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April 13, 2026

Via PRCe360 e-Filing and Case Management System

Ms. Melanie Sandoval
Bureau Chief of Records Management
New Mexico Public Regulation Commission
P.O. Box 1269
Santa Fe, NM 87504-1269
prc.records@prc.nm.gov

Re: El Paso Electric Company's Application for a Certificate of Public Convenience and Necessity for a Replacement 200 MW Eddy High Voltage Direct Current Tie

Dear Ms. Sandoval:

El Paso Electric Company ("EPE") hereby files for Commission approval of a Certificate of Public Convenience and Necessity ("CCN") to construct, own, and operate a new 200 megawatt ("MW") High Voltage Direct Current ("HVDC") Tie facility located outside of Artesia, New Mexico. Please note that the Application includes a request for expedited approval.

This filing includes the direct testimony of five EPE witnesses and contains the following components:

- Application
- Proposed Form of Notice
- Compliance Matrix
- Direct Testimony and Exhibits of George Novela, Jonathan M. Trejo, Teresa M. Sosa, David C. Hawkins, and Omar Gallegos.

This Application will be emailed to the parties in EPE's most recent general rate case in Case No. 25-00082-UT. EPE respectfully requests that the Commission issue a final order approving the CCN within eight-and-a-half months of this filing (by December 31, 2026).

This Application is being filed electronically and a check in the amount of $25.00 for the Application will be mailed to the Commission. A copy of the check will be emailed to NMPRC Records separately.

Thank you for your assistance in this matter.

Very truly yours,

/s/ Jeffrey J. Wechsler
Jeffrey J. Wechsler

JJW:yms
Enclosures

Cc: Service List in Case No. 25-00082-UT

BEFORE THE NEW MEXICO PUBLIC REGULATION COMMISSION

IN THE MATTER OF EL PASO ELECTRIC COMPANY'S APPLICATION FOR A CERTIFICATE OF PUBLIC CONVENIENCE AND NECESSITY FOR A REPLACEMENT 200 MW EDDY HIGH VOLTAGE DIRECT CURRENT TIE	)	**Case No. 26-00___**
EL PASO ELECTRIC COMPANY, Applicant	)	

APPLICATION FOR APPROVAL OF CERTIFICATE OF PUBLIC CONVENIENCE AND NECESSITY AND REQUEST FOR EXPEDITED TREATMENT

El Paso Electric Company ("EPE" or "Company") respectfully files this Application with the New Mexico Public Regulation Commission ("NMPRC" or "Commission") for a Certificate of Public Convenience and Necessity ("CCN") in accordance with the New Mexico Public Utility Act ("PUA") NMSA 1978, Sections 62-9-1 and 62-9-6. EPE is seeking this CCN on an expedited basis in order to replace the existing 200 megawatt ("MW") High Voltage Direct Current ("HVDC") Eddy County Converter Station (or "Eddy Tie") facility with a new 200 MW HVDC facility located approximately 10 miles east of the city of Artesia, New Mexico in Eddy County (the "Project"). The existing Eddy Tie facility was built in the mid-1980s. Replacement of the Eddy Tie facility is necessary to support electrical grid reliability, resiliency, and operational performance, enabling EPE to continue to provide adequate and reliable service without unnecessary duplication or economic waste. The Project will provide a net benefit to EPE's customers and is in the public interest.

If approved, replacement of the Eddy Tie is scheduled to be in service to meet the summer peak season of the year 2031. NMSA 1978, Section 62-9-1(C) provides that the Commission must issue an order on a CCN Application within nine months from the date the Application is filed, with the possibility of a six-month extension for good cause. However, EPE respectfully requests

expedited approval by the end of December 2026, in order to save approximately $27.4 million in construction costs for the Project.

In support of this Application, EPE respectfully states as follows:

1. EPE is certified and authorized to conduct the business of providing public utility service within the State of New Mexico and is a public utility subject to the jurisdiction of the Commission under the PUA.

2. EPE generates, transmits, and distributes electricity through an interconnected system to customers in southern New Mexico and Texas. EPE owns, operates, leases, or controls the plant, property, and facilities used by it for the generation, transmission, distribution, sale, or furnishing of electricity to or for the public within New Mexico and Texas.

3. EPE's principal business address and telephone number for its New Mexico service area are:

El Paso Electric Company
100 N. Stanton Street
El Paso, Texas 79901
(915) 543-5711

4. The existing Eddy Tie was certificated by the New Mexico Public Service Commission (the Commission's predecessor) and was completed in 1984. It has been in operation for over 40 years and has reached the end of its useful life from an operational perspective. The age and condition of the existing Eddy Tie significantly diminish its reliability and benefits for EPE customers. The proposed replacement Project would restore the capacity of the Eddy Tie to a full 200 MW capacity on a firm basis.

5. The proposed Project would encompass an area of approximately 15.8 acres of Bureau of Land Management land, immediately adjacent to the existing Eddy Tie facility site. The replacement Eddy Tie facility will accommodate the import and export of 200 MW of power continuously, to ensure availability of electricity during "energy scarcity" events and to balance

power flow within the system by injecting power from the east. Related to the Project (but not a subject of this application), portions of the existing EPE transmission line emanating to and from the new tie will be upgraded in structure height to increase the capacity of the transmission line. Also related to the Project are the installation of communication fiber on the existing transmission line to provide the communications capability necessary for the newer technology equipment.

6. The existing Eddy Tie facility is co-owned by EPE and PNM with a two-thirds and one-third ownership, respectively. However, PNM has opted not to participate in the replacement Eddy Tie. Therefore, EPE will be the sole owner and operator of the proposed new Eddy Tie facility.

7. The United States electricity grid is divided into three main interconnections: Eastern, Western, and Texas. HVDC ties are essential to connect these otherwise independent power grids. The Eddy Tie is located at the "seam" where the Western Interconnection connects to the Eastern Interconnection. The location of the Eddy Tie is significant because it is one of only a few places where the two Interconnections meet, allowing power to move between the two Interconnections.

8. HVDC ties act as electricity highways allowing power to bypass congested AC lines and enable reliable electricity to transfer between the grids. This strengthens the grid during emergency, weather-related shortages and enhances grid resilience against severe weather disasters.

9. The replacement Eddy Tie facility would provide consistently reliable electricity transfer and allow EPE to source energy resources on the eastern side of the Tie, as well as allow users on the eastern side of the Tie to access resources from the west.

10. When western lines become constrained—whether from high loads during summer peaks, planned maintenance outages, or a contingency event—EPE's ability to import power from the west diminishes. The Eddy Tie addresses this issue because it connects to the Eastern

Interconnection and therefore represents an independent import path. Therefore, the connectivity through the Eddy Tie provides diversity and resiliency. Without this replacement Tie facility, EPE will have to plan its system without the benefit of the eastern import path, placing greater stress on the western lines.

11. EPE anticipates that the Project will lead to customer cost savings by increasing opportunities for power to be purchased from and sold to entities across the Tie – benefitting customers through a combination of reductions in fuel costs, reductions in purchased power costs, and increases in revenues.

12. If CCN approval is provided by December 31, 2026, the estimated total cost of the Project (not including Allowance for Funds Used During Construction, or AFUDC) is $289,391,575. The Project is the most economical choice among feasible alternatives, in part because there are no other feasible alternatives that provide similar benefits to the replacement Eddy Tie Project.

13. The replacement Eddy Tie Project will result in a net public benefit.

14. The Project is not expected to result in significant impacts to environmental resources. EPE will incorporate appropriate mitigation measures and best industry practices into all stages of the Project and will conduct periodic environmental inspections to ensure that these measures are properly implemented.

15. No Commission approval is required under the provisions of NMSA 1978, Section 62-9-3(D) concerning location control. Line location approval does not apply because the transmission line involved with the Project is an existing transmission line.

16. Due to considerable interest in the Eddy Tie from stakeholders in EPE's 2025 Integrated Resource Plan ("IRP"), EPE's 2025 IRP Action Plan includes an action item that "EPE will take steps to initiate replacing the Eddy Tie and seek all necessary approvals." This Application satisfies the IRP action item.

17. EPE's supporting testimony and exhibits demonstrate that the proposed replacement Eddy Tie is required by the public convenience and necessity and will not result in unnecessary duplication or economic waste. EPE's witnesses and the subjects they address are as follows:

George Novela – Mr. Novela is EPE's Senior Director of Regulatory Policy and Rates. He addresses the regulatory requirements for approval, explains how this Project meets those requirements, introduces the other witnesses, and explains the anticipated timeline for the Project. In addition, he addresses ownership of the facility, and the impact on rates charged to customers in New Mexico.

Jonathan M. Trejo – Mr. Trejo is EPE's Manager of the Protection, Metering, Automation, and Control Department. His testimony discusses the current condition of the Eddy Tie, which is nearing the end of its useful life, and why replacement is necessary to maintain system reliability and operational flexibility. His testimony also describes the proposed replacement facility, its technology and benefits to the transmission system, the estimated capital cost of the Project, and how the Project represents a prudent and necessary investment to ensure continued interconnection capability between the Eastern and Western Interconnections for the benefit of EPE's customers.

Teresa M. Sosa – Ms. Sosa is EPE's Director of Environmental and Safety Departments, overseeing environmental compliance across all aspects of Company operations. Her testimony addresses environmental, ecological, and cultural impact studies for the proposed Project.

David C. Hawkins – David C. Hawkins is EPE's Vice President of Operations Support. His testimony describes the benefits of the Project, particularly in terms of system reliability and customer cost savings. He also discusses information and studies showing the need for the facility, and the Project's nominal benefits and net present value.

18. Omar Gallegos – Mr. Gallegos is EPE's Vice President of System Planning and Construction. Mr. Gallegos describes EPE's transmission system; discusses why this project is needed and the lack of alternatives, and explains the benefits the Project will bring to EPE's system and net public benefit to customers. His testimony also describes how the existing Eddy Tie has been used to benefit EPE's customers since it was built in the mid-1980s, and the net economic benefit for customers and resulting Benefit Cost Ratio. Service of all notices, pleadings and other documents related to this Application should be made as follows:

Nancy B. Burns
Leslie Padilla
El Paso Electric Company
300 Galisteo Street, Suite 206
Santa Fe, New Mexico 87501
Telephone (505) 982-7391
nancy.burns@epelectric.com
Leslie.padilla@epelectric.com

and

Jeffrey J. Wechsler
Post Office Box 2307
Santa Fe, New Mexico 87504-2307
(505) 982-3873
jwechsler@spencerfane.com

In addition to service on the above, EPE requests electronic service of all pleadings and documents as follows:samantha.lamas@epelectric.com
nancy.burns@epelectric.com
leslie.padilla@epelectric.com
EPE_Reg_Mgmt@epelectric.com
jwechsler@spencerfane.com
kaolson@spencerfane.com
aharris@spencerfane.com
tpacheco@spencerfane.com
ysandoval@spencerfane.com

19. EPE has e-mailed a copy of its Application and supporting Direct Testimonies and Exhibits to parties to EPE's most recent general rate case (NMPRC Case No. 25-00082-UT).

20. A proposed form of Notice is attached as **Exhibit A**.

21. EPE seeks timely treatment of its Application in order to keep construction costs as low as possible. EPE requests, if no protests are filed within sixty days of the date of notice, that the Commission approve EPE's Application without a formal hearing. If a hearing is necessary, EPE requests that this matter be concluded within eight-and-a-half months from the date of filing this Application. NMSA 1978, § 62-9-l(C). EPE makes this request for the benefit of its customers because the contract for construction of the Project includes a cost escalation if CCN approval is not received by December 31, 2026.

WHEREFORE, EPE respectfully requests that the Commission, after such notice and hearing as it deems necessary, issue a Final Order in this case that:

A. Approves a CCN to replace the Eddy Tie, a 200 MW HVDC converter, at a location immediately north of its current footprint;

B. Reserves ratemaking treatment of capital costs and plant maintenance and operational expenses for the Eddy Tie Replacement Project for a future general rate case proceeding; and

C. Grants such other approvals, authorizations, and relief as may be necessary or appropriate.

Respectfully submitted,

Nancy B. Burns, Deputy General Counsel
Leslie Padilla, Senior Attorney
El Paso Electric Company
300 Galisteo St. Ste. 206
Santa Fe, NM 87501
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ATTORNEYS FOR EL PASO ELECTRIC COMPANY

EL PASO ELECTRIC COMPANY
NMPRC DOCKET NO. 26-00___
COMPLIANCE MATRIX

Requirement	Source	Witness	Section
Consistency with the public convenience and necessity and net public benefit	NMSA 1978, Sections 62-9-1(A) and 62-9-6	Novela, Hawkins and Gallegos	Section V of Novela Direct Testimony; Sections V, VI and VII of Gallegos Direct Testimony; Sections III and IV of Hawkins Direct Testimony
Information or studies showing the need or use for the facility being proposed.	Staff	Gallegos, Trejo and Hawkins	Section III of Gallegos Direct Testimony; Sections III through V of Trejo Direct Testimony; Section V of Hawkins Direct Testimony
Information providing specific cost information for the facility being proposed.	Staff	Trejo	Section VI of Direct Testimony
Environmental, ecological and/or cultural impact studies for the facility being proposed.	Staff	Sosa	Section III of Direct Testimony
Specific information demonstrating that the proposed facility is the most economical choice among any feasible alternatives.	Staff	Gallegos, Trejo and Hawkins	Section VII of Gallegos Direct Testimony; Section V of Trejo Direct Testimony; Section V of Hawkins Direct Testimony

EXHIBIT A

BEFORE THE NEW MEXICO PUBLIC REGULATION COMMISSION

IN THE MATTER OF EL PASO ELECTRIC COMPANY'S APPLICATION FOR A CERTIFICATE OF PUBLIC CONVENIENCE AND NECESSITY FOR A REPLACEMENT 200 MW EDDY HIGH VOLTAGE DIRECT CURRENT TIE	)	**Case No. 26-00___**
EL PASO ELECTRIC COMPANY, Applicant	)	

EL PASO ELECTRIC COMPANY'S PROPOSED
NOTICE TO CUSTOMERS

The New Mexico Public Regulation Commission ("Commission" or "NMPRC") hereby gives notice of the following:

1. On April 13, 2026, El Paso Electric Company ("EPE" or "Company") filed with the Commission an Application and Supporting Direct Testimony for an expedited Certificate of Public Convenience and Necessity ("CCN") to replace the existing 200 megawatt ("MW") High Voltage Direct Current ("HDVC") Eddy County Converter Station ("Eddy Tie") facility with a new 200 MW HVDC facility located immediately adjacent to the current Eddy Tie facility, approximately 10 miles east of the city of Artesia in Eddy County, New Mexico. The Application is accessible online on EPE's website, www.epelectric.com/company/public-notices and at https://e360.prc.nm.gov/portal/public/#/public/nm-prc/en/home.

1. EPE's Application states that: (a) the existing Eddy Tie facility has reached the end of its useful life; (b) replacement of the Eddy Tie facility is consistent with public convenience and necessity, and (c) EPE is not seeking any relief related to rates in this proceeding.

2. The Commission has assigned Case No. 26-00_____ to this Application, and all

inquiries and correspondence concerning this matter should refer to that case number.

3. The Commission's Rules of Practice and Procedure, 1.2.2 NMAC, apply to this case except as modified by Order. A copy of 1.2.2 NMAC may be obtained online at https://www.srca.nm.gov/nmac-home/nmac-titles/title-1-general-government-administration/ or from the office of the Commission.

4. The Commission has set the schedule for hearing of this case as follows:

A. Deadline for motions to intervene to become a party to this case: _____, 2026.

B. Deadline by which Commission Staff shall, and Intervenors may, file direct testimony regarding EPE's Application: _____, 2026

C. Deadline to file Rebuttal Testimony, if any: _____, 2026.

D. Public Evidentiary Hearing: _____, 2026 to _____, 2026.

PUBLIC HEARING

5. A public hearing will be held beginning at _____ a.m. on _____, 2026, and will continue through _____, 2026. The public hearing is where the Commission receives testimony, exhibits, and legal arguments about the Application. Members of the public can watch the hearing via a livestream on the Commission's YouTube channel and its website, https://www.prc.nm.gov/public-hearings/. Please contact the Commission for confirmation of the hearing because hearings are occasionally cancelled or rescheduled.

PUBLIC COMMENT

6. If you are interested in the case but do not wish to become a party, you may make oral and written comment as allowed by Rule 1.2.2.23(F) NMAC. The Commission will host a public comment session at which members of the public may make comments in person. The date, time, and place of the public comment session will be announced on the Commission's website.

7. Public comment can be provided at Commission open meetings. The open meetings schedule is available on the Commission website at www.prc.nm.gov/nmprc-open-meeting-agenda/.

8. Public comment will not be taken at the evidentiary hearing because comments are not evidence. You may send written comments before the Commission takes final action by sending the comment, which must specifically reference Case No. 26-00_____, to prc.records@prc.nm.gov, or Commission Records Management Bureau, P.O. Box 1269, Santa Fe NM 87504. The Commission may be reached by telephone at 1-888-427-5772.

9. IF YOU ARE AN INDIVIDUAL WITH A DISABILITY WHO IS IN NEED OF A READER, AMPLIFIER, QUALFIED SIGN LANGUAGE INTERPRETER, OR ANY OTHER FORM OF AUXILIARY AID OR SERVICE TO ATTEND OR PARTICIPATE IN THE HEARING OR FOR A SUMMARY OR OTHER TYPE OF ACCESSIBLE FORMAT OF PUBLIC DOCUMENTS, PLEASE CONTACT THE DIRECTOR OF ADMINISTRATIVE SERVICES OF THE COMMISSION AT (505) 827-8019 AS SOON AS POSSIBLE PRIOR TO THE HEARING.

10. Anyone needing more information about this case may contact the Commission by phone at (505) 827-4084 or 1-888-427-5772 or by email at Ryan.Jimenez@prc.nm.gov.

I S S U E D at Santa Fe, New Mexico this ____ day of _____, 2026.

NEW MEXICO PUBLIC REGULATION COMMISSION

_____

Hearing Examiner

BEFORE THE NEW MEXICO PUBLIC REGULATION COMMISSION

IN THE MATTER OF EL PASO ELECTRIC COMPANY'S APPLICATION FOR A CERTIFICATE OF PUBLIC CONVENIENCE AND NECESSITY FOR A REPLACEMENT 200 MW EDDY HIGH VOLTAGE DIRECT CURRENT TIE	)	**Case No. 26-00___**
EL PASO ELECTRIC COMPANY, Applicant	)	

DIRECT TESTIMONY OF

GEORGE NOVELA

ON BEHALF OF

EL PASO ELECTRIC COMPANY

APRIL 13, 2026

EL PASO ELECTRIC COMPANY
DIRECT TESTIMONY OF
GEORGE NOVELA

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EXHIBITS

EL PASO ELECTRIC COMPANY
DIRECT TESTIMONY OF
GEORGE NOVELA

I. INTRODUCTION AND QUALIFICATIONS

Q1. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is George Novela. My business address is 100 North Stanton Street, El Paso, Texas 79901.

Q2. WHO IS YOUR CURRENT EMPLOYER AND WHAT POSITION DO YOU HOLD?

A. I am employed by El Paso Electric Company ("EPE" or the "Company") as Senior Director of Regulatory Policy and Rates.

Q3. PLEASE SUMMARIZE YOUR EDUCATIONAL BACKGROUND AND PROFESSIONAL EXPERIENCE.

A. I graduated from The University of Texas at El Paso with a Bachelor of Business Administration in Economics in 2006, a Master of Science in Economics in 2008, and a Master of Business Administration in Finance in 2012. I received a Graduate Certificate in Public Utility Regulation & Economics from New Mexico State University in 2014.

Prior to working at EPE, I worked as the Research Coordinator for the City of El Paso's Department of Economic Development from 2007 to 2008. My duties included calculating incentive packages for new and expanding businesses, producing impact studies, and coordinating recruitment efforts with various public and private stakeholders.

In 2008, I began working for EPE as a Load Research Specialist, where I specialized in analyzing EPE's large customers. I was promoted to Senior Economist in 2011, where my responsibilities included the development of the long-term energy,

demand, and customer forecasts used for planning purposes. In 2014, I worked briefly for EPE's Energy Efficiency Department as a Program Coordinator, where I oversaw energy efficiency initiatives for residential customers in both Texas and New Mexico. In 2014, I was promoted to Manager of Economic Research, where I oversaw the Company's long-term forecasting and load research programs. I was promoted to Director of Economic and Rate Research in 2021, where I managed and directed the activities of the Rates Department and Load Research and Data Analytics Department. As of 2024, I serve as Senior Director of Regulatory Policy and Rates, where I lead and represent the company, from a policy perspective, in various regulatory filings, while continuing to oversee my previous responsibilities.

Alongside my professional career, I occasionally teach undergraduate courses in Macroeconomics and Microeconomics at El Paso Community College.

Q4. WHAT ARE YOUR CURRENT RESPONSIBILITIES WITH EPE?

A. As the Senior Director of Regulatory Policy and Rates, I oversee and direct activities of EPE's Rates Department and Load Research and Data Analytics Department. The Rates Department responsibilities include jurisdictional and class cost of service studies, rate design analysis, and the development of EPE's retail rate schedules and charges. The responsibilities of the Load Research and Data Analytics Department include the preparation of long-term customer, energy, and load forecasts, preparation of weather normalization, analysis of load research data, and the preparation of load research studies and reports. As the Senior Director of Regulatory Policy and Rates, I also lead and have direct participation in several regulatory filings made by EPE with the New Mexico Public

Regulation Commission ("NMPRC" or "Commission") and the Public Utility Commission of Texas ("PUCT").

Q5. HAVE YOU PREVIOUSLY PRESENTED TESTIMONY IN REGULATORY PROCEEDINGS?

A. Yes. I have previously filed testimony with both the NMPRC and the PUCT.

II. PURPOSE OF DIRECT TESTIMONY

Q6. WHAT IS THE PURPOSE OF YOUR DIRECT TESTIMONY?

A. The purpose of my testimony is to present EPE's Application for Approval of a Certificate of Public Convenience and Necessity ("CCN") for a Replacement 200 MW Eddy High Voltage Direct Current ("HVDC") Tie (the "Project").

I summarize the proposed Project, introduce EPE's other witnesses who are filing testimony in this proceeding and discuss the regulatory requirements for approval of the Company's request in this filing. I also summarize how the Project meets those requirements. In addition, I address the ownership of the facility and the impact on rates charged to customers in New Mexico.

Q7. ARE YOU SPONSORING ANY EXHIBITS IN SUPPORT OF YOUR TESTIMONY?

A. Yes, I am sponsoring the following exhibits:

- GN-1 – Eddy Tie 1982 CCNs
- GN-2 – Eddy Tie Project AFUDC Calculations

Q8. PLEASE IDENTIFY THE OTHER WITNESSES TESTIFYING ON BEHALF OF EPE AND THE SUBJECTS THEY ADDRESS.

A. The other witnesses and their subject areas are as follows:

- Jonathan M. Trejo, Manager of Protection, Metering, Automation, and Control Department, describes the existing Eddy Tie, including its current condition along with the reasons it must be replaced. He also describes the benefits of the new technology proposed for its replacement, the additional system upgrades needed to support the replacement of the Eddy Tie, as well as the estimated costs and construction schedule.
- Teresa M. Sosa, Director of the Environmental and Safety Departments, discusses environmental considerations related to and in support of EPE's proposed replacement of the Eddy Tie.
- David C. Hawkins, EPE's Vice President of Operations Support, explains the system reliability benefits the Project would bring as well as the benefits customers would realize from reduction of expenses through participation in wholesale market transactions and transmission wheeling revenues.
- Omar A. Gallegos, EPE's Vice President of System Planning and Construction, summarizes EPE's system, which provides context for the benefits of the proposed new Eddy Tie. He also describes the net cost benefits for customers and discusses the qualitative reliability benefits of a new Eddy Tie.

III. PROJECT SUMMARY, REQUESTED RELIEF AND CCN REQUIREMENTS

Q9. PLEASE SUMMARIZE THE PROJECT FOR WHICH EPE IS SEEKING A CCN.

A. EPE is requesting a CCN to replace the existing 200 MW HVDC Eddy Tie with a new 200 MW facility based on current technology. EPE respectfully requests expedited approval by the end of December 2026 in order to benefit from the early pricing proposal of the vendor, GE Vernova. Any approval after the end of 2026 will be associated with a higher cost.

Q10. DID THE COMMISSION ISSUE A CCN FOR THE EXISTING EDDY TIE AND ASSOCIATED TRANSMISSION FACILITIES?

A. Yes. In 1982 in Case No. 1724, the Commission granted CCNs for the existing Eddy Tie facility and related facilities to both EPE and to Texas-New Mexico Power Company ("TNP"). TNP is now part of Public Service Company of New Mexico ("PNM"). The CCNs in Case No. 1724 authorized EPE and TNP to construct, own, operate, and maintain a DC terminal adjacent to an SPS switching station in Eddy County, New Mexico (the "Existing Eddy Tie"); a 345KV transmission line between the DC terminal and the AMRAD substation in Otero County ("AMRAD-Eddy Line"); an expansion of the AMRAD 115KV substation; and a new 345KV substation at AMRAD. A copy of the Order granting the CCNs in Case No. 1724 is attached as Exhibit GN-1.

Q11. WHY WAS THE CCN IN CASE NO. 1724 ISSUED TO BOTH EPE AND TNP?

A. At the time, EPE owned 67 percent of the facilities and TNP owned the remaining 33 percent of the facilities. It is my understanding that EPE and TNP jointly planned the

Existing Eddy Tie to be part of the Eastern Interconnection Project. The basic purpose of the project was to permit power to flow to or from the EPE, TNP or SPS service territories.

Q12. DOES EPE STILL OWN 67 PERCENT OF THE EXISTING EDDY TIE?

A. Yes. EPE continues to own 67 percent of the Eddy Tie, and PNM owns 33 percent. I discuss the ownership of the Project later in my testimony.

Q13. WHY IS EPE SEEKING TO REPLACE THE EDDY TIE?

A. As described by EPE witness Trejo, the existing Eddy Tie has been in service for more than 40 years and has reached the end of its useful life from an operational perspective. As described by EPE witnesses Gallegos and Hawkins, the Project to replace the tie is needed to maintain system reliability benefits; is necessary to maintain the existing interconnectivity with the eastern grid; and will provide a net benefit to EPE customers.

Q14. WHAT REGULATORY APPPROVAL IS EPE SEEKING IN THIS CASE?

A. EPE is seeking a CCN for the replacement Eddy Tie.

Q15. WHY IS EPE ASKING FOR EXPEDITED APPROVAL OF THE PROPOSED PROJECT?

A. EPE is requesting expedited approval to ensure that lower capital costs to develop the proposed facility are realized that will in turn benefit customers. As described in the testimony of EPE witness Trejo, the estimated total cost of the GE Vernova contract for the Project is $242,600,000. That price was negotiated with GE Vernova in January 2026

based on GE Vernova's need to reserve manufacturing slots and to commit its engineering resources in a time of many challenges for manufacturers. If approval occurs after December 31, 2026, the estimated cost will increase to $270,000,000. If approval occurs after June 30, 2027, the Project will need to be renegotiated with GE Vernova, and the total cost is expected to exceed $270,000,000. Therefore, expediting the CCN approval will allow the Company to move forward with the Project in a timely manner, help avoid additional costs, and ultimately benefit EPE's New Mexico customers.

Q16. WHY DID EPE AGREE TO A PRICE INCREASE IN 2027 IF THE CCN IS NOT OBTAINED BY THE END OF 2026?

A. In my experience, it is common for contracts between electric utilities and contractors to include price increases after a set period of time. EPE and GE Vernona reached agreement in January 2026, and the parties agreed that the estimated cost of $242,600 would apply only if the Commission approved a CCN in 2026. EPE agreed to this provision in the hopes that it could receive expedited approval and thereby save money for customers.

Q17. HOW DOES EPE'S EXPEDITED REQUEST RELATE TO THE PROCEDURES IN THIS CASE?

A. If no protest is filed within 60 days of the date notice is given that a CCN application has been filed, the Commission may approve the application without a formal hearing.

Assuming a hearing is held, the Commission has a nine-month period in which to act on a request for a CCN, with the possibility of a six-month extension for good cause.[1]

[1] NMSA 1978, Section 62-9-1(C).

In this case, if the Commission approves the CCN by December 31, 2026 (approximately an eight-and-a-half-month window), as explained by EPE witness Trejo, EPE will secure a lower cost from the vendor, GE Vernova. Therefore, EPE is requesting that the Hearing Examiner adopt a procedural schedule that allows the Commission to act on the application before the end of 2026.

Q18. WHAT STANDARDS DOES THE COMMISSION APPLY IN ISSUING A CCN?

A. In determining whether to issue a CCN, the Commission considers whether the new public utility plant or system is consistent with the "public convenience and necessity."[2] The Commission has equated "public convenience and necessity" with the public interest.[3] In recent years, the Commission has interpreted the "public convenience and necessity" standard as requiring the showing of a "net benefit to the public." In CCNs involving resource acquisitions, the utility applicant must also show that the proposed project is the most cost-effective alternative. This standard has also been applied in cases involving transmission lines and associated facilities.

Q19. HAS THE COMMISSION UTILITY DIVISION STAFF ("STAFF") ALSO SPECIFIED CERTAIN INFORMATION THAT IS USEFUL IN REVIEWING CCN APPLICATIONS?

A. Yes. Staff has testified in CCN proceedings that it considers the following information when reviewing CCN applications:

[2] NMSA 1978, Sections 62-9-1(A) and 62-9-6.
[3] *See Public Service Co. of N.M. v. N.M. Pub. Serv. Comm'n*, 112 N.M. 379, 815 (1991).

1. Information or studies showing the need or use for the facility being proposed;
2. Information providing specific cost information for the facility being proposed;
3. Environment, ecological and/or cultural impact studies for the facility being proposed; and
4. Specific information demonstrating that the proposed facility is the most economical choice among any feasible alternatives.

Q20. YOU MENTIONED THAT EPE AND PNM JOINTLY OWN THE EDDY TIE, IS THAT CORRECT?

A. Yes, EPE owns 67 percent of the existing Eddy Tie facility and PNM owns 33 percent.

Q21. IS PNM A CO-APPLICANT FOR THIS CCN APPLICATION?

A. No. As discussed by EPE witness Gallegos, PNM has opted not to participate in the new Eddy HVDC Tie. EPE will be the sole owner and operator of the proposed new Eddy Tie.

Q22. IS EPE SEEKING APPROVAL TO ABANDON THE EXISTING EDDY TIE AT THIS TIME?

A. No. As described by EPE witness Gallegos, although the Eddy Tie is currently limited in use, it is still providing some benefit to EPE's customers. It is being used during peak season to enhance energy availability during energy scarcity events. Additionally, it is also used to help balance power flows and is being utilized for opportunity sales and/or purchases, including arbitrage transactions, to the benefit of reducing customer fuel and purchased power costs since the revenues from wheeling service to third parties are credited back to EPE's customers as an offset to base rates in a general rate case.

Q23. IS EPE SEEKING A CCN FOR THE TRANSMISSION-RELATED ASPECTS OF THE PROJECT?

A. No. The transmission-related aspects of the Project are described by EPE witness Trejo. That part of the Project consists of routine transmission work done in the ordinary course of business as described in NMSA 1978, Section 62-9-1(A). That statute explains that a CCN is not required for an extension of transmission plant that is "in the ordinary course of business." A CCN is therefore not required for the transmission elements of the Project.

Q24. IS EPE SEEKING LOCATION APPROVAL AS PART OF THIS APPLICATION?

A. No. It is my understanding that the Project does not require line location approval. Section 62-9-3(D) of the Public Utility Act provides that location approval "shall not be required for additions to or modifications of an existing plant or transmission line." Line location approval does not apply because the transmission line involved with the Project is an existing transmission line. EPE will use existing rights of way for this Project.

IV. REGULATORY REQUIREMENTS

Staff Criteria #1: Information or studies showing the need or use for the facility being proposed.

Q25. IS THERE A NEED OR USE FOR THE PROPOSED EDDY TIE REPLACEMENT PROJECT?

A. Yes. As described by EPE witness Trejo, the existing Eddy Tie has been in service for more than 40 years and has reached the end of its useful life from an operational

perspective. As described by EPE witnesses Gallegos and Hawkins, the Project to replace is necessary to maintain the existing interconnectivity with the eastern grid and to provide system reliability benefits.

Staff Criteria #2: Information providing specific cost information for the facility being proposed.

Q26. WHAT IS THE COST OF THE PROPOSED PROJECT?

A. EPE witness Trejo provides detailed estimates of the costs of the new facilities in his testimony. The estimated cash construction cost of the Project is approximately $289,300,000. Allowance for funds used during construction ("AFUDC"), (as shown in Exhibit GN-2) is estimated at approximately $43,300,000 million. Together, these two estimates total an estimated cost of $332,600,000, excluding any associated transmission costs at the Project site or other required transmission upgrades. Although EPE is not seeking approval of any costs for the Project at this time, EPE estimates those transmission costs would be approximately an additional $11,200,000.

As described by EPE witness Trejo, and as explained briefly above, this pricing is contingent on EPE receiving a CCN by December 2026.

Q27. IS EPE SEEKING RATE TREATMENT FOR PROJECT COSTS IN THIS CCN PROCEEDING?

A. No. EPE will seek rate treatment in a future general rate case.

Q28. WILL EPE BE MAKING A SIMILAR REQUEST TO ITS TEXAS REGULATORS?

A. Yes. EPE plans to file a similar request to the PUCT shortly after the New Mexico filing is complete.

Q29. WHAT IS THE ESTIMATED RATE IMPACT ON A RESIDENTIAL CUSTOMER OF THE ESTIMATED PROJECT COST?

A. In the near-term, construction of the Project is expected to result in an annual New Mexico jurisdictional revenue requirement of approximately $7.1 million, resulting in an estimated monthly residential impact of $0.004823 per kWh, or $3.96 per month for a typical customer using 719 kWh per month.

Staff Criteria #3: Environment, ecological and/or cultural impact studies for the facility being proposed.

Q30. WILL EPE CONDUCT AN ASSESSMENT OF THE ENVIRONMENTAL IMPACTS OF THE PROPOSED PROJECT?

A. Yes. EPE is required to conduct an environmental assessment to meet Bureau of Land Management ("BLM") requirements and expects to submit that assessment in July of 2026.

Q31. PLEASE SUMMARIZE THE EXPECTED RESULTS OF THOSE ASSESSMENTS.

A. Preliminary results of the environmental assessments conducted indicate that the proposed Project is not expected to result in significant impacts to environmental resources. EPE will incorporate appropriate mitigation measures and best industry practices into all stages of the Project and will conduct periodic environmental inspections to ensure that these

measures are properly implemented. EPE witness Sosa provides further information about the environmental assessment in her direct testimony.

Staff Criteria #4: Specific information demonstrating that the proposed facility is the most economical choice among any feasible alternatives.

Q32. IS THE PROPOSED PROJECT THE MOST ECONOMIC CHOICE AMONG THE FEASIBLE ALTERNATIVES?

A. Yes. EPE witness Trejo describes that an overhaul or refurbishment of the existing Eddy Tie is not possible and that the only possible alternative is not feasible.

V. NET PUBLIC BENEFIT CRITERIA

Q33. PLEASE SUMMARIZE THE NET PUBLIC BENEFIT OF THE PROPOSED PROJECT.

A. EPE witness Gallegos describes the reliability benefits of a new Eddy Tie in his testimony and provides an analysis that the net economic benefit to EPE's customers is $128 million. The economic benefits are a result of the savings in fuel and purchase power versus the Eddy Tie investment and operating expenses. The financial net present value ("NPV") analysis is provided in EPE witness Gallegos' Exhibit OAG-02.

Q34. ARE THERE OTHER POSSIBLE CUSTOMER BENEFITS FROM THE EDDY TIE BEING REPLACED?

A. Yes. EPE is planning to file with the Federal Energy Regulatory Commission ("FERC") for transmission incentives. FERC regulations (18 CFR § 35.35) list the available financial

incentives for transmission projects. Out of the six available incentives, the Eddy Tie Project would likely qualify and benefit from three of them. If approved, these incentives can increase EPE's Open Access Transmission Tariff, which, in turn, could increase the total FERC transmission revenue credited to EPE's retail customers.

Q35. HAS EPE PROVIDED THE INFORMATION REQUIRED BY THE PUBLIC UTILITY ACT AND STAFF AS PART OF ITS APPLICATION AND ACCOMPANYING TESTIMONY?

A. Yes. The need for the proposed project is addressed in EPE witnesses Hawkins' and Gallegos' testimonies. The cost information associated with the proposed Project is discussed by EPE witness Trejo. Environmental and related considerations for the proposed Project are discussed in EPE witness Sosa's testimony. Finally, the evaluation and explanation for why the proposed facility represents the most economical option among feasible alternatives are provided by witnesses Trejo, Hawkins, and Gallegos.

VI. CONCLUSION

Q36. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes, it does.

BEFORE THE NEW MEXICO PUBLIC SERVICE COMMISSION

IN THE MATTER OF THE APPLICATION OF TEXAS-NEW MEXICO POWER COMPANY AND EL PASO ELECTRIC COMPANY FOR CERTIFICATES OF PUBLIC CONVENIENCE AND NECESSITY FOR THE EASTERN INTERCONNECTION PROJECT,	)	
TEXAS-NEW MEXICO POWER COMPANY AND EL PASO ELECTRIC COMPANY,	)	Case No. 1724
Petitioners	)	

ORDER GRANTING CERTIFICATES
OF PUBLIC CONVENIENCE AND NECESSITY

This matter came on before the New Mexico Public Service Commission ("Commission") upon the Certification of the Hearing Examiner and the Settlement Stipulation of the parties attached thereto. The Commission having reviewed the Certification and Settlement Stipulation and being otherwise fully informed of the premises, F I N D S that:

1. Texas-New Mexico Power Company ("TNP") and El Paso Electric Company ("EPE") are Texas corporations which own, operate, lease or control plant, property, or facilities for the generation, transmission, distribution, sale, or furnishing of electricity for light, heat, power or other uses to or for the public in the State of New Mexico. Certified copies of the articles of incorporation of TNP and EPE are on file in the office of the Commission.

2. TNP and EPE are qualified to transact and are transacting business in the State of New Mexico.

3. TNP and EPE are not engaged solely in interstate business.

4. TNP and EPE are public utilities as defined in Section 62-3-3G, NMSA 1978, and are subject to the provisions of the Public Utility Act, Sections 62-3-1 et seq., NMSA 1978.

5. TNP provides retail electric service to customers in Catron, Grant, Hidalgo, Luna, Lincoln and Otero counties, New Mexico. EPE provides retail electric service to customers in Dona Ana, Luna, Otero and Sierra counties, New Mexico.

6. TNP and EPE have determined it necessary, in the ordinary course of business, to interconnect their electrical transmission systems with the electrical transmission system of Southwestern Public Service Company ("SPS").

7. The interconnection of the electrical transmission systems of TNP, EPE, and SPS will permit each utility to purchase and sell energy, whether on a firm, contingent, interruptible, economy or emergency basis, to each other utility and to improve the quality of service to each utility by providing increased system reliability.

8. On February 12, 1982, TNP and EPE filed with this Commission a petition ("Petition") in which TNP and EPE each requested a Certificate of Public Convenience and Necessity ("CCN") and authority for TNP and EPE to construct, own, operate and maintain:

A. A back-to-back Direct Current Terminal Station ("DC Terminal") in or adjacent to the Eddy County Switching Station in Eddy County, New Mexico, which is presently owned and operated by SPS.

B. A 345KV transmission line and related facilities ("AMRAD-Eddy Line") between the DC Terminal and the AMRAD Substation, Otero County, New Mexico, which is presently owned and operated by EPE.

C. An expansion to the present AMRAD 115KV Substation ("AMRAD Expansion"), and

D. A new 345KV Substation and related facilities at AMRAD ("AMRAD 345 Substation").

9. In the Petition, TNP separately requested a Certificate of Public Convenience and Necessity and authority to construct, own, operate and maintain a 115KV transmission line and associated facilities between the AMRAD 345 Substation and the Alamogordo Substation, Otero County, New Mexico, which is presently owned and operated by TNP ("Alamogordo-AMRAD Line").

10. In the Petition, EPE separately requested a Certificate of Public Convenience and Necessity and authority to construct, own, operate and maintain a 345KV transmission line and associated facilities from the AMRAD 345 Substation to EPE's Newman Substation ("AMRAD-Newman Line").

11. The DC Terminal, AMRAD-Eddy Line, AMRAD Expansion, AMRAD 345 Substaion, Alamogordo-AMRAD Line, AMRAD-Newman Line and the related facilities (collectively, the "Eastern Interconnection Project"), are anticipated to be located along the route shown on Exhibit IRT-1 filed herein.

12. The DC Terminal, AMRAD-Eddy Line, AMRAD Expansion, and AMRAD 345 Substation will be jointly owned by TNP and EPE, with each utility holding an undivided interest as a tenant in common. The proposed respective ownership interest, and the cost responsibilities, of the various components of the DC Terminal, AMRAD-Eddy Line, AMRAD Expansion, and AMRAD 345 Substation are shown on Exhibit BEB-1 and set forth in the Direct Testimony of Billye E. Bostic filed herein. The exact percentage of ownership interest and cost responsibility for any particular component may change to accommodate particular situations encountered by TNP and EPE during construction of the project; however,

the final percentage of ownership interests and costs responsibilities will be substantially in accordance with Exhibit BEB-1 and the Direct Testimony of Billye E. Bostic.

13. The Eastern Interconnection Project is feasible from an engineering and economic standpoint and is needed by TNP and EPE in order that they may be able to continue to perform their statutory duties of rendering reasonable and adequate service to the public. TNP and EPE are ready, willing and able to undertake and complete the proposed Eastern Interconnection Project.

14. TNP has entered into an Interconnection Agreement with SPS ("TNP-SPS Interconnection Agreement"). The TNP-SPS Interconnection Agreement provides that either party may furnish or receive emergency service and economy energy service and provides TNP with 66 megawatts of firm capacity for a period of 20 years. The TNP-SPS Interconnection Agreement and the Eastern Interconnection Project will provide TNP with access to an additional supply of electrical energy and will increase TNP's system reliability by providing an additional source of electrical energy.

15. EPE has entered into an Interconnection Agreement with SPS ("EPE-SPS Interconnection Agreement"). The EPE-SPS Interconnection Agreement provides that either party may furnish or receive emergency service and economy energy service and provides EPE with interruptible power service for a period of 20 years. The EPE-SPS Interconnection Agreement and the Eastern Interconnection Project will provide EPE with access to an additional supply of electrical energy and will increase EPE's system reliability by providing an additional source of electrical energy.

16. The cost of the Eastern Interconnection Project is estimated to be approximately $55,700,000.

17. Construction of the Eastern Interconnection Project will result in (a) lower cost bulk power than is presently available, (b) greater reliability of service, (c) greater flexibility in the operation of the electrical

systems of TNP and EPE, and (d) will not result in unnecessary duplication and economic waste. Public convenience and necessity therefore require construction and operation of the Eastern Interconnection Project.

18. On February 18, 1982, the Commission issued its Order of Hearing and of Notice in this case.

19. The Order of Hearing and of Notice was duly published in newspapers of general circulation within the territory in which the Eastern Interconnection Project will be built.

20. On March 5, 1982, a joint petition for leave to intervene was filed by Public Service Company of New Mexico ("PNM") and New Mexico Electric Service Company ("NME") but was withdrawn by motion filed by PNM and NME on March 26, 1982.

21. TNP, EPE and the Commission Staff executed a Settlement Stipulation on March 26, 1982, wherein they state that they are in agreement as to the resolution of the issues in this case. Exhibit A to the Settlement Stipulation shows that PNM and NME support TNP and EPE in their petition for Certificates of Public Convenience and Necessity in connection with the Eastern Interconnection Project.

Based on the foregoing, the Commission C O N C L U D E S that:

1. The Commission has jurisdiction over the parties hereto and the subject matter herein.

2. This matter has duly proceeded in accordance with the Public Utility Act.

3. Construction of the Eastern Interconnection Project will result in (a) lower cost bulk power than is presently available, (b) greater reliability of service, (c) greater flexibility in the operation of the electrical systems of TNP and EPE, and (d) will not result in unnecessary duplication and economic waste. Public convenience and necessity therefore require construction and operation of the Eastern Interconnection Project.

NOW, THEREFORE, IT IS HEREBY ORDERED by the New Mexico Public Service Commission that:

1. The Settlement Stipulation between the parties attached to the Hearing Examiner's Certification is hereby accepted and approved without modification or exception, but this decision is strictly limited to the facts before the Commission in this case and has no precedential value with respect to the application or interpretation of Section 62-9-3, NMSA 1978 in any future cases.

2. TNP is hereby issued a Certificate of Public Convenience and Necessity for the construction, operation, extension and ownership of its portion of the Eastern Interconnection Project subject to the provisions of Paragraph 4, below.

3. EPE is hereby issued a Certificate of Public Convenience and Necessity for the construction, operation, extension and ownership of its portion of the Eastern Interconnection Project subject to the provisions of Paragraph 4, below.

4. The Certificates of Public Convenience and Necessity granted to TNP and EPE in this Order are approved and authorized in the manner proposed by TNP and EPE to the extent that such approval and authorization of the Commission are required by the laws of the State of New Mexico, provided:

A. This Order shall constitute appropriate evidence, and the only evidence required, of the issuance of a CCN to TNP and to EPE for the construction and operation of the Eastern Interconnection Project, and the CCN's and accompanying authority and authorization granted by this Order are not transferable;

B. Nothing contained herein shall be considered or construed as a finding by the Commission of: (i) the value for

ratemaking purposes of any of SPS'sproperties; or (ii) the justness or reasonableness of any expenses incurred by SPS;

C. Nothing contained herein shall be considered or construed as affecting in any way the Commission's jurisdiction to exercise the Commission's full authority over rates, service and other matters pursuant to law;

D. The approval, authorization and CCN's granted herein are based on the representations presented in this case by representatives of TNP and EPE regarding the manner in which TNP and EPE shall construct and operate the Eastern Interconnection Project, and should the conditions, terms or provisions of that construction and operation be materially or substantially amended, the Commission retains jurisdiction and reserves the right, as a condition of the approval, authorization and CCN's granted herein, to review and determine the propriety of the amendments and to change or modify such approval, authorization and CCN's granted herein as the Commission deems appropriate.

5. TNP and EPE shall file within thirty (30) days following the completion of the construction of the Eastern Interconnection Project, TNP's and EPE's verified report or reports showing the completion, together with the date thereof, a statement of any deviations or amendments in the location, construction or operation of the Eastern Interconnection Project from the manner proposed in TNP's and EPE's Petition and in TNP's and EPE's testimony in this case, and a statement of the actual cost of construction of the Line.

6. This order shall become effective immediately.

I S S U E D under the Seal of the Commission at Santa Fe, New Mexico, this 5th day of April, 1982.

NEW MEXICO PUBLIC SERVICE COMMISSION

Richard P. Montoya, Chairman

Phil R. Lucero, Commissioner

Dolores M. Lee, Commissioner

El Paso Electric Company
High Voltage Direct Current (HVDC) Tie
Cashflow and AFUDC Based on Forecasted Capital thru Commercial Operation Date

	CASH							TOTAL
Month	HVDC (Eddy Tie)	Accumulated Cash Flow	Monthly AFUDC (No Compounding)	Accumulated AFUDC (Uncompounded)	AFUDC (on CASH ONLY CUMULATIVE)	Semi-Annual AFUDC (on AFUDC ONLY)	TOTAL AFUDC (Compounded on Cumulative Balance)	All Inclusive Project Balance
Jan-26	2,405	2,405	-	-	-		-	2,405
Feb-26	2,405	4,811	-	-	-		-	4,811
Mar-26	1,685,525	1,690,335	-	-	-		-	1,690,335
Apr-26	323,417	2,013,752	-	-	-		-	2,013,752
May-26	355,955	2,369,706	-	-	-		-	2,369,706
Jun-26	494,900	2,864,607	-	-	-	-	-	2,864,607
Jul-26	439,922	3,304,529	-	-	-		-	3,304,529
Aug-26	472,460	3,776,989	-	-	-		-	3,776,989
Sep-26	597,002	4,373,991	-	-	-		-	4,373,991
Oct-26	519,584	4,893,575	-	-	-		-	4,893,575
Nov-26	77,516	4,971,091	-	-	-		-	4,971,091
Dec-26	195,326	5,166,418	-	-	-	-	-	5,166,418
Jan-27	2,922,073	8,088,490	42,014	42,014	42,014		42,014	8,130,504
Feb-27	2,922,073	11,010,563	60,538	102,552	60,538		102,552	11,113,115
Mar-27	3,062,323	14,072,886	79,507	182,059	79,507		182,059	14,254,945
Apr-27	2,955,733	17,028,619	98,582	280,641	98,582		280,641	17,309,260
May-27	2,950,123	19,978,742	117,302	397,943	117,302		397,943	20,376,685
Jun-27	2,922,073	22,900,815	135,915	533,858	135,915	3,384	537,242	23,438,057
Jul-27	3,038,480	25,939,295	154,808	688,666	154,808		692,050	26,631,345
Aug-27	2,987,990	28,927,285	173,910	862,576	173,910		865,961	29,793,246
Sep-27	2,926,280	31,853,566	192,657	1,055,233	192,657		1,058,617	32,912,183
Oct-27	2,926,280	34,779,846	211,207	1,266,440	211,207		1,269,825	36,049,671
Nov-27	3,122,630	37,902,476	230,381	1,496,821	230,381		1,500,205	39,402,682
Dec-27	2,959,940	40,862,417	249,660	1,746,481	249,660	11,072	1,760,937	42,623,354
Jan-28	6,739,045	47,601,462	280,403	2,026,885	280,403		2,041,341	49,642,803
Feb-28	7,441,287	55,042,749	325,351	2,352,235	325,351		2,366,691	57,409,441
Mar-28	8,967,788	64,010,537	377,362	2,729,597	377,362		2,744,053	66,754,590
Apr-28	8,886,188	72,896,725	433,954	3,163,551	433,954		3,178,007	76,074,732
May-28	8,967,788	81,864,512	490,545	3,654,097	490,545		3,668,553	85,533,065
Jun-28	9,054,786	90,919,298	547,671	4,201,768	547,671	26,637	4,242,861	95,162,159
Jul-28	9,084,494	100,003,792	605,167	4,806,936	605,167		4,848,028	104,851,820
Aug-28	9,115,094	109,118,886	662,855	5,469,790	662,855		5,510,883	114,629,768
Sep-28	9,084,494	118,203,379	720,542	6,190,332	720,542		6,231,424	124,434,804
Oct-28	9,115,094	127,318,473	778,229	6,968,561	778,229		7,009,653	134,328,126
Nov-28	9,079,445	136,397,917	835,900	7,804,460	835,900		7,845,553	144,243,470
Dec-28	9,053,945	145,451,862	893,377	8,697,837	893,377	55,139	8,794,069	154,245,931
Jan-29	6,507,033	151,958,895	942,701	9,640,538	942,701		9,736,769	161,695,664
Feb-29	6,522,333	158,481,228	984,000	10,624,538	984,000		10,720,769	169,201,997
Mar-29	6,540,948	165,022,176	1,025,406	11,649,944	1,025,406		11,746,175	176,768,351
Apr-29	6,515,448	171,537,624	1,066,791	12,716,735	1,066,791		12,812,966	184,350,590
May-29	6,549,363	178,086,987	1,108,202	13,824,937	1,108,202		13,921,169	192,008,156
Jun-29	6,536,486	184,623,472	1,149,681	14,974,618	1,149,681	94,930	15,165,779	199,789,251
Jul-29	6,536,486	191,159,958	1,191,118	16,165,735	1,191,118		16,356,897	207,516,855
Aug-29	6,536,486	197,696,443	1,232,555	17,398,290	1,232,555		17,589,452	215,285,895
Sep-29	6,536,486	204,232,929	1,273,992	18,672,283	1,273,992		18,863,444	223,096,373
Oct-29	6,536,486	210,769,415	1,315,430	19,987,712	1,315,430		20,178,874	230,948,288
Nov-29	6,536,486	217,305,900	1,356,867	21,344,579	1,356,867		21,535,741	238,841,641
Dec-29	6,519,656	223,825,556	1,398,251	22,742,830	1,398,251	144,176	23,078,167	246,903,723
Jan-30	6,383,764	230,209,320	1,439,151	24,181,981	1,439,151		24,517,318	254,726,638
Feb-30	6,383,764	236,593,084	1,479,620	25,661,601	1,479,620		25,996,938	262,590,022
Mar-30	6,383,764	242,976,848	1,520,089	27,181,690	1,520,089		27,517,027	270,493,875
Apr-30	6,383,764	249,360,612	1,560,558	28,742,248	1,560,558		29,077,585	278,438,197
May-30	6,375,349	255,735,961	1,601,001	30,343,249	1,601,001		30,678,586	286,414,546
Jun-30	6,375,349	262,111,310	1,641,416	31,984,665	1,641,416	202,763	32,522,765	294,634,075
Jul-30	5,797,693	267,909,003	1,680,001	33,664,667	1,680,001		34,202,767	302,111,770
Aug-30	4,283,807	272,192,810	1,711,956	35,376,623	1,711,956		35,914,723	308,107,533
Sep-30	4,283,807	276,476,617	1,739,113	37,115,736	1,739,113		37,653,836	314,130,453
Oct-30	4,283,807	280,760,424	1,766,270	38,882,006	1,766,270		39,420,106	320,180,530
Nov-30	4,283,807	285,044,231	1,793,427	40,675,433	1,793,427		41,213,533	326,257,764
Dec-30	4,283,807	289,328,038	1,820,583	42,496,016	1,820,583	269,399	43,303,515	332,631,552
	289,328,038		**42,496,016**		**42,496,016**	**807,499**		

AFUDC Monthly Rates

2026
0.00634

BEFORE THE NEW MEXICO PUBLIC REGULATION COMMISSION

IN THE MATTER OF EL PASO ELECTRIC COMPANY'S APPLICATION FOR A CERTIFICATE OF PUBLIC CONVENIENCE AND NECESSITY FOR A REPLACEMENT 200 MW EDDY HIGH VOLTAGE DIRECT CURRENT TIE	)	**Case No. 26-00___**
EL PASO ELECTRIC COMPANY, Applicant	)	

DECLARATION OF GEORGE NOVELA IN SUPPORT OF THE FOREGOING DIRECT TESTIMONY OF EL PASO ELECTRIC COMPANY'S APPLICATION FOR A CERTIFICATE OF PUBLIC CONVENIENCE AND NECESSITY FOR A REPLACEMENT 200 MW EDDY HIGH VOLTAGE DIRECT CURRENT TIE

I ***George Novela***, pursuant to Rule 1-011 NMRA, state as follows:

1. I affirm in writing under penalty of perjury under the laws of the State of New Mexico that the following statements are true and correct.

2. I am over 18 years of age and have personal knowledge of the facts stated herein. I am employed by El Paso Electric Company ("EPE" or "the Company") as *Senior Director of Regulatory Policy and Rates.*

3. The foregoing Direct Testimony of George Novela, together with all exhibits sponsored therein and attached thereto, is true and accurate based on my knowledge and belief.

4. I submit this Declaration, based upon my personal knowledge and upon information and belief, in support of EPE's ***Application for a Certificate of Public Convenience and Necessity for a Replacement 200 MW Eddy High Voltage Direct Current Tie.***

FURTHER, DECLARANT SAYETH NAUGHT.

I declare under penalty of perjury that the foregoing is true and correct.

Executed on April 13, 2026.

/s/ *George Novela*

GEORGE NOVELA

BEFORE THE NEW MEXICO PUBLIC REGULATION COMMISSION

IN THE MATTER OF EL PASO ELECTRIC COMPANY'S APPLICATION FOR A CERTIFICATE OF PUBLIC CONVENIENCE AND NECESSITY FOR A REPLACEMENT 200 MW EDDY HIGH VOLTAGE DIRECT CURRENT TIE	)	**Case No. 26-00___**
EL PASO ELECTRIC COMPANY, **Applicant**	)	

DIRECT TESTIMONY OF

JONATHAN M. TREJO

ON BEHALF OF

EL PASO ELECTRIC COMPANY

APRIL 13, 2026

EL PASO ELECTRIC COMPANY
DIRECT TESTIMONY OF
JONATHAN M. TREJO

TABLE OF CONTENTS

EXHIBITS

EL PASO ELECTRIC COMPANY
DIRECT TESTIMONY OF
JONATHAN M. TREJO

I. INTRODUCTION AND QUALIFICATIONS

Q1. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Jonathan M. Trejo. My business address is 100 N. Stanton Street, El Paso, Texas 79901.

Q2. WHO IS YOUR CURRENT EMPLOYER AND WHAT POSITION DO YOU HOLD?

A. I am employed by El Paso Electric Company ("EPE" or the "Company") as the Manager of the Protection, Metering, Automation, and Control Department.

Q3. PLEASE SUMMARIZE YOUR EDUCATIONAL BACKGROUND AND PROFESSIONAL EXPERIENCE.

A. I graduated from New Mexico State University with a Bachelor of Science degree in Engineering in 2007, a Master of Business Administration with a specialization in Finance in 2010, and a Master of Science degree in Electrical Engineering in 2013. I received a Graduate Certificate in Public Utility Regulation & Economics from New Mexico State University in 2019. I am a licensed Professional Engineer ("P.E.") in the states of Texas, New Mexico, and Arizona and hold a Professional Project Management certificate thru the Project Management Institute.

In 2012, I began working for EPE as a Substation & Protection Engineer, specializing in the design of high voltage substations and protection and control schemes. In 2013, I transitioned to a Protection and Control Engineer, a position I

held until 2020 when I was promoted to Principal Protection and Control Engineer. In this role, I was responsible for the design, implementation, and commissioning of several high voltage protection and control projects, investigating and researching new technologies, and developing standards related to protection and control engineering. I also served as the subject matter expert for all protection and control standards of the North American Electric Reliability Corporation ("NERC"). Additionally, I assisted with the operation and maintenance of the Eddy County HVDC Tie, including sourcing spare parts and troubleshooting of the Tie during unplanned outages. In 2021, I was promoted to Supervisor of Protection and Control Engineering, overseeing the design of complex high voltage protection and control schemes, SCADA upgrades, telemetry, and metering schemes. In 2024, I was promoted to be the Manager of Protection, Metering, Automation and Control group.

I occasionally teach graduate lab courses in electrical engineering focusing on power systems and protection at New Mexico State University.

Q4. WHAT ARE YOUR CURRENT RESPONSIBILITIES WITH EPE?

A. As the Manager of Protection, Metering, Automation, and Control, I oversee and lead activities related to the engineering, construction and maintenance of EPE's protection and metering systems. The Protection and Control Department's responsibilities include designing, constructing, and testing protection and control systems needed for the safe and reliable operation of the electric grid. The Metering

Department's responsibilities include the installation and testing of metering systems on residential, commercial, industrial, and large load customers. In addition, the Metering Department is also responsible for the metering of all generation facilities (both conventional and inverter-based generation) and tie-lines within the EPE service territory.

II. PURPOSE OF DIRECT TESTIMONY

Q5. WHAT IS THE PURPOSE OF YOUR DIRECT TESTIMONY?

A. The purpose of my direct testimony is to support El Paso Electric Company's ("EPE" or the "Company") Application for a Certificate of Public Convenience and Necessity ("CCN") to replace the existing 200 MW Eddy High Voltage Direct Current ("HVDC") Tie (the "Eddy Tie" or "Tie"). Specifically, my testimony describes the existing Eddy Tie, including its design, current operating condition, and the technical and operational limitations resulting from its age and obsolescence. I explain why the existing facility can no longer reliably serve its intended purpose and why replacement, rather than refurbishment, is necessary to maintain system reliability and operational flexibility. My testimony also describes the proposed replacement facility, including the advanced HVDC technology EPE plans to deploy; the benefits of that technology to the transmission system; and the manner in which the new facility will enhance reliability, resiliency, and operational performance. In addition, I summarize the transmission-related upgrades that will support the replacement project and describe how EPE plans to

maintain operations during construction. Finally, I describe the estimated capital cost of the replacement project and related facilities, and explain how the proposed project represents a prudent and necessary investment to ensure continued interconnection capability between the Eastern and Western Interconnections for the benefit of EPE's customers.

Q6. ARE YOU SPONSORING ANY EXHIBITS IN SUPPORT OF YOUR TESTIMONY?

A. Yes, I am sponsoring the following exhibits:

- Exhibit JMT-01: Electric Power Research Institute Report – "Life Extension Guidelines of Existing HVDC Systems"
- Exhibit JMT-02: Eddy –Empire- Amrad 345kV Transmission Line Map

III. DESCRIPTION OF THE EXISTING EDDY TIE

Q7. PLEASE DESCRIBE THE EXISTING EDDY TIE FACILITY.

A. The existing Eddy Tie is a 200 MW HVDC back-to-back Line-Commutated Converter ("LCC"). It was originally built by General Electric ("GE") and placed into service in 1984. The Eddy Tie is located in Eddy County, New Mexico, approximately 10 miles east of Artesia, New Mexico, on a parcel of Bureau of Land Management ("BLM") land. The Eddy Tie is one of only eight back-to-back HVDC ties located in the United States. It is used to connect the Eastern and Western grids.

Q8. WHAT IS AN HVDC TIE?

A. An HVDC tie is a highly specialized power electronic transmission facility that connects two independent, asynchronous alternating current ("AC") power grids, which enables electricity to flow between the two grids without requiring them to be perfectly synchronized in phase or frequency. Please see Figure JMT-1 below for an electrical schematic of an HVDC tie.

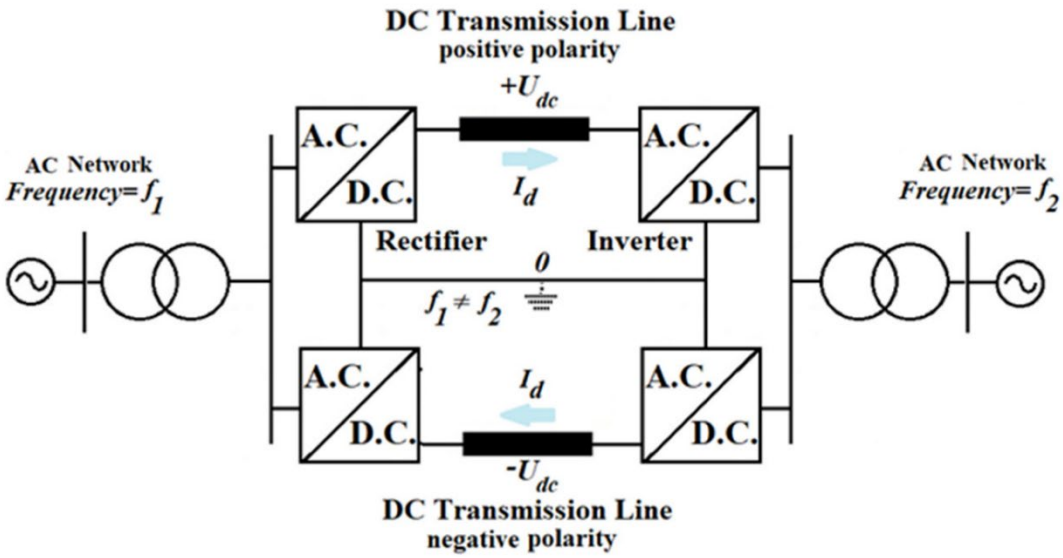

Figure JMT-1 – HVDC Tie Schematic

Q9. WHY DOES THE TRANSMISSION SYSTEM IN THE U.S. NEED HVDC TIES?

A. The U.S. grid is divided into three main, separate, and asynchronous interconnections: Eastern, Western, and Texas. HVDC ties are essential to connect

these otherwise independent power grids. HVDC ties are the only way to move power between these independent systems, as they allow electricity to be converted to direct current ("DC"), bypassing the need for perfect frequency and phase angle synchronization. Essentially, HVDC ties act as electricity highways allowing power to bypass congested AC lines, which strengthens the grid during emergency, weather-related shortages. HVDC ties enable reliable electricity transfer between the grids. They also facilitate energy integration and enhance grid resilience against severe weather disasters. As discussed in the direct testimony of Company witness Omar Gallegos, DC ties can also foster economic benefits. Figure JMT-2 below shows the location of the existing HVDC ties that connect the Eastern Grid to the Western Grid.

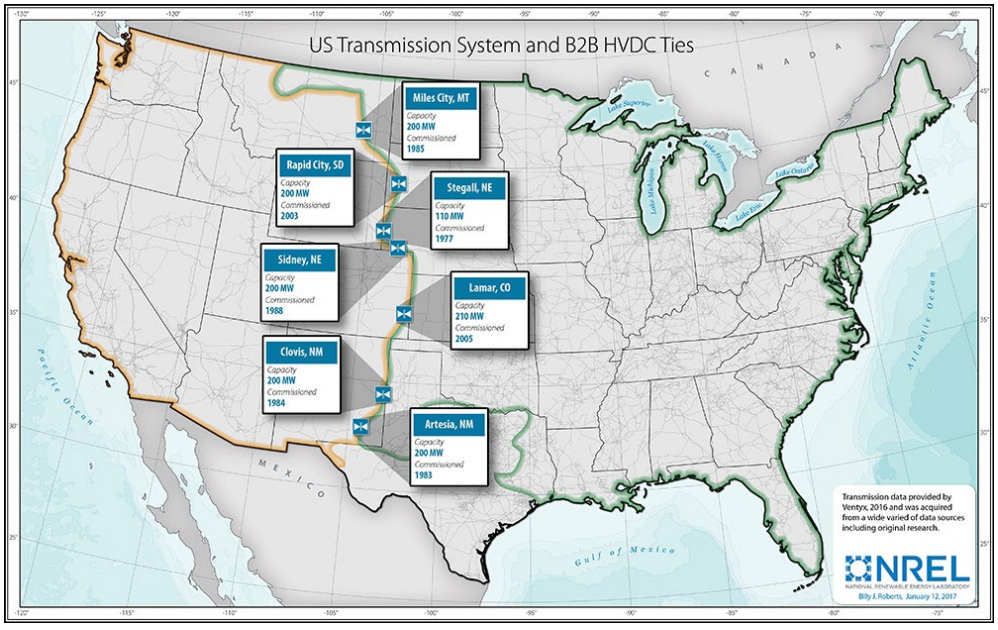

Figure JMT-2 – HVDC Tie Locations

Q10. HOW IS THE EXISTING EDDY TIE USED?

A. Please refer to the direct testimony of EPE witness Gallegos for an explanation of how the existing Eddy Tie has been used to benefit EPE's customers since it was built in the mid-1980s.

Q11. DOES EPE HAVE A CCN FOR THE EXISTING EDDY TIE?

A. Yes. The New Mexico Public Service Commission (the Commission's predecessor entity) issued a CCN for the Eddy Tie in 1982 as part of its approvals in Case No. 1724. In that case, EPE and Texas New Mexico Power ("TNP") (now Public Service Company of New Mexico, or PNM) sought and received CCNs for all of the facilities and transmission lines needed to build the "Eastern Interconnect Project." The Eddy Tie was referred to in that case as the "DC Terminal." The 1982 CCN is discussed in more detail in the direct testimony of EPE witness George Novela.

IV. CURRENT CONDITION OF THE EDDY TIE

Q12. WHEN WAS THE EDDY TIE BUILT?

A. The Eddy Tie was built in 1983 and commissioned in 1984, so it has been in operation for over 40 years. Given this age, and for the reasons I will explain in detail in this section of my testimony, the Eddy Tie must be replaced.

Q13. HAS THE FACILITY'S AGE AFFECTED ITS ABILITY TO SERVE ITS INTENDED PURPOSE?

A. Yes. Due to its age, the Eddy Tie has faced limitations in its ability to transfer power between the Eastern and Western grids. Currently, the maximum power transfer capability of the Eddy Tie is restricted to 105 MW to prevent component failures within the Tie. Additionally, there have been more unplanned outages due to the failure of older equipment. In recent years, the Tie has experienced unplanned outages caused by failed control boards, power electronic valve modules, gassing converter transformers, and faulty high-voltage equipment bushings. As time has passed, equipment failures have increased, and sourcing spare parts to keep the Tie operational has become increasingly difficult. These unplanned outages have affected the reliability of EPE's transmission system by limiting the amount of power that can be imported into EPE's system during the peak months.

Q14. PLEASE EXPLAIN HOW THE CONDITION OF THE EXISTING EDDY TIE IS AFFECTING THE RELIABILITY OF EPE'S TRANSMISSION SYSTEM.

A. The current Eddy Tie is available for use on a non-firm basis only. Due to the number and duration of outages at the Tie, EPE is prevented from offering firm transmission service at that location to anyone, including EPE's own merchant operation (EPE's marketing group). This non-firm service does not allow EPE or other entities to book long-term firm generation or firm transmission capacity

across the Tie. From a resource and transmission planning perspective, therefore, EPE cannot rely on the Tie. This inability to book the Tie for long-term generation capacity has decreased the operational flexibility of EPE's transmission system. In addition, currently there are operating limits on the Tie that limit its total transfer capability, which will be later discussed in my testimony.

Q15. PLEASE DESCRIBE THE MAINTENANCE OF THE FACILITY OVER ITS LIFETIME.

A. Until relatively recently, the maintenance of the Eddy Tie was primarily managed by Southwestern Public Service Company ("SPS"), which owns and operates significant transmission facilities on the eastern side of the Eddy Tie, under an agreement with EPE and PNM. SPS routinely performed maintenance on the Tie either annually or bi-annually. For example, every year SPS would take the Tie down for maintenance and perform maintenance activities on all the major equipment (transformers, breakers, filters, switchgear, valve modules, relays, etc.) at the Eddy Tie. For several years, the Tie was taken down twice a year to perform the same maintenance activities. SPS also performed weekly inspections of the Eddy Tie to ensure that all equipment was operating as intended and designed.

In the last ten years, SPS has expressed concerns about the ability to find replacement parts for the maintenance of the Eddy Tie. Since that time, EPE and SPS have collaborated on the maintenance of the Tie. This includes quarterly Engineering and Operations meetings where critical maintenance items are

discussed and addressed. On average for the past five years, the yearly O&M cost of the Tie has been approximately $260,000.

Q16. DOES EPE PAY FOR THE MAINTENANCE COST?

A. Yes. EPE pays approximately two-thirds of the total cost of maintenance for the Tie, while PNM pays the remaining one-third.

Q17. WHAT IS THE TYPICAL LIFESPAN FOR AN HVDC TIE?

A. Numerous research papers published by the Electric Power Research Institute ("EPRI") and the Institute of Electrical and Electronic Engineers have concluded that the typical lifespan of a back-to-back HVDC tie is approximately thirty to forty years. Exhibit JMT-01 is a copy of a 2007 EPRI report on the life extension guidelines for HVDC Systems. It details the expected age for major components of HVDC ties. For example, included in an appendix of the report (Appendix C) is a table of the estimated service life for the major components of a HVDC system. This table shows that most of the components have a service life of forty years or less.

Q18. IS THE EDDY TIE NEARING THE END OF ITS OPERATIONAL LIFE?

A. Yes. The Eddy Tie has been in operation for over 40 years and has now reached the end of its useful life from an operational perspective. Back-to-back HVDC stations of this vintage were not designed to exceed their intended lifespan, despite any

incremental improvements. Its sister unit, located in Oklaunion, Texas, was a nearly identical back-to-back 200 MW tie built and commissioned by GE in 1984. In 2014, the Oklaunion DC tie was decommissioned and fully replaced, which helps demonstrate that the Eddy Tie has similarly reached, if not exceeded, its operational life expectancy.

Q19. IS THE EXISTING EDDY TIE EXPERIENCING FREQUENT OUTAGES?

A. Yes. Over the past five years, the Eddy Tie has experienced a total of thirty-five unscheduled outages, primarily due to the failure of aging components and equipment. For instance, in 2020, the 230kV converter transformer was replaced due to internal gassing. In 2021, there were thyristor and valve module failures. In 2023, control boards failed, and in 2024, faulty high voltage bushings were found and replaced on the 345kV shunt reactor. Most recently, in 2025, we encountered a failure of a three-phase battery charging system. Each of these failures resulted in the Tie being out of service while solutions were investigated and implemented. Whenever a failure occurs or components or equipment are replaced, it comes with a cost that is ultimately borne by customers.

Q20. HOW HAVE THESE OUTAGES AFFECTED THE DAY-TO-DAY OPERATION OF THE TIE?

A. As discussed above, the total transfer capability of the Tie is currently limited to 105 MW. This limitation is primarily due to the increase in failed power electronic

modules when the Tie is run above the 105 MW capacity limit. Also, because there is potential damage to the Tie from repeated on/off cycling, EPE has established operational limits which include the following criteria:

- 24-hour notice for a system impact study and coordination with SPS (acting as Operating Agent) as to start/stop times in order to schedule crews to be on site.
- The minimum "on" time is three days or 72 continuous hours.
- The minimum "off" time is two days or 48 continuous hours.
- The Minimum Net Schedule is 35 MW.

Q21. IS IT FEASIBLE TO UPGRADE OR REFURBISH THE EXISTING EDDY TIE?

A. A major overhaul or refurbishment is neither cost-effective nor practical. A complete refurbishment of the Tie would require the replacement of all of the power electronic components, control systems, cooling equipment, and high-voltage substation equipment. From a cost perspective, a complete refurbishment would net to approximately the same cost as building a new DC tie. However, as I address below, complete refurbishment is not possible. In addition, a complete overhaul would require the Tie to be taken out of service for a substantial amount of time, which would affect the reliability of the EPE system.

Q22. HAS EPE REACHED OUT TO ANY VENDORS TO SEE IF THE EXISTING TIE CAN BE REFURBISHED?

A. Yes. EPE has had discussions with the original manufacturer of the Eddy Tie (GE Vernova) regarding a refurbishment of the existing Tie. During those discussions, GE notified EPE that GE could only support the refurbishment of the HVDC power electronic valve modules, but all the other major components could not be refurbished because they were at the end of their life. In other words, a complete refurbishment of the existing Eddy Tie is not possible. As a result, EPE has proceeded to refurbish the power electronic valve modules to help extend the life of the Eddy Tie while EPE goes through the process of planning for the replacement of the existing HVDC Tie and seeking needed regulatory approvals.

Q23. IF THE EXISTING FACILITY IS NOT REPLACED AT THIS TIME, HOW MUCH LONGER DO YOU ESTIMATE IT WILL REMAIN OPERABLE?

A. Given the current condition of the Tie and its equipment, it is anticipated that the Tie could remain operational for another one to five years. EPE has implemented a power electronic valve module replacement program to ensure the Tie remains functional for the next few years while EPE seeks regulatory approvals to replace the Tie.

V. DESCRIPTION OF THE NEW HVDC TECHNOLOGY

Q24. PLEASE DESCRIBE THE TECHNOLOGY THAT THE NEW FACILITY WILL USE.

A. The new 200 MW back-to-back HVDC tie will utilize the latest Voltage Source Converter ("VSC")-based technology, which represents advanced power electronic devices known as Insulated-Gate Bipolar Transistors in a modular multi-level converter ("MMC") arrangement. This arrangement will be complemented by the Control & Protection system, consisting of centralized computers with discrete processing, high speed communications, and customized software. Additionally, the new facility will incorporate modern asset monitoring and cybersecurity systems, enabling EPE to operate and maintain the new facility with maximum efficiency. These are significant upgrades over the existing facility. Figure JMT-3 below shows a picture of VSC HVDC valve hall with an MMC arrangement.

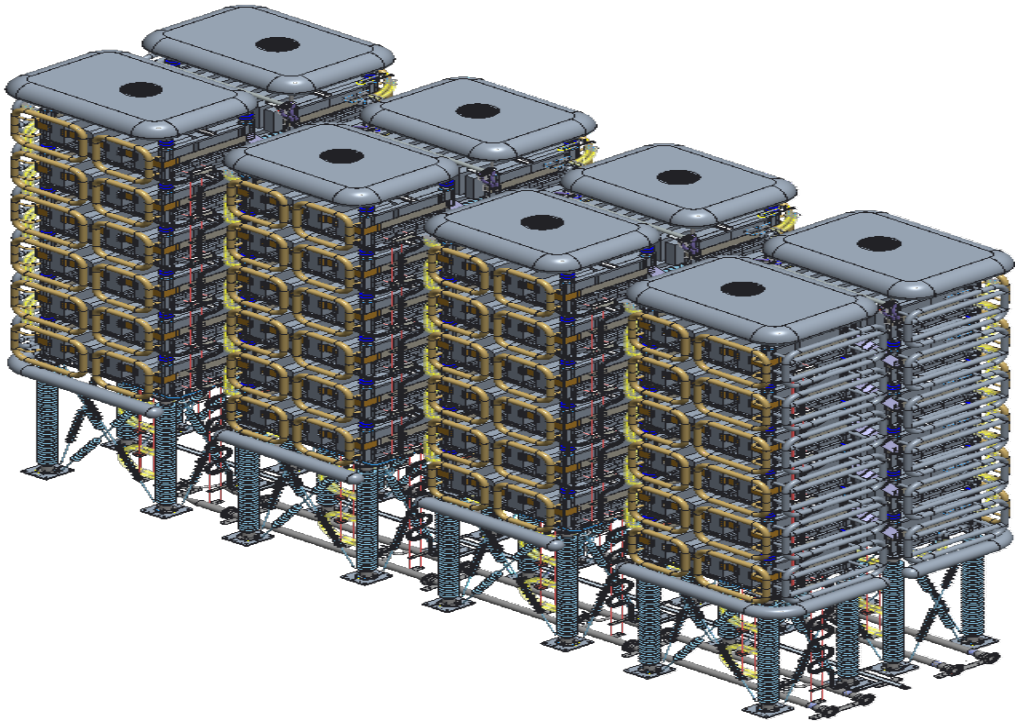

Figure JMT-3 – VSC MMC Valve Hall & Technology

Q25. PLEASE DESCRIBE THE BENEFITS OF THE NEW TECHNOLOGY.

A. HVDC VSC technology offers several benefits to the power grid. First, HVDC VSC systems allow for precise control of power flow, reactive power, and voltage, which is crucial for maintaining grid stability. Secondly, an HVDC VSC system can operate as a grid-forming technology, meaning it can maintain grid frequency and voltage even in the absence of conventional generators, a feature essential for black-start capabilities. HVDC VSC systems can also independently absorb reactive power, which provides voltage support on either side of the tie even when

there is no power transfer across it. Lastly, HVDC VSC systems exhibit excellent AC fault ride-through capabilities, enabling them to continue operating during grid disturbances, thereby enhancing grid resilience.

Q26. ARE THERE OTHER SIGNIFICANT BENEFITS OF THE SELECTED NEW TECHNOLOGY?

A. Yes, the new HVDC VSC technology will help alleviate water consumption in the Artesia region due to its integrated cooling technology. The existing Eddy Tie uses an open-loop cooling system, which relies on water's evaporative effect to cool the HVDC power electronic valves. In contrast, the new VSC valve cooling designs are closed-loop, meaning there is virtually no water loss in the system. Currently, the Eddy Tie facility consumes nearly 1.6 million gallons of groundwater annually, primarily for the valve cooling system. The new VSC technology will decrease this water consumption to almost zero gallons of water consumption per year. This decrease in water consumption will also help to decrease the monthly O&M cost for water usage at the new HVDC tie.

Q27. HAS EPE CONDUCTED ANY STUDIES RELATED TO THE NEW HVDC TECHNOLOGY AND ITS IMPACT TO THE EPE GRID?

A. Yes. EPE hired Power Engineers (now WSP) to conduct feasibility studies for the addition of the new HVDC VSC technology to the EPE power grid. These studies included steady-state power flow analysis, transient stability analysis, and short-

circuit analysis. Overall, the studies concluded that the new technology would integrate with EPE's system, with some needed system upgrades, including an increase in capacity on the 345kV line from Amrad to Empire and a need for OPGW on the transmission line. Those upgrades are discussed in greater detail later in my testimony.

Q28. PLEASE DESCRIBE THE AVAILABLE ALTERNATIVES FOR HVDC TECHNOLOGY.

A. There is only one available alternative to a HVDC tie, which is called a Variable Frequency Transformer ("VFT"). VFTs are like HVDC ties in that they can connect two asynchronous grids together. However, VFTs operate similar to a conventional power system machine, using a rotor and stator to exchange power via magnetic coupling, whereas HVDC ties use power electronics to control the exchange of power.

Q29. IS THE VFT TECHNOLOGY A FEASIBLE OPTION?

A. No, not in my opinion. VFT technology is not widely used and there is only one such installation in the United States. In addition, there is only one vendor in the world that can provide this solution. VFTs also do not provide the same ancillary benefits that HVDC ties provide as described in Q24 of my testimony. For example, VFTs have slower dynamic response for faults and limited real and reactive power controllability compared to HVDC VSC technology. For all of these reasons, I

believe VFT technology is not a feasible alternative and that the HVDC VSC technology is a much better solution for the Eddy Tie replacement.

VI. SELECTION OF NEW TECHNOLOGY AND VENDOR

Q30. HAS EPE SELECTED THE VENDOR FOR THE REPLACEMENT OF THE EDDY TIE?

A. Yes. EPE issued a Request for Proposals ("RFP") to various vendors for the replacement of the Eddy Tie in April 2025. A final decision was made in December 2025 to proceed with GE Vernova as the vendor for the replacement of the Eddy Tie. Given the complexity and the niche market of HVDC technology, there are only four proven vendors in the world that can manufacture HVDC ties. These vendors are GE Vernova, Siemens, Hitachi, and Mitsubishi.

Q31. WHAT WERE THE FACTORS LEADING TO LEADING TO EPE'S SELECTION OF GE VERNOVA AS THE VENDOR?

A. The main factors leading to the selection of a vendor for the DC Tie were as follows: price, lead time, and technical capability. GE Vernova's proposal led on all three aspects when compared to the other vendors that provided a bid for the project and thus the reason why GE was selected. GE Vernova was also the only vendor to provide a firm price and schedule compared to the other vendors during the bidding process.

Q32. WHAT IS THE TOTAL CAPITAL COST FOR THE REPLACEMENT OF THE TIE?

A. The estimated cost to replace the Eddy Tie (not including Allowance for Funds Used During Construction, or AFUDC) is $289,391,575 if CCN approval can be obtained by the end of 2026. This amount includes a cost of $242,600,000 from GE Vernova for the major components of the HVDC tie (i.e. transformers, valves, protection and control equipment, DC components, AC components, etc.); $3,483,250 for civil construction costs (foundations, conduit, ground grid, construction costs, removal of old equipment etc.); $10,500,000 for the site preparation (grading, drainage, etc.); $6,500,000 for the new valve hall building needed to house the power electronic valves, cooling equipment, and protection and control equipment; and $26,308,325 for a ten percent contingency cost on the project.

Q33. WILL THE COST OF THE PROJECT CHANGE IF CCN APPROVAL IS OBTAINED AFTER THE END OF 2026?

A. Yes. The $242,600,000 price of the GE Vernova contract described above assumes approval of the CCN before the end of 2026. That price was negotiated with GE Vernova based on GE's need to reserve manufacturing slots and to commit engineering and other resources to the Project. If approval occurs after December 31, 2026, the estimated cost of the GE Vernova contract will increase to $270,000,000, or approximately 11 percent higher. The increase in cost reflects

long-term price uncertainty being experienced by electrical sub-station equipment manufacturers and the demand for equipment driven largely by data center growth. There is currently a large demand for HVDC projects in Europe and Asia and therefore it is difficult for any vendor to guarantee prices past twelve to eighteen months. The higher contract price would raise the total cost of the project over $317 million. If approval occurs after June 30, 2027, the price of the new Eddy Tie will have to be renegotiated with GE Vernova.

Q34. DOES EPE NEED TO ACQUIRE ANY NEW LAND RIGHTS TO IMPLEMENT THE PROJECT?

A. Yes. As I mentioned above, the existing Eddy Tie is located on BLM land. EPE is in the process of acquiring an easement of approximately sixteen acres of land from the BLM for the replacement of the Tie. This property will be located adjacent to the existing Eddy Tie as shown in Figure JMT-4 below. The red area in the figure is the easement that EPE is pursuing with the BLM to build the new replacement tie while the green area to the south of the new easement is the location of the existing Eddy Tie. EPE witness Teresa Sosa discusses the BLM application in more detail in her testimony.

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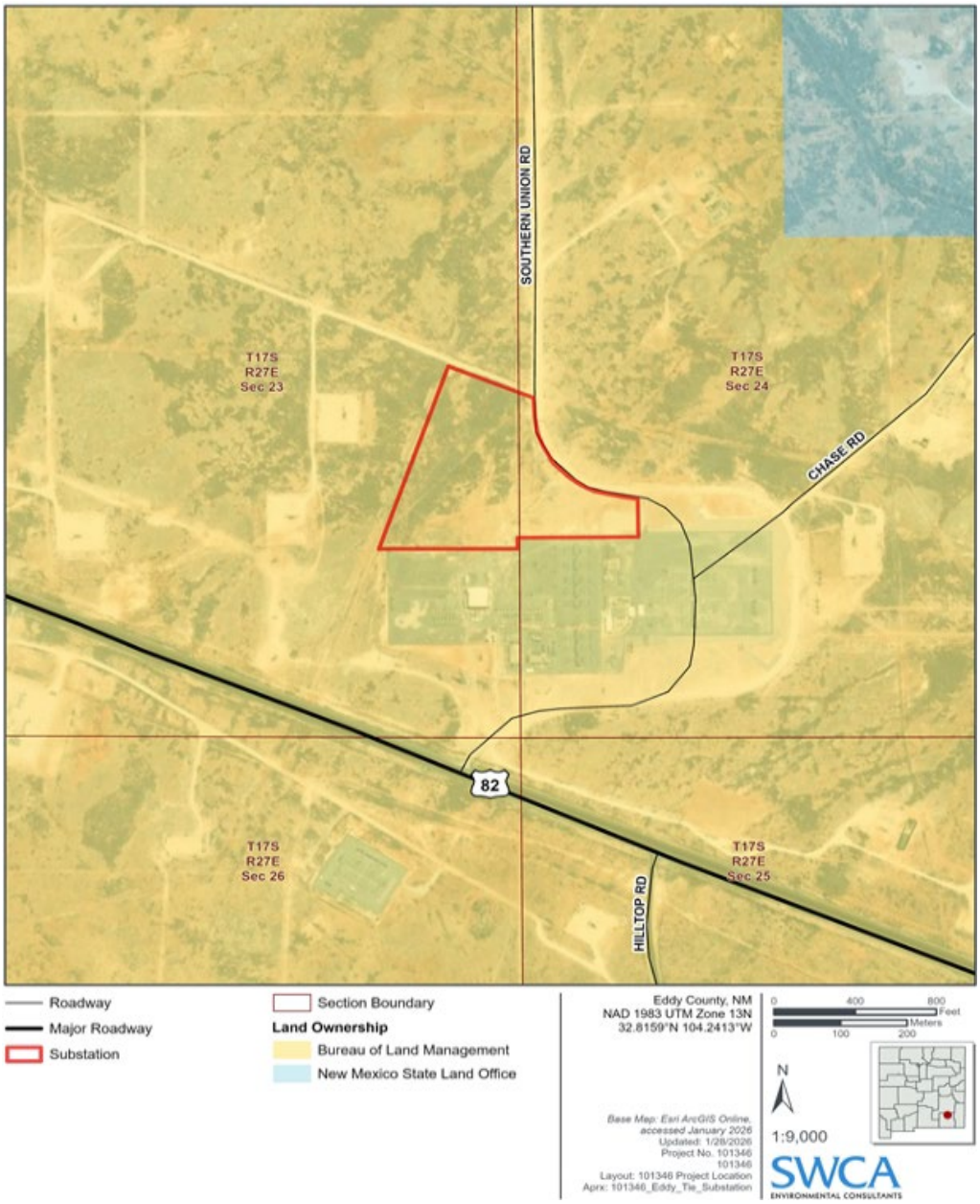

Figure JMT-4 – BLM Easement for New HVDC Tie

VII. TRANSMISSION UPGRADES

Q35. IS EPE SEEKING COMMISSION APPROVAL OF THE TRANSMISSION UPGRADES?

A. No, as discussed by EPE witness Novela, EPE is not seeking approval of the transmission upgrades. I am providing the following summary only to allow the Commission to have a complete picture of the project.

Q36. PLEASE DESCRIBE THE TRANSMISSION-RELATED ASPECTS OF THE PROJECT.

A. The transmission-related aspects of the project involve replacing one existing wood H-Frame 345kV transmission structure along the 125 mile long transmission line commencing at Amrad Substation and terminating at Empire Substation. Empire substation is approximately 2200 feet east of the Eddy Tie (see exhibit JMT-02). The existing wood structure will be replaced with a steel H-Frame structure designed in accordance with current EPE Transmission Construction Standards, applicable to National Electrical Safety Code ("NESC") requirements, and EPE loading criteria. The project will increase phase-to-ground clearances and restore the line to achieve a higher MVA capacity. The existing line segment is presently limited to 400 MVA due to conductor sag limitations caused by clearance constraints. Following replacement of the identified structure, the line is expected to achieve a higher capacity.

The Project also includes the installation of Optical Ground Wire ("OPGW") along the full route between Amrad Substation and Empire Substation. The OPGW will provide high-speed fiber optic communications necessary to support protective relaying, SCADA, system protection schemes, and integration of the proposed DC Tie.

Q37. HOW DID EPE DETERMINE THAT ONE TRANSMISSION STRUCTURE NEEDED TO BE UPGRADED?

A. EPE identified the need to upgrade one transmission structure through an engineering analysis of the line's existing sag-limited spans. EPE performed clearance evaluations using LiDAR survey data and PLS-CADD modeling. These analyses indicated that one span along the Amrad - Empire 345kV line did not provide sufficient phase-to-ground clearance under applicable loading and temperature conditions to support the conductor's thermal capability to achieve a higher MVA rating. The clearance limitations resulted in a reduced operational line rating of approximately 400 MVA. As a result, one wood structure was identified for replacement with a taller steel structure to increase the rating.

Q38. WHAT IS THE APPROXIMATE COST OF THE TRANSMISSION-RELATED UPGRADES?

A. The estimated cost of the transmission-related upgrades (transmission structure replacement and high speed fiber connection) related to the Project is $7,100,000.

EPE is not seeking regulatory approval of the transmission-related aspects of the project in this CCN submittal; this is for informational purposes only.

VIII. OPERATIONS DURING CONSTRUCTION

Q39. WHEN IS THE PROJECT TARGETED TO BE FULLY OPERATIONAL?

A. Assuming that EPE can get CCN approval within six to eight months of this CCN filing, it is projecting that the replacement Eddy Tie will be fully operational by the fourth quarter of 2030. If CCN approval takes longer than six to eight months, then it is projected that the replacement Eddy Tie would be operational by the fourth quarter of 2031.

Q40. WILL THE PROJECT REQUIRE THE EXISTING TIE TO BE TAKEN OUT OF SERVICE?

A. No. Since EPE is acquiring new land rights to build the replacement Eddy Tie, the existing Tie can remain in service until the new tie is completed and fully commissioned. If EPE were not acquiring the new land rights, the existing Tie would have been taken out of service for approximately 18 to 24 months to rebuild the tie in the existing location.

Q41. WILL SPS CONTINUE TO MAINTAIN THE EDDY TIE ONCE THE REPLACEMENT EDDY TIE IS COMPLETED?

A. No. EPE will lead all maintenance and operation efforts related to the new DC Tie. With the proposed new VSC MMC technology, the new DC Tie will only need to be taken out of service for one week each year to perform maintenance activities. The new DC Tie will also have remote monitoring capabilities that will notify EPE personnel of any alarms or maintenance needs remotely, which means that maintenance crews will only need to be dispatched for major maintenance items. The new DC Tie will be operated by EPE's System Operations Team.

IX. CONCLUSION

Q42. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes, it does.

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Life Extension Guidelines of Existing HVDC Systems

1012516

Life Extension Guidelines of Existing HVDC Systems

1012516

Technical Update, March 2007

EPRI Project Manager

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Life Extension Guidelines of Existing HVDC Systems, EPRI, Palo Alto, CA: 2007, 1012516.

ABSTRACT

High Voltage Direct Current (HVDC) converter stations and transmission lines represent a significant investment and source of revenue for the electric utilities owning them. Many installations are approaching or exceeding 30 years of service. Components are aging. Manufacturers may no longer be in business or have merged and consolidated their resources with different business priorities. Engineering and technical staffs are retiring and the knowledge base is being lost. Technology is advancing making existing technology obsolete or so dated it no longer functions efficiently. Owners and Operators are in need of guidelines describing an approach to extend the life of these facilities. These procedures can be as simple as selective refurbishment/replacement of equipment or as complex as the complete replacement of the scheme. In addition, maintenance practices can impact the facility life expectancy and are discussed in the guideline. The Owners and Operators of these facilities are now being faced with the decision of what action to pursue. In most cases, the transmission path provided by operating HVDC converter stations is not only profitable but is needed for reliability; life extension is not an option, it is a necessity. HVDC converter station equipment and systems are complex and have varying lifetimes. With an infrastructure of 25 to 30 years of service, much of the facility equipment needs attention. It is in need of replacement or refurbishment. This guideline is intended to serve as a resource to the Owners and Operators for the development of program for the assessment of their aging HVDC facility and to assist in developing a program of maintenance to enhance the life of the facility.

ACKNOWLEDGEMENTS

This interim report was prepared under the EPRI project management of Dr. Rambabu Adapa. High Energy Inc. led by Ruth Johnson directed the project team contributing to this effort including Dennis Woodford of Electranix Corporation, Bill Mele of Indoor Environmental Solutions, Inc., Bruce Lavier of Lavier Engineering, LLC, Gene Wolf of Lone Wolf Engineering, LLC, Randy Wachal of Manitoba HVDC Research Centre and Duane Torgerson of Winfield Enterprise, LLC.

This report has benefited from discussion held during a project kick-off meeting in Denver, Colorado that was attended by approximately 19 interested utilities and project participants with another 5 participants interacting via a conference phone connection. A summary of this meeting and list of attendees is included in Appendix A.

CONTENTS

1
LIST OF HVDC CONVERTER STATIONS

Introduction

The objective of the "List of HVDC Converter Station" Chapter is to identify all of the known High Voltage Direct Current (HVDC) converter stations currently in service in the world. These stations have been identified from publications by the Institute of Electrical and Electronic Engineers (IEEE) and the Comité International des Grands Réseaux Electrique (CIGRE). Most recently this list has been compiled and updated by the IEEE's Power Engineering Society's (PES) Transmission and Distribution Committee's HVDC and FACTS Subcommittee. The updated list was distributed during the HVDC and FACTS Subcommittee's meeting held during the June 2006 the PES General Meeting in Montreal, Quebec, Canada.

Using this list, a simple survey was sent out to operators of the HVDC converter stations that were identified as being upgraded or where life extension activities have been undertaken. A summary description is provided from this list. Known information and published descriptions are used for this compilation, starting with the published CIGRE report "Guide for Upgrading Transmission Systems with HVDC Transmission" SC 14 WG 14.11, 1998 [1].

The life extension activities summarized herein serve as a reference for those contemplating such activities at their own HVDC converter stations. The actual converter stations included in the summary are not specifically identified.

Existing HVDC Facilities

HVDC converter stations that are included in the updated IEEE list are summarized in Table 1-1 and Appendix B:

Table 1-1
Summary of HVDC Schemes in the World

Classification of HVDC Schemes	Number
Number of HVDC schemes with overhead transmission lines	24
Number of HVDC schemes with undersea cables (with thyristor converters)	28
Number of back-to-back schemes	34
Number of voltage sourced converter transmission schemes	5
Total number of operating HVDC schemes (2006)	91
Number of de-commissioned HVDC schemes	10
Number of HVDC projects in construction, planned or future	37

The distribution of these schemes throughout the world, by regions, is assembled in Table 1-2.

Table 1-2

Regions of the world where HVDC transmission schemes are installed

Regions of the World	Number of DC Links	Average Age of Converters (Years)
North America	25	22
Northern Europe	13	17
Europe and Mediterranean	6	14
India	9	9
China	6	9
South America	7	14
North East Asia	10	15
South East Asia	2	7
Russia	5	24
Africa	2	27
Australia and New Zealand	6	14

The largest numbers of HVDC converter stations are located in the U.S.A. and Canada, followed by northern Europe. India and China are currently building the largest rated converters for HVDC interconnections between asynchronous regions.

The oldest operating HVDC converter stations are located in Africa and Russia. North America has the largest number of aging HVDC converter stations in service.

HVDC Life Extension Activities

A simple survey was sent to operators in eight countries to determine the HVDC life extension activities that have begun or were completed. Replies were received from 26 HVDC interconnections. The survey requested whether life extension activities had been started on the interconnection's major equipment. The major equipment included converter transformers, valves, valve electronics, controls, valve cooling, ac filters, smoothing reactors and switches/circuit breakers.

For each piece of major equipment, the life extension activities are summarized over time in the following charts. Each chart show for five year spans the percentage of the HVDC converter stations commissioned in that span that have the designated equipment refurbished or replaced. Table 1-3 shows the number of converter stations reported for each five year span.

Table 1-3
Converter stations reporting life extension activities each 5 year span

5 Year Span	65-69	70-74	75-79	80-84	85-89	90-94	95-99	00-05
No. of Converter Stations	2	2	5	2	7	1	2	5

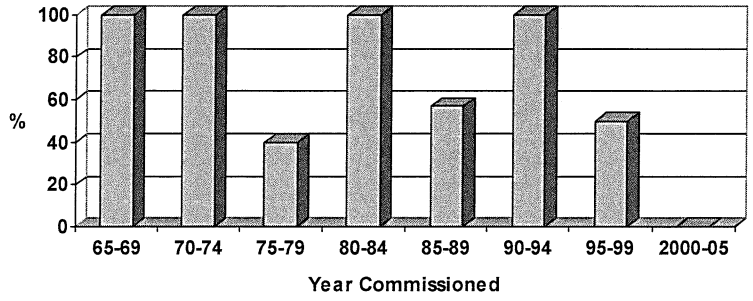

Figure 1-1
Life extension activities for converter transformers undertaken since commissioning

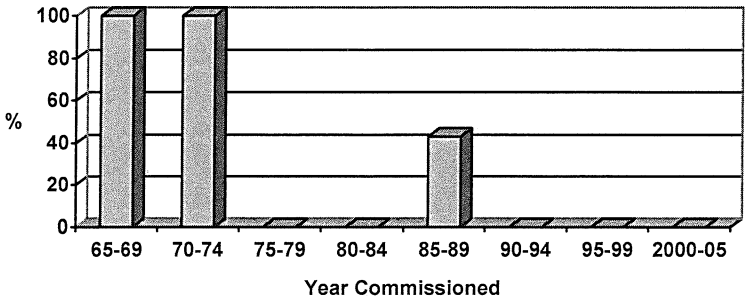

Figure 1-2
Life extension activities for converter valves undertaken since commissioning

The valve activities prior to 1974 were the replacement of mercury arc valves with thyristor valves. Two thyristor schemes have also undergone the complete replacement of their thyristor valves in the period from 1985-89.

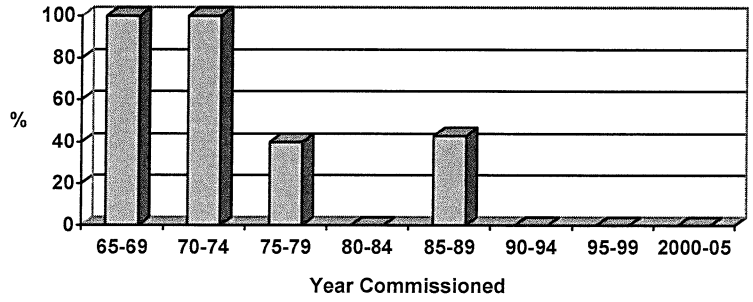

Figure 1-3
Life extension activities for valve electronics including valve base electronics

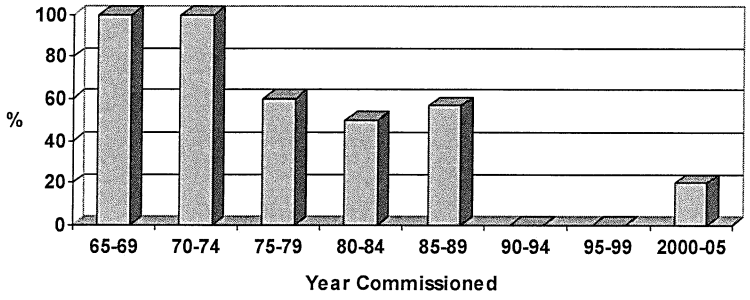

Figure 1-4
Life extension activities for HVDC system controls undertaken since commissioning

The survey revealed an interesting data point. For the period between 2000 and 2005, the activity reported described the replacement of the control system in the first of two back-to-back HVDC converters to match the controls of the second, with both built by the same supplier at the same location.

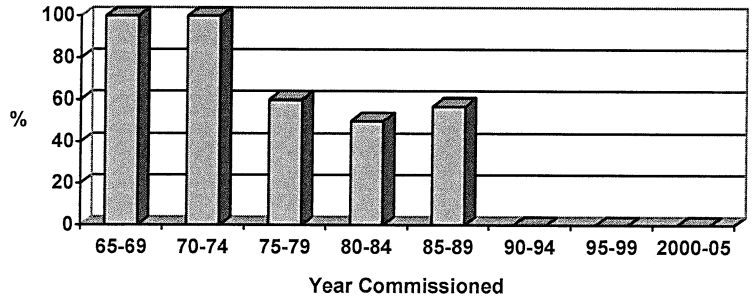

Figure 1-5
Life extension activities for HVDC valve cooling undertaken since commissioning

Comparison of figures 1-4 and 1-5 indicate that life extension activities of HVDC controls and valve cooling equipment are similar.

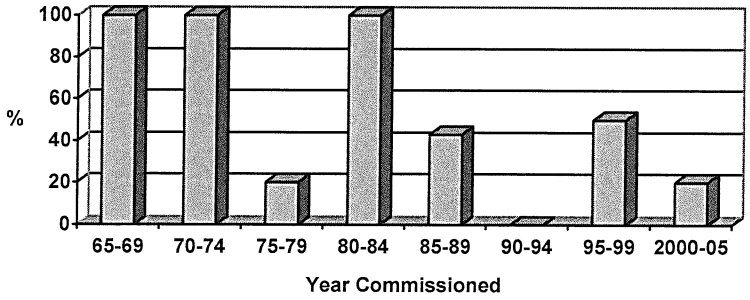

Figure 1-6
Life extension activities for ac filters undertaken since commissioning

The recent life extension activities reported for the ac filters shown in Figure 1-6 for the years 1995-99 and 2000-05 were included as upgrades and replacement of measurement and protection systems.

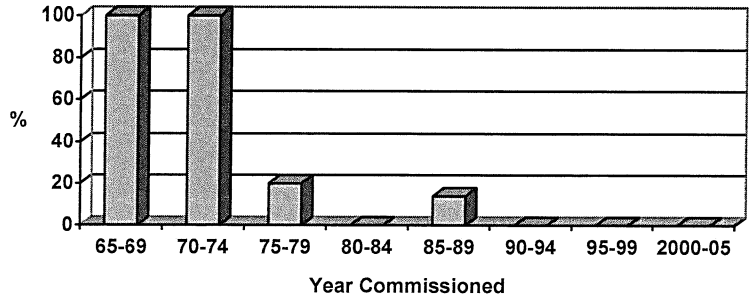

Figure 1-7
Life extension activities for dc smoothing reactors since commissioning

Although a report on dc filters was not specifically requested in the life extension survey, it was noted in one case that the dc filters were more of a problem than the ac filters. The original dc filters were replaced because of the high frequency of outages related to the filters. Within a few years, the replacement capacitors were all replaced again and then individually as they continued to fail. At the other end, they have been replaced one additional time during other life extension project. The dc filters installed at each end of the HVDC transmission lines are not redundant and are therefore critical to the operation of the HVDC system.

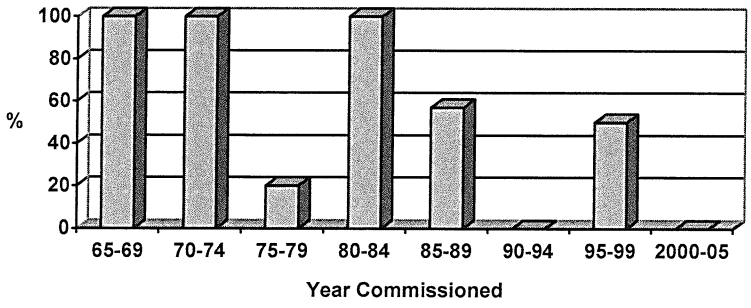

Figure 1-8
Life extension activities for ac switches and circuit breakers since commissioning

Summary

The results from the survey of the 24 HVDC interconnections indicated that most converter stations older than 10 years are undergoing some form of life extension upgrade. Most of the owners of HVDC transmission systems have expressed an interest in extending the life of their investment. They have also indicated they have maintenance programs in place to keep the

stations operational. The older projects such as the Pacific HVDC Intertie and the Nelson River bipoles have substantial maintenance programs in place. They also continue to upgrade their investments to ensure the systems continue to operate reliably [3]. In addition, the survey results from the Nelson River bipoles concluded that: "It is safe to say Nelson River has a continual life extension project active in one form or another." This statement accurately reflects the intent of the owners of most of the HVDC projects responding. The lifetime of converter stations require the stations to be extended as long as the associated transmission lines remain serviceable.

It is worthwhile to note that 10 HVDC transmission schemes have been decommissioned as indicated in Table 1-1. The reasons for decommissioning vary, and include being replaced by larger more efficient transmission lines, small ratings that served little purpose in networks that outgrew them and poor maintenance resulting in deteriorating reliability.

From the results of the survey on life extension activities, the following summary observations are made:

- HVDC projects with mercury arc valves commissioned prior to the early 1970's have now, for the most part, had replacement thyristor valves installed. Even some older projects with thyristor valves have replaced or are intending to replace those thyristor valves with new thyristor valves.

- Converter transformers are key elements in HVDC systems. In some HVDC projects the transformers have been replaced or undergone rebuilding to correct design problems. There is also an unresolved debate on what has caused performance problems or the rapid aging of the converter transformers. In some HVDC schemes however, the converter transformers have aged exceedingly well and have not been a problem.

- When converter valves or thyristors have been replaced, the converter electronics including the valve base electronics have been replaced also. When HVDC control systems are replaced, the valves are typically not replaced. The valve based electronics, if operating satisfactorily, may not be replaced with control system replacement either.

- Control systems of the early HVDC transmission systems were analog based and usually lasted as long as the valve systems. Recent trends of maintenance staff retiring have had an impact on those systems. Unfortunately those retiring are the most familiar with the analog control systems. This has led to control system replacements that are digital, programmable, and supportable by both the owner and the manufacturer. The useful lifetime or the ability of a supplier to continue supporting digital control systems is a pertinent question being asked by HVDC transmission owners.

- Wet valve cooling systems require consideration. Typically they are a source of high maintenance. They also require replacement at an accelerated rate compared to other system at a converter station. They are one of the major equipments that impact life extension requirements. Some HVDC facilities are considering or have replaced wet heat exchanger systems with dry (air cooled) systems to reduce maintenance, remove hazardous chemicals, and eliminate water usage. Liquids are still the cooling medium of choice for valve cooling by the manufacturers.

- AC filter life extension is often focused in replacement capacitors. In earlier systems this was precipitated by the need to phase out capacitor cans containing polychlorinated

biphenyls (PCBs). Capacitors for dc filters however are designed differently from ac filters and are damaged or their useful life reduced with high speed polarity reversals. Commutation failure is a common cause of transient voltage reversals and affects the life of dc filter capacitors.

- Smoothing reactors have fared well over time, suggesting a 30+ year lifetime.
- Switchgear, particularly where switched capacitor, filter and reactor banks are concerned have required replacement or refurbishment due to the constant use.

Chapter References

[1] Guide for Upgrading Transmission Systems with HVDC Transmission, CIGRE Brochure Ref. 127, SC14, WG 14.11, 1998.

[2] J.A.C. Forrest, B. Allard, Thermal Problems Caused by Harmonic Frequency Leakage Fluxes in Three-Phase, Three-Winding Converter Transformers, IEEE Transactions on Power Delivery, Vol. 19, No. 1, January 2004, pp 208-213.

[3] J.J. Cochrane, M.P. Emerson, J.A. Donahue, G. Wolf, A Survey of HVDC Operating and Maintenance Practices and their Impact on Reliability and Performance, IEEE Transactions on Power Delivery, Vol. 11, No. 1, January 1996, pp 514-518.

[4] I. Vancers, F.J. Hormozi, A Summary of North American HVDC Converter Station Reliability Specifications, IEEE Transactions on Power Delivery, Vol. 8, No. 3, July 1993, pp 1114-1122.

[5] P. Lips, Water Cooling of HVDC Thyristor Valves, IEEE Transactions on Power Delivery, Vol. 9, 1994, pp 1930-1937.

2
CIGRE HVDC SYSTEM PERFORMANCE DATA

Introduction

This chapter summarizes key HVDC system performance metrics. They are based upon a review of published CIGRE HVDC reliability data gathered throughout the world from 1993 to 2004 [1, 2, 3, 4, 5, 6]. The summary information includes data on energy availability, energy utilization, forced energy unavailability, scheduled energy unavailability, thyristor cell failure rates and an examination of equipment categories resulting in outages or loss of HVDC system capacity. CIGRE's HVDC reliability data is reported worldwide using a protocol for collecting operational performance of HVDC systems developed by Advisory Group B4.04 of CIGRE Study Committee B4 (HVDC and Power Electronics). The CIGRE protocol is published for reference in IEEE Std. 1240, IEEE Guide for the Evaluation of the Reliability of HVDC Converter Stations [7].

Performance Metrics

The CIGRE performance data that have been reviewed represents information compiled from 51 different converter stations throughout the world over a period of twelve years. The converter station's commissioning dates begin in 1972 and extend through 2004, with ratings between 150 MW to 3,000 MW. The statistics presented in this Chapter have been grouped into the following three age groups based on their commissioning dates:

- Age < 10-years
- 10-years ≤ Age < 20-years
- Age ≥ 20-years

HVDC transmission line statistics have not been included.

Energy Availability

Energy availability (EA) statistics reported by CIGRE indicate a measure of the energy, which could have been transmitted except for limitations of capacity. These limitations are due primarily to scheduled and forced outages of converter station equipment, dc transmission lines, or cables. Factors that are involved in the CIGRE calculation of EA include the HVDC system's total equivalent forced and scheduled outage hours (EOH) and period hours (PH) for the reporting period. EA is expressed as a percentage based on the following formula:

$$EA\ (\%) = 100 - (EOH)/(PH) \times 100$$

The EA data is provided in the 1993-2004 CIGRE reports for 51 HVDC systems, each with its own energy availability statistics. The CIGRE data has been sorted into the three age groups shown in Table 2-1. It is interesting to note that the data defines an average and median age of 15-years for the converters. The published MW rating and EA for each of the 51 HVDC systems

is used to calculate total maximum energy ratings and total energy available ratings. These are used to obtain combined average energy availability for each age group (see Table 2-1 and Figure 2-1).

Table 2-1
Summary of HVDC System Energy Availability

Age Group of Systems (Years)	Total Rating of Stations Reporting (MW)	Total Maximum Energy Ratings (MW-Hr)	Total Energy Available Ratings (MW-Hr)	Average Energy Availability (%)
Age < 10-years	14,700	250,888,800	234,975,516	93.66%
10-years ≤ Age < 20-years	21,693	1,092,872,880	1,031,897,322	94.42%
Age ≥ 20-years	13,994	998,432,184	942,373,496	94.39%
Average/Median Age = 15-years				94.32%

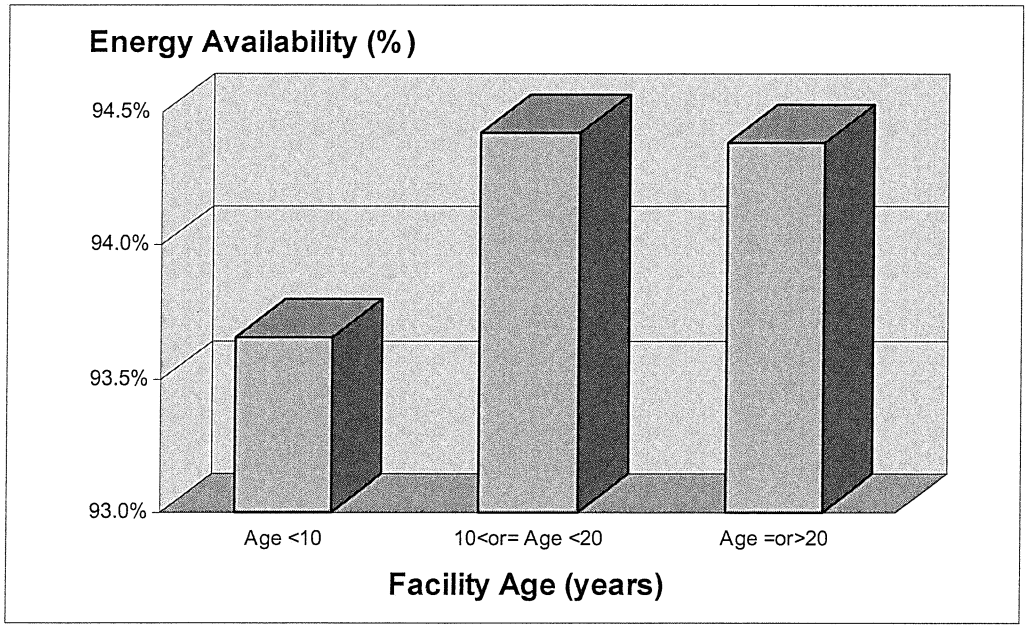

Figure 2-1
HVDC System Energy Availability (1993-2004)

Energy Utilization

Energy utilization (U) statistics reported by CIGRE represents a measure of the energy actually transmitted over the HVDC system. Factors that are involved in the calculation of U include the HVDC systems maximum continuous capacity (Pm), total energy transmitted and period hours (PH) for the reporting period. U is expressed as a percentage based on the following formula:

U (%) = [(total energy transmitted)/(Pm x PH)] x 100

The CIGRE energy utilization data has been sorted into the three age groups shown in Table 2-2. The published MW rating and U for each of the 50 HVDC systems that reported their utilization data is used to calculate total maximum energy utilization ratings and total energy utilization ratings. These are used to calculate the combined average energy availability for each age group (see Table 2-2 and Figure 2-2). It should be noted that one of the 51 HVDC systems reporting EA statistics did not report their U statistics.

Table 2-2
Summary of HVDC System Energy Utilization

Age Group of Systems (Years)	Total Rating of Stations Reporting (MW)	Total Maximum Energy Utilization Ratings (MW-Hr)	Total Energy Utilization Ratings Achieved (MW-Hr)	Average Energy Utilization (%)
Age < 10-years	14,700	250,888,800	128,672,702	51.3%
10-years ≤ Age < 20-years	21,693	1,092,872,880	564,858,547	51.7%
Age ≥ 20-years	12,994	971,924,424	580,570,717	59.7%
Average/Median Age = 15-years				55.0%

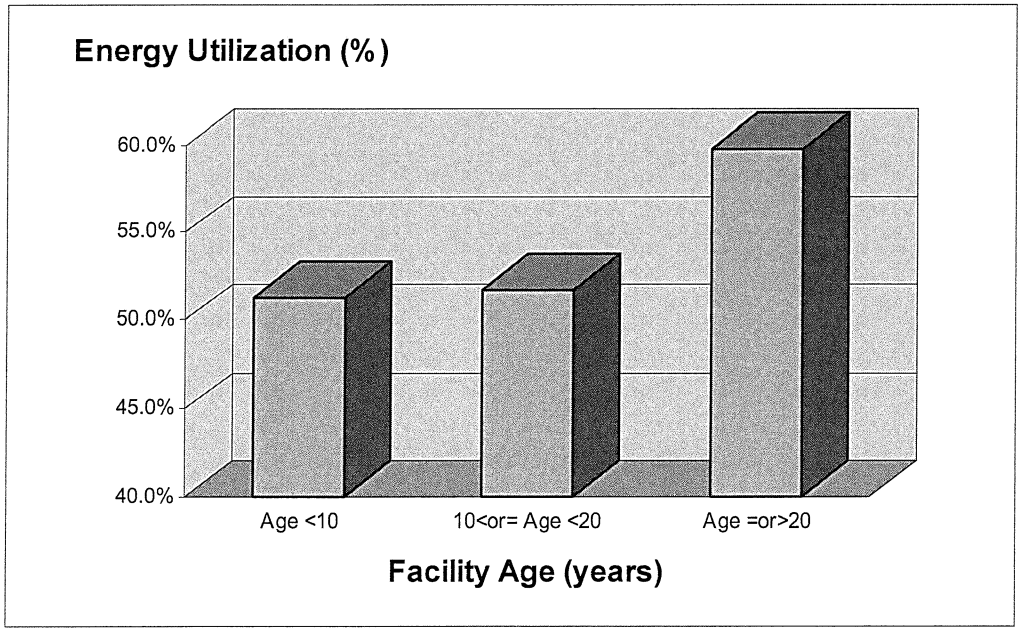

Figure 2-2
CIGRE HVDC System Energy Utilization (1993-2004)

Forced and Scheduled Energy Unavailability

Energy unavailability is a measure of the energy, which could not be transmitted due to outages. The HVDC system is unavailable for operation at its maximum capacity due to an event directly related to converter station equipment or dc transmission line. AC system related outages are not included in HVDC system unavailability calculations. Additionally, outages taken for major reconfiguration or upgrading of a converter station is not reported.

A scheduled outage is one that is either planned or which can be deferred until a suitable time. Scheduled outages are typically planned well in advance for preventive maintenance purposes and may be an indication of annual maintenance activities. If a scheduled outage is extended due to additional work, which would otherwise have lead to a forced outage, the excess period time is considered as a forced outage. Forced outages are events in which the converter station equipment is unavailable for normal operation but is not in the scheduled outage condition.

Forced energy unavailability (FEU) is calculated by determining the equivalent forced outage hours (EFOH) for the period hours (PH) based on the following formula:

FEU (%) = (EFOH/PH) x 100

Likewise the scheduled energy unavailability (SEU) is calculated by determining the equivalent schedule outage hours (ESOH) for the period hours (PH) based on the following formula:

SEU (%) = (ESOH/PH) x 100

It should be noted that on an annual basis the PH are 8760 hours except during leap years when PH are 8784 hours.

The CIGRE forced and scheduled energy unavailability data is sorted into the three age groups shown in Table 2-3 and Table 2-4. The published MW rating and corresponding FEU and SEU for each of the 51 HVDC systems reporting has been used to calculate the total maximum energy ratings and total energy forced and scheduled unavailability ratings. These are used to obtain the combined average energy unavailability for each age group (see Table 2-3, Table 2-4, Figure 2-3 and Figure 2-4).

Table 2-3
Summary of HVDC System Forced Energy Unavailability

Age Group of Systems (Years)	Total Rating of Stations Reporting (MW)	Total Maximum Energy Ratings (MW-Hr)	Total Forced Energy Unavailable (MW-Hr)	Average Forced Energy Unavailability (%)
Age < 10-years	14,700	235,120,800	5,232,983	2.2%
10-years ≤ Age < 20-years	21,693	1,082,360,880	18,104,685	1.7%
Age ≥ 20-years	13,994	998,432,184	15,394,243	1.5%
Average/Median Age = 15-years				1.7%

Table 2-4
Summary of HVDC System Scheduled Energy Unavailability

Age Group of Systems (Years)	Total Rating of Stations Reporting (MW)	Total Maximum Energy Ratings (MW-Hr)	Total Scheduled Energy Unavailable (MW-Hr)	Average Scheduled Energy Unavailability (%)
Age < 10-years	14,700	235,120,800	8,301,170	3.5%
10-years ≤ Age < 20-years	21,693	1,082,360,880	35,566,098	3.3%
Age ≥ 20-years	13,994	998,432,184	38,680,357	3.9%
Average/Median Age = 15-years				3.6%

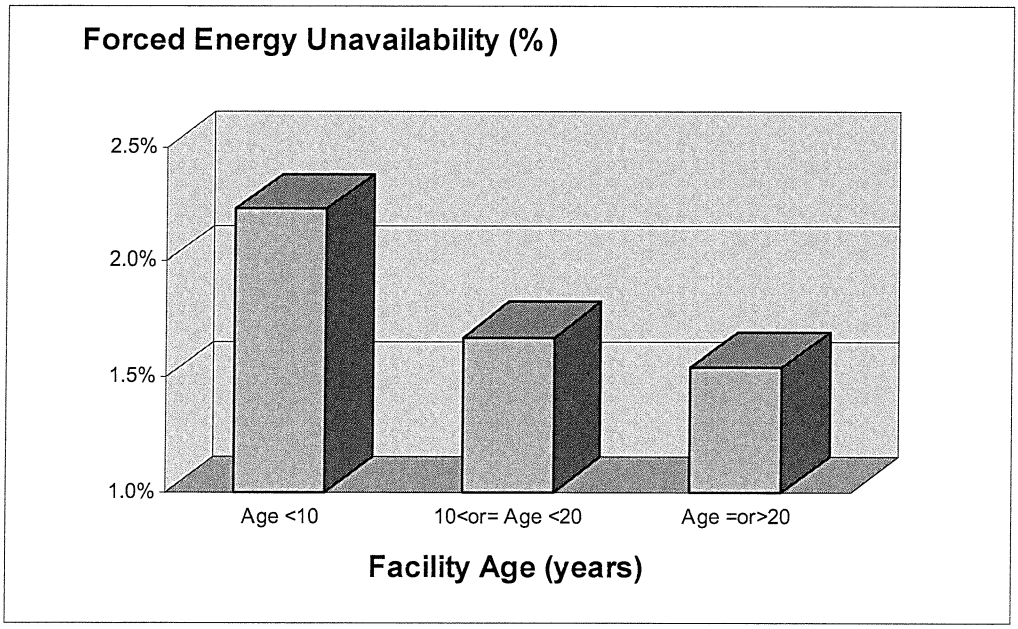

Figure 2-3
CIGRE HVDC System Forced Energy Unavailability (1993-2004)

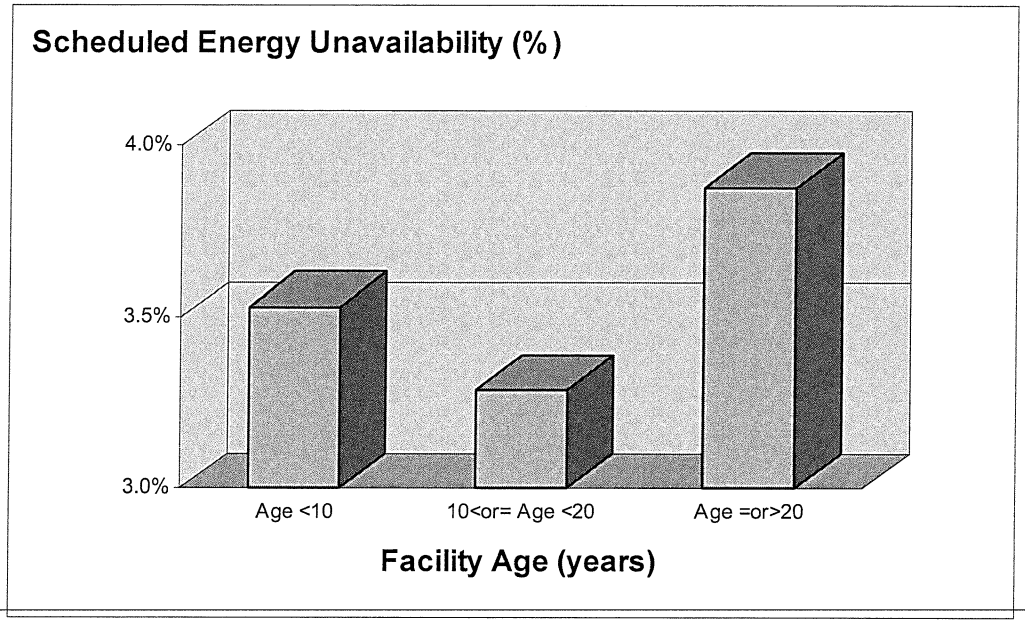

Figure 2-4
CIGRE HVDC System Scheduled Energy Unavailability

Thyristor Cell Failure Rates

The CIGRE data is used to calculate thyristor cell failure rates. It combines the total number of cells installed in each facility with the number of years for which data was reported to calculate the total thyristor cell-years included in Table 2-5. This data is sorted into the three age groups shown in Table 2-5. The published total thyristor cell failures in Table 2-5 are used to determine the annual percent cell failures with the trends indicated in Figure 2-5 for each age group.

Note: CIGRE defines a thyristor cell as an individual thyristor with its associated auxiliary circuits.

Table 2-5
Summary of HVDC System Thyristor Cell Failure Rates

Age Group of Systems (Years)	Total Rating of Stations Reporting (MW)	Total Thyristor Cell-Years Reported (Cell-Years)	Total Thyristor Cell Failures Reported (Cells)	Annual Percent Cell Failures (%)
Age < 10-years	6,900	34,992	18	0.051%
10-years ≤ Age < 20-years	15,505	341,160	243	0.071%
Age ≥ 20-years	12,009	872,208	1,111	0.127%
Average/Median Age = 15-years				0.110%

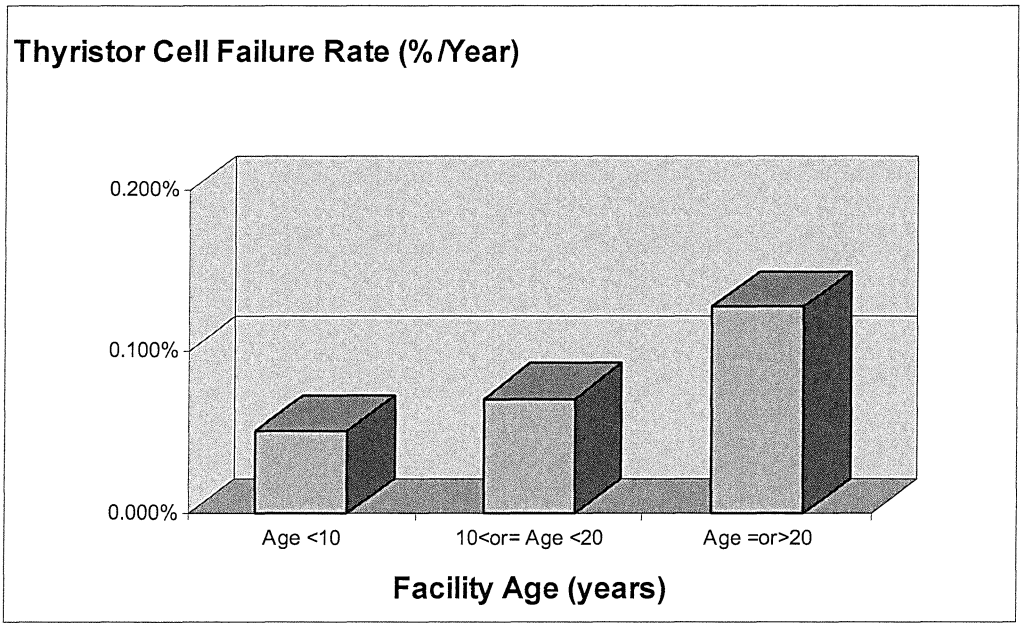

Figure 2-5
CIGRE HVDC System Thyristor Cell Failure Rate

Forced Outage Statistics

The CIGRE reports define the total number of forced outage events (2,639) and corresponding total forced outage hours (39,563) between 1993 and 2004. CIGRE further defined outages for each of the equipment categories listed below. These statistics do not include outages due to dc transmission lines and cables, which would have added 478 outage events and 12,741 hours.

- AC and Auxiliary Equipment (AC-E): This category covers loss of station capacity resulting from all ac main equipment at a converter station. It starts at the incoming ac connection and extends to the external connection on the valve winding bushing of the converter transformer. This equipment includes ac filters, shunt compensation, PLC filters, ac control and protection, converter transformers, synchronous compensators, auxiliary equipment, auxiliary power, cooling systems, civil works, ac circuit breakers, disconnect switches, grounding switches, surge arresters buswork, insulators, etc.
- Valves (V): This category covers loss of station capacity as a result of all parts of a thyristor valve including all auxiliaries and components integral with the valve. The valve cooling system associated with a valve failure includes only that part of the cooling system at high potential.
- Control and Protection (C&P): This category covers loss of station capacity due to equipment used for the control, monitoring and protection of the overall HVDC system.
- DC Equipment (DC-E): This category covers loss of station capacity due to all other HVDC equipment, including dc smoothing reactors, dc switching equipment, dc ground electrode, dc surge arresters, wall bushings, current and voltage measuring devices, insulators, etc…
- Other (O): Loss of station capacity or an extension of outage durations due to human error or unknown causes is assigned to this category.

The percentage of total number of forced outage events and equivalent forced outage hours for each category are shown in Figure 2-6 and Figure 2-7 respectively. The equivalent forced outage hours is the sum of the actual forced outage hours after the outage duration has been adjusted for the percentage of reduction in capacity due to the outage. Of particular interest is the fact that while converter transformer outages account for approximately 146 events in the AC-E category of Figure 2-6, they also account for approximately 23,052 of the forced outage hours shown in Figure 2-7.

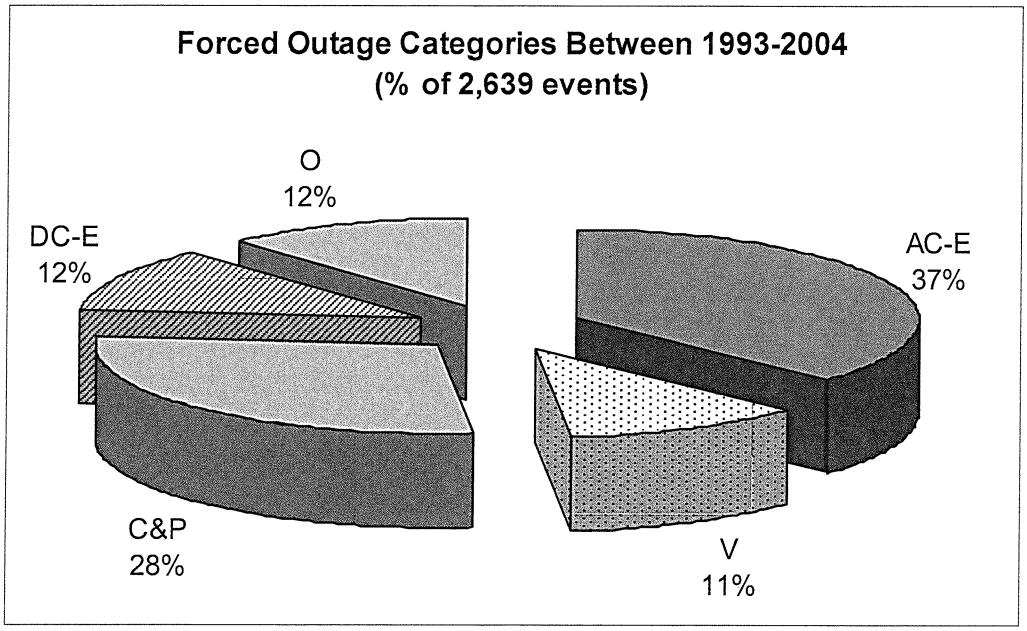

Figure 2-6
CIGRE HVDC System Forced Outage Categories by Events (1993-2004)

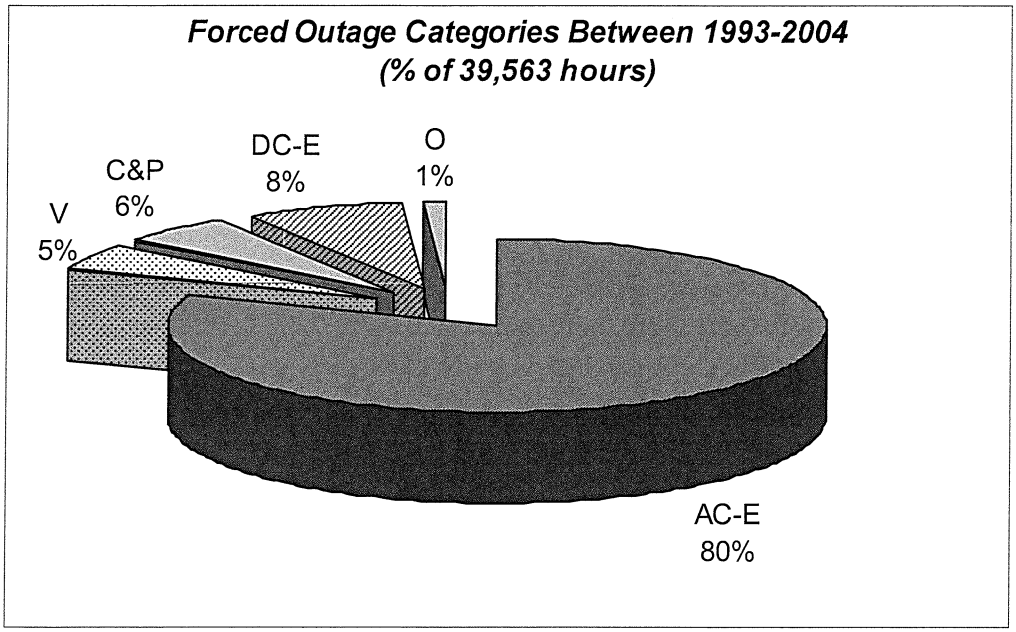

Figure 2-7
CIGRE HVDC System Forced Outage Categories by Hours (1993-2004)

Summary

Various performance statistics from HVDC systems, which reported their data to CIGRE between 1993 and 2004 have been reviewed and reported in this Chapter. The following are the summary observations:

- The average energy availability of HVDC systems, as a function of age, tends to rise after the first 10-years of operation and remain relatively constant. The overall average EA is approximately 94.3%.
- The average energy utilization of HVDC systems, as a function of age, tends to rise significantly for those facilities greater than 20-years of age indicating a high value is placed on their use.
- Forced energy unavailability tends to improve with age perhaps indicating improved diagnostics as HVDC systems age.
- Scheduled energy unavailability increases for those facilities greater than 20-years of age, perhaps indicating a higher level of maintenance is required for older HVDC systems.
- Thyristor cell failure rates tend to rise significantly for those facilities greater than 20-years of age.
- The total number of forced outage events between 1993 and 2004 is greatest for ac equipment (AC-E) and least for thyristor valves (V).

- The total number of forced outage hours between 1993 and 2004 is greatest for ac equipment (AC-E) and least due to human error or unknown causes (O).

In particular, a significant observation drawn from the forced outage data shown in Figure 2-6 and Figure 2-7 is the impact on the number of events and hours that the AC-E equipment category (AC and Auxiliary Equipment) has on the forced outage performance. Although the AC-E number of events is an important performance metric, the hours associated with these events is more critical, since each outage hour represents an hour where the HVDC system is not generating revenue for the owners. This in turn, leads to a conclusion that emphasizes the need for extending the life of ac equipment to maintain overall HVDC system reliability.

Chapter References

[1] CIGRE 1996:14-101, A Survey of the Reliability of HVDC Systems Throughout the World During 1993-1994, Paris, France
[2] CIGRE 1998:14-102, A Survey of the Reliability of HVDC Systems Throughout the World During 1995-1996, Paris, France
[3] CIGRE 2000:14-102, A Survey of the Reliability of HVDC Systems Throughout the World During 1997-1998, Paris, France
[4] CIGRE 2002:14-101, A Survey of the Reliability of HVDC Systems Throughout the World During 1999-2000, Paris, France
[5] CIGRE 2004:B4-201, A Survey of the Reliability of HVDC Systems Throughout the World During 2001-2002, Paris, France
[6] CIGRE 2006:B4-202, A Survey of the Reliability of HVDC Systems Throughout the World During 2003-2004, Paris, France
[7] IEEE Std 1240-2000, IEEE Guide for the Evaluation of the Reliability of HVDC Converter Stations, Appendix B – CIGRE's "Protocol for Reporting the Operational Performance of HVDC Transmission Systems"

3
COMPONENT LIFETIMES

Introduction

The basic intent of this chapter is to identify the expected service life of major equipment items associated with HVDC converter stations. Additionally, a high-level assessment of typical cost breakdowns and representative replacement outage times for each of the equipment items are addressed in this Chapter.

Expected Lifetimes

In general, the service life of electrical equipment is defined as that period of time prior to breakdown or failure during which a set of equipment is expected to operate satisfactorily and used economically, while meeting specific performance requirements. A chart indicating the expected service lives of HVDC converter station equipment items is included in Appendix C. The data shown in Appendix C is based on published information and from experience of project team members [1, 2]. An important consideration that must be factored into any equipment life expectancy is the initial design, operational use, maintenance and whether or not the equipment has been overloaded during its lifetime.

The chart in Appendix C is divided into the following five major categories to coincide with the CIGRE data-base presented in a previous Chapter:

- AC & Auxiliary Equipment: This category of equipment includes ac filters, reactive compensation, ac switching equipment, ac line, ac surge arresters, ac buswork, ac instrumentation, ac control and protection, cooling equipment, and converter transformers.
- Thyristor Valves: This category includes all parts of the converter valve including thyristors, grading capacitors, fiber optics, snubber circuits, reactors, heat-sinks, cooling tubing, electronics and other components and auxiliaries integral to the valve.
- HVDC Control and Protection: This category includes the equipment used to control, monitor, and protect the overall HVDC system.
- DC Equipment: This category includes the dc filters, dc smoothing reactors, dc switching equipment, dc ground electrode and electrode line, dc-side arresters, dc buswork, dc wall bushings and dc instrumentation.
- Other: The other category shown in Appendix C is reserved for costing information only and is not used to indicate information related to service lives or replacement times.

AC & Auxiliary Equipment

AC Filters

AC current harmonics are generated by a converter station as a result of the ac/dc conversion process. AC filters are installed in order to limit the level of ac voltage distortion and communication system interference caused by these harmonics. The conversion process also

causes the converter to consume reactive power, which is compensated, in part, by the ac filter banks. The total reactive power from the ac filters can range from 10% to 40% of the active power transfer of the converter station. The filters considered in this Guideline are of the non-active type consisting of fixed capacitors, reactors and resistors arranged in an outdoor configuration.

- Individual capacitor units associated with ac filter capacitor banks are typically of all film design as used in substation shunt capacitor banks. However, many of the older HVDC facilities have been around long enough to have capacitor units with PCB dielectric fluids. If they do have these style capacitors, the units are often replaced to bring the facility into compliance with current PCB regulations independent of life expectancy. Capacitor units are replaced during the course of normal maintenance as a function of spare parts availability. An average service life of 25 years (this is an average figure, a light duty cycle may extend the lifetime well beyond averages) has been assigned to ac filter capacitor banks [2].
- Reactors associated with ac filter equipment are typically single phase and either dry air core or oil immersed iron core type. An average service life of 25 years has been assigned to dry air core reactors and 35 years for oil immersed units (these are average figures, a light duty cycle may extend the lifetime well beyond averages) [2].
- Power resistors used in ac filters are typically the fixed resistance wire wound power or steel plate design type. An average service life of 40 years has been assigned to these types of resistors based on calculations per MIL-HDBK-217F (Military Handbook – Reliability Prediction of Electronic Equipment).

Reactive Compensation

The reactive power demand of HVDC systems is typically 50% to 60% of the active power transferred during normal operation. The reactive power design for HVDC systems needs to consider the following criteria:

- AC bus voltage regulation.
- Stability and speed of the HVDC control system.
- Overvoltage due to load rejection.

The majority of HVDC systems use switched shunt capacitors in combination with ac filters to meet the reactive power demand. Additionally, shunt reactors are sometimes used to reduce steady-state overvoltages associated with low dc power transfers.

Individual capacitor units associated with shunt capacitor banks are typically replaced during the course of normal maintenance as a function of spare parts availability. An average service life of 25 years has been assigned to shunt capacitor banks [2].

Shunt reactors associated with reactive compensation equipment are typically single phase and either dry air core or oil immersed iron core type. An average service life of 25 years has been assigned to dry air core reactors and 35 years for oil immersed units [2]. The life expectancy of air core reactors is effected by the environmental conditions (farming, coastal, heat, etc.) of the location of the installation. Oil filled reactors are protected by the steel tank.

Reactive compensation and voltage support can also be supplied by the use of synchronous condensers.

AC Circuit Breakers

Converter stations are connected to ac systems with conventional circuit breakers rated to carry full load current, interrupt fault currents and energize the converter transformers. Additionally, ac circuit breakers are used for switching and protection of reactive compensation and ac filters. In these applications, the normal life expectancy can be reduced by the extreme number of operations switching the filter banks off and on. It is not unusual for filter breakers to reach 10,000 operations in less than twenty years (AC applications of circuit breakers consider 2,000 operations a normal lifetime). The user needs to consider many factors with each application of ac circuit breakers including voltage and current ratings, system growth, closing sequence, interrupting capacity, and operating (close/open) times. Most components within an ac circuit breaker can be replaced during the course of normal maintenance as a function of spare part availability. An average service life of 35 years has been assigned to ac circuit breakers [2].

Interrupting Switches

Interrupting switches are air break switches equipped with an interrupter device used to control the insertion or removal of shunt reactive power equipment. Interrupting switches are typically refurbished or replaced during the course of normal maintenance as a function of the number of operations and spare parts availability. An average service life of 20 years has been assigned to these type switches [2].

Circuit Switchers

Many HVDC converter schemes use circuit switchers as the interrupting device of choice for insertion or removal of shunt reactive power equipment. Circuit switchers are typically refurbished or replaced during the course of normal maintenance as a function of the number of operations and spare parts availability. An average service life of 25 years has been assigned to these type switches.

Disconnecting Switches

Disconnecting switches are used to isolate equipment from buses or other energized apparatus and are generally not used for load break applications. Grounding switches are typically used in conjunction with disconnect switches to provide equipment grounding provisions. Disconnecting and grounding switches are typically refurbished or replaced during the course of normal maintenance as a function of the number of operations and spare parts availability. It is not unusual to replace only the live parts of the switch to extend its life or increase its circuit rating. An average service life of 35 years has been assigned to these type switches [2].

Surge Arresters

Surge arresters applied in the ac portion of converter stations are for standard overvoltage protection as well as nonstandard applications such as ac filter component protection. The following arresters are typically installed:

- Bus arresters
- Filter reactor arresters
- Shunt reactor arresters
- Converter transformer arresters

Choosing the protective voltage levels and energy rating of specific arresters is an involved process requiring a detailed insulation coordination study. Failures can be detected by laboratory testing or catastrophic failure. Typically catastrophic failures cause a forced outage and requires immediate replacement. Non-catastrophic failures can be replaced during normal maintenance cycles as a function of replacement parts availability. An average service life of 35 years has been assigned to surge arresters [2].

It should be noted, the standard surge arrester used prior to the late 1970s was the gapped silicon carbide design. Many utilities removed this style device from their systems and replaced them with the metal oxide types. This was due in part to the aging characteristics of the silicon carbine and in service failures experienced by the industry.

Line Traps (Carrier Wave Traps)

Line traps (sometimes referred to as wave traps) are used in protective relaying schemes, where a high frequency carrier signal is coupled to a transmission line to transmit information. The line trap is a tuning device used to decouple the carrier signal and prevent shorting of the carrier signal by an external transmission line fault. An average service life of 20 years has been assigned to line traps [2].

Buswork, Insulators and Structures

Buswork, insulators and structures are used in combination with electrical grade tubing and cable conductors to provide electrical interconnections and safe clearances within substations. This type of equipment should not deteriorate except for environmental conditions, material flaws or changes to the electrical network that result in original design limits being exceeded. Individual failed buswork, insulators or structures are typically replaced during the course of normal maintenance as a function of replacement parts availability. An average service life of 50 years has been assigned to buswork, insulators and structures.

AC Control & Protection

AC control and protection equipment can be electro-mechanical to highly sophisticated digital packages. Typically they are comprised of electronic panels for monitoring, controlling and protecting major equipment within a substation. Individual components, panels or boards are typically replaced during the course of normal maintenance due to failure or obsolescence. Improvements in technology, design, hardware and software, as well as changes in network conditions, tend to make the service life of these equipment items relatively short. An average service life for the digital devices of 15 years has been assigned to ac control and protection equipment [2].

Instrument Transformers

Conventional ac instrument transformers are used for the following functions:

- Revenue Metering: Wound type potential and current transformers.
- Capacitive Voltage Transformer (CVT): Used for control, indication and protection.
- Capacitor Coupled Voltage Transformer (CCVT): Used for the same control, indication and protection functions as the CVT, but also has a coupling device to allow it to be used for power line carrier (PLC) functions.
- Bushing Type Current Transformer (CT): Protection and control.
- Freestanding Current Transformer: Protection and control.

Individual instrument transformers are typically replaced during the course of normal maintenance due to failure. An average service life of 30 years has been assigned to instrument transformer equipment [2].

Cooling Systems

Heating, ventilating and air conditioning (HVAC) systems are installed to accommodate converter station control buildings and valve halls. Although valve halls may not include air conditioning, air-cleaning equipment may be provided to prevent contaminant accumulation within the valve structures. Valve halls may also be equipped with fire detection and/or prevention systems. An average service life of 20 years has been assigned to building HVAC and valve hall fire prevention systems assuming continued cleaning and routine maintenance.

Thyristor valve cooling systems use air, glycol, de-ionized-glycol, or de-ionized water as the primary heat transfer medium. Heat is transferred from the thyristor heat-sinks and other valve equipment, requiring cooling, to the cooling medium. Water-cooled systems use a treated de-ionized water solution to transfer the heat to outside cooling towers. In like manner, air cooled systems transfer the heat to a liquid water-glycol solution to outside cooling towers. Cooling towers typically utilize a dry or wet surface design for heat transfer. An average service life of 15 years has been assigned to wet surface cooling towers and 20 years to dry surface cooling towers assuming continued cleaning and routine maintenance.

Converter Transformers

Converter transformers are used to transform the ac system voltage to a voltage level required for the dc rectification or inversion conversion process. Converter transformers may be designed as single-phase or three-phase units with three or four windings. The configuration depends on ratings, reliability, maintenance and spare requirements. Features that make a converter transformer different from conventional ac power transformers include the following:

- Valve-side secondary windings are configured with one set of delta and one set of wye floating windings.
- The valve-side windings are subject to dc bias voltages.
- Windings carry cyclic dc current with a rectangular waveform and associated harmonic currents.

- The core is subjected to small amounts of dc current and must be able to handle those currents.
- The difference in impedances between phases must be less that 5%.
- Load tap changing (LTC) mechanisms are typically coordinated with the station reactive power requirements and valve firing controls with a representative LTC range of 20% in 1% to 2% steps.
- Leakage inductance is a critical parameter that forms the converter's primary source of commutating reactance.

An average service life of 40-year has been assigned to converter transformers following review of expected lifetimes of ac transformers [2] and the CIGRE Joint Task Force technical report [3].

It is of interest to note that a study of the CIGRE data provided in Chapter 2 indicates that converter transformers have been a major source of outages within the "AC and Auxiliary Equipment" category. A CIGRE Joint Task Force (JTF) was established in an attempt to identify the transformer failures and the probable causes [3]. Although there remain uncertainties in making any conclusion regarding the JTF findings, there appear to be a couple of items of particular interest, e.g., (1) 15 of the 24 failures in 2000 and 2001 (62.5%) were reported by three systems; (2) Systems without spare transformers were a major contributor to unavailability; (3) Transformer failures for the reporting period 1972 to 2002 excluding one major system were 54.1 years/failure; (4) Transformer failures for the reporting period 1972 to 2002 including the previously excluded major system were 31.4 years/failure.

Civil Works

Civil works generally refer to the physical works and facilities making up the converter station. They include grading, drainage, concrete placement, steel erection, geotechnical issues, surveying, structures, service roads, buildings, etc. An average service life of 50 years has been assigned to civil works assuming continued maintenance such as cleaning, painting and building roof replacement as part of routine maintenance.

Auxiliary Power Equipment

Auxiliary power equipment associated with converter stations are similar to large ac substation installations and include redundant power for critical loads. Converter station loads that are typically critical include the following:

- Control and Protection: AC and dc service to control panels, protection panels, operator controls, switchgear, etc.
- Valve Cooling: Valve cooling pump stations, heat exchanger fans, etc.
- Building: Lighting, heating, ventilating, air conditioning, fire protection, security systems, etc.
- Yard: Equipment heaters, lighting, maintenance service, etc.

An average service life of 20 years has been assigned to battery chargers, 15 years to batteries and 40 years to station service transformers assuming routine maintenance and availability of spare parts [2].

Thyristor Valves

Thyristor valves are built in different physical arrangements depending on the application and manufacturer. A single thyristor cell or parallel connected thyristor cells and their associated components (for control, voltage grading, protection and monitoring) constitute a single voltage level within a thyristor valve. Each thyristor valve is comprised of a number of series connected thyristor levels, with a snubber circuit composed of a resistor and capacitor and reactors to limit the rate of change of voltage across the thyristor. The reactors are designed to limit the rate of rise of current when the thyristor valve is triggered. The thyristor valve turn-on (trigger) process is initiated by an electrical gate pulse from ground potential via the valve base electronics (VBE) unit. The VBE provides the individual thyristor levels with a pulse that triggers each thyristor level via a thyristor control unit (TCU) located near each thyristor cell. Recently developed direct light triggered thyristors are not covered in these guidelines.

Thyristor valves are protected from overvoltages by arresters typically installed within the valve hall at the following locations:

- DC bus arrester to ground.
- Valve arrester across each thyristor valve.
- Bridge arrester across each 6-pulse bridge.
- Midpoint arrester between the 6-pulse bridge and ground.

Choosing the protective voltage levels and energy rating of specific valve arresters is an involved process requiring a detailed insulation coordination study.

Other components associated with a thyristor valve include fiber optics, heat-sinks, cooling tubing and cooling system electrodes. Individual components of a thyristor valve are generally considered replaceable items assuming spare parts are available and obsolescence has not become an issue. An average service life of 30 years has been assigned to thyristor valve equipment [2].

HVDC Control and Protection

Analog Electronics

It is technically possible to repair and refurbish existing analog control systems. The long-term challenge of this approach is obtaining and retaining the knowledge base, components, staffing and funding to undertake such a program. Replacement of analog control system with digital technology has been considered by many utilities while others continue to maintain analog control systems as long as components and staff expertise can be obtained. An average service life of 25 years has been assigned to analog electronic systems assuming routine maintenance and availability of spare parts.

Digital Electronics

Improvements in technology, design, hardware and software as well as changes in system requirements tend to make the service life of digital electronics relatively short. An average service life of 15 years has been assigned to digital electronic systems assuming routine maintenance and availability of spare parts.

Power Supplies

Uninterruptible power supply (UPS) systems provide a reliable power source for critical station equipment following interruption of the main power system. Changing UPS technologies and station equipment loads can often be cause for replacement of UPS equipment. An average service life of 10 years has been assigned to UPS systems assuming routine maintenance and availability of spare parts [2].

DFR and SER

Digital fault recorders (DFR) and sequence of events recorders (SER) are used for recording system faults, transients and disturbances. Improvements in technology, hardware and software as well as changes in system requirements tend to make the service life of these instruments relatively short. An average service life of 15 years has been assigned to DFR and SER components assuming routine maintenance and availability of spare parts [2].

SCADA

Supervisory Control and Data Acquisition (SCADA) systems can perform individual control operations as well as obtain numerous quantities of equipment or system operating data. These systems typically consist of: (1) A remote terminal unit (RTU); (2) A Human-machine interface (HMI) system; and (3) A central processor or computer. Changing technologies and equipment obsolescence are considerations when determining the service life of SCADA, RTU and HMI equipment. An average service life of 10 years has been assigned to SCADA and RTU components including the HMI system assuming routine maintenance and availability of spare parts [2].

Communication Systems

Telephone networks, microwave transmitter and receiver, and fiber optics communications systems are typically constructed of many replaceable parts, which can be serviced under normal maintenance programs. However, complete replacement of networks or systems may be required at intervals because of changes in requirements or obsolescence. An average service life of 10 years has been assigned to communication systems assuming routine maintenance and availability of spare parts [2].

DC Equipment

Smoothing Reactor

DC smoothing reactors can be either oil or air insulated and functionally provide several key features, including:

- Smooth the dc current to prevent discontinuous current at low power transfer levels.
- Decrease the incidence of commutation failures.
- Prevent steep-front surges from the dc line or dc yard from entering the valve hall.
- Provide a part of the overall dc harmonic filtering.

An average service life of 25 years has been assigned to air core smoothing reactors and 35 years to oil insulated smoothing reactor assuming routine maintenance and availability of spare parts.

The life expectancy of air core reactors is effected by the environmental conditions (farming, coastal, heat, etc.) of the location of the installation. Oil filled reactors are protected by the steel tank.

Switching Equipment

DC switching equipment, such as disconnecting switches, is used to isolate equipment from buses or other energized apparatus and is not used for load break applications. Grounding switches are typically used in conjunction with disconnect switches to provide equipment grounding provisions. Disconnecting and grounding switches are usually repaired and replaced during the course of normal maintenance as a function of the number of operations and spare parts availability. An average service life of 35 years has been assigned to these type switches.

Ground Electrode

The American National Standards Institute (ANSI) standard ANSI C2, National Electrical Safety Code (NESC) 2002 indicates, in part, that monopolar operation of a bipolar HVDC system is permissible, for limited periods, during emergencies and maintenance. Additionally, transmission networks can not be designed to use the earth normally as the sole conductor for any part of the circuit. Based on the limited use of ground electrodes an average service life of 40 years has been assigned to ground electrodes. At least one HVDC facility has inspected electrodes that have been in service for 29 and 34 years and found no indication of deterioration.

Surge Arresters

Arresters applied on dc equipment typically include the following:

- DC filter reactors.
- Smoothing reactors.
- DC transmission line poles.
- Neutral bus.

Choosing the protective voltage levels and energy rating of specific arresters is an involved process requiring a detailed insulation coordination study. Failures can be catastrophic in nature. Typically this causes a forced outage and requires immediate replacement. Non-catastrophic failures can be replaced during normal maintenance cycles as a function of replacement parts availability. An average service life of 35 years has been assigned to surge arresters [2].

DC Filters

HVDC converters create harmonics on dc transmission lines that can cause interference in nearby telecommunications systems. DC filters installed at the converter ends and electrode lines of HVDC transmission systems are designed to eliminate these interference effects. Normally they are considerably smaller and less expensive than filters on the ac side. The filter components are comprised of passive components such as capacitors, grading resistors and reactors. Active dc filters using power electronic as a means to reduce harmonic interference are not covered in these Guidelines. Usually no filters are needed for back-to-back or cable transmission systems. An average service life of 20 years has been assigned to dc filters.

Wall Bushings

DC wall bushings form the transition for the electrical connections between the indoor valve hall equipment and outdoor yard equipment. DC bushings have a different design from AC bushings requiring longer creepage distances or different shed profiles than ac bushings of similar peak rating due to contamination issues related to dc fields. An average service life of 35 years has been assigned to dc wall bushings.

Instrumentation

DC potential and current transducers are installed for control, protection and indication purposes. An average service life of 30 years has been assigned to dc instrumentation.

Buswork, Insulators and Structures

Buswork, insulators and structures are used in combination with electrical grade tubing and cable conductors to provide electrical interconnections and safe clearances within converter stations. This type of equipment should not deteriorate except for environmental conditions, material flaws or changes to the converter station that result in original design limits being exceeded. Individual failed buswork, insulators or structures are typically replaced during the course of normal maintenance as a function of replacement parts availability. An average service life of 50 years has been assigned to buswork, insulators and structures.

Costs

A critical step in determining whether to refurbish equipment items or replace a converter station is the methodology used to evaluate the associated cost. Factors that should be considered include:

1. A project evaluation plan combining objectives, assessment criteria, present value analysis model and schedule.
2. Existing equipment performance, civil works, building, land and environmental issues.
3. Outage impact on customers and revenue.
4. Maintenance history, spare parts, staffing and lead time to replace existing or failed equipment.
5. Impact of increasing or decreasing converter station rating.
6. Existing or new design and performance constraints.
7. Discussion with potential suppliers and impact of new technologies, market conditions and currency exchange rates.
8. Develop a refurbishment or replacement strategy that addresses all equipment items within a converter station.
9. Contractual terms and conditions that could impact refurbishment or replacement costs such as liquidated damages, warranty provisions, schedule, etc.
10. The difference between forced and scheduled outages on sales, reliability, and availability.

The available options along with the many factors that need to be considered make it very difficult to render specific cost factors for refurbishing or replacement of a converter station

without a custom evaluation of a specific converter station's requirements [4]. The percentage costs of various converter station categories has been cited in literature and included in Appendix C for reference [5, 6, 7, 8].

Replacement Times

Representative converter station outage times for equipment replacement are included on the chart in Appendix C. These outage times are included only for reference. Actual time to replace various pieces of equipment will vary depending on the type of installation, skill of personnel, availability of heavy equipment, spare parts, etc. Each utility should evaluate the cost impact associated with outages when evaluating the options of refurbishing or replacing converter station equipment recognizing that work could be scheduled during scheduled annual maintenance periods.

Chapter References

[1] Guidelines for the Life Extension of Substations, EPRI, November 2002 Update, Technical Report 1001779

[2] Replacements – Units, Service Lives, Factors, Western Area Power Administration and Bureau of Reclamation, May 2006

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[6] EPRI, High Voltage Direct Current Handbook, Chapter 8, First Addition, Project RP3158-01, TR-104166, 1994

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4

DRAFT OUTLINE FOR LIFE EXTENSION OF EXISITNG HVDC SYSTEMS

Introduction

The guidelines outlined in this chapter are the first of a two phase multi-year effort. Phase I addresses the life extension of HVDC converter station equipment including those summarized in Appendix C. The Phase I Guidelines will examine natural commutated converters that utilize thyristors (single or parallel combinations) connected in series to build up thyristor valves. The Guidelines will not specifically address forced commutated converters or capacitor commutated converters although many of the principles covered here can be applied.

Phase II will address the life extension of HVDC transmission lines and cables. Phase II will be defined and funded separately following the successful completion of Phase I. Phase II will also include a training course on the life extension guidelines for the operation, maintenance and reliability assessment strategies of HVDC systems. As a result, the emphasis of this Chapter is placed on the HVDC converter station and its associated equipment. This approach is based on experience indicating that HVDC converter station life extension is the primary need at this time. The majority of HVDC converter station equipment is approaching the end of its useful operating lifetime. It requires attention before HVDC transmission lines due to the longer operating lifetime of those transmission lines.

Background

The aging infrastructure of HVDC converter stations and transmission line systems is of growing concern to utilities interconnected with those systems. In most cases, the transmission path provided by operating HVDC converter stations is profitable and life extension is not only an option, but a necessity. With many installations approaching 25 to 30 years of service, the justifications for extending the converter station's life needs to be addressed before reliability and availability are impacted.

The choices facing the industry are:

- Refurbishing the systems.
- Replacing aging components.
- Building new facilities.
- Phasing out the old facilities.

Purpose of the Guidelines

These Guidelines are intended to be used in conjunction with a utility's in-house procedures and to supplement industry standards and manufacturers' recommendations. Where in-house

procedures are minimal, these guidelines can assist in forming the basis for extending existing maintenance practices.

These Guidelines will help utilities:

- Establish refurbishment strategies to extend equipment life of existing HVDC converter stations.
- Evaluate Operating and Maintenance (O&M) and reliability performance improvement methods for existing HVDC converter stations.
- Increase existing asset utilization by extending the life of HVDC converter stations and improve return on investment.

Guideline Format

A draft outline of the Guidelines has been developed and is described in this section. There are many HVDC converter station equipment items, subsystems and components, which are similar in type and functionality to those found in conventional ac substations. Those items that are similar to those in conventional substations are covered by EPRI's existing "Guidelines for the Life Extension of Substations" [1]. As such, only equipment items, subsystems and components unique to HVDC converter stations will be discussed in these Guidelines.

The Guidelines will consist of eight (8) main chapters with associated sections and appendices as follows:

1. Introduction
    - Background
    - Purpose
    - How to use
2. Framework of Maintenance Decisions
    - Overview
    - Maintenance philosophies
    - Maintenance considerations
    - Data management
    - Asset management
    - Performance metrics
3. AC & Auxiliary Equipment
    - AC harmonic filters
    - Reactive compensation
    - AC control & protection
    - AC circuit breakers
    - Others

4. Converter Transformers
5. Cooling Systems
    - Building and valve hall heating, ventilating and air conditioning (HVAC)
    - Thyristor valve cooling
6. Thyristor Valves
7. HVDC Control, Protection and Communication Systems
8. Grounding and Static Shielding System
    - Grid and equipment grounding review in relation to the latest revision to IEEE-80
    - Lightning protection coverage review of the total facility
9. DC Equipment
    - Smoothing reactors
    - Switching equipment
    - Ground electrodes
    - Filters
    - Wall bushings
    - Instrumentation
    - Insulators and buswork

After the introductory and framework chapters, each of the equipment items, in the remaining chapters, will be divided into the following sections:

- Description: This section will provide a description of the main characteristics of the subject equipment including the different types of equipment used, their function in converter stations and the various ways in which the equipment is applied.
- Trouble Modes: This section will describe common aging and failure modes for the subject equipment and methods for detecting these failures. Causes of these failure modes will also be reviewed.
- Maintenance: Maintenance will be defined as periodic scheduled inspection and testing of equipment to ensure trouble-free performance. Maintenance will also include the refurbishment of equipment components that are replaced periodically. The maintenance section will include information on routine maintenance and inspection procedures commonly applied to the subject equipment.
- Condition Assessment: Condition assessment will be defined as that testing outside the scope of testing normally performed as part of scheduled maintenance. The tests performed as part of a condition assessment program will be undertaken to determine the status and reliability of equipment. Other topics include reasons for performing these tests and the use of these test results.
- Replacement/Refurbishment: The factors to be considered when deciding on the replacement or refurbishment of a piece of equipment will be reviewed. The costs to be accounted for in this process and the methodology to be used will also be discussed including, (a) spare parts, (b) new technologies, (c) replacement costs and minimizing converter station downtime, (d) increasing capacity, (e) control system replacement "plug-and-play" strategies, (f) equipment service life estimations and (g) present value analysis procedures.

Chapter References

[1] Guidelines for the Life Extension of Substations, EPRI, November 2002 Update, Technical Report 100

A
APPENDIX

October 4, 2006 Meeting Notes

Background

HVDC facilities represent a significant investment and revenue source for electric utilities. As these facilities age, utilities are in need of guidelines to extend the life with selected system refurbishment or placement, maintenance practices, or complete replacement.

EPRI is starting a project to produce Guidelines for Life Extension of Existing HVDC Systems (EPRI Project Number 062819-1). These guidelines will initially focus of HVDC Converter Stations. High Energy Inc. (HEI), an engineering consulting company, has been retained to prepare these guidelines. HEI's project team consists of Ruth Johnson, Bruce Lavier, Bill Mele, Duane Torgerson, Randy Wachal, Gene Wolf and Dennis Woodford.

Introductions/Opening Remarks

A meeting was held on October 4, 2006 to officially begin the project, discuss the purposes and expectations, and obtain input from interested utilities. An attendance list is attached.

Dr. Ram Adapa, the EPRI project manager for this project, welcomed participants to the meeting and discussed the need for this project. He invited utility participants to have a continuous open dialog with the project team so the guidelines can reflect the highest priority items, provide experiences with life extension efforts, and issues and problems with HVDC systems.

EPRI has a complimentary project for life extension of High Voltage AC Substations which is available on a compact disk. Ram will obtain copies of this CD for the project team for use on this specific project.

Ram also mentioned several other related projects EPRI is pursuing, including:

- Advanced HVDC systems that operate at 800kV and above.
- HVDC Reference Guide.
- An HVDC Conference, possibly in the Winnipeg, Canada area early next year. There was an HVDC conference recently held in South Africa.

Expectations of Project

It is expected the guidelines will provide a useful tool for utilities interested in life extension of HVDC systems. The guidelines will initially focus on converter stations. The guidelines will initially focus on the converter components identified as the highest priority items, then as more funding for the project becomes available, provide detailed guidelines on all components and eventually include information on HVDC transmission lines.

The guidelines should provide some guidance on maintenance practices, methods of measuring and forecasting remaining life, some projections on timeframes for refurbishment and replacement activities so they can be scheduled, and help with financial justifications of projects.

Project Tasks

The scope of work for the current project involves the following six distinct tasks:

- Task 1 – Kickoff Meeting
- Task 2 – List of HVDC Converter Stations
- Task 3 – Review of CIRGE HVDC Outage Statistics
- Task 4 – Component Lifetimes
- Task 5 – Draft Outline for Life Extension for Existing HVDC Systems
- Task 6 – Prepare "Life Extension for HVDC Systems"

It is planned the work through task 5 will be completed by the end of 2006.

List of HVDC Converter Stations

This task will focus on the creation of a list of HVDC converter stations along with a high level summary of life extension efforts that have taken place or are planned. The list will be started through the use of IEEE and CIGRE lists and will focus on facilities located in North America. The project team will make attempts to gather information on facilities in other parts of the world; this will be done through CIGRE, by contacting utilities that are CIGRE members. Duane Torgerson has a list of all DC links around the world. Ram will send to Ruth an electronic copy of it. Also, Irina Merson of HEI has contacts in Russian Federation utility (which is also an EPRI member). Also, Irina will find appropriate contacts at Minnesota Power and New Brunswick Utility.

Also, it was recommended that the team contact the United Kingdom's National Grid, which owns the facility near Boston.

A draft copy of the list will be available by the end of October. Additional information will be added to the list as it is received.

Review of CIRGE HVDC Outage Statistics

The team will obtain and review the outage statistics collected and published by CIGRE from HVDC converter stations. These statistics will be used as a starting point for correlations with known life extension upgrades.

There was some discussion of the "manufacturer-supported user groups" as a possible source of additional information. It was suggested that Los Angles Department of Water and Power (LADWP) may have information on such "user groups".

For example: the information could be grouped and better analyzed, with more specific recommendations, for facilities equipped by the same manufacturer (GE, or Siemens, or ABB).

Component Lifetimes

The project team will consider published information on component lifetimes to create a chart of typical component lifetimes. There was a desire among utility representatives to include information on how to determine the remaining life of equipment specific to their converter station.

There will also be some discussion in the guidelines of spare parts and the role they play in life extension efforts. There was a study done by Siemens several years ago to determine if thyristors age while on the shelf. It was determined at that time that they do not: there were no changes in their parameters. The question was raised at the meeting: what truly is the life expectation of the thyristor unit? There are several stations that have experienced very few thyristors failures while others have experienced many failures.

Also discussed at the meeting was the issue of converter transformer performance, related to their aging and failures. EPRI is considering a project to study this issue in detail. Meanwhile, the guidelines will consider this issue in as much detail as possible.

The Bonneville Power Administration (BPA) has information on aging of equipment; it was furnished to the project team during the meeting.

The Western Area Power Administration (Western) periodically publishes a document on typical lifetimes for equipment. The representatives from Western will check if they can obtain a copy of this document for the project team; they will send it to Ruth.

It is desired from the utility representatives the guidelines contain information on when equipment needs replacing, with possible lead times and some justifications. It is also desired the guidelines be a complete, in-depth report. Since there is a limited budget for the project, the highest priority components will be discussed in detail with lower priority components discussed in as much detail as the budget allows.

Draft Outline for Life Extension for Existing HVDC Systems

The outline for the guidelines will be prepared in draft form. This outline will contain a section on transmission lines; however, transmission line components will be covered at only a very high level.

There are many components in an HVDC converter station that are also contained in traditional AC stations. Where these components are covered in other EPRI publications, those publications will be referenced and discussion will be provided only if it is unique to DC stations. The AC equipment in HVDC stations is an important component, since AC equipment operates a lot.

Prepare "Life Extension for HVDC Systems"

The guidelines will be prepared using information gathered in the above tasks. The guidelines are intended to be a guide for utilities to use for determining remaining life of an HVDC converter stations and methods of extending this life.

The guidelines will also contain information required to help utilities make business cases for replacement or refurbishment of components within the HVDC converter stations.

Input from Industry Advisors/Interested Utilities

There was interest in including information on the personnel element of converter station operation and maintenance, both of which can affect station availability and life extension efforts. Detailed knowledge of converter stations, both from engineering and craft personnel, is typically gained over many years of experience with a specific station. As the workforce ages, there is concern about losing this knowledge through retirements. Education of the future work force is an important task.

Several people also mentioned concern over the control and cooling systems of converter stations. For example, in Colorado and New Mexico, the water tables have been dropping as the population has been growing; this creates a serious issue for the station cooling systems.

There were questions on live line work of HVDC transmission lines and stations. There is consideration of the creation of a live line HVDC project within EPRI at a later date. During this project, the list will be developed of the potential problems related to transmission lines connecting HVDC stations.

Future Project Updates

Ruth Johnson of HEI will send out periodic updates of the project via e-mail, to a mailing list consisting of meeting participants and invited guests, as well as to any other interested parties. Anyone else who is interested in being on the mailing list should contact Ruth.

Future Opportunities for Project Input from Interested Utilities

The team welcomes input from utilities for development of priorities for the guidelines; on past and planned efforts in life extension; and on special issues they would like considered in the guidelines.

Project Funding

This project is funded through EPRI program 162 – HVDC Systems. Utilities that fund this target will be eligible to receive copies of the guidelines; all utilities interested in this project are encouraged to discuss their organization's funding of this program area with their utilities MEP.

This project is funded through the end of 2006. Funding of work in 2007 will be dependent upon the funding levels of this program by member utilities. It has been proposed that by the end of 2007, the report would be published – if the sufficient funding is available – on most critical components of HVDC stations, such as valves, controls, cooling systems, converter transformers (creating prioritized list of components will be part of Task 5).

A-1
Kickoff Meeting Attendance

EPRI Project No. 062819-1: LIFE EXTENSION OF EXISTING HVDC SYSTEMS Project Meeting - October 4, 2006 (11:00 am to 4:00 pm) Tri-State G&T - Westminster, Colorado				
Attend	**Name**	**Company**	**email**	**phone**
1	Adapa, Ram	EPRI	radapa@epri.com	650-855-8988
1	Blaquiere, Ben	Western Area Power Administration	blaquier@wapa.gov	406-232-8306
1	Britton, Greg	Tri-State G&T	gbritton@tristategt.org	303-254-3444
1	Hurst, Jack	Tri-State G&T	jhurst@tristategt.org	303-254-3605
1	Johnson, Ruth	High Energy Inc.	ruth.johnson@highenergyinc.com	303-494-3328
1	Lavier, Bruce	Lavier Engineering LLC	blavier@gorge.net	541-980-8881
1	Litzenberger, Wayne	Bonneville Power Administration	wlitzenberger@bpa.gov	360-619-6291
1	Mander, Art	Tri-State G&T	amander@tristategt.org	303-254-3323
1	Mele, Bill	Indoor Environmental Solutions, Inc.	bmele@msn.com	303-948-0500
1	Merson, Irina	High Energy Inc.	irina.merson@highenergyinc.com	303-399-1098
1	Michael, Randy	Xcel Energy Services	Randy.Michael@xcelenergy.com	806-796-3325
1	Mitchell, Bruce	Tri-State G&T	bmitchell@tristategt.org	303-254-3411
1	Poggi, Ernie	Xcel Energy Services	ernest.poggi@xcelenergy.com	303-273-4703
1	Ramsay, Dill	Tri-State G&T	dramsay@tristategt.org	303-254-3450
1	Schmidt, Ernie	Western Area Power Administration	schmidt@wapa.gov	308-254-3046
1	Selman, Jeff	Tri-State G&T	jselman@tristategt.org	303-254-3403
1	Torgerson, Duane	Winfield Enterprise, LLC	drtorgerson@msn.com	303-202-3933
1	Wolf, Gene	Lone Wolf Engineering, LLC	lonewolfengineering@comcast.net	505 898-9491

I	Woodford, Dennis	Electranix Corporation	daw@electranix.com	204-953-1832
P	Chase, Don	Vermont Electric Power Company	dchase@velco.com	802-770-6299
P	Mehraban, Ben	American Electric Power Service Corp.	bmehraban@aep.com	614-552-1742
P	Mortensen, Karl	Great River Energy	kmortensen@grenergy.com	763-241-2365
P	Recksiedler, Les	Manitoba Hydro	lrecksiedler@hydro.mb.ca	204-474-3192
P	Wachal, Randy	Manitoba HVDC Research Centre	rww@hvdc.ca	204-989-2149
I	Bier, Michael	Kansas City Power & Light Co.	mike.bier@kcpl.com	816-245-3987
I	Crist, Paul	Lincoln Electric System	pcrist@les.com	402-467-7615
I	Holladay, Damon	Hoosier Energy Rural Electric Coop., Inc	holladay@hepn.com	812-876-0290
I	Jensen, Darwin	El Paso Company	djensen@epelectric.com	915-543-2094
I	Keri, Albert	American Electric Power Service Corp.	ajkeri@aep.com	614-552-1965
I	Ludington, Ron	Texas New Mexico Power Company	ronald.ludington@tnmp.com	505-538-3768
I	Oliver, Jonathan	Arkansas Electric Cooperative Corp.	joliver@aecc.com	501-570-2488
I	Pillay, Logan	ESKOM	logan.pillay@eskom.co.za	02-711-629-5170
I	Saum, Steve	Richmond Power & Light	steves@rp-l.com	765-973-7410
N	Bhuiyan, Mukhles	Los Angeles Department of Water & Power	Mukhlesur.Bhuiyan@ladwp.com	213-367-2532
N	Dalloul, Iyad	Public Service Electric & Gas Co.	iyad.dalloul@pseg.com	908-412-7687
N	Goosen, Piet	ESKOM	piet.goosen@eskom.co.za	
N	McNichol, John	Manitoba Hydro	jrmcnichol@hydro.mb.ca	
N	Osborne, Mark	National Grid Company plc	mark.osborne@uk.ngrid.com	44-192-665-5517
		BC Hydro		
		EDF (Electricite de France)		
	Bilodeau, Hubert	Hydro-Quebec	bilodeau.hubert@hydro.qc.ca	
		Minnesota Power		
		New Brunswick Power Transmission		
	Wu, Tim	Los Angeles Department of Water & Power	Chuan-Hsier.Wu@ladwp.com	213-367-0650

19	<-- Attending	I => Invited
5	<-- Phone-in	n=> Not attending
24	<-- Total	p=> Phone-in

B
APPENDIX

List of HVDC Transmission Schemes

(This list is in the public domain by courtesy of IEEE HVDC and FACTS Subcommittee and CIGRE Study Committee B4)

HVDC PROJECTS LISTING
Prepared for the
DC and Flexible AC Transmission Subcommittee
of the
IEEE Transmission and Distribution Committee
by the
Working Group on HVDC and FACTS Bibliography and Records

SYSTEM / PROJECT	HVDC SUPPLIER	YEAR COMMISSIONED	POWER RATING (MW)	DC VOLTAGE (kV)
MOSOW-KASHIRA (retired from service)	RUSSIAN	1951 (____)	30	±100
GOTLAND I (retired from service)	ASEA	1954 (1986)	20	±100
GOTLAND EXTENSION (retired from service)	ASEA	1970 (1986)	30	±150
GOTLAND II	ASEA	1983	130	150
GOTLAND III	ASEA	1987	260	±150
GOTLAND HVDC LIGHT	ABB	1999	50	±60
ENGLISH CHANNEL (retired from service)	ASEA	1961 (1984)	160	±100
VOLGOGRAD-DONBASS	MINISTRY FOR ELECTROTECHNICAL INDUSTRY OF USSR	1962/65	720	±400
NEW ZEALAND HYBRID INTER ISLAND LINK	ASEA	1965	600	±250
NEW ZEALAND HYBRID INTER ISLAND LINK	ABB	1992	1240	+270/-350
NEW ZEALAND HYBRID INTER ISLAND LINK		PLANNED		
KONTI-SKAN 1	ASEA	1965	250	±250
KONTI-SKAN 1	AREVA	2005	250	±250
KONTI-SKAN 2	ASEA	1988	300	285

SAKUMA (retired from service)	ASEA	1965 (1993)	300	2x125
SARDINIA (retired from service)	ENGLISH ELECTRIC	1967 (1992)	200	200
VANCOUVER I	ASEA	1968/69	312	±260
VANCOUVER II	GENERAL ELECTRIC	1977/79	370	±280
PACIFIC INTERTIE	ASEA/GE	1970	1440	±400
PACIFIC INTERTIE	ASEA/GE	1982	1600	±400
PAC INTERTIE UPGRADE	ASEA	1985	2000	±500
PACIFIC INTERTIE EXPANSION	BROWN BOVERI	1989	3100	±500
KINGSNORTH (retired from service)	ENGLISH ELECTRIC	1972 (1987)	640	±266
EEL RIVER	GENERAL ELECTRIC	1972	320	±80
NELSON RIVER 1	ENGLISH ELECTRIC/GEC ALSTHOM	1973	1854	±463
NELSON RIVER 1	GEC ALSTHOM	1992/93	1854	±463
NELSON RIVER 1	SIEMENS	2001/02	1854	±463
NELSON RIVER 1	SIEMENS	2004	1854	±463
NELSON RIVER 2	AEG/BBC/SIEMENS	1978	900	±250
NELSON RIVER 2	AEG/BBC/SIEMENS	1985	2000	±500
SKAGERRAK I	ASEA	1976	275	±250
SKAGERRAK II	ASEA	1977	275	±250
SKAGERRAK III	ABB	1993	500	±350
SHIN-SHINANO 1	HITACHI/TOSHIBA/NISSHIN	1977	300	125
SHIN-SHINANO 2	HITACHI/TOSHIBA/NISSHIN	1992	300	125
SQUARE BUTTE	GENERAL ELECTRIC	1977	500	±250
DAVID A. HAMIL	GENERAL ELECTRIC	1977	100	±50
CAHORA-BASSA	AEG/BBC/SIEMENS	1977/78/79	1920	±533
C.U.	ASEA	1979	1000	±400
HOKKAIDO-HONSHU	ASEA	1979	150	125
HOKKAIDO-HONSHU	HITACHI/TOSHIBA	1980	300	250
HOKKAIDO-HONSHU	HITACHI/TOSHIBA	1993	600	±250
ACARAY	SIEMENS	1981	50	±25.6
VYBORG	MINISTRY FOR ELECTROTECHNICAL INDUSTRY OF USSR	1981	355	1X170(±85)

VYBORG	MINISTRY FOR ELECTROTECHNICAL INDUSTRY OF USSR	1982	710	2x170
VYBORG	MINISTRY FOR ELECTROTECHNICAL INDUSTRY OF USSR	1984	1065	3x170
VYBORG	MINISTRY FOR ELECTROTECHNICAL INDUSTRY OF USSR	1999	4x405	±85
ZHOU SHAN PROJECT		1982	50	100
INGA-SHABA	ASEA/GE	1982/83	560	±500
DUERNROHR 1 (retired from service)	AEG/BBC/SIEMENS	1983 (1997)	550	145
EDDY COUNTY	GENERAL ELECTRIC	1983	200	82
CHATEAUGUAY	BBC/SIEMENS	1984	2x500	2x140.6
OKLAUNION	GENERAL ELECTRIC	1984	200	82
ITAIPU 1	ASEA	1984	1575	±300
ITAIPU 1	ASEA	1985	2383	±300
ITAIPU 1	ASEA	1986	3150	±600
ITAIPU 2	ASEA	1987	3150	±600
BLACKWATER	BBC	1985	200	57
SACOI	CGEE/ALSTHOM	1985	50	200
SACOI THREE TERMINAL	ANSADO/GENERAL ELECTRIC	1993	300	±200
HIGHGATE	ASEA	1985	200	±56
MADAWASKA	GENERAL ELECTRIC	1985	350	130.5
MILES CITY HVDC SYSTEM (MCCS)	GENERAL ELECTRIC	1985	200	82
BROKEN HILL	ASEA	1986	40	2x17 (±8.33)
INTERMOUNTAIN POWER PROJECT (I.P.P.)	ASEA	1986	1920	±500
CROSS CHANNEL BP 1+2	CGEE-ALSTHOM/GEC-ALSTHOM	1985/86	2000	±270
DES CANTONS-COMFERFORD	GENERAL ELECTRIC	1986	690	±450
QUEBEC-NEW ENGLAND THREE TERMINAL	ABB	1990-92	2250	±450
VIRGINIA SMITH	SIEMENS	1987	200	50
GESHA (GEZHOUBA-SHANGHAI)	ABB/SIEMENS	1989	600	500
GESHA (GEZHOUBA-	ABB/SIEMENS	1990	1200	±500

SHANGHAI)				
VINDHYACHAL	ASEA	1989	500	2x69.7
McNEILL	GEC ALSTHOM	1989	150	42
FENNO-SKAN	ABB/ALCATEL	1989/98	572	400
FENNO-SKAN 2		PLANNED 2010	800	500
BARSOOR LOWER SILERU	BHEL	1989/91	100	±200
BARSOOR LOWER SILERU	BHEL	FUTURE	400	
RIHAND-DELHI	ABB/BHEL	1991	750	500
RIHAND-DELHI	ABB/BHEL	1992	1500	±500
NICOLET TAP	ASEA	1992	2000	
SAKUMA	HITACHI/TOSHIBA/MIT SUBISHI/NISSHIN	1993	300	±125
ETZENRICHT (retired from service)	SIEMENS	1993 (1997)	600	160
VIENNA SOUTH-EAST (retired from service)	SIEMENS	1993 (1997)	600	145
URUGUAIANA	TOSHIBA	1994	50	15
BALTIC CABLE	ABB	1994	600	±450
WELSH	SIEMENS	1995	600	162
KONTEK	ABB/NKT CABLES	1995	600	400
HAENAM-CHEJU	GEC ALSTHOM	1997	300	±180
CHANDRAPUR-RAMAGUNDUM	GEC ALSTHOM	1997/98	1000	2x205
CHANDRAPUR-PADGHE	ABB	1998	1500	±500
LEYTE-LUZON	ABB/MARUBENI	1998	440	350
VISAKHAPATNAM	GEC ALSTHOM	1998	500	205
MINAMI-FUKUMITZU	HITACHI/TOSHIBA	1999	300	125
VIZAG 1	GEC ALSTHOM	1999	500	205
VIZAG 2	ABB	2005	500	±88
KAALAMO		PLANNED 1999	40	20
NORTH-SOUTHEAST		PLANNED 1999	1000	
SWEPOL LINK	ABB	2000	600	±450
DIRECTLINK	ABB	2000	3 x 60	±80
KII CHANNEL	HITACHI/TOSHIBA/MIT SUBISHI	2000	1400	±250
KII CHANNEL		FUTURE	2800	±500
GARABI 1	ABB	2000	1100	±70
GARABI 2	ABB	2002	2000	±70
RIVERA	GEC ALSTHOM	2000	70	20

GRITA	PIRELLI/ABB	2001	500	400
TIAN-GUANG	SIEMENS	2001	1800	±500
HIGASHI-SHIMIZU	HITACHI/TOSHIBA	2001	300	125
MOYLE INTERCONNECTOR	SIEMENS	2001	2x250	2x250
THAILAND-MALAYSIA	SIEMENS	2001	300	±300
MANTARO-SOCABAYA		PLANNED 2001	300	±190
CROSS SOUND	ABB	2002	330	±150
MURRAYLINK	ABB	2002	200	±150
SASARAM	GEC ALSTHOM	2002	500	205
IB VALLEY-JAIPUR		PLANNED 2002	3000	
EUROCABLE		PLANNED 2002	600	500
RAPID CITY TIE	ABB	2003	2 x 100	±13
EAST-SOUTH INTERCONNECTOR	SIEMENS	2003	2000	±500
BAKUN			2130	3x±500
STOREBAELT		PLANNED 2010	600	400
THREE GORGES-CHANGZHOU	ABB/SIEMENS	2003	3000	±500
THREE GORGES-GUANGDONG	ABB	2004	3000	±500
GUI-GUANG	SIEMENS	2004	3000	±500
TROLL A	ABB	2004	2x40	±60
LEYTE-MINDANAO		PLANNED 2004	400	
VIKING CABLE		PLANNED 2004	600	450
LAMAR	SIEMENS	2005	211	±63
EAST-WEST ENERGY BRIDGE		PLANNED 2005	500	600
EAST-WEST ENERGY BRIDGE		PLANNED 2010	1000	
ICELAND-SCOTLAND LINK		PLANNED 2005	550	400
ICELAND-SCOTLAND LINK		FUTURE	1100	±400
NORWAY-UK		PLANNED 2005	800	
MEPANDA UNCUA		PLANNED 2006	500	
BASSLINK	SIEMENS	2006	500	400
ESTLINK	ABB	UNDER CONSTRUCTION 2006	350	150
LEWIS DE-ICER	AREVA	UNDER CONSTRUCTION 2006	250	±17.4
LONG ISLAND CABLE PROJECT		2007	600	±450
TEXAS-COLORADO		PLANNED 2007	400	

RUSSIA-CHINA		PLANNED 2007	2500	
NORNED		UNDER CONSTRUCTION 2007	700	±450
THREE GORGES-SHANGHAI		UNDER CONSTRUCTION 2007	3000	±500
NEPTUNE	SIEMENS	UNDER CONSTRUCTION		±500
SAPEI	ABB	PLANNED 2008/09	500	±500
CHINA-RUSSIA (HEIHE)		PLANNED 2008	750	
NORTHEAST-NORTH (GOALING)		PLANNED 2008	1500	
YUNNAN-GUANGDONG		PLANNED 2009	5000	800
LINGBAO EXPANSION		PLANNED 2009	750	
AL FADHILI	AREVA	UNDER CONSTRUCTION 2009	3 x 600	3 x 222
HUGO INTERTIE		PLANNED 2010	375	
STOREBAELT		PLANNED 2010	600	400
FAREAST (RUSSIA) - NE CHINA		PLANNED 2010	3000	
HULUNBEIR (INNER MONGOLIA) - SHENYANG		PLANNED 2010	3000	
NINGXIA-TIANJING		PLANNED 2010	3000	
NW-SICHUAN (BAOJI-DEYANG)		PLANNED 2011	3000	
NORTH SHAANXI-SHANDONG		PLANNED 2011	3000	
SHANDONG-EAST		PLANNED 2011	1200	
GEZHOUBA-SHANGHAI EXPANSION		PLANNED 2011	3000	
XIANJIABA-SHANGHAI		PLANNED 2011	6400	800
JINGPING-EAST CHINA		PLANNED 2012	6400	800
NORTH-CENTRAL		PLANNED 2012	1000	
JINGHONG-THAILAND		PLANNED 2013	3000	
XILUODU-HUNAN		PLANNED 2014	6400	800
LABRADOR-NEWFOUNDLAND (LOWER CHURCHILL PROJECT)		PLANNED 2015		
IRKUTSK (RUSSIA) - BEIJING		PLANNED 2015	6400	800

XILUODU-HANZHOU		PLANNED 2015	6400	800
NUOZHADU-GUANGDONG		PLANNED 2015	6400	800
HUMENG-SHANDONG		PLANNED 2015	6400	800
JINSHA RIVER II - EAST CHINA		PLANNED 2016	6400	800
HUMENG-TIANJING		PLANNED 2016	6400	800
GOUPITAN-GUANGDONG		PLANNED 2016	3000	
HUMENG-LIAONING		PLANNED 2018	6400	800
JINSHA RIVER II - FUJIAN		PLANNED 2018	6400	800
HAMI-C.CHINA		PLANNED 2018	6400	800
JINSHA RIVER II - EAST CHINA		PLANNED 2019	6400	800
TALCHER-BANGALORE	SIEMENS	FUTURE	2000	±500
CEPA (RASPIER-RAJASTHAN)		FUTURE	2000	500
ISACCEA		FUTURE	600	
OUTAOUAIS		FUTURE	2x625	
POLAND-LITHUANIA		FUTURE		
UK-NETHERLANDS		FUTURE		

The above HVDC List was based on the 2005 version of the CIGRE Compendium of HVDC Schemes Throughout the World.

Initial changes to the CIGRE list were made by incorporating changes from:

Mike Barhman, ABB - January 2006

Neil Kirby, AREVA – April 2006

Robyn Taylor, Teshmont - modifications based on the detailed descriptions from the 2005 version of CIGRE AG B4.04, COMPENDIUM OF HVDC SCHEMES THROUGHOUT THE WORLD

Robyn Taylor, Teshmont - modifications based on the IEEE HVDC Projects Listing, January 2000 Issue

C
APPENDIX

Service Life, Cost Breakdown and Replacement Time

Table C-1

Category	Typical Percent of Cost (%)	Equipment	Items	Estimated Service Life (Years)	Representative Replacement Outage Time (Hours)
AC & Auxiliary Equipment	9%	a) AC Filters	Capacitors	25	Maint.
			Resistors	40	Maint.
			Air Reactors	25	Maint.
			Oil Reactors	35	Maint.
		b) Reactive Compensation	Capacitors	25	Maint.
			Air Reactors	25	Maint.
			Oil Reactors	35	Maint.
		c) AC Circuit Breakers		35	64 †
		d) Interrupting Switches		20	32 ††
		e) Circuit Switchers		25	32 ††
		f) Disconnecting Switches		35	32 †
		g) Surge Arresters		35	8
		h) Carrier Wave Traps		20	8
		i) Buswork, Insulators & Structures		50	Maint.
		j) AC Control & Protection		15	Maint.
		k) Instrument Transformers		30	12
		l) Cooling Systems		15	*
	19%	m) Converter Transformers		40	†††
	13%	n) Civil Works		50	Maint.
			Chargers	20	12
	2%	n) Auxiliary Power & Equipment	Batteries	15	24
			Transformer	40	12

Thyristor Valves	20%	Thyristor Levels		30	670
HVDC Control and Protection	7%	a) Analog Electronics		25	Maint.
		b) Digital Electronics		15	670
		c) Power Supplies	UPS	10	Maint.
		d) DFR and SER		15	Maint.
		e) SCADA		10	Maint.
		f) Communication Systems		10	Maint.
		HVAC System	Boilers	20	
			Unitary Packaged Equipment	15	
DC Equipment	5%	a) DC Smoothing Reactor	Oil	35	120
			Air	25	40
		b) DC Switching Equipment		35	Maint.
		c) DC Ground Electrode		40	Maint.
		d) DC Surge Arresters		35	Maint.
		e) DC Filters		20	Maint.
		f) DC Wall Bushings		35	Maint.
		g) DC Instrumentation	Current	30	Maint.
			Voltage	30	Maint.
		h) Buswork, Insulators & Structures		50	Maint.
Other	8%	a) Erection & Commissioning		na	NA
	10%	b) Engineering		na	NA
	5%	c) Freight & Insurance		na	NA
	2%	d) Project Administration		na	NA

Notes:

1. Maint. => replace as required as part of maintenance.
2. NA => not applicable.

† Normal breaker removal can take 24 hours and installation of a new breaker up to 40 hours.

†† Ordinary switch removal takes 8 hours and installation of a new switch up to 16 hours. If a motor operator is part of the replacement add an additional 8 hours.

††† Transformer replacement has been done in 24 hours at converter stations equipped with rail systems and quick disconnect control wiring. If heavy cranes are required, the time for

replacement is dependent on their availability. Oil handling if required will add many days to the outage. Each utility should access their limitations and abilities.

* Valve cooling system estimated life cycles vary with individual system designs and component selection. Fifteen years is a conservative estimate representing the most susceptible of component arrangements.

Export Control Restrictions

Access to and use of EPRI Intellectual Property is granted with the specific understanding and requirement that responsibility for ensuring full compliance with all applicable U.S. and foreign export laws and regulations is being undertaken by you and your company. This includes an obligation to ensure that any individual receiving access hereunder who is not a U.S. citizen or permanent U.S. resident is permitted access under applicable U.S. and foreign export laws and regulations. In the event you are uncertain whether you or your company may lawfully obtain access to this EPRI Intellectual Property, you acknowledge that it is your obligation to consult with your company's legal counsel to determine whether this access is lawful. Although EPRI may make available on a case-by-case basis an informal assessment of the applicable U.S. export classification for specific EPRI Intellectual Property, you and your company acknowledge that this assessment is solely for informational purposes and not for reliance purposes. You and your company acknowledge that it is still the obligation of you and your company to make your own assessment of the applicable U.S. export classification and ensure compliance accordingly. You and your company understand and acknowledge your obligations to make a prompt report to EPRI and the appropriate authorities regarding any access to or use of EPRI Intellectual Property hereunder that may be in violation of applicable U.S. or foreign export laws or regulations.

The Electric Power Research Institute (EPRI)

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ELECTRIC POWER RESEARCH INSTITUTE
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800.313.3774 • 650.855.2121 • askepri@epri.com • www.epri.com

EL PASO ELECTRIC SERVICE TERRITORY

CONTROL AREA BOUNDARIES

POINTS OF INTERCONNECTION

WEST MESA	345.	(to PNM)
LUNA	345.	
LUNA 345/115.		(to PNM/TRI)
LUNA 345 TO LEF 345.		(to PNM)
AFTON	345.	
AFTON 345 TO AFTON G		(to PNM)
AFTON 345 TO AFTON S		(to PNM)
AMRAD	115.	(to PNM)
AIRPORT	115.	(to PNM)
HOLLOMAN	115.	(to PNM)
HIDALGO	345/115.	(to PNM)
PICACHO	115.	(to PNM)
LAS CRUCES	115.	(to TRI)
ORO GRANDE	115.	(to TRI)
MACHO SPRINGS	345.	(to TEP Wind Farm)
SPRINGERVILLE	345.	(to TEP)
GREENLEE	345.	(to TEP)
EMPIRE	345.	(to TEP)
ARTESIA	230.	(On SPS side of DC Terminal)

MAP REPRESENTATION NOT TO SCALE

LEGEND

- TRANSMISSION - 345KV
- TRANSMISSION - 115KV
- TRANSMISSION - 69KV
- TRANSMISSION - OTHER UTILITIES
- [S] GENERATING STATION - STEAM
- [T] GENERATING STATION - GAS
- [S] EPE GENERATING STATION - STEAM
- [T] EPE GENERATING STATION - GAS
- SOLAR
- SUBSTATION - TRANSMISSION
- SUBSTATION - DISTRIBUTION
- POINT OF WHOLESALE DELIVERY

OTHER UTILITIES

CEC	COLUMBUS ELECTRIC CO-OP, INC.
PNM	PUBLIC SERVICE COMPANY OF NEW MEXICO
SPS	SOUTHWESTERN PUBLIC SERVICE COMPANY
TEP	TUCSON ELECTRIC POWER COMPANY
TRI	TRISTATE GENERATION AND TRANSMISSION ASSOCIATION, INC.

SOURCE:
SYSTEM INTERCONNECTION,
C.Corral 01/23/2023
*GIS Image from Google Earth

The Electric Company
El Paso Electric

KEY MAP

BEFORE THE NEW MEXICO PUBLIC REGULATION COMMISSION

IN THE MATTER OF EL PASO ELECTRIC COMPANY'S APPLICATION FOR A CERTIFICATE OF PUBLIC CONVENIENCE AND NECESSITY FOR A REPLACEMENT 200 MW EDDY HIGH VOLTAGE DIRECT CURRENT TIE	)	**Case No. 26-00___**
EL PASO ELECTRIC COMPANY, Applicant	)	

DECLARATION OF JONATHAN M. TREJO IN SUPPORT OF THE FOREGOING DIRECT TESTIMONY OF EL PASO ELECTRIC COMPANY'S APPLICATION FOR A CERTIFICATE OF PUBLIC CONVENIENCE AND NECESSITY FOR A REPLACEMENT 200 MW EDDY HIGH VOLTAGE DIRECT CURRENT TIE

I ***Jonathan M. Trejo***, pursuant to Rule 1-011 NMRA, state as follows:

1. I affirm in writing under penalty of perjury under the laws of the State of New Mexico that the following statements are true and correct.

2. I am over 18 years of age and have personal knowledge of the facts stated herein. I am employed by El Paso Electric Company ("EPE" or "the Company") as *Manager of Protection, Metering, Automation, and Control.*

3. The foregoing Direct Testimony of Jonathan M. Trejo, together with all exhibits sponsored therein and attached thereto, is true and accurate based on my knowledge and belief.

4. I submit this Declaration, based upon my personal knowledge and upon information and belief, in support of EPE's ***Application for a Certificate of Public Convenience and Necessity for a Replacement 200 MW Eddy High Voltage Direct Current Tie.***

FURTHER, DECLARANT SAYETH NAUGHT.

I declare under penalty of perjury that the foregoing is true and correct.

Executed on April 13, 2026.

/s/ *Jonathan M. Trejo*

JONATHAN M. TREJO

BEFORE THE NEW MEXICO PUBLIC REGULATION COMMISSION

IN THE MATTER OF EL PASO ELECTRIC COMPANY'S APPLICATION FOR A CERTIFICATE OF PUBLIC CONVENIENCE AND NECESSITY FOR A REPLACEMENT 200 MW EDDY HIGH VOLTAGE DIRECT CURRENT TIE	)	**Case No. 26-00___**
EL PASO ELECTRIC COMPANY, Applicant	)	

DIRECT TESTIMONY

OF

TERESA M. SOSA

ON BEHALF OF

EL PASO ELECTRIC COMPANY

APRIL 13, 2026

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EXHIBITS

EL PASO ELECTRIC COMPANY
DIRECT TESTIMONY OF
TERESA M. SOSA

I. INTRODUCTION AND QUALIFICATIONS

Q1. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Teresa M. Sosa. My business address is 100 N. Stanton Street, El Paso, Texas 79901.

Q2. WHO IS YOUR CURRENT EMPLOYER AND WHAT POSITION DO YOU HOLD?

A. I am employed by El Paso Electric Company ("EPE" or the "Company"). I am the Director of the Company's Environmental and Safety Departments.

Q3. PLEASE SUMMARIZE YOUR EDUCATIONAL BACKGROUND AND PROFESSIONAL EXPERIENCE.

A. I have a Bachelor of Science degree in Civil Engineering, a Master of Science degree in Environmental Engineering, and a Doctoral degree in Environmental Science and Engineering from the University of Texas at El Paso.

From 2007 to 2009 I worked for a civil engineering firm, Gray, Jansing, and Associates, as an engineer in training, designing land plan subdivisions including street grading and drainage, water, and wastewater infrastructure. I also coordinated with local government entities to seek approval for improvement plans in both

El Paso and Horizon, Texas; and worked with the Horizon Regional Municipal Utility District to review water and wastewater plans for new developments.

In 2009, I obtained the Bridge to the Doctorate Fellowship to continue my graduate studies. I pursued my Masters and my Doctoral degrees in Environmental Science and Engineering while working part-time at the University of Texas at El Paso doing research for a water and wastewater laboratory and as a teaching assistant for the Introduction to Thermal-Fluid Science class. I completed my doctoral degree in December 2013.

In 2014, I started working for EPE as an engineer in the Environmental Department where I have been responsible for environmental compliance tied to power generation under air, wastewater, and drinking water programs. I have also been part of the team overseeing the coordination and data collection effort for the Company's Sustainability Report since its first release in 2018. In 2022, I was promoted to Environmental Manager, overseeing environmental compliance across all aspects of company operations, including air, water, waste, spill prevention, and natural resources. In September 2024, I was promoted to Director of Environmental and Safety.

Q4. WHAT ARE YOUR CURRENT RESPONSIBILITIES WITH EPE?

A. As EPE's Director of the Environmental and Safety Departments, I oversee environmental compliance across all aspects of Company operations, including air, water, waste, spill prevention, and natural resources, as well as safety compliance companywide.

II. PURPOSE OF TESTIMONY

Q5. WHAT IS THE PURPOSE OF YOUR TESTIMONY IN THIS PROCEEDING?

A. The Commission's Utility Division Staff has indicated in prior CCN cases that applicants should address environmental, ecological and/or cultural impact studies for the proposed facility. Therefore, the purpose of my testimony in this proceeding is to discuss environmental issues in support of EPE's Application for Approval of a Certificate of Public Convenience and Necessity ("CCN") for EPE's proposed replacement of the 200 megawatts ("MW") Eddy High Voltage Direct Current ("HVDC") converter ("Eddy Tie" or the "Project").

Q6. ARE YOU SPONSORING EXHIBITS TO YOUR TESTIMONY?

A. Yes, I am sponsoring the following exhibits:

- Exhibit TMS-1, Standard Form 299 – Bureau of Land Management Right of Way Application

- Exhibit TMS-2, Preliminary Plan of Development ("POD")

III. ENVIRONMENTAL SUMMARY

Q7. PLEASE PROVIDE A GENERAL DESCRIPTION OF THE PROJECT.

A. The Project would replace the existing Eddy County HVDC Tie at a location immediately north of its current footprint and would encompass a project area of approximately 15.8 acres of Bureau of Land Management ("BLM") land. The new Eddy Tie will accommodate the import and export of 200 MW of power continuously to support the projected economic benefits; ensure energy availability during energy scarcity events; and balance power flow on the system by injecting power from the east, among other reliability benefits as described by EPE witness Omar Gallegos in his direct testimony. The Project is located approximately 10 miles east of the city of Artesia, New Mexico in Eddy County. Further information about the Project is available in the direct testimony of EPE witness Jonathan Trejo.

Q8. WHAT ENVIRONMENTAL AUTHORIZATIONS AND PERMITS MUST BE OBTAINED BY EPE PRIOR TO BEGINNING THE CONSTRUCTION OF THE NEW EDDY TIE?

A. Prior to construction of the proposed replacement Eddy Tie, EPE will obtain a right-of-way ("ROW") grant from the Bureau of Land Management ("BLM"). In

support of this effort, EPE has retained SWCA as consultants to assist with the ROW acquisition process. EPE has submitted a Standard Form 299 (SF-299) Application for a new right-of-way to the BLM Carlsbad Field Office for the Eddy Tie Project for a term of 30 years. A copy of the SF-299 Application is provided as my exhibit TMS-1. The proposed project would be accessed via existing road infrastructure and would not require new access roads to be constructed. A Figure of the Project Location is included in the direct testimony of EPE witness Trejo as Exhibit JMT-4.

To satisfy BLM requirements under the National Environmental Policy Act ("NEPA"), SWCA will prepare an Environmental Assessment ("EA"), which is anticipated to be submitted to the BLM in July 2026. A biological survey will be conducted in April 2026, and the results of that survey will be documented in the EA. The Project qualifies for and has been enrolled in the Permian Basin Programmatic Agreement ("PBPA") for cultural resource compliance. The PBPA is a BLM-approved programmatic approach to Section 106 compliance under the National Historic Preservation Act that allows projects to avoid known cultural resource sites and contribute to a regional mitigation fund in lieu of conducting project-specific archaeological surveys. When a project is enrolled in the program, it avoids known cultural sites while still requiring protections for any unanticipated discoveries. In addition, during the construction phase, EPE will develop a

Stormwater Pollution Prevention Plan in accordance with Section 402 of the Clean Water Act. A Spill Prevention, Control, and Countermeasures ("SPCC") evaluation will also be completed for the Project and, if required, an SPCC plan will be developed.

Q9. WHAT IS A PRELIMINARY PLAN OF DEVELOPMENT?

A. When prepared as part of a BLM ROW grant application, a preliminary plan of development ("POD") is a planning-level document submitted to support the SF-299 Application that describes the proposed facilities, anticipated construction methods, operation and maintenance activities, and preliminary environmental protections for use of BLM-managed lands. The POD allows the BLM to evaluate environmental, cultural, and land-use impacts under NEPA. Information from this preliminary POD will be amended as the project moves forward and will be incorporated into the EA.

Q10. HAS EPE PREPARED A PRELIMINARY PLAN OF DEVELOPMENT?

A. Yes. A copy of the preliminary POD is attached to my testimony as Exhibit TMS-2.

Q11. WHAT PROCESS IS EPE EMPLOYING TO ENSURE BEST MANAGEMENT PRACTICES ON ENVIRONMENTAL ISSUES?

A. Prior to the start of construction, there will be a meeting with the construction crew about the environmental concerns in the project area. EPE will ensure the construction crew has a copy of the stipulations listed in the grants as well as the mitigation measures listed in the Preliminary POD. In addition, EPE will conduct periodic environmental inspections during the construction phase.

Q12. WHAT ARE EPE'S PLANS TO MITIGATE HARM TO FISH, WILDLIFE, AND PLANT LIFE IN THE AREA OF THE PROJECT?

A. EPE will ensure its contractors receive instruction about sensitive resources that could be present, such as sensitive plants, in-use nests, and animals. Mitigations include adhering to the BLM's fencing mitigations, pre-construction surveys to identify sensitive plant and wildlife species, and Migratory Bird Protection Act pre-construction nesting surveys if construction activities occur during the nesting season (March 1 – September 31).

Q13. WHAT ARE EPE'S PLANS TO MINIMIZE IMPACT TO SCENIC, HISTORIC, AND RELIGIOUS SITES AND STRUCTURES IN THE VICINITY OF THE PROJECT?

A. No scenic, historical, or religious sites or structures are expected to be located in the vicinity of the project. After construction, all disturbed areas not needed for the Project will be returned to approximate pre-construction conditions and will be restored and revegetated according to BLM standards.

Q14. WHAT ARE EPE'S PLANS TO MINIMIZE IMPACT TO CULTURAL RESOURCE SITES IN THE VICINITY OF THE PROJECT?

A. A Class I Archaeological Records Management Section database search of the proposed project area was conducted by SWCA in February 2026. That search found that there are no previously recorded cultural resource sites within the Project area or within 100 feet of the edge of the project ROW. The Project area is within the PBPA boundary and, as noted above, EPE has enrolled the project into the PBPA to complete cultural coverage for the project. An Unanticipated Discovery Plan for Cultural Resources will be developed to outline measures to be followed during construction if there are unanticipated discoveries. EPE employees and contractors will be informed about relevant federal regulations protecting cultural resources. If any cultural remains, monument sites, objects, or antiquities subject to the Antiquities Act of June 8, 1906, or the Archaeological Resources Protection Act of 1979 are discovered during construction, activities would immediately cease and the responsible BLM Authorized Officer would be notified.

Q15. WHAT ARE EPE'S PLANS TO REDUCE NOISE EMISSION LEVELS AND PREVENT INTERFERENCE WITH COMMUNICATION SIGNALS?

A. There are no noise-sensitive properties within 500 feet of the proposed Project. During construction, there will be a temporary increase in noise above ambient background levels. However, noise levels during operation are not expected to exceed ambient background levels at 500 feet from the ROW.

Q16. WILL EPE MONITOR THE ENVIRONMENTAL CONDITIONS AT THE CONSTRUCTION SITE TO ENSURE ACHIEVEMENT OF MITIGATION ACTIONS, IF ANY SUCH ACTIONS ARE NEEDED?

A. Yes, EPE plans to conduct periodic environmental inspections throughout the construction phase. If determined appropriate by EPE or relevant agencies, there would be an onsite monitor for the duration of the construction phase.

Q17. WILL THE ENVIORNMENTAL ASSESSMENT BE PUBLICLY AVAILABLE ONCE IT IS COMPLETE?

A. Yes. Following completion of the EA and issuance of a Finding of No Significant Impact and Decision Record, the EA will be published in the BLM's ePlanning

website and will remain available as part of the project's administrative record at the BLM (see https://eplanning.blm.gov/ for the ePlanning website).

IV. SUMMARY AND CONCLUSION

Q18. PLEASE SUMMARIZE YOUR TESTIMONY.

A. This testimony demonstrates that the Eddy Tie replacement Project will comply with all applicable environmental requirements, minimize impacts through established mitigation measures, and support the projected economic and system reliability benefits while responsibly using BLM land.

Q19. BASED ON YOUR EXPERTISE AND THROUGH YOUR EVALUATION AND ASSESSMENT OF THE PROPOSED PROJECT, WILL EPE'S PROJECT UNDULY IMPAIR IMPORTANT ENVIRONMENTAL VALUES OR CREATE IMPACTS THAT SIGNIFICANTLY AND ADVERSELY AFFECT THE QUALITY OF THE HUMAN ENVIRONMENT?

A. No. EPE has committed to implementing best management practices, biological and cultural resource protections, construction-phase monitoring, and site restoration measures. With these measures in place and compliance with all applicable federal and state environmental requirements, the Project is not expected

to unduly impair important environmental values or result in impacts that would significantly and adversely affect the quality of the human environment.

Q20. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A. Yes, it does.

STANDARD FORM 299
APPLICATION FOR TRANSPORTATION, UTILITY SYSTEMS, TELECOMMUNICATIONS AND FACILITIES ON FEDERAL LANDS AND PROPERTY

FORM APPROVED
OMB Control Number: 0596-0249
Expiration Date: 02/28/2023

FOR AGENCY USE ONLY

NOTE: Before completing and filing the application for an authorization (easement, right-of-way, lease, license or permit), the applicant should completely review this package, including instructions, and schedule a pre-application meeting with representatives of the agency responsible for processing the application. Each agency may have specific and unique requirements to be met in preparing and processing the application. Many times, with the help of the agency representative, the application can be completed at the pre-application meeting.

Application Number
NMNM106776893

Date Filed

1. Name and address of applicant

Riley Gibbs
El Paso Electric Company
P.O. Box 982
100 North Stanton
El Paso, Texas 79901

2. Name and address of authorized agent if different from item 1

3. Applicant telephone number and email:

(575) 499-7786
Riley.Gibbs@epelectric.com

Authorized agent telephone number and email:

4. As applicant are you? *(check one)*

- a. ☐ Individual
- b. ☒ Corporation*
- c. ☐ Partnership/Association*
- d. ☐ State Government/State Agency
- e. ☐ Local Government
- f. ☐ Federal Agency

** If checked, complete supplemental page*

5. Specify what application is for: *(check one)*

- a. ☒ New authorization
- b. ☐ Renewing existing authorization number
- c. ☐ Amend existing authorization number
- d. ☐ Assign existing authorization number
- e. ☐ Existing use for which no authorization has been received *
- f. ☐ Other*

** If checked, provide details under item 7*

6. If an individual, or partnership, are you a citizen(s) of the United States? ☐ Yes ☐ No

7. Project description (describe in detail): (a) Type of use or occupancy, *(e.g., canal, pipeline, road, telecommunications);* (b) related structures and facilities; (c) physical specifications *(Length, width, grading, etc.*); (d) term of days/years needed: (e) time of year of use or operation; (f) Volume or amount of product to be transported; (g) duration and timing of construction; and (h) temporary work areas needed for activity/construction *(Attach additional sheets, if additional space is needed.)*

El Paso Electric Company (EPE), requests a new authorization for a Right-of-Way (ROW) grant to expand north of the existing Eddy County Substation (authorized under NMNM106170249 and legacy serial number NM-139982). The Eddy Tie Substation (project) would encompass approximately 16 acres of Bureau of Land Management (BLM) Carlsbad Field Office (CFO)-administered lands, and is needed to accommodate the import or export of 200 megawatts (MWs) of power continuously. EPE is requesting the ROW grant for a term of 30 years. No temporary work areas are needed.

8. Attach a map covering area and show location of project proposal.

9. State or Local government approval: ☐ Attached ☐ Applied for ☒ Not Required

10. Nonrefundable application fee: ☒ Attached ☐ Not required ☐ To be determined by agency

11. Does project cross international boundary or affect international waterways? ☐ Yes ☒ No *(if "yes," indicate on map)*

12. Give statement of your technical and financial capability to construct, operate, maintain, and terminate system for which authorization is being requested.

EPE is a regional electric utility that was founded in 1901 and generates, transmits, and distributes power to approximately 460,000 customers across a 10,000-square-mile area in the Rio Grande Valley, spanning from Hatch, New Mexico to Van Horn, Texas.

13a. Describe other alternative locations considered.

None.

b. Why were these alternatives not selected?

N/A.

c. Give explanation as to why it is necessary to use or occupy Federal assets (lands or buildings).

It is necessary to expand on the existing substation (located on BLM lands) to fulfill the energy needs of the public.

14. List authorizations and pending applications filed for similar projects which may provide information to the authorizing agency. *(Specify number, date, code, or name)*

See Box 7.

15. Provide statement of need for project, including the economic feasibility and items such as: (a) cost of proposal (construction, operation, and maintenance); (b) estimated cost of next best alternative; and (c) expected public benefits.

The project is needed in order to satisfy FERC requirements and customer needs and reliability. Cost is unknown at this time. This project would benefit the public by providing reliable energy and the continuous import and export of 200 MWs of power.

16. Describe probable effects on the population in the area, including the social and economic aspects, and the rural lifestyles.

Probable effects are greater economic stability and better electrical reliability. Because the project would be sited adjacent to the existing substation, there would be little to no probable effect on rural lifestyles.

17. Describe likely environmental effects that the proposed project will have on: (a) air quality; (b) visual impact; (c) surface and ground water quality and quantity; (d) the control or structural change on any stream or other body of water; (e) existing noise levels; and (f) the surface of the land, including vegetation, permafrost, soil, and soil stability; and, (g) historic or archaeological resources or properties.

None known at this time.

18. Describe the probable effects that the proposed project will have on (a) populations of fish, plant life, wildlife, and marine life, including threatened and endangered species; and (b) marine mammals, including hunting, capturing, collecting, or killing these animals.

None known at this time.

19. State whether any hazardous material, as defined in this paragraph, would be used, produced, transported or stored on or in a federal building or federal lands or would be used in connection with the proposed use or occupancy. “Hazardous material” shall mean (a) any hazardous substance under section 101(14) of the Comprehensive Environmental Response, Compensation, and Liability Act (CERCLA), 42 U.S.C. § 9601(14); (b) any pollutant or contaminant under section 101(33) of CERCLA, 42 U.S.C. § 9601(33); (c) any petroleum product or its derivative, including fuel oil, and waste oils; and (d) any hazardous substance, extremely hazardous substance, toxic substance, hazardous waste, ignitable, reactive or corrosive materials, pollutant, contaminant, element, compound, mixture, solution or substance that may pose a present or potential hazard to human health or the environment under any applicable environmental laws. The holder shall not store any hazardous materials at the site without prior written approval from the authorized officer. This approval shall not be unreasonably withheld. If the authorized officer provides approval, this permit shall include (or in the case of approval provided after this permit is issued, shall be amended to include) specific terms addressing the storage of hazardous materials, including the specific type of materials to be stored, the volume, the type of storage, and a spill plan. Such terms shall be proposed by the holder and are subject to approval by the authorized officer.

None known at this time.

20. Name all the Federal Department(s)/Agency(ies) where this application is being filed.

BLM CFO.

I HEREBY CERTIFY, That I am of legal age and authorized to do business in the State and that I have personally examined the information contained in the application and believe that the information submitted is correct to the best of my knowledge.

Signature of Applicant		Date
Riley Gibbs	Digitally signed by Riley Gibbs Date: 2026.01.30 13:35:30 -07'00'	January 30, 2026

Title 18, U.S.C. Section 1001, makes it a crime for any person knowingly and willfully to make to any department or agency of the United States any false, fictitious, or fraudulent statements or representations as to any matter within its jurisdiction.

GENERAL INFORMATION
ALASKA NATIONAL INTEREST LANDS

This application will be used when applying for a right-of-way, permit, license, lease, or certificate for the use of Federal lands which lie within conservation system units and National Recreation or Conservation Areas as defined in the Alaska National Interest lands Conservation Act. Conservation system units include the National Park System, National Wildlife Refuge System, National Wild and Scenic Rivers System, National Trails System, National Wilderness Preservation System, and National Forest Monuments.

Transportation utility systems telecommunication installations facility uses for which the application may be used are:

1. Canals, ditches, flumes, laterals, pipes, pipelines, tunnels, and other systems for the transportation of water.

2. Pipelines and other systems for the transportation of liquids other than water, including oil, natural gas, synthetic liquid and gaseous fuels, and any refined product produced therefrom.

3. Pipelines, slurry and emulsion systems, and conveyor belts for transportation of solid materials.

4. Systems for the transmission and distribution of electric energy.

5. Wired and wireless systems for transmission or reception of radio, television, telephone, telegraph, and other electronic signals, and other means of communications.

6. Improved right-of-way for snow machines, air cushion vehicles, and all-terrain vehicles.

7. Roads, highways, railroads, tunnels, tramways, airports, landing strips, docks, and other systems of general transportation.

This application must be filed simultaneously with each Federal department or agency requiring authorization to establish and operate your proposal.

In Alaska, the following agencies will help the applicant file an application and identify the other agencies the applicant should contact and possibly file with:

Department of Agriculture
Regional Forester, Forest Service (USFS)
P.O. Box 21628
Juneau, Alaska 99802-1628
Telephone: (907) 586-7847 *(or a local Forest Service Office)*

Department of the Interior
Bureau of Indian Affairs (BIA)
Alaska Regional Office
709 West 9th Street
Juneau, Alaska 99802
Telephone: (907) 586-7177

Department of the Interior
Alaska State Office
Bureau of Land Management
222 West 7th Avenue #13
Anchorage, Alaska 99513
Public Room: 907-271-5960
FAX: 907-271-3684
(or a local BLM Office)

U.S. Fish & Wildlife Service (FWS)
Office of the Regional Director 1011
East Tudor Road Anchorage, Alaska
99503 Telephone: (907) 786-3440

National Park Service (NPS)
Alaska Regional Office
240 West 5th Avenue
Anchorage, Alaska 99501
Telephone: (907) 644-3510

Note - Filings with any Interior agency may be filed with any office noted above or with the Office of the Secretary of the Interior, Regional Environmental Officer, P.O. Box 120, 1675 C Street, Anchorage, Alaska 99513.

Department of Transportation
Federal Aviation Administration
Alaska Region AAL-4, 222 West 7th Ave., Box 14
Anchorage, Alaska 99513-7587
Telephone: (907) 271-5285

NOTE - The Department of Transportation has established the above central filing point for agencies within that Department. Affected agencies are: Federal Aviation Administration (FAA), Coast Guard (USCG), Federal Highway Administration (FHWA), Federal Railroad Administration (FRA).

OTHER THAN ALASKA NATIONAL INTEREST LANDS

Use of this form is not limited to National Interest Conservation Lands of Alaska.

Individual department/agencies may authorize the use of this form by applicants for transportation, utility systems, telecommunication installations and facilities on other Federal lands outside those areas described above.

For proposals located outside of Alaska, applications will be filed at the local agency office or at a location specified by the responsible Federal agency.

SPECIFIC INSTRUCTIONS
(Items not listed are self-explanatory)

7 Attach preliminary site and facility construction plans. The responsible agency will provide instructions whenever specific plans are required.

8 Generally, the map must show the section(s), township(s), and range(s) within which the project is to be located. Show the proposed location of the project on the map as accurately as possible. Some agencies require detailed survey maps. The responsible agency will provide additional instructions.

9, 10, and 12 The responsible agency will provide additional instructions.

13 Providing information on alternate locations in as much detail as possible, discussing why certain locations were rejected and why it is necessary to use Federal assets will assist the agency(ies) in processing your application and reaching a final decision. Include only reasonable alternate locations as related to current technology and economics.

14 The responsible agency will provide instructions.

15 Generally, a simple statement of the purpose of the proposal will be sufficient. However, major proposals located in critical or sensitive areas may require a full analysis with additional specific information. The responsible agency will provide additional instructions.

16 through 19 Providing this information with as much detail as possible will assist the Federal agency(ies) in processing the application and reaching a decision. When completing these items, you should use a sound judgment in furnishing relevant information. For example, if the project is not near a stream or other body of water, do not address this subject. The responsible agency will provide additional instructions.

Application must be signed by the applicant or applicant's authorized representative.

EFFECT OF NOT PROVIDING INFORMATION

Disclosure of the information is voluntary. If all the information is not provided, the proposal or application may be rejected.

DATA COLLECTION STATEMENT

The Federal agencies collect this information from proponents and applicants requesting a right-of-way, permit, license, lease, or certification for use of Federal assets. The Federal agencies use this information to evaluate a proponent's or applicant's proposal to use Federal assets.

BURDEN STATEMENT

According to the Paperwork Reduction Act of 1995, an agency may not conduct or sponsor, and a person is not required to respond to a collection of information unless it displays a valid OMB control number. The valid OMB control number for this information collection is 0596-0249. The time required to complete this information collection is estimated to average 8 hours per response, including the time for reviewing instructions, searching existing data sources, gathering and maintaining the data needed, and completing and reviewing the collection of information. The authority to collect this information is derived from 47 U.S.C. 1455(c)(3) and 16 U.S.C. 3210.

USDA NONDISCRIMNATION STATEMENT

The U.S. Department of Agriculture (USDA) prohibits discrimination in all its programs and activities on the basis of race, color, national origin, age, disability, and where applicable, sex, marital status, familial status, parental status, religion, sexual orientation, genetic information, political beliefs, reprisal, or because all or part of an individual's income is derived from any public assistance. (Not all prohibited bases apply to all programs.) Persons with disabilities who require alternative means for communication of program information (Braille, large print, audiotape, etc.) should contact USDA's TARGET Center at 202-720-2600 (voice and TDD).

To file a complaint of discrimination, write USDA, Director, Office of Civil Rights, 1400 Independence Avenue, SW, Washington, DC 20250-9410 or call toll free (866) 632-9992 (voice). TDD users can contact USDA through local relay or the Federal relay at (800) 877-8339 (TDD) or (866) 377-8642 (relay voice). USDA is an equal opportunity provider and employer.

The Privacy Act of 1974 (5 U.S.C. 552a) and the Freedom of Information Act (5 U.S.C. 552) govern the confidentiality to be provided for information received by the Forest Service.

SUPPLEMENTAL		
NOTE: The responsible agency(ies) will provide instructions	CHECK APPROPRIATE BLOCK	
I - PRIVATE CORPORATIONS	ATTACHED	FILED*
a. Articles of Incorporation	☐	☐
b. Corporation Bylaws	☐	☐
c. A certification from the State showing the corporation is in good standing and is entitled to operate within the State	☐	☐
d Copy of resolution authorizing filing	☐	☐
e. The name and address of each shareholder owning 3 percent or more of the shares, together with the number and percentage of any class of voting shares of the entity which such shareholder is authorized to vote and the name and address of each affiliate of the entity together with, in the case of an affiliate controlled by the entity, the number of shares and the percentage of any class of voting stock of that affiliate owned, directly or indirectly, by that entity, and in the case of an affiliate which controls that entity, the number of shares and the percentage of any class of voting stock of that entity owned, directly or indirectly, by the affiliate.	☐	☐
f. If application is for an oil or gas pipeline, describe any related right-of-way or temporary use permit applications, and identify previous applications.	☐	☐
g. If application is for an oil and gas pipeline, identify all Federal lands by agency impacted by proposal.	☐	☐
II - PUBLIC CORPORATIONS		
a. Copy of law forming corporation	☐	☐
b. Proof of organization	☐	☐
c. Copy of Bylaws	☐	☐
d. Copy of resolution authorizing filing	☐	☐
e. If application is for an oil or gas pipeline, provide information required by item "I - f" and "I - g" above.	☐	☐
III - PARTNERSHIP OR OTHER UNINCORPORATED ENTITY		
a. Articles of association, if any	☐	☐
b. If one partner is authorized to sign, resolution authorizing action is	☐	☐
c. Name and address of each participant, partner, association, or other	☐	☐
d. If application is for an oil or gas pipeline, provide information required by item "I - f" and "I - g" above.	☐	☐

*If the required information is already filed with the agency processing this application and is current, check block entitled "Filed." Provide the file identification information *(e.g., number, date, code, name)*. If not on file or current, attach the requested information.

PLAN OF DEVELOPMENT

Eddy Tie Project
Eddy County, New Mexico
El Paso Electric Company

U.S. Department of the Interior
Bureau of Land Management
Pecos District
Carlsbad Field Office
620 East Greene Street
Carlsbad, New Mexico 88220
Phone: (575) 887-6544
Fax: (575) 885-9264

April 2026

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List of Abbreviations and Acronyms

AO	Authorized Officer
BLM	Bureau of Land Management
CFO	Carlsbad Field Office
EA	Environmental Assessment
EPE	El Paso Electric Company
kV	kilovolt
NEPA	National Environmental Policy Act
POD	Plan of Development
Project	Eddy Tie Project
ROW	right-of-way
SF-299	Standard Form 299
SGC	Southwest Geophysical Consulting, LLC
SPCC	Spill Prevention, Control, and Countermeasures
SSPS	special status plant species
USACE	U.S. Army Corps of Engineers
USFWS	U.S. Fish and Wildlife Service

PLAN OF DEVELOPMENT

1.0 INTRODUCTION

El Paso Electric Company (EPE) has submitted a Standard Form 299 (SF-299) Application for a new right-of-way (ROW) to the Bureau of Land Management (BLM) Carlsbad Field Office (CFO) for the Eddy Tie Project (Proposed Action, or project), for a term of 30 years.

The project would replace the existing Eddy High Voltage Direct Current converter (authorized under NMNM106170249 and legacy serial number NM-139982) northward from its current footprint and would encompass a project area of approximately 15.8 acres on BLM-managed lands. The project would accommodate the import or export of 200 megawatts of power continuously and support existing and future oil and gas operations. The proposed project would access existing road infrastructure and would not require new access roads to be constructed. The staging of equipment would occur within the 15.8-acre project area. The location of the proposed project is shown on the map provided in Appendix A.

This preliminary Plan of Development (POD) provides an overview of the project and information from this POD will be incorporated into an environmental assessment (EA) that will be prepared for the project to meet BLM's requirements under the National Environmental Policy Act (NEPA). It includes a general description of the design, construction, operation, and maintenance of the project. It also provides detailed information on the proposed project facilities, procedures, and measures that EPE, as the proponent, will implement during construction, operation, maintenance, and decommissioning of the project. EPE would construct and operate the project in conformity with this POD, which will be included as part of the ROW grant.

2.0 PURPOSE AND NEED

The BLM's purpose is to respond to EPE's request for legal use of and access across BLM-managed public lands by granting EPE a ROW for the proposed project and associated infrastructure. As stated in 43 CFR 2801.9, a BLM ROW grant is required for use of public lands for "systems or facilities over, under, on, or through public lands," including transmission facilities. The BLM's mandate for multiple uses of public lands includes development of energy transmission in a manner that conserves the multitude of other resources found on public lands. The need for the BLM's action is established by the Federal Land Policy and Management Act (FLPMA) and is to respond to an application for a ROW grant by evaluating the application for use of federal land for construction of a 200 MW Eddy High Voltage Direct Current Tie on federal land. The BLM would consider the application in accordance with 43 CFR 2800 (Rights-of-Way under FLPMA) and the Energy Policy Act of 2005.

The applicant's purpose is to safely and efficiently develop the Eddy Tie Project.

3.0 ROW LOCATION

The project is located entirely on BLM-managed lands, approximately 9.3 miles east of the city of Artesia, New Mexico in Eddy County. The legal description of disturbance associated with the project is shown below.

Legal Description for project on BLM lands

Township 17 South, Range 27 East, NMPM
section (sec.) 23: E½SE¼;
sec. 24: W½SW¼.

ROW Description on BLM Land for Purposes of the Grant

- **The total permanent acreage on BLM lands is 15.8 acres.**

4.0 FACILITY DESIGN FACTORS

4.1.1 Project

The project would be constructed in Eddy County, New Mexico (see map in Appendix A). Approximately 15.8 acres of permanent disturbance would occur from the construction replacing the existing 200 MW Eddy Tie High Voltage Direct Current (HVDC).

Table 1. Acreages of New Surface Disturbance for Proposed Project

Project Element	Land Ownership	Length (feet)	Width (feet)	Total Proposed Disturbance (acres)
Eddy Tie	BLM	Irregular in shape	Irregular in shape	15.8

4.1.2 Access Roads

Existing access roads from Highway 82 (Lovington Highway) or Southern Un Road will be used to access the project area. No new access roads are proposed for this project.

4.1.3 Project Construction Workspace

No additional construction workspace is proposed for this project.

4.1.4 Project Construction Staging Areas

Areas within the project area will be used as construction staging areas.

4.2 GOVERNMENT AGENCIES INVOLVED

Various federal and state agencies regulate different aspects of development. Table 2 lists the environmental permits and approvals that may be required for the proposed project.

Table 2. Potential Permits, Approvals, and Clearances Needed for Construction, Operation, and Maintenance of the Project.

Permit/Notification	Issuing Agency	Project Involvement
Federal Permit, Approval, or Clearance		
ROW grant	BLM	Subject of this application.
Clearance under Section 7 of the Endangered Species Act	U.S. Fish and Wildlife Service (USFWS)	A biological survey has not yet been conducted. Findings will be described in Chapter 3 of the Environmental Assessment. The BLM would determine what form of consultation with USFWS is warranted for this project.

Permit/Notification	Issuing Agency	Project Involvement
Clean Water Act Section 404 Permit	U.S. Army Corps of Engineers (USACE)	A biological survey has not yet been conducted; however, desktop review data indicates there are no potentially jurisdictional water bodies (i.e., waters of the U.S.) that would be crossed by the proposed project. The biological survey, once conducted, will verify the desktop data. A Section 404 permit is not anticipated.
Federal Cave Resource Protection Act	Department of the Interior	The proposed project is within an area designated as having a high karst potential occurrence. A karst survey was conducted for the project area on September 25, 2025. There are no known karst features within the project area and therefore the project would be in compliance with the Federal Cave Resources Protection Act.
State Permit, Approval, or Clearance		
Clean Water Act Section 401 certification	New Mexico Environment Department	A biological survey has not yet been conducted; however, desktop review data indicates there are no potentially jurisdictional water bodies (i.e., waters of the U.S.) that would be crossed by the proposed project. The biological survey, once conducted, will verify the desktop data. A Section 401 permit is not anticipated.
Clean Water Act Section 402 General Construction (Stormwater) Permit	New Mexico Environment Department	The permit would be obtained prior to construction under the U.S. Environmental Protection Agency's Construction General Permit.
Section 106 of the NHPA	New Mexico State Historic Preservation Office	The project will be enrolled within the Permian Basin PA for cultural resources.
Tribal communications: consultation to determine if the proposed project would impact receptors of cultural importance	Native American tribes	Any consultation with Native American tribes would be managed by the BLM.

4.3 PROJECT SCHEDULE AND WORKFORCE

4.3.1 Construction Schedule

Construction of the project is scheduled to begin in December of 2026 and would take approximately 18-24 months to complete.

4.3.2 Project Workforce

Approximately 30 workers would be employed during the construction phase of the project. They are expected to find housing in Artesia or Carlsbad. The expected work schedule during construction is 6-7 days per week, with 50+ hours per week per worker. The existing Eddy Tie projectis operated and monitored remotely 24 hours a day, 7 days a week, 365 days a year to provide safe and reliable service.

4.3.3 Traffic

The majority of the workers would commute to the project site early in the morning (between 7:00 a.m. and 8:00 a.m.) and would return in the evening during non-peak traffic hours (between 5:30 p.m. and 6:30 p.m.). Heavy equipment vehicles would be transported to the site and left within the ROW until construction is complete.

5.0 GENERAL PROJECT CONSTRUCTION PROCEDURE

5.1.1 Eddy Tie Project

This project is part of a long-range plan designed to provide needed diversity and capacity for additional energy requirements on EPE's existing transmission system caused by significant load increases in recent years.

The proposed Eddy Tie Project would relieve potential overloading on existing transmission facilities and would provide connections to new and existing 345-kV and 230-kV transmission lines. The project would enhance system reliability and is being designed to accommodate current and anticipated future load requirements.

5.1.1.1 Project Design Features

Security lighting designed to comply with all local ordinances would be installed at the facility. The area would be surfaced with a combination of concrete pads, compacted road base for internal access roads, gravel, and compacted earth. Service power would be required for facility operations, and it is anticipated that this demand would be served from an existing Xcel and Central Valley Cooperative distribution line located within the existing Eddy County Substation.

The Eddy Tie Project would include the following components:

- 345/230-kV interface transformer(s)
- 230-kV and 345-kV circuit breakers
- 230-kV and 345-kV disconnect switches, motor operated
- High voltage DC power electronic valves
- DC valve reactors
- Cooling equipment
- Metering equipment
- Protection, Control, and Communication equipment
- Associated bus, conductor, surge arresters, and structural steel supports
- Ground conductors, ground rods, and associated hardware for connecting steel and equipment to a new ground grid
- Underground conduits, control cable, pull boxes, junction boxes, and cable trench
- 345-kV and 230-kV dead-end/pull off structures to interface with transmission lines
- Foundations and site surfacing, grading, drainage, etc.
- Metering, Protection and Control, and Communication Control building(s)
- Valve Hall Building
- Graded parking area for maintenance vehicles
- Perimeter fence (chain link, concrete block or other material) with security lighting
- Distribution poles to deliver power from the substation service line to a 240/480V transformer

5.1.2 Project Construction

Construction of the Eddy Tie project would consist of the completion of the following tasks and activities, which should occur in sequential order, as shown below:

5.1.2.1 Detailed Project Surveys

A detailed survey to locate project foundations, site wall locations, locations for underground duct banks, and all other pertinent features would be completed and submitted to BLM prior to beginning construction. All limits of the proposed project boundary, ground disturbance, structure locations, and project construction areas will be flagged and staked, where necessary.

5.1.2.2 Clearing and Grading

After the initial survey and vegetation clearing, the pad for the substation would be brought to grade and compacted by the recommendations of the geotechnical report. Clearing and grading of the entire project area will be necessary to prepare the site for construction. The site will be graded to create a level surface with a moderate slope for drainage as necessary. Grading will also be engineered to allow for adequate clearances to energized conductors entering the project. All topsoil will be stockpiled and segregated from other excavated soil, which will be used as backfill, berms, or as fill for other nearby areas. If excess spoils cannot be completely contained within the ROW, EPE will coordinate with the BLM to dispose of or purchase the excess material for disposal.

The surface of the substation will be covered with an insulating layer to protect personnel from high currents and voltages in the event of a faulty condition. Approximately 4 to 6 inches of crushed rock will be applied to the finished surface of the substation, which will then be treated with a soil sterilizer to prevent vegetation growth. If necessary, drainage structures such as ditches and culverts will be installed.

5.1.2.3 Excavating and Installing Foundations and Underground Duct Banks

Substation structures would generally be supported on cast-in-place concrete slab foundations or cast-in-place concrete piers with prefabricated anchors. Foundations would be excavated using backhoes and truck-mounted augers. Rebar cages would be delivered to the site and installed, as required, then commercially available concrete would be delivered to pour all cast-in-place foundations.

Underground duct banks would be excavated with a backhoe, all conduit banks would be placed in the ground, and all trenches would be backfilled as required.

5.1.2.4 Fencing

The security fencing around the substation would be constructed of chain link fence to accommodate U.S. Border Patrol security interests for visibility through the substation. After the fencing and gates are constructed, cast-in-place concrete foundations, as required, would be excavated and installed.

5.1.2.5 Grounding

Based on the results of the ground resistivity testing, a ground grid would be installed, which would consist of copper or steel rods riven into the ground in approximately 20 foot by 20-foot grid over the area of the substation. The ground grid would be attached to the substation bus work and equipment supports that would be installed on the concrete foundations. Steel structures, for transmission line dead-end/pull-off structures would be erected with a hydraulic crane and bolted to the concrete foundations previously installed.

5.1.2.6 Structure and Equipment Installation

Steel structures to support some substation equipment will be affixed on the concrete foundation anchor bolts with a track-mounted crane. Equipment such as transformers, reactors, and circuit breakers can be mounted directly to the foundations without supporting structures. The equipment will then be assembled, tested, and connected electrically to the control building through multi-conductor control cables installed in conduits and/or a precast concrete cable trench system.

5.1.3 Oil Containment

A Spill Prevention, Control, and Countermeasures (SPCC) evaluation will be completed for the project. If deemed necessary, a SPCC plan will be developed

5.1.4 Cleanup and Restoration of Affected Areas

The project site would be kept clean and orderly throughout construction. Refuse and trash would be removed and disposed of in an approved manner. In remote areas, trash and refuse would be contained temporarily until it can be hauled to an approved landfill. No open burning of construction trash would occur.

During cleanup and restoration, any hazardous materials use and disposal would be properly managed. Bulk chemicals and hazardous materials are not expected to be produced or stored on-site, and during cleanup and restoration, any hazardous materials such as petroleum products used for equipment would be properly managed in accordance with applicable federal, state, and local regulations regarding the use of hazardous substances. Procedures for proper management of any use of hazardous materials and equipment refueling would be addressed in the Final POD and consistent with EPE's Emergency Spill Response Procedures.

During construction, topsoil would be stockpiled and used to restore disturbed areas to preconstruction conditions as much as possible.

5.2 SPECIAL CONSTRUCTION TECHNIQUES

5.2.1 Road Crossings

The proposed project would be accessed from New Mexico Highway 82, Crane Road, and Southern Un Road. No roads would need to be constructed or rerouted during the construction of the proposed project as there are no road crossings for the project.

5.2.2 Waterbody and Wetland Crossings

Desktop review indicates the project would not cross any waterbodies or jurisdictional drainages. The upcoming general biological survey will verify desktop review results.

5.2.3 Fueling and Hazardous Materials

Fuels would be stored within the project ROW temporarily. EPE would take measures to minimize the occurrence of contaminants from construction equipment, welding, and refueling from entering surface water.

5.2.4 Fire Control

EPE would notify the BLM Authorized Officer (AO) of any fires during construction and would comply with all rules and regulations administered by the BLM AO concerning the use, prevention, and suppression of fires on federal lands.

In the event of a fire, EPE or its contractors would initiate fire suppression actions in the work area. Suppression would continue until the fire is out or until the crew is relieved by an authorized representative of the agency on whose land the fire occurred. Heavy equipment would not be used for fire suppression outside the project ROW without prior approval of the BLM AO unless there is imminent danger to life or property. EPE or its contractors would be responsible for all costs associated with the suppression of fires and the rehabilitation of fire damage resulting from their operations, employees, or contractors.

5.2.5 Dust Control

Dust suppression techniques may be used in the project ROW to mitigate the impacts of fugitive dust emissions. It is estimated that one (1) water truck could be required for dust control during construction.

Water for dust control would be obtained from either a private or municipal source. Magnesium chloride would not be used for dust control.

5.2.6 Weed Control

The upcoming general biological survey will include surveys for noxious weeds listed by the New Mexico Department of Agriculture for control and prevention. If noxious weeds are identified during the biological survey, they will be recorded and mapped for control and prevention. If weed infestations exist at the time of construction, driving, parking, and equipment staging would not be allowed in infestation areas. Following construction, exposed soils would be re-seeded according to BLM standards.

5.2.7 Survey Monuments

All survey monuments, witness corners, reference monuments, and bearing trees within the project ROW would be protected against disturbance during construction, operation, maintenance, and restoration. If any monument, corner, or accessory is destroyed, obliterated, or damaged, a registered land surveyor would restore the disturbed monument, corner, or accessory. The survey would be recorded in the appropriate county and a copy would be sent to the appropriate BLM field office.

5.2.8 Erosion Control

Temporary erosion controls would be installed immediately after initial disturbance (clearing) and would be properly maintained throughout construction and reinstalled as necessary until replaced by permanent erosion controls or restoration is complete. These measures may include but are not limited to sediment barriers, slope breakers, mulch, and erosion control fabric.

5.3 RESOURCE VALUES AND ENVIRONMENTAL CONCERNS

5.3.1 Biological Resources

The proposed project partially overlaps with BLM's modeled unsurveyed potential habitat layer for Scheer's beehive cactus (*Coryphantha robustispina* var. *scheeri*) and Tharp's blue-star (*Amsonia tharpii*). Both species are listed as BLM Sensitive and endangered by the State of New Mexico. The purpose of the upcoming biological and special status plant species (SSPS) surveys are to evaluate the potential for special status plant and animal species to occur within the proposed project area and to identify waters of the U.S. or sensitive aquatic habitats. The results will be included in the environmental assessment for the project.

5.3.2 Cultural Resources

SWCA conducted a Class I Archaeological Records Management Section database search of the proposed project area in February 2026 and there are no previously recorded cultural resource sites within the project area or within 100 feet from the edge of the project ROW. In addition, the project area is within the Permian Basin Programmatic Agreement boundary. EPE will enroll the project into the PBPA to complete cultural coverage for the project.

An Unanticipated Discovery Plan for Cultural Resources will be developed to outline measures to be followed during construction if there are unanticipated discoveries. EPE employees and contractors will be informed about relevant federal regulations protecting cultural resources. If any cultural remains, monument sites, objects, or antiquities subject to the *Antiquities Act of June 8, 1906* or the *Archaeological Resources Protection Act of 1979* are discovered during construction, activities would immediately cease and the responsible BLM AO would be notified.

5.3.3 Karst Resources

The proposed project overlaps with BLM's modeled karst occurrence potential layer for an area defined as having a high potential for karst resources. An aerial karst survey was conducted by Southwest Geophysical Consulting, LLC (SGC) on September 25, 2025. Findings were detailed in SGC's *Cave and*

Karst Inventory Report El Paso Electric Eddy Tie Substation report on file with the BLM CFO. One high-likelihood and three medium-likelihood surface karst features were located within the survey area; however, these features are not affected by the currently proposed project. The high-likelihood surface karst feature is approximately 222.0 feet south of the proposed project area and approximately 32 feet west of the existing Eddy County Substation. SGS recommends employing a BLM CFO-approved karst monitor on site during construction.

6.0 STABILIZATION AND REHABILITATION

After construction, all disturbed areas not needed for the project would be returned to approximate pre-construction conditions and would be restored and revegetated according to BLM standards. Vegetation, soil, and rocks left as a result of construction would be randomly scattered over the project area and would not be left in rows, piles, or berms unless requested by the BLM. In those areas where erosion control structures are required to stabilize soil conditions, the structures would be installed for the specific soil conditions encountered in the field and in accordance with sound management practices.

7.0 SUBSTATION OPERATION AND MAINTENANCE

EPE would routinely patrol and inspect the substation to check for problems such as routine maintenance activities, replacement of individual structures, erosion, ROW conditions, unauthorized encroachment on the ROW, and any other situations that may result in a safety hazard or may require preventive maintenance. These inspections would be conducted on foot or from a vehicle along existing roads. If damage should occur to the substation from external sources, repair or replacement would be completed.

8.0 ABANDONMENT

8.1.1 ROW Renewal

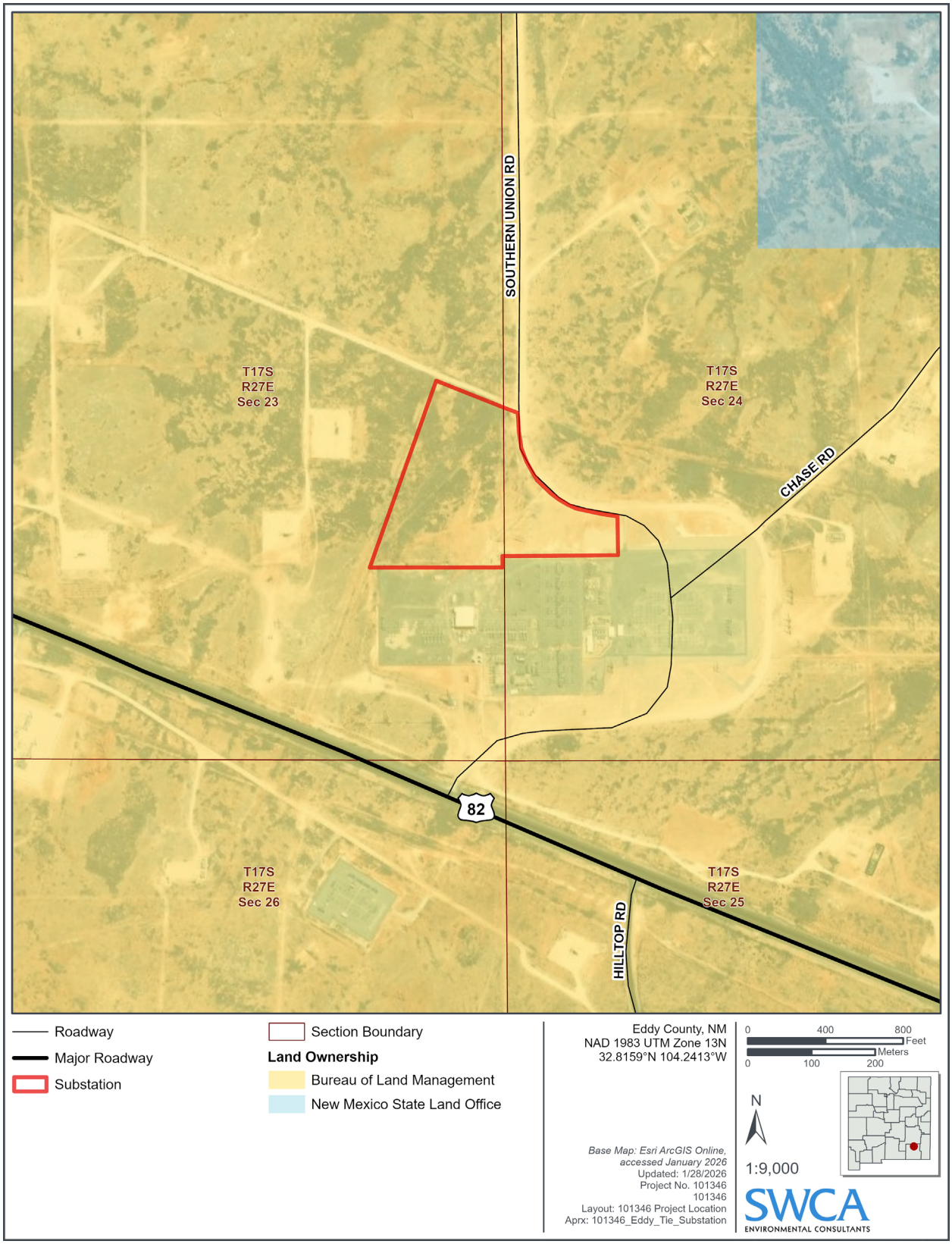
The proposed project would have a minimum projected operation life of 40 years or longer. A ROW grant issued for 30 years with the option of renewal would be necessary for the operation, maintenance, and decommissioning of the substation facilities located on BLM-managed lands. At the end of the ROW grant term (30 years), EPE would have the option to renew the ROW grant past 30 years to continue operation of the tie and additional equipment. The terms and conditions in the original ROW grant could be modified for the renewed ROW grant.

8.1.2 Project Decommissioning

New substations are designed to be on the EPE system perpetually and are rarely decommissioned. Components of the substation and new HVDC tie are designed for a 40-year service life. At the end of the service life, components are replaced and upgraded to the latest design standards. When the BLM ROW grant approaches expiration, the necessary authorizations would be obtained from the BLM AO to renew the ROW grant or decommission the project. Future decommissioning of the substation would include removal of conductors and structures. All materials would be removed from the ROW. Equipment at the substations and unsalvageable materials would be disposed of at authorized sites. Regarding and revegetation of disturbed areas would be completed according to BLM standards. The abandoned ROW would revert to the control of the landowners.

Appendix A

Project Location Map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T17S
R27E
Sec 23
T17S
R27E
Sec 24
CHASE RD
82
T17S
R27E
Sec 26
T17S
R27E
Sec 25
HILLTOP RD
Roadway
Major Roadway
Substation
Section Boundary
Land Ownership
Bureau of Land Management
New Mexico State Land Office
Eddy County, NM
NAD 1983 UTM Zone 13N
32.8159°N 104.2413°W
0 400 800
Feet
0 100 200
Meters
N
1:9,000
Base Map: Esri ArcGIS Online, accessed January 2026
Updated: 1/28/2026
Project No. 101346
101346
Layout: 101346 Project Location
Aprx: 101346_Eddy_Tie_Substation
SWCA
ENVIRONMENTAL CONSULTANTS

BEFORE THE NEW MEXICO PUBLIC REGULATION COMMISSION

IN THE MATTER OF EL PASO ELECTRIC COMPANY'S APPLICATION FOR A CERTIFICATE OF PUBLIC CONVENIENCE AND NECESSITY FOR A REPLACEMENT 200 MW EDDY HIGH VOLTAGE DIRECT CURRENT TIE	)	**Case No. 26-00___**
EL PASO ELECTRIC COMPANY, Applicant	)	

DECLARATION OF TERESA M. SOSA IN SUPPORT OF THE FOREGOING DIRECT TESTIMONY OF EL PASO ELECTRIC COMPANY'S APPLICATION FOR A CERTIFICATE OF PUBLIC CONVENIENCE AND NECESSITY FOR A REPLACEMENT 200 MW EDDY HIGH VOLTAGE DIRECT CURRENT TIE

I ***Teresa M. Sosa***, pursuant to Rule 1-011 NMRA, state as follows:

1. I affirm in writing under penalty of perjury under the laws of the State of New Mexico that the following statements are true and correct.

2. I am over 18 years of age and have personal knowledge of the facts stated herein. I am employed by El Paso Electric Company ("EPE" or "the Company") as *Director of Environmental and Safety.*

3. The foregoing Direct Testimony of Teresa M. Sosa, together with all exhibits sponsored therein and attached thereto, is true and accurate based on my knowledge and belief.

4. I submit this Declaration, based upon my personal knowledge and upon information and belief, in support of EPE's ***Application for a Certificate of Public Convenience and Necessity for a Replacement 200 MW Eddy High Voltage Direct Current Tie.***

FURTHER, DECLARANT SAYETH NAUGHT.

I declare under penalty of perjury that the foregoing is true and correct.

Executed on April 13, 2026.

/s/ *Teresa M. Sosa*

TERESA M. SOSA

BEFORE THE NEW MEXICO PUBLIC REGULATION COMMISSION

IN THE MATTER OF EL PASO ELECTRIC COMPANY'S APPLICATION FOR A CERTIFICATE OF PUBLIC CONVENIENCE AND NECESSITY FOR A REPLACEMENT 200 MW EDDY HIGH VOLTAGE DIRECT CURRENT TIE	)	**Case No. 26-00___**
EL PASO ELECTRIC COMPANY, **Applicant**	)	

DIRECT TESTIMONY OF

DAVID C. HAWKINS

ON BEHALF OF

EL PASO ELECTRIC COMPANY

APRIL 13, 2026

EL PASO ELECTRIC COMPANY
DIRECT TESTIMONY OF
DAVID C. HAWKINS

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EXHIBIT

EL PASO ELECTRIC COMPANY
DIRECT TESTIMONY OF
DAVID C. HAWKINS

I. INTRODUCTION AND QUALIFICATIONS

Q1. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is David C. Hawkins. My business address is 100 N. Stanton Street, El Paso, Texas 79901.

Q2. WHO IS YOUR CURRENT EMPLOYER AND WHAT POSITION DO YOU HOLD?

A. I am employed by El Paso Electric Company ("EPE" or the "Company") as Vice President of Operations Support.

Q3. PLEASE SUMMARIZE YOUR EDUCATIONAL BACKGROUND AND PROFESSIONAL EXPERIENCE.

A. I hold a Master of Science degree and a Bachelor of Science degree in Electrical Engineering from New Mexico State University. I have been with EPE since 2002, where I have held various positions including Vice President of Generation, System Planning and Dispatch and Vice President of Power Marketing, Fuels and Resource Planning. Before joining EPE, I served as a Wholesale Power Marketing Analyst at Public Service Company of New Mexico ("PNM").

Q4. WHAT ARE YOUR RESPONSIBILITIES WITH EPE AS VICE PRESIDENT OF OPERATIONS SUPPORT?

A. I am responsible for the oversight and direction of EPE's System Operations,

Environmental and Safety, Energy Resources and Support Services departments. These departments are responsible for grid reliability; fuel and energy needs for the system and required regulatory support; compliance with related North American Electricity Reliability Corporation ("NERC") standards; monitoring EPE's water and air emissions for regulatory compliance; fleet operations; security; and facilities operations. I oversaw System Planning and Interconnections, as well as Resource Strategy and Land Management through April 6, 2026.

Q5. HAVE YOU PREVIOUSLY PRESENTED TESTIMONY IN REGULATORY PROCEEDINGS?

A. Yes. I have previously filed testimony with the Federal Energy Regulatory Commission, testified before the Public Utility Commission of Texas, and testified before the New Mexico Public Regulation Commission ("NMPRC" or "Commission").

II. PURPOSE OF DIRECT TESTIMONY

Q6. WHAT IS THE PURPOSE OF YOUR DIRECT TESTIMONY?

A. My direct testimony supports EPE's expedited request for a Certificate of Public Convenience and Necessity ("CCN") to replace the existing 200MW HVDC Eddy County Converter Station (or "Eddy Tie") with a new 200 MW facility based on new technology. Specifically, I support the system reliability benefits to the

transmission system, resource diversity benefits, and projected cost savings for EPE's customers of the proposed replacement facility.

Q7. ARE YOU SPONSORING ANY EXHIBITS IN SUPPORT OF YOUR TESTIMONY?

A. Yes, I am sponsoring the following exhibit:

- Exhibit DCH-1 E3 Integrated Resource Plan Analysis

III. SYSTEM RELIABILITY BENEFITS

Q8. WHAT IS SYSTEM RELIABILITY?

A. System reliability is the ability of a utility's system to continuously deliver power to customers at accepted standards and in the amounts demanded. System reliability includes adequacy, which is the capacity to have sufficient generation, transmission, and distribution resources to meet customer demand at all times, including during peak loads and planned outages. System reliability also includes security, which is the ability to withstand sudden, unexpected disturbances such as equipment failures or the loss of major generation or transmission resources without widespread service interruptions.

Q9. HOW DOES THE EDDY TIE SUPPORT SYSTEM RELIABILITY?

A. New Mexico is uniquely positioned because it straddles both the Eastern and Western Interconnections. EPE is connected to the Southwest Power Pool ("SPP")

through the existing Eddy Tie, which gives EPE a bidirectional link to the Eastern Interconnection. This is important because EPE otherwise operates within the Western Interconnection. Historically, EPE has relied upon short-term wholesale market purchases, imported over available transmission capacity, to meet reliability needs and reduce EPE's customers' costs. The Eddy Tie allows EPE to import power from, or export power to, the east, providing an alternative supply path that is independent of EPE's western transmission connections.

Imports from the Western Interconnection flow primarily through Path 47, which consists of the 345 kV lines on the western side of its system (the West Mesa-Arroyo 345 kV line and the two lines tying into Tucson Electric Power via the Luna substation). When those western lines become constrained—whether from high loads during summer peaks, planned maintenance outages, or a contingency event like losing one of the lines under N-1 conditions—EPE's ability to import power from the west diminishes.

The Eddy Tie addresses this issue because it connects to the Eastern Interconnection and therefore represents an independent import path. The connectivity through the Eddy Tie provides diversity and resiliency. In practical terms, it means the EPE system is not wholly dependent on a single directional transmission corridor from the west.

Q10. HAS THE CURRENT CONDITION OF THE EXISTING EDDY TIE REDUCED ITS SYSTEM RELIABILITY BENEFITS?

A. Yes. As discussed by EPE witnesses Jonathan Trejo and Omar Gallegos, the Eddy Tie is nearing the end of its useful life. Replacement parts are so difficult to find that the Tie is chronically out of service. The Tie is the only part of the EPE transmission system that is unable to provide firm service across it. Unless a replacement tie is approved, EPE will have to plan its system without the benefit of the eastern import path, which would place even greater stress on the western lines. Therefore, the replacement of the Eddy Tie is not just an economic issue; it is a reliability priority to restore diversity that EPE needs to manage constraints on the western side of its system.

Q11. HOW DOES THE PROPOSED PROJECT TO REPLACE THE EDDY TIE SUPPORT EPE'S OPERATIONAL RELIABILITY?

A. The proposed Eddy Tie replacement project would restore the ability of this part of the EPE transmission system to support firm service, allowing for reliable transmission import capability to access a geographically diverse source of resources. It would allow EPE's customers to benefit from resources located to the east of EPE's service territory at times when such resources can be secured at lower cost, and at times when other resources face challenges from transmission constraints.

Q12. WOULD THE EDDY TIE REPLACEMENT PROJECT ALLOW ACCESS TO RESOURCES ON BOTH A LONG-TERM BASIS AND A SHORT-TERM BASIS?

A. Yes. The Eddy Tie Project would restore the firm nature of this part of EPE's transmission system and would allow access to resources on a long-term basis, a short-term basis, or both. On a long-term basis, the replacement Eddy Tie would allow EPE to enter into long-term purchased power agreements with generators in the Eastern Interconnection. On a short-term basis, as I discuss below, a replacement Eddy Tie would facilitate EPE purchasing power opportunistically when prices are favorable or when EPE faces unanticipated demand. In other words, the replacement Eddy Tie would restore better real-time operational flexibility.

Q13. DO CUSTOMERS REALIZE COST SAVINGS FROM SHORT-TERM PURCHASES?

A. Yes. Short-term purchases allow EPE to meet energy needs for shorter durations for either reliability benefits, or when there are lower cost alternatives to EPE's other resources. When power is available to the east of the Eddy Tie at prices below EPE's incremental cost of generation or western wholesale power market prices, the replacement tie would allow EPE to make short-term power purchases. These savings are passed on to EPE's customers. In addition, when transmission constraints limit access to existing power sources to the west for other third-party

utilities, the replacement tie would allow for an alternative that has economic benefits. I will discuss these customer benefits later in my testimony.

IV. OTHER BENEFITS TO REPLACING THE EDDY TIE

Q14. IN ADDITION TO RELIABILITY, WILL EPE CUSTOMERS BENEFIT IN OTHER WAYS FROM THE NEW TIE?

A. Yes. The replacement Eddy Tie is expected to increase the frequency and volume of power flows across the terminal, allowing for greater opportunities for power to be purchased from and sold to entities located across the Tie.

Q15. HOW WOULD THIS BENEFIT EPE'S CUSTOMERS IN NEW MEXICO?

A. The benefits to EPE's New Mexico retail customers would be realized through a combination of reductions in fuel costs, reductions in purchased power costs, and increases in revenues achieved through wheeling transactions. Fuel costs and purchased power costs would be reduced because power will be available at a lower cost across the replacement Eddy Tie. Having greater access to resources on the east of the Eddy Tie allows EPE to evaluate these resources as an alternative to the resources available from western sources, or to mitigate the challenges that are experienced when EPE is unable to fully access western resources due to western transmission import limitations.

Q16. IS THE EDDY TIE EXCLUSIVELY FOR EPE'S OWN USE, OR CAN THIRD PARTIES USE THIS PART OF EPE'S TRANSMISSION SYSTEM?

A. Access to the Eddy Tie is available to others under EPE's Open Access Transmission Tariff.

Q17. PLEASE EXPLAIN HOW EPE'S CUSTOMERS BENEFIT WHEN THE EDDY TIE IS USED TO SERVE THIRD PARTIES.

A. The Eddy Tie, once it is restored to firm status with the replacement, is likely to be attractive to a wide variety of users. Third parties may identify opportunities to purchase power from sellers located to the east of the tie, and then secure transmission services from EPE to move that power across the Eddy Tie into EPE's system and beyond (or vice versa) to (i) take advantage of resource availability in the east at advantageous prices, and/or (ii) serve consumer needs to the east of the tie with western resources, when western resources are not being fully used by western consumers. The Eddy Tie is part of the EPE transmission system**.** Companies that seek to move power over available transmission on EPE's system, known as wheeling, pay for the right to wheel power over the EPE transmission system. Wheeling transactions that move across the new Eddy Tie would be charged the FERC rate under EPE's Open Access Transmission Tariff. The wheeling revenue that EPE collects under its FERC tariff benefits EPE's customers by reducing the transmission revenue requirements collected from retail customers. The reduction of transmission revenue requirements results in lower retail rates.

Q18. HAS EPE COLLECTED WHEELING REVENUE FROM THIRD PARTIES USING THE EPE TRANSMISSION SYSTEM TO MOVE POWER ACROSS THE EDDY TIE?

A. Yes. Between 2021 and 2025, approximately 468,000 MWh of third-party wheeling transactions across the Eddy Tie yielded approximately $6.35 million in revenue. During those years, the Tie was available on a non-firm basis only and was subject to interruptions. The ability to have a more stable transmission path as a result of the Eddy Tie Project would minimize interruptions to wheeling transactions, which would provide additional benefit to EPE's customers.

V. OPPORTUNITIES AT THE SEAM

Q19. WHAT IS A SEAM AS IT RELATES TO THE ELECTRIC GRID?

A. A "seam" refers to the boundary between regional transmission organizations or balancing authority areas. The electric grid in the United States is divided between two broad areas, called Interconnections. The Eddy Tie is located at the seam between those two Interconnections. It sits at the point where the Western Interconnection of the United States connects to the Eastern Interconnection of the United States. EPE's transmission system is located within the Western Interconnection.

Q20. WHAT IS LOCATED TO THE EAST OF THE TIE?

A. The transmission system of Southwestern Public Service Company ("SPS") is located to the east of the Eddy Tie and is directly connected to the Tie. SPS is in the Eastern Interconnection, and is a member of the Southwest Power Pool ("SPP").

Q21. IS THE LOCATION OF THE EDDY TIE AT THE SEAM SIGNIFICANT?

A. Yes. There are very few locations within the United States where the two Interconnections are electrically connected at the seam through high voltage DC terminals. The Eddy Tie is significant in this respect. EPE witness Trejo addresses this issue in more detail in his direct testimony.

Q22. HOW DOES THIS LOCATION TRANSLATE INTO MARKET OPPORTUNITIES?

A. It allows for power to move between the two Interconnections by moving across the seam through the terminal. When market conditions on one side of the terminal are different from market conditions on the other side of the terminal, these differences create opportunities for transactions that provide cost savings for retail customers in EPE's service territory. When power resources are more scarce or more constrained on one side of the seam, compared to conditions on the other side of the seam, the terminal allows for resources to move across the seam to reach buyers on the side where the greater scarcity or constraints exist.

Q23. THERE IS NO ORGANIZED WHOLESALE MARKET AT THE WESTERN INTERFACE OF THE EDDY TIE AT THIS TIME. DOES THAT MATTER?

A. Organized wholesale power markets are forming in the Western Interconnection. The replacement Eddy Tie's capability to move power across the seam *on a firm basis* is expected to reap benefits to EPE's retail customers, with or without the presence of organized markets on the western side of the seam. When organized markets are present on both sides of the seam, the opportunities for beneficial transactions across the seam are enhanced.

Q24. DID EPE COMMISSION A STUDY TO EVALUATE THE IMPACT OF THE EDDY TIE AS IT RELATES TO ORGANIZED DAY-AHEAD MARKETS?

A. Yes. As part of the NMPRC's Inquiry and Proposed Rulemaking Pertaining to Investor-Owned Electric Utilities' Regional Market Activity (Docket No. 23-00268-UT), EPE requested the Brattle Group to conduct a study of the day-ahead markets.

Q25. PLEASE SUMMARIZE THE ANALYSES PERFORMED BY THE BRATTLE GROUP.

A. The Brattle Group studied multiple scenarios of EPE's participation in organized western markets. The scenarios evaluated the organized market benefits using a

one-year snapshot of system and market conditions for 2032. As a component of these scenarios, the impact of the Eddy Tie as a benefit to EPE's customers was included. The Eddy Tie scenarios all showed various levels of benefits to EPE's customers depending on the scenarios' assumptions.

Q26. WILL THE BENEFITS OF JOINING A DAY-AHEAD MARKET EXIST REGARDLESS OF WHICH MARKET EPE JOINS?

A. Yes. EPE has informed the Commission that it is planning to join Markets+, but there would be meaningful benefits if EPE had joined the Extended Day-Ahead Market ("EDAM"). Moreover, as both EDAM and Markets+ mature, and as the Western Interconnection moves from a largely bilateral trading system to a multi-market environment, the DC ties at the interconnection boundaries, including the replacement Eddy Tie, will be critical infrastructure for managing the seams between these overlapping market and reliability frameworks.

Q27. DOES EPE RELY ON THE BRATTLE GROUP'S ANALYSIS IN ITS ECONOMIC JUSTIFICATION OF THE EDDY TIE PROJECT?

A. Not directly. As I explained, there are significant benefits to the Eddy Tie without considering day-ahead markets. However, the Brattle Group's analysis does emphasize that there are additional benefits associated with the replacement of the Eddy Tie that EPE customers would realize from day-ahead markets, regardless of which market EPE had joined.

Q28. PLEASE PROVIDE A SUMMARY OF THE ANALYSES PERFORMED BY E3 AS TO THE OPPORTUNITIES LOCATED TO THE EAST OF THE EDDY TIE.

A. As part of its 2025 Integrated Resource Plan ("IRP"), EPE commissioned E3 to study a stakeholder-requested scenario in which it assumed a replacement Eddy Tie in 2030, with EPE having the capability of importing or exporting up to 200 MW over the new tie. Additionally, it was assumed that EPE received 70 MW of firm capacity over the new tie. E3 relied on price forecasts in SPP as well as Palo Verde switching station as provided by E3's Core Case Market Price Forecast. E3's results were shared in the IRP facilitated stakeholder engagement process. E3 identified $821 million in nominal benefits through 2045 from the replacement Eddy Tie, or $376 million on a net present value basis, under this scenario. These benefits were the result of offsetting new generation builds in EPE's service territory by the 70 MW of firm capacity purchases over the new tie, as well as capturing benefits of SPP market opportunities on the east side of the Eddy Tie. The E3 analysis is attached as Exhibit DCH-1. If the benefits of avoided new generation costs are not counted, the $824 million in nominal benefits identified in E3's analysis through 2045 would be approximately $610 million, or $277 million on a net present value basis.

Q29. WAS THE EDDY TIE PRESENTED IN THE IRP STAKEHOLDER PROCESS?

A. Yes. There was considerable interest among the IRP stakeholders in EPE's proposed replacement of the existing Eddy Tie with a new 200 MW facility. EPE's 2025 IRP Action Plan therefore includes the action item that "EPE will take steps to initiate replacing the Eddy Tie and seek all necessary approvals."

Q30. WERE THERE ADDITIONAL ANALYSES PERFORMED THAT DEMONSTRATE BENEFITS OF THE EDDY TIE REPLACEMENT PROJECT?

A. Yes. EPE evaluated the benefits of the Eddy Tie Project over a 40-year life utilizing the load and resources selected as part of EPE's 2025 All-Source RFP. This analysis assessed the revenue requirement of EPE's selected portfolio of resources with and without the Eddy Tie. With the replacement Eddy Tie taken into account, the revenue requirement of the selected portfolio was substantially lower. The production cost benefits, fuel and purchased power costs benefits, of the replacement Eddy Tie identified in this analysis are $2.45 billion in nominal dollars, or $464 million on a net present value basis, and are shown in EPE witness Gallegos' Exhibit OAG-2.

VI. CONCLUSION

Q31. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes.

El Paso Electric
2025 New Mexico Integrated Resource Plan
Eddy Tie Analysis

Total System Cost Comparison (2026-2045)

NOMINAL ($ MILLIONS)	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	Total
Base Case	$154.06	$244.36	$208.10	$218.34	$440.42	$478.72	$530.91	$560.16	$628.04	$663.62	$715.64	$763.83	$853.26	$918.30	$948.25	$1,002.89	$1,041.59	$1,080.82	$1,160.89	$1,199.20	$13,811.39
70 MW Eddy	$154.41	$244.79	$208.47	$218.05	$411.03	$428.31	$501.67	$528.50	$598.43	$638.67	$677.12	$717.49	$823.39	$880.82	$912.23	$966.09	$997.06	$1,033.80	$1,116.73	$1,144.19	$13,201.27
Nominal Net System Cost Savings	**$0.35**	**$0.43**	**$0.38**	**($0.29)**	**($29.39)**	**($50.40)**	**($29.24)**	**($31.66)**	**($29.62)**	**($24.94)**	**($38.52)**	**($46.34)**	**($29.87)**	**($37.47)**	**($36.02)**	**($36.79)**	**($44.53)**	**($47.02)**	**($44.16)**	**($55.01)**	**($610.11)**

NET PRESENT VALUE ($ MILLIONS)	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	Total
Base Case	$144.54	$215.10	$171.87	$169.19	$320.19	$326.54	$339.77	$336.35	$353.81	$350.76	$354.89	$355.39	$372.48	$376.11	$364.39	$361.58	$352.34	$343.02	$345.68	$335.03	$6,289.03
70 MW Eddy	$144.87	$215.48	$172.18	$168.96	$298.83	$292.16	$321.06	$317.34	$337.13	$337.58	$335.79	$333.83	$359.44	$360.76	$350.55	$348.31	$337.27	$328.10	$332.53	$319.66	$6,011.83
NPV Net System Cost Savings	**$0.33**	**$0.38**	**$0.31**	**($0.23)**	**($21.36)**	**($34.38)**	**($18.71)**	**($19.01)**	**($16.68)**	**($13.18)**	**($19.10)**	**($21.56)**	**($13.04)**	**($15.35)**	**($13.84)**	**($13.27)**	**($15.06)**	**($14.92)**	**($13.15)**	**($15.37)**	**($277.20)**

BEFORE THE NEW MEXICO PUBLIC REGULATION COMMISSION

IN THE MATTER OF EL PASO ELECTRIC COMPANY'S APPLICATION FOR A CERTIFICATE OF PUBLIC CONVENIENCE AND NECESSITY FOR A REPLACEMENT 200 MW EDDY HIGH VOLTAGE DIRECT CURRENT TIE	)	**Case No. 26-00___**
EL PASO ELECTRIC COMPANY, Applicant	)	

DECLARATION OF DAVID C. HAWKINS IN SUPPORT OF THE FOREGOING DIRECT TESTIMONY OF EL PASO ELECTRIC COMPANY'S APPLICATION FOR A CERTIFICATE OF PUBLIC CONVENIENCE AND NECESSITY FOR A REPLACEMENT 200 MW EDDY HIGH VOLTAGE DIRECT CURRENT TIE

I ***David C. Hawkins***, pursuant to Rule 1-011 NMRA, state as follows:

1. I affirm in writing under penalty of perjury under the laws of the State of New Mexico that the following statements are true and correct.

2. I am over 18 years of age and have personal knowledge of the facts stated herein. I am employed by El Paso Electric Company ("EPE" or "the Company") as *Vice President of Operations Support.*

3. The foregoing Direct Testimony of David C. Hawkins, together with all exhibits sponsored therein and attached thereto, is true and accurate based on my knowledge and belief.

4. I submit this Declaration, based upon my personal knowledge and upon information and belief, in support of EPE's ***Application for a Certificate of Public Convenience and Necessity for a Replacement 200 MW Eddy High Voltage Direct Current Tie.***

FURTHER, DECLARANT SAYETH NAUGHT.

I declare under penalty of perjury that the foregoing is true and correct.

Executed on April 13, 2026.

/s/ *David C. Hawkins*

DAVID C. HAWKINS

BEFORE THE NEW MEXICO PUBLIC REGULATION COMMISSION

IN THE MATTER OF EL PASO ELECTRIC COMPANY'S APPLICATION FOR A CERTIFICATE OF PUBLIC CONVENIENCE AND NECESSITY FOR A REPLACEMENT 200 MW EDDY HIGH VOLTAGE DIRECT CURRENT TIE	)	**Case No. 26-00___**
EL PASO ELECTRIC COMPANY, Applicant	)	

DIRECT TESTIMONY OF

OMAR A. GALLEGOS

ON BEHALF OF

EL PASO ELECTRIC COMPANY

APRIL 13, 2026

EL PASO ELECTRIC COMPANY
DIRECT TESTIMONY OF
OMAR A. GALLEGOS

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EXHIBITS

EL PASO ELECTRIC COMPANY
DIRECT TESTIMONY OF
OMAR A. GALLEGOS

I. INTRODUCTION AND QUALIFICATIONS

Q1. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Omar A. Gallegos. My business address is 100 N. Stanton Street, El Paso, Texas 79901.

Q2. WHO IS YOUR CURRENT EMPLOYER AND WHAT POSITION DO YOU HOLD?

A. I am employed by El Paso Electric Company ("EPE" or the "Company") as Vice President of System Planning and Construction.

Q3. PLEASE SUMMARIZE YOUR EDUCATIONAL BACKGROUND AND PROFESSIONAL EXPERIENCE.

A. In 1995, I graduated from the University of Texas at El Paso with a Bachelor of Science degree in Mechanical Engineering and a Master of Business Administration degree in 2006. In 2014, I completed a Graduate Certificate in Public Utility Regulation and Economics from New Mexico State University.

From 1995 to May 2009, I was employed by Delphi Corporation in product engineering. During my final eight years at Delphi Corporation, I was Supervisor for Product Engineering, where my responsibilities included design development, product validation, cost estimating, and project management.

In May 2009, I accepted a position with EPE as a Real-Time Scheduler. In

that capacity, I was responsible for managing energy transfer schedules over the Company's transmission lines in accordance with Federal Energy Regulatory Commission ("FERC") requirements and North American Electric Reliability Corporation ("NERC") reliability standards. From September 2010 to May 2013, I was an Associate - Business Development working as a Project Manager for renewable energy projects and new generation projects. My responsibilities in that position included financial analysis, business process flows, and evaluation of emerging technologies. In May 2013, I was promoted to System Operations Outage Coordinator where I coordinated EPE's transmission, generation, and system outages in adherence with reliability requirements. In March 2014, I was promoted to Manager-Asset Management Services. During that time, I was responsible for Transmission and Distribution project management initiatives, budgeting, asset management, and support of regulatory permitting for transmission assets. In February 2016, I was promoted to Director of the Resource Planning Department with responsibility for development of EPE's annual Loads and Resources ("L&R") analysis, Integrated Resource Plan ("IRP"), New Mexico Renewable Portfolio Standard ("RPS") plan, and selection of resources via competitive Requests for Proposals. In July 2016, I assumed responsibility of EPE's Resource Planning and Management Department. In 2022, I was named Vice President of Energy Delivery. The Energy Delivery Division is, essentially, the Transmission and Distribution ("T&D") "wires" portion of EPE, which includes Transmission,

Substations and Relays ("TSR"); Distribution System Engineering; Distribution Operations; TSR Construction and Maintenance; Meter Testing; and Project Management subdivisions. I am responsible for ensuring that each of these systems operate in a safe and reliable manner to collectively provide T&D service to EPE customers.

Q4. WHAT ARE YOUR CURRENT RESPONSIBILITIES WITH EPE?

A. In April 2026, I was named Vice President of System Planning and Construction. In this role I am responsible for the oversight and direction of EPE's Integrated System Planning, inclusive of Resource Planning, Transmission System Planning and Distribution System Planning. This includes grid strategy, modernization and incorporation of distributed and load side resources. Additionally, I am responsible for the oversight of Engineering, Permitting and Construction of Generation and Transmission Projects.

Q5. HAVE YOU PREVIOUSLY PRESENTED TESTIMONY IN REGULATORY PROCEEDINGS?

A. Yes. I have previously filed testimony with the Public Utility Commission of Texas and testified before the New Mexico Public Regulation Commission ("NMPRC" or "Commission").

II. PURPOSE OF DIRECT TESTIMONY

Q6. WHAT IS THE PURPOSE OF YOUR DIRECT TESTIMONY?

A. My direct testimony supports EPE's expedited request for a Certificate of Public Convenience and Necessity ("CCN") to replace the existing 200MW HVDC Eddy County Converter Station (the "Eddy Tie" or "Tie") with a new 200-megawatt ("MW") facility based on new technology (the "Project"). First, in order to provide context for the significant benefits that the Project will bring to EPE's system and its customers, I provide a description of EPE's transmission system. I then summarize the qualitative and quantitative benefits of the Project and support the Project's net economic benefit of $128M for customers, which results in a Project Benefit Cost Ratio of 1.38.

Q7. ARE YOU SPONSORING ANY EXHIBITS IN SUPPORT OF YOUR TESTIMONY?

A. Yes, I am sponsoring the following exhibits:

- Exhibit OAG-01: EPE's Regional Location versus Electrical Grids
- Exhibit OAG-02: Net Benefit and Benefit Cost Ratio

III. DESCRIPTION OF THE EPE SYSTEM

Q8. PLEASE DESCRIBE EPE'S TRANSMISSION SYSTEM AND ITS CONNECTIONS TO THE EAST AND WEST.

A. EPE's transmission system is comprised of 345kV transmission tie lines to the Western Interconnection and 115kV and 69kV transmission lines that transmit power across EPE's service territory. EPE's service territory is located in the southeasternmost corner of the Western Interconnection as depicted in Exhibit OAG-01. The Western Interconnection is regulated by the Western Electricity Coordinating Council ("WECC") on behalf of the NERC. WECC monitors compliance with NERC Reliability Standards and defines additional WECC-specific reliability standards to ensure reliable planning and operation of the Western Interconnection. As depicted in Exhibit OAG-01, EPE is interconnected to the Western Interconnection via three 345kV tie-lines formally identified as the "WECC Path 47 through gate."

The existing Eddy Tie provides a 200 MW asynchronous connection to the Eastern Interconnection, specifically the Southwest Power Pool. EPE does not have an interconnection to the Electric Reliability Council of Texas, or ERCOT, system. EPE also has two 115kV transmission tie-lines to Mexico which are normally not energized and only available for use for emergency purposes under a Presidential Permit.

Q9. PLEASE DESCRIBE EPE'S CURRENT CONNECTION TO THE WESTERN INTERCONNECTION IN MORE DETAIL.

A. WECC Path 47 is explicitly defined by the following three transmission lines:

- Greenlee-Hidalgo-Luna: ~120 miles and initially constructed in 1977;
- Springerville-Macho Springs-Luna: ~200 miles and initially constructed in 1989; and
- West Mesa-Arroyo: ~200 miles and initially constructed in 1977.

Both the Greenlee-Hidalgo-Luna and the West Mesa-Arroyo lines are wood H-frame structures with a small quantity of steel structures as a result of replacements due to maintenance or forced outage restoration. The Springerville-Macho Springs-Luna transmission line is also a wood H-frame construction except for the approximately 50 miles that traverse the Gila National Forest. In that area, the transmission lines are steel structures because of the increased potential for wildfires in the Gila. In recent years, the Gila has experienced wildfires every year. Since 2020 there have been six fires that have encroached within 10 miles of the transmission line, while in 2025 the Buck Fire actually traversed 50 of the steel transmission structures.

WECC Path 47 has a total firm capacity of 940 MW that is allocated between EPE, Public Service Company of New Mexico ("PNM"), and Tri-State Generation and Transmission. EPE's allocation is 645 MW, which is sufficient to import EPE's 633 MW of generation from the Palo Verde Generating Station in Arizona.

Q10. AS CURRENTLY CONFIGURED, DOES EPE'S SYSTEM AT THE SOUTHEASTERN-MOST EDGE OF THE WECC HAVE IMPORT LIMITATIONS FROM THE WEST?

A. Yes. WECC Path 47 has a firm capacity limitation and a more restrictive import limitation in conditions known as "N -1." NERC reliability standards require that the transmission system be operated in a manner that if one transmission element is suddenly de-energized as part of a forced outage, the transmission system must stay stable and no transmission element can exceed its rating. As such, this results in the WECC Path 47 contractual total firm capacity of 940 MW with EPE's share being 645 MW, which is defined at this amount, in part, to comply with NERC N-1 standards. More importantly, imports from the west are drastically impacted under N-1 conditions. For example, a Springerville to Luna outage would reduce EPE's import capacity to 438 MW. Especially during summer peak season, these limitations can impact EPE's resource availability for serving firm load.

IV. DESCRIPTION OF THE EXISTING EDDY TIE AND ITS USAGE

Q11. PLEASE DESCRIBE THE EXISTING EDDY TIE.

A. The existing Eddy Tie was completed in 1984, after having received a CCN from the Commission in 1982. It is a 200 MW back-to-back HVDC tie interconnecting EPE to the Eastern Interconnection. EPE witness Jonathan Trejo further describes

the technical aspects of the existing Eddy Tie and its current operational state in his direct testimony.

Q12. WHERE IS THE EDDY TIE LOCATED?

A. The Eddy Tie is located just outside of Artesia, New Mexico, approximately 140 miles from EPE's urban load pockets of Las Cruces, New Mexico and El Paso, Texas. The Eddy Tie is a part of EPE's transmission system and is referenced in OAG-01.

Q13. WHAT IS THE CURRENT OWNERSHIP STRUCTURE OF THE EXISTING EDDY TIE?

A. The existing Eddy Tie is co-owned by EPE and PNM with a two-thirds and one-third ownership, respectively. This ownership structure has been in place since construction of the initial Eddy Tie in 1984 and applies to both capital expenditures and operations and maintenance expenses.

Q14. HOW IS THE EDDY TIE USED BY EPE?

A. The most important uses of the Eddy Tie are during EPE's peak season to enhance energy availability during energy scarcity events and during N-1 transmission outages from the west. It is also used to help balance power flows on the system by injecting power from the east.

In addition, EPE utilizes the Eddy Tie for opportunity sales and/or purchases, including simultaneous exchange transactions, to the benefit of reducing fuel and purchased power costs that our customers would otherwise have to pay.

Finally, the Eddy Tie also enables EPE to provide wheeling service to third parties. The revenue from those services is credited back to EPE's customers as an offset to base rates in a general rate case.

Q15. HAS EPE RELIED UPON THE EXISTING EDDY TIE FOR RESOURCE ADEQUACY?

A. Yes. EPE has been able to utilize the Eddy Tie to flow power across the Tie from east to west during energy scarcity events and when EPE has been in energy emergencies. The dates of those scarcity and emergency events since 2022 are provided in Table OAG-01. Since 2022, there were an additional thirteen days of strained system conditions (not shown on Table OAG-01) where reserve margins were under 100 MW and Eddy Tie was flowing and supporting EPE load.

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Table OAG-01

Date	Energy Emergency Alert ("EEA")
7/1/2024	EEA 2
5/17/2024	Strained Conditions*
7/20/2023	EEA 2
6/19/2023	EEA 2
6/16/2022	EEA 2
6/10/2022	EEA 2
8/21/2019	EEA 3

*The Eddy Tie was called on during strained conditions to avoid an EEA.

Q16. WAS THE EDDY TIE UTILIZED FOR RESOURCE ADEQUACY DURING THE JANUARY 2026 POLAR VORTEX?

A. Yes. The January 2026 Polar Vortex was an outbreak of Arctic air that plunged much of North America into prolonged, extreme cold due to a destabilized jet stream. It had only marginal impact on EPE's gas supply and EPE did not require imports from the east. However, impacts were greater to utilities in the Eastern Interconnection. The Eddy Tie was utilized to flow power from west to east to support southeast New Mexico's energy needs during the freeze event. It was requested by the Southwest Power Pool to flow east as a proactive measure to mitigate resource adequacy risks for the residents and oil and gas production load in southeast New Mexico.

Q17. HOW HAS THE EXISTING EDDY TIE BEEN USED BY PNM?

A. PNM has not made use of the Eddy Tie in some time. For PNM, there are more limitations to utilizing the Tie given that the PNM transmission system lacks capability to make regular use of the Tie to exchange of power with PNM's primary service areas. Specifically, PNM would have to obtain wheeling transmission service from EPE in order to deliver power from the Eddy Tie to or from its customers.

It is also important to note that PNM has 100 percent ownership of the Blackwater HVDC Tie, which is located in northern New Mexico on PNM's transmission system east of Albuquerque, New Mexico. As with the Eddy Tie, the Blackwater tie is also a location at which the Western Interconnection and the Eastern Interconnection meet. This is important because, unlike EPE, PNM has another means of flowing power between the Western and Eastern interconnections.

Q18. HAS PNM OPTED TO PARTICIPATE AS AN OWNER IN THE NEW EDDY HVDC TIE?

A. No. PNM is not currently planning to participate in the new Eddy Tie. EPE is planning to be the sole owner of the proposed new Eddy Tie.

Q19. CAN YOU BRIEFLY EXPLAIN THE BASIS FOR THE COMMISSION'S APPROVAL OF THE 1982 CCN FOR THE EXISTING EDDY TIE?

A. Yes. At the time EPE and Texas New Mexico Power ("TNP") applied for the original CCN, there was no interconnection between the EPE and TNP systems, on the one hand, and the Southwestern Public Service Company ("SPS") system, on the other hand. The Commission found that construction of the Eastern Interconnection Project (which included not only the Eddy Tie, but also a number of related transmission facilities) would result in lower cost bulk power than was then available; greater service reliability; and greater flexibility in how EPE and TNP (now PNM) operate their systems. The Commission also found that the project would not result in unnecessary duplication and economic waste.

Q20. DO THOSE SAME REASONS APPLY TO EPE'S REQUEST FOR A REPLACEMENT TIE?

A. Yes. The same benefits of reduced bulk electric cost and added reliability benefits exist today. It is also important to note that society's increased dependence on reliable electric service has become more paramount given electrification, dependence on electronics, and digital systems. These characteristics accentuate the importance of the reliability benefits the Eddy Tie brings to EPE's customers. No economic waste will occur because the existing Eddy Tie is at the end of its useful life.

V. BENEFITS OF THE PROPOSED EDDY TIE REPLACEMENT

Q21. PLEASE DESCRIBE THE PROPOSED EDDY TIE REPLACEMENT PROJECT AND SUMMARIZE THE QUALITATIVE AND QUANTITATIVE BENEFITS TO EPE'S CUSTOMERS.

A. The Project involves the construction of a new HVDC tie with the most current technology build by a vendor selected pursuant to a competitive solicitation. It will be built on land immediately adjacent to the current Eddy Tie site. The proposed technology and project description is further explained by EPE witness Trejo. In terms of quantitative benefits, the replacement Eddy Tie will provide a reduction of fuel and purchased power costs via the market and arbitrage opportunities mentioned above. EPE witness David Hawkins describes and quantifies the fuel and purchased power cost benefits that the Eddy Tie is estimated to provide customers in his direct testimony.

Q22. WHY DO MARKET AND ARBITRAGE OPPORTUNITIES EXIST VIA THE EDDY HVDC TIE?

A. The Eddy Tie bridges the Western and Eastern Interconnections. It therefore allows energy resources between the two regions to be optimally dispatched to the benefit of customers. Additionally, since each market has its own supply and demand ecosystem, there will typically be a price differential between the two markets. Explained more simply, the two regions peak in electricity demand at different

times, in part due to the time zone spread but also because of varying climate differentials across the broad geography. For example, it is unlikely that a heat wave, which drives summer peak demand, would encompass both western Arizona/California and the area encompassing eastern New Mexico and the panhandle of Texas. Both of these phenomena are referred to as geographic load diversity.

Q23. HAS EPE LEVERAGED THE EXISTING EDDY TIE IN THE PAST FOR ARBITRAGE OPPORTUNITIES TO THE BENEFIT OF CUSTOMERS?

A. Yes. EPE solicited and received FERC approval for simultaneous exchanges which permitted arbitrage transactions from 2021 through 2023. Subsequently, EPE was again granted FERC approval to engage in these types of transactions through the end of 2026. EPE exercised the FERC approval rights to transact in 2024 and 2025. EPE plans to seek an extension of the simultaneous exchange transaction from FERC in 2026.

One hundred percent of the monetary net benefit allocated to New Mexico from these arbitrage transactions flows back to customers via fuel clause filings.

Q24. INDEPENDENT OF EPE'S ANALYSIS, HAS THE U.S. DEPARTMENT OF ENERGY NOTED THE MARKET VALUE ACROSS THE WESTERN AND

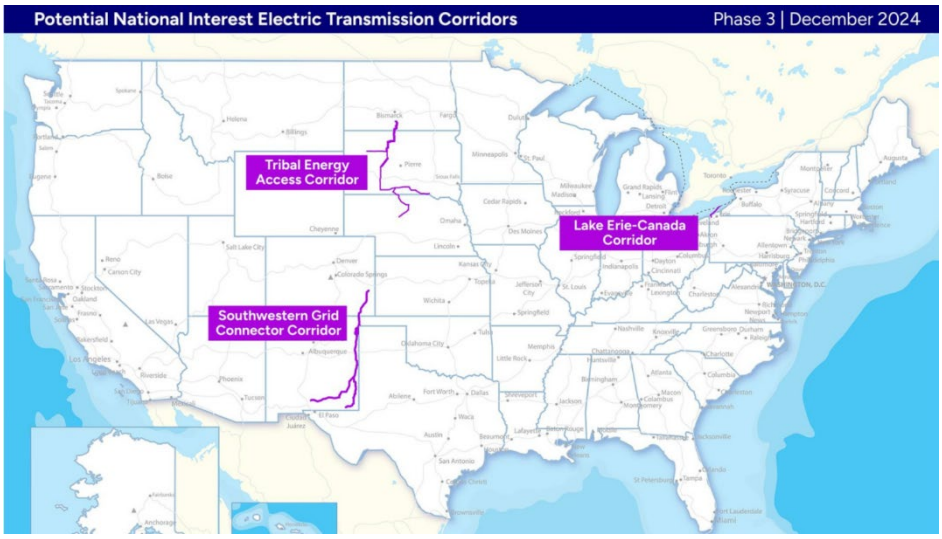
EASTERN INTERCONNECTION ALONG THE EDDY TIE TRANSMISSION CORRIDOR?

A. Yes. The U.S. Department of Energy ("DOE") has identified the southeastern New Mexico Eddy Tie corridor as one of three National Interest Electric Transmission Corridors ("NIETC") for further development[1]. This NIETC designation process was undertaken by the DOE to identify transmission corridors where the lack of transmission infrastructure can harm electric customers with higher energy costs, energy scarcity during climate events and longer system restoration, and the development of new transmission would promote important national interests, including increased reliability and reduced costs to customers.

Q25. IS THERE A MAP IDENTIFYING THESE CORRIDORS?

A. Yes. The following image is provided from the same energy.gov reference above. Note that the Eddy Tie corridor in conjunction with the planned Xcel 765kV transmission line correlates to the denoted DOE Southwestern Grid Connector Corridor.

[1] https://www.energy.gov/gdo/national-interest-electric-transmission-corridor-designation-process



Q26. HAS THE TRANSMISSION CONGESTION VALUE BEEN QUANTIFIED INDEPENDENT OF EPE'S ANALYSIS?

A. Yes. A Lawrence Berkeley National Laboratory report dated July 2024[2] quantified average transmission congestion values across multiple regions. The graphic below is from that report. The corridors between the Western and Eastern Interconnections were identified with the highest values with the exception of the ERCOT to Southwest corridor denoted at $61/MWh. The Eddy Tie corridor was quantified at $43/MWh. This demonstrates the beneficial energy market differentials that exist on either side of the Eddy Tie due to the limited transmission capacity.

[2] https://eta-publications.lbl.gov/sites/default/files/lbnl-transmissionvalue-techbrief-2023update-20230710_0.pdf

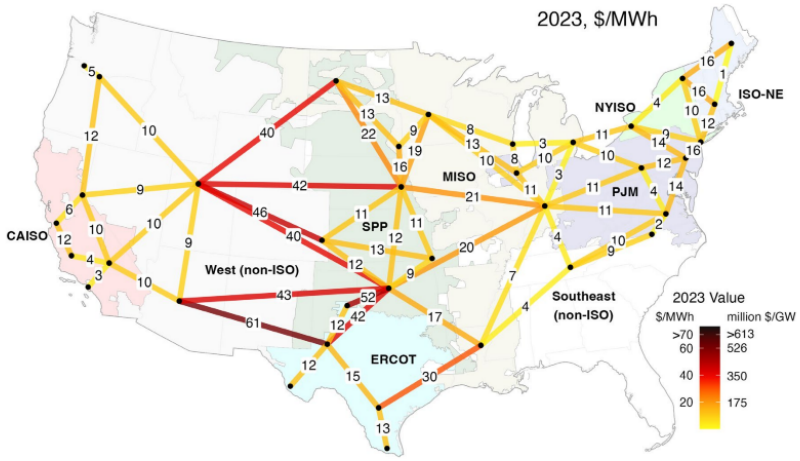


Figure 1. *2023 transmission value across a set of selected links. Transmission value was relatively high for links that cross between two of the three grid interconnection regions (the Western Interconnection includes CAISO and much of the Non-Iso West, the Texas Interconnection includes ERCOT, and the Eastern Interconnection includes the remaining regions shown). Also, a number of links that cross between different system operators within the same interconnection region saw relatively high transmission value. Note: at a GW of new transmission capacity, these values would likely be reduced by 10 – 30% due to market depth constraints as discussed in the text.*

Q27. HAS EPE ESTIMATED THE EXPECTED FUEL AND PURCHASED POWER BENEFITS OF THESE MARKET OPPORTUNITIES?

A. Yes. EPE witness Hawkins provides these results in his direct testimony.

Q28. DID EPE PURSUE ANY OF THE PAST DOE GRANT FUNDING OPPORTUNITIES?

A. Yes. In 2024, EPE applied for the DOE's Grid Resiliency and Innovative Partnership ("GRIP") grant opportunity per Funding Opportunity Announcement Number DE-FOA-0003195. EPE applied under Topic Area 2: Smart Grid Grants, which specifically called out HVDC interests. EPE applied for a 300 MW HVDC because one of the DOE's goals for the GRIP program was to increase capacity to

150 percent of existing facilities. However, EPE was not awarded the DOE GRIP grant.

Q29. DOES EPE PLAN TO PURSUE ANY OF THE RECENT DOE GRANT FUNDING OPPORTUNITIES AVAILABLE IN 2026?

A. Yes. EPE has submitted a concept paper in the current DOE Grid Resiliency and Innovative Partnership ("GRIP") grant opportunity per Funding Opportunity Announcement Number DE-FOA-0003580. EPE intends to apply under Topic Area 1: Grid Resilience. EPE will again apply for a 300 MW HVDC because one of the goals of the DOE is again to increase capacity to 150 percent of existing facilities. If awarded, the grant funding is capped at $100M, which would cover the cost of the additional 100 MW capacity and would likely offset a subset of the estimated costs in this CCN filing. More importantly, it would increase the net benefit to customers by allowing a greater amount of transfer capacity and increase fuel and purchased power cost benefits.

VI. RELIABILITY BENEFITS OF THE REPLACEMENT OF THE EDDY TIE

Q30. PLEASE DESCRIBE WHAT IS MEANT BY RELIABILITY WITH REGARD TO AN ELECTRIC UTILITY SYSTEM.

A. Reliability at the bulk electric system level entails attaining sufficient energy resources to meet forecasted load and the ability to deliver that power via the

transmission system to the various load pockets. It encompasses maintaining the capability of the transmission system to move power to load and sufficient reserve margins to meet the industry standard of meeting one loss of load event in ten years,[3] while also satisfying federal reliability requirements that govern how the transmission system must withstand the loss of facilities under various conditions.

Q31. DOES THE EXISTING EDDY TIE PROVIDE RELIABILITY BENEFITS?

A. Yes, it does. But as discussed by EPE witness Hawkins in his direct testimony, those benefits are greatly diminished by the condition of the existing Eddy Tie.

Q32. WILL THE PROPOSED PROJECT PROVIDE ADDITIONAL RELIABILITY BENEFITS?

A. Yes. First, the replacement project would restore the capacity of the Eddy Tie to the full 200 MW capacity on a consistent basis. As EPE witness Trejo explains in his testimony, the age of the existing Eddy Tie has significantly diminished its reliable capacity. Secondly, the technology's reactive power capabilities and ancillary services will also provide greater grid resiliency via voltage stability, as also explained in more detail by Mr. Trejo. Furthermore, with the ability to quickly change flows and even direction of flow, the Project can assist in responsiveness to

[3] EPE is in a transition to adopting the one loss of load in ten years standard by 2030 per its Commission-accepted Integrated Resource Plan.

address reliability challenges from forced outages. For example, if there were an unplanned loss of one of EPE's transmission lines to the west, the Eddy Tie could be utilized to import power from the Eastern Interconnection on short notice if power is acquired. EPE witness Hawkins provides additional testimony on the reliability benefits in his direct testimony.

Q33. WILL THE PROPOSED EDDY TIE REPLACEMENT HELP PROMOTE THE DEVELOPMENT OF ADDITIONAL ENERGY RESOURCES?

A. The new Eddy Tie, given its reliability, will allow for firm transfer capability and will provide an option for EPE to source energy resources from the eastern side of the Tie. Additionally, resources on the western side of the tie could also be sourced by users in the east. Given the current state of the existing Eddy Tie, EPE has not sourced resources to the east of the tie on a firm long-term basis, because those resources would be repeatedly stranded when the tie goes down. The current non-firm-only status of the tie will be restored to a state capable of supporting firm service with the new tie.

Q34. WILL THE PROPOSED EDDY TIE REPLACEMENT HAVE BENEFITS RELATED TO OPTIMIZED DISPATCH AND USE OF RESOURCES?

A. Yes. EPE's fuel and purchased power cost impact is presented by EPE witness Hawkins and shows the estimated cost savings. This was also corroborated by

consulting firm E3, whom we contracted to perform an analysis using its energy market forecast. The E3 study as presented by Mr. Hawkins also estimated a fuel and purchased power cost savings.

VII. NET PUBLIC BENEFIT

Q35. IS THERE A METHODOLOGY FOR ASSESSING THE NET BENEFITS OF AN HVDC TIE BETWEEN TWO MARKETS SUCH AS THE EDDY TIE?

A. Yes. It is first necessary to perform a production cost modelling run with a software system such as Plexxos. A production cost model selects an optimal generation resource dispatch to quantify the estimated fuel and purchased power cost over a multiple year horizon. In order to assess the value of an HVDC tie, the model is run with two scenarios, with and without the Eddy Tie. This quantifies the difference in fuel and purchased power cost between the two scenarios. EPE used this methodology to assess the net benefit of the replacement of the Eddy Tie.

Q36. WHAT WERE THE RESULTS OF THE PRODUCTION COST RUN?

A. As EPE witness Hawkins describes in his direct testimony, the analysis demonstrates that the replacement of the Eddy Tie will result in an annual cost savings in fuel and purchased power.

Q37. WHAT IS THE NEXT STEP OF THE ANALYSIS?

A. Second, an annual revenue requirement is calculated to quantify the cost impact to customers for the capital investment needed for the replacement Eddy Tie. The revenue requirement includes return of investment, return on equity and operating expenses of the replacement Eddy Tie. The net benefit analysis then compares the revenue requirement to the annual cost savings.

Q38. DOES THE REPLACEMENT OF THE EDDY TIE RESULT IN A NET BENEFIT TO CUSTOMERS?

A. Yes. The replacement of the Eddy Tie will result in $128M Net Present Value savings to customers over the 40-year life of the Eddy Tie. A project's benefit can also be quantified in terms of the Benefit Cost Ratio ("BCR"), which is calculated as cost savings divided by the revenue requirement. A BCR value of 1.0 would indicate breakeven or a net zero impact. Any value above 1.0 indicates a benefit to customers. The Eddy Tie Project results in a BCR of 1.38, which is a robust result.

VIII. EVALUATION OF ALTERNATIVES

Q39. ARE THERE ANY ALTERNATIVES TO THE PROPOSED PROJECT THAT WOULD PROVIDE THE SAME ACCESS TO POWER FROM THE EASTERN INTERCONNECTION FOR FUEL AND PURCHASED POWER BENEFITS AS WELL AS THE ADDED RELIABILITY BENEFITS?

A. No. The energy price differentials between the two markets are only accessible via a connection such as an HVDC tie as similarly discussed in the original 1982 CCN. For example, building an alternative transmission line to the west would access only the same trading hubs in the west to which already EPE has access. It would not offer the benefits of leveraging energy price differentials between the two interconnections.

Q40. WOULD AN ADDITIONAL TRANSMISSION TIE TO THE WEST OFFER THE SAME RELIABILITY BENEFIT DURING ENERGY SCARCITY EVENTS IN THE WEST?

A. No. An additional transmission tie line to the west is not as likely to address energy scarcity events in the Western Interconnection because that transmission line could only reach western resources, and western import capability into the EPE service territory is limited. With the proposed new tie's ability to access resources to the east, and with the EPE service territory having the benefit of being right on the border between the Western and Eastern Interconnections, there is greater likelihood that resources to the east could be secured and moved across the new tie to address conditions of energy scarcity in EPE's service territory.

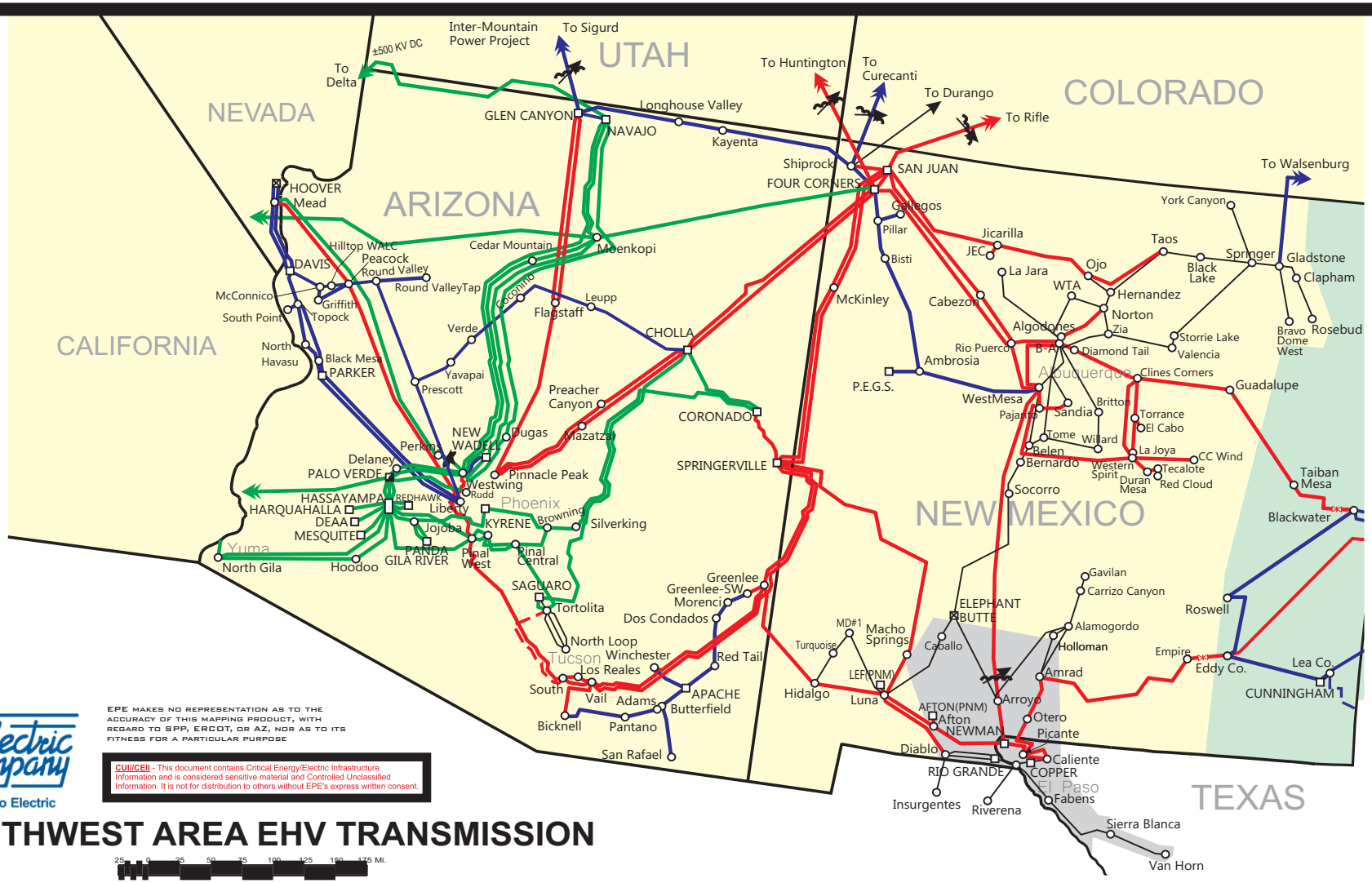
Q41. ARE THERE ANY ALTERNATIVE TECHNOLOGY OPTIONS FOR CONNECTING TO THE EASTERN INTERCONNECTION BESIDES AN HVDC TIE?

A. Yes, but they are not commercially proven. EPE witness Trejo describes this further in his testimony.

IX. CONCLUSION

Q42. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes, it does.



The Electric Company
El Paso Electric

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SOUTHWEST AREA EHV TRANSMISSION

25 0 25 50 75 100 125 150 175 Mi.

- FOSSIL FUELED ELECTRIC POWER PLANT
- HYDRO-ELECTRIC POWER PLANT
- NUCLEAR-ELECTRIC POWER PLANT
- MAJOR SUBSTATION
- AC-DC-AC TIE FACILITY
- 500 KV & OVER TRANSMISSION LINES
- 345 KV TRANSMISSION LINES
- 230 KV TRANSMISSION LINES
- 115-161 KV TRANSMISSION LINES
- TRANSMISSION LINE-PROPOSED

- EL PASO ELECTRIC SERVICE TERRITORY
- WESTERN ELECTRICITY COORDINATING COUNCIL
- SOUTHWEST POWER POOL
- ELECTRIC RELIABILITY COUNCIL OF TEXAS

SOURCE: SYSTEM INTERCONNECTIONS, C. Corral 05/09/24

Discount Rate	6.88%
Escalation	2.50%

40-Years	Nominal ($M)	NPV ($M)		
Gross System Cost Savings	$ (2,445.60)	$ (463.62)		
Revenue Requirements for Eddy Tie	$ 1,031.42	$ 335.66	**1.38123469**	**Benefit Cost Ratio**
Net System Cost Savings	$ (1,414.18)	**$ (127.96)**		

Total System Cost Comparison from PLEXOS (2026-2035)	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**	**Total**
Eddy Tie Expires 2030	$ 242.61	$ 341.66	$ 515.92	$ 861.50	$ 877.17	$ 908.51	$ 961.53	$ 985.50	$ 1,070.11	$ 1,151.82	$ 10,554.35
Eddy Tie Extend 2030	$ 242.62	$ 341.59	$ 515.97	$ 861.81	$ 854.07	$ 886.21	$ 941.58	$ 961.49	$ 1,041.09	$ 1,125.53	$ 10,326.36
Nominal Gross System Cost Savings	**$ 0.01**	**$ (0.07)**	**$ 0.05**	**$ 0.31**	**$ (23.11)**	**$ (22.31)**	**$ (19.95)**	**$ (24.01)**	**$ (29.03)**	**$ (26.29)**	**$ (227.99)**
Nominal Revenue Requirements for Eddy Tie Rebuild	$ -	$ -	$ -	$ -	$ 43.95	$ 42.95	$ 41.64	$ 40.40	$ 39.22	$ 38.10	$ 246.26
Nominal Net System Cost Savings	**$ 0.01**	**$ (0.07)**	**$ 0.05**	**$ 0.31**	**$ 20.84**	**$ 20.64**	**$ 21.70**	**$ 16.39**	**$ 10.20**	**$ 11.81**	**$ 18.27**

Total System Cost Comparison Projected (2046-2065)	**2046**	**2047**	**2048**	**2049**	**2050**	**2051**	**2052**	**2053**	**2054**	**2055**	**Total**
Project System Cost Savings	$ (57.31)	$ (58.74)	$ (60.21)	$ (61.71)	$ (63.26)	$ (64.84)	$ (66.46)	$ (68.12)	$ (69.82)	$ (71.57)	$ (641.44)
Nominal Gross System Cost Savings	**$ (57.31)**	**$ (58.74)**	**$ (60.21)**	**$ (61.71)**	**$ (63.26)**	**$ (64.84)**	**$ (66.46)**	**$ (68.12)**	**$ (69.82)**	**$ (71.57)**	**$ (641.44)**
Nominal Revenue Requirements for Eddy Tie Rebuild	$ 26.67	$ 26.02	$ 25.37	$ 24.72	$ 24.07	$ 23.42	$ 22.78	$ 22.13	$ 21.49	$ 20.85	$ 235.47
Nominal Net System Cost Savings	**$ (30.64)**	**$ (32.72)**	**$ (34.84)**	**$ (36.99)**	**$ (39.18)**	**$ (41.41)**	**$ (43.68)**	**$ (45.99)**	**$ (48.34)**	**$ (50.72)**	**$ (405.97)**

Total System Cost Comparison Projected (2046-2065)	**2056**	**2057**	**2058**	**2059**	**2060**	**2061**	**2062**	**2063**	**2064**	**2065**	**Total**
Project System Cost Savings	$ (73.36)	$ (75.19)	$ (77.07)	$ (79.00)	$ (80.97)	$ (83.00)	$ (85.07)	$ (87.20)	$ (89.38)	$ (91.62)	$ (822.85)
Nominal Gross System Cost Savings	**$ (73.36)**	**$ (75.19)**	**$ (77.07)**	**$ (79.00)**	**$ (80.97)**	**$ (83.00)**	**$ (85.07)**	**$ (87.20)**	**$ (89.38)**	**$ (91.62)**	**$ (822.85)**
Nominal Revenue Requirements for Eddy Tie Rebuild	$ 20.20	$ 19.56	$ 18.92	$ 18.28	$ 17.65	$ 17.01	$ 16.38	$ 15.74	$ 15.11	$ 14.48	$ 173.33
Nominal Net System Cost Savings	**$ (53.16)**	**$ (55.63)**	**$ (58.15)**	**$ (60.72)**	**$ (63.33)**	**$ (65.99)**	**$ (68.70)**	**$ (71.46)**	**$ (74.27)**	**$ (77.13)**	**$ (649.52)**

Total System Cost Comparison Projected (2046-2065)	**2066**	**2067**	**2068**	**2069**	**2070**	**2071**	**2072**	**2073**	**2074**	**2075**	**Total**
Project System Cost Savings	$ (93.91)	$ (96.25)	$ (98.66)	$ (101.13)	$ -	$ -	$ -	$ -	$ -	$ -	$ (389.95)
Nominal Gross System Cost Savings	**$ (93.91)**	**$ (96.25)**	**$ (98.66)**	**$ (101.13)**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ (389.95)**
Nominal Revenue Requirements for Eddy Tie Rebuild	$ 13.85	$ 13.22	$ 12.60	$ 11.97	$ -	$ -	$ -	$ -	$ -	$ -	$ 51.65
Nominal Net System Cost Savings	**$ (80.05)**	**$ (83.03)**	**$ (86.06)**	**$ (89.15)**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ (338.30)**

Total System Costs ($ million)

	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045
Gas - CC	$ 98	$ 135	$ 142	$ 160	$ 158	$ 166	$ 83	$ 87	$ 92	$ 87	$ 90	$ 94	$ 98	$ 102	$ 110	$ 114	$ 122	$ 124	$ 131	$ 137
Gas - ST	$ 37	$ 35	$ 38	$ 45	$ 42	$ 41	$ 42	$ 44	$ 4	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Nuclear	$ 139	$ 141	$ 147	$ 154	$ 158	$ 160	$ 162	$ 165	$ 167	$ 170	$ 173	$ 175	$ 177	$ 180	$ 184	$ 186	$ 189	$ 192	$ 196	$ 199
Geothermal	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Wind	$ -	$ -	$ -	$ -	$ -	$ -	$ 23	$ 37	$ 65	$ 103	$ 114	$ 114	$ 114	$ 114	$ 114	$ 114	$ 114	$ 114	$ 114	$ 114
Gas - CT	$ 80	$ 105	$ 137	$ 446	$ 491	$ 511	$ 499	$ 498	$ 511	$ 508	$ 525	$ 558	$ 594	$ 621	$ 676	$ 712	$ 748	$ 755	$ 792	$ 839
Paired Solar	$ (8)	$ (17)	$ 2	$ (24)	$ (33)	$ (33)	$ (33)	$ (34)	$ (37)	$ (37)	$ (38)	$ (20)	$ (9)	$ 3	$ 37	$ 37	$ 37	$ 37	$ 37	$ 37
Interconnection	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Standalone Solar	$ -	$ -	$ -	$ -	$ -	$ -	$ 134	$ 142	$ 168	$ 196	$ 207	$ 216	$ 217	$ 240	$ 247	$ 247	$ 247	$ 247	$ 247	$ 247
Energy Market	$ (104)	$ (96)	$ (57)	$ (25)	$ (46)	$ (42)	$ (57)	$ (61)	$ (49)	$ (45)	$ (43)	$ (35)	$ (31)	$ (32)	$ (56)	$ (46)	$ (28)	$ 5	$ 32	$ 38
Paired Battery	$ 1	$ 1	$ 51	$ 50	$ 50	$ 50	$ 51	$ 51	$ 51	$ 51	$ 51	$ 51	$ 51	$ 51	$ 51	$ 51	$ 51	$ 51	$ 51	$ 51
Standalone Battery	$ -	$ 37	$ 57	$ 56	$ 56	$ 56	$ 57	$ 56	$ 97	$ 118	$ 118	$ 118	$ 118	$ 118	$ 118	$ 118	$ 118	$ 118	$ 118	$ 118
Demand Response	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
HVDC	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Transmission Upgrades	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total Net Cost ($ million)	$ 243	$ 342	$ 516	$ 862	$ 877	$ 909	$ 962	$ 985	$ 1,070	$ 1,152	$ 1,199	$ 1,271	$ 1,331	$ 1,399	$ 1,482	$ 1,534	$ 1,600	$ 1,644	$ 1,718	$ 1,781
Total NPV ($ million) per year	$ 227	$ 299	$ 423	$ 660	$ 629	$ 610	$ 604	$ 579	$ 588	$ 592	$ 577	$ 572	$ 560	$ 551	$ 546	$ 529	$ 516	$ 497	$ 486	$ 471
Total NPV ($ million) - Cumulative	$ 227	$ 526	$ 949	$ 1,609	$ 2,238	$ 2,847	$ 3,451	$ 4,030	$ 4,618	$ 5,210	$ 5,787	$ 6,359	$ 6,919	$ 7,470	$ 8,017	$ 8,546	$ 9,062	$ 9,559	$ 10,044	$ 10,515

Total System Costs ($ million)

	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045
Gas - CC	$ 98	$ 135	$ 142	$ 160	$ 157	$ 165	$ 84	$ 86	$ 91	$ 84	$ 88	$ 92	$ 95	$ 99	$ 108	$ 109	$ 115	$ 117	$ 125	$ 130
Gas - ST	$ 37	$ 35	$ 38	$ 45	$ 39	$ 41	$ 40	$ 42	$ 4	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Nuclear	$ 139	$ 141	$ 147	$ 154	$ 158	$ 160	$ 162	$ 165	$ 167	$ 170	$ 173	$ 175	$ 177	$ 180	$ 184	$ 186	$ 189	$ 192	$ 196	$ 199
Geothermal	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Wind	$ -	$ -	$ -	$ -	$ -	$ -	$ 12	$ 28	$ 75	$ 106	$ 114	$ 114	$ 114	$ 114	$ 114	$ 114	$ 114	$ 114	$ 114	$ 114
Gas - CT	$ 80	$ 105	$ 137	$ 446	$ 482	$ 499	$ 493	$ 493	$ 493	$ 487	$ 496	$ 536	$ 567	$ 603	$ 657	$ 689	$ 729	$ 723	$ 751	$ 791
Paired Solar	$ (8)	$ (17)	$ 2	$ (24)	$ (33)	$ (33)	$ (33)	$ (34)	$ (37)	$ (37)	$ (38)	$ (20)	$ (9)	$ 3	$ 37	$ 37	$ 37	$ 37	$ 37	$ 37
Interconnection	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Standalone Solar	$ -	$ -	$ -	$ -	$ -	$ -	$ 164	$ 167	$ 192	$ 226	$ 236	$ 242	$ 242	$ 242	$ 242	$ 242	$ 242	$ 242	$ 242	$ 242
Energy Market	$ (104)	$ (96)	$ (57)	$ (25)	$ (55)	$ (52)	$ (88)	$ (93)	$ (82)	$ (80)	$ (74)	$ (71)	$ (58)	$ (54)	$ (83)	$ (60)	$ (48)	$ (4)	$ 33	$ 43
Paired Battery	$ 1	$ 1	$ 51	$ 50	$ 50	$ 50	$ 51	$ 51	$ 51	$ 51	$ 51	$ 51	$ 51	$ 51	$ 51	$ 51	$ 51	$ 51	$ 51	$ 51
Standalone Battery	$ -	$ 37	$ 57	$ 56	$ 56	$ 56	$ 57	$ 56	$ 87	$ 118	$ 119	$ 118	$ 118	$ 118	$ 118	$ 118	$ 119	$ 118	$ 118	$ 118
Demand Response	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
HVDC	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Transmission Upgrades	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total Net Cost ($ million)	$ 243	$ 342	$ 516	$ 862	$ 854	$ 886	$ 942	$ 961	$ 1,041	$ 1,126	$ 1,165	$ 1,238	$ 1,298	$ 1,358	$ 1,430	$ 1,487	$ 1,550	$ 1,592	$ 1,668	$ 1,725
Total NPV ($ million) per year	$ 227	$ 299	$ 423	$ 660	$ 612	$ 595	$ 591	$ 565	$ 572	$ 579	$ 560	$ 557	$ 547	$ 535	$ 527	$ 513	$ 500	$ 481	$ 471	$ 456
Total NPV ($ million) - Cumulative	$ 227	$ 526	$ 949	$ 1,609	$ 2,222	$ 2,816	$ 3,407	$ 3,972	$ 4,544	$ 5,123	$ 5,683	$ 6,241	$ 6,787	$ 7,322	$ 7,849	$ 8,362	$ 8,863	$ 9,343	$ 9,815	$ 10,271

BEFORE THE NEW MEXICO PUBLIC REGULATION COMMISSION

IN THE MATTER OF EL PASO ELECTRIC COMPANY'S APPLICATION FOR A CERTIFICATE OF PUBLIC CONVENIENCE AND NECESSITY FOR A REPLACEMENT 200 MW EDDY HIGH VOLTAGE DIRECT CURRENT TIE	)	**Case No. 26-00___**
EL PASO ELECTRIC COMPANY, Applicant	)	

DECLARATION OF OMAR A. GALLEGOS IN SUPPORT OF THE FOREGOING DIRECT TESTIMONY OF EL PASO ELECTRIC COMPANY'S APPLICATION FOR A CERTIFICATE OF PUBLIC CONVENIENCE AND NECESSITY FOR A REPLACEMENT 200 MW EDDY HIGH VOLTAGE DIRECT CURRENT TIE

I ***Omar A. Gallegos***, pursuant to Rule 1-011 NMRA, state as follows:

1. I affirm in writing under penalty of perjury under the laws of the State of New Mexico that the following statements are true and correct.

2. I am over 18 years of age and have personal knowledge of the facts stated herein. I am employed by El Paso Electric Company ("EPE" or "the Company") as *Vice President of System Planning and Construction.*

3. The foregoing Direct Testimony of Omar A. Gallegos, together with all exhibits sponsored therein and attached thereto, is true and accurate based on my knowledge and belief.

4. I submit this Declaration, based upon my personal knowledge and upon information and belief, in support of EPE's ***Application for a Certificate of Public Convenience and Necessity for a Replacement 200 MW Eddy High Voltage Direct Current Tie.***

FURTHER, DECLARANT SAYETH NAUGHT.

I declare under penalty of perjury that the foregoing is true and correct.

Executed on April 13, 2026.

/s/ *Omar A. Gallegos*

OMAR A. GALLEGOS