 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 with regard to the project sponsor qualification criteria in its comparative analysis for purposes of selection of 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 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 with regard to selection factor 24.5.4(i), the ISO has determined that there is no material difference among the proposals of the five project sponsors with regard to this factor.

### **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 CAISO; and (2) has the ability to meet that schedule.”

#### **3.18.1 ISO Comparative Analysis**

The ISO previously determined and posted notice on its website that all five project sponsors submitted 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 with regard to the project sponsor qualification criteria in its comparative analysis for purposes of selection of 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 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 with regard to selection factor 24.5.4(d), the ISO has determined that there is no material difference among the proposals of DATC, NEET West, and TC/SCE, that they are slightly better than the proposals of CTD and DCRT, and that CTD’s proposal is slightly better than DCRT’s proposal, with regard to 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 ISO Comparative Analysis**

The ISO previously determined and posted notice on its website that all five project sponsors submitted 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 with regard to the project sponsor qualification criteria in its comparative analysis for purposes of selection of the approved project sponsor.

This qualification criterion essentially duplicates the factors that are addressed by qualification criterion 24.5.3.1(a) and, by extension, selection factors 24.5.4(f), (g), and (h) discussed above. For this reason, the ISO bases its comparative analysis for this criterion on the results of the comparative analysis for the qualification criterion above.

As discussed above with regard to qualification criterion 24.5.3.1(a), the ISO has determined that TC/SCE's proposal is slightly better than DATC's proposal, which is slightly better than NEET West's proposal, which is slightly better than CTD's proposal, which is in turn slightly better than DCRT's proposal, with regard to this criterion.

### **3.20 Qualification Criterion 24.5.3.1(f): Commitment to Enter Into TCA and Adhere to Applicable Reliability Criteria**

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 CTD**

CTD stated that, if selected as the approved sponsor, it would apply to become a PTO for the purpose of turning the project over to the ISO's operational control and would enter into the TCA and that it would adhere to all applicable reliability criteria and comply with applicable NERC registration requirements and NERC and WECC standards. (QS-5)

#### **3.20.2 Information Provided by DCRT**

DCRT stated that it commits to become a PTO with the ISO with regard to, and turn over operational control of, the project in three respects:

1. DCRT's team includes Abengoa, which DCRT indicated has personnel experienced with NERC, WECC, and O&M requirements for resources operating in both California and Arizona (including the Solana project for APS). DCRT stated that these experienced personnel would register DCRT with NERC and WECC as a Transmission Owner and Transmission Operator, just as they have done for other Abengoa resources operating in California and Arizona.
2. DCRT stated that it has entered into an arrangement with VEA and that VEA owns and operates transmission facilities, is a PTO with the ISO, and has executed the TCA with the ISO.
3. DCRT stated that VEA is registered with NERC and WECC as a Transmission Owner and Transmission Operator. DCRT stated that it would be responsible for operating and maintaining the project and any related facilities as required in the TCA and consistent with NERC and WECC reliability criteria, ISO operating procedures, and ISO protocols. (QS-5)

#### **3.20.3 Information Provided by DATC**

DATC stated that it is the intent of the DATC team for all applicable parties to become PTOs, sign the TCA, turn over all operational control to the ISO, adhere to all applicable

reliability criteria, and comply with NERC registration requirements and NERC and WECC standards, where applicable. DATC stated that its wholly-owned subsidiary, DATC Path 15, LLC, is a PTO for existing facilities within the control of the ISO and that DATC commits to becoming a PTO for the project and to enter into the TCA upon award of project sponsorship. DATC stated that, for clarity, DATC would use the newly-created DATC West Energy to join the ISO as PTO and to sign the TCA for this project. DATC stated that Western DSW would turn the transmission element over to the ISO's operational control, become a PTO for the project, and enter into the TCA, as required. DATC stated that Citizens Energy is a PTO through its subsidiary, Citizens Sunrise Transmission LLC, which owns Citizens Energy's interest in the Sunrise Powerlink. DATC stated that Citizens Energy would create a new legal entity for this project, which would join the ISO as a new PTO and sign the TCA. (QS-5)

#### **3.20.4 Information Provided by NEET West**

NEET West stated that, if selected by the ISO as the approved project sponsor, NEET West would become a PTO with the ISO and that it would construct and own the project and turn over the transmission element to the ISO's operational control, enter into the TCA with respect to the transmission element as applicable, and adhere to all applicable reliability criteria and comply with NERC registration requirements and NERC and WECC standards, where applicable. (QS-5)

#### **3.20.5 Information Provided by TC/SCE**

TC/SCE stated that TransCanyon is committed to becoming a PTO for the purposes of turning the project over to the ISO's operational control, to entering into the TCA with respect to the transmission element, to adhering to all applicable reliability criteria, and to complying with NERC registration requirements and NERC, WECC, and applicable ISO standards, where applicable. (QS-5)

#### **3.20.6 ISO Comparative Analysis**

The ISO previously determined and posted notice on its website that all five project sponsors submitted 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 with regard to the project sponsor qualification criteria in its comparative analysis for purposes of selection of the approved project sponsor.

All five project sponsors have committed to becoming a PTO, turning over control of the project to the ISO, abiding by the terms of the TCA, and adhering to all applicable reliability criteria. Consequently, the ISO has determined that there is no material difference among the proposals of the five project sponsors with regard to 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 2013-2014 transmission planning process, the ISO identified an economically-driven need for the Delaney-Colorado River transmission project – the first project in the history of the ISO’s competitive solicitation process based on this justification. 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. CTD, DCRT, DATC, NEET West, and TC/SCE all submitted strong, well-prepared proposals to develop the project. The ISO was also presented with some strong and innovative cost containment proposals. The ISO would like to re-emphasize that it considers all project sponsors to be qualified to finance, construct, own, operate, and maintain the 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 ISO’s analysis determined that there are either no material differences or only slight differences among the project sponsors and their proposals with regard to most of the selection factors and qualification criteria. The primary selection factor for which the ISO identified significant differences among the project sponsors’ proposals is the selection factor with regard to cost containment, particularly the project sponsors’ commitments to binding cost containment measures. As discussed above, this factor is not only one of the three key selection factors identified by the ISO at the outset of this procurement process, but it is particularly important in this instance given that the justification for this project is solely based on economic benefits to ratepayers. Although the proposals of the other project sponsors have certain slight advantages over DCRT’s proposal with regard to other selection factors and qualification criteria, the ISO has concluded that none of these advantages is sufficient (either individually or in aggregate) to outweigh the significant advantage of DCRT’s proposal with regard to cost containment and producing materially lower project costs to the benefit of ratepayers. The ISO has determined that, given the specific nature of this project and taking into account the key selection factors, the overall advantage goes to DCRT primarily because (1) DCRT’s proposal includes the lowest projected revenue requirements of all the project sponsors’ proposals, and which are significantly less than the nearest project sponsor’s proposal, (2) DCRT’s binding cost containment proposal covers capital costs and return on equity, (3) DCRT’s proposed capital cost containment limits cover up to a specified amount in route risk, which the ISO’s expert consultants determined to be low, particularly in terms of potential cost escalation, and (4), although the proposals of other project sponsors are slightly better than DCRT’s proposal with regard to other selection factors and qualification criteria, the ISO determined that DCRT is qualified to complete the project.

As noted above, the ISO’s analysis determined that other project sponsors provided slightly better proposals than DCRT with regard to experience in acquiring rights-of-way,

adhering to a project schedule, acquiring environmental permits, engineering and design, maintenance, and operations. These slight differences result primarily from DCRT's proposal to use contractors with less experience with 500 kV transmission projects in Arizona and California. DCRT's EPC contractor, ATI, is Abengoa's transmission subsidiary in the U.S. and is a relatively new company. Thus, it has relatively less experience than other project sponsors with respect to high-voltage transmission facilities, particularly experience in California and Arizona. However, Abengoa has an extensive, successful track record with large scale transmission projects outside of the U.S. Similarly, DCRT's O&M contractor does not have specific experience maintaining 500 kV transmission lines. However, it is an existing PTO, has successfully complied with the ISO's maintenance standards, has demonstrated compliance with applicable NERC standards, and has demonstrated reliable operations. The ISO considers these two contractors qualified and capable of performing these functions for this particular project. The ISO's analysis also determined that, although other project sponsors have better financial metrics than DCRT, DCRT has sufficient financial resources to complete the project, and its financial backers have a successful track record of financing projects.

For the foregoing reasons, the ISO has determined that DCRT 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 for this economically-justified project. Based on the ISO's review of the proposals and a comparative analysis with regard to all of the selection factors and qualification criteria, the ISO has determined that DCRT's proposal is better than the proposals of CTD, DATC, NEET West, and TC/SCE with regard to this particular project and this particular justification for its need. The result of this competitive solicitation process is that the ISO has selected DCR Transmission, LLC (DCRT), a joint venture company owned by Abengoa Transmission & Infrastructure, LLC and an affiliate of Starwood Energy Group Global, Inc., as the approved project sponsor to finance, construct, own, operate, and maintain the Delaney-Colorado River project.

Attachment 1

Competitive Solicitation Transmission Project Sponsor Application



## Transmission Project Sponsor Proposal – Application

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## Introduction

In accordance with ISO Tariff section 24.5 (Transmission Planning Process Phase 3), the ISO will initiate a period of at least two (2) months 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 application 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 (PTO) and will sign the Transmission Control Agreement (TCA) and a Reliability Standards Agreement (RSA). 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.

## General Instructions

The information to be included in this application will be used by the ISO to determine if 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 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 should provide information that reflects a thorough understanding of the requirements, processes, and activities needed to accomplish project completion and continuing operation and maintenance.

This application 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, QS-1 for Sponsor Qualifications, QP-1 for Project Qualification, E – 1 for Environmental and Public Process items, S-1 for Substation related items, 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 a project sponsor provides attachments as part of the response, the project sponsor should specify the file name of the attachment in the space provided for the response. In addition, the project sponsor should name the attached files using the following naming convention – the file name should include the unique identifier for the application item that the information responds to (e.g., E-1.a) and a description of the contents (e.g., E-1.a 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. In addition, the application should include a table or index in Microsoft Word format that contains a list of documents provided. The table or index must include the file name, contents, and a description of the application section(s) and items that it responds to. The project sponsor must provide a copy of the application in Word format. The project sponsor must provide all responses and attached material in English or the ISO may disregard the information submitted.

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. If the project sponsor believes that any item of the application is not applicable to its project proposal, it may indicate “N/A” but should provide a brief reason why it believes it is not applicable.

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, regulatory, and reliability requirements.

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 should also indicate how its response

would change depending on how many of its proposals are approved by the ISO. For example, the project sponsor should 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.

Note that at end of the application there is an officer certification form that must be signed by an officer of the authorized representative for the application to be considered complete.

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 handled 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.

Project sponsors should note that the maximum size of an e-mail submitted to the ISO should not exceed 5 MB or the ISO's e-mail system may not be able to process it. An application that includes files or attachments larger than 5 MB must be compressed to files of a size less than 5 MB. Project sponsors may also submit their information via CD or DVD medium. If this option is selected, please provide 3 complete sets of 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.

A project sponsor may submit questions to the ISO for clarification regarding any particular transmission procurement proposal. The ISO will attempt to answer these questions in a timely manner. The answers will be made available in a table that will be posted to the ISO website on the "Transmission Planning" page. Note that the identity of the project sponsor posing the question will not be included in the table. In general, the ISO will update this table on a weekly basis or as needed.

Please note that there are several tables in the application 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. Payment instructions and a project sponsor deposit form can be found in Section 13 of this application.

## Project Sponsor, Name and Qualifications

Project Sponsor Name:

*Response: (Enter Project Sponsor Company Name)*

Project Description:

*Response: (Enter Project Description)*

Submittal Date:

*Response: (Enter Submittal Date)*

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 should include but not be limited to the following information:

- Which entity or entities 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.
- Which entity will service the debt associated with the design, procurement, construction and placing the project in service and the debt carried after commercial operation
- The entity (or planned entity) that will have the responsibility for carrying out the siting, permitting, engineering, procurement, construction and placing the project into operation; also describe if this is to be accomplished through a turn-key EPC contract or some other manner and the type of relationship to be used (e.g. fixed price contract, etc.)
- The entity (or planned entity) that will be responsible for the operation of the project; also describe the mechanism to be used for carrying out this responsibility (e.g. in-house staff, subsidiary, outsourced to a separate O&M company, etc.)

*Response:*

**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. 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).

**Project Sponsor Qualification**

The project sponsor must demonstrate that it meets the project sponsor qualification criteria for the needed transmission element by providing responses to the following five items (QS-1, QS-2, QS-3, QS-4, QS-5) that relate to the qualification of the project sponsor. Note that when providing these responses, the project sponsor may refer to information that has been provided in other sections of this application for additional information and support. However, the following five responses should provide a complete demonstration of qualification – either through the responses directly or by including references in the responses to material provided in responses to other items in this application.

Describe and demonstrate how:

QS-1. The project sponsor has assembled a sufficiently-sized team (or planned team) with the manpower, equipment, knowledge, and skill required to undertake the design, construction, operation, and maintenance of the transmission solution.

*Response:*

QS-2. The project sponsor and its team (or planned team) will have sufficient financial resources; for example, 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.

*Response:*

QS-3. The project sponsor (1) has a proposed schedule for development and completion of the transmission solution consistent with needed in service date identified by the ISO and (2) has the ability to meet that schedule.

*Response:*

QS-4. The project sponsor and its team (or planned team) have the necessary technical and engineering qualifications and experience to undertake the design, construction, operation and maintenance of the transmission solution.

*Response:*

QS-5. 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:*

### **Proposal Qualification**

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. Note: when providing these responses, the applicant may refer to information that has been provided in other sections of this application for additional information and support. However, the following two responses should provide a complete demonstration or qualification – either through the two responses directly or by including references in the two responses to material provided in responses to other items in this 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:*

## Past Projects, Project Management and Cost Containment

### Project Sponsor's Past Project Information

- P - 1. Provide a list of all transmission lines (if this proposed project includes one or more transmission lines) and substations wherever located, (if this proposed project includes one or more substations) which the Project Sponsor or the Project Sponsor's team or planned team has constructed, financed, owned, operated and/or maintained within the last five years. Segregate the transmission line projects from the substation projects. For each project include the following in the table provided below:
- 1) For transmission line projects, provide a description of the line including type of construction (underground, overhead, steel pole, etc.). For substation projects include the number of breakers by voltage and the bus arrangement (BAAH, DBDB, etc.).
  - 2) location (country, state, city),
  - 3) voltage level(s),
  - 4) length,
  - 5) nominal rating of transmission line or total MVA of substation transformers,
  - 6) capital cost,
  - 7) year placed in service, and
  - 8) whether the sponsor was responsible for each of the following for the projects listed - financing (F), designing (D), siting (S), constructing (C), operating (O) and maintaining (M) the line or substation. List all areas that apply. For example if the Project sponsor had responsibility for only Construction, Operation and Maintenance on a project, then a C, O, M would be entered in that cell in the table.



**P-1 Responses - List of Past Projects**

<b>P-1 Transmission Line Projects</b>							
<b>(1)Project Description</b>	<b>(2)Location (Country, City(ies))</b>	<b>(3)Voltage Level(s)</b>	<b>(4)Length (4) (Miles)</b>	<b>(5)Nominal Rating (MVA)</b>	<b>(6)Capital Cost (Million USD)</b>	<b>(7)Date Placed in Service(7)</b>	<b>(8)Sponsor and Team Responsibility (F, D, S, C, O, M)</b>
<b>P-1 Substation Projects</b>							
<b>(1)Project Description</b>	<b>(2)Location (Country, City(ies))</b>	<b>(3)Voltage Level(s)</b>	<b>(4)Length (Miles)</b>	<b>(5)Nominal Rating of All Transformers (MVA)</b>	<b>(6)Capital Cost (Million USD)</b>	<b>(7)Date Placed in Service</b>	<b>(8)Sponsor and Team Responsibility (F, D, S, C, O, M)</b>

### Project Cost Related

- P - 2. Provide a capital cost estimate presented as a buildup of costs by category, such as environmental, engineering, civil works, materials, equipment, construction, construction management, physical and price contingencies, allowance for funds used during construction (AFUDC), and all other categories for which the proposing Project Sponsor plans to seek FERC approval to recover. The above categories are illustrative; the Project Sponsor should aggregate costs into the categories most relevant to its development of the proposed project. For projects with transmission and substation components, the costs for each component should be clearly separated). All costs should be in constant 2015 dollars.

*Response:*

- P - 3. Provide the Project Sponsor's assumptions for the cost estimate (e.g. design assumptions, weather, manpower needed and work schedule like 10 hour days, construction area access, planned outages needed, cost of capital, etc.) and any sensitivity analyses performed in developing the cost estimate. (Note: all assumptions and sensitivities need to be documented).

*Response:*

- P - 4. Provide a detailed estimate of the anticipated average annual operating and maintenance cost to operate the project over its life (i.e. the specific incremental project O&M cost information and not total aggregate costs for the operation and maintenance of a sponsor's overall transmission system). Detail all of the components of the cost estimate. All costs should be in constant 2015 dollars.

*Response:*

- P - 5. 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.

*Response:*

### Project Management, Historical Performance Related

- P - 6. For the transmission and substation projects included in the response to P-1, provide the following:
- Overall project description;
  - Initial schedule **and** final project in-service date; explain the circumstances for a project that did not meet the initial in-service date
  - Overall cost summary, including initial budget for the project **and** final project cost; explain the circumstances for a project that did exceed the initial project budget

- Major issues confronted and resolved during project;
- Typical management progress reports for the project;
- Other specific materials that reflect project management skills for an actual project.

*Response:*

### **Project Management, Project Related**

- P - 7. Provide a general description of the proposed approach to project management and scheduling (PM&S) for the transmission element.

*Response:*

- P - 8. Provide the proposed management structure, organization, authority levels and resources committed to PM&S for the transmission element, including relevant experience and capability for proposed Project Manager (PM) and other relevant decision-makers for the project. If the sponsor does not have a team in place, please provide your plan to meet these requirements.

*Response:*

- P - 9. 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;
- Permitting; R/W and land acquisition;
- Engineering and design;
- Material and equipment procurement;
- Facility construction;
- Agreements (interconnection, operating, scheduling, etc.) with other entities;
- Pre-operations testing;
- 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 start date in the schedule was delayed by 6 months.

*Response:*

- P - 10. For the proposed project, identify the major risks and obstacles to successful project completion on schedule and within cost budget and identify proposed mitigations to minimize the risks. Describe all actions that the Project Sponsor will take to keep the project on schedule and within budget in light of the major risks identified.

If the Project Sponsor is sponsoring more than one project, the Project Sponsor should 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:*

**Cost Containment Overall Process**

- P - 11. Describe the Project Sponsor’s cost containment approach and capabilities and how these will be applied to the proposed project. This should include, but not be limited, to the following information:
- Overall description of how the project risks described in P-10 are allocated and managed.
  - If a turn-key EPC contract will be used, provide a description of the provisions in the contract (or planned to be included in the contract) to support containing the costs of this activity (e.g. performance bonds, invoice retention, etc.).
  - If O&M will be outsourced, provide a description of the provisions in the contract (or planned to be included in the contract) to support containing the costs of this activity (e.g. planning and budgeting, insurance, standards of performance, etc).

*Response:*

**Cost Containment Cost Cap and Emergency Costs**

- P - 12. Does the Project Sponsor propose a binding cost cap (or some other binding cost containment measures)? If so, specify the amount of the cost cap and describe the cost cap or other cost containment measure in detail.

*Response:*

- P - 13. Indicate the authorized government body from which the Project Sponsor will seek siting approval for the transmission and/or substation solution and the authority of the selected siting authority to impose binding cost caps or cost containment measures on the Project Sponsor. Indicate the history of imposing such measures by this authorized government body.

*Response:*

## Financial

The project sponsor 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. In the event the project sponsor proposes to rely on an affiliated entity to meet any or all of these financial criteria, as evidenced by the submission of a non-project sponsor's financial statements or credit ratings, the ISO will require that the affiliated entity provide financial assurances in the form of a written guarantee acceptable to the ISO following the award of the project.

### General

- F - 1. Describe the financial and legal structure of the project sponsor, including type of corporation if a corporation, or type of entity if it is a Special Purpose Entity (SPE; e.g., project financed LLC) created explicitly for the proposed project. 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 this application, please describe the entity's relationship to the Project Sponsor in the form of a corporate hierarchy. In addition, provide details of the parent or affiliated entity's plan for providing for credit, investment or financing arrangements including providing the ISO the necessary guarantees for financial backing of the project. If the financial recourse is limited, please describe under what conditions recourse is available to the parent or affiliate'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. If available, provide annual, audited financial statements or equivalent (for example, 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 Sponsor may provide other documentation demonstrating financial capability. If this information is available electronically, it is acceptable for the Applicant to provide links to the appropriate documents. NOTE: All financial statements must be provided in English.

*Response:*

- F - 4. If available, provide quarterly, unaudited financial statements or equivalent published since the last annual, audited financial statement. If not available, the Sponsor may provide other documentation demonstrating financial capability. If this information is available electronically, it is acceptable for the Applicant to provide links to the appropriate document. 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, provide pro-forma financials (balance sheet, income statement, statement of cash flows, assumptions) for the SPE for each year of the useful life of the project's duration. 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.]

*Response:*

- F - 6. If available, provide current credit ratings and rating agency reports from Moody's Investor Services and Standard & Poor's or another rating agency designated by the U.S. Securities and Exchange Commission as a Nationally Recognized Statistical Rating Organization. If not available, the 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 a Special Purpose Entity (SPE), report any such failures by its 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 affiliated entities including any predecessor SPEs.

*Response:*

- F - 9. Based upon the most recent audited financial statements (if available), provide a ratio of total assets to the total projected capital costs of the project.

*Response:*

- F - 10. For each year for which audited financial statements were submitted according to F – 3 above, provide the following financial ratios:
- a. Funds from operations to interest coverage
  - b. Funds from operations to total debt
  - c. Total debt to total capital

*Response:*

**Project Financing**

For the entity that will secure project financing and is required to provide financial assurances for the project, provide the information requested in F-11 through F-16.

F - 11. Describe the financing used on up to five projects listed in the P-1 Response that are similar in type and size to (or larger than) the transmission element and/or substation proposed in this application. Include the following in your response and use the table provided below:

- 1) Project description
- 2) Financing structure (e.g. LLC vs. corporate, etc.)
- 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. Specify the estimated useful life of the transmission element(s) (i.e., the “operating period”) and describe your ability to finance unexpected repairs or replacement construction during the operating period (e.g., replacement of a series of towers). For example, this demonstration could include but not be limited to the following: use of account set-asides or accumulated funds, parent organization guarantees, letters of credit, letters of intent from 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.

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:*

- F - 14. For financing sources other than the capital markets, describe the benefits to ratepayers and others of your proposed financing source(s). This should include the projected cost of the financing sources.

*Response:*

- F - 15. Describe the detailed financial plan, including planning assumptions, on a monthly basis during the construction period and the first three years of commercial operation for the project. The plan should present the costs and financial outlays in each month of the construction period, and the corresponding sources of financing (equity contribution and debt drawdown), as in the following illustrative table. Data should include an estimate of the cost of both physical and price contingencies during the construction period. The same cost categories and amounts as used in P – 2. The financing plan should indicate the ability of the sponsor to finance the construction of the proposed project under base case and contingency scenarios. Once commercial operation is achieved, the plan should present ongoing maintenance costs as well as cash inflows as construction costs are recovered via the anticipated revenue stream from the project.

In addition to the contingencies included in the base plan, demonstrate how financing would be accomplished under significant project overruns and delays in completion. This should be demonstrated by developing a second plan (or changes to the base plan) that demonstrates how a project that is 30% over budget during construction would be financed, and a third plan (or changes to the base plan) that demonstrates how a project whose commercial operation date is delayed by 20% of the planned time to reach this milestone would be financed.



Item	Cost Categories	Month	Year 1												Year 2												Total
			1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24	
1	Environmental and Related																										
2	Engineering																										
3	Civil Works																										
4	Materials																										
5	Equipment																										
6	Construction																										
7	Construction Management																										
8	Other																										
9	Subtotal - Base Cost																										
10	Physical Contingencies																										
11	Price Contingencies																										
12	Subtotal - Installed Cost																										
13	Working Capital																										
14	AFUDC																										
15	Total Cost = Total Financing Req'd																										
16	Finance Drawdowns																										
17	Debt																										
18	Equity																										
19	Total Finance Drawdowns																										

*Response:*

- F - 16. Provide the annual revenue forecasts for the project - including assumptions. Provide a draft version of the revenue requirement calculation in a format that is similar to what would be included in the tariff application to FERC, indicating the requested tariff level and all assumptions used in the calculations. This should include but not be limited to the assumptions regarding rate of return, depreciation life, split between debt and capital, AFUDC, CWIP, special rate or return adders or bonuses and the weighted cost of capital.

*Response:*

## Environment and Public Processes

- E - 1. Provide an overview of the various project activities needed to achieve siting approval, obtain rights of way (ROW) or other land acquisition for the project, and any other necessary public processes required to construct the project. Include which agencies and permits may be required and why. Base this on a review of the proposed project ROW and/or substation lands to be acquired. Provide a description of the business practices that will be followed (e.g. list of steps or flow chart). If the project is located within more than one state provide a response for each state as applicable.

*Response:*

### Environmental Team and Experience

- E - 2. Provide a list of and description of the firm or group who will be responsible for the siting, land acquisition and permitting aspects of the project. Specify the relationship between the Project Sponsor and these firms or groups (e.g. owned by the Project Sponsor, under contract to Project Sponsor, a division or department of the Project Sponsor, etc.). For each of the firms or groups listed, indicate their individual responsibilities and provide a resume for each lead individual. If the sponsor does not have a team assembled, provide your plan to meet these requirements.

*Response:*

- E - 3. Complete a section of the table below for each firm or group listed in E-2, whether in place or planned. For each of the firms or groups listed provide a list of all transmission substation projects in which they have had the responsibility for siting, land acquisition and/or permitting aspects of the project within the last five years. Include the following information:
- 1) Firm or group name
  - 2) Summary of the project (purpose, include voltage level(s), capacity, number of breakers and arrangement)
  - 3) The firm or group's responsibility on the project (e.g. siting, permitting, ROW acquisition, etc.)
  - 4) Year project was completed
  - 5) Capital cost of the project in US Dollars (millions)
  - 6) Client, who the firm or group worked for

E-3 (1) Firm or Group Name [Use for first firm or group]				
(2) Project Summary	(3) Firm/Group Responsibility	(4) Year Comp	(5) Capital Cost (USD) (M)	(6) Client

(1) Firm or Group Name [Use for second firm or group if needed]				
(2) Project Summary	(3) Firm/Group Responsibility	(4) Year Comp	(5) Capital Cost (USD) (M)	(6) Client
(1) Firm or Group Name [Use for third firm or group if needed]				
(2) Project Summary	(3) Firm/Group Responsibility	(4) Year Comp	(5) Capital Cost (USD) (M)	(6) Client

E - 4. For each firm or group listed, indicate what work the Project Sponsor has completed in the past using these firms for similar areas of responsibilities.

*Response:*

**Permitting**

E - 5. Using your best estimate and available resources, indicate whether any Federal discretionary permit(s) will be required, which agency and under which governing rule or statute. Describe these in detail e.g. EPA Clean Water Act, USACOE Section 401- 404, USFWS Biological Opinion required, etc.

*Response:*

- E - 6. Using your best estimate and available resources, indicate whether any state discretionary permit(s) will be required and the type of permit to be filed (e.g. incidental take permit, water quality Section 401, etc.)

*Response:*

- E - 7. Provide a generalized schedule of the permit activities anticipated and their dependencies and timelines.

*Response:*

- E - 8. Indicate if any federal land (for example Forest Service, BLM, etc.) is proposed to be crossed and if a NEPA (National Environmental Policy Act) environmental process is required.

*Response:*

- E - 9. 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<sup>9</sup> (BMPs) and Applicant Proposed Measures<sup>10</sup> (APMs) that would be applicable for the proposed project.

*Response:*

---

<sup>9</sup> BMPs, which are environmental industry standard terminology, are the applicant'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/injury reporting, community involvement programs involving both the local elected officials and the immediate community that will be impacted by the proposed project.

<sup>10</sup> An environmental consultant industry standard generic term found in any environmental application, that the project proponent would offer in their application submitted to their Lead Agency as initial mitigation for potential environmental impact that the applicant has identified. Normally APMs are fully accepted by the Lead Agency which would then build upon the offered measures based upon the Lead Agencies further assessment of construction impacts to the environment. For example, an applicant's APMs could be a commitment to limit project construction speed limits to 10 mph in order to limit fugitive dust and to re-fuel motor vehicles at least 100 feet from any body of water.

- i. BMPs – provide Project Sponsor standing policies, related to siting and permit processes, that all employees are required to observe, how are they implemented, how are they reported.

*Response:*

- ii. APMs –provide 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:*

- c. Indicate if you expect to perform any public outreach (e.g. open houses, project hotline number, project update mailings etc.) and describe the planned program in general.

*Response:*

#### **Transmission or Substation ROW Acquisition**

- E - 10. 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 (CNDDDB) 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, dismissed and justification for preferred.

*Response:*

- E - 11. 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:*

- E - 12. Provide an indication of whether the Project Sponsor has eminent domain authority. Describe the negotiation strategy in general up to the necessity to file for eminent domain. If applicant does not have eminent domain authority and does not plan to obtain eminent domain authority, describe strategy for acquisition of necessary land rights.

*Response:*

- E - 13. Indicate whether the Project Sponsor has any existing ROW or substations or plans to acquire existing ROWs or substation property from another party 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 / or risks associated with using the existing ROW (for example negotiating additional land rights or the potential of "overburdening" existing easements, etc.).

*Response:*

- E - 14. Provide information describing all transmission lines that were constructed in the last 5 years for which the Project Sponsor or its environmental contractor (designated to complete the environmental and public processes for this proposed project) completed the environmental and public processes associated with the project. The information provided should include:

- a. Transmission line routing and length of routes

*Response:*

- b. Rights of way acquired

*Response:*

- c. Federal and State permits acquired to construct the project

*Response:*

- d. Environmental processes and results as follows:
- i. Provide Federal NEPA or State environmental review determinations if applicable. For projects in California provide CEQA filing history and link to agency web site of the final adjudication or Cal State Clearinghouse number;

*Response:*

- ii. Provide a list of post project mitigation agreements for endangered species impact mitigation; and

*Response:*

- iii. Provide a list of any management plans instituted to comply with Fed/State permits authorizing construction.

*Response:*

E - 15. Provide information describing all transmission substation projects that were constructed in the last 5 years in which the Project Sponsor or its contractor (designated to complete the environmental and public processes for this proposed project) completed the environmental and public processes. The information provided should include (for multiple projects, duplicate the headings (a-d) and Response boxes for each project):

a. Substation location

*Response:*

b. Land acquired

*Response:*

c. Federal and State permits acquired to construct the project

*Response:*

d. Environmental processes and results as follows:

*Response:*

i. Provide Federal NEPA or State environmental review determinations if applicable. For projects in California provide CEQA filing history and link to agency web site of the final adjudication or Cal State Clearinghouse number;

*Response:*

ii. Provide a list of post project mitigation agreements for endangered species impact mitigation; and

*Response:*

iii. Provide list of any management plans instituted to comply with Fed/State permits authorizing construction.

*Response:*

E - 16. Provide information related only to transmission line and substation siting, permits, rights of way and land acquisition in the last 5 years. Provide:

a. A description of any project Notice of Violation (NOV) in the last 5 years

*Response:*

b. Fines levied by the Project approval authority and any other discretionary/ministerial authority

*Response:*

- c. Remediation actions taken to avoid future violations

*Response:*

- d. A summary of law violations by the Project Sponsor found by federal or state courts, federal regulatory agencies, state public utility commissions, other regulatory agencies, or attorneys general

*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 is currently under investigation or is a defendant in a proceeding involving an attorney general or any state or federal regulatory agency, for violation of any laws

*Response:*



## Substation

The S items listed below should only be completed if the propose transmission solution contains a substation or facilities similar to a substation (e.g. synchronous condenser, STATCOM, etc.).

- 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. Provide a list and a description of the firms or groups who will be responsible for substation design and construction. Indicate if the work will be done by the Applicant’s personnel, specific firms, firms pre-approved by the Applicant or a combination. Specify the relationship between the Project Sponsor and these firms or groups (e.g. owned by the Project Sponsor, under contract to Project Sponsor, a division or department of the Project Sponsor, etc.). For each of the firms or groups listed indicate their individual responsibilities on the proposed project (e.g. design, construction, etc.) and provide a resume for the lead individual for each group or firm. If this information is not available provide your plan to meet these requirements.

*Response:*

- S - 3. Complete a section of the table below for each firm or group listed in S-2, whether in place or planned. For each firm or group listed provide a list of all transmission substation projects they have constructed within the last five years.
1. Firm or group name
  2. Summary of the project (purpose, include voltage level(s), capacity, number of breakers and arrangement)
  3. The firm or group’s responsibility on the project (e.g. engineering, construction, procurement, etc.)
  4. Year project was completed
  5. Capital cost of the project in US Dollars (million)

S-3 (1) Firm or Group Name [Use for first firm or group]			
(2) Project Summary	(3) Firm/Group Responsibility	(4) Year Completed	(5) Capital Cost (USD) (M)

(1) Firm or Group Name [Use for second firm or group if needed]			
(2) Project Summary	(3) Firm/Group Responsibility	(4) Year Completed	(5) Capital Cost (USD) (M)
(1) Firm or Group Name [Use for third firm or group if needed]			
(2) Project Summary	(3) Firm/Group Responsibility	(4) Year Completed	(5) Capital Cost (USD) (M)

S - 4. For each firm or group listed, indicate what previous work (list projects or activities) the Project Sponsor has completed using these firms. In particular, list any previous work that is similar to the work that the firm or group will be responsible for on the project.

*Response:*

S - 5. For each proposed substation provide the substation siting criteria that will be used on the project (e.g. future area plans, constructability, earthquake activity, flood plain and mud slide considerations, etc.).

*Response:*

S - 6. For each proposed substation provide the basic parameters for the substation - primary and secondary voltage, BIL<sup>11</sup>, initial design power capacity and final design power capacity (if developed in stages).

<sup>11</sup> 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.

*Response:*

- S - 7. For each proposed substation provide a preliminary design criteria document that specifies the criteria that will be used in the design of the substation or its equivalent. Also provide a list of standards and requirements that will be used in the substation design - e.g. IEEE 142, etc. Provide a complete list of state specific requirements for each US state that the project will be located in (e.g. California and other state specific requirements if part of the project or the entire project is located outside California).

*Response:*

- S - 8. For each proposed substation 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,
  - viii. bus type and rating,
  - ix. high voltage switch types and ratings,
  - x. switchgear type and ratings,
  - xi. battery system arrangements,
  - xii. substation layout with equipment location, fencing, grounding, control/relay building, etc.

*Response:*

- S - 9. For each proposed substation describe the protection system criteria and specific components included in the substation design for primary and back-up protection. Identify any special protection considerations for the substation.

*Response:*

- S - 10. For each proposed substation describe the SCADA incorporated in the design; list the data that will be provided to the ISO; list the control functions that will be included, and which entity will be in control of the devices.

*Response:*

- S - 11. For each proposed substation describe the substation physical security criteria and specific security measures that will be incorporated in the final substation design and the substation oil containment criteria and specific containment measures that will be incorporated in the final design.

*Response:*

## Transmission Line

The T 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,
  - 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 a description of the firms or groups who will be responsible for the transmission line design and construction. Indicate if the work will be done by the Applicant’s personnel, specific firms, firms pre-approved by the Applicant or a combination. Specify the relationship between the Project Sponsor and these firms or groups (e.g. owned by the Project Sponsor, under contract to Project Sponsor, a division or department of the Project Sponsor, etc.). For each of

the firms or groups listed indicate their individual responsibilities on the proposed project (e.g. design, construction, etc.) and provide a resume for the lead individual for each group or firm. Specify the relationship between the Project Sponsor and these firms or groups (e.g. owned by the Project Sponsor, under contract to Project Sponsor, etc.) If this information is not currently available, please provide your plan to meet these requirements.

*Response:*

- T - 3. Complete a section of the table below for each firm or group listed in T-2, whether in place or planned. For each of the firms or groups listed provide a list of all transmission line projects they have designed or constructed within the last five years and the following information:
1. Firm or group name
  2. Summary of the project purpose, include voltage level(s), capacity, conductor, structure type, and mileage. If both overhead and underground transmission was included separate info into overhead and underground.
  3. The firm or group’s responsibility on the project (e.g. engineering, construction, procurement, etc.)
  4. Year project was completed
  5. Capital cost of the project in US Dollars (million)
  6. Client – who the firm or group worked for on the project

<b>T-3 (1) Firm or Group Name [Use for first firm or group]</b>				
<b>(2) Project Summary</b>	<b>(3) Firm/Group Responsibility</b>	<b>(4) Year Comp</b>	<b>(5) Capital Cost (USD) (M)</b>	<b>(6) Client</b>
<b>(1) Firm or Group Name [Use for second firm or group]</b>				
<b>(2) Project Summary</b>	<b>(3) Firm/Group Responsibility</b>	<b>(4) Year Comp</b>	<b>(5) Capital Cost (USD) (M)</b>	<b>(6) Client</b>

- T - 4. For each firm or group listed, indicate what previous work the Project Sponsor has completed using these firms for similar areas of responsibility.

*Response:*

- T - 5. 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 - 6. 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 - 7. 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, etc. 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 - 8. 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 - 9. Provide the following information in the table provided for any proposed overhead transmission line:
- 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:

- a description of the proposed support structures and conductor geometry,
- 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 GO95 Grade of Construction.
- i. Provide NESC and/or GO95 Loading Corridor Separation.
- j. Identify all existing or permitted transmission lines, including voltage, structure type, and separation, located in the same corridor as the proposed project. Identify the criteria used to establish the corridor separation.

T-9 Item	Response
a	
b	
c	
d	
e	
f	
g	
h	
i	
j	

T - 10. For any proposed overhead 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 - 11. 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.
- Corridor Separation
- h. Identify all existing or permitted transmission lines, including voltage, structure type, and separation, located in the same corridor as the proposed project.

T-11 Item	Response
a	
b	
c	
d	
e	
f	
g	
h	

- T - 12. For any proposed underground transmission sections 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.

<i>Response:</i>
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- T - 13. 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, etc.) 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, etc.).
- 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 be paid for by the Project Sponsor.

T-13 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, 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, to provide material to contractors, quality, and expediting.

*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, expected helicopter work, etc.)

*Response:*

## Operation and Maintenance

### Operation and Maintenance Team and Operating and Maintenance Record

- O-1 Provide a chart of the Project Sponsor's proposed organizations showing the reporting relationships of the maintenance and operations organizations including compliance management functions. Describe the roles and responsibilities of the maintenance and operations organizations, including operating jurisdictions as they relate to the proposed project. Describe any organizational changes to the Project Sponsor's current organization that are planned to accommodate the proposed project.

*Response:*

- O-2 Provide resumes describing the qualifications and experience of key management personnel in the proposed maintenance and operating organizations. Relate each resume to a position on the organization chart provided in response to O-1.

*Response:*

- O-3 Describe the experience over the past 5 years with operating and maintaining all transmission facilities by the Project Sponsor or Project Sponsor team members. Describe the role played by the proposed project team members in operating and maintaining those facilities.

*Response:*

- O-4 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 and experience requirements for operators and field personnel.

*Response:*

- O-5 Describe the Project Sponsor's training program for operations and maintenance personnel. Include initial and continuing education requirements for maintaining qualifications for classifications with operation and maintenance responsibilities (e.g. what are the training and certification requirements for operators, linemen and substation electricians?). Identify training resources used.

*Response:*

### Maintenance Practices

- O-6 Describe the Project Sponsor's capability and experience 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 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 these ISO Transmission Maintenance Standards. The effectiveness of each PTO's Maintenance Practices will be gauged through the Availability performance monitoring system. Each PTO's adherence to its Maintenance Practices will be assessed through an ISO review. (TCA Appendix C Maintenance Procedure 4).

*Response:*

- O-7 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:*

- O-8 Provide information, notices or reports regarding the Project Sponsor's experience with implementation and compliance with its standards for inspection, maintenance, repair and replacement of similar facilities.

*Response:*

- O-9 Describe the Project Sponsor's capability and experience that will enable it to provide its Availability Measures in accordance with TCA Appendix C 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 and experience.

*Response:*

- O-10 Would adding the project to the ISO controlled grid require any changes or exceptions to the provisions of the TCA? If "yes", describe.

*Response:*

### **Operating Practices**

- O-11 Identify the NERC functions for which the Project Sponsor has registered or intends to become registered related to the proposed project. 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.

*Response:*

- O-12 If the Project Sponsor plans to contract for services to perform any NERC functions, describe how the Project Sponsor will ensure that these reliability standard(s) or requirement(s) will be accomplished?

*Response:*

- O-13 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 5.1.6. Explain any.

*Response:*

- O-14 Provide information demonstrating that the Project Sponsor has been in compliance with the Applicable Reliability Standards for all transmission facilities that it owns, operates, and or maintains. This could include information for facilities outside the ISO controlled grid and should include available NERC compliance audit results and any notices of violation. Provide information describing the amount of transmission facilities subject to NERC compliance, e.g. miles of line by voltage class, number of substations by voltage class. If the Project Sponsor does not have experience with transmission facilities subject to NERC Standard, provide information demonstrating compliance with standards that do apply to those facilities and the amount of facilities subject to such compliance.

*Response:*

- O-15 Describe, in general, how the Project Sponsor proposes to divide responsibility for NERC reliability standards between the Project Sponsor and the ISO in the Reliability Standards Agreement. Compare your response with existing agreements between the CAISO and other PTOs, and describe expected differences if any. Existing agreements are available on the CAISO website.

*Response:*

- O-16 Describe the applicable agreements that will define the Transmission Operator responsibilities and authority with respect to 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-17 Describe how the Project Sponsor will meet the requirement that Transmission Operators 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 4.3.

*Response:*

- O-18 Describe the Project Sponsor's (for its team or planned team) capability and experience that will enable it to comply with the activities required by TCA 6.1. Physical Operation of Facilities. (Operation, ISO Operating Orders, Duty of Care, Outages, Return to Service and Written Report), TCA 6.3 Other Responsibilities and TCA 7 Operations and Maintenance. (Scheduled Maintenance, Exercise of Contractual Rights and Unscheduled Maintenance).

*Response:*

- O-19 Describe the Project Sponsor's capability (for its team or its planned team) and experience that will enable it to comply with the activities required by TCA 9.2. Management of Emergencies by Participating TOs and 9.3. System Emergency Reports: TO Obligations. Identify resources available, including spare parts and material, 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-20 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 the ISO's Operational Control are subject, together with any documents creating such Encumbrances and any instructions on how to implement Encumbrances and Entitlements in accordance with the TCA 6.4.2.

*Response:*

**Miscellaneous:**

M-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 application.

*Response:*



## Officer Certification

### OFFICER CERTIFICATION FORM

<b>Project Sponsor Name:</b> _____
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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 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 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 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 should be made payable to the CAISO.

#### Overnight Address

California ISO  
Attn: Julie Balch  
Grid Assets  
P.O. Box 639014

California ISO  
Attn: Julie Balch  
Grid Assets  
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: April 7, 2014

Effective Date: April 7, 2014

Application Owner: Stephen Rutty

Application Owner's Title: Director, Grid Assets

## Revision History

Version	Date	Description
4	4-07-2014	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