CALIFORNIA ENERGY COMMISSION

STRATEGIC TRANSMISSION INVESTMENT PLAN

Prepared in Support of the 2009 Integrated Energy Policy Report Proceeding (09-IEP-1D)

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Abstract

This *2009 Strategic Transmission Investment Plan* describes the immediate actions that California must take to plan, permit, construct, operate, and maintain a cost-effective, reliable electric transmission system that is capable of responding to important policy challenges such as achieving significant greenhouse gas reduction and Renewables Portfolio Standard goals. This document, prepared in support of the *2009 Integrated Energy Policy Report*, examines California and western states initiatives, trends, and drivers that affect the successful integration of renewable generation. In particular, the California Renewable Energy Transmission Initiative has proven to be a successful model for integrating land use and environmental concerns with electrical path analyses, using a stakeholder-driven collaborative process. The report recommends that the Renewable Energy Transmission Initiative results be leveraged in the Western Renewable Energy Zone effort. The report recommends both short-term and long-term planning process changes that draw upon the Renewable Energy Transmission Initiative model as well as the recently formed California Transmission Planning Group. The Energy Commission used data collected throughout the 2009 Strategic Transmission Investment Plan process, including the Renewable Energy Transmission Initiative Phase 2A results, to analyze and make recommendations for prioritizing the development of transmission projects and transmission corridors for possible designation under the state's transmission corridor designation program. The report also addresses opportunities to enhance the value of the state's corridor designation program. Finally, the report explores a scenario-based approach to meeting long-term statewide transmission needs.

Keywords: Electric transmission, renewable energy, renewable generation, transmission planning, transmission corridor planning, transmission projects, Senate Bill 1059, Senate Bill 1565, Renewables Portfolio Standard, California Renewable Energy Transmission Initiative, California Transmission Planning Group, Solar Energy Programmatic Environmental Impact Statement, Executive Order No. S-14-08, Renewable Energy Action Team, transmission research for renewables integration, *Integrated Energy Policy Report*

Executive Summary

Achieving California's renewable energy goals and meeting the state's aggressive greenhouse gas emission reduction targets will require significant new transmission infrastructure to interconnect remote renewable generation to the transmission grid. In its most recent energy policy report, the *2008 Integrated Energy Policy Report Update*, the California Energy Commission assessed the major transmission barriers to achieving these goals. Most notable is the lack of a fully coordinated and effective statewide transmission planning process that includes broad stakeholder support and targets the most cost-effective and environmentally acceptable transmission additions and upgrades to access renewables. This joint Integrated Energy Policy Report (IEPR) and Siting Committees (Committees) *2009 Strategic Transmission Investment Plan (2009 Strategic Plan)* emphasizes the need for coordinated and effective statewide transmission planning and an effective way to resolve land use conflicts that emerge when permitting transmission lines.

Diverse and often conflicting demands on land use make it very challenging to both develop renewable energy power plants and their associated transmission lines and conserve habitat. Nevertheless, California is determined to decrease its carbon footprint and evolve its energy infrastructure. As California pursues its renewable goals, it faces perhaps the greatest development challenge California has ever seen.

Despite these challenges, California agencies are working diligently to collaborate, but cohesive, statewide transmission planning remains elusive. Current transmission planning efforts remain disjointed and uncoordinated. Furthermore, they do not adequately address future transmission infrastructure needs on a statewide basis. The lack of a guiding transmission plan will give rise to a suboptimal outcome – from both a cost and environmental perspective – and it will be too slow in meeting our greenhouse gas emissions reduction and renewable energy goals.

In addition, there is no single transmission planning process that addresses the state's complete transmission system/grid that has broad support and collaborates effectively with stakeholders. No existing transmission planning processes adequately consider transmission line routing and related land use and environmental implications, nor do they adequately considers long-term needs well beyond the 10-year time horizon. Unless these transmission planning problems are resolved, the transmission permitting processes will continue to be ineffective in helping to ensure needed transmission infrastructure is developed in California in a timely manner.

However, promising efforts are now underway to help correct these transmission planning shortcomings in the future.

The most significant development toward a formal statewide transmission plan for California has been the informal Renewable Energy Transmission Initiative (RETI) stakeholder collaborative. RETI has demonstrated that divergent stakeholder interests can work together to create a plan that can help advise and influence the transmission planning processes. The

Committees commend the many stakeholders that have committed their time and resources to the RETI process – educating each other and engaging in collective problem-solving.

The California Independent System Operator (California ISO), California Municipal Utilities Association (CMUA), Imperial Irrigation District (IID), City of Los Angeles Department of Water and Power (LADWP), Pacific Gas and Electric Company (PG&E), Southern California Edison Company (SCE), San Diego Gas & Electric Company (SDG&E), Sacramento Municipal Utility District (SMUD), and the Transmission Agency of Northern California (TANC) have made significant progress toward establishing a coordinated statewide utility transmission planning process by forming the California Transmission Planning Group (CTPG). Coordination among all electric utilities with the California ISO is critical to achieving a statewide transmission plan. If the CTPG's consolidated utility approach to future statewide transmission needs is successful, and if it fully considers broad stakeholder interests, it will be a cornerstone for a formal statewide transmission planning process.

Challenges to Achieving a Coordinated Statewide Strategic Transmission Plan

Transmission planning involves assessing several key aspects of the electrical system, including grid operation, electrical system reliability and congestion issues, and scenario options for meeting the state's climate and Renewable Portfolios Standard (RPS) goals, and then determining how to expand and upgrade the existing system to meet projected load growth. As indicated above, transmission planning is critical to future transmission infrastructure development and renewable energy development in California because it will assist in overcoming permitting process conflicts and issues.

The key to implementing a consolidated transmission planning process for California is to link existing transmission planning entities and activities together in a manner that emphasizes each entity's roles and responsibilities while building efficiencies and streamlining whenever possible. As articulated in Chapter 4, internal electric utility transmission planning, the California ISO annual transmission plan, the CTPG statewide plan, the Energy Commission's *Strategic Transmission Investment Plan* (*Strategic Plan*) and transmission corridor designation, and broad stakeholder participation as exemplified by RETI, are critical components that must work in concert toward achieving a fully coordinated statewide transmission plan.

The Committees suggest this transmission planning process for the state:

Step 1: Electric utilities undertake transmission planning for their individual service areas.

Step 2: The California ISO (via its annual planning results) identifies needed transmission projects (those necessary to meet reliability, reduce transmission congestion, and provide access to renewable generation).

Step 3: The CTPG considers the identified transmission projects and identifies potential common routing of transmission projects. The CTPG would work with parties to maximize those corridors and projects that would minimize redundancy, costs, land use impacts, and environmental impacts.

Step 4: The Energy Commission considers the results of the CTPG in its biennial Strategic Plan proceeding – a public forum where these transmission projects and corridors would be vetted and evaluated for conformance with state policies and objectives.

Step 5: The CPUC and publicly owned utility governing boards would give great weight to the Energy Commission *Strategic Plan's* findings in their permitting processes. A critical component of this proposed planning process is the integration of broad stakeholder interests under the California ISO annual planning process, the CTPG planning process, and the Energy Commission's biennial *Strategic Plan*. Additional stakeholder participation would occur in the corridor designation and permitting processes.

To avoid future transmission infrastructure development problems, it is imperative to have a concerted effort by transmission planning entities, including a willingness to approach transmission planning in a more coordinated manner conducive to broad stakeholder participation. The Committees make the following recommendations to ensure that short-term (10 years) and longer-term (30 years) planning is effective.

- The Energy Commission staff should work with the recently formed California Transmission Planning Group (CTPG) and California ISO in a concerted effort to establish a 10-year statewide transmission planning process that uses the Strategic Plan proceeding to vet the CTPG plan described in Chapter 4, with emphasis on broad stakeholder participation.
- The Energy Commission staff should work with the RETI stakeholders to establish a two-year cycle for updating the RETI conceptual transmission plan.
- The Energy Commission staff should solicit input from electric utilities and interested stakeholders and develop the scope, content, and process for a 30-year transmission plan for California as part of the 2011 Strategic Plan proceeding.
- The 30-year conceptual transmission planning process should be implemented in the 2011 Strategic Plan proceeding.
- The Energy Commission staff should work with the California ISO, California Public Utilities Commission (CPUC), and publicly owned utilities (POUs) on a simplified need assessment process that fosters the use of common assumptions and streamlined decisions.

California Transmission Initiatives, Trends, and Drivers

California's three primary energy agencies (the Energy Commission, CPUC, and California ISO) have produced numerous of accomplishments relating to transmission planning and permitting (either completed or in progress) since the *2007 Strategic Transmission Investment Plan* and the *2008 Integrated Energy Policy Report Update* were published. The CPUC, Energy Commission, and California ISO formed RETI in September 2007 and were quickly joined by Sacramento Municipal Utility District, the Northern California Power Agency, and the Southern California Public Power Authority. RETI is an informal California stakeholder collaborative process charged with developing a conceptual plan for expanding the state's electric transmission grid to provide access to renewable energy resource areas necessary and meet state energy goals. RETI released its Phase 2A conceptual transmission plan in August 2009, which is designed to meet the goal of obtaining 33 percent of the state's electricity from renewable resources by 2020. The plan was created with valuable input from an engaged Stakeholder Steering Committee composed of representatives of environmental groups; renewable developers; public and investor-owned utilities; state, federal, and local governments; Native American tribes; and consumers.

The Energy Commission and the CPUC have also been given new responsibilities with Executive Order S-14-08 (November 2008), which establishes a Renewables Portfolio Standard (RPS) target for California that directs all retail sellers of electricity to serve 33 percent of their load with renewable energy by 2020. The order also directs state government agencies "to take all appropriate actions to implement this target in all regulatory proceedings, including siting, permitting, and procurement for renewable energy power plants and transmission lines." The order and its associated memoranda of understanding with several state and federal agencies establish the joint state-federal Renewable Energy Action Team.

On September 15, 2009, Governor Schwarzenegger signed Executive Order S-21-09, which directs the California Air Resources Board (ARB), by July 31, 2010, to adopt a regulation consistent with the 33 percent renewable energy target established in Executive Order S-14-08 The executive order also directs the Energy Commission and the CPUC to work with the ARB to ensure that this regulation encourages that all renewable energy sources build on the RPS program and oversees all California load-serving entities in their efforts. It states that the ARB may delegate to the Energy Commission and the CPUC any policy development or program implementation responsibilities that would reduce duplication and improve consistency with other energy programs such as demand response, energy efficiency, and energy storage. Furthermore, it orders the ARB to establish the highest priority for those resources that provide the greatest environmental benefits with the least environmental costs and impacts on public health that can be developed most quickly and that support reliable, efficient, cost-effective electricity system operations, including resources and facilities located throughout the Western Interconnection. The Energy Commission's *2009 IEPR* contains additional information on activities relating to implementing this executive order.

As noted in the *2008 Integrated Energy Policy Report Update*, the primary barrier to increased development of renewable resources continues to be the lack of transmission to access these resources. Despite the implementation of these two executive orders, there is still a lack of coordination and lack of efficiency among these transmission-related planning processes. The Committees makes the following recommendations:

- The Energy Commission staff should actively participate in interagency proceedings at the CPUC and the California ISO that affect the planning and permitting of transmission projects needed to interconnect renewable generation. These include the California ISO stakeholder initiative to establish a new tariff category for renewable transmission projects to meet the 33 percent RPS goal and the CPUC Investigation and Rulemaking on Transmission for Renewable Resources.
- The Energy Commission should continue support for ongoing RETI-related activities, including the Coordinating Committee, Stakeholder Steering Committee, and working groups by providing appropriate personnel and contract resources.
- The Energy Commission staff should continue to support the Renewable Energy Action Team's mission to streamline and expedite the permitting processes for renewable energy projects, while conserving endangered species and natural communities at the ecosystem scale in the Mojave and Colorado Desert regions through the Desert Renewable Energy Conservation Plan.

Western Region Transmission Initiatives, Trends, and Drivers

California's transmission infrastructure is an intrinsic component of the high-voltage Western Interconnection, making the state both an essential participant and a partner in various regional and federal planning and permitting initiatives that will alter the way transmission planning and permitting takes place in the future. The majority of these efforts encourage centralized transmission planning at the regional level, supplemented by federal incentives and regulation. Developers of new transmission projects are also focused on the western United States, proposing more than 30 enhancements and new projects that could increase the transfer capacity in various sub-regions and across the interconnection to bring renewable energy resources to market. Chapter 3 summarizes several major initiatives of Western regional entities, federal agencies, and Congress, and concludes with recommendations emphasizing the need for enhanced collaboration among western states and the Western region.

In order to assure implementation of California's energy policies in the development of regional transmission planning, the Committees recommend the following:

- The Energy Commission should continue participation in and support for Western Interconnection transmission planning including representation on the Western Electricity Coordinating Council (WECC) Transmission Expansion Planning Policy Committee and related technical groups. The Energy Commission should also support participation in new entities formed under the U.S. Department of Energy's Funding Opportunity Announcement for regional transmission planning funding to WECC and the Western Governors' Association.
- The Energy Commission should continue participation in and support for the Western Renewable Energy Zone (WREZ) process to ensure consistency with RETI results for

both preferred renewable development areas as well as environmentally sensitive areas that should be avoided.

Statewide Transmission Corridor Planning

In 2006, the Legislature passed Senate Bill 1059 (Escutia and Morrow, Chapter 638, Statutes of 2006), which granted the Energy Commission the authority to designate transmission corridors to help assure that California can develop a robust and reliable high-voltage transmission system that will meet future electricity needs, reduce congestion costs, integrate renewable resources into the state's energy mix, and meet the state's critical energy and environmental policy goals. The transmission corridor designation process is to promote public involvement in the transmission planning processes and to link transmission planning processes with transmission permitting to assure the timely permitting and construction of needed transmission facilities.

Although the utilities have no current plans for submitting transmission corridor designation applications to the Energy Commission, they all agreed that early outreach now to local governments and other land use agencies is an important part of the transmission planning process. Early outreach will inform land use agencies of the state's needs for expanding its transmission system to meet its renewable energy goals and other energy policy objectives, discuss the nature of the transmission corridor designation process, identify the critical roles that the land use have in identifying and resolving environmental and land use issues, and identify and evaluate potential corridor alternatives.

Some initiatives are already underway to aid in the early identification and resolution or to avoid land use and environmental constraints to promote timely development of California's renewable generation resources and associated transmission lines. The RETI collaborative process has identified and prioritized preferred renewable resource development areas and associated transmission line links to deliver renewable power to load centers.

Since the Energy Commission's transmission corridor designation program is new, California's electric investor-owned utilities have no assurance they will be allowed to recover – through electric rates – the cost of land purchased within an Energy Commission-designated corridor. This regulatory uncertainty is a barrier to implementing the program. Another barrier is the conflict between the implementing regulations of the designation process "…to identify appropriate corridors for transmission planning, taking into consideration the state's principles of encouraging the use of existing rights-of-way, the expansion of existing rights-of-way, and the creation of new rights-of-way in that order" vs. the WECC transmission planning reliability criteria (TPL-[001 thru 004]-WECC-1-CR-System Performance Criteria) (Common Corridor Criteria), which is more stringent than the standard adopted by the North American Electric Reliability Corporation and places tighter restrictions on placing multiple high-voltage lines in existing or expanded rights-of-way. The Committees therefore make the following recommendations in Chapter 5 to maximize the effectiveness and pro-activeness of the corridor designation program.

- The Energy Commission staff should continue early outreach to local governments and other land use agencies to inform them of the need for and the planning initiatives that are underway to promote the development of renewable generation. The Energy Commission staff should encourage timely participation by land use planning agencies in planning for and designating transmission corridors to help meet the state's energy policy objectives.
- The Energy Commission staff should initiate outreach with the Federal Energy Regulatory Commission (FERC) to settle the uncertainties about whether the FERC would allow "ratebasing" of land assets acquired within Energy Commission-designated transmission corridors.
- The Energy Commission staff should participate in the WECC Reliability Subcommittee's evaluation of WECC's Reliability Criteria regarding the separation of adjacent transmission lines in a corridor to ensure that environmental issues are appropriately considered and the issue is resolved promptly.

Prioritizing the Development of Renewable Transmission Projects and Corridors for Designation

California has many options to improve transmission infrastructure within the state. The challenge regulators face is identifying the best mix of transmission projects to ensure a reliable network, improve access to renewable generation, and minimize consumer electricity prices and environmental impacts. In its *2005 Strategic Transmission Investment Plan*, the Energy Commission highlighted the need for new transmission to reduce congestion costs borne by California ratepayers. The Energy Commission's *2007 Strategic Plan* examined the need for major transmission projects over 10 years, through 2017, and highlighted transmission required to help achieve California's RPS and greenhouse gas reduction goals. This year (2009) is a transitional year for transmission development in California, with much of the planning focused on meeting renewable targets and greenhouse gas reduction goals. In this *2009 Strategic Plan* the joint Committees continue to support the projects identified in previous Strategic Plans and see the next step as a short-term, 10-year transmission plan focused on the statewide renewable energy goals and the identification of transmission projects that will aid the attainment of the RPS targets.

The Committees are using the *RETI Phase 2A Final Report* described earlier to develop the next step for California and identify transmission projects that will build a robust transmission network in conjunction with projects previously supported in the *2005* and *2007 Strategic Plans*. The *RETI Phase 2A Final Report* makes several recommendations to support the development of transmission required to enable California to meet its renewable energy policy goals. It presents a conceptual transmission expansion plan containing 102 transmission line segments, to increase the capacity of the state's transmission grid to deliver renewable generation to load centers. Like a major highway system with rural roads, highways, interstates, and interchanges, the transmission grid consists of collector lines, delivery lines, foundations lines, and substations to connect them all. The Renewable Collector lines in the RETI conceptual transmission plan will collect energy from U.S. Bureau of Land Management (BLM) Solar Energy Zones, Desert Renewable Energy Conservation Plan generation development areas, and Competitive Renewable Energy Zones most likely to be developed; the energy will then be transferred to Renewable Foundation lines and from there by way of the Renewable Delivery lines to the load centers where the majority of the electricity will be used.

The Committees used the *RETI Phase 2A Final Report* as one of the data sources for prioritizing the transmission projects to interconnect renewables that are in the state's best interests. That report also forms the basis for the development of a draft method for identifying which of the RETI line segments should be considered for corridor designation. The Committees make the following recommendations in Chapter 6 to prioritize the development of renewable transmission projects and to promote a method for reaching consensus on RETI segments that should be considered for corridor designation.

- Prioritize transmission planning and permitting efforts for renewable generation at the California ISO, the CTPG, and the Energy Commission as follows, and work on overcoming barriers and finding solutions that would aid their development:
  - The first priority should be placed on those projects supported by the Energy Commission in the *2005* and *2007 Strategic Plans*:
    - Imperial Irrigation District (IID) Upgrades
    - Southern California Edison Company (SCE)Tehachapi Upgrades (Segment 1 – Antelope-Pardee; Segment 2 – Antelope-Vincent; Segment 3 – Antelope-Tehachapi; and Segments 4-11 – Tehachapi Renewable Transmission Project)
    - SCE Devers – Palo Verde 2 (the entire California-Arizona interconnection, as well as the California-only variation)
    - Los Angeles Department of Water and Power (LADWP) Tehachapi Upgrade (Barren Ridge Renewable Transmission Project)
    - Pacific Gas and Electric Company (PG&E) Central California Clean Energy Transmission Project (C3ETP)
    - San Diego Gas & Electric Company (SDG&E) Sunrise Powerlink Transmission Project
    - Lake Elsinore Advanced Pumped Storage (LEAPS) Project – Transmission Portion
    - Green Path North Coordinated Projects
  - The second priority should be the RETI Phase 2 projects that include the "no regrets" line segments that do not require new corridors, plus two additional projects (Gregg – Alpha Four and Tracy – Alpha Four) that do not meet these criteria but are needed

to complete a link to Northern California load centers. (Without these two lines the renewables would reach Fresno but not load centers in the Bay Area.)

    - Kramer – Lugo 500 kV
    - Lugo – Victorville #2 500 kV
    - Devers – Mira Loma #1 and #2 500 kV
    - Gregg – Alpha Four 500 kV
    - Tracy – Alpha Four 500 kV 1 & 2:
    - Devers – Valley #3 500 kV
    - Tesla – Newark 230 kV
    - Tracy – Livermore 230 kV

  - The third priority should be to begin outreach for those "no regrets" RETI segments that require new corridors and to begin developing phased solutions to interconnect specific renewable zones as generators commit to developing power plants.

- The Committees recommend that the permitting analysis for the Southern California Edison El Dorado – Ivanpah Transmission Project should proceed, as interconnecting proposed renewable projects to the planned Ivanpah Substation is critical to attainment of the state's near-term RPS goals. (This recommendation is not an endorsement of the Solar Partners' Ivanpah Solar Electric Generating System, which is currently being evaluated by the Energy Commission.)
- The Energy Commission staff should continue to coordinate with the RETI stakeholders group to incorporate RETI's new information in applying the method described in Chapter 6 to reach consensus on the appropriate transmission line segments that should be considered for corridor designation to promote renewable energy development.

Developing Long-Term Statewide Transmission Scenarios

Scenario planning could provide the vision needed to build a 30-year statewide transmission planning process. Using the RETI Phase 2A conceptual transmission plan results as a starting point staff developed three illustrative scenarios with a 40 percent RPS by 2030, 50 percent RPS by 2030, and 50 percent RPS by 2040. The staff then explored potential planning, siting and operational consequences and opportunities to gain insights on the potential new and existing transmission lines that could be required as California increases its RPS beyond 2020.

- The Committees recommend that the Energy Commission staff should identify and establish a method for the *2011 Strategic Plan* that uses scenarios in the development of a 30-year transmission plan for California, building upon the long-term planning process described in Chapter 4 as well as the analysis described in Chapter 7.

Summary of Highest-Priority Recommendations

Based upon the recommendations contained within each chapter and listed above, the Committees believe that the highest priorities for this Strategic Plan are the following:

- The Energy Commission staff should work with the recently formed California Transmission Planning Group (CTPG) and California ISO in a concerted effort to establish a 10-year statewide transmission planning process that uses the Strategic Plan proceeding to vet the CTPG plan described in Chapter 4, with emphasis on broad stakeholder participation.
- The Energy Commission staff should work with the California ISO, CPUC, and POUs on a simplified need assessment process that fosters the use of common assumptions and streamlined decisions.
- The Energy Commission staff should continue to support the Renewable Energy Action Team's mission to streamline and expedite the permitting processes for renewable energy projects, while conserving endangered species and natural communities at the ecosystem scale in the Mojave and Colorado Desert regions through the Desert Renewable Energy Conservation Plan.
- Prioritize transmission planning and permitting efforts for renewable generation at the California ISO, the California Transmission Planning Group, and the Energy Commission as outlined in Chapter 6; work on overcoming barriers and finding solutions that would aid their development.
- The Energy Commission should continue supporting ongoing RETI-related activities, including the Coordinating Committee, Stakeholder Steering Committee, and working groups by providing appropriate personnel and contract resources.
- The Energy Commission staff should continue to coordinate with the RETI stakeholders group to incorporate RETI's new information in applying the method described in Chapter 6 to reach consensus on the appropriate transmission line segments that should be considered for corridor designation to promote renewable energy development.

CHAPTER 1: Introduction

Purpose and Legislative Authority

In 2004, Senate Bill (SB) 1565 (Bowen, Chapter 692, Statutes of 2004) added the following section 25324 to the Public Resources Code:

> The [Energy] Commission, in consultation with the Public Utilities Commission, the California Independent System Operator, transmission owners, users, and consumers, shall adopt a strategic plan for the state's electric transmission grid using existing resources. The strategic plan shall identify and recommend actions required to implement investments needed to ensure reliability, relieve congestion, and meet future load growth in load and generation, including, but not limited to, renewable resources, energy efficiency, and other demand reduction measures.

With the adoption of SB 1565 the Legislature acknowledged the importance of the state's role in the transmission planning process and recognized the importance of an energy agency with statewide authority over all control areas and the need to balance reliability, cost, and environmental criteria. The *2005 Strategic Transmission Investment Plan (2005 Strategic Plan)* identified barriers to the development of an efficient and reliable bulk transmission system for California and made recommendations for addressing the barriers.

In further recognition of the importance of the state's role in transmission planning, the Legislature also passed Senate Bill 1059 (Escutia and Morrow, Chapter 638, Statutes of 2006). SB 1059 creates a link between transmission planning and permitting by authorizing the Energy Commission to designate transmission corridor zones (transmission corridors) on non-federal lands that will be available in the future to allow for the timely permitting of high-voltage transmission projects. A transmission corridor can be proposed for designation by the Energy Commission or by any person or entity planning to build an electric transmission line in the state. A corridor must be reviewed under the California Environmental Quality Act (CEQA). SB 1059 identifies the Energy Commission as the lead agency responsible for preparing an environmental assessment for transmission corridors proposed for designation. Additionally, any corridor proposed for designation must be consistent with the state's needs and objectives as identified in the latest adopted *Strategic Plan*.

The *2007 Strategic Plan* described the major immediate actions that California must take to develop and maintain a cost-effective, reliable transmission system that is also capable of responding to important policy challenges such as mitigating global climate change. The report noted that achievement of state greenhouse gas policy objectives by the electricity sector will depend to a large degree on the interconnection and integration of renewable resources into the state's transmission grid. The report, prepared in support of the *2007 Integrated Energy Policy Report*, described the state's transmission challenges and provides recommendations for overcoming them. The document also made recommendations regarding both in-state transmission corridor planning and in-state transmission projects.

This draft joint Integrated Energy Policy Report (IEPR) and Siting Committees (Committees) *2009 Strategic Plan* is a companion to the draft IEPR Committee *2009 Integrated Energy Policy Report*. Among other topics, the *2009 Integrated Energy Policy Report* describes the important system integration challenges California's electricity sector is facing in meeting its energy policy goals for increasing renewable energy, decreasing the use of once-through cooling in power plants, retiring aging power plants, reducing greenhouse gas emissions in the electricity sector, and modernizing the state's transmission system.

Report Organization

In addition to the Energy Commission, California Public Utilities Commission (CPUC), and California Independent System Operator (California ISO) activities and accomplishments described below, this chapter provides a "scorecard" of progress made on recommendations from the *2007 Strategic Transmission Investment Plan* (*2007 Strategic Plan*), as well as the *2008 Integrated Energy Policy Report Update* (*2008 IEPR Update*). Many of these agency activities are on-going and are therefore also described as current transmission-related trends and drivers in "Chapter 2: California Transmission Initiatives, Trends, and Drivers," and "Chapter 3: Western Region Transmission Initiatives, Trends, and Drivers."

Chapters 2 and 3 will provide the reader with the background and context needed to appreciate the number, content, and complexity of efforts being undertaken. Understanding these initiatives, trends, and drivers forms the basis for the Committees' policy discussions on overcoming transmission planning process challenges to achieving a coordinated statewide strategic transmission plan (Chapter 4), developing specific short-term, statewide strategic transmission priorities (Chapter 5), conducting statewide transmission corridor planning (Chapter 6), and developing and analyzing scenarios for a long-term statewide transmission plan for California (Chapter 7).

Chapter 3 describes western initiatives, trends, and drivers. With California's transmission infrastructure being an intrinsic component of the Western Interconnection (WI) high-voltage transmission system, California needs to be both a participant and a partner in regional and federal initiatives that are likely to alter the way states and the WI undertake transmission planning and permitting. The chapter summarizes trends and drivers reflected in the initiatives of major western regional entities, federal agencies, and Congress. In general, all of these seek to encourage and centralize transmission planning at regional levels, supplemented by federal incentives and regulation. The developers of new transmission are also focused on the western United States, proposing more than 30 enhancements and new projects that could increase the transfer capacity in various sub-regions and across the interconnection. The chapter concludes with discussion, observations, and recommendations that emphasize the need for enhanced collaboration among Western states, the region, and national initiatives.

Chapter 4 discusses the problems associated with how transmission planning is currently being carried out in California. In addition, this chapter addresses how existing planning can be restructured, reorganized, and consolidated to address the planning process problems identified. Chapter 4 also addresses how transmission planning, particularly at the electric utility level, can leverage the Energy Commission's Strategic Plan proceeding to vet statewide planning proposals with broad stakeholder interests in an open and public participation-friendly process. In addition, this chapter discusses the need for a longer-term transmission plan and proposes a 30-year planning process under the Strategic Plan proceeding to augment the normal 10-year planning process currently being undertaken by the electric utilities and the California ISO. It also emphasizes the value of the Renewable Energy Transmission Initiative (RETI) in supporting effective transmission planning.

Chapter 5 describes (1) the status of transmission corridor designation planning in California; (2) the objectives and structure of the transmission corridor designation process; and (3) issues that may prevent the effective use of the process. There was consensus expressed by electric utilities at the Committees' May 4, 2009, workshop on transmission planning on the importance of the transmission corridor designation process: that the process should be used as a scenario-based planning tool to address the uncertainties associated with long-term transmission infrastructure needs; and that the process should be used to streamline transmission line permitting within designated corridors through early public involvement, a programmatic evaluation of environmental and land use issues, and coordination with existing or proposed corridors on federal lands. Although none of California's electric utilities are currently planning to submit an application for transmission corridor designation to the Energy Commission, a number of them may do so in the future as the need arises for new rights-of-way to expand their transmission systems. Two major issues that may affect the viability of the transmission corridor designation process include the uncertainty of a utility's ability to recover the cost of land investments in designated corridors for siting future transmission lines; and the potential conflict between the state's transmission planning priorities and Western Electricity Coordinating Council's (WECC) reliability criteria, which restrict the placement of multiple transmission lines in a single corridor.

Chapter 6 focuses on prioritizing the development of short-term renewable transmission projects as well as corridors for designation in the longer term. The short-term transmission plan focuses on the identification of transmission projects that will aid the attainment of the state's renewable energy goals. The Committees relied on data from a variety of sources, including transmission submittals, the California ISO transmission plan, and the *RETI Phase 2A Final Report*. In particular, the *RETI Phase 2A Final Report* developed a conceptual transmission plan that, if completely built out, could provide the transmission infrastructure needed to fulfill California's 33 percent renewable energy target through 2030. The *RETI Phase 2AFinal Report* is used as one of the data sources for prioritizing the transmission projects to interconnect renewables that are in the state's best interests. It also forms the basis for the development of a draft method for identifying which of the RETI transmission line segments should be considered for corridor designation.

Chapter 7 describes a method that uses a scenarios-based approach to develop a long-term 30-year transmission plan for California as proposed in Chapter 4. The scenario-based planning process builds on the RETI conceptual transmission plan, the California ISO annual transmission plan, and California Transmission Planning Group planning concerning attainment of the 33 percent RPS in 2020, as a starting point for the analysis of a longer-term, higher percentage renewables future. It proposes an analysis of incremental transmission needs for three long-term scenarios: 40 percent RPS in 2030; 50 percent RPS in 2030; and 50 percent RPS in 2040. The chapter explores potential planning, siting and operational consequences and opportunities with regard to new and existing transmission lines that could be required if California increases its RPS requirements beyond 2020.

Status of Key Recommendations From the *2007 Strategic Plan* and the *2008 IEPR Update*

The *2007 Strategic Plan* made a number of recommendations in the following areas[1]:

- Achieving state policy objectives by removing barriers to transmission for renewables integration.
- Improving in-state transmission corridor planning.
- Developing in-state transmission projects that provide significant benefits to California.
- Resolving issues relating to western regional transmission projects.

With the formation of RETI in September 2007, the CPUC, Energy Commission, and California ISO recognized the need to bring together renewable transmission and generation stakeholders in California to participate in a consensus-based process to identify, plan, and establish a rigorous analytical basis for regulatory approvals of the next major transmission projects needed to access renewable resources in California and adjacent areas. This critical link between transmission planning and transmission permitting must be made so that needed projects are planned for, have corridors set aside as necessary, and are permitted in a timely and effective manner that maximizes the use of existing infrastructure and rights-of-way, minimizes environmental impacts, and takes advantage of technological advances.

RETI is an informal collaborative, stakeholder-driven planning process that provides a mechanism for ensuring that land use and environmental issues are considered together with proposed electrical paths to access competitive renewable energy zones. Applying the RETI

[1] The complete list of recommendations is contained in the *2007 Strategic Plan* Executive Summary. See: *2007 Strategic Transmission Investment Plan*, pp. 1-9, California Energy Commission, Sacramento, CA, November 2007, Publication Number CEC-700-2007-018-CMF, http://www.energy.ca.gov/2007publications/CEC-700-2007-018/CEC-700-2007-018-CMF.PDF, posted November 15, 2007, accessed July 20, 2009.

results in a coordinated statewide planning process[2] is the most effective means for facilitating the implementation of new transmission because it helps to address the most common problem in the planning process (lack of consideration of land use and environmental issues when analyzing electrical paths) that adversely affects transmission permitting. This failure to propose, analyze, and gain consensus on "permittable" routing options at the planning stage has resulted in protracted and/or contentious licensing proceedings, or even project failure. Another key aspect of RETI is its inclusion of both investor-owned utilities (IOUs) and publicly owned utilities (POUs) in the process, thus ensuring the development of a true statewide plan for renewables interconnection.

RETI's accomplishments to date are encouraging, but it is not yet known if RETI will substantially influence formal transmission planning in California. Therefore, the success of RETI cannot be determined until the next cycle of transmission planning for California is complete, and the degree to which RETI influenced the outcome is evaluated.

In its *2008 Integrated Energy Policy Report Update* (*2008 IEPR Update*), the Energy Commission provided a "scorecard" on the state's progress on implementing transmission recommendations made in the *2007 Strategic Plan*, the *2005 Strategic Plan*, and the *2005 IEPR*.[3] The *2008 IEPR Update* noted that the state had made substantial progress toward implementing the following transmission-related recommendations:

- Develop a comprehensive planning process.
- Establish a statewide corridor planning process to designate corridors for future use.
- Work collaboratively with state, federal, local, and regional planning agencies, investor-owned utilities, publicly owned utilities, generators and developers, and the public.
- Participate in federal corridor planning.
- Implement changes to the California ISO tariff to encourage the construction of transmission for renewables.

In the *2008 IEPR Update*, the Energy Commission focused on five critical topics relating to California's energy systems that required immediate action. One of those topics is the physical, operational, and market changes necessary for California's electric system to support a

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[2] Although RETI was limited to bringing forward transmission projects to interconnect renewable generation, a coordinated statewide planning process must also consider projects needed for reliability purposes as well as for economic reasons.

[3] The transmission scorecard is contained in Chapter 6 of the *2008 IEPR Update*. See: *2008 Integrated Energy Policy Report Update*, pp. 109-112, California Energy Commission, Sacramento, CA, date, Publication Number CEC-100-2008-008-CMF, <http://www.energy.ca.gov/2008publications/CEC-100-2008-008/CEC-100-2008-008-CMF.PDF>, adopted November 20, 2008, accessed July 20, 2009.

minimum of 33 percent renewables by 2020. The report notes that the primary barrier to increased development of renewable resources continues to be the lack of transmission infrastructure to access renewable resources, particularly in remote areas of the state.

Using the *2007 Strategic Plan* analysis of renewable transmission barriers as a starting point, the Energy Commission staff held a workshop on July 23, 2008 at which the participants discussed transmission barriers for renewables and identified key issues for the *2009 Strategic Plan*, including two major transmission-related barriers to achieving the state's renewables goals. First, there is a need for mechanisms to remove barriers to joint transmission projects between POUs and IOUs. Second, with regard to transmission siting, the state must continue to actively address environmental, land use, and local public opposition issues by working closely with stakeholders. Drawing from the staff workshop as well as the *2007 Strategic Plan* and other resources, the *2008 IEPR Update* made several recommendations.[4] The status of each of these recommendations is described below.

Status of Key 2008 IEPR Update Recommendations

The Energy Commission should work collaboratively with IOUs and POUs in RETI Phase 2 to develop conceptual transmission plans that will inform the *2009 Strategic Plan* and use information gathered in the 2009 cycle to identify opportunities for joint project collaboration – The Energy Commission and its staff have provided, and continue to provide, substantial resources to the RETI effort. These include participating in the RETI Coordinating Committee, Stakeholder Steering Committee, Conceptual Planning Working Group, and Environmental Working Group, as well as providing the funding for, and contract management of, the RETI co-coordinators. The RETI Phase 2A results were discussed in detail at the May 4, 2009, and June 15, 2009, joint IEPR/Siting Committee workshops, and the Committees have considered these results in the development of this report.

The Energy Commission should use the *2009 Strategic Plan* as a forum to identify and evaluate regulatory or policy changes that would reduce both legal and market obstacles to joint projects development – The Committees are pleased to recognize the formation of the California Transmission Planning Group (CTPG) and the significant progress the CTPG appears to be making toward establishing a coordinated statewide utility transmission planning process. The Committees support the plans of the IOUs, POUs, and the California ISO to work together to avoid transmission duplication, optimize use of existing rights-of-way, reduce environmental impacts, and lower costs for consumers. Notwithstanding this progress, it is uncertain if the CTPG will be successful in implementing a true statewide planning process that will reflect broad stakeholder interests.

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[4] *2008 Integrated Energy Policy Report Update*, p. 28, California Energy Commission, Sacramento, California, Publication Number CEC-100-2008-008-CMF, <http://www.energy.ca.gov/2008publications/CEC-100-2008-008/CEC-100-2008-008-CMF.PDF>, adopted November 20, 2008, accessed July 20, 2009

For more information on the CTPG and the Committees' vision for the role of the CTPG in statewide transmission planning, see "Chapter 2: Current California Transmission-Related Initiatives, Trends, and Drivers" and "Chapter 4: Challenges to Achieving a Coordinated Statewide Strategic Transmission Plan."

The Energy Commission should work closely with stakeholders in RETI Phase 2 to ensure that land use and environmental concerns are evaluated and considered – The Energy Commission and its staff have provided, and continue to provide, substantial resources to the RETI Environmental Working Group (EWG) to ensure that land use and environmental concerns are evaluated and considered, in concert with stakeholders. The goal of the EWG is to identify those CREZs in which renewable energy development is prohibited or severely restricted by existing laws or policies, as well as those for which renewable energy development is expected to be least damaging to the environment.

The Energy Commission should re-establish ERPA funding to assist local governments with general plan transmission and energy elements that recognize the importance of statewide goals – The Energy Commission's Transportation Fuels Division, in cooperation with the Siting, Transmission and Environmental Protection Division, is preparing an updated *Energy Aware Planning Guide* for generation and transmission siting for use by local governments. The Transportation Fuels Division is also evaluating funding options for reactivating the Commission's Siting and Permit Assistance Program to provide grants to local governments, with Energy Commission oversight, for the development of energy elements or transmission line elements to promote the development of renewable energy resources.

Status of Key 2007 Recommended Projects of Statewide Significance

The Energy Commission has recommended 10 specific transmission projects of statewide significance. The *2005 Strategic Plan* recommended the following five projects: (1) Southern California Edison Company (SCE) Palo Verde-Devers No. 2 Transmission Project; (2) San Diego Gas & Electric Company (SDG&E) Sunrise Powerlink Transmission Project; (3) SCE Tehachapi Transmission Segments 1, 2, and 3; (4) Imperial Valley Transmission Upgrade; and (5) Trans Bay Cable Project. To this list the *2007 Strategic Plan* added the following five projects: (6) Pacific Gas and Electric Company (PG&E) Central California Clean Energy Transmission Project; (7) the transmission component of the Lake Elsinore Advanced Pumped Storage project (known as The Nevada Hydro Company Inc.'s (TNHC) Talega-Escondido/Valley-Serrano (TE/VS) 500 kilovolt (kV) Interconnect Project); (8) the Los Angeles Department of Water and Power (LADWP)/Imperial Irrigation District (IID)/Citizens Energy Green Path Coordinated Projects; (9) LADWP'S Tehachapi Project; and (10) SCE's Tehachapi Renewable Transmission Project.

For a more detailed description of these projects, please see Appendix C, "Summary of Projects Supported in 2005 and 2007 Strategic Transmission Investment Plans."

(1) SCE Palo Verde-Devers No. 2 Transmission Project

The original scope of the Palo Verde – Devers No. 2 (DPV2) included 225 miles of 500 kV transmission line between Arizona and California, and a 42-mile 230 kV transmission line between SCE's Devers and Valley substations in California. The CPUC approved the project in January 2007 (Decision No. 07-01-040), but the Arizona Corporations Commission denied the Arizona portion in June 2007. On May 14, 2008, SCE filed a petition to modify the original Certificate of Public Convenience and Necessity (CPCN) request, which included a request for authorization to construct DPV2 facilities in California to allow SCE to access potential new renewable and conventional gas-fired generation in the Blythe, California, area to help enable California to meet its renewable energy goals. As part of this modification to the DPV2 project, SCE also requested authorization to construct the Midpoint Substation, near Blythe. A CPUC decision on the project modifications is expected sometime in the fourth quarter of 2009. The Committees continue to support the DPV2 and believe the California-only portion would provide a valuable link to renewable generation in Eastern Riverside County and eventually Arizona.

(2) SDG&E Sunrise Powerlink Transmission Project

The CPUC issued a CPCN for the Sunrise Powerlink in December 2008. The approved route did not follow SDG&E's preferred route through the Anza-Borrego Desert State Park but instead followed an environmentally superior southern route. (A full description of the project and permitting process can be found in Appendix C.) The final permit, from the U.S. Forest Service, is expected to be granted in the fall of 2009, and construction may begin as early as December 2009. SDG&E expects to complete construction in June 2012.

(3) SCE Tehachapi Segments 1, 2, and 3

Transmission segments 1–3 have been approved by the CPUC and the U.S. Forest Service. Segment 1 was originally filed as Antelope-Pardee Transmission Line. Transmission segments 1–3 include the Antelope – Pardee 500 kV, Antelope – Vincent No. 1 500 kV, Antelope – Windhub 500 kV and Windhub – Highwind 230 kV transmission lines. Segments 2 and 3 were originally filed as Antelope Transmission Project. Upon completion, these three segments will have total transmission capability of 700 megawatts (MW). Expected completion date for the 500 kV portion of Segments 1 – 3 is the fourth quarter of 2009, and summer 2010 for the 230 kV portion.

(4) Imperial Valley Transmission Upgrades

The Imperial Valley Transmission Upgrade is currently a plan that includes more than 10 segments that are designed to collect and deliver generation in the Imperial Valley to California and Arizona. For a complete description of transmission segments, see Appendix C. The Imperial Irrigation District continues to develop the plan and to acquire the necessary permits.

Construction of the segments themselves will not begin until there are commitments from a sufficient number of generators.

(5) Trans Bay Cable Project

Construction has begun on the high-voltage direct current (DC) cable between Pittsburg and San Francisco. The DC convertor stations are expected to be completed late in 2009, with the cable being operational by March 2010. When completed, the project will deliver up to 400 MW to San Francisco.

(6) PG&E Central California Clean Energy Transmission Project

The Central California Clean Energy Transmission Project (C3ETP) is currently being studied by the California ISO and could be voted on by the California ISO board of governors by the end of 2009. The C3ETP was proposed by PG&E in its 2007 transmission plan as a 500 kV transmission line from the Midway Substation near Buttonwillow to a new substation near Fresno. In December 2007 the California ISO initiated a stakeholder study process of the proposed project and many alternatives. The draft *C3ETP Preliminary Study Report* was issued by the California ISO on October 21, 2008 (http://www.caiso.com/2063/2063f3bb583a0.pdf). The C3ETP will require approval by the California ISO board of governors and a CPCN from the CPUC. PG&E has proposed a 2013 operational date for the project. However, since the CPCN process has not been initiated, this is a very optimistic date.

(7) Talega-Escondido/Valley-Serrano 500-kV Interconnect (aka transmission component of LEAPS)

The 28.5-mile, 500 kV transmission component of the Lake Elsinore Advanced Pumped Storage (LEAPS) project would connect to a tap on SCE's 500 kV Valley-Serrano line, as well as to a new substation near the existing Talega-Escondido 230-kV line where the line enters Camp Pendleton in Northern San Diego County. In February 2008 The Nevada Hydro Company (TNHC) filed a Proponents Environmental Assessment (PEA) at the CPUC for a CPCN for the transmission portion of the LEAPS project. The PEA was deemed incomplete, and on April 17, 2009, the CPUC denied the application due to continuing deficiencies in the PEA. The treatment of the project in the California ISO's transmission planning process is still under consideration at the FERC as is the unexecuted Large Generator Interconnection Agreement. The transmission portion of the LEAPS project was included in the RETI Phase 2A conceptual transmission plan.

(8) Green Path Coordinated Projects

The Green Path Coordinated Projects essentially tie the collector system of the Imperial Valley Transmission Upgrades to the California ISO-controlled grid and LADWP. One component, the Sunrise Powerlink, has been discussed earlier. The LADWP's Green Path North as currently proposed would connect Imperial Valley generation to load centers in Los Angeles. The Green Path North Project was originally proposed as a 500 kV transmission line but recently LADWP has been exploring 230 kV options and routing alternatives as a means to reduce potential environmental impacts.

(9) LADWP Tehachapi Transmission Project (Barren Ridge Renewable Transmission Project)

In 2009 the LADWP Tehachapi Project was replaced by the Barren Ridge Renewable Transmission Project, a renewable resources project that will consist of a new 61-mile double-circuit 230 kV transmission line between the Barren Ride Switching Station and a new Haskell Canyon Switching Station. With the construction of the new line and the reconductoring, the rating of the existing system, which is approximately 400 MW, will be increased to approximately 2200 MW. LADWP is analyzing the project's impacts and if approved, the project is expected to be in service by late 2013.

(10) SCE Tehachapi Renewable Transmission Project

The SCE Tehachapi Renewable Transmission Project (TRTP) would provide the electrical facilities necessary to integrate new wind generation – more than 700 MW and up to approximately 4,500 MW in the Tehachapi Wind Resource Area. The project was split into 11 segments, the first three (1-3) of which received CPUC approval in 2007. SCE filed a CPCN application June 29, 2007, for the project, referred to as segments 4 through 11[5] of the Tehachapi Expansion Plan. SCE also submitted an application for a special use authorization to the U.S. Forest Service. The proposed project must be reviewed under both the California Environmental Quality Act and the National Environmental Policy Act. The CPUC and the USDA Forest Service are currently preparing the Final EIR/EIS, which is expected to be published in November 2009.

[5] Segment 1 of the Tehachapi Expansion Project received approval from the CPUC on March 1, 2007; Segments 2 and 3 received approval from the CPUC on March 15, 2007.

CHAPTER 2: California Transmission Initiatives, Trends, and Drivers

This chapter describes current transmission-related initiatives, trends, and drivers in California. It will provide the reader with the background and context needed to appreciate the range and complexity of efforts underway Understanding these initiatives, trends, and drivers forms the basis for the Joint Integrated Energy Policy Report (IEPR) and Siting Committees' (the Committees) policy discussions on overcoming transmission planning process challenges to achieving a coordinated statewide strategic transmission plan (Chapter 4), conducting statewide transmission corridor planning (Chapter 5), developing specific short-term, statewide strategic transmission project and corridor priorities (Chapter 6), and developing long-term statewide transmission scenarios (Chapter 7).

As population grows and load-serving entity (LSE) energy supply portfolios change, new transmission facilities are likely to be needed to maintain system reliability and deliver electricity—including increasing amounts of renewable energy—to consumers. Conceptual planning identifies such potential transmission facilities for detailed study. Power flow modeling and production cost simulations performed by the California ISO and electric utilities then determine which projects are needed for reliability and make economic sense, and how they must be configured electrically. A plan capable of being implemented can be developed only after such detailed study, and only after land use and environmental implications are fully considered for specific transmission routing (see Chapter 4, "Challenges to Achieving a Coordinated Statewide Strategic Transmission Plan").

Planning Process Initiatives

California's Renewable Energy Transmission Initiative (RETI)

Introduction

The Renewable Energy Transmission Initiative (RETI) is an informal California stakeholder collaborative process[6] charged with developing a conceptual plan for expanding the state's electric transmission grid to provide access to renewable energy resource areas necessary and meet state energy goals.[7] The California Public Utilities Commission (CPUC), Energy

[6] The RETI effort is supervised by a Coordinating Committee composed of California entities responsible for ensuring the implementation of the state's renewable energy policies and development of electric infrastructure, including the Energy Commission, California Public Utilities Commission (CPUC), California Independent System Operator (California ISO), and publicly owned utilities (the Southern California Public Power Authority, Sacramento Municipal Utility District, and Northern California Power Agency).

[7] http://www.energy.ca.gov/reti/index.html

Commission, and California Independent System Operator (California ISO) formed RETI and were joined by Sacramento Municipal Utility District (SMUD), the Northern California Power Agency, and the Southern California Public Power Authority.

All RETI activities are undertaken at the direction of the 30-member Stakeholder Steering Committee (SSC). The SSC is composed of representatives of environmental groups; renewable developers; public and investor-owned utilities; state, federal, and local governments; Native American tribes; and consumers. Much of the detailed work is performed largely by working groups composed of volunteers representing a wide range of interests and perspectives. RETI stakeholders are committed to ensuring that its process is open and transparent and that recommendations are based on the best publicly available information. Stakeholders seek to inform and influence formal transmission planning and permitting processes at the California ISO, California Public Utilities Commission (CPUC), Energy Commission, and transmission planning at the electric utilities.

RETI released its Phase 2A conceptual transmission plan in August 2009, which was designed to meet the goal of obtaining 33 percent of the state's electricity from renewable resources by 2020. RETI's work will be used as an input into the Desert Renewable Energy Conceptual Plan (DRECP), the California ISO annual transmission planning process, and the Energy Commission's corridor designation process.

This plan is intended to help expedite development and approval of renewable energy infrastructure found to be required, in ways that minimize the economic cost and environmental impacts, while avoiding development of duplicative transmission lines. RETI work is organized into three phases:

- Phase 1: Identification, characterization and ranking of Competitive Renewable Energy Zones (CREZ) specified for solar, wind, geothermal, or biomass energy facilities in California and neighboring regions.
- Phase 2: Development of a statewide conceptual transmission plan to access priority CREZ, based on more detailed analysis of CREZ.
- Phase 3: Development of detailed plans of service for priority components of the statewide transmission plan.

The final Phase 1B report was completed in January 2009.[8] The Phase 2A report was completed in August 2009.[9] The RETI stakeholders have not yet determined the detailed activities of RETI

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[8] *Renewable Energy Transmission Initiative Phase 1B Final Report,* Publication Number RETI-1000-2008-003-F, http://www.energy.ca.gov/2008publications/RETI-1000-2008-003/RETI-1000-2008-003-F.PDF, posted January 5, 2009, accessed August 11, 2009.

[9] *Renewable Energy Transmission Initiative Phase 2A Final Report*, Publication Number RETI-1000-2009-001-F, http://www.energy.ca.gov/2009publications/RETI-1000-2009-001/RETI-1000-2009-001-F.PDF, posted August 12, 2009, accessed August 13, 2009.

Phase 3, which will ultimately be influenced by how the California ISO and electric utilities respond to RETI stakeholder efforts to this point.

The *RETI Phase 2A Final Report* will be used by state and local agencies as well as utilities and members of the public in developing detailed transmission plans. Based on information available today regarding the potential for renewable development, the report:

- Identifies additional transmission capacity to access and deliver renewable energy to meet the state's renewable energy goals in 2020.
- Evaluates relative usefulness of potential lines for accessing the delivering renewable energy.
- Identifies potential transmission network lines for further detailed study by the California ISO and electric utilities.
- Locates most conceptual lines in existing right of way and/or designated utility corridors.
- Includes environmental considerations and high level screening of conceptual transmission lines.
- Incorporates a wide range of stakeholder perspectives.

Summary of RETI Results

The Phase 1A report, accepted by the SSC on May 21, 2008, described the method, assumptions and resource information to be used in Phase 1B of the RETI project.

The Phase 1B Report was a high-level screening analysis that applied the resource valuation method developed in Phase 1A. Potential renewable energy projects were grouped into CREZs based on geographic proximity, development timeframe, shared transmission constraints, and additive economic benefits. CREZs were ranked according to cost effectiveness, environmental concerns, development and schedule certainty, and other factors to provide a renewable resource base case for California.

RETI Phase 2A work focused on two major tasks: expanded evaluation and re-ranking of CREZ preliminarily identified in Phase 1, and development of a statewide conceptual transmission expansion plan to access the CREZ.

The RETI Phase 2A work revised the descriptions, adjusted the boundaries, and re-ranked CREZ initially identified in Phase 1. These changes incorporate new information from many sources, including on-the-ground evaluation of permitting and project viability ("developability") issues. Revised CREZ provide a more accurate basis for estimating the electricity generation potential of biomass, geothermal, solar, or wind projects sited in those areas. The timing and scale of actual generating projects that may be developed, however, remain uncertain.

The RETI Phase 2A statewide conceptual transmission expansion plan represents the consensus recommendation of a diverse set of stakeholders for two groups of major transmission line upgrades of the California grid, referred to as Renewable Foundation[10] lines and Renewable Delivery[11] lines. These facilities increase the capacity of the grid, allowing energy to flow north or south as needed, and deliver energy to load centers. In addition to Renewable Foundation lines and Renewable Delivery lines, the plan includes groups of Renewable Collector[12] lines, which provide access to geographically adjacent CREZs.

In the *RETI Phase 2A Final Report*, the RETI SSC recommended components of the conceptual plan for such detailed study. They represented potential network connections between substations. Most of these line segments are located in existing transmission rights-of-way or designated corridors, or parallel existing transmission line rights-of-way.

RETI did not determine precise geographic routings in the conceptual plan. In addition, RETI did not evaluate the extent to which the existing grid can accommodate new sources of renewable generation. However, RETI did note that given the amount of renewable energy required to meet state goals in 2020, a number of the Renewable Foundation and Renewable Delivery lines that RETI identified and evaluated are likely to be required. Importantly, some are also likely to be needed to meet growing energy demand regardless of generation source. Lines likely to be used no matter how the future unfolds—how population grows, energy efficiency savings accrue and generation develops—are referred to as "least-regrets upgrades." They are so named because decision-makers who approve, and the customers who pay for, such infrastructure are unlikely to regret doing so.

For the latest RETI Phase 2A maps showing the Renewable Foundation, Delivery, and Collector lines, please refer to the following website:
http://www.energy.ca.gov/reti/documents/phase2A_final/maps/

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[10] **Renewable Foundation** lines increase the capacity of the California transmission network between Palm Springs and Sacramento, allowing energy to flow north or south as needed. There are 14 key line segments in the Renewable Foundation Group. The capacity these lines provide is likely to be essential to be able to deliver renewable energy from any CREZ to consumers in all major load centers. The usefulness of the Renewable Foundation Group is not limited to renewable energy. The increased capacity these lines provide is likely to be needed to meet growing energy demand regardless of generation source.

[11] **Renewable Delivery** lines move energy from Renewable Foundation lines to major load centers. The increased capacity provided by the lines of this group is likely to be needed to meet growing energy demand regardless of generation source. There are 13 major line segments in the Renewable Delivery Group.

[12] **Renewable Collector** lines carry power from CREZ to Renewable Foundation and Renewable Delivery lines. These line segments are grouped geographically into projects capable of accessing adjacent CREZ. There are 12 groupings of collector lines. Several of these lines form portions of or connect to major inter-tie lines connecting California to the Western regional grid, and therefore provide access to out of state resources.

In summary, the RETI conceptual transmission plan:

- Identifies additional transmission capacity to access and deliver renewable energy to meet the state renewable energy goals in 2020.
- Evaluates relative usefulness of potential lines for accessing renewable energy.
- Identifies potential transmission network lines for further detailed study by the California ISO and electric utilities.
- Locates most conceptual lines in existing right of way and/or designated utility corridors.
- Includes environmental considerations and high level screening of conceptual transmission lines.
- Incorporates a wide range of stakeholder perspectives.

The RETI conceptual transmission plan does not:

- Include precise routing of lines.
- Preclude study of other areas with renewable energy potential.
- Provide determination of need, or information about power flows, congestion, or reliability.
- Determine the ability of the existing electrical system to accommodate flows of new renewable generation.
- Provide the project-level environmental impact assessments required for specific project approvals.

To support expedited approval and development of the infrastructure required to enable California to meet its policy goals while minimizing environmental and economic costs, in the *RETI Phase 2A Final Report*, the RETI SSC recommended that:

- The California ISO, investor-owned utilities (IOUs), and publicly owned utilities (POUs) perform detailed, contingency-based technical analysis of Renewable Foundation lines and Renewable Delivery lines as soon as possible to determine which are needed and how construction should be phased to ensure that sufficient transmission is placed in service to meet state goals by 2020.[13]

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[13] Renewable Foundation lines and Renewable Delivery lines form the core of the RETI conceptual plan. Renewable Collector lines, defined in Section 1.4.3 and described in Section 3.5 of the *RETI Phase 2A Final Report*, will be analyzed in more detail and prioritized in future RETI work.

- To avoid duplicative facilities, California transmission-planning authorities work closely with one another to identify, propose, study, and approve joint IOU-POU projects, and eliminate barriers to joint use of such facilities.
- The Energy Commission, working with the CPUC, California ISO, IOUs, and POUs, conducts a study to determine the extent to which multiple transmission charges present barriers to achieving state renewable energy and greenhouse gas reduction goals and recommends measures to eliminate or mitigate these barriers while ensuring that transmission owners recover their costs.
- The California Department of Conservation expand and expedite its efforts to define, identify, and map vacant and disturbed lands throughout California, focusing first on counties that RETI has identified as having large renewable energy and transmission development potential, and make this information available as soon as possible.
- The Energy Commission, in conjunction with other state and federal agencies, local governments and renewable energy stakeholders, identify an action plan to address land ownership consolidation of disturbed or degraded private lands for renewable energy development on an expedited basis.
- Entities planning new transmission lines engage local governments, environmentalists, and other interested parties in a collaborative process to identify and assess potential alternatives, including other transmission alternatives, non-transmission alternatives, as well as alternative routes for the proposed line, early in their planning processes. The entities within California Natural Resources Agency should provide participants with pertinent data and information in geographic information system format together with assistance in using the Web-based Planning Alternative Corridors for Transmission (PACT) assessment application.
- The Energy Commission, as authorized by Public Resources Code Section 25331, should begin immediately to consider the RETI transmission line segments to determine which are the best candidates for corridor designation. The Energy Commission should immediately initiate public outreach to agencies and stakeholders that would participate in a corridor designation proceeding. Corridors considered for designation should be beyond those already established by federal agencies or utilities' rights of way and should preserve and protect transmission access to areas where renewable energy development is likely to take place. They should include likely routes for Renewable Foundation lines, Renewable Delivery lines, Renewable Collector lines, and potential expansion of existing rights-of-way. Corridor designation must be coordinated among local, state, and federal agencies and tribal governments and support access to, for example, U.S. Bureau of Land Management (BLM) Solar Energy Zones, and Desert Renewable Energy Conservation Plan (DRECP) generation development areas, as well as to CREZ most likely to be developed.

RETI Next Steps

There are several steps under consideration by the RETI stakeholders. These include a possible update of the *RETI Phase 2A Final Report* to address developments in the tax code that affect the economic rankings of the CREZ. The stakeholders are also considering participation in the California ISO Annual Transmission Plan proceeding and the electric utilities' California Transmission Planning Group as described below in the section titled "California Transmission Planning Group." Beyond this, the stakeholders are evaluating the benefits of conducting Phase 2B work to prioritize the transmission infrastructure identified in the conceptual transmission plan, address in greater detail the out-of-state renewable resources and revise the transmission infrastructure accordingly, and develop an interim interconnection plan to exploit initial renewable generation opportunities that can rely on temporary fixes to the existing grid to be brought on line.

Executive Order No. S-14-08 on Renewables Resource Development, Streamlining Permitting, and Collaborative Planning

Executive Order S-14-08, signed by Governor Schwarzenegger on November 17, 2008, establishes a Renewables Portfolio Standard (RPS) target for California that directs all retail sellers of electricity to serve 33 percent of their load with renewable energy by 2020.[14] The order directs state government agencies "to take all appropriate actions to implement this target in all regulatory proceedings, including siting, permitting, and procurement for renewable energy power plants and transmission lines." The Executive Order and associated Memoranda of Understanding by and among several state and federal agencies established a joint state-federal Renewable Energy Action Team (REAT). Federal participation is supported by the Secretary of the Interior's Secretarial Order 3285 (March 2009) directing all Department of the Interior agencies and departments (which include the BLM and USFWS) to encourage the timely and responsible development of renewable energy, while protecting and enhancing the nation's water, wildlife and other natural resources.[15]

The REAT's primary mission is to streamline and expedite the permitting processes for renewable energy projects, while conserving endangered species and natural communities at the ecosystem scale. The Executive Order directs the REAT to achieve these twin goals in the Mojave and Colorado Desert regions through the Desert Renewable Energy Conservation Plan (DRECP). The DRECP will address both project permitting and resource conservation objectives through a comprehensive regional planning approach. This approach is supported by California's Natural Community Conservation Planning Act, which has been used

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[14] Executive Order S-14-08 can be found at: http://gov.ca.gov/executive-order/11072/. Posted November 17, 2008, accessed August 13, 2009.

[15] http://www.energy.ca.gov/33by2020/index.html

successfully in several regions of the state since its enactment in 1991[16], and the habitat conservation planning provisions of the federal Endangered Species Act.[17]

The REAT agencies composed of the Bureau of Land Management, the U.S. Fish and Wildlife Service, the California Department of Fish and Game, and the California Energy Commission held initial public outreach and scoping meetings on the Governor's Executive Order on March 12 and 17, 2009, in Sacramento and Palm Springs, respectively. On June 18, 2009, the REAT agencies held a workshop in Victorville to discuss the Governor's Renewable Energy Executive Order and the DRECP. Presentations were given on the elements and timing of the DRECP, the opportunities made available for public and agency participation, and some environmental groups gave presentations on the various planning activities that are underway in the California Deserts. The Executive Order activities are being closely coordinated with RETI and the BLM/DOE Solar Programmatic Environmental Impact Statement work in progress. The REAT also held meetings with county supervisors and planning staff in the six California desert counties to obtain local agency input on the DRECP effort to identify areas for both development and conservation.

Work on the renewable energy permitting elements of the Executive Order is split up into six tasks including: (1) developing the DRECP Planning Agreement; (2) developing and gathering public stakeholder and independent scientific input; (3) developing the Draft DRECP Conservation Strategy by December 2009; (4) developing the Draft DRECP by December 2010; (5) completing the final Draft DRECP environmental review and approval by June 2012 and (6) publishing a Best Management Practices Manual for the development of renewable energy projects by December 2009.

Executive Order No. S-21-09 on Development of Regulations to Implement a 33 Percent Renewable Energy Target

On September 15, 2009, Governor Schwarzenegger signed Executive Order S-21-09, which directs the California Air Resources Board (ARB), by July 31, 2010, to adopt a regulation consistent with the 33 percent renewable energy target established in Executive Order S-14-08.[18] Furthermore, the order states that, in developing the regulation, the ARB may increase the target and accelerate and expand the timeframe based on an assessment of such factors as technical feasibility, system reliability, cost, greenhouse gas emissions, environmental protection, or other relevant factors.

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[16] http://www.dfg.ca.gov/habcon/nccp/

[17] http://www.fws.gov/endangered/hcp/

[18] Executive Order S-21-09 can be found at: http://gov.ca.gov/executive-order/13269/. Posted September 15, 2009, accessed September 22, 2009.

The executive order directs the Energy Commission and the CPUC to work with the ARB to ensure that such a regulation to encourage the creation and use of renewable energy sources shall build upon the RPS program and shall regulate all California load-serving entities. It states that the ARB may delegate to the Energy Commission and the CPUC any policy development or program implementation responsibilities that would reduce duplication and improve consistency with other energy programs such as demand response, energy efficiency, and energy storage. Furthermore, it orders the ARB to establish the highest priority for those resources that provide the greatest environmental benefits with the least environmental costs and impacts on public health that can be developed most quickly and that support reliable, efficient, cost-effective electricity system operations, including resources and facilities located throughout the Western Interconnection.

Federal Solar Energy Development Programmatic Environmental Impact Statement Effort

The Energy Policy Act of 2005[19] directed the Secretary of the Interior to plan for installing at least 10,000 megawatts (MW) of renewable energy electricity generators on public lands in six Western states. On May 29, 2008, the BLM and the U.S. Department of Energy (U.S. DOE) announced they were preparing a programmatic environmental impact statement (PEIS) for development of large-scale, grid-connected solar electric facilities in Arizona, California, Colorado, Nevada, New Mexico, and Utah (Solar PEIS).[20] The federal agencies are evaluating whether to establish environmental policies and mitigation strategies for all future solar energy facility development on BLM-managed lands and for all U.S. DOE-funded solar facilities. Similar work to aid geothermal and wind energy development and western energy corridor designation has already been completed.

The Energy Commission is a cooperating agency with the BLM for the Solar PEIS. In addition, the Energy Commission organized and leads an interagency working group of California-based federal, state, and local government agencies to aid their review of pre-public-release draft chapters of the Solar PEIS. On June 29, 2009, Secretary of the Interior Ken Salazar added 24 solar energy study areas to the scope of the Solar PEIS to accomplish his policy goal of establishing renewable energy zones on federally managed land. Four solar energy study areas were proposed in California based on economic and environmental criteria and resemble five CREZs identified in the RETI process, but unlike CREZs, their boundaries are limited to BLM-managed land only. The solar energy study areas may be designated later as solar energy zones and if approved, projects within designated solar energy zones would receive expedited environmental review.

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[19] National Energy Policy Act of 2005, Public Law 109–58, signed August 8, 2005; [http://www.epa.gov/oust/fedlaws/publ_109-058.pdf]; accessed August 13, 2009.

[20] http://solareis.anl.gov/index.cfm

The purpose of the Solar PEIS is not to eliminate the need for site-specific environmental review for individual solar development proposals. Once the Solar PEIS has been completed, these site-specific reviews will determine whether the proposed projects' plans of development follow the best management practices and mitigation strategies prescribed in the Solar PEIS.

The Solar PEIS will also consider whether new transmission corridors are needed on BLM-managed land to interconnect solar electric facilities to the grid. Once the Solar PEIS is completed, the BLM will issue a Record of Decision to amend approximately 10 land use plans covering BLM-managed lands in the California desert to allow solar resource development.

California ISO Interconnection Queue

On September 26, 2008, the Federal Energy Regulatory Commission (FERC) approved changes to the California ISO's tariff that modified the process through which large generators (those greater than 20 MW) would connect to the California ISO controlled grid. Previously, in conformance with the FERC's Large Generator Interconnection Rule ("Order 2003"), the California ISO had based its generation interconnection on a serial process in which generators were studied and given priority access to the transmission grid based on the timing of their entry into the interconnection process or queue. The costs of entering the process and maintaining a place in the interconnection queue were low, which led to an unmanageable interconnection process. The studies required for the generator interconnection were regularly updated and generators were often uncertain as to their interconnection costs leading to both extensive delays in the interconnection process and too much uncertainty for generators. In January 2007 the California ISO began the Generator Interconnection Process Reform (GIPR) initiative, which resulted in a new cluster window approach to generator interconnection instead of the serial approach and significantly raised the fees for large generators to enter the process. The new process creates two application periods or windows each year and treats all generators that apply for interconnection during that window the same. The effects on the transmission network of generators that propose to connect near one another and in the same window are studied as a cluster, which should decrease the study time. It is too soon to judge the success of the new California ISO Large Generator Interconnection Process. As of July 2009 the California ISO completed the first phase of the analysis for projects that were in the transition cluster, but no projects in the cluster process have completed an interconnection agreement or begun to deliver power to the California grid. As designed, the new interconnection process should fix many of the problems that plagued the generator interconnection process, but it is impossible to judge until generators in the process begin delivering power to the California grid.

Relationship Between California ISO's Location Constrained Resource Interconnection Policy and Agency Certification of Energy Resource Areas

On January 25, 2007, the California ISO filed a petition with FERC for a Declaratory Order seeking conceptual approval of a new financing mechanism to aid the construction of interconnection facilities for location constrained resources (primarily remotely located renewables). On April 19, 2007, FERC granted the ISO's petition and accepted the design concepts proposed therein, thereby paving the way for the ISO to file tariff language for implementing this important initiative. The California ISO filed a tariff amendment for the Location Constrained Resource Interconnection (LCRI) on October 31, 2007. FERC approved the amendment on December 21, 2007.[21]

FERC's Declaratory Order also authorized the Energy Commission and the CPUC to certify renewable energy resource areas, defined as areas in which multiple location constrained resource interconnection generators could be located. FERC also authorized the California ISO to approve transmission projects to interconnect location constrained generation until the Energy Commission and CPUC do so. Until the Energy Commission- and CPUC-certified areas are provided (see discussion below), the California ISO will only approve such transmission projects on a limited case-by-case and as-needed basis. In May 2009 the California ISO approved the first location-constrained transmission project.[22] The Highwind-Windhub transmission line helps with the initial interconnection of approximately 759 MW in the Tehachapi area. The Highwind-Windhub project is scheduled to be on-line December 31, 2010.[23]

The Energy Commission and CPUC have not developed a process for certifying LCRI-related energy resource areas at this time. However, it is expected that the RETI CREZs will be fully considered in this regard. In addition, renewable zones identified in the agency-driven DRECP process, under Executive Order S-14-08 (described above), will likely play a significant part in the LCRI-related agency designations.

A New ISO Tariff Category For Renewable Transmission Projects

The California ISO released a straw proposal on September 15, 2009 that outlines the processes and criteria it should adopt to meet the 33 percent RPS goal by 2020. The California ISO will develop the initial long-term renewable transmission plan by focusing on the Renewable Foundation lines identified in the *RETI Phase 2A Final Report*. The California ISO proposes to

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[21] For more information on the development of the LCRI Policy development, see the following website: http://www.caiso.com/1816/1816d22953ec0.html

[22] "California ISO Okays First Location-constrained Transmission Project," California ISO press release dated May 18, 2009, http://www.caiso.com/23b2/23b2cb348860.pdf, accessed August 11, 2009.

[23] *Renewable Resources and the California Electric Power Industry: System Operations, Wholesale Markets and Grid Planning*, p. 28, California ISO, July 20, 2009, http://www.caiso.com/23f1/23f19422741b0.pdf, accessed August 11, 2009.

add a new transmission category to its tariff that will allow the California ISO to approve projects through its transmission planning process that will connect to renewable energy areas. The current proposal includes three criteria for screening and evaluating transmission projects and annual recalibration of the 33 percent transmission plan. Beginning with the 2010 planning cycle, the California ISO will coordinate the initial long-term renewable transmission plan to achieve the 33 percent RPS goal with other ISO initiatives, including the generator interconnection processes and the location-constrained resource interconnection process.[24]

CPUC Investigation and Rulemaking on Transmission for Renewable Resources

The CPUC has an ongoing Investigation and Rulemaking (I. 08-03-010/R.08-03-009) to consider issues related to the development of transmission infrastructure to provide access to renewable energy resources for California. This proceeding seeks to improve transmission access to renewable energy generation, consider options for streamlining of existing regulatory processes, and serve as a forum for addressing issues identified in RETI that may require CPUC investigation or formal decision. This proceeding was initiated in March 2008 and expected to build upon the prior CPUC proceeding devoted to promoting the development of transmission infrastructure to renewable resource areas and other transmission and renewable-related proceedings.

On February 26, 2009, the CPUC held a prehearing conference and staff workshop to consider whether the output of the statewide RETI results could be used to support cost recovery for transmission planning and the CPUC's standards for determining "need" within the transmission permitting process. The role of RETI in transmission planning, particularly its integration into the California ISO's planning and project approval and the CPUC's CPCN processes, was discussed in statements filed by the major stakeholders. In its prehearing conference statement,[25] the California ISO suggested adding the following to the list of key issues identified by the CPUC's February 5, 2009, ruling[26]: Consideration of the ISO's LCRI cost recovery mechanism and a proposal that the CPUC, in conjunction with the Energy Commission, certify that the areas defined in the ISO LCRI tariff be accepted as "Energy Resources Areas." The California ISO noted that CREZs have been identified by RETI and may provide a basis for certification. The California ISO and other parties also addressed: 1) the use of RETI results in the California ISO long-term transmission planning process; 2) whether a

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[24] For more information, see the following California ISO website entitled *33 Percent RPS: Establishing a New ISO Tariff Category for Renewable Transmission Project:* http://www.caiso.com/242a/242abe1517440.html

[25] *Prehearing Conference and Workshop Statement of the California Independent System Operator Corporation*, February 23, 2009, http://docs.cpuc.ca.gov/efile/ST/97852.pdf, accessed August 25, 2009.

[26] *Administrative Law Judge's Ruling Scheduling a Prehearing Conference and Workshop*, February 5, 2009, http://docs.cpuc.ca.gov/efile/RULINGS/97073.pdf, Section 3, accessed August 25, 2009.

rebuttable presumption of need should be afforded to renewable transmission projects studied and approved by the California ISO; and 3) how project development costs can be recovered by project proponents. The CPUC has not issued a proposed decision or subsequent notice to date.

Assuming the California ISO uses the RETI Phase 2A results in the ISO's transmission planning process study assumptions, the California ISO's study results will include "need" determinations for specific projects necessary to connect the high priority CREZs. The CPUC affords a rebuttable presumption of reasonableness in a CPCN process under certain conditions. At issue is whether this mechanism should be expanded to include a layer of special deference for projects that provide access to high priority CREZs in response to the California ISO's need determination.

California Transmission Planning Group

The California ISO, California Municipal Utilities Association, Imperial Irrigation District, City of Los Angeles Department of Water and Power, Pacific Gas and Electric Company, Southern California Edison Company, San Diego Gas & Electric Company, and the Transmission Agency of Northern California make up the California Transmission Planning Group (CTPG).

As described by the joint comments received under this proceeding by the CTPG[27], the purpose of the CTPG is to find the best transmission solutions for meeting California's environmental, reliability, economic, and other policy objectives. Under the CTPG, electric utilities and the California ISO are planning to work together to avoid transmission duplication, optimize use of existing rights-of-way, reduce environmental impacts, and lower costs for consumers. The CTPG is intended, along with existing efforts, to fulfill the CTPG member's obligations and requirements under Order No. 890 issued by the FERC. It is notable that Order No. 890 requirements include nine transmission planning principles that address many of the issues central to an open and inclusive planning process, including

- Coordination with customers and neighboring transmission providers.
- Open meetings available to all parties.
- Transparency in methodology, criteria, and processes.
- Opportunities to use customer data and methodological input.
- The obligation to meet specific service requests of transmission customers on a comparable basis; (6) a clear dispute resolution process.
- Regional coordination.

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[27] *Post-Workshop Comments of Joint Parties Comments on Transmission Planning Information and Policy Actions*, May 29, 2009, http://www.energy.ca.gov/2009_energypolicy/documents/2009-05-04_workshop/comments/Joint_Parties_Post-Workshop_Comments_052909_TN-51751.pdf, posted May 29, 2009, accessed August 6, 2009.

- Study of economic effect of congestion and integration of new resources.
- A process for allocating costs of new projects.

Furthermore, the CTPG also intends to bring together the various California transmission planning and operating entities to use consistent assumptions and methodologies to identify and address the transmission needs of California. CTPG plans to support regional and sub-regional planning activities in the Western Electricity Coordinating Council (WECC) as required by WECC regional transmission planning procedures and guidelines. The CTPG planning activities are also intended to comply with the North American Electric Reliability Corporation (NERC) and WECC reliability standards so that the reliability of the power grid is not compromised.

The role of the CTPG in statewide transmission planning is addressed in "Chapter 4: Challenges to Achieving a Coordinated Statewide Strategic Transmission Plan," particularly with regard to the CTPG's relationship with other transmission planning entities, including RETI.

The CTPG's schedule for producing its 2009 Study Plan is:

- Stakeholder Meeting, August 11, 2009
- Complete Base Case Development, August 15, 2009
- Complete Technical Studies, November 2, 2009
- Present to Executive Committee, November 13, 2009
- Draft Report, December 2009
- Stakeholder Meeting, December 2009
- Final Report, January 2010.

Other Issues and Drivers

Once-Through Cooling Policy Implications

On June 30, 2009, the State Water Resource Control Board posted its Draft Statewide Water Quality Control Board Policy on the Use of Coastal and Estuarine Waters for Power Plant Cooling.[28] If adopted, this policy would require that generators currently using once through cooling use a different cooling method by dates specified in the draft policy.[29]

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[28] http://www.swrcb.ca.gov/water_issues/programs/npdes/docs/cwa316/draft_otcpolicy.pdf, accessed August 18, 2009.

[29] The dates are generator-specific and range from one year after the effective date of the policy to December 31, 2022.

Many of the plants that use once-through cooling are old, well past their 30-year operating lives and do not operate enough to justify the significant expenditures required to change to a new form of cooling. As a result, many will likely stop operating if the proposed policy is adopted. Because many of these plants are located in major load centers where it is difficult to build replacement generation due to air quality rules and lack of air emissions credits, new transmission may be required, especially in the Los Angeles Basin.

For more information on this issue, please see the *Committee Draft 2009 Integrated Energy Policy Report*.

South Coast Air Quality Management District Air Emissions Credits

In August 2007, the South Coast Air Quality Management District (SCAQMD) amended its rules by establishing air quality and economic criteria that allowed offsets from the SCAQMD's Priority Reserve account to be purchased for new power plants licensed by the Energy Commission.[30] The SCAQMD, under Rule 1309.1, limited these power plant credits, requiring developers to have a one-year power sales contract and a license from the Energy Commission to construct their facility before the SCAQMD Board would release any credits for that facility. Plants being proposed by municipal utilities were allowed only enough credits to build projects that served their native load. The SCAQMD also limited the total amount of new electricity generating capacity that could access Priority Reserve credits, including that associated with replacing aging plants' capacity, to no more than 2,700 MW.

The SCAQMD Priority Reserve Rule was challenged in Los Angeles Superior Court, and in July 2008, the court decision found the air district's California Environmental Quality Act (CEQA) analysis inadequate and indicated that a sufficient environmental analysis document would require significant new analysis. The SCAQMD believes it cannot reasonably provide the environmental analysis for power plants. [31] As a consequence, at this time the SCAQMD is unable to issue any offsets for power plants or for any facilities requiring a permit for emissions.

Energy Commission Power Plant Siting of Renewables

In the past two years, 13 renewable or renewable hybrid power plants under the Energy Commission's jurisdiction (thermal power plants 50 MW or larger) have applied for certification and are currently under review. With few exceptions, the renewable energy projects are solar thermal applications – solar trough, solar tower, Stirling engine, or compact linear Fresnel reflector technologies. Several projects are large, phased developments, and while initial phases

[30] http://www.aqmd.gov/hb/2007/february/070214a.html

[31] Superior Court of the State of California, County of Los Angeles, Case No. BS 110792, *Natural Resources Defense Council, Inc., et al. vs. South Coast Air Quality Management District*, Decision on Ruling on Respondent's Motion for Summary Adjudication, July 28, 2008.

will have facility interconnection agreements, later phases will likely require transmission upgrades or reconductoring to deliver generation to the load centers. The 13 solar projects currently under review total more than 6,500 MW[32] (as of September 25, 2009.)

Many large solar energy projects are being proposed in California's desert areas, predominantly on federal BLM land. Most proposed projects are located in remote areas, underscoring the need for additional or new transmission upgrades or additions to deliver the generation to load centers. As of June 2009, the BLM had received right-of-way requests affecting more than 577,000 acres for the development of approximately 66 large solar thermal power plants totaling as much as 47,500 MW.[33] Solar thermal projects under Energy Commission and BLM jurisdiction will require approvals from both agencies before construction. To aid the joint review process, the BLM and the Energy Commission entered into an MOU in August 2007[34] to efficiently provide the required NEPA and CEQA reviews.

California's retail sellers of electricity are clearly increasing their reliance on solar energy to help meet the state's aggressive RPS requirements. At the same time, the federal government is adding stimulus funding to federal and state efforts to more quickly deploy renewable energy and electric power transmission projects. New renewable energy projects placed in service during 2009 or 2010, or that have been certified and will begin construction during 2009 or 2010, may take advantage of specific funding, grants, or loan guarantees available under the American Recovery and Reinvestment Act of 2009[35] (ARRA). In addition to projects already under review, the Energy Commission received several applications for certification in August

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[32] Information about large solar thermal energy projects currently under review by the Energy Commission and the BLM is available at http://www.energy.ca.gov/siting/solar/index.html. Information about other large solar thermal projects that have been publicly announced or have power purchase agreements pending with or approved by the CPUC or a publicly owned utility are also tracked, along with utility-scale solar PV projects (5 MW and larger) that have been announced. As of August 13, 2009, as much as 5,905 MW of large solar thermal and over 1,300 MW of solar PV have been announced. A subset of the announced projects tracked on the Energy Commission's website has also filed applications with the BLM.

[33] Information about solar energy projects in California under BLM jurisdiction, including summary statistics for solar applications as of June 2009, is available at http://www.blm.gov/ca/st/en/fo/cdd/alternative_energy/SolarEnergy.html (accessed August 24, 2009). With one exception, all applications are in the BLM's California Desert District.

[34] Memorandum of Understanding Between the U.S. Department of the Interior, Bureau of Land Management, California Desert District and the California Energy Commission Staff Concerning Joint Environmental Review for Solar Thermal Power Plant Projects, http://www.energy.ca.gov/siting/solar/BLM_CEC_MOU.PDF, accessed August 12, 2009.

[35] HR 1 American Recovery and Reinvestment Act of 2009, signed by President Obama on February 17, 2009, http://frwebgate.access.gpo.gov/cgi-bin/getdoc.cgi?dbname=111_cong_bills&docid=f:h1enr.pdf, accessed August 12, 2009.

2009, which will need expedited permitting review and approvals by November 30, 2010, to qualify for ARRA funding.

Treatment of Non-Wires Alternatives

In the *2007 Strategic Plan* the Energy Commission recommended future work to explore options for, and identify the potential benefits of, earlier consideration of non-wires alternatives[36] in statewide planning processes. Under Public Resources Code Section 1002.3[37], the CPUC currently performs a *project-specific* non-wires alternative analysis as part of its environmental review process, initiated with the filing of a Certificate of Public Convenience and Necessity (CPCN). The Energy Commission's transmission corridor designation process considers non-wires alternatives in the demonstration of need and conformance with the Strategic Plan currently required in a proposed corridor application and subsequent decision. See "Chapter 5: Statewide Transmission Corridor Planning," for more information. The Energy Commission's corridor designation process is seen as a means to expedite both environmental review and need determination for transmission lines, assuming that the results of the Energy Commission's corridor designations are used in subsequent CPUC and publicly owned utility (POU) permitting processes.

The *2007 Strategic Plan* discussion was focused on ways to overcome the major challenge for California to develop the transmission infrastructure needed to support the state's 33 percent RPS goals by 2020. Streamlining and expediting the transmission planning and permitting processes was identified as essential to this effort. A statewide analysis of non-wires alternatives could be used to identify cost-effective non-wires alternatives already being deployed and

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[36] Generally, non-wires alternatives include energy efficiency, demand reduction measures (demand response and load management) and local generation. Local generation refers to small-scale and customer-level distributed generation (DG) resources and/or clean fossil-fired central station generation located within the load service area. DG resources include rooftop solar photovoltaic (PV) generation, combined heat and power units, and biomass facilities (typically municipal waste/landfill), small wind, and other small scale, often community-based, renewable technologies. Non-wires alternatives are also essentially the same loading order resources defined in the current *Energy Action Plan*. (http://www.energy.ca.gov/energy_action_plan/2003-05-08_ACTION_PLAN.PDF; posted May 8, 2003, accessed August 18, 2009.) Non-wires alternatives are distinct from "system alternatives" that rely on different transmission line upgrades and interconnections. Within a proposed project area, these alternatives may include upgrades to the existing transmission infrastructure, different voltage configurations of the proposed lines, interconnections to different points, or alternative transmission technologies, including smart grid.

[37] Public Resources Code Section 1002.3. In considering an application for a certificate for an electric transmission facility under Section 1001, the commission shall consider cost-effective alternatives to transmission facilities that meet the need for an efficient, reliable, and affordable supply of electricity, including, but not limited to, demand-side alternatives such as targeted energy efficiency, ultraclean distributed generation, as defined in Section 353.2, and other demand reduction resources.

expected to be available in the future to meet resource needs. Conceivably, prior accounting for non-wires alternatives could save time and expense in individual project evaluation. However, analysis of non-wires alternatives would have to be carried to a load service area level in order to be used in a specific project area application.

Earlier consideration of non-wires alternatives in statewide planning processes must take into account current statutory requirements and jurisdictional boundaries governing transmission project permitting and corridor designation, as well as overarching policy goals and direction. The CPUC is required to consider "cost-effective" alternatives to transmission facilities and is seeking input on whether it is appropriate to continue addressing this statutory requirement solely in the environmental phase of its review of transmission lines. The Energy Commission should actively participate the CPUC Investigation and Rulemaking on Transmission for Renewable Resources (discussed above) addressing this topic. All parties are seeking coordinated, streamlined, and expedited transmission planning and project review which can be achieved only through a collaborative effort.

Consideration of non-wires alternatives is consistent with the implementation of the loading order priorities as laid out in the current Energy Action Plan, meeting the aggressive GHG reduction targets established in the AB 32 scoping plan[38], and other policy directives. Cost-effective energy efficiency is the resource of first choice for meeting California's energy needs. While committed energy efficiency and demand reduction are accounted for in the adopted demand forecasts, further load reductions from energy efficiency (uncommitted) is under debate and agreed-upon levels should be considered among non-wires alternatives. Simultaneously, it is imperative that California reach its 33 percent RPS goals and expand distributed generation (DG) applications, particularly rooftop solar photovoltaics (PV) and combined heat and power. Non-wires alternatives are specifically linked to the demonstration of need for proposed transmission projects before the CPUC and the California ISO, and, increasingly, non-wires alternatives are being identified as viable alternatives to new conventional generation and transmission facilities required to connect new generation to demand centers.

In all cases, the time frame of analysis and the source and appropriateness of data and assumptions are critical to the required analysis at a specific point in time. The Energy Commission's demand forecast extends 10 years, which is the standard for CPUC and California ISO transmission analyses. However, transmission planning and the Energy Commission Transmission Corridor Designation process must look well beyond 10 years which will invite increased forecast and planning uncertainty. The description and quantification of non-wires alternatives used in regulatory proceedings should not be at the discretion of the applicant, but should be guided by a set of consistent and agreed-upon long-term loads and resource procurement assumptions. The Energy Commission's *IEPR* forecasts and analysis should be a starting point and help inform transmission planning and permitting processes.

[38] http://www.arb.ca.gov/cc/scopingplan/scopingplan.htm, accessed August 18, 2009.

Trends in Transmission Research for Renewables Integration

As California develops more renewable energy resources, both hardware and software improvements will become increasingly important for the successful integration of them into the bulk system grid. The promotion of technologies could mitigate the variability and intermittency of wind and some solar and alleviate operational and reliability constraints that control area operators will have to manage on a day-to-day basis. Technological advancement could increase the transfer capability on existing transmission lines, minimizing the amount of land that would be needed for new rights-of-way, and reducing the overall footprint. Below is a list of research areas that could provide solutions to the increased penetration of renewable generation. A detailed discussion is provided in Appendix A, *Trends in Transmission Research for Renewables Integration*.

- Operational Integration Technologies (Software) – will provide control area operators with the tools needed to manage and better understand the operating characteristics of intermittent renewable generation.
- Energy Storage – will be critical to integrate intermittent renewable generation into the grid and provide grid system support.
- Transmission Undergrounding – could reduce public opposition to new transmission lines.
- High-Capacity Conductors – an emerging technology that could reduce transmission line sag and carry more current than conventional conductors.
- Maximizing Existing Facilities and Rights-of-Way – technologies that could increase the power-carrying capacity within the constraints of an existing right-of-way, ranging in cost and complexity from sag mitigation and reconductoring to superconducting cables.
- Power System Control Technologies –could allow control area operators greater system control.
- Advanced Transmission Planning Tools – needed to address uncertainty and provide more accurate forecasts of system status and behavior.

Recommendations

The Committees makes the following recommendations:

- The Energy Commission staff should actively participate in interagency proceedings at the CPUC and the California ISO that affect the planning and permitting of transmission projects needed to interconnect renewable generation. These include the California ISO stakeholder initiative to establish a new tariff category for renewable transmission projects to meet the 33 percent RPS goal and the CPUC Investigation and Rulemaking on Transmission for Renewable Resources.

- The Energy Commission should continue support for ongoing RETI-related activities, including the Coordinating Committee, Stakeholder Steering Committee, and working groups by providing appropriate personnel and contract resources.
- The Energy Commission staff should continue to support the Renewable Energy Action Team's mission to streamline and expedite the permitting processes for renewable energy projects, while conserving endangered species and natural communities at the ecosystem scale in the Mojave and Colorado Desert regions through the Desert Renewable Energy Conservation Plan.

Summary

As described in this chapter, California's three primary energy entities (the Energy Commission, CPUC, and California ISO) have produced a number of accomplishments relating to transmission planning and permitting (either completed or in progress) since the *2007 Strategic Plan* and the *2008 Integrated Energy Policy Report* were published. However, there is still a lack of total coordination and lack of efficiency among these transmission-related planning processes. The Committees believe that the short- and long-term planning process changes described in Chapter 4 provide effective mechanisms for resolving the challenge of developing California's renewable resources and transmission infrastructure in the most timely and cost-effective way, with least environmental impact and with the best use of limited government and stakeholder resources.

CHAPTER 3: Western Region Transmission Initiatives, Trends, and Drivers

Overview

California's transmission infrastructure is an intrinsic component of the high-voltage Western Interconnection (WI), making the state both an essential participant and a partner in various regional and federal planning and permitting initiatives that will alter the way transmission planning and permitting takes place in the future. The majority of these efforts encourage centralized transmission planning at the regional level, supplemented by federal incentives and regulation. Developers of new transmission are also focused on the Western United States, proposing over 30 enhancements and new projects that could increase the transfer capacity in various sub-regions and across the interconnection to bring renewable energy resources to market. This chapter summarizes several major initiatives of Western regional entities, federal agencies, and Congress, and concludes with recommendations emphasizing the need for enhanced collaboration among Western states.

Given the major progress made in identifying California renewable energy zones, and the associated transmission segments and corridors described in Chapters 2 and 6, the question arises as to why activities in the larger Western region matter to California. The results of Western activities described in this chapter that will affect California include the following:

- New federal funding expected to be provided in 2010 for regional transmission planning will result in interconnection-wide 10-year and 20-year transmission plans for the Western Electricity Coordinating Council (WECC). These plans may identify projects and/or corridors that are "needed," and these will become candidates for Federal Energy Regulatory Commission (FERC) ratemaking and possibly other federal incentives. It is critical that California engage in defining what these plans are and ensuring that they reflect California's policies and assumptions accurately.
- If federal legislation establishing new FERC authority for siting and cost allocation passes in 2009-2010, the pressure to site new interstate line(s) will increase, with associated controversy over siting processes and impacts on environmental resources (both in and out of state). If FERC mandates a cost allocation method, California could be required to pay for projects not consistent with the California Renewable Energy Transmission Initiative (RETI), the Desert Renewable Energy Conservation Plan results, California Renewables Portfolio Standard (RPS) goals, and carbon reduction policies.
- Transmission system upgrades and additions anywhere in the WI will affect the operation of existing lines, including those owned by California utilities and private companies. Proactively participating in WECC analyses of new lines and path ratings is critical to ensuring continued high performance levels of key paths such as the California-Oregon Intertie.

- With federal funding, Western sub-regional transmission planning groups are taking on enhanced planning roles, including preparation of an Integrated 10-year Subregional Transmission Plan. Successful development and engagement of the California Transmission Planning Group (CTPG) and participation of the California Independent System Operator (California ISO) are essential to find consensus on projects and analyses reflective of California interests.
- Greatly increased federal funding for the Western Governors' Association (WGA) Western Renewable Energy Zone (WREZ) Phase 3 and 4 projects (described below) will continue to promote geographically constrained low-carbon resources and large-scale transmission to move remote resource generation to distant loads. If California prefers to procure more resources locally, as reflected in RETI, conflict among states seeking to export and in-state development interests will emerge.
- Major project developers continue the trend of pursuing large transmission projects to deliver power to coastal and desert load centers. Significant resources are being spent to evaluate feasibility and siting for these projects. The development of these projects could have considerable impacts on California.

Western Governors' Association Pursues Regional Transmission Development

Western Governors' Association WREZ Initiative

With the goal of facilitating the construction of "new, utility scale renewable energy facilities[39] and any needed transmission to deliver that energy *across* the Western Interconnection"[40] [emphasis added], in late 2007 the Western Governors' Association (WGA) initiated the WREZ project. Phase 1 of the project conducted an in-depth technical review of the West's renewable resource potential. Beginning with detailed mapping of Western renewable resources compiled by the National Renewable Energy Laboratory, WREZ screened for the most concentrated and highest value resource areas. These candidate study areas were then screened further for regulatory and physical limitations and reduced to a smaller number of qualified resource areas. With additional evaluation, the centroids of the qualified resource areas were identified as the hubs of potential renewable energy zones.

In June 2009, the Western governors adopted the WREZ Phase 1 report describing two years of work focused on mapping concentrated, high quality resources to meet demand in the Western Interconnection's distant markets. The report contains the WREZ Initiative Hub Map (see

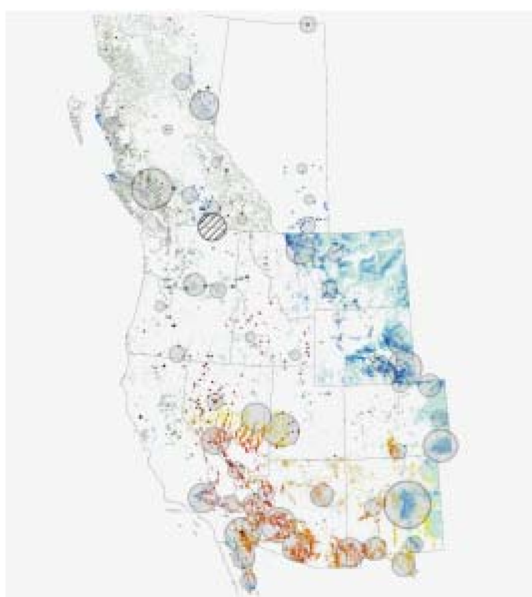
[39] Defined as 1,500 megawatts (MW) solar or wind, or 500 MW biomass, geothermal, or hydropower.

[40] *Western Renewable Energy Zones – Phase 1 Report*, page 2, Western Governors' Association and U.S. DOE, June 2009, http://www.westgov.org/wga/publicat/WREZ09.pdf, accessed August 11, 2009.

Figure 1) that combines the WREZ's state-specific "hubs" and displays graphical representations of regional utility-scale renewable resource potential, as defined by WREZ assumptions. These hubs are identified to evaluate interstate transmission lines in future WREZ phases. The hubs represent energy generation potential far greater than current WI Renewables Portfolio Standards (RPS) require, and the overall economic resource potential is significantly larger than policy scenarios identified to date. The West is thus in the enviable position of debating what types and locations of resource development should take place, rather than having insufficient options to meet requirements and goals.

California's position in WREZ is to ensure consistency with state-sponsored RETI results for both preferred renewable development areas as well as environmentally sensitive areas that should be avoided. The Integrated Energy Policy Report and Siting Committees (the Committees) are supportive of coordinated western planning but are cautious of a regional effort that dictates state options.

Figure 1: WREZ Initiative Hub Map



Source: *Western Renewable Energy Zones – Phase 1 Report,* June 2009, pages 12-13.

Future work in the four-phase WREZ project will include:

- Defining the WREZs (completing Phase 1)
- Forging transmission plans (Phase 2)
- Coordinating energy purchasing from the WREZs (Phase 3)
- Fostering interstate cooperation for developing energy generation and transmission (Phase 4)

WGA intends that the remaining work will be directly paid for by the U.S. Department of Energy (U.S. DOE). To accomplish this, the WGA has submitted a response to the U.S. DOE Funding Opportunity Announcement (FOA) for the American Recovery and Reinvestment Act of 2009 (ARRA) stimulus dollars allocated for states to participate in regional transmission planning. (See section below, "Increased Federal Funding for Transmission Planning and Projects.")

WGA Policy Statements

In addition to pursuing the WREZ initiative, the Governors' Staff Council has overseen the process of articulating Western state positions on matters in federal legislation and agency policies. WGA asserts Western policies that urge Congress to guide centralized regional transmission planning, implemented through actions and policies of federal agencies such as FERC, BLM, and U.S. DOE. The policy letters explicitly urge Congress to require a regional transmission plan, chosen and approved by WGA, that could be enforced by U.S. DOE and FERC through mechanisms such as incentives, federal corridor designation, National Interest Electricity Corridor Designation, possible siting preemption/backstop authority, and prescriptive cost allocation under methods specified by the FERC.[41] They have also sought support from Congressional leaders to have federal government policy support and financing of "up-sizing" of new transmission lines to serve "geographically constrained, low carbon resources" in the West.[42] The detailed implementation of the WGA policy statements will in significant degree depend on what if any legislation is approved by Congress in the 2009-10 time frame (or beyond). Pending legislation is described below in the section "Congressional Attention on Increasing Requirements for Federal and Regional Transmission Planning/Permitting."

Western Electricity Coordinating Council Increases Focus and Resources for Regional Transmission Planning

The WI is fortunate that its electric grid reliability operation and planning functions have been organized on an interconnection-wide regional basis for several decades.[43] The WECC is the

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[41] Western Governors' Association Letter to the Honorable Jeff Bingaman, May 1, 2009, http://www.westgov.org/wga/testim/transmission5-1-09.pdf.

[42] Western Governors' Association Letter to the Honorable Pelosi, Reid, Boehner, and McConnell, January 27, 2009, http://www.westgov.org/wga/testim/transmission-for-renewables1-27-09.pdf.

[43] There are three electrical interconnections in the United States and adjacent portions of Canada: the WI (11 Western states and Baja Norte, British Columbia, and Alberta); Texas; and the Eastern Interconnection. The Eastern Interconnection has not yet been organized on an interconnection-wide

regional entity responsible for overseeing implementation of mandatory system reliability standards approved by the North American Electric Reliability Corporation (NERC) and FERC under authority specified in the Energy Policy Act of 2005 (EPAct-05).[44] Among other major responsibilities, WECC administers the Western Renewable Energy Generation Information System (WREGIS), under contract to the Energy Commission, and has been asked by Western stakeholders to undertake comprehensive transmission system planning for both operations and expansion.

WECC operates through member committees composed largely of volunteers with technical knowledge and experience in system operation and planning. The two committees most central in transmission expansion planning are the Planning Coordination Committee (PCC) and the Transmission Expansion Planning Policy Committee (TEPPC). The PCC is responsible for conducting the three-phase rating process for new transmission projects proposed by transmission owners for construction and operation in the WI. Proposed projects must successfully complete this process to receive a path rating and to energize a new facility. More than 30 projects are presently in or have recently completed the rating process, as shown in Table 1 and as described in more detail in the section below, "Western Transmission and Generation Developers Seek Access to Load Areas." (More detail on selected projects is also provided in Appendix D, *Summary of Proposed Regional Transmission Projects*.)

Formed in 2006, TEPPC undertakes the functions of transmission congestion and expansion analyses for the WI. Consisting of 18 members representing all stakeholders and states/provinces in the interconnection, TEPPC is a forum for all interests to participate in collaborative deliberations on the planning of the current and future high-voltage system. No other multi-state interconnection authority has established an entity such as TEPPC. Thus, WECC is well-positioned to respond to the requirements of the DOE Stimulus FOA on regional transmission planning outlined below. TEPPC's three main functions specified in its charter are to maintain public databases for use in system assessment; manage the policy and regional transmission planning process; and coordinate studies of system congestion and potential expansion opportunities. The major products reflecting implementation of these functions include two Annual Study Reports (2007 and 2008) a planning protocol approved under FERC Order 890 and a Study Program for 2009, currently being implemented by WECC staff and the four main TEPPC work groups.[45] For more information on these TEPPC work products, please see the following website:

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basis and consists of six distinct regional reliability councils, multiple independent system operators, and 38 states or portions thereof.

[44] http://www.epa.gov/oust/fedlaws/publ_109-058.pdf, Public Law 109-58, passed August 8, 2005; accessed August 19, 2009.

[45] These are Data, Modeling, Historical Analysis, and Studies; each of these work groups has teams of volunteers from WECC members (including the California utilities, Energy Commission and California Public Utilities Commission staff, and the California ISO) who are responsible for work group activities and products.

http://www.wecc.biz/Planning/TransmissionExpansion/Pages/default.aspx

One of TEPPC's key study goals is to evaluate congestion under a variety of different load and generation scenarios and cases in the 10- and 20-year time frames.[46] Potential solutions to the identified congestion are chosen from the many proposed projects currently being pursued by developers in the interconnection, such as those identified in Figure 2 and described in part in "Appendix D: Summary of Proposed Regional Transmission Projects." An important auxiliary function of TEPPC and the WECC facilitator is developing and maintaining the WECC Transmission Information Portal, a comprehensive database tracking the status of Western transmission projects. TEPPC also provides a central point of coordination for the interconnection's sub-regional transmission planning groups (SPGs) that plan for sub-areas of the WI, including the California Independent System Operator and the recently formed California Transmission Planning Group (CTPG) described in "Chapter 4: Challenges to Achieving a Coordinated Statewide Strategic Transmission Plan." Under the FOA response summarized below, WECC and the sub-regions will increase the level of collaboration and integration of sub-regional planning and plans.

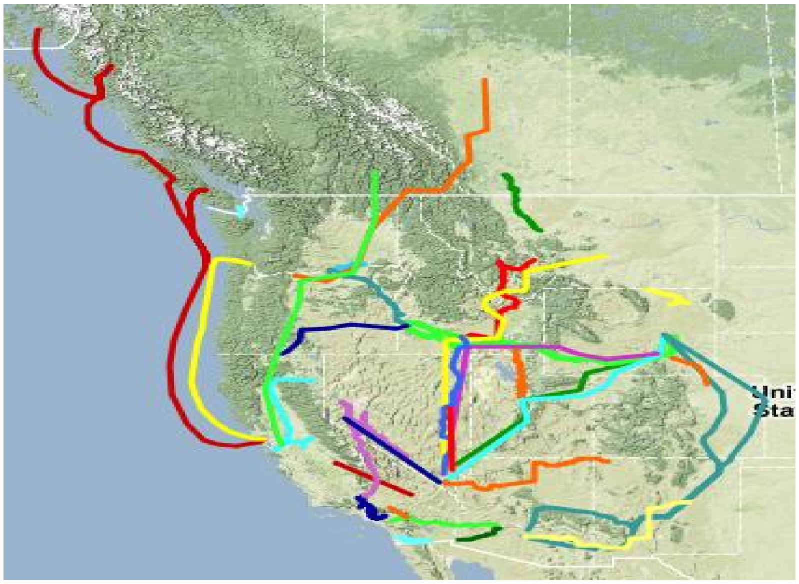
Table 1: Projects in WECC Path Rating or Regional Planning*

Navajo Transmission Project	CA Clean Energy Transmission
Northern Lights-Celilo Project	Chinook
Palo Verde-North Gila	Devers-Palo Verde 2
Southwest Intertie Project	Boardman to Hemingway
Ely Energy Center	Sunrise Power Link
G3 Power Plan	SunZia
Southwest Transmission Project	LS Power
Gateway Central (Populus- Mona-Oquirrh)	TANC Transmission Project*
Gateway South (Aeolus-Mona-Crystal)	Tehachapi
Gateway West	TransWest Express
Green Path North Project	Triton (Sea Breeze)
Hemingway to Captain Jack	Vulcan Proposed Line
High Plains Express	Walla Walla to McNary
Hughes Transmission Project	West Coast Cable (Sea Breeze)
Juan de Fuca (Sea Breeze)	Wyoming-Colorado Intertie
Montana-Alberta Intertie	Zephyr
Mountain States Intertie Project	* *As of May 4, 2009. List subject to frequent changes/additions.*

[46] This work is led by TEPPC facilitator Steve Walton with lead WECC staff members Donald Davies, Heidi Pacini, Stan Holland, Donald Scoffield, and Brad Nickell.

TEPPC, in concert with the WECC staff, was also given responsibility by the WECC board of directors for completion of the WECC response to the U.S. DOE FOA on regional transmission planning. This will result in the first WECC conceptual regional transmission plan in June 2011.

Figure 2: Major Projects Proposed in WI



Source: Doug Larson, Western Interstate Energy Board (WIEB) Staff, Committee on Regional Electric Power Cooperation Fall Meeting November 2008, San Diego, California.

Increased Federal Funding for Transmission Planning and Projects

An unexpected new source of focus and funding for transmission infrastructure has recently appeared in the form of the American Recovery and Reinvestment Act (ARRA), in which more than $39 billion is allocated for energy-related activities. Electricity transmission-related funding is approximately $17 billion, divided among the following: loan guarantees for renewable technologies and transmission technologies ($6.0 billion); Western Area Power Administration (WAPA) new borrowing authority to develop renewable transmission ($3.25 billion); increase in borrowing authority for the Bonneville Power Administration to undertake line construction for shovel ready projects ($3.25 billion); and electricity delivery and energy reliability ($4.5 billion),[47] the latter including $80 million earmarked for regional transmission

[47] This $4.5 billion is allocated toward $100 million for worker training; $10 million for smart grid interoperability standards; $80 million regional transmission assessment and planning; distribution of the balance discretionary to U.S. DOE for items such as to modernize the grid, conduct energy storage research, establish smart grid regional demonstrations, and others.

planning. For this document, the most relevant aspects of the ARRA funding are the regional transmission planning funds and WAPA renewable transmission borrowing authority. As described in the transmission FOA released by the U.S. DOE on June 15, 2009,[48] approximately $60 million is proposed for award to the three interconnections. The ARRA[49] provides that these funds shall be used for:

- Facilitating the development of regional transmission plans.
- Conducting resource assessment/analysis of future demand and transmission requirements.
- Providing technical assistance for the formation of interconnection-based transmission plans for the Eastern and Western Interconnections.
- Supporting regions and states for the development of coordinated state electricity policies, programs, laws, and regulations.

The FOA sought responses for two broad topics:

Topic A— Interconnection-level Analysis and Planning

Topic B—Cooperation Among States on Electric Resource Planning and Priorities

WECC submitted its FOA response on August 12, 2009, and WGA submitted its response to Topic B of the FOA on September 11, 2009. WGA requested approximately $14 million; $6.5 million of the request is to be allocated to providing input from states/provinces into WECC and sub-regional planning work funded under Topic A of the FOA. These responses are summarized in "Appendix B: American Recovery and Reinvestment Act of 2009 Regional Transmission Planning Responses."

The proposed total funding requested by WECC for Topic A activities is approximately $16 million (2010-13), divided among six functions as summarized in Table B-1 in "Appendix B: American Recovery and Reinvestment Act of 2009 Regional Transmission Planning Responses."[50] With the funding and the requirements specified explicitly in the DOE FOA, important new functions will be funded for the first time. These include: coordination of SPG plans into one integrated 10-year reliability-constrained WI assessment; funding for participation in regional and sub-regional planning activities of non-governmental organizations; completion of highly detailed system stability studies under high levels of

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[48] Financial Assistance Funding Opportunity Notice, U.S. DOE National Energy Technology Laboratory Transmission Analysis and Planning, FON: DE-FOA0000068.

[49] ARRA, Op cit.

[50] Lead responsibility for preparation of the WECC response resides with WECC staff Tom Schneider, Director of Planning, and Brad Nickell, Director Renewable Integration; material in this sub-section is referenced to the FOA and Tom Schneider/Brad Nickell WECC Staff Presentation to WECC Board of Directors, July 30, 2009, Loveland, Colorado.

intermittent generation additions (by western universities); and continued funding of meetings of the western utilities' resource planners in a biannual forum. Final decisions about funding will be made later in 2009 with funding scheduled to begin in January 2010. The extent of the work will be based on the award and will be reflected in the TEPPC 2010 Study Program.

WGA has requested $14 million in ARRA funding over the period 2010-2014. WREZ Phase 3 and 4 will be explicitly funded by the FOA awards and will be overseen by the WGA Staff Council. More detailed information is available in Figure B-2 of Appendix B. A new 24-member state/provincial steering committee will be formed to oversee work that provides input into the Topic A work to be undertaken as proposed by the WECC. Major new work on a "decision support system" for wildlife habitat corridors, mapping carbon sequestration, and exploring the water-energy nexus is proposed, all under the oversight of the Staff Council. Final decision making by the U.S. DOE regarding funding for both Topic A and B requests by WECC and WGA will be made later in 2009 with funding scheduled to begin in January 2010. The entire $27.5 million requested likely will not be available to the WI, given competition for funds coming from the Eastern Interconnection and the Electricity Reliability Council of Texas.

WAPA Stimulus Funding

ARRA funding of significant importance to renewable transmission infrastructure development is the new borrowing authority provided to WAPA. WAPA has developed its Transmission Infrastructure Program implementation requirements and has conducted an open solicitation for projects seeking funding under the new borrowing authority. This program could affect California as projects granted funding will affect operation of the existing system and could be designed to deliver renewable energy generation to meet California requirements. More than 30 responses to the competitive project solicitation were received and are being evaluated

Congressional Attention on Increasing Requirements for Federal and Regional Transmission Planning/Permitting

Currently, there is a high degree of interest at the federal level in moving toward inter-connection-wide transmission planning and federal intervention in planning, permitting, and cost allocation. Five major pieces of draft legislation on the subject reflect varying degrees of mandatory planning requirements and direct federal regulation (sponsors include Senators Bingaman, Reid, Nelson, and Dorgan and Representatives Waxman and Markey). The three drafts currently receiving the most attention are those sponsored by Senators Reid and Bingaman and the provisions included in the Waxman-Markey climate bill.

Provisions of the various legislative proposals are in a state of flux and subject to change, but a snapshot of key provisions at the time of this writing is provided below; however, these proposals are works-in-progress.[51] Parameters of importance to the West include planning

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[51] *Comparative Summary of Federal Transmission Legislation,* Victoria Ravenscroft, Western Interstate Energy Board staff, July 2009 and previous dates; 303-573-8910 (incorrect or outdated characterizations are chapter author responsibility, not WIEB staff).

requirements, planning authority and plan approval, siting preemption and conditions, Renewable Energy Zone (REZ) designation requirements, federal agency authorities and responsibilities for coordinating siting, and cost allocation provisions. Individual bills vary greatly on specifications for these key components.

The Bingaman Senate Energy Staff is working on draft legislation that would allow far-reaching federal intervention at both the regional and state levels of transmission planning, permitting and cost-allocation, including the following:

- Directing FERC to coordinate the planning of high-priority national transmission projects (≥ 345 kV AC and ≥ 300 kV DC); requires interconnection-wide or regional plans and requires FERC to adopt plans.
- Allowing FERC to preempt the state's siting authority without a National Interest Electric Transmission Corridor (NIETC) designation for lines that are part of a "high-priority national transmission project," if the state: "fails to approve" the project within one year, rejects the application, or imposes unreasonable conditions on the permit; directs that FERC shall give due weight to the environmental record and results of the state siting process.
- Requiring FERC to establish a cost allocation method (costs may be allocated across all or part of a region but must be just and reasonable and must not be disproportionate to the anticipated benefits in any given area); FERC shall give deference to cost allocation proposals supported by broad agreement of states.
- Establishing the U.S. Department of the Interior as the lead agency for coordinating environmental review by federal agencies; states that are willing may coordinate with FERC and federal agencies.
- The Secretary of the Interior will prepare the NEPA environmental review document. (For federal authorizations, federal agencies shall use existing 368 corridors or must create new corridors according to §368[c].)
- Does not establish a WREZ or national RPS requirement but suggests that potential renewable energy resources must be considered in planning.

A more modest approach to increased structure in regional planning and enhanced federal oversight, with a focus on renewable or zero-carbon generation, is contained in Waxman-Markey's "American Clean Energy and Security Act of 2009 (HR 2454)." Key transmission provisions of this bill (as of July 6, 2009) include:

- Directs FERC to coordinate the regional planning process to aid the deployment of renewable and other zero-carbon energy.

- Allows one year for FERC to issue planning principles; plans must be submitted by regional entities within 18 months after the planning principles are issued.

- For the Western Interconnection only, FERC siting preemption is provided, which include:
  - No NIETC designation requirement but the proposed project must be a multi-state line identified in a regional plan.
  - The facility must be needed in "significant measure" to meet renewable energy demand under plan.
  - FERC can preempt the state's siting authority if it did not issue a decision within one year, denied the application or authorized the project subject to conditions that "unreasonably" interfere with the project.
- FERC shall consider and incorporate state-imposed constraints and mitigation.

Senate Majority Leader Reid also has pending legislation, S 539. This bill would enhance the electric grid to take full advantage of renewable resources and create an interconnection-wide "green transmission grid," a high-voltage (≥ 345 kV) "backbone" with renewable energy feeder lines. As introduced, the bill would require that 75 percent of line capacity must be available to renewable resources (this amount can be adjusted for reliability), and it would require the President to designate REZs.

At this writing, the outcomes of the various proposed legislation for the end of the calendar year is uncertain. However, the content of the principal legislative vehicles hold important implications for Western projects and regulatory processes.

U.S. DOE Identifies Transmission Congestion in 2009 Study to Congress

Under the provisions of EPAct-05, the U.S. DOE is directed to conduct triennial assessments of transmission congestion in major regions of the country. These assessments are due to Congress in August of each third year, beginning in 2006. The congestion assessments provide the technical foundation for the Secretary of Energy, at his discretion, to make designations of NIETCs; transmission facilities proposed in these corridors are then eligible for siting preemption by the FERC, if not approved in a timely manner by state regulatory authorities ("backstop siting authority").

The U.S. DOE's first *National Electric Transmission Congestion Study* (Congestion Study)[52] provided a basis for the Secretary to designate NIETCs, including one covering most of Southern California. Multiple other congestion areas were also identified by the U.S. DOE, including the Seattle Corridor and the San Francisco Bay Area. Areas of concern identified in 2006 were revisited during the 2009 study and could become potential candidates for NIETC designation later in 2009-10. At the same time, the NIETC designation process has been the

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[52] *National Electric Transmission Congestion Study*, U.S. DOE, August 2006, http://nietc.anl.gov/congestionstudy/, accessed August 12, 2009.

subject of successful court challenges, and the statutory authority for designation is proposed for repeal and replacement by a more comprehensive permitting role for FERC in the draft federal transmission legislation as summarized above.[53]

The 2009 Congestion Study was scheduled to be delivered to Congress in August 2009 but has been delayed with no new target date announced. Based on information presented at the U.S. DOE Congestion Conference in Chicago in late March 2009, it seems clear U.S. DOE staff responsible for the Report will be relying heavily on the WECC TEPPC analysis conducted under its 2008 Study Plan, particularly the historical analysis of congestion, as well as additional Western SPG analyses.

Western Transmission Developers Seek Access to Load Areas

As described in the *2007 Strategic Plan*, significant and sustained interest continues in developing major projects in the Western Interconnection. Most of those described in the *2007 Strategic Plan* (TransWest Express Project, Northern Lights Initiative, Canada-Pacific Northwest-Northern California Transmission Project, California Oregon Intertie Upgrade Project and the Southern Transmission System [Intermountain DC Upgrade]) remain active, though in some cases ownership has changed. As noted earlier more than 30 projects are engaged in the WECC regional planning and three-phase rating process. Table 1 above shows a list of these projects.

Purposes, locations, sizes, and sponsors of these projects vary markedly. For example, many are sponsored by transmission owners and are being constructed to serve load and meet reliability requirements in their own service territories. Others are proposed to transfer new generation relatively short distances; sizes range from 365 to 500 kV, though it often is difficult to find sponsors to support the larger and longer lines at the 500 kV level. One new dimension since 2007 is that most projects identify their purpose to be delivery of renewable resources to loads in states with RPS requirements or carbon limitations. This is in part a response to the WREZ, Western Interconnection Regional Advisory Body, and TEPPC focus on evaluating congestion under alternative futures with varying degrees of commitment to renewable penetrations.

Proponents of major new lines emphasize that there has been only limited expansion of significant transmission for 20 or more years; the existing transmission base is depreciated in the rate base; and there is uncertainty whether to build because of restructuring and the slowly unfolding implementation of Order 890 and other FERC policies. The recent push for RPS and GHG/carbon reduction and unknown federal policies for cap and trade, as well as the need to recharge the expected increase in electric vehicles, have added complexity to the situation.

[53] The denial of the Application for a Certificate of Environmental Compatibility, a siting permit, by the Arizona Corporations Commission for the Arizona portion of the Palo Verde Devers 2 project led SCE to file for backstop permitting from the FERC. However, the siting application for the Arizona portion of this line, including the federal permit application, has been withdrawn.

These regulatory policies, even if uncertain, have resulted in wind and solar proponents rushing to develop projects, often ahead of associated transmission. While LSEs are waiting for regulatory certainty, merchants are seeking WECC path ratings and ROW permitting while awaiting contracts to implement their projects. This has resulted in the BLM calling for regional planning and an interconnection-wide plan that sets priorities. This could also reduce the likelihood of multiple applications for one ROW or worse (from an environmental standpoint), applications for multiple lines in new, adjacent corridors.[54]

A plethora of proposed transmission projects, some of which are clearly duplicative, raises alarms for regulators and questions for all, since many would be headed for California while more than 7,000 MW of capacity appears to be headed for the El Dorado Valley near Las Vegas, yet little firm transmission is available from those locations to major nearby load centers. For those who believe major new additions to the high-voltage Western transmission system are essential, Figure 2 presents an exciting vision of possible future investments. To others who are less convinced of the need for new facilities, the figure presents a worrying picture of potential environmental impacts on critical wildlife corridors, endangered species and urban landscapes.

Regardless of one's point of view, a daunting set of challenges confront any major new project. Many of those challenges detailed in Chapter 5 of the *2007 Strategic Plan* remain today.[55] Presentations at the Energy Commission's joint Integrated Energy Policy Report and Siting Committee (the Committees) workshop on May 4, 2009, highlighted pressing present-day questions many projects face.[56] Presenters posed the following questions:

- Would tradeoffs be made between AC and or DC technologies for specific projects?
- Would the West's local or regional agendas be implemented"
- Will regionalized renewable markets be developed for renewable energy credits (RECs)?
- How will cost allocation take place if multiple balancing authorities are involved?
- Are conservation of right-of-way and capacity banking alternatives workable?
- Does an interstate "grid overlay" concept make sense?
- What technologies can accommodate designs for expansions?

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[54] See the Chapter 5 section titled "Potential Conflict between Transmission Planning Priorities and WECC Reliability Criteria" for more information on this topic.

[55] See, for example the excellent treatment of transmission challenges reviewed by Joseph Eto, *2007 Strategic Plan*, "Chapter 5: Western Regional Transmission Issues and Solutions, " http://www.energy.ca.gov/2007_energypolicy/documents/2007-05-14_workshop/presentations/06%20Joe%20Eto%20CostAlloc%20IEPR%20final.pdf, posted on May 15, 2007, accessed on August 11, 2009.

[56] Grace Anderson, Bill Chamberlain, and Rich Bayless, presentation to Energy Commission IEPR and Siting Committees, May 4, 2009, http://www.energy.ca.gov/2009_energypolicy/documents/2009-05-04_workshop/presentations/Grace_Anderson_2009-04-30.PDF, posted April 30, 2009, accessed August 13, 2009.

- Can uncertainties regarding project cost recovery and funding be resolved?
- What coalitions are needed to address land planning, use, and permitting controversy?

Responses by participants in the workshop included:

- Duplicative projects are competing for corridor space but few have contracts with LSEs.
- States and utilities need to engage and articulate policies on specific procurement (geographic and time frame).
- Any major line addition will affect existing system operation and other projects in planning/permitting/path rating processes.
- The first-in-line federal agency (BLM) siting process could result in "less preferred" projects receiving scarce corridor right-of-way allocations.
- Creating multiple new corridors will increase opposition and potential environmental impacts of new lines.
- California load centers are central in project definition and Western region planning.

Recommendations

In order to assure implementation of California's energy policies in the development of regional transmission planning, the Committees recommend the following:

- The Energy Commission should continue participation in and support for Western Interconnection transmission planning including representation on the Western Electricity Coordinating Council (WECC) Transmission Expansion Planning Policy Committee and related technical groups. The Energy Commission should also support participation in new entities formed under the U.S. Department of Energy's Funding Opportunity Announcement for regional transmission planning funding to WECC and the Western Governors' Association.
- The Energy Commission should continue participation in and support for the Western Renewable Energy Zone (WREZ) process to ensure consistency with RETI results for both preferred renewable development areas as well as environmentally sensitive areas that should be avoided.

CHAPTER 4: Challenges to Achieving a Coordinated Statewide Strategic Transmission Plan

Introduction

Transmission planning involves assessing several key aspects of the electrical system, including grid operation, electrical system reliability and congestion issues, and scenario options for meeting the state's climate and Renewables Portfolio Standard (RPS) goals, and then determining how to expand and upgrade the existing system to meet projected load growth. Transmission planning is critical to future transmission infrastructure development in California, but to be successful it must be effective.

Effective transmission planning requires the following essential elements:

(1) Evaluation of two primary components; a) the electrical system, and b) land use and environmental implications regarding transmission line routing. In the final analysis, these two components must come together to provide a balanced approach to meeting future electrical system expansion that addresses electrical system considerations and reduces land use and environmental conflicts associated with transmission line routing. Otherwise, it is much more difficult to successfully mesh the electrical needs with land use and environmental considerations during the permitting phase, where it may be too late.

(2) Active stakeholder participation. In this regard transmission planning should be user-friendly and transparent and should seek broad stakeholder participation and consensus. Addressing transmission line routing and related land use and environmental issues in the planning process, as addressed above, would also promote stakeholder participation because there is considerable stakeholder interest in this area. Otherwise, resistance to future transmission infrastructure proposals will likely be significant and potentially insurmountable, and implementation of transmission plans will be limited and cumbersome because of a lack of broad support.

(3) Significant coordination and linkage between transmission planning organizations, in particular among the electric utilities and the California Independent System Operator (California ISO). Otherwise, planning becomes disjointed and/or duplicative, and lacks the continuity needed to achieve a statewide approach to timely transmission infrastructure development.

(4) Full coordination with regional transmission planning efforts in the western states, including the Western Electricity Coordinating Council's (WECC) Transmission Expansion Planning and the Western Renewable Energy Zone (WREZ)[57] initiative that is

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[57] The Western Governors' Association launched the Western Renewable Energy Zones initiative in May 2008. The WREZ seeks to identify those areas in the West with vast renewable resources to expedite the

modeled after California's Renewable Energy Transmission Initiative (RETI) collaborative transmission planning process. (See below under "Existing Transmission Planning Processes.") Otherwise, economic and environmental advantages associated with leveraging the western states grid and related expansion will not be fully realized.

(5) An assessment of transmission needs well into the future, significantly beyond the normal 10-year planning horizon. In this regard, a longer-term view of up to 30 years or more should be considered so that the 10-year plan does not preclude or conflict with much longer-term needs, and to introduce longer-term transmissions issues as early as possible for consideration of the more detailed 10-year planning horizon.

(6) Timeliness. Otherwise transmission infrastructure development will proceed on a slower pace and in an uncoordinated manner, and this will interfere with opportunities for statewide transmission optimization of the electrical system, land use and environmental implications, and ratepayer costs, and with the attainment of RPS and other policy goals.

A transmission planning process having these qualities will support an efficient transmission permitting process because it assesses issues associated with need, land use, environmental impacts, and electric system conflicts before the filing of permit applications. This is particularly important for land use and environmental conflicts, which are typically the major impediment to securing any transmission permit. Transmission planning with these qualities will also support achieving the state's renewable energy and greenhouse gas reduction goals and requirements because it will provide a clear roadmap for how to interconnect renewable energy to the grid well into the future. Effective transmission planning can do this while addressing grid operation, reliability and congestion issues independent of, and resulting from, the substantial renewable generation integration necessary to support RPS. Effective transmission planning becomes even more critical if renewable integration targets increase over time.

On the other hand, ineffective transmission planning results in contentious, lengthy, and ineffective permitting processes, and confusion about what transmission infrastructure is suitable for California now and in the future. Ineffective transmission planning also results in a

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development and delivery of renewable energy to where it is needed. Renewable energy resources are being analyzed within 11 states, two Canadian provinces, and areas in Mexico that are part of the Western Interconnection. The WREZ project will generate:

- Reliable information for use by decision-makers that supports the cost-effective and environmentally sensitive development of renewable energy in specified zones.
- Conceptual transmission plans for delivering that energy to load centers within the Western Interconnection. A number of factors will be considered, including the potential for development, time frames, common transmission needs, and costs. The project also will evaluate all feasible renewable resource technologies that are likely to contribute to the realization of the goal in WGA's policy resolution calls for the development of 30,000 megawatts of clean and diversified energy by 2015.

lack of public confidence that government, utility, and other organizations responsible for various aspects of transmission infrastructure are taking actions that are in the best interest of the state of California, its citizens, and its environment. A concerted effort by transmission planning entities, including a willingness to approach transmission planning in a more coordinated manner conducive to broad stakeholder participation, will be necessary to avoid current transmission infrastructure development problems going forward. Furthermore, these problems will only become more exacerbated in the future unless statewide transmission planning is successful.

Overview

This chapter addresses how transmission planning is being undertaken in California and the problems associated with this existing transmission planning process. It also addresses how existing planning can be restructured, reorganized, and consolidated to address the existing planning process problems.

This chapter also addresses how transmission planning, particularly at the electric utility level, can leverage the Energy Commission's Strategic Plan proceeding to vet statewide planning proposals with broad stakeholder interests in an open and user-friendly process. With the adoption of Senate Bill 1565 (Bowen, Chapter 692, Statutes of 2004), which requires the development of a *Strategic Transmission Investment Plan* (*Strategic Plan*), the Legislature acknowledged the importance of the state's role in the transmission planning process and recognized the Energy Commission as the state agency best suited to help implement an effective planning process. The objective is to help ensure development of a uniform and optimized statewide plan, with broad stakeholder support, that emphasizes the best interests of the state of California, with consideration of electric utility and the California ISO planning processes.

The Existing Transmission Planning Processes

The existing transmission planning process is comprised of various planning efforts undertaken by the electric utilities, the California ISO, the Energy Commission, and informally, by the Renewable Energy Transmission Initiative (RETI). These planning processes are depicted in Figure 3 below and summarized as follows:

Electric Utilities

Detailed electrical system related transmission planning in California takes place at electric utilities (investor-owned electric utilities [IOUs] and publicly owned utility [POU] balancing authorities). Each electric utility plans for its own service territory. To varying degrees, these organizations also consider general land use issues, but lack of sufficient attention to the importance of land use and environmental issues is often lacking, as evidenced by recent difficulties with utility transmission proposals such as the San Diego Gas & Electric Company (SDG&E) Sunrise Powerlink Transmission Project and the Transmission Agency of Northern California (TANC) Transmission Project.

IOUs submit their transmission planning considerations to the California ISO Annual Transmission Planning process. (See below.) They also submit their future transmission project priorities to the Energy Commission's Strategic Plan process (see below). Publicly owned electric utilities (balancing authorities) do not participate in the California ISO planning process, but they do submit their future transmission project priorities to the Energy Commission under the Strategic Plan process.

California ISO

On an annual basis the California ISO assesses the reliability of the transmission network under its control using national industry standards. This effort includes identifying the short-term need for grid upgrades and developing a long-term infrastructure vision that incorporates state and federal policy initiatives including compliance with the federal reliability requirements.[58] The result of this effort is the California ISO Annual Transmission Plan. Within its annual planning process the California ISO is required to implement Federal Energy Regulatory Commission (FERC) Order No. 890 concerning an open access transmission tariff.[59] Under Order No. 890 the California ISO is required to ensure that transmission service is provided on a non-discriminatory basis by developing an open, coordinated, and transparent transmission planning process.

As important as the California ISO's annual plan is to future transmission development in California today, it is not a fully coordinated statewide transmission plan because it addresses only the California ISO-controlled grid (in other words, the IOU system). In addition, the annual plan is limited to electrical system planning requirements, and therefore land use and environmental implications, which are the most important consideration for many stakeholders, are not considered in the annual plan. Notwithstanding FERC-required transparency, this land use/environmental limitation contributes to stakeholder frustration when participating in the annual planning process because the plan does not translate future electrical system requirements into a vision for future transmission line routing. Furthermore, the annual plan captures only a 10-year time horizon and does not assess transmission needs well into the future for a longer-term view.

The California ISO's Annual Transmission Plan establishes the need for new transmission infrastructure proposals by IOUs who in turn seek permits for these transmission facilities at

[58] http://www.nerc.com/page.php?cid=2%7C20; accessed August 18, 2009.

[59] http://www.ferc.gov/whats-new/comm-meet/2007/021507/E-1.pdf; accessed August 18, 2009.

the California Public Utilities Commission (CPUC). The annual plan is also an important foundational link upon which the Energy Commission's *Strategic Plan* is built. (See below.)

California Energy Commission

The Energy Commission undertakes components of transmission planning. The Energy Commission is required by Senate Bill 1565 (Bowen, Chapter 692, Statutes of 2004) to adopt the *Strategic Plan* for the entire state's electric transmission grid (IOU and POU transmission networks) that identifies and recommends actions required to implement investments needed to ensure reliability, relieve congestion, and meet future load growth. In this regard, the *Strategic Plan* describes the major immediate actions that California must take to develop and maintain a cost-effective, reliable transmission system that is also capable of responding to important policy challenges such as meeting RPS goals and reducing greenhouse gas emissions. The *Strategic Plan* also describes the state's transmission challenges and provides recommendations for overcoming them.

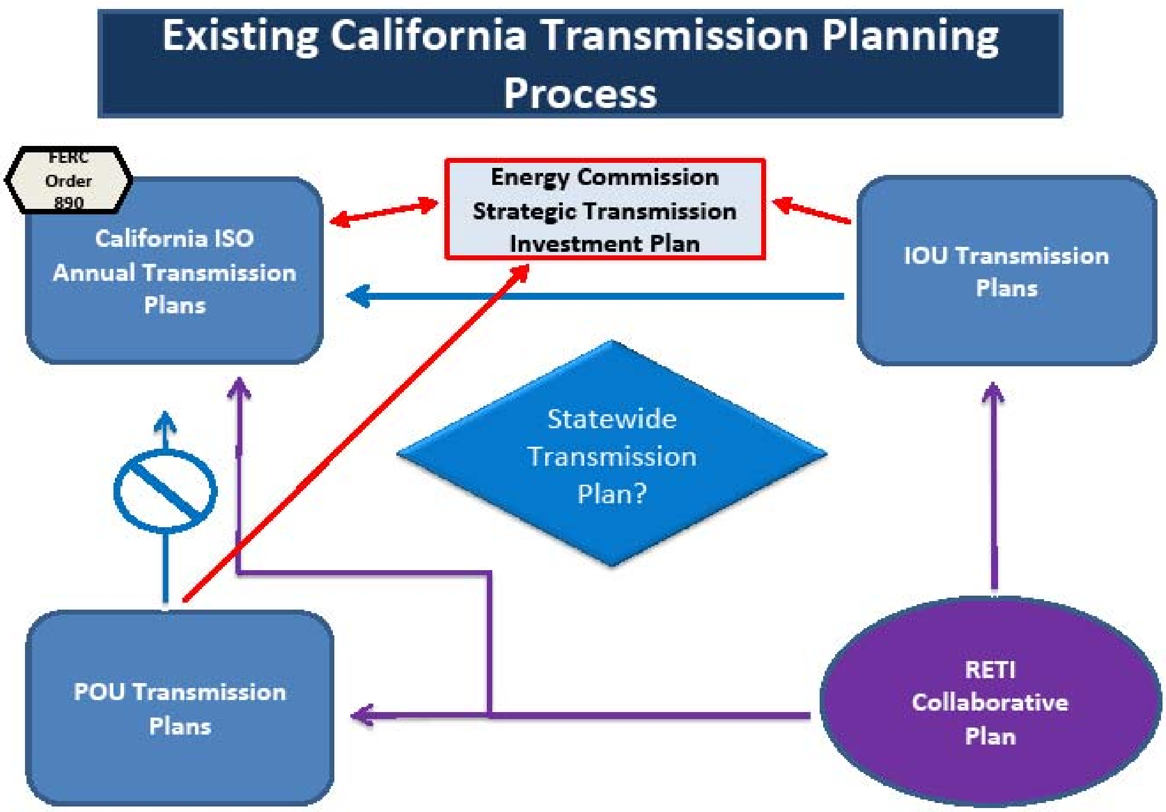
The *Strategic Plan* identifies high-priority transmission projects (based on submittals provided by both IOUs and POUs). IOU projects are then integrated into the subsequent California ISO annual plan.

Renewable Energy Transmission Initiative (RETI)

Lastly, the informal RETI process is influencing formal transmission planning. The electric utilities, the California ISO, and the Energy Commission have all indicated their commitment to consider RETI output with regard to their transmission planning processes. For example, the California ISO has committed to considering the RETI conceptual transmission plan in its 2010 annual planning process and in its recently initiated work to develop a 33 percent renewable conceptual transmission plan to support its 2010 annual planning process. The RETI collaborative has already created momentum toward establishment of key elements of a formal statewide transmission planning process. (See below under "Efforts in Support of a Consolidated Statewide Transmission Plan.")

The RETI stakeholder collaborative planning process will not result in a complete and detailed California transmission plan of service because it addresses only the interconnection of renewable energy as opposed to all transmission network needs and requirements, and it is being conducted at the conceptual level. While RETI is producing only a conceptual transmission plan for renewable development, it is nonetheless the first step toward achievement of a detailed transmission plan on a statewide basis. This is because it articulates conceptual transmission requirements associated with integration of renewable resources, which is the most important and difficult requirement for future transmission infrastructure in California, and it does this for all electric service territories. In doing so, it balances electrical considerations with land use and environmental considerations associated with transmission line routing. More importantly, it does so as a collaborative effort of stakeholders to help create broad stakeholder support needed for new transmission infrastructure. It seeks to address the statewide transmission requirements of California from the perspective of varied stakeholder interests and concerns, and it seeks to create a conceptual roadmap of future transmission development in California on a statewide basis to support RPS goals and requirements. Ultimately, RETI seeks to significantly influence formal transmission planning processes in California.

Figure 3: Existing California Transmission Planning Process



Source: California Energy Commission staff, August 2009.

Key Problems With the Existing Transmission Planning Processes

Statewide collaboration with regard to formal transmission planning does not exist and remains elusive. Formal transmission planning organizations in California are currently disjointed and uncoordinated, and as a result their efforts do not adequately address future transmission infrastructure requirements on a statewide basis. None of the existing transmission planning processes adequately considers transmission line routing and related land use and environmental implications, and existing planning processes do not adequately consider long-term needs well beyond the 10-year time horizon. Specifically, transmission planning in California lacks the following:

- A single, consolidated, and uniform approach that addresses the entire state. Without this cohesive approach, transmission planning will continue to be disjointed.
- A planning perspective that effectively balances electrical requirements with land use and environmental considerations. Without this balance, permitting of future transmission infrastructure will remain significantly contentious.
- A plan that has broad stakeholder support, including full consideration of the RETI collaborative results. Without this stakeholder support, permitting of future transmission infrastructure will continue to lack support substantially beyond electric utilities and the California ISO.
- A plan that presents a longer-term view beyond the normal 10-year planning horizon. Without this longer-term view, shorter-term transmission infrastructure decisions could interfere with longer-term needs, or make longer-term needs more costly, more difficult to meet, or create greater land use and environmental conflicts.
- A plan that is coordinated with the western states' regional planning efforts, in particular the Western Renewable Energy Zone (WREZ) initiative. Without this coordination, transmission infrastructure in California could be overbuilt because regional transmission projects that can address some of California's needs may be overlooked, or suboptimal regional lines will be built that do not mesh with California's priorities.

Unless these problems are resolved, transmission planning will continue to be ineffective in ensuring needed transmission infrastructure is developed in California in a timely manner. However, promising efforts are now underway to help ensure these transmission planning shortcomings are corrected in the future.

Efforts in Support of a Consolidated Statewide Transmission Plan

The single most significant development toward facilitation of a formal statewide transmission plan for California has been the formation of the informal RETI stakeholder collaborative. As indicated above, RETI has demonstrated that divergent stakeholder interests can work together to create a plan that can help advise and influence transmission planning processes. We commend the many stakeholders who have committed their time and resources to the RETI process – educating each other and engaging in collective problem-solving.

The RETI process appears to have already influenced transmission planning. Specifically, the California ISO, California Municipal Utilities Association (CMUA), Imperial Irrigation District (IID), City of Los Angeles Department of Water and Power (LADWP), Pacific Gas and Electric Company (PG&E), Southern California Edison Company (SCE), San Diego Gas & Electric Company (SDG&E), Sacramento Municipal Utility District (SMUD), and the Transmission Agency of Northern California (TANC) have made significant progress toward establishing a coordinated statewide utility transmission planning process by activating the California Transmission Planning Group (CTPG). Coordination among all electric utilities with the California ISO is critical to achieving a statewide transmission plan. Ultimately, the electric utilities are responsible to their ratepayers for ensuring their transmission infrastructure meets growing demand and evolving energy policy at a reasonable cost, and consistent with this, the California ISO establishes the need for new transmission infrastructure (for IOUs). Furthermore, notwithstanding the existing limitations and problems associated with California transmission planning as described, electric utilities and the California ISO are the only organizations capable of conducting detailed electrical planning, which is a principal element in developing a forward-looking transmission plan for California. If the CTPG's consolidated utility approach to future statewide transmission needs is successful, and if it fully considers broad stakeholder interests, including the RETI collaborative, it will directly encourage a formal statewide plan as reflected in the California ISO annual transmission plan.

Consolidated Statewide Transmission Plan Proposal

Introduction

This section addresses a proposal that statewide transmission planning be divided into two time frames. The first time frame is consistent with normal transmission planning time horizon and the RPS goal of 33 percent renewable integration, essentially 10 years. The secondary time frame looks beyond the established 10-year planning horizon and addresses the 10- to 30-year horizon. However, this longer-term timeframe is much less certain that the 10-year planning horizon because more variables that cannot be quantified come into play. Therefore, this longer-term plan must reflect added uncertainty, be more abstract than the 10-year plan, and use a scenario planning approach to capture the range of possibilities. See Chapter 7 for discussion of scenario planning approaches to building a long-term abstract plan.

Short-Term 10-Year Planning Horizon

Figure 4 below depicts a proposed statewide transmission planning process that emphasizes a fully coordinated planning approach for the established 10-year planning horizon. It involves transmission planning conducted by the CTPG, the California ISO, IOUs, equivalent publicly owned electric utilities plans (POU balancing authorities), and RETI stakeholders. Figure 4 distinguishes transmission projects that have statewide significance because they have electrical relationships to the statewide grid and promote state policy preferences, from transmission projects that have little or no relationship with the statewide grid because they are focused on individual electric service territory needs and requirements. The Committees suggest consideration of the following transmission planning process for the state:

Step 1: Electric utilities undertake transmission planning for their individual service areas.

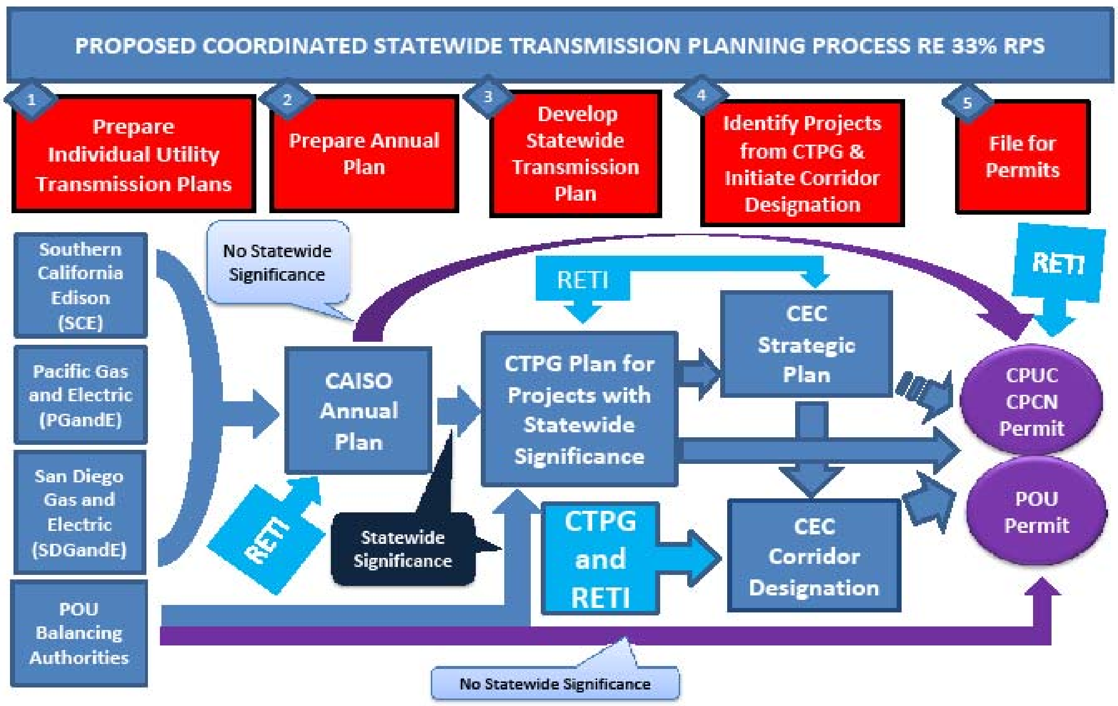
Step 2: The California ISO (via its annual planning results) identifies needed transmission projects (needed to meet reliability, reduce transmission congestion, and access renewable generation).

Step 3: The CTPG considers the identified transmission projects and identifies potential common routing of transmission projects. The CTPG would work with parties to maximize corridors and projects to minimize redundancy, costs, land use impacts, and environmental impacts.

Step 4: The Energy Commission considers the results of the CTPG in its biennial Strategic Plan proceeding – a public forum where needed transmission projects and corridors would be vetted and conformance with state policies and objectives would be measured.

Step 5: The CPUC and publicly owned utility governing boards would give great weight to the Energy Commission *Strategic Plan's* findings in their permitting processes. A critical component of this proposed planning process is the integration of broad stakeholder interests under the California ISO annual planning process, the CTPG planning process, and the Energy Commission's biennial *Strategic Plan*. Additional stakeholder participation would occur in both the corridor designation process and the permitting processes.

Figure 4: Coordinated Statewide Transmission Planning Process



Source: California Energy Commission staff, August 2009.

First Step – Prepare Individual Utility Transmission Plans

The first step in this proposed transmission planning process acknowledges individual electric utility service area transmission planning undertaken by all electric utilities. Each IOU submits its planning perspective to the California ISO. POU balancing authorities do not currently participate in the California ISO planning process, and as described in steps three and five (see below), would submit planned transmission projects of statewide significance with the CTPG, or submit projects that do not have significance beyond their service territories directly to the POU transmission permitting process.

Second Step – Prepare Annual California ISO Transmission Plan

The second step in this proposed transmission planning process acknowledges the importance of the formal California ISO annual transmission planning process. The annual plan addresses the California ISO controlled electric transmission grid, but it does not currently address any transmission infrastructure outside the California ISO controlled grid, including the POU controlled transmission grids. The distinction between transmission of statewide significance and transmission without statewide significance is emphasized at this point in the proposed process. As indicated above, transmission projects that have statewide significance have electrical relationships to the statewide grid. Transmission projects that do not statewide significance have little or no relationship with the statewide grid because they are focused on individual electric service territory needs and requirements. Transmission projects that do not have statewide significance would go directly to permitting because they will not significantly affect statewide planning. However, IOU and POU balancing authority transmission projects that have statewide significance would be considered under a consolidated statewide planning process undertaken by the CTPG. The RETI stakeholders would play an important role at this stage of the proposed planning process to help ensure RETI conceptual planning results are adequately considered by the California ISO.

Third Step – Develop Statewide Transmission Plan

The third step in this proposed transmission planning process is the heart of consolidated statewide transmission planning and depends on the success of the CTPG to develop a single statewide transmission plan. The IOUs and POU balancing authorities would act in a fully coordinated manner, addressing all electric utilities' requirements having statewide significance regardless of service territory, to create a single statewide transmission plan for California.

This step acknowledges CTPG was formed to create the needed organization at the electric utility level to advance statewide utility coordination and recognizes that transmission electrical planning must be conducted by the electric utilities because they understand their electrical system configuration and issues more than any other entity, and they are best equipped to perform the necessary power flow analyses and other electric system related evaluations. Ultimately, it is the electric utilities that are accountable to their ratepayers to deliver electricity within their service territories on a reliable basis and at competitive rates, consistent with federal and regional reliability requirements, and as such they should be at the forefront of the planning process.

It is vital that the CTPG reflects stakeholder interests and state policy to help guide the ensuing permitting processes and avoid unworkable transmission project applications. Therefore, to be successful, the CTPG plan must have broad stakeholder support, and it must have a proactive process to respond to stakeholder interests at all phases of development, particularly with regard to RETI. This step in the process envisions an iterative, interactive, and open stakeholder process that will promote stakeholder feedback at each development stage of the plan, from scoping to completion. Consensus is not realistic on a statewide basis. However, the goal should be to achieve broad enough stakeholder support that transmission permitting will be less contentious and have a greater likelihood of success. In the final analysis, to be implemented, a successful statewide plan must build substantive support for approval of projects.

Currently, all electric utilities submit their transmission project priorities to the Energy Commission for evaluation under the *Strategic Plan*. This proposed process envisions that the CTPG statewide plan results would be submitted to the Energy Commission's Strategic Plan proceeding instead of individual electric utility submittals (see fourth step below.) As depicted in Figure 4, CTPG transmission projects consistent with the CTPG statewide plan would also move to the CPUC or POU for permitting review, as appropriate.

Fourth Step – Identify Projects from CTPG and Initiate Corridor Designation

The fourth step in this proposed planning process is evaluation of the CTPG plan and related transmission projects under the Energy Commission's *Strategic Plan*. The objective would be to ensure that state interests regarding state policy goals and objectives are evaluated in a public forum. This step assumes that the CTPG plan would replace the current submittals to the Strategic Plan proceeding by individual electric utilities. In addition, this step envisions that projects the Energy Commission determines are in conformance with state policy goals and objectives would be given great weight in the permitting processes.

The *Strategic Plan* is also required to target transmission projects for the Energy Commission's corridor designation process, and this step in the proposed planning process acknowledges that this action would continue, albeit with greater emphasis and support. Specifically, this step envisions a program approach to corridor designation such that a package of transmission projects as articulated in the CTPG statewide plan, and as evaluated in the *Strategic Plan*, would be recommended for designation on a simultaneous basis. This approach would be much more effective and timely for the preservation of corridors than a piecemeal approach of one corridor designation proceeding at a time. As indicated in Figure 4, this proposed planning process envisions that the CTPG and RETI stakeholders would help guide development of the transmission corridor application, including local agency coordination, and support the designation process as active parties to the proceeding.

Fifth Step – File Applications for Permits

The fifth step (the permitting process) is essentially the culmination of the transmission planning process. Transmission permitting is the most controversial administrative stage of transmission development because it involves the highest level of analysis and scrutiny. The CPUC has jurisdiction over IOU transmission line projects, and the POU balancing authorities have jurisdiction over transmission line projects proposed for their POU service territories. As pointed out, an inadequate transmission planning process compromises the transmission line permitting process because transmission owners seeking permit approvals for transmission line projects resulting from inadequate planning will likely fail for lack of support and because of active stakeholder resistance. This step assumes that need for new transmission is ultimately determined during the permitting process. However, this process envisions that analyses in support of need determination are being carried out during each of the preceding steps.

Assuming the CTPG statewide plan secures broad stakeholder support, this permitting step envisions RETI stakeholders' support for transmission project permit applications that are consistent with the CTPG plan.

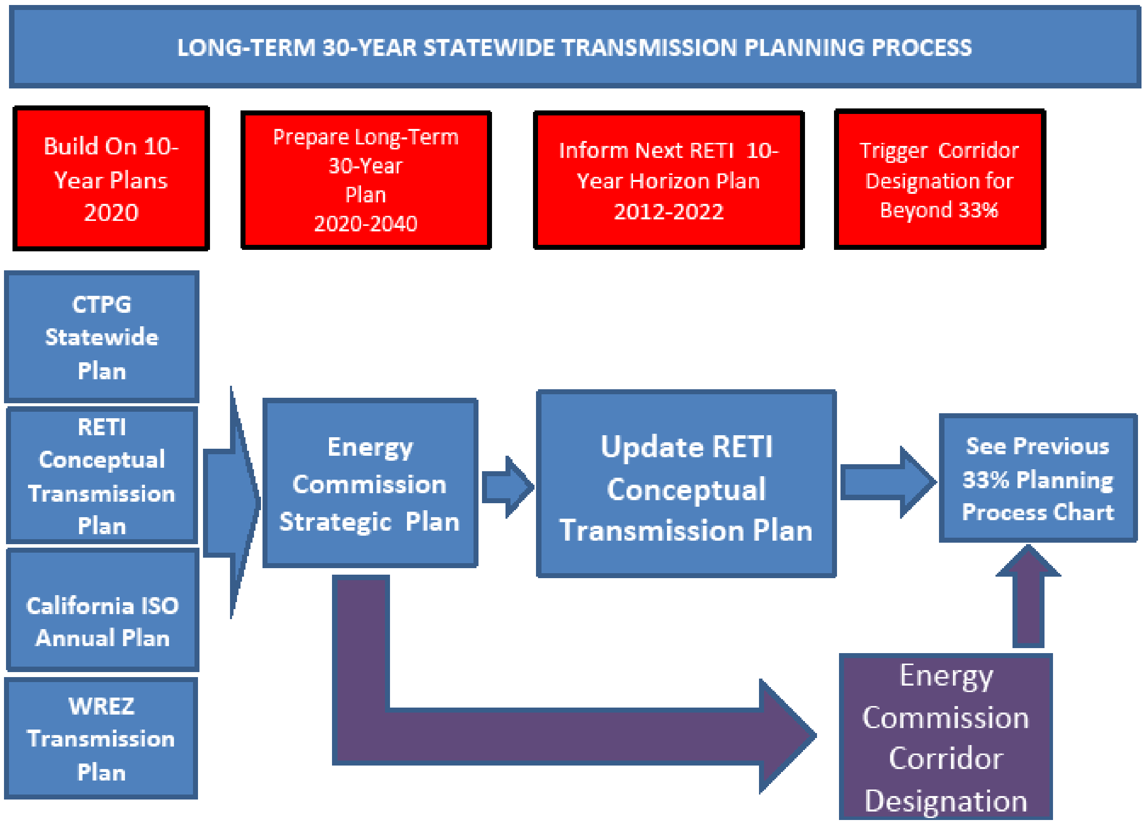
Long-Term 30-Year Planning Horizon

Figure 5 below depicts a proposed statewide transmission planning process for a long-term planning horizon that would assess the 10- to 30-year time frame. Most, if not all variables for this time frame are uncertain. Therefore, it is unrealistic to produce a 30-year plan similar to the detailed 10-year California ISO annual transmission plan, or even the RETI conceptual transmission plan. Instead, the 30-year plan must assess wide-ranging planning assumptions and variables to create a range of possible longer-term transmission infrastructure requirements.

The long-term plan would effectively build on the 10-year California ISO annual transmission plan and CTPG statewide plan and would consider the RETI conceptual plan and WREZ initiative planning output. The process under discussion here proposes that the Energy Commission would prepare and vet the plan in its Strategic Plan proceeding, with the cooperation of electric utilities and interested stakeholders. The long-term plan would feed back into subsequent RETI conceptual transmission planning cycles, which this planning approach assumes would be undertaken every two years. The objective of subsequent RETI cycles would be to update the conceptual transmission plan completed two years previously. In addition, like the 10-year transmission planning proposal, the long-term plan would signal transmission corridor needs for the Energy Commission's corridor designation program.

This type of far-reaching planning horizon would not seek precision, but it would offer a vision of possible future transmission needs for California significantly into the future. In addition, it would help ensure that shorter-term planning by the California ISO, electric utilities, and the RETI collaborative stakeholder process do not preclude or conflict with longer-term transmission options for California beyond the customary 10-year planning horizon.

Figure 5: Long-Term Coordinated Statewide Transmission Planning Process



Source: California Energy Commission staff, August 2009.

Issues Raised by Parties Concerning the Proposed Consolidated Statewide Transmission Plan

This section is divided into two parts: selected comments that raise issues and concerns about different aspects of the proposed transmission planning processes, and selected comments in support of different aspects of the proposed planning processes. These comments were heard at the transmission workshops held on May 4 and June 15, 2009, in developing this report.

Feedback That Raises Issues and Concerns

- Several parties indicated that while there is a role for the *Strategic Plan* with regard to statewide transmission planning, it should not duplicate the utility planning taking place under the CTPG, and it should not result in another approval process. Along these lines, several parties suggested that the *Strategic Plan* should not create another plan or second guess the CTPG plan because it would confuse transmission planning efforts.

  Response: The Committees believe it is imperative that the CTPG obtain official state of California support for its transmission plan. Otherwise the likelihood of implementation would be diminished because state regulators would have no formal basis to emphasize favorable policy implications associated with CTPG transmission projects, and stakeholder support that would come with state concurrence would not be as broad-based without it. The Strategic Plan proceeding is already in place, and in this regard the Energy Commission is required to identify key actions to facilitate transmission investment. Under the proposed transmission planning process, the Energy Commission would shift focus to the CTPG transmission plan as the basis for recommending key actions for the *Strategic Plan*. In order to do this, the CTPG plan would be vetted in the Strategic Plan proceeding, and as a result of this, the Energy Commission would adopt revisions, if any, to the plan based on input from the formal vetting process, and recommend that the CTPG integrate the revisions into its transmission plan. The CTPG plan and any Energy Commission revisions would then inform the permitting processes and any related regulatory actions associated with transmission project applications. Transmission owners would base their transmission project permit applications on the CTPG plan and the Energy Commission adopted revisions. The CTPG may decide not to integrate Energy Commission revisions to its plan. In this case, the transmission owners would ultimately need to determine how to shape their permit applications in consideration of the interests of the state of California as articulated in the adopted revisions to the CTPG plan.

- The California ISO indicated that all of the transmission balancing authorities already conduct planning in an open and transparent manner consistent with FERC Order 890 with stakeholder involvement, implying that an additional stakeholder process as proposed by Energy Commission staff under the *Strategic Plan* was not necessarily needed. They also indicated that the 10-year planning horizon is really a developed horizon, and the longer-term horizon beyond 10 years is where the strategic issues really come to bear, including land use considerations.[60] The implication of this perspective is that planning is relatively locked in for the 10-year period.

[60] Edson, Karen, California ISO, Transcript of the joint IEPR/Siting Committee June 15, 2009, *Workshop on Transmission Planning Process/Strategies Refinement and Corridor Information Development*, pp. 77-78, California Energy Commission, Sacramento, California, http://www.energy.ca.gov/2009_energypolicy/documents/2009-06-15_workshop/2009-06-15_transcript.pdf, accessed August 18, 2009.

Response: The Committees believe that the FERC Order 890 required transparency is a reasonable first step with regards to utility planning but that a more thorough pubic process is required to secure adoption by the state of California. Specifically, the kind of vetting, public access, and record building demonstrated in Energy Commission policy proceedings is the level of openness and transparency required when seeking concurrence from the state of California.

- Several parties suggested that the *Strategic Plan* role would better fit prior to the CTPG planning process instead of afterwards as staff proposed. Specifics about what the *Strategic Plan* would contribute before CTPG planning were not offered.

  Response: The Committees believe that the state of California must ultimately concur with the CTPG plan and that the *Strategic Plan* is the best existing formal proceeding to accomplish concurrence. Therefore, the *Strategic Plan* should follow the CTPG planning process and increase exposure of the plan, seek more public input, and help secure as much broad based stakeholder support as possible.

- Several parties indicated that the two-year RETI update cycle was too frequent because, as reflected in Southern California Edison's (SCE) comments, it would be "creating an environment where assumptions are continually changing and you can't make decisions."[61] SCE clarified this concern by explaining that it prefers to stick with assumptions over a longer period of time than two years to set plans in motion without second guessing and re-starting the analysis as assumptions change. However, SCE representatives indicated that "having a perfect set of assumptions where nothing needs to be mitigated is not a possible future."[62]

  Response: The Committees believe that it is critical to keep the momentum generated in the RETI process and ensure that the RETI output is updated in a timely manner to continue to inform and influence transmission planning and permitting. In order to maintain momentum and institutional knowledge, periods of inactivity must be kept to a minimum. The RETI process would lose continuity and be much less efficient when it comes to restarting the complex technical updating process if the update process is too infrequent.

- Several parties suggested that a five-year RETI update was more appropriate than a two-year cycle.

  Response: See response above.

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[61] Arons, Patricia, SCE, Transcript of the joint IEPR/Siting Committee June 15, 2009, *Workshop on Transmission Planning Process/Strategies Refinement and Corridor Information Development*, p. 87, California Energy Commission, Sacramento, California, http://www.energy.ca.gov/2009_energypolicy/documents/2009-06-15_workshop/2009-06-15_transcript.pdf, accessed August 18, 2009.

[62] Ibid, p. 88.

- The Center for Energy Efficient Renewable Technology (CEERT) posited whether RETI will actually assist the California ISO and POUs with transmission planning or help with expedited permitting, and noted that RETI had not yet produced a final conceptual plan and has therefore not been tested in this regard. In addition, CEERT noted that when RETI stakeholders got closer to actually recommending specific transmission facilities and ranking them, what tended to dominate were the transmission owner's proposed projects, not necessarily statewide coordination, optimization, and minimization of unnecessary transmission. CEERT further noted that, like RETI, it will also be difficult for the CTPG to overcome this issue and focus on statewide perspective so that the statewide plan is not merely the sum of all the individual transmission owners' plans.[63]

  Response: The Committees agree with these comments.

Feedback That Supports the Proposals

- CEERT indicated that RETI created a large group of mobilized stakeholders that have become knowledgeable and concerned and could add a lot of value to the process. Further, RETI provides an additional dimension of stakeholder involvement beyond anything that any of the transmission owners now anticipate incorporating into their planning, and that the Strategic Plan process could be a venue to review the CTPG transmission plan and allow a broader set of stakeholder interests to help improve and optimize the results.[64]
- A number of parties indicated that RETI would influence transmission planning processes and organizations.
- PG&E indicated that vetting planning proposals with the *Strategic Plan* "can lay the groundwork for more detailed talks" and get planning organizations "over the hump."[65]
- The Sierra Club indicated that statewide transmission planning allows stakeholders to see the entire array of issues under consideration in combination, not in isolation from

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[63] Olsen, Dave, CEERT, Transcript of the joint IEPR/Siting Committee June 15, 2009 *Workshop on Transmission Planning Process/Strategies Refinement and Corridor Information Development*, pp. 82-24 and 101-103, California Energy Commission, Sacramento, California, http://www.energy.ca.gov/2009_energypolicy/documents/2009-06-15_workshop/2009-06-15_transcript.pdf, accessed August 18, 2009.

[64] Ibid, pp. 84 and 100-101.

[65] Thalman, Jon Eric, PG&E, Transcript of the joint IEPR/Siting Committee June 15, 2009 *Workshop on Transmission Planning Process/Strategies Refinement and Corridor Information Development*, p. 99, California Energy Commission, Sacramento, California, http://www.energy.ca.gov/2009_energypolicy/documents/2009-06-15_workshop/2009-06-15_transcript.pdf, accessed August 18, 2009.

each other, and that this helps provide a clearer perspective. The Sierra Club also indicated that it behooves planners and stakeholders to not just look at the short-term costs, but also to consider the longer-term effects and benefits of the system California will ultimately have. They also indicated that if California plans for the cheapest possible system, it will miss any opportunities to take advantage of innovation and solutions that avoid controversy.[66]

Recommendations

The Committees make the following recommendations to ensure that short-term (10 years) and longer-term (30 years) planning is effective.

- The Energy Commission staff should work with the recently formed California Transmission Planning Group (CTPG) and California ISO in a concerted effort to establish a 10-year statewide transmission planning process that uses the Strategic Plan proceeding to vet the CTPG plan described in Chapter 4, with emphasis on broad stakeholder participation.
- The Energy Commission staff should work with the RETI stakeholders to establish a two-year cycle for updating the RETI conceptual transmission plan.
- The Energy Commission staff should solicit input from electric utilities and interested stakeholders and develop the scope, content, and process for a 30-year transmission plan for California as part of the 2011 Strategic Plan proceeding.
- The 30-year conceptual transmission planning process should be implemented in the 2011 Strategic Plan proceeding.
- The Energy Commission staff should work with the California ISO, CPUC, and POUs on a simplified need assessment process that fosters the use of common assumptions and streamlined decisions.

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[66] Zichella, Carl, Sierra Club, Transcript of the joint IEPR/Siting Committee May 4, 2009, *Workshop on Transmission Planning Information and Policy Actions*, pp. 193-194, California Energy Commission, Sacramento, California, http://www.energy.ca.gov/2009_energypolicy/documents/2009-05-04_workshop/2009-05-04_TRANSCRIPT.PDF, accessed August 18, 2009.

CHAPTER 5: Statewide Transmission Corridor Planning

Introduction

In 2006, the Legislature passed Senate Bill 1059 (Escutia and Morrow, Chapter 638, Statutes of 2006), which granted the Energy Commission the authority to designate transmission corridors to help assure that California can develop a robust and reliable high-voltage transmission system that will meet future electricity needs, reduce congestion costs, integrate renewable resources into the state's energy mix, and meet the state's critical energy and environmental policy goals. The transmission corridor designation process promotes public involvement in the transmission planning processes and links transmission planning processes with transmission permitting to assure the timely permitting and construction of needed transmission facilities.

In 2007 the Energy Commission vetted its new transmission corridor designation process and incorporated the comments received in its final regulations.[67] The primary focus of the comments was on (1) ensuring the transparency of the process through early active participation of stakeholders to inform them of regional and statewide needs for transmission lines and to identify and address land use and environmental constraints to transmission expansion; and (2) integrating the process in a collaborative effort with utility transmission planning, the land use planning of federal, state and local governments, existing transmission permitting processes, and the initiatives to establish energy corridors on federal lands under Section 368 of the 2005 Energy Policy Act.[68] The Southern California Edison Company (SCE) indicated that one of the most important issues that could impede the corridor designation process was the restriction on the length of time a utility can hold lands or easements purchased for future use in its rate base.

This chapter discusses (1) the status of transmission corridor designation planning in California; (2) the objectives and structure of the transmission corridor designation process; (3) issues that may prevent the effective use of the process; and (4) recommendations.

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[67] http://www.energy.ca.gov/sb1059/index.html; posted July 24, 2008; accessed August 10, 2009.

[68] Section 368 of the Energy Policy Act of 2005 required the U.S. Department of Energy (U.S. DOE), the U.S. Bureau of Land Management, and the U.S. Forest Service, in cooperation with the departments of Agriculture, Commerce, Defense, and Interior, to designate new right-of-way corridors on federal lands in 11 Western states for electricity transmission and distribution facilities, as well as oil, gas, and hydrogen pipelines. For more information, see the DOE website at: http://www.oe.energy.gov/corridors.htm

Status of Transmission Corridor Planning in California

To gain a better understanding of the status of electric utility planning in 2009 for the designation of transmission corridors, the Energy Commission included in its *Forms and Instructions For Submitting Electric Transmission-Related Data*[69] requests for the utilities to discuss:

- Their potential corridor needs.
- The circumstances or planning time frames where they would opt to obtain a transmission corridor designation.
- Why they would not consider applying for a transmission corridor designation (if applicable).

Utility responses were discussed at the May 4, 2009, joint Integrated Energy Policy Report (IEPR) and Siting Committee (Committees) workshop on transmission planning,[70] and further discussions were held on the role of corridor designation in transmission planning at the June 15, 2009, Committees workshop,[71] including the potential designation of corridors to accommodate transmission line segments identified in the California Renewable Energy Transmission Initiative (RETI) *Phase 2A Final Report*.

Only four utilities provided specific responses to staff's information requests regarding their potential need for transmission corridor designations. Those responses included the Imperial Irrigation District (IID), Los Angeles Department of Water and Power (LADWP), San Diego Gas & Electric Company (SDG&E) and SCE.

IID's current plans to expand its transmission system using existing rights-of-way do not involve the need to designate a transmission corridor. If in the future IID identifies the need for a transmission line in a location where there is not existing transmission right-of-way available or existing transmission corridors, IID would consider applying for a transmission corridor designation. However, IID cautions that new transmission corridors should not be designated

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[69] *Forms and Instructions for Submitting Electric Transmission-Related Data*, California Energy Commission, Sacramento, California, January 2009, publication number CEC-100-2008-012-CMF, http://www.energy.ca.gov/2008publications/CEC-100-2008-012/CEC-100-2008-012-CMF.PDF, adopted January 14, 2009, accessed August 6, 2009.

[70] California Energy Commission, Documents Webpage – *2009 Integrated Energy Policy Report* (Docket no. 09-IEP-1), Documents for the May 4, 2009 Joint Integrated Energy Policy Report and Siting Committee Workshop on Transmission Planning Information and Policy Actions, http://www.energy.ca.gov/2009_energypolicy/documents/index.html#050409, accessed August 6, 2009.

[71] California Energy Commission, Documents Webpage – *2009 Integrated Energy Policy Report* (Docket no. 09-IEP-1), Documents for the June 15, 2009 Joint Integrated Energy Policy Report and Siting Committee Workshop on Transmission Planning Process/Strategies Refinement and Corridor Information Development, http://www.energy.ca.gov/2009_energypolicy/documents/index.html#061509, accessed August 6, 2009.

within its district in areas such as the Salton Sea region, which currently has more than 1,000 MW of excess transmission capacity.

LADWP did not identify the need for the designation of new corridors on non-federal land but did state that new federal corridor designation under Section 368 of the 2005 Energy Policy Act would benefit its proposed Green Path North and Barren Ridge Renewable Transmission projects.

Although SDG&E currently has no plans to propose a transmission corridor for designation, it did recommend that the Energy Commission designate transmission corridors on a very long-term basis coordinated with federal corridors, perhaps up to 50 years, in areas where transmission lines already exist in anticipation of expanding future transfer capability and access to areas with significant renewable generation potential, as well as expanding existing rights-of-way to aid the rebuilding of existing transmission facilities, including substations. SDG&E intends to evaluate the transmission needs identified by RETI for potential joint development with other utilities and is prepared to pursue the creation of needed corridors through the Energy Commission to aid such development.

SCE stated that the greatest opportunity for coordination between federal and state corridor designation programs is for the Energy Commission to geographically extend any of the corridor boundaries on federal lands to non-federal lands in California. Although SCE did not indicate that it is planning to submit a transmission corridor designation application to the Energy Commission, SCE identified a number of corridors that it believes are critical in meeting future growing demand, accessing new diversified generating resources, and reducing potential congestion due to significant load growth in Southern California, which is surrounded mostly by federally owned lands. Those new corridors include the following:

- Crossing the San Bernardino National Forest to bring power to the load centers in western Riverside County from the Desert Southwest, as well as improve reliability in the area.
- Crossing the northern end of the Cleveland National Forest to bring power from the Desert Southwest to the load centers in Orange County.
- From Palmdale, crossing the Angeles National Forest, and ending near Irwindale to bring power from Northern California and renewable power from the Mojave Desert to major load centers in the Los Angeles Basin.
- From Buttonwillow in Kern County to the Tehachapi area near Lancaster in Los Angeles County, and a separate corridor that would continue from Tehachapi, traverse the Angeles National Forest near Palmdale, and end near Santa Clarita. These corridors would bring economic power from the Northern California and Pacific Northwest areas to Southern California and integrate renewable resources developed in the Mojave Desert.
- Starting near the southern tip of Nevada, crossing the Mojave National Preserve, and ending near Barstow, California. The corridor would accommodate future interregional

transmission facilities that would bring economic power to the major load centers in Southern California and would deliver electricity to Southern California load centers from renewable resources in eastern and central San Bernardino County identified in the *RETI Phase 2A Final Report* as totaling about 7,686 MW. This large renewable generation capacity would require several 500 kilovolt (kV) circuits to integrate and deliver its output. For this reason, SCE has proposed the new corridor rather than using the existing nearby federal corridor that crosses U.S. Bureau of Land Management (BLM) lands because of their concern that "simultaneous outage of 500 kV circuits within a common corridor may have unacceptable consequences on system reliability… due to the large amount of generation that could be affected if the new circuits are placed in one common corridor."[72]

- From Ventura to Goleta, which would cross the southern portions of Los Padres National Forest. The corridor would provide additional transmission capacity to serve loads as well as improve reliability.
- From Southern Arizona near Palo Verde to the Palmdale area in California, crossing southern portions of the Joshua Tree National Park. The corridor would accommodate future interstate transmission facilities from southern Arizona, and would deliver electricity to Southern California load centers from renewable resources in Riverside County, Imperial County, and Baja (Mexico) identified in the *RETI Phase 2A Final Report* as totaling about 10,627 MW. This large renewable generation capacity would require several 500 kV circuits to integrate and deliver its output. For this reason, SCE has proposed the new corridor rather than using the existing nearby federal corridor that crosses BLM lands because of their concern that "simultaneous outage of 500 kV circuits within a common corridor may have unacceptable consequences on system reliability… due to the large amount of generation that could be affected if the new circuits are placed in one common corridor."[73]

However, the utilities' transmission planning efforts, particularly in Southern California, will be significantly influenced by the statewide implementation of Executive Order S-14-08, signed by Governor Schwarzenegger on November 17, 2008. (See Chapter 2). The primary objective is to streamline and expedite the permitting processes for renewable energy projects, while conserving endangered species and natural communities at the ecosystem scale. The Executive Order directs the joint state-federal Renewable Energy Action Team (REAT) to achieve these twin goals in the Mojave and Colorado Desert regions through development of the Desert Renewable Energy Conservation Plan (DRECP). The DRECP will address both project permitting and resource conservation objectives through a comprehensive regional planning

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[72] Southern California Edison, 2009 Integrated Energy Policy Report (IEPR) Transmission-Related Data Response Update, Docket No. 09-IEP-1D, June 26, 2009, page 24.

[73] Southern California Edison, 2009 Integrated Energy Policy Report (IEPR) Transmission-Related Data Response Update, Docket No. 09-IEP-1D, June 26, 2009, page 25.

approach, supported by California's Natural Community Conservation Planning Act (NCCPA) and the habitat conservation planning provisions of the federal Endangered Species Act. The planning goals of the DRECP include identifying the most appropriate locations within the DRECP planning area for the development of utility-scale renewable energy projects and related transmission, taking into account potential impacts to threatened and endangered species and sensitive natural communities. The participating agencies are expected to build on the competitive renewable energy zones identified and analyzed by the RETI in designating areas where renewable energy generation project permitting can be expedited, subject to compliance with the NCCPA. Identification of appropriate transmission facilities and potential transmission corridors for designation will also be informed by the DRECP.

The Role of Transmission Corridor Designation

There was consensus among the participants at the May 4, 2009, Committees workshop on transmission planning that the transmission corridor designation process should be used as a scenario-based planning tool to address long-term transmission infrastructure needs – perhaps 20 to 30 years – to meet broad state policy goals, including the Renewables Portfolio Standard (RPS) and the California Global Warming Solutions Act of 2006 (Assembly Bill 32, Núñez, Chapter 488, Statutes of 2006), and to help guide future urban growth patterns and land use changes to accommodate transmission infrastructure needs. Such efforts should be broad – "at the thirty thousand foot level" – to reflect the uncertainties inherent in forecasting future infrastructure needs and to provide utilities with the flexibility and options needed to respond to changing demands. The designation process should also be used to help streamline the permitting process by (1) providing a transparent programmatic evaluation and resolution of land use and environmental issues through early public involvement that is recognized by both agencies and stakeholders in the subsequent planning for and permitting of transmission lines within the designated corridors, and (2) coordinating with existing or proposed transmission corridors on federal lands to maximize the benefits of federal and state actions. Recognizing the likelihood that siting options will be more limited in the future, designated transmission corridors can also provide opportunities for utilities to work together to meet their transmission infrastructure needs.

Transmission Corridor Designation Process

Objectives

The main objectives of the designation process are as follows:

- To identify appropriate corridors for transmission planning consistent with the state's principles of encouraging the use of existing rights-of-way, expanding existing rights-of-way, and creating new rights-of-way; and consistent with the state's needs and objectives as set forth in the most recently adopted *Strategic Transmission Investment Plan (Strategic Plan)*.

- To prepare an environmental assessment of each proposed corridor.
- To coordinate the state's designation of corridors with existing or proposed federal corridors.
- To work with state and local governments and California Native American tribes through whose jurisdictions a transmission corridor is proposed.
- To provide a forum for public participation.[74]

Beginning the Process: Strategic Plan Discussion of Potential Corridors and Alternatives

The public dialogue regarding the need for transmission corridors to be designated by the Energy Commission is intended to begin in the Commission's Strategic Plan process. During that process the Commission gathers information from utilities on their transmission corridor planning activities and confers with cities and counties, state and federal agencies, and California Native American tribes to identify appropriate areas within their jurisdictions that may be suitable for a transmission corridor. The intent of this effort is, to the extent feasible, coordinate actions to identify corridor options for addressing the long-term transmission needs of the state within the land use plans of these agencies.

Early Engagement of Land Use Agencies and Use of the PACT "Tool" for Evaluating Corridors

Whether building on the dialogue begun in the Strategic Plan process or initiating planning for designating a transmission corridor, a utility or other proponent will need to carry out coordinated outreach to potentially affected land use agencies. The outreach will educate land use agencies about the transmission planning and corridor designation processes and related activities, review their existing land use plans and policies relating to the placement of transmission lines, and identify the constraints and opportunities for locating transmission corridors within their jurisdictions, including alternative corridor options. The cooperative relationships established and the information gathered during the outreach process are important in developing an application for corridor designation and in facilitating the timely processing of an application once the Energy Commission has received it.

Although the utilities have no current plans for submitting transmission corridor designation applications to the Energy Commission, they all agreed that early outreach now to local governments and other land use agencies is an important part of the transmission planning

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[74] See Title 20, California Code of Regulations, Chapter 6, Article 2, Section 2320, http://www.leginfo.ca.gov/pub/05-06/bill/sen/sb_1051-1100/sb_1059_bill_20060929_chaptered.pdf

process. Early outreach would inform land use agencies of the state's needs for expanding its transmission system to meet its renewable energy goals and other energy policy objectives; discuss the nature of the transmission corridor designation process; identify the critical roles that the land use agencies need to play in that process to help identify and resolve environmental and land use issues; and identify and evaluate potential corridor alternatives.

Some initiatives are already underway to aid in the early identification and resolution or to avoid land use and environmental constraints to promote timely development of California's renewable generation resources and associated transmission lines. The RETI collaborative process has identified and prioritized preferred renewable resource development areas and associated transmission line links to deliver renewable power to load centers. Under the Governor's Executive Order S-14-08,[75] state agencies are working cooperatively to take all appropriate actions to accelerate renewable energy development in all regulatory proceedings, including siting, permitting, and procurement for renewable energy power plants and transmission lines. In addition to the "energy corridors" established under the federal 2005 Energy Policy Act Section 368 on federal lands in California to aid transmission expansion, the Department of Interior is also updating its land use plans to expedite the timely development of solar energy generation resources on federal lands.

To provide more effective tools for evaluating transmission corridor alternatives, the Energy Commission is developing, in cooperation with SCE and with input from a broad advisory committee, the "Planning Alternative Corridors for Transmission (PACT)" computer model.[76] The PACT model consists of a suite of powerful scenario-based modeling applications with geographic information system functionality to aid planning and evaluation of complex transmission line siting projects. The PACT tool can be used to evaluate and compare different corridor alignments; develop a transparent process for stakeholder involvement in transmission corridor designation; and dynamically display and calculate the results of environmental, land use, and engineering comparisons. The Energy Commission is currently updating its *Energy Aware Planning Guide: Energy Facilities*[77] (*Planning Guide*) to inform local governments about the state's processes for permitting of thermal power plants 50 MW and larger and designation of transmission corridors, including the role of local governments in those processes. The *Planning Guide* will also assist local governments in permitting of power plants that are not under the

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[75] Executive Order S-14-08, signed by Governor Schwarzenegger on November 17, 2008, established a Renewables Portfolio Standard target for California that directs all retail sellers of electricity to serve 33 percent of their load with renewable energy by 2020. The order directs state government agencies "to take all appropriate actions to implement this target in all regulatory proceedings, including siting, permitting, and procurement for renewable energy power plants and transmission lines." See the link at: http://gov.ca.gov/executive-order/11072/

[76] http://www.energy.ca.gov/reti/steering/2008-05-21_meeting/presentations/Planning_Alternative_Corridors_for_Transmission_Lines.pdf; posted June 13, 2008; accessed August 20, 2009.

[77] http://www.energy.ca.gov/energy_aware_guide/P700-96-006.PDF; accessed August 20, 2009.

Energy Commission's jurisdiction. The Energy Commission staff plans to use both the PACT model and the updated *Planning Guide* in its outreach efforts with local governments and other land use agencies to evaluate potential transmission corridor alternatives for designation.

The Committees agree that early outreach now to local governments and other land use agencies is important to engage in a dialog on best strategies to promote the development of renewable generation and to encourage their active participation in planning for and designating transmission corridors to transform energy to low carbon alternatives that Californians support. To this end the Energy Commission should carry out a number of outreach activities, including the following:

- Provide information on the transmission corridor designation process to local governments as part of the Energy Commission's outreach to inform them of work being carried out under the Governor's executive order to promote renewable energy development to meet the state's RPS goals.
- Work with local governments in areas where renewable generation and transmission development is expected to take place to help develop "energy elements" or "transmission elements" for their general plans on accommodating renewable generation development and the designation of transmission corridors. Also, provide assistance to update zoning codes to further policy implementation.
- Work with local governments to identify and evaluate land use and environmental constraints associated with possible utility transmission corridors identified by the RETI collaborative that are intended to deliver electricity from renewable generation facilities. This should include use of the PACT modeling tool to evaluate transmission corridor alternatives.

Application for Transmission Corridor Designation

An application for transmission corridor designation must include a description of the proposed corridor and its location, the transmission facilities anticipated to be within it, and a discussion of the need for the proposed corridor based on the state's needs and objectives as set forth in the latest adopted *Strategic Plan* (Public Resources Code Section 25331). The discussion of the need for a proposed corridor must include a description of the expected load growth, capacity, and energy levels for the planning time frame of the transmission project anticipated within the proposed corridor. It must also consider the potential for energy supply, demand reduction, and efficiency initiatives in the load area as "non-wires alternatives" to the proposed transmission expansion.

An application must also include a description of reasonably foreseeable effects on the environment, including land use, or to public health and safety; a description of mitigation measures proposed to minimize or avoid such effects; and a description of a reasonable range of alternative corridors that could achieve the basic objectives of the proposed corridor.

The Energy Commission's review of an application for a transmission corridor designation is a 12-month process, consisting of public workshops; an independent staff analysis of the application, including the preparation of an environmental impact report; and public hearings for receiving testimony and public comments. The Commission's final decision on an application must include the following findings and conclusions based on the hearing record:

- Whether the proposed transmission corridor conforms with the applicable *Strategic Plan*.
- Whether the proposed transmission corridor is consistent with land uses within and adjacent to the corridor and with applicable land use plans adopted by local, regional, state, or federal governments.
- Whether there exist within or adjacent to the proposed corridor any notable areas of sensitivity, such as parks, natural reserves, or historic preservation areas.
- The extent to which the proposed designation and the construction of facilities within the corridor would cause any reasonably foreseeable significant adverse environmental, land use, public health and safety, economic, or transmission system effects.
- Whether there are feasible means of reducing or avoiding any of the significant adverse effects identified.
- Any changes or modifications to the proposal that the Energy Commission should require.
- Whether there are feasible alternatives that are preferable to the proposed corridor.

Non-Wires Alternatives

The load forecasts and supply assumptions used in a corridor designation application should be based on the most recent *IEPR* findings and conclusions and consistent with the long-term procurement plans (LTPPs) submitted by the load-serving entities (LSEs) to the Energy Commission and the California Public Utilities Commission (CPUC). Currently, procurement plans reflect a 10-year planning time frame and incorporate the *Energy Action Plan* loading order investment and resource adequacy policies. [78] The CPUC is developing standardized resource planning practices and assumptions that the investor-owned utilities (IOUs) will be expected to use to develop their LTPPs that may be incorporated into CPUC Certificate of Public Convenience and Necessity (CPCN) proceedings when determining the need for, and alternatives to, a proposed transmission line. When the *IEPR* or the CPUC's LTPP proceeding

[78] The "loading order" established that the state, in meeting its energy needs, would invest first in energy efficiency and demand-side resources, followed by renewable resources, and only then in clean, conventional electricity supply. See the *Final 2008 Energy Action Plan Update*, available at: http://www.energy.ca.gov/2008publications/CEC-100-2008-001/CEC-100-2008-001.PDF; accessed August 20, 2009.

adopts, approves, or otherwise uses a longer-term forecast (for example, 20 years), the load forecast and supply assumptions used in a corridor designation should be based on available and agreed-upon longer-term forecast and associated plans. Until longer-term forecasts are forthcoming, the applicant should use longer-term load forecast and supply assumptions that are consistent with approved 10-year forecasts and qualitative projections of likely longer-term trends.

The analysis of alternatives performed in transmission permitting proceedings typically includes wire and non-wire alternatives and is included as part of the environmental review process initiated with the filing of a CPCN. Non-wires alternatives include energy efficiency, demand reduction measures (demand response and load management), and local generation. Local generation may include small-scale and customer-level distributed generation (DG) resources, renewable generation, and utility-scale clean fossil-fired generation located within the load service area, allowing the utility to help meet reliability targets. Non-wires alternatives are distinct from "system alternatives" that rely on different transmission line upgrades and interconnections.

Among the information requirements contained in the Energy Commission's corridor designation regulations, an application is to include consideration of non-wires alternatives in demonstrating the need for the proposed corridor and conformance with the latest *Strategic Plan*. While the term "non-wires alternatives" is not mentioned specifically, a discussion of non-wires alternatives to transmission expansion is outlined insofar as an application must discuss:

- Demand and supply forecasts for the load area that define the timing and need for new generation and transmission.
- Energy efficiency and demand reduction measures that could serve as an alternative to transmission expansion.
- The need for the proposed transmission corridor to achieve the stated objectives of locating transmission project(s) within the proposed corridor, given the potential for supply, demand, and efficiency alternatives.

The corridor application should project energy efficiency, demand reduction measures, DG, and other supply-side alternatives beyond that already assumed in long-term procurement plans to evaluate alternatives within and beyond the 10-year procurement planning period. Scenario analysis and uncertainties inherent in forecasting and evaluating future resource options are discussed in the *2009 IEPR*, particularly in reference to implementation of the 33 percent RPS. Because the corridor designation process is a scenario-based planning tool used to address long-term transmission infrastructure needs well beyond 10 years, the application's analysis of non-wires alternatives is somewhat speculative. Therefore, in all cases, the applicant should use consistent and reasonable data and assumptions to demonstrate need and conformance with the most recent *Strategic Plan*.

Uses of Transmission Corridor Designation Decisions

A corridor designation decision provides a record to advise both transmission line and land use planning, as well as transmission line permitting. SB 1059 requires that the decision be included in the Energy Commission's subsequent *Strategic Plan* and will provide input to the California Independent System Operator (California ISO) and utility transmission planning processes. The Energy Commission must deliver a copy of its decision to each affected city, county, state agency, and federal agency. Each affected city or county is required to consider the designated corridor zone when making a determination regarding a land use change within or adjacent to the transmission corridor zone that could affect its continuing viability. The designation decision record, including the environmental impact report, also provides information to the CPUC and other regulatory agencies to aid the permitting of transmission lines proposed to be constructed within the designated corridor. The Energy Commission is required to regularly review and revise its designated transmission corridors as necessary, but not less than once every 10 years.

Issues Affecting Transmission Corridor Designation

Cost Recovery for Land Investments Within Designated Transmission Corridors

Because the Energy Commission's transmission corridor designation program is new and untested, California's electric IOUs have no assurance they will be allowed to recover in their electric rates the cost of land purchased within an Energy Commission-designated corridor. This regulatory uncertainty is a potential barrier to implementing the program. The following section provides background on this issue and recommends next steps.

Once the Energy Commission has designated a transmission corridor that was proposed by an IOU, land within the corridor should be preserved for future transmission-line routes. Otherwise, the land might be developed with incompatible uses before a transmission project can be permitted and built within the designated corridor. The utility could preserve this land by purchasing strategically located parcels and transmission easements.

The Federal Energy Regulatory Commission (FERC) determines which transmission-related costs a California IOU may recover through its wholesale and retail electricity rates.[79] The sum of all FERC-approved costs is called the utility's annual "transmission revenue requirement," which is published in its Transmission Owner Tariff. Land costs are recovered through the utility's "base transmission revenue requirement."

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[79] When the California ISO began operating the transmission systems of the state's investor-owned utilities, jurisdiction over the transmission component of IOUs' electric rates was transferred from the CPUC to FERC.

The IOU would record costs for land acquired within an Energy Commission- designated transmission corridor in its Plant Held for Future Use (PHFU) account. FERC regulations generally allow land assets in PHFU to be included in the "base transmission revenue requirement," provided the utility can demonstrate it plans to use the land for a transmission project. An outstanding question affecting the success of the program is whether FERC would regard an Energy Commission designation of a transmission corridor to be sufficient evidence of a plan for the land assets' future use. The Committees believe a utility has demonstrated that it has a plan to use land assets if it has obtained a transmission-corridor designation from the Energy Commission and the land assets in question are within that corridor.

To add new land assets to its "base transmission revenue requirement," an IOU must petition FERC to amend its Transmission Owner Tariff. FERC would then conduct a rate case proceeding before ruling on the proposed amendment. The FERC would publish a declaratory order containing its decision on whether to allow cost recovery for specific land purchases.

Other electric utilities that use a California IOU's transmission system pay wholesale transmission rates to that utility through the California ISO's transmission access charge. Therefore, organizations representing California's publicly owned utilities, other California IOUs, and the CPUC often intervene in rate case proceedings at FERC to raise concerns about potential rate effects or other issues. The CPUC's intervention in these proceedings seeks to minimize potential transmission-rate increases for retail electricity consumers.

The FERC's recent practice has been to send contested filings to a settlement process rather than conduct evidentiary hearings during the rate case proceeding. In the settlement process there are extensive data requests and dialogue about the contested issues. For example, the IOU would explain its plan to use proposed land additions for future transmission projects. In 2007, for example, the Transmission Agency of Northern California (TANC) intervened in an SDG&E rate case proceeding. SDG&E sought to increase its base transmission revenue requirement by including land purchased for future transmission rights-of-way and substation sites. TANC argued that SDG&E's proposal required "further investigation in order to ensure that SDG&E [did] not over-procure land without a corresponding use for transmission expansion at a later period." [80] TANC asserted that "safeguards were necessary to prevent land purchased under plant held for future use from being sold or otherwise not used for purposes of transmission expansion."[81] To alleviate TANC's concerns, the issue went to a settlement process. FERC's final declaratory order conditioned including land assets in SDG&E's transmission revenue requirement on SDG&E first "acquiring a relevant certificate of public convenience and necessity [CPCN] from the CPUC."[82] The Committees believe this requirement discourages

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[80] Federal Energy Regulatory Commission, "Order Conditionally Accepting and Suspending Tariff Sheets, and Establishing Settlement Judge and Hearing Procedures," January 31, 2007, Docket No. ER07-284-000, Page 6, http://www.ferc.gov/EventCalendar/Files/20070131184334-ER07-284-000.pdf.

[81] Ibid.

[82] Federal Energy Regulatory Commission, op. cit., page 11.

SDG&E from participating in the Energy Commission's transmission corridor program because SDG&E is only allowed to recover land costs for short-term transmission projects (that is, projects about to begin construction). By law, the Energy Commission's transmission corridor program must identify the long-term needs for electric transmission corridor zones within the state and, therefore, uses a 10-to-15 year planning horizon.

To assure that FERC will allow cost recovery of land assets acquired within Energy Commission-designated transmission corridors, the Committees recommend that the Energy Commission staff do the following:

- Contact appropriate FERC staff to inform them of the state's new transmission corridor designation program
- Collaborate with the state's electric IOUs, the California ISO, and the CPUC to jointly petition FERC to issue a declaratory order that determines:
    - An Energy Commission designation of a transmission corridor is sufficient evidence of a plan for the future use of land assets within that corridor so they may be recorded in the utility's PHFU account.
    - While these land assets are in the utility's PHFU account, the FERC will allow cost recovery for these assets through the utility's base transmission revenue requirement.
    - Land assets in the utility's PHFU account that are within an Energy Commission-designated corridor can remain in the utility's base transmission revenue requirement until either: 1) all anticipated transmission-line projects within the designated corridor have received CPCNs, or 2) the Energy Commission terminates the transmission-corridor designation.

Potential Conflict Between Transmission Planning Priorities and WECC Reliability Criteria

One of the main objectives of the transmission corridor designation process, stated in the implementing regulations, is "to identify appropriate corridors for transmission planning, taking into consideration the state's principles of encouraging the use of existing rights-of-way, the expansion of existing rights-of-way, and the creation of new rights-of-way in that order."[83] Nevertheless, as SCE pointed out in its response to staff's information requests, use of existing corridors that already contain 500 kV lines to accommodate another 500 kV line may not be acceptable from an operational standpoint: "Simultaneous outage of 500 kV circuits within a common corridor may have unacceptable consequences on system reliability . . ."[84] SCE's

[83] Title 20, California Code of Regulations, Chapter 6, Article 2, Section 2320.

[84] Southern California Edison, 2009 Integrated Energy Policy Report (IEPR) Transmission-Related Data Response Update, Docket No. 09-IEP-1D, June 26, 2009, page 25.

assessment is based on Western Electricity Coordinating Council (WECC) transmission planning reliability criteria (TPL-[001 thru 004]-WECC-1-CR-System Performance Criteria), which requires study of adjacent circuits in a corridor.[85] This standard is more stringent than the standard adopted by the North American Electric Reliability Corporation (NERC), which requires only a study of circuits on a common structure.

Concerns regarding the effect of WECC's more stringent criteria on the use of transmission corridors in the siting and construction of transmission lines has been addressed by the Southwest Area Transmission (SWAT) Common Corridor Task Force in its recent white paper.[86] The white paper discusses the tension between the reliability benefits of increasing the separation of circuits in a common corridor versus the increased cost of the extra land needed and the creation of additional land use conflicts and environmental impacts. The additional requirements in WECC could also result in significant reduction in path ratings and render proposed projects in corridors with existing lines, or proposed double-circuit projects in new corridors, uneconomical.

The white paper does not propose a universal solution that can be applied to every evaluation of corridor separation. However, it does describe the issues that are to be weighed whenever evaluating the addition of a circuit with existing circuits or new common corridors: system reliability or operational benefits; additional cost from increased easement requirements; increased land use restrictions; reduced transmission line routing options; creation of additional corridors; and increased difficulty of siting transmission corridors across public lands.

In carrying out its Transmission Corridor Designation program under its "balancing mandate" and as lead agency under the California Environmental Quality Act (CEQA), the Energy Commission must strive to balance the state's electricity needs and the reliability of its transmission system with the need to protect the environment and public health and safety. WECC's more stringent Reliability Criteria makes meeting that mandate more difficult. The WECC Reliability Subcommittee is evaluating WECC's Reliability Criteria to determine if the WECC Criteria should be changed to match the NERC standard. The Energy Commission staff should participate in the WECC Reliability Subcommittee's evaluation of WECC's Reliability Criteria to ensure that the issue is resolved appropriately and promptly.

Recommendations

The Committees therefore make the following recommendations in Chapter 5 to maximize the effectiveness and pro-activeness of the corridor designation program.

- The Energy Commission staff should continue early outreach to local governments and other land use agencies to inform them of the need for and the planning initiatives that

[85] http://www.wecc.biz/Standards/WECC%20Criteria/Forms/AllItems.aspx, accessed August 20, 2009.

[86] Southwest Area Transmission Common Corridor Task Force White Paper on Corridor Separation, April, 2009, http://www.westconnect.com/documents_results.php?categoryid=78.

are underway to promote the development of renewable generation. The Energy Commission staff should encourage timely participation by land use agencies in planning for and designating transmission corridors to help meet the state's energy policy objectives.

- The Energy Commission staff should initiate outreach with the Federal Energy Regulatory Commission (FERC) to settle the uncertainties about whether the FERC would allow "ratebasing" of land assets acquired within Energy Commission-designated transmission corridors.
- The Energy Commission staff should participate in the WECC Reliability Subcommittee's evaluation of WECC's Reliability Criteria regarding the separation of adjacent transmission lines in a corridor to ensure that environmental issues are appropriately considered and the issue is resolved promptly.

CHAPTER 6: Prioritizing the Development of Renewable Transmission Projects and Corridors for Designation

Background

California has many opportunities to improve transmission infrastructure within the state. The challenge regulators face is identifying the best mix of transmission projects to ensure a reliable network, improve access to renewable generation, and minimize consumer electricity prices and environmental impacts. In the *2005 Strategic Transmission Investment Plan* (*2005 Strategic Plan*), the Energy Commission highlighted the need for new transmission to reduce congestion costs borne by California ratepayers. The Energy Commission's *2007 Strategic Plan* examined the need for major transmission projects over 10 years, through 2017, and highlighted transmission required to help achieve California's Renewables Portfolio Standard (RPS) and greenhouse gas (GHG) reduction goals. This year (2009) is a transitional year for transmission development in California, with much of the planning focused on meeting renewable targets and GHG reduction goals. In the *2009 Strategic Plan* the joint Integrated Energy Policy Report (IEPR) and Siting Committees (Committees) continue to support the projects identified in previous *Strategic Plans* and see the next step as a short-term, 10-year transmission plan focused on the statewide renewable energy goals and the identification of transmission projects that will aid the attainment of the RPS targets.

The Committees are using the California Renewable Energy Transmission Initiative (RETI) *Phase 2A Final Report* described in earlier chapters to develop the next step for California and identify transmission projects that will build a robust transmission network in conjunction with previously supported projects. The *RETI Phase 2A Final Report* makes several recommendations to support the development of transmission required to enable California to meet its renewable energy policy goals.[87] It presents a conceptual transmission expansion plan, containing 102 transmission line segments, to increase the capacity of the state's transmission grid to deliver renewable generation to load centers. Like a major highway system with rural roads, highways, interstates, and interchanges, the transmission grid consists of collector lines, delivery lines, foundation lines, and substations to connect them all. The Renewable Collector lines in the RETI conceptual transmission plan will collect energy from U.S. Bureau of Land Management (BLM) Solar Energy Zones, Desert Renewable Energy Conservation Plan (DRECP) generation development areas, and Competitive Renewable Energy Zones (CREZs) most likely to be developed; the energy will then be transferred to Renewable Foundation lines and from there

[87] See *RETI Phase 2A Final Report* – Appendix D. Transmission Line Segment Analysis located on the Energy Commission's website at: http://www.energy.ca.gov/reti/documents/index.html; posted August 12, 2009; access August 20, 2009.

by way of the Renewable Delivery lines to the load centers where the majority of the electricity will be used.

The *RETI Phase 2A Final Report* is one of the data sources for prioritizing the transmission projects to interconnect renewables that are in the state's best interests. It also forms the basis for the development of a draft method for identifying which of the RETI line segments should be considered for corridor designation.

Analysis of Transmission Project Information

The Energy Commission analyzed more than 150 individual transmission projects identified by utilities in response to the Energy Commission's *Forms and Instructions for Submitting Transmission-Related Data*[88] for the 2009 IEPR proceeding (transmission submittals), and also discussed in Energy Commission workshops. Based on the utility filings, over the next 10 years the vast majority of planned transmission projects are either reconductoring or other small-scale projects. While significant projects are necessary for maintaining the reliable delivery of electricity to California customers, these projects usually do not require certification or are more locally significant. However, there are also a few large transmission projects that require California Environmental Quality Act (CEQA) review and other regulatory approvals. The state needs these projects for several reasons: to improve overall system reliability, deliver power economically, and meet state-mandated RPS goals.

For the *2009 Strategic Plan*, the Energy Commission relied on data from a variety of sources, including submittals from transmission-owning load-serving entities (LSEs), the California Independent System Operator's (California ISO's) transmission plan, and the *RETI Phase 2A Final Report*. The responses included data on each transmission owner's system, including expansion plans. The California ISO's transmission plan identified many projects, including those requiring approval from the California ISO Board of Governors, while the *RETI Phase 2A Final Report* developed a conceptual transmission plan that if completely built out could provide transmission needed to fulfill California's 33 percent renewable energy target through 2020. The Energy Commission also used published utility transmission and resource expansion plans, the California ISO's transmission plan, California ISO studies, and data submitted by different parties in California Public Utilities Commission (CPUC) proceedings. While the data essentially came from transmission plans and proponents of transmission projects, the Committees have critically examined each source in the development of its overall recommendations for the *2009 Strategic Plan*.

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[88] *Forms and Instructions for Submitting Electric Transmission-Related Data*, California Energy Commission, Sacramento, California, January 2009, publication number CEC-100-2008-012-CMF, http://www.energy.ca.gov/2008publications/CEC-100-2008-012/CEC-100-2008-012-CMF.PDF, adopted January 14, 2009, accessed August 6, 2009.

The *RETI Final Phase 2A Report* conceptual transmission plan identified the transmission upgrades required to deliver approximately 100,000 gigawatt-hours (GWh)[89] of renewable generation to load centers in California. The plan separated the transmission projects into three groups: Renewable Foundation, Delivery and Collector lines. Generally the Renewable Foundation and Renewable Delivery lines were categorized as "no regrets" because they are going to be needed regardless of which specific renewable generation areas are developed and could help to improve reliability and serve California's growing electricity needs. The Renewable Collector lines would be developed based on the location of renewable generators. In the short run, between 2009 and 2020, the Committees believe that the RETI conceptual transmission plan provides a roadmap through which California can achieve renewable energy targets and meet GHG reduction goals. However, the RETI plan identified 102 transmission segments,[90] more than 20 of which were labeled "no regrets." California needs to prioritize the development of these transmission segments to efficiently meet the 20 percent RPS target by 2010 as well as Governor Schwarzenegger's goal of 33 percent RPS by 2020.

The CPUC's June 2009 *33% Renewables Portfolio Standard Implementation Analysis Preliminary Results* report[91] highlights the difficulties that California would face if the development of the transmission segments is not prioritized in some sort of plan. There are not enough human and regulatory resources to permit all of the conceptual plan transmission segments, even those categorized as "no regrets." According to the *RETI Phase 2A Final Report*, the majority of the RETI segments will be required for California to meet RPS goals eventually, if not by 2020, then beyond 2020. This chapter develops a method to prioritize the development of the RETI conceptual transmission segments.

The *RETI Phase 2A Final Report* included analysis of several projects that the Energy Commission supported in the *2005* and *2007 Strategic Plans*, and the Committees continue to support these projects and their continued analysis and permitting. These supported projects would provide the transmission to access three of California's richest renewable areas (the Tehachapi region, the Imperial Valley and eastern Riverside County) as well as improve the network's ability to move generation in Southern California to Northern California. These projects should continue to be the focus of statewide planning and permitting efforts. The Committees are using the *RETI Phase 2A Final Report* to develop the next steps for California

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[89] http://www.energy.ca.gov/2009publications/RETI-1000-2009-001/RETI-1000-2009-001-F.PDF, p. 1-11.

[90] http://www.energy.ca.gov/2009publications/RETI-1000-2009-001/RETI-1000-2009-001-F.PDF; see Appendix H which consists of 102 line segments plus two transformers. Posted August 12, 2009, accessed August 20, 2009.

[91] *33% Renewables Portfolio Standard Implementation Analysis Preliminary Results*, California Public Utilities Commission, San Francisco, California, June 2009, http://www.cpuc.ca.gov/NR/rdonlyres/1865C207-FEB5-43CF-99EB-A212B78467F6/0/33PercentRPSImplementationAnalysisInterimReport.pdf, accessed August 18, 2009.

and identify transmission projects that will build a robust transmission network in conjunction with previously supported projects.

Prioritizing the Development of Renewable Transmission Projects

As noted above, the RETI conceptual transmission plan includes more than 100 transmission segments that vary in their economic risk and environmental impacts through their function and their construction requirements. The Renewable Foundation and Renewable Delivery segments would deliver remote renewable energy to load centers throughout California. Because the Renewable Foundation and Renewable Delivery transmission segments are not tied to specific renewable energy zones, there is little economic risk that the transmission investment would be stranded or unused. The Renewable Collector transmission segments would bring generation from specific renewable areas to transmission hubs. Planning, permitting, and constructing transmission facilities take time and expertise, but only a limited number of facilities can be planned, permitted, and constructed at any given time. To meet its renewable goals, California must prioritize the use of its resources.

The Committees believe the development of the RETI segments should be divided into phases that separate the segments based on their function (Renewable Foundation, Delivery, or Collector), their potential environmental impacts, and the likelihood that the renewable generation that they would interconnect would be developed. The Renewable Foundation and Renewable Delivery lines would strengthen California's transmission backbone that, coupled with the Renewable Collector lines, would ensure that renewable generation reaches load centers throughout the state. The Renewable Collector lines are tied to single renewable areas, so the value of any line would depend on how the generation develops. The potential environmental and land use impacts of lines that require new corridors would likely be higher than lines that use or expand existing corridors. Higher environmental and land use impacts would likely result in increased uncertainty as well as a lengthier planning and permitting processes. Lines that would use or expand existing corridors are likely to have fewer environmental and land use impacts and require the analysis of fewer alternatives, thus reducing the permitting time and the likelihood that the line would meet significant opposition. The Committees believe that California utilities and regulators should focus planning and permitting resources first on the RETI "no regrets" segments that do not require new transmission corridors, while beginning the community outreach and other necessary steps for the development of the segments that require new corridors.

First Priority

The first priority for California is to continue planning and permitting those projects identified in the Energy Commission's *2005* and *2007 Strategic Plans*. The Energy Commission found that these projects met the criteria for strategic transmission resources because they provided statewide benefits. As currently planned, these projects would significantly increase the transmission network's ability to reliably connect renewable generation to California load centers. These projects include:

- Imperial Irrigation District (IID) Upgrades
- Southern California Edison Company (SCE)Tehachapi Upgrades (Segment 1 – Antelope-Pardee; Segment 2 – Antelope-Vincent; Segment 3 – Antelope-Tehachapi; and Segments 4-11 – Tehachapi Renewable Transmission Project)
- SCE Devers – Palo Verde 2 (the entire California-Arizona interconnection, as well as the California-only variation)
- Los Angeles Department of Water and Power (LADWP) Tehachapi Upgrade (Barren Ridge Renewable Transmission Project)
- Pacific Gas and Electric Company (PG&E) Central California Clean Energy Transmission Project (C3ETP)
- San Diego Gas & Electric Company (SDG&E) Sunrise Powerlink Transmission Project
- Lake Elsinore Advanced Pumped Storage (LEAPS) Project – Transmission Portion
- Green Path North Coordinated Projects
- SCE El Dorado to Ivanpah Transmission Project (new project not in previous *Strategic Plans*)

A complete description of these projects and their current status is provided in "Appendix C: Summary of Projects Supported in the 2005 and 2007 Strategic Transmission Investment Plans." A brief summary of their status was provided in "Chapter 1: Introduction." The previously endorsed projects provide collection systems for three of California's richest renewable resources areas (the Imperial Valley, the Tehachapi region and eastern Riverside County.) The IID Upgrades are a series of 11 new lines and upgrades in the Imperial Valley region that are designed to collect and distribute renewable generation to Southern California utilities. The 11 Tehachapi segments and LADWP's Barren Ridge Renewable Transmission Project are designed to deliver new generation in the Tehachapi region to Southern California load centers. The California portion of the Devers – Palo Verde 2 transmission line could connect generation near Blythe to the SCE load centers. The Sunrise Powerlink and LEAPS projects would increase transmission to and from the San Diego area. The Green Path North projects provide pathways for renewable generation in the Imperial Valley and Mexico wind generation to reach load centers in the Los Angeles basin and even in Northern California. The Committees also believe the permitting for the SCE El Dorado to Ivanpah Transmission Project should proceed so that the lack of transmission does not slow the development of renewable generation in the Ivanpah Dry Lake area. The El Dorado to Ivanpah Transmission Project uses an existing transmission corridor and would allow for the interconnection of up to 1,400 MW of new generation. (This is not an endorsement of the Solar Partners' Ivanpah Solar Electric Generating System project, which is currently being evaluated by the Energy Commission.)

Second Priority

The second priority should be placed on those "no regrets" RETI Renewable Foundation and Renewable Delivery segments that limit environmental impacts by using or expanding existing transmission segments. Together with the previously endorsed projects, these segments would provide a strong system that could move and deliver electricity throughout California. RETI did not perform the thorough planning studies that are required to move these projects forward toward permitting approvals. The detailed analysis of these projects should be conducted through RETI or the newly formed California Transmission Planning Group (CTPG). Six conceptual transmission projects meet these criteria. They are the "no regrets" RETI lines that could be built within an existing transmission corridor or by expanding an existing corridor. Two additional projects (Gregg – Alpha Four and Tracy – Alpha Four) do not meet these criteria but are needed to complete a link to Northern California load centers, without these two lines the renewables would reach Fresno but not load centers in the Bay Area.

Renewable Foundation:

- Kramer – Lugo 500 kV: This is a 48-mile 500 kV transmission line using an existing corridor that would enhance access to the Nevada, Inyokern, and Kramer CREZs.
- Lugo – Victorville #2 500 kV: This 13-mile line with an estimated cost of $78 million would require the expansion of an existing corridor and would provide a link between SCE's and LADWP's corridors.
- Devers – Mira Loma #1 and #2 500 kV: These lines represent two circuits on one set of towers that would be 61 miles long in an existing transmission corridor. They would strengthen the tie between the Palm Springs area and SCE load centers. With the Vincent-Mira Loma 500 kV line that is part of the Tehachapi Renewable Transmission Project and the Imperial Valley Upgrades, the Devers-Mira Loma line would provide a strong link between the Imperial Valley, Baja, and Riverside renewable areas and Northern California.
- Gregg – Alpha Four 500 kV: This would be a 100-mile double-circuit 500 kV line in a new corridor that in conjunction with the Tracy- Alpha Four 500 kV line would tie PG&E's C3ETP to the San Francisco Bay Area and increase the transmission network's ability to deliver Southern California generation to Northern California load centers.
- Tracy – Alpha Four 500 kV 1 & 2: This 45-mile double-circuit 500 kV line would require a new corridor (See Gregg – Alpha Four above).

Renewable Delivery:

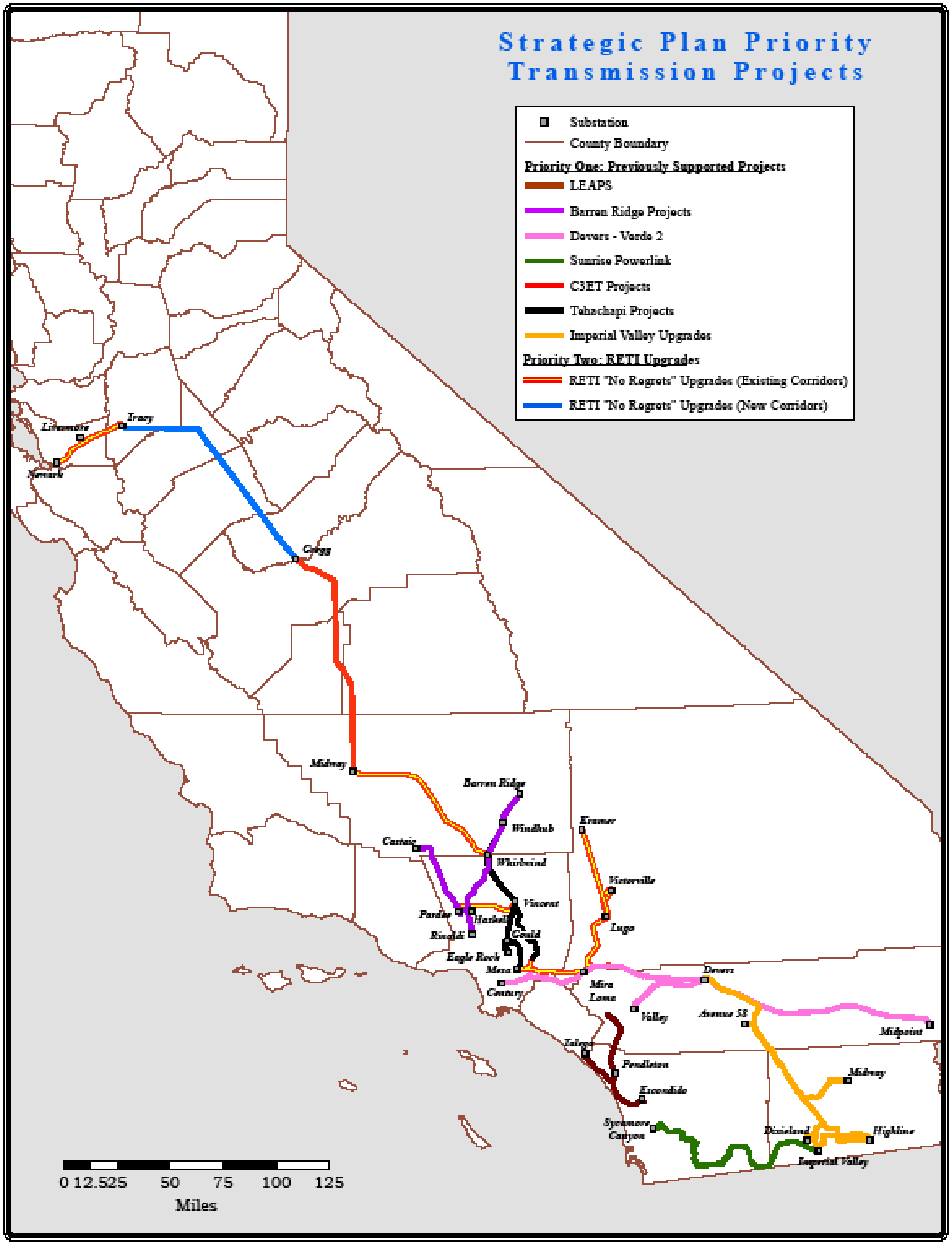
- Devers – Valley #3 500 kV: This is a 40-mile line that would require the expansion of an existing corridor. This would be the third 500 kV line between the Devers and Valley substations. One line is operating, and the second was supported as part of the Devers-Palo Verde 2 project.
- Tesla – Newark 230 kV: (see below)

- Tracy – Livermore 230 kV: The 29-mile Tesla-Newark line would expand an existing corridor and the 13-mile Tracy –Livermore line would use an existing corridor. These lines provide a link to the southern San Francisco Bay Area from the Tracy area.

These eight lines would be part of a network that includes the projects previously endorsed by the Energy Commission in the *2005* and *2007 Strategic Plans*. The combination of projects previously supported by the Energy Commission and the RETI *Final Phase 2A Report* "no regrets" projects that rely on existing transmission corridors creates a firm foundation for achieving California's renewable goals. The Green Path North and DPV2 projects, when coupled with the Devers-Valley and Devers-Mira Loma RETI upgrades, could deliver the power that flows into the Devers substation to load centers near Los Angeles and on into Northern California through some of the Tehachapi area upgrades. The Tehachapi Renewable Transmission Project in conjunction with the C3ETP could connect a significant wind resource to both Northern and Southern California. However, the C3ETP does not reach beyond the Fresno area. RETI identified the Gregg – Alpha Four, which when combined with the Tracy – Alpha Four – Tracy portion of the now-shelved Transmission Agency of Northern California Transmission Project, could deliver renewable energy to Northern California municipal utilities. The Gregg – Alpha 4 line would require a new corridor and thus would take longer to permit than the lines that use existing corridors. Planning studies for these lines will probably identify other segments that are required to maintain system reliability.

Figure 6 shows the first priority projects (previously supported projects) and second priority projects (RETI "no regrets" Renewable Foundation and Renewable Delivery segments).

Figure 6: Strategic Plan First and Second Priority Transmission Projects



Source: California Energy Commission, August 2009.

Third Priority

The third priority should be given to continue the analysis of the RETI Renewable Foundation and Renewable Collector lines that require new corridors and begin the planning work for the priority renewable areas outside Tehachapi, the Imperial Valley, and eastern Riverside County. Public outreach and corridor identification for the RETI "no regrets" lines that require new corridors should continue with local RETI forums, and the transmission planning should be developed through the California Transmission Planning Group. Which areas or CREZs should be given priority should be revisited because there are several factors that will affect the viability of the areas. The proposed national monument in the Mojave Desert area could reduce the size of several of the CREZs. The Solar Programmatic Environmental Impact Statement currently being developed by the BLM will likely identify preferred solar development areas while removing other areas from development. The California ISO is completing its first clustered interconnection studies based on the new Generator Interconnection Process. While these studies will only identify transmission needs for a small part of the generation potential of many of the CREZs, the new studies will identify some of the transmission upgrades that are required to reliably connect proposed generators to the existing transmission grid, and the extent of these required upgrades could affect the development of renewable areas. All of these studies will help identify preferred renewable generation areas for California and will help prioritize the planning and permitting of future transmission needs.

Transmission Project Conclusions

The interconnection and delivery of renewable energy to load centers throughout California is not the only transmission need for California. Electricity must still be provided reliably to Californians. Ongoing transmission planning processes have planned and permitted the facilities required to meet basic reliability requirements; however, RPS goals have added another layer to California's transmission needs. The Committees have focused this discussion of California's short-term, 10-year transmission needs on the RPS goals because only a focused, coordinated statewide planning and permitting effort will allow California to meet these goals. The next section deals with longer-term RETI segments that could be candidates for corridor designation.

RETI Transmission Line Segment Case Study Evaluation for Corridor Designation Consideration

The *RETI Phase 2A Final Report* makes several recommendations to support the development of transmission required to enable California to meet its renewable energy policy goals.[92] The report presents a conceptual transmission expansion plan, containing 102 transmission line segments,[93] to increase the capacity of the state's transmission grid to deliver renewable generation to load centers. The Renewable Collector lines in the RETI conceptual transmission plan will collect energy from BLM Solar Energy Zones, DRECP generation development areas, and CREZs most likely to be developed; the energy is then transferred to Renewable Foundation lines and from there by way of the Renewable Delivery lines to the load centers where the majority of the electricity is used.

Method

The Energy Commission staff developed a draft method for identifying which of the transmission line segments included in the RETI *Final Phase 2A Report* conceptual plan should be considered for corridor designation. At the June 15, 2009, joint Committees workshop, Commission staff presented its draft corridor selection method and the line segment attributes from the *RETI Phase 2A Final Report*. The Energy Commission staff has revised the draft method based on comments received from stakeholders at the workshop regarding inconsistency in weighting attributes. The staff presents the following case study of potential transmission line segments for corridor designation to demonstrate the revised selection method.

The *RETI Phase 2A Final Report* includes 23 Renewable Foundation line segments, 13 Renewable Delivery line segments, 66 Renewable Collector line segments, and 2 transformers.[94] Since no right-of-way is required for transformers, they were disregarded in this exercise. The attributes considered for assessing the line segments include the on-line service date, environmental concerns, type of right-of-way required, and energy potential of each line segment. After being screened for on-line service dates, the remaining transmission line segments were sorted alphabetically and described according to the remaining criteria.

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[92] See *RETI Phase 2A Final Report* – Appendix D. Transmission Line Segment Analysis located on the Energy Commission's website at: http://www.energy.ca.gov/reti/documents/index.html.

[93] http://www.energy.ca.gov/2009publications/RETI-1000-2009-001/RETI-1000-2009-001-F.PDF; see pg. H-83. Appendix H consists of 102 line segments plus 2 transformers.

[94] RETI *Phase 2A Final Report*, Appendix F. Posted August 12, 2009, accessed August 20, 2009.

On-Line Service Date

According to the CPUC, the planning, permitting and construction of a high-voltage transmission line project can take 7-13 years.[95] Accordingly, if any of the RETI identified line segments were selected for detailed study in 2010, the on-line service dates could range from 2017 to 2023. In addition, on-line service dates could slip one or more years for a variety of reasons. Consequently, line segments with on-line service dates before 2020 were not considered in this method as candidates for corridor designation. Out of the 100 transmission line segments, 10 met the criterion of having an on-line service date of 2020 or later. See Table 2 for these 10 line segments, sorted alphabetically by line segment name.

Environmental Concerns

Members of the RETI Environmental Working Group with land use and environmental expertise in Northern and Southern California provided an overall environmental rating for each line segment using resources available to them combined with their collective professional judgment. A checklist of potential issues[96] was developed, and each line segment was rated accordingly with a low, medium, or high level of environmental concern:

1. Low levels of concern and/or potential impacts relatively easy to mitigate.
2. Medium levels of concern and/or some difficulty expected with mitigation.
3. High levels of concern and/or difficulty identifying adequate mitigation.

Type of Right-of-Way Required

The next attribute considered was the type of right-of-way required. Five types of rights-of-way were identified by RETI, including:

- No change to an existing right-of-way where transmission lines were being reconductored or rebuilt.
- Expand an existing right-of-way to accommodate rebuilding or adding transmission lines.
- New right-of-way proposed in a designated transmission corridor.
- New right-of-way co-located within a half mile of an existing right-of-way but not in a designated corridor.

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[95] California Public Utilities Commission, General Information on Permitting Electric Transmission Projects at the California Public Utilities Commission, June, 2009, *www.cpuc.ca.gov/PUC/energy/Environment/*, accessed August 19, 2009.

[96] See RETI *Phase 2A Final Report* – Appendix D. Transmission Line Segment Analysis located on the Energy Commission's website at: http://www.energy.ca.gov/reti/documents/index.html.

- New right-of-way that was neither co-located nor in a designated corridor.

A new right-of-way proposed in a designated transmission corridor was eliminated if a BLM or 2005 Energy Policy Act Section 368[97] corridor designation exists and it encompassed the entire length of the line segment.

Table 2: RETI Phase 2A Transmission Line Segments With 2020 On-Line Service Dates

Line Segment	Type of Line Segment	On-Line Service Date	Environmental Concerns	ROW Required	Energy Potential of Line Segment (GWh)	Line Segment Length in Miles
BANN_DEVR_1**	Collector	2020	High	New/Coloc	6,436	91
COLL_PITT_1*	Delivery	2020	Low	New ROW	913	1
COLL_PITT_2*	Delivery	2020	Low	New ROW	819	1
COLL_TRCY2_1*	Collector	2020	Medium	New/Coloc	1,864	40
DESC_DEVR_2**	Collector	2020	High	Expand	1,828	76
DEVR_VALL_3**	Delivery	2020	High	Existing	949	40
IMPV_BANN_1**	Collector	2020	High	New/Coloc	5,034	51
IRMT_SCEJ_2**	Collector	2020	High	Existing	1,622	39
NEO_COLL_1*	Collector	2020	High	New/Des	480	640
SCEJ_PISG_2**	Collector	2020	High	New/Des	1,932	84

* Denotes a transmission line segment in Northern California

** Denotes a transmission line segment in Southern California

ROW = Right of Way; Coloc = Co-located; Des = Already designated

Source: Energy Commission staff, August 2009, adapted from the *RETI Phase 2A Final Report*.

Although expanding an existing right-of-way could be the subject of a corridor designation proceeding, the method discarded this group of line segments because expanding existing rights-of-way is typically less of an issue than developing a new or co-located right-of-way. The method considered those line segments requiring a new or co-located right-of-way, including

[97] http://www.epa.gov/oust/fedlaws/publ_109-058.pdf; accessed August 20, 2009.

those line segments that were proposed to run partially in existing BLM or Section 368 corridors. This resulted in dropping four of the line segments from further consideration, one "existing" right-of-way, one "expand" right-of-way, and two new lines in already-designated corridors.

Energy Potential of Line Segment

The method used RETI results that assessed the energy potential of each CREZ and assigned a total energy potential value in gigawatt-hours (GWh) to each transmission line segment. The value was based on the energy potential of the CREZ being accessed, multiplied by a shift factor[98] for that line.

Line Segments Considered for Corridor Designation

After assigning the energy potential value to each line segment, the final set of line segments included four Renewable Collector line segments and two Renewable Delivery line segments, as shown in Table 3.

Table 3: RETI Phase 2A Remaining Transmission Line Segments Sorted by Environmental Concern, ROW, and GWh

Line Segment	Type of Line Segment	On-Line Service Date	Environmental Concerns	ROW Required	Energy Potential of Line Segment (GWh)	Line Segment Length in Miles
COLL_PITT_1*	Delivery	2020	Low	New ROW	913	1
COLL_PITT_2*	Delivery	2020	Low	New ROW	819	1
COLL_TRCY2_1*	Collector	2020	Medium	New/Coloc	1,864	40
BANN_DEVR_1**	Collector	2020	High	New/Coloc	6,436	91
IMPV_BANN_1**	Collector	2020	High	New/Coloc	5,034	51
NEO_COLL_1*	Collector	2020	High	New/Des	480	640
* Denotes a transmission line segment in Northern California ** Denotes a transmission line segment in Southern California						

Source: Energy Commission staff, August 2009, adapted from the *RETI Phase 2A Final Report*.

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[98] Shift factor provides a relative measure of how much energy can be expected to flow in any transmission line segment in either direction. For more information, see the RETI *Phase 2A Final Report*.

Further Line Segment Analysis

Table 3 provides a starting point in determining what line segments should be chosen for corridor designation considering other factors, including:

- Projected timing of the development of a CREZ group based on the availability of contracts and interconnection agreements.
- Access to CREZ groups located on lands designated by the BLM for study in the Solar Programmatic Environment Impact Statement.
- Access to geographic areas identified in the DRECP.
- Line segments connecting to existing BLM or Section 368 corridors.

Collinsville-Pittsburg Line Segments

The Coll_Pitt_1 and Coll_Pitt_2 line segments are proposed submarine line segments approximately one mile in length under the San Francisco Bay in Northern California. The line segments are part of the proposed Canada - Pacific Northwest - Northern California Transmission Project. Since the line segments are only one mile long and would be installed under the Bay, a corridor designation is not required; therefore, the segments were eliminated from further consideration.

Neo-Collinsville and Collinsville-Tracy Line Segments

The Neo-Collinsville and Collinsville-Tracy line segments are part of the proposed Canada - Pacific Northwest - Northern California Transmission project, which is proposed to improve system reliability and bring renewable energy from the Pacific Northwest into Northern California.

The Neo-Collinsville is a Renewable Collector line approximately 640 miles long that originates in Oregon and continues into California. A part of the Northern California line segment would be located in a designated Section 368 corridor, and the remainder of the line would require a new right-of-way that would connect to the Section 368 corridor. The line's rating for environmental concerns is high, and the energy potential is 480 GWh. The line would bring wind energy from CREZs in Northern California identified in the *RETI Phase 2A Final Report*.

The Collinsville-Tracy is a Renewable Collector line approximately 40 miles long that is an extension of the Neo-Collinsville line segment. The line's rating for environmental concerns is medium, and the energy potential is 1,864 GWh. The line segment would require a new right-of-way co-located next to an existing right-of-way. The line would access wind energy from Northern California CREZs.

Imperial Valley-Bannister and Bannister-Devers Line Segments

The Imperial Valley-Bannister line segment is a Renewable Collector line approximately 51 miles long that would require a new right-of-way co-located next to an existing right-of-way. Its rating for environmental concerns is high, and its energy potential is 5,034 GWh. The line segment would access renewable energy from a number of CREZs in Southern California and a BLM area identified for study in the Solar Programmatic Environment Impact Statement.

The Bannister-Devers line segment is a Renewable Collector line approximately 91 miles long that is an extension of the Imperial Valley-Bannister line segment. The portion of the line running south to north would require a new right-of-way co-located next to an existing right-of-way. A portion of the line that runs east to west would be located in designated BLM corridors, and other portions would require a new right-of-way co-located next to an existing right-of-way that would connect to the BLM corridor. The line's rating for environmental concerns is high, and its energy potential is 6,436 GWh. The line segment would access renewable energy from a number of CREZs in Southern California, a BLM area identified for study in the Solar Programmatic Environment Impact Statement, and potential DRECP areas in the desert once the study is completed.

Transmission Corridor Case Study Conclusions

There are two distinct projects that are identified using the selection method: the Neo-Collinsville and Collinsville-Tracy line segments in Northern California, and the Imperial Valley-Bannister and Bannister-Devers line segments in Southern California. The Southern California line segments could provide more overall benefit to California because of the greater amount of renewable energy they would access, 11,470 GWh compared to 2,344 GWh. The Southern California line segments would provide access to areas that the BLM has identified for study in the Solar Programmatic Environment Impact Statement. While both projects have been identified to have a high environmental concern, the Southern California line segments would require a new right-of-way co-located next to an existing right-of-way, and the Northern California line segments would require a new right-of-way. Both projects' line segments would provide the opportunity to link up with existing BLM and/or Section 368 designated corridors.

Recommendations

The Committees make the following recommendations to prioritize the development of renewable transmission projects and to promote a method for reaching consensus on RETI segments that should be considered for corridor designation.

- Prioritize transmission planning and permitting efforts for renewable generation at the California ISO, the CTPG, and the Energy Commission as follows, and work on overcoming barriers and finding solutions that would aid their development:

- The first priority should be placed on those projects supported by the Energy Commission in the *2005* and *2007 Strategic Plans*:
    - Imperial Irrigation District (IID) Upgrades
    - Southern California Edison Company (SCE)Tehachapi Upgrades (Segment 1 – Antelope-Pardee; Segment 2 – Antelope-Vincent; Segment 3 – Antelope-Tehachapi; and Segments 4-11 – Tehachapi Renewable Transmission Project)
    - SCE Devers – Palo Verde 2 (the entire California-Arizona interconnection, as well as the California-only variation)
    - Los Angeles Department of Water and Power (LADWP) Tehachapi Upgrade (Barren Ridge Renewable Transmission Project)
    - Pacific Gas and Electric Company (PG&E) Central California Clean Energy Transmission Project (C3ETP)
    - San Diego Gas & Electric Company (SDG&E) Sunrise Powerlink Transmission Project
    - Lake Elsinore Advanced Pumped Storage (LEAPS) Project – Transmission Portion
    - Green Path North Coordinated Projects
- The second priority should be the RETI Phase 2 projects that include the "no regrets" line segments that do not require new corridors, plus two additional projects (Gregg – Alpha Four and Tracy – Alpha Four) that do not meet these criteria but are needed to complete a link to Northern California load centers. (Without these two lines the renewables would reach Fresno but not load centers in the Bay Area.)
    - Kramer – Lugo 500 kV
    - Lugo – Victorville #2 500 kV
    - Devers – Mira Loma #1 and #2 500 kV
    - Gregg – Alpha Four 500 kV
    - Tracy – Alpha Four 500 kV 1 & 2:
    - Devers – Valley #3 500 kV
    - Tesla – Newark 230 kV
    - Tracy – Livermore 230 kV
- The third priority should be to begin outreach for those "no regrets" RETI segments that require new corridors and to begin developing phased solutions to interconnect specific renewable zones as generators commit to developing power plants.

- The Committees recommend that the permitting analysis for the Southern California Edison El Dorado – Ivanpah Transmission Project should proceed, as interconnecting proposed renewable projects to the planned Ivanpah Substation is critical to attainment of the state's near-term RPS goals. (This recommendation is not an endorsement of the

Solar Partners' Ivanpah Solar Electric Generating System, which is currently being evaluated by the Energy Commission.)

- The Energy Commission staff should continue to coordinate with the RETI stakeholders group to incorporate RETI's new information in applying the method described in this chapter to reach consensus on the appropriate transmission line segments that should be considered for corridor designation to promote renewable energy development.

CHAPTER 7: Developing Long-Term Statewide Transmission Scenarios

Background

On November 17, 2008, Governor Schwarzenegger signed Executive Order S-14-08, requiring retail sellers of electricity to serve 33 percent of their load with renewable energy by 2020.[99] Investment in renewable generation and transmission is needed for California to meet this requirement. The California Renewable Energy Transmission Initiative (RETI), a cooperative stakeholder effort, was formed to identify transmission projects needed to accommodate the state's renewable energy goals.[100] First, RETI completed its assessment of the Competitive Renewable Energy Zones (CREZs)[101] which can provide renewable energy to California. Next, RETI identified 102 transmission line segments[102] that can deliver 1.6 times the amount of renewable energy needed for a 33 percent RPS by 2020. On August 12, 2009, RETI presented its recommendations in the *Final Phase 2A Report*.[103] The transmission line segments identified by RETI were used as the starting point for the three long-term transmission scenarios in this chapter.

Overview

"Chapter 4: Challenges to Achieving a Coordinated Statewide Strategic Transmission Plan" addressed how the existing transmission planning process could be restructured, reorganized, and consolidated as California moves toward a new paradigm. The 30-year transmission planning process outlined in Chapter 4 assesses wide-ranging planning assumptions and variables to create a range of possible longer-term transmission infrastructure requirements. Scenario planning could provide the vision needed to build a 30-year statewide transmission planning process.

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[99] http://gov.ca.gov/executive-order/11072/, posted November 17, 2008, accessed August 20, 2009.

[100] http://www.energy.ca.gov/reti/index.html, accessed August 20, 2009.

[101] The Renewable Energy Transmission Initiative Phase 1A and 1B Reports are located on the Energy Commission's website at http://www.energy.ca.gov/reti/documents/index.html, accessed August 20, 2009.

[102] http://www.energy.ca.gov/2009publications/RETI-1000-2009-001/RETI-1000-2009-001-F.PDF, see Appendix H, which consists of 102 line segments plus two transformers.

[103] The Renewable Energy Transmission Initiative Phase 2A Report is located on the Energy Commission's website at http://www.energy.ca.gov/reti/documents/index.html.

This chapter describes the development of a method for assessing potential long-term transmission infrastructure requirements in 2030 and 2040 based on a higher RPS. This chapter explores potential planning, siting and operational consequences and opportunities with regard to new and existing transmission lines that could be required as California increases its RPS beyond 2020.

Scenario Development and Descriptions

The Energy Commission staff developed three illustrative scenarios based on a 40 percent RPS by 2030, 50 percent RPS by 2030, and 50 percent RPS by 2040 using the RETI results as a starting point. The staff then explored potential planning, siting and operational consequences and opportunities to gain insights on the potential new and existing transmission lines that could be required as California increases its RPS beyond 2020.

The *RETI Phase 2A Report* is the 2020 Reference Case used to compare the three long-term transmission planning scenarios. RETI calculated the amount of additional renewable energy, called the renewable net short, that would be required to meet a 33 percent RPS by multiplying the load-serving entities' (LSE) sales by the RPS percentage, then subtracting existing renewables and miscellaneous other renewables.

For Scenarios 1 through 3, the 2020 Reference Case LSE sales of 301,974 gigawatt-hours (GWh) and a future load growth of 0.8 percent per year were used to forecast future LSE sales. The 0.8 percent load growth is based on the Energy Commission's *California Energy Demand 2010-2020 Staff Draft Report*.[104] The Northwest Power and Conservation Council's Draft Demand Forecast also indicated that Northern and Southern California load growth rate would be less than 1 percent through 2027.[105] For this analysis, the existing renewables and miscellaneous other renewables remained constant, and the same percentages were used for the renewable energy resource categories: (1) 75 percent for remote in-state renewables, (2) 15 percent for out-of-state renewables, and (3) 10 percent for commercial/industrial photovoltaic (PV).[106]

[104] The *California Energy Demand 2010-2020 Staff Draft Forecast Report* is posted on the Energy Commission's website at: http://www.energy.ca.gov/2009publications/CEC-200-2009-012/CEC-200-2009-012-SD.PDF. The 0.8 percent load growth is referenced on page 8 of the report. Posted June 16, 2009, accessed August 20, 2009.

[105] The *Draft Demand Forecast* – Appendix C is located on the Northwest Power and Conservation Council's website at: http://www.nwcouncil.org/library/2009/2009-04.pdf. Posted February 13, 2009, accessed August 20, 2009. See Figure C19 on page 26 of the document.

[106] PV is defined as commercial/industrial photovoltaic or other in-basin renewable energy resources that count toward RPS but do not require transmission. (In other words, they are on the utility side of the meter rather than on the customer side of the meter, as with residential rooftop PV.)

2020 Reference Case Assumptions – 33 Percent RPS by 2020

The *RETI Phase 2A Final Report* used the following assumptions to derive the renewable net short calculation at 33 percent by 2020:

- Load-Serving Entity Sales = 301,974 GWh
- Existing Renewables = 36,807 GWh;
- Miscellaneous Other Renewables = 3,134 GWh
- **Renewable Net Short Calculation:** [33% * 301,974] – 36,807 – 3,134 = 59,710 GWh additional renewable energy required to meet the 33 percent RPS by 2020

Renewable Energy Resource Category Requirements

- Remote In-State Renewables: 75% of 59,710 GWh = 44,800 GWh**
- Out-of-State Renewables: 15% of 59,710 GWh = 9,000 GWh**
- Commercial/Industrial Photovoltaic (PV): 10% of 59,710 GWh = 6,000 GWh**

** Denotes GWh rounded up or down to nearest 100.

Scenario 1 Assumptions – 40 Percent RPS by 2030

Scenario 1 is based on California reaching a 40 percent RPS by 2030.

- Load-Serving Entity Sales = 301,974 * 1.008^{10} = 327,020 GWh
- Existing Renewables = 36,807 GWh
- Miscellaneous Other Renewables = 3,134 GWh
- **Renewable Net Short Calculation:** [40% * 327,020] – 36,807 – 3,134 = 90,867 GWh additional renewable energy required to meet the 40 percent RPS by 2030

Renewable Energy Resource Category Requirements

- Remote In-State Renewables: 75% of 90,867 GWh = 68,200 GWh**
- Out-of-State Renewables: 15% of 90,867 GWh = 13,600 GWh**
- Commercial/Industrial Photovoltaic (PV): 10% of 90,867 GWh = 9,100 GWh*

** Denotes GWh rounded up or down to nearest 100.

Scenario 2 Assumptions – 50 Percent RPS by 2030

Scenario 2 is based on California reaching a 50 percent RPS by 2030.

- Load-Serving Entity Sales = 301,974 * 1.008^{10} = 327,020 GWh
- Existing Renewables = 36,807 GWh

- Miscellaneous Other Renewables = 3,134 GWh
- **Renewable Net Short Calculation:** [50% * 327,020] – 36,807 – 3,134 = 123,569 GWh additional renewable energy required to meet the 50 percent RPS by 2030

Renewable Energy Resource Category Requirements

- Remote In-State Renewables: 75% of 123,569 GWh = 92,700 GWh**
- Out-of-State Renewables: 15% of 123,569 GWh = 18,500 GWh**
- Commercial/Industrial Photovoltaic (PV): 10% of 123,569 GWh = 12,400 GWh**

** Denotes GWh rounded up or down to nearest 100.

Scenario 3 Assumptions – 50 Percent RPS by 2040

Scenario 3 is based on California reaching a 50 percent RPS by 2040.

- Load-Serving Entity (LSE) Sales = 301,974 * 1.008^{20} = 354,144 GWh
- Existing Renewables = 36,807 GWh
- Miscellaneous Other Renewables = 3,134 GWh
- **Renewable Net Short Calculation:** [50% * 354,144] – 36,807 – 3,134 = 137,131 GWh additional renewable energy required to meet the 50 percent RPS by 2040

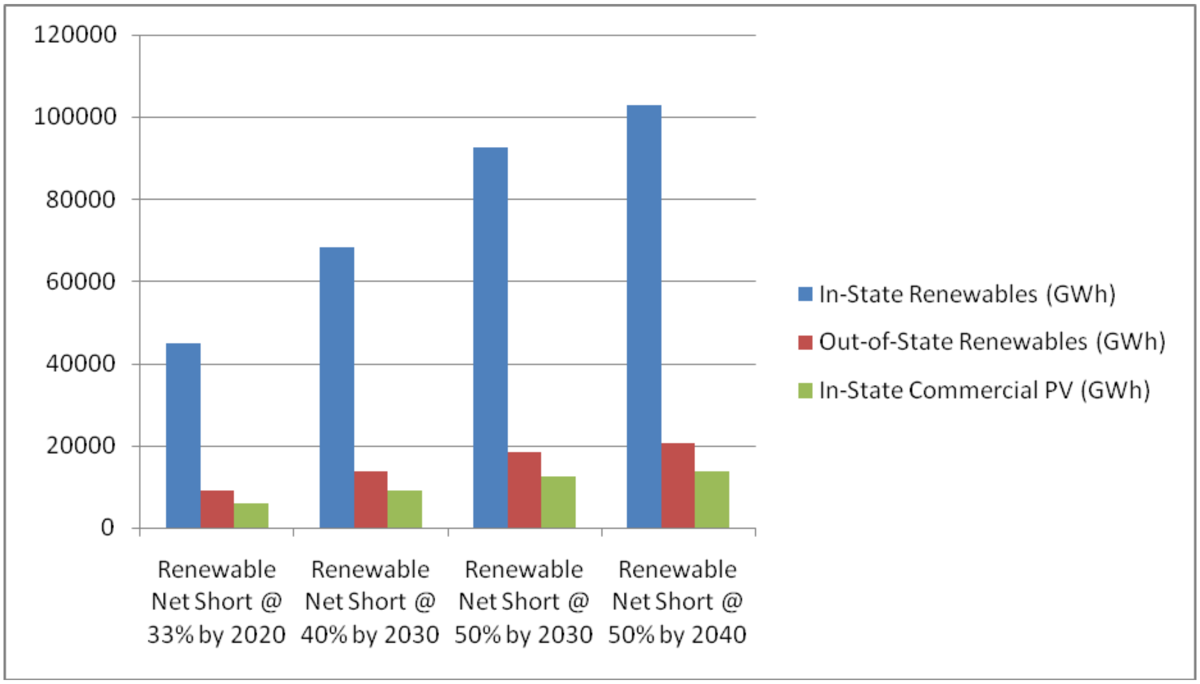
Renewable Energy Resource Category Requirements

- Remote In-State Renewables: 75% of 137,131 GWh = 102,800 GWh**
- Out-of-State Renewables: 15% of 137,131 GWh = 20,600 GWh**
- Commercial/Industrial Photovoltaic (PV): 10% of 137,131 GWh = 13,700 GWh**

** Denotes GWh rounded up or down to nearest 100.

Figure 7 depicts the amount of in-state renewables, out-of-state renewables, and in-state commercial/industrial PV required in the 2020 Reference Case and Scenarios 1-3 as outlined above.

Figure 7: Three Scenarios Compared to 2020 Reference Case



Source: Energy Commission staff, August 2009.

Comparison of Scenarios to 2020 Reference Case

Scenario 1 – 40 Percent RPS by 2030

Scenario 1 is based on California reaching a 40 percent RPS by 2030. Under this scenario, the renewable net short calculation of 90,867 GWh could be achieved by constructing all the RETI transmission line segments to access the renewable energy in the CREZs.

Renewable Energy Resource Category Requirements

Remote in-state renewable resources: requires 68,200 GWh, an increase of 23,400 GWh compared to the 2020 Reference Case.

Out-of-state resources: requires 13,600 GWh, an increase of 4,600 GWh compared to the 2020 Reference Case.

In-state commercial/industrial PV: requires 9,100 GWh, an increase of 3,100 GWh compared to the 2020 Reference Case.

Scenario 2 – 50 Percent RPS by 2030

Scenario 2 is based on California reaching a 50 percent RPS by 2030. Under this scenario, the renewable net short calculation of 123,569 GWh is greater than the 95,536 GWh identified by RETI that would require either new or upgrades to transmission line segments to accommodate additional in-state renewable energy resources.

Renewable Energy Resource Category Requirements

Remote in-state renewable resources: requires 92,700 GWh, an increase of 47,900 GWh compared to the 2020 Reference Case.

Out-of-state resources: requires 18,500 GWh, an increase of 9,500 GWh compared to the 2020 Reference Case.

In-state commercial/industrial PV: requires 12,400 GWh, an increase of 6,400 GWh compared to the 2020 Reference Case.

Scenario 3 – 50 Percent RPS by 2040

Scenario 3 is based on California reaching a 50 percent RPS by 2040. Under this scenario, the renewable net short calculation of 137,131 GWh is greater than the 95,536 GWh identified by RETI that would require either new or upgrades to transmission line segments to accommodate additional in-state renewable energy resources.

Renewable Energy Resource Category Requirements

Remote in-state renewable resources: requires 102,800 GWh, an additional 58,000 GWh compared to the 2020 Reference Case.

Out-of-state resources: requires 20,600 GWh, an additional 11,600 GWh compared to the 2020 Reference Case.

In-state commercial/industrial PV: requires 13,700 GWh, an increase of 7,700 GWh compared to the 2020 Reference Case.

Transmission Line Segment Assessment Compared to Full Buildout of RETI Phase 2A Transmission Plan

The RETI Phase 2A conceptual transmission plan was designed to deliver 1.6 times the estimated renewable net short for a 33 percent by 2020 RPS target, which equates to 95,536 GWh of renewable generation. Overall this means that a full buildout of the RETI transmission plan would allow California to meet Scenario 1’s renewable net short calculation of 90,867 GWh for a

40 percent RPS by 2030. For Scenarios 2 and 3 California would need to identify transmission facilities to deliver an additional 28,033 GWh and 41,595 GWh, respectively, beyond the RETI Phase 2A plan. Below is an illustrative assessment of the number of additional transmission lines that could be required above the 102 transmission line segments identified by RETI.

Full Buildout of RETI Phase 2A

Renewable Energy Resource Category Requirements

- Remote in-state renewable resources: 75% of 95,536 GWh = 71,700 GWh**
- Out-of-state resources: 15% of 95,536 GWh = 14,300 GWh**
- In-state commercial/industrial PV: 10% of 95,536 GWh = 9,600 GWh**

** Denotes GWh rounded up or down to nearest 100.

Scenario 1 – 40 Percent RPS by 2030

The RETI Phase 2A transmission plan identified all the transmission facilities needed to meet a 40 percent RPS by 2030.

Transmission Line Requirement by Renewable Energy Resource Category

Remote in-state renewable resources: requires 68,200 GWh, which is less than the 71,700 GWh the full RETI Phase 2A transmission plan would deliver.

Out-of-state resources: requires 13,600 GWh, which is less than the 14,300 GWh the full RETI Phase 2A transmission plan would deliver.

In-state commercial/industrial PV: requires 9,100 GWh, which is less than the 9,600 GWh the full RETI Phase 2A transmission plan assumed.

Scenario 2 – 50 Percent RPS by 2030

Under Scenario 2, the renewable net short is 123,569 GWh as calculated in the Scenario 2 Assumptions section. To meet a 50 percent RPS by 2030 an additional 28,033 GWh of renewable energy resources would be needed requiring either new or upgrades to transmission line segments to accommodate the additional energy.

Transmission Line Requirement by Renewable Energy Resource Category

Remote in-state renewable resources: requires 92,700 GWh. An additional 21,000 GWh is required compared to the full RETI Phase 2A transmission plan.

Transmission Line Requirement:

- Assume additional in-state resources would consist primarily of wind and solar
- Capacity factors for wind and solar range between 25 percent and 40 percent
- GWh to MW Conversion:
  - 21,000 GWh/(.40*8.76) = 6,000 MW
  - 21,000 GWh/(.25*8.76) = 9,600 MW
- Assume a new 500 kV transmission line could deliver 1,200 MW

Based on the above assumptions and calculations, an additional five to eight new 500 kV transmission lines would be required to deliver the additional remote in-state renewable resources required to meet a 50 percent RPS by 2030 above the 102 RETI transmission line segments.

Out-of-state resources: requires 18,500 GWh. An additional 4,200 GWh is required compared to the full RETI Phase 2A transmission plan.

Transmission Line Requirement:

- Assume additional out-of-state resources would consist primarily of wind and solar
- Capacity factors for wind and solar range between 25 percent and 40 percent
- GWh to MW Conversion:
  - 4,200 GWh/(.40*8.76) = 1,200 MW
  - 4,200 GWh/(.25*8.76) = 1,900 MW
- Assume a new 500 kV transmission line could deliver 1,200 MW

Based on the above assumptions and calculations, an additional one to two out-of-state 500 kV transmission lines would be required to deliver the out-of-state renewable energy into California.

In-state commercial/industrial PV: requires 12,400 GWh. An additional 2,800 GWh is required compared to the full RETI Phase 2A transmission plan. These resources would be located near load centers and would not likely require major transmission interconnections.

Scenario 3 – 50 Percent RPS by 2040

Under Scenario 3, the renewable net short calculation is 137,131 GWh as calculated in the Scenario 3 Assumptions section. To meet a 50 percent RPS by 2040 an additional 41,595 GWh of renewable energy resources would be needed requiring either new or upgrades to transmission line segments to accommodate the additional energy.

Transmission Line Requirement by Renewable Energy Resource Category

Remote in-state renewable resources: requires 102,800 GWh. An additional 31,100 GWh is required compared to the full RETI Phase 2A transmission plan.

Transmission Line Requirement:

- Assume additional in-state resources would consist primarily of wind and solar
- Capacity Factors for wind and solar range between 25 percent and 40 percent
- GWh to MW Conversion:
  - 31,100 GWh/(.40*8.76) = 8,900 MW
  - 31,100 GWh/(.25*8.76) = 14,200 MW
- Assume a new 500 kV transmission line could deliver 1,200 MW

Based on the above assumptions and calculations, an additional 8 to 12 new 500 kV transmission lines would be required to deliver the remote in-state renewable resources required to meet a 50 percent RPS by 2040 above the 102 RETI transmission line segments.

Out-of-state resources: requires 20,600 GWh. An additional 6,300 GWh is required compared to the full RETI Phase 2A transmission plan.

Transmission Line Requirement:

- Assume additional out-of-state resources would consist primarily of wind and solar
- Capacity Factors for wind and solar range between 25 percent and 40 percent
- GWh to MW Conversion:
  - 6,300 GWh/(.40*8.76) = 1,800 MW
  - 6,300 GWh/(.25*8.76) = 2,900 MW
- Assume a new 500 kV transmission line could deliver 1,200 MW

Based on the above assumptions and calculations, an additional two to three out-of-state 500 kV transmission lines would be required to deliver the out-of-state renewable energy into California.

In-state commercial/industrial PV: requires 13,700 GWh. An additional 4,100 GWh is required compared to the full RETI Phase 2A transmission plan. These resources would be located near load centers and would not likely require major transmission interconnections.

Observations

California is committed to a 33 percent RPS by 2020, requiring substantial investment in renewable generation and transmission lines. As the RPS increases beyond 2020, California will need to decide if the 75/15/10 mix of in-state to out-of-state resources is best for the state, while taking into consideration land use and grid reliability. Below is a discussion of potential planning, siting and operational consequences, and opportunities for each of the renewable energy resource categories compared to the full buildout of RETI Phase 2A: (1) in-state transmission, (2) out-of-state transmission and, (3) commercial/industrial PV.

In-State Transmission

The *RETI Phase 2A Final Report* identified 102 transmission line segments that would be needed to deliver 95,536 GWh of renewable energy to load centers throughout California. In all three scenarios all the transmission line segments would be required for California to meet a higher RPS in 2030 and 2040. In Scenarios 2 and 3, an additional 21,000-31,100 GWh of renewable energy projects within some of the CREZs would be required to meet the increased RPS requirements due to load growth. Between 8 and 12 new 500 kV transmission lines or upgrades to existing transmission lines (through conventional methods or technological advancements) would be required to accommodate the additional energy. A subset of the RETI transmission line segments that would be needed is shown in Table 4 below. This subset of lines was considered in "Chapter 6: Prioritizing the Development of Renewable Transmission Projects and Corridors for Designation" for potential corridor designation. (See Chapter 6 for a description of the RETI Phase 2A types of line segments [Renewable Collector and Renewable Delivery] contained in Table 4.)

Table 4: RETI Phase 2A Transmission Line Segments With 2020 On-Line Service Dates

Line Segment	Type of Line Segment	On-Line Service Date	Energy Potential of Line Segment (GWh)
BANN_DEVR_1**	Collector	2020	6,436
COLL_PITT_1*	Delivery	2020	913
COLL_PITT_2*	Delivery	2020	819
COLL_TRCY2_1*	Collector	2020	1,864
DESC_DEVR_2**	Collector	2020	1,828
DEVR_VALL_3**	Delivery	2020	949
IMPV_BANN_1**	Collector	2020	5,034
IRMT_SCEJ_2	Collector	2020	1,622
NEO_COLL_1*	Collector	2020	480
SCEJ_PISG_2**	Collector	2020	1,932

* Denotes a transmission line segment in Northern California

** Denotes a transmission line segment in Southern California

Source: Energy Commission staff, August 2009, adapted from the *RETI Phase 2A Final Report*.

Planning

Under all three scenarios, it is apparent that for California to achieve a higher RPS beyond 2020, a long-term coordinated statewide planning process is critical to ensure the timely development of transmission infrastructure. This process would help to identify the size, location, and timing for these facilities. The three scenarios developed in this chapter could be used as part of the Long-Term 30-Year Statewide Transmission Planning Process outlined in "Chapter 4: Challenges to Achieving a Coordinated Statewide Strategic Transmission Plan" to identify the potential issues and challenges that could arise long-term as renewable generation is built and integrated into the grid.

Siting

The construction of transmission lines could have long-term effects, including but not limited to land use restrictions and impacts to property owners, aesthetics, wildlife habitat, recreation areas, and agricultural lands. Approximately 4,500[107] miles of right-of-way would be required to build the ≥ 230 kV RETI transmission line segments that would require a new or expanded right-of-way. To put this into perspective, California has already set aside approximately 16,784[108] miles of right-of-way for transmission lines ≥ 230 kV. If California decides to move toward a higher RPS, as in Scenarios 2 and 3, the potential for setting aside additional land for a right-of-way increases.

The Energy Commission's authority to designate transmission corridors could help minimize the societal impact and public disruption that comes with setting aside land for transmission lines through the inclusion of the public in the decision-making process. As discussed in "Chapter 5: Statewide Transmission Corridor Planning," the Energy Commission was granted the authority to designate appropriate transmission corridors for future use. [109] Designating land in advance of project identification should assure the timely permitting and construction of needed transmission facilities to access renewable resources.

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[107] The 4,500 miles of right-of-way data was calculated from the RETI Phase 2A Supplemental Materials – Conceptual Plan Data, posted August 12, 2009 on the Energy Commission's website at: http://www.energy.ca.gov/reti/documents/index.html. A line segment in an existing right-of-way was not included.

[108] The 16,784 miles of existing right-of-way for transmission lines 230 kV and above was provided by the California Energy Commission's cartography department.

[109] http://www.leginfo.ca.gov/pub/05-06/bill/sen/sb_1051-1100/sb_1059_bill_20060929_chaptered.pdf; SB 1059 (Escutia, Chapter 638, Statutes of 2006), accessed August 20, 2009.

Operations

The increased number of transmission lines that would be needed to access renewable resources could present operational issues and challenges for the California ISO and publicly owned utilities (POUs) with respect to the successful integration of renewable resources into the grid. The variability and intermittency of some of the renewable generation, wind and some solar, would have to be accommodated by each control area operator. In addition, the transmission system has physical limitations on the amount of power that can be transmitted. New and emerging technologies will become increasingly important to expand the existing system's transfer capacity to accommodate the increased penetration of renewable generation, as conventional solutions alone could prove inadequate.

The successful integration of renewable resources into the existing portfolios of the California ISO and POUs is an important issue that should be addressed now. As California's RPS goal continues to increase, so does the opportunity to promote mature and emerging technologies that could reduce intermittency impacts and alleviate operational and reliability constraints.

The advancement of storage technology, including batteries, flywheels, compressed air energy storage, capacitors, and superconducting magnetic energy storage, will become increasingly important with the increased integration of renewable generation into the grid. Storage technology could provide control area operators the means to inject renewable energy into the grid when it is needed as opposed to when it is generated. Energy storage could also provide grid system support in the form of voltage support, generation and frequency regulation, black start capabilities, and spinning reserve. Continued investment in storage technology is needed to provide control area operators greater flexibility in integrating intermittent resources into their existing portfolio and managing the bulk power system.

As discussed in "Appendix A: Trends in Transmission Research for Renewables Integration," there are a number of mature and emerging technologies that could increase the transfer capability on existing transmission lines, thereby minimizing the need to set aside land for new transmission lines, thereby reducing the overall footprint. Some of the mature technologies include re-conductoring, conversion of single-circuit line to double-circuit, compact lines, and voltage uprating. One of the emerging technologies currently being field tested on the East Coast is high-temperature superconductor (HTSC) cable, which has the capability to handle the same amount of power as conventional overhead or underground transmission lines in a smaller right-of-way. In addition, H.R. 2347 – Advanced Cable Deployment Authorization Act of 2009, introduced by Representative Hoyer, was referred to the Subcommittee on Energy and Environment on May 17, 2009.[110] The bill would provide funding for the advancement of electric transmission cable, including HTSC cable.

[110] http://majorityleader.gov/docUploads/Transmission2051209.pdf, accessed August 20, 2009.

Out-of-State Transmission

Only Scenarios 2 and 3 would require additional out-of-state renewable resources ranging from 4,200-6,300 GWh when compared to the full buildout of RETI Phase 2A. This assumes that the Canada - Pacific Northwest - Northern California Transmission Project identified by RETI (NEO_COLL_1* and COLL_TRCY2_1* identified in Table 4 above), and other regional transmission line projects would be needed to bring qualifying RPS renewable energy into California. In addition to the RETI out-of-state projects, one to three other 500 kV lines would be required to accommodate the additional out-of-state renewables needed for a 50 percent RPS in 2030 and 2040. For illustrative purposes, a subset of the regional projects identified in "Chapter 3: Western Region Transmission Initiatives, Trends and Drivers" that could bring renewable energy not only into California but surrounding states is shown below in Table 5. A detailed description of each project is provided in "Appendix D: Summary of Proposed Regional Transmission Projects."

Table 5: Proposed Regional Transmission Projects

Pacific Northwest		
Project	**Location**	**Transfer Capability**
West Coast Cable	Portland OR – San Francisco, CA	1,200 MW
Gateway West	Wyoming – Idaho Idaho – OR/CA border	3,000 MW 1,500 MW
Inland		
Gateway South	Wyoming – Utah Utah – Las Vegas, NV	3,000 MW 1,500 MW
TransWest Express	Wyoming – Colorado – Utah – Las Vegas, NV	3,000 MW
Zephyr	Wyoming – Las Vegas, NV	3,000 MW
Chinook	Montana – Las Vegas, NV	3,000 MW
Desert Southwest		
SunZia Southwest	New Mexico - Arizona	3,000 MW
Mexico		
Energía Sierra Juárez U.S. Transmission	La Rumorosa, Baja California, Mexico – Jacumba, CA	1,250 MW

Source: Energy Commission staff, August 2009.

Planning

Regional cooperation would become increasingly important as more renewable energy projects are brought on-line throughout the western United States. Regional cooperation means states that are part of the Western Interconnection work together at the planning and permitting stages to ensure needed facilities get built as further discussed in "Chapter 3: Western Region Transmission Initiatives, Trends, and Drivers." California and some of the western states that have RPS mandates could rely on each other for renewable energy. With increased penetration of renewable generation throughout the West, regional cooperation will be crucial for maintaining grid reliability and the successful integration of intermittent resources throughout the Western Interconnection.

Regional cooperation could provide an opportunity to resolve the cost allocation issue with respect to constructing transmission lines. Any state that would benefit from a transmission line being built to deliver renewable energy should pay its fair share. For example, if Montana builds a transmission line that would deliver renewable energy into Nevada, Arizona, and California, then all states benefiting should pay their fair share for the cost of constructing the transmission lines.

Siting

Land use will be more of an issue for the western states building the transmission lines that would deliver renewable energy into California and other states. Land use could become an issue for California if existing transmission lines or transmission lines identified by RETI require upgrading to accommodate the additional energy coming into California. Upgrading a transmission line could require a new right-of-way or expanding an existing right-of-way, which would mean setting aside more land for future use.

As discussed in the "In-State Transmission" section above and in "Appendix A: Trends in Transmission Research for Renewables Integration," promoting the advancement of mature and emerging technologies that increase the transfer capability on existing transmission lines would minimize the amount of land needed for new transmission lines, at least in California.

In addition, as part of the corridor designation process, the Energy Commission could consider expanding corridors to the California border to access future out-of-state renewable energy. As mentioned in the "In-State Transmission" section, corridor designation should minimize the societal impact and public disruption that comes with setting aside land for future transmission line construction by including the public in the overall corridor designation decision-making process.

Operations

All states within the Western Interconnection face the same renewables integration issues. As discussed earlier, storage technologies could prove a key element for the successful integration of intermittent resources into the grid and maintaining system reliability.

A more detailed discussion of storage technology is presented in "Appendix A: Trends in Transmission Research for Renewables Integration."

Commercial/Industrial PV

Only Scenarios 2 and 3 would require additional in-state commercial/industrial PV ranging from 2,800-4,100 GWh when compared to the full buildout of RETI Phase 2A. Since no additional transmission lines would be required because of the close proximity to existing transmission lines, no further analysis was performed.

Summary

All three illustrative scenarios suggest that if California decides to build most of its own renewable energy resources to meet its RPS goals, then many miles of land would be needed for new transmission lines. California will need to decide the best diversification of in-state to out-of-state renewable resources as the RPS increases beyond 33 percent, while taking into consideration land use and grid system reliability.

Long-term planning and the development of a Long-Term 30-Year Statewide Transmission Planning Process as outlined in "Chapter 4: Challenges to Achieving a Coordinated Statewide Strategic Transmission Plan" would be an important first step for making such an assessment. Long-term planning would help identify future corridor designations. In addition, regional cooperation becomes increasingly important at the planning and permitting stages to ensure needed facilities are built, for integrating renewable generation, maintaining grid reliability and resolving cost allocation issues.

The Energy Commission's corridor designation process should assure the timely permitting and construction of needed transmission facilities to access renewable resources and benefit the public by including them in the overall corridor designation review process. Technological advancements that increase the transfer capability on existing transmission lines could minimize the need to set aside land for new and existing transmission lines reducing the overall footprint of facilities.

Investment in both mature and emerging technologies will be critical for the successful operation of the bulk system grid. Regardless of the ratio of in-state to out-of-state renewable resources, storage technologies will be a key component for integrating intermittent resources throughout the Western Interconnection and operating the grid reliably.

Recommendations

Scenario planning could provide the vision needed to build a 30-year statewide transmission planning process. Using the RETI Phase 2A conceptual transmission plan results as a starting point staff developed three illustrative scenarios with a 40 percent RPS by 2030, 50 percent RPS by 2030, and 50 percent RPS by 2040. The staff then explored potential planning, siting and operational consequences and opportunities to gain insights on the potential new and existing transmission lines that could be required as California increases its RPS beyond 2020.

- The Committees recommend that the Energy Commission staff should identify and establish a method for the *2011 Strategic Plan* that uses scenarios in the development of a 30-year transmission plan for California, building upon the long-term planning process described in Chapter 4 as well as the analysis described in Chapter 7.

ACRONYMS

AB – Assembly Bill

AC – Alternating current

ACC – Arizona Corporation Commission

ACEC – Area of Critical Environmental Concern

ACR – Assigned Commissioner's Ruling

AFC – Application For Certification

ALJ – Administrative Law Judge

APS – Arizona Public Service

ARB – California Air Resources Board

ARRA – American Recovery and Reinvestment Act of 2009

BIA – U.S. Department of Interior's Bureau of Indian Affairs

BLM – U.S. Bureau of Land Management

BMP – Best Management Practices

BPA – Bonneville Power Administration

California ISO – California Independent System Operator

CBC – California Biodiversity Council

CBD – Center for Biological Diversity

C3ETP – Central California Clean Energy Transmission Project (PG&E)

CDFG – California Department of Fish and Game

CEERT – Center for Energy Efficiency and Renewable Technologies

CEQA – California Environmental Quality Act

CERTS – Consortium of Electric Reliability Technology Solutions

CFE – Comisión Federal de Electricidad (Mexico)

CMUA – California Municipal Utilities Association

COI – California-Oregon Intertie

COTP – California-Oregon Transmission Project

CPCN – Certificate of Public Convenience and Necessity

CPUC – California Public Utilities Commission

CREZ – Competitive Renewable Energy Zone

CSP – Concentrating solar power

CTPG – California Transmission Planning Group

DC – Direct current

DFG – California Department of Fish and Game

DG – Distributed generation

DOD – U.S. Department of Defense

DRECP – Desert Renewable Energy Conservation Plan

DSM – Demand-side management

DSW – Desert Southwest

DWMA – Desert Wildlife Management Area

DWR – California Department of Water Resources

EHV – Extra high voltage

EIR – Environmental impact report

EIS – Environmental impact statement

EMF – Electric and magnetic fields

EMS – Energy management system

EPAct-05 – Energy Policy Act of 2005

EWG – RETI Environmental Working Group

EPRI – Electric Power Research Institute

FEIS – Final environmental impact statement

FERC – Federal Energy Regulatory Commission

FOA – Funding Opportunity Announcement

GIS – Geographic Information System

GHG – Greenhouse gas

GO – General Order

GWh – Gigawatt-hour (1 GWh = 1 thousand MWh)

HCP – Habitat Conservation Plan

HTLS – High temperature, low sag

HVAC – High voltage alternating current

HVDC – High voltage direct current

IAP – Intermittency Analysis Project

IID – Imperial Irrigation District

IOU - Investor-owned utility

IVSG – Imperial Valley Study Group

kV – Kilovolt

kWh – Kilowatt-hour

LADWP – Los Angeles Department of Water and Power

LCRI – Location Constrained Resource Interconnection

LEAPS - Lake Elsinore Advanced Pumped Storage project

LRA – Local Reliability Area

LSE – Load-serving entity

LTTP – Long-term Procurement Plan

MID – Modesto Irrigation District

MOA – Memorandum of agreement

MOU – Memorandum of understanding

MRTU – California ISO's Market Redesign and Technology Update

MW – Megawatt

MWD – Metropolitan Water District of Southern California

MWh – Megawatt-hour (1 MWh = 1 thousand kWh)

NAHC – Native American Heritage Commission

NCCP – Natural Communities Conservation Planning

NEPA – National Environmental Policy Act

NERC – North American Electric Reliability Corporation

NIETC – National Interest Electric Transmission Corridor

NIMBY – Not In My Backyard

NOI – Notice of Inquiry

NPS – National Park Service

NRDC – Natural Resources Defense Council

NREL – National Renewable Energy Laboratory

NTTG – Northern Tier Transmission Group

OATT – Open Access Transmission Tariff

OII – Order Instituting Investigation

OIR – Order Instituting Rulemaking

O&M – Operation and Maintenance

OPR – Governor's Office of Planning and Research

PACT – Planning Alternative Corridors for Transmission

PCC – WECC's Planning Coordination Committee

PEA – Proponent's Environmental Assessment

PEIR – Programmatic Environmental Impact Report

PEIS – Programmatic Environmental Impact Statement

PG&E – Pacific Gas and Electric Company

PHFU – Plant Held for Future Use

PIER Program – Public Interest Energy Research Program

PMU – Phasor Measurement Unit

PNW – Pacific Northwest

POU – Publicly Owned Utility

PTC – Permit To Construct

PTO – Participating Transmission Owner

PRC – Public Resources Code

PV - Photovoltaic

PVD2 – Palo Verde-Devers No. 2 500 kV line

RD&D – Research, development & demonstration

REAT – Renewable Energy Action Team

RETI – California Renewable Energy Transmission Initiative

REZ – Renewable Energy Zone

RMR – Reliability must run

ROW – Right-of-way

RPS – Renewables Portfolio Standard

RTO – Regional Transmission Organization

RTR – Real-time ratings

RTSO – Real-time system operations

SB – Senate Bill

SCE – Southern California Edison Company

SDG&E – San Diego Gas & Electric Company

SMUD – Sacramento Municipal Utility District

SPG – Subregional Planning Group

TAC – Transmission Access Charge

TANC – Transmission Agency of Northern California

TEPPC – WECC's Transmission Expansion Planning Policy Committee

TID – Turlock Irrigation District

TLSE – Transmission-owning load-serving entity

TNHC – The Nevada Hydro Company, Inc.

TPP – California ISO's annual Transmission Planning Process

TRP – PIER Transmission Research Program

TRTP – Tehachapi Renewable Transmission Project (SCE)

TV/ES – Talega-Escondido/Valley Serrano

UCAN – Utility Consumers' Action Network

USAF – United States Air Force

U.S. DOE – U.S. Department of Energy

USFS – United States Forest Service

USFWS – United States Fish and Wildlife Service

USMC – United States Marine Corps

WAG – Western Assessment Group

WAPA – Western Area Power Administration

WCATF – Western Congestion Assessment Task Force

WECC – Western Electricity Coordinating Council

WGA – Western Governors' Association

WIEB – Western Interstate Energy Board

WREGIS – Western Renewable Energy Generation Information System

WREZ – Western Renewable Energy Zone

APPENDIX A: Trends in Transmission Research for Renewables Integration

New transmission technologies, especially as part of an integrated smart grid, can reduce costs, improve effectiveness, and enable regulatory compliance of transmission.

Operational Integration Technologies

Grid operators are concerned with increased penetrations of centralized and distributed intermittent renewable generators, especially those using electronic inverter interconnections. Research, development, and demonstration (RD&D) is needed to understand the system dynamic response at higher renewable penetrations and to develop technical solutions accordingly.

Research is needed to determine the effective inertia and other operating characteristics of renewable interconnection equipment. Identified problems will require RD&D for improved interconnection equipment. RD&D is required for new methods for dispatching power generation and deploying energy storage and reactive power management systems.

Situational awareness for grid operations and control is becoming important as operational uncertainties grow. New hour-ahead and day-ahead situational analyses, renewable generation "ramp-down" and "ramp- up" predictions, and real-time power system control tools are needed to provide transmission grid operators with information. RD&D of generator modeling will also be needed as new types of renewable generators are deployed. Emerging synchrophasor technology is enabling an unprecedented capability in grid situational awareness. Operators across the WECC are deploying this technology for enhanced monitoring and data analysis of grid disturbances, but RD&D is needed to find new synchrophasor measurement-based tools that produce information for grid operators and automation. Some of these are tools for detection, analysis, and reduction of low-frequency oscillations and voltage instabilities.

Renewable DG, such as photovoltaics, raises some grid operation concerns. Pockets of high concentrations of photovoltaics will change the inertia of the local grid. As penetrations grow, the effects on transmission system configurations and operations will also change. RD&D will be needed to understand these effects and develop technical solutions.

Energy Storage

Energy storage is a critical part of the solution given California's ongoing effort to achieve state and federal energy goals (for example, accelerated Renewables Portfolio Standard (RPS), net-zero energy buildings, and other energy efficiency goals, California Solar Initiative, and Assembly Bill 32) and the implementation of Smart Grid. Both large (utility-scale) and small (distributed) energy storage will be critical to integrate the necessary intermittent renewable technologies (for example, solar and wind generation) into the grid. It can also provide other grid benefits, such as voltage support, system stability enhancement, generation and frequency regulation, black start capabilities, and spinning reserve. There are a number of different storage technologies, currently available and under development, that can be matched to various applications. These include batteries, flywheels, compressed air energy storage, hydroelectric plants, capacitors, flow batteries, and others. These technologies can provide significant value at each level in the transmission and distribution system, varying in type and size to fulfill that level's unique service needs. Energy storage offers a solution to many renewable integration problems, but successful deployment remains elusive. Many of the barriers reside in regulation and market structures, and RD&D in these can help remove some of the barriers.

Energy storage technologies have a variety of properties that can serve multiple purposes in stabilizing the energy grid. At present, many storage technologies have not matured to the cost and performance points that are needed for use by the grid; moreover, many of the conventional storage technologies that are mature are not suitable for many of the emerging applications or are limited by geographic constraints. Some technologies, however, are feasible and cost-effective for niche applications, and costs and performance are steadily improving through research.

Funding of research should continue of new energy storage technologies and their development. Researching the proper placement and sizing of new and existing technologies is essential so they become an asset and not a burden to the state's electrical system. The focus should be to resolve grid stability and operation issues related to higher penetrations of renewables, reduce the costs of those technologies, analyze their integration with solar and wind power plants, and accelerate their commercialization. Since storage can provide multiple benefits, aggregation of these benefits is necessary for cost-effectiveness in many cases.

Developments should continue to be monitored and selected research supported to meet California's needs.

Transmission Undergrounding

Underground transmission lines inherently have no visual effects, which could reduce public opposition and speed approval of new lines. Costs and environmental impacts during construction, however, are much greater than for overhead lines. That gap is narrowing, as the costs to site and build even a standard overhead alternating current (AC) line are increasing.

New converter technologies and cables and new construction methods such as directional drilling have emerged that are improving the costs and environmental impacts of underground lines. Research to assess the status and applicability of underground technologies for California would provide regulators and potential investors with a better understanding of the cost/benefit tradeoffs.

High-Capacity Conductors

Power flowing through a conductor heats it, and as the amount of power is increased, it eventually will reach an upper limit where the temperature causes the line sags too much or to be damaged. Replacing a line with a larger diameter cable to get more power capacity incurs the cost of structural modifications to towers to support the increased weight, as well as a permitting process. An emerging alternative is a class of conductors, called high-temperature, low-sag (HTLS), made with new core materials that can withstand higher temperatures while sagging less. HTLS cables can safely carry several times more current than conventional ones, even though they run hotter; since they are similar in appearance and weight to conventional cables, they can be retrofitted on existing towers. Issues with HTLS conductors include increased power losses, required extra care and handling during installation, and considerably higher cost than conventional conductors.

HTLS conductors are still viewed as comparatively risky and expensive. There are niche applications, such as tight clearance situations and road and river crossings, where sag must be controlled. Field trials have provided information needed on installation costs, techniques and hardware (clamps, connectors, and others) that are required, training for line crews and contractors, and longevity in the field. There also issues with downstream transmission components, like substations, that must be upgraded to handle the higher power flows.

Maximizing of Existing Facilities and Rights-of-Way

As it becomes increasingly difficult to site new transmission, it becomes increasingly desirable for each right-of-way (ROW) to carry more power. One way is to build another line in the same ROW, assuming space is available to maintain WECC clearance standards. (See the Chapter 6 section titled "Potential Conflict Between Transmission Planning Priorities and WECC Reliability Criteria" for more information on this topic.) Since there is a limit to the space in a ROW, there are a number of other technological approaches for increasing the power-carrying capacity within the constraints of the existing ROW. These approaches include, in generally increasing order of cost and complexity:

Sag Mitigation: Physical methods to control sag that is limiting the power capacity of thermally constrained lines.

Re-Conductoring: Replaces existing line conductors with ones of higher capacity.

Bundled Conductors: Install additional conductors in parallel with existing conductors.

Conversion of Single-Circuit Line to Double-Circuit: Rebuild towers to put two vertically oriented three-phase circuits in the same space as a horizontally oriented line.

Compact Lines: Special designs that employ smaller spacing between phase conductors.

Voltage Uprating: A line can be converted to a higher voltage, hence higher power, by replacing terminal (substation) equipment, including transformers.

VSC-Based HVDC: A new HVDC technology using advanced power electronics based on voltage-source converters (VSCs) instead of thyristors, and solid-dielectric direct-buried cables instead of overhead conductors. It is less expensive on a per unit basis than conventional HVDC (see below) but has not been developed and implemented to the same high levels of power.

High Phase Order: Two or more circuits arranged on the transmission structure to allow very close phase spacing.

HVDC Transmission: High voltage direct current (HVDC) lines are more compact than HVAC lines, allowing for higher power transfer in the same ROW.

Underground Cables: Insulated conductors installed underground in duct banks (See section above).

Superconducting Cable: Cable – currently being demonstrated in field tests – made of material that has zero electric resistance when sufficiently cooled (for example, at liquid nitrogen temperatures), allowing it to handle a hundred times the current of conventional cables materials.

Many of these technologies could increase the utility of valuable land and reduce or eliminate the visual effects of transmission lines. Many are mature and readily available, while others require more research to become more commercially viable. Higher risks of damage to transmission equipment and outages of greater consequence are some of the tradeoffs of greater power flows through a ROW, risks that research may be able to mitigate.

Power System Control Technologies

Power flows and dynamic response to disturbances within the power system are largely dictated by the physics of the topology of the network. Grid operators today have limited control over how much power flows in a given circuit. Consequently, some circuit paths can be heavily loaded and others less so, resulting in overloads, under-utilization of assets, congestion, and other operating and planning issues. Also, there are limited options to respond to disturbances. The growing uncertainty under which grids are planned, operated, and protected, coupled with the need to operate the system closer to its physical limits, call for developing technologies for greater system control, including automation guided by greater intelligence.

HVDC transmission systems, due to the use of power electronic converters in place of transformers, have an inherently higher degree of control of the amount of power flowing through the circuit and can compensate for dynamic events on the rest of the grid, contributing to overall system stability. Back-to-back HVDC links can be used on tie lines between neighboring systems for buffering one area from dynamic events in another and limiting the spread of system instabilities. Emerging HVDC technologies, using VSC electronics, are potentially less expensive and have greater capabilities for voltage support and control functions, both in HVDC transmission lines as well as stand-alone control devices. Flexible AC Transmission Systems are power electronics-based devices that can be located in AC systems and used for control in numerous ways, such as balancing flows on lines, maintaining voltage, and counteracting dynamic events to keep the system stable.

Critical applications of power system controls include fault current control, and mitigation of line overloads, congestion, and renewables variability. Near-term research is needed on equipment that addresses these applications.

Advanced Transmission Planning Tools

Traditional power system analysis tools are becoming increasingly inadequate for addressing the changes and growing uncertainties arising from new regulations, markets structures, and renewable generation. Research should be directed at planning tools to improve the ability of transmission planning and analysis to address uncertainty and provide more accurate forecasts of system status and behavior. Potential applications include congestion management planning, project cost/benefit, operations risk assessment and mitigation, and extreme events analysis.

APPENDIX B:
American Recovery and Reinvestment Act of 2009 Regional Transmission Planning Responses

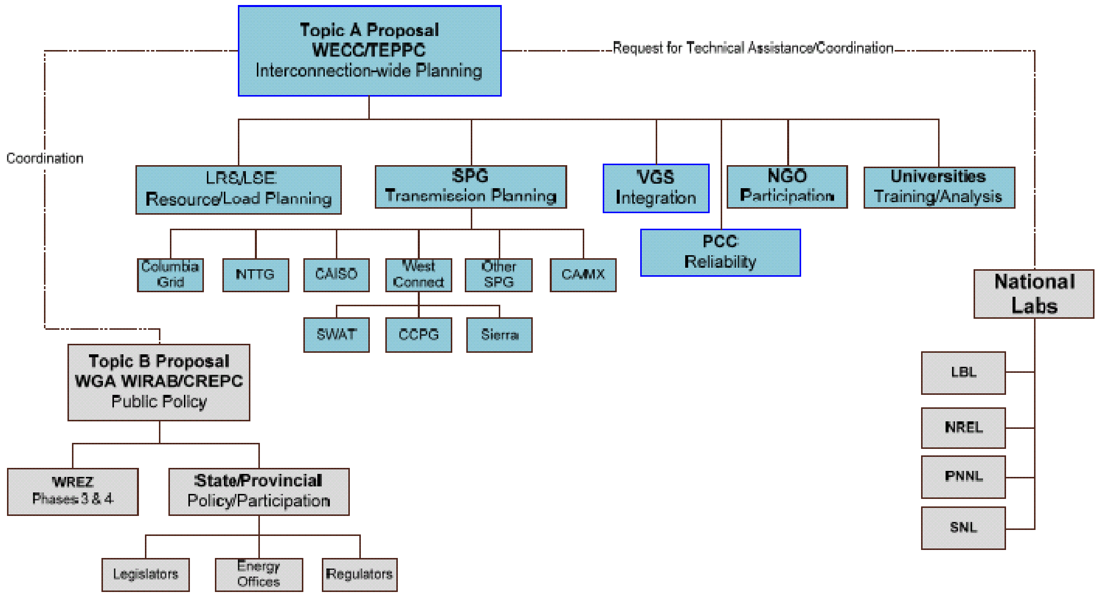
Funding Opportunity Announcement Topic A Requirements

The main requirements in the Funding Opportunity Announcement (FOA) Topic A (from the Western Electricity Coordinating Council [WECC]) are:

- Creation of interconnection-wide, long-term, scenario-based transmission plans
    - Identification of alternative transmission system configurations
    - Quantify reliability and cost implications
    - Attention to technology and policy uncertainties
- Deliverables due in June 2011 and June 2013
- Establishment of a multi-constituency steering group to guide scenario process
    - One-third state officials
    - Non-traditional stakeholders
- Funding for non-profit and non-governmental organization participation in planning processes

Responding to these FOA requirements, the main funding elements of the WECC proposal to the U.S. Department of Energy (U.S. DOE) are highlighted in Figure B-1.

Figure B-1: Overview of Transmission Planning Response for Western Interconnection



Source: WECC Staff Funding Proposal [Final] Interconnection level Analysis and Planning Framework for the Response to DOE-FOA0000068, Topic A, August 4, 2009.

The proposed total funding requested by WECC for Topic A activities is approximately $16 million, as shown in Table B-1 (2010-13).[111] With the funding and the requirements specified explicitly in the DOE FOA, important new functions will be funded for the first time. These include: coordination of sub-regional planning group (SPG) plans into one integrated 10-year reliability-constrained WI assessment; funding for participation in regional and sub-regional planning activities of non-governmental organizations (such as CEERT); completion of highly detailed system stability studies under high levels of intermittent generation additions (by western universities); and, continued funding of meeting of the western utilities' resource planners in a biannual forum setting. Work to be accomplished that will be based on the award in January 2010 will be reflected in the TEPPC 2010 Study Program.

The increased funding will allow WECC and the sub-regional planning groups to move toward development of interconnection-wide plans for both the 10- and 20-year time horizons. Deliverables under the proposed funding in June 2011 would include:

- *10-Year Sub-regional Planning Group Coordinated Reliability Plan*

[111] Lead responsibility for preparation of the WECC response resides with WECC staff Tom Schneider, Director of Planning, and Brad Nickell, Director Renewable Integration; material in this sub-section is referenced to the FOA and Tom Schneider/Brad Nickell WECC Staff Presentation to WECC Board of Directors, July, 30, 2009, Loveland, Colorado.

- *10-Year Regional Transmission Plan*
- Planning Engineer Education Program
- Technology Reliability Assessment

Deliverables in June 2013 include updates to the 2011 products as well as a *20-Year Regional Transmission Target Plan*.

Table B-1: WECC Regional Planning Topic A Funding Overview 2010-2013

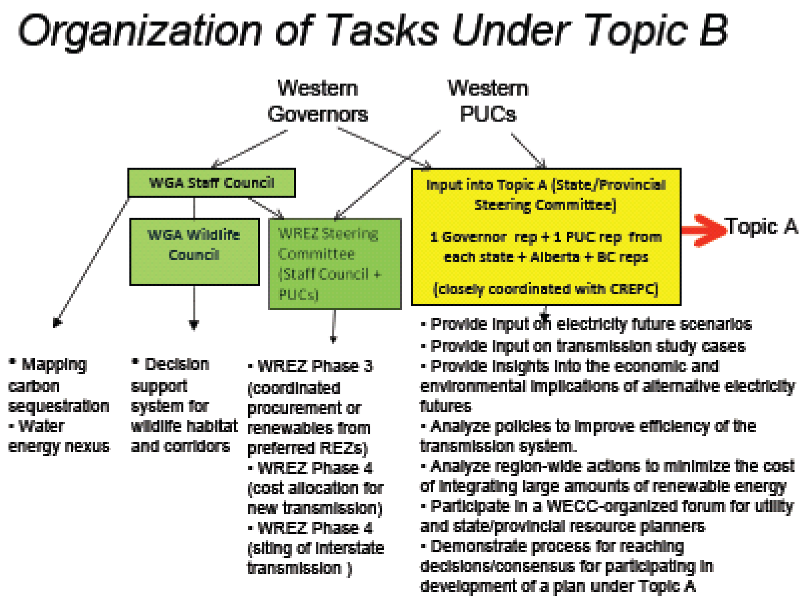
Regional Planning Funding Overview					
Expense $k/Year	**2010**	**2011**	**2012**	**2013**	**Total**
WECC Tech Staff	$450,000	$450,000	$450,000	$450,000	$1,800,000
WECC Administration	$274,800	$274,800	$274,800	$274,800	$1,099,200
WECC Auditor	$100,000	$100,000	$100,000	$100,000	$400,000
WECC Sub-contracts	$360,000	$360,000	$180,000	$180,000	$1,080,000
WECC Travel	$51,200	$51,200	$51,200	$51,200	$204,800
WECC Meetings	$100,000	$100,000	$100,000	$100,000	$400,000
WECC Outreach	$100,000	$100,000	$100,000	$100,000	$400,000
WECC Capital & Software	$532,200	$110,200	$60,200	$60,200	$762,800
WECC Total	**$1,968,200**	**$1,546,200**	**$1,316,200**	**$1,316,200**	**$6,146,800**
SPG Analysis	$405,000	$405,000	$405,000	$405,000	$1,620,000
SPG Meetings	$80,000	$80,000	$80,000	$80,000	$320,000
SPG Outreach	$50,000	$50,000	$50,000	$50,000	$200,000
SPG Total	**$535,000**	**$535,000**	**$535,000**	**$535,000**	**$2,140,000**
SPSG Tech Support & Facilitator	$360,000	$360,000	$360,000	$360,000	$1,440,000
SPSG Planning Facilitator	$180,000	$180,000	$180,000	$180,000	$720,000
SPSG Travel	$38,400	$38,400	$38,400	$38,400	$153,600
SPSG Meetings	$80,000	$80,000	$80,000	$80,000	$320,000
SPSG Outreach	$50,000	$50,000	$50,000	$50,000	$200,000
SPSG Total	**$708,400**	**$708,400**	**$708,400**	**$708,400**	**$2,833,600**
SPSG NGO Rep Stipend	$102,400	$102,400	$102,400	$102,400	$409,600
SPSG NGO Rep Travel	$51,200	$51,200	$51,200	$51,200	$204,800
NGO Participation Travel (TEPPC & SPG)	$204,800	$204,800	$204,800	$204,800	$819,200
NGO Participation Time (TEPPC & SPG)	$204,800	$204,800	$204,800	$204,800	$819,200
NGO Outreach	$50,000	$50,000	$50,000	$50,000	$200,000
NGO Participation Total	**$613,200**	**$613,200**	**$613,200**	**$613,200**	**$2,452,800**
University Training	$97,882	$97,882	$97,882	$0	$293,647
University Analysis	$734,118	$734,118	$734,118	$0	$2,202,353
University Travel	$35,000	$35,000	$35,000	$0	$105,000
University Total	**$867,000**	**$867,000**	**$867,000**	**$0**	**$2,601,000**
WIRPF Meetings	**$40,000**	**$40,000**	**$40,000**	**$40,000**	**$160,000**
Grand Total	**$4,731,800**	**$4,309,800**	**$4,079,800**	**$3,212,800**	**$16,334,200**

Source: WECC Staff Funding Proposal [Final] Interconnection level Analysis and Planning Framework for the Response to DOE-FOA0000068, Topic A August 4, 2009

Funding Opportunity Announcement Topic B Requirements

The FOA also contains detailed requirements for state activities in support of regional transmission planning and project development. WGA has submitted a response to the U.S. DOE. Figure B-2 provides an overview of the response.

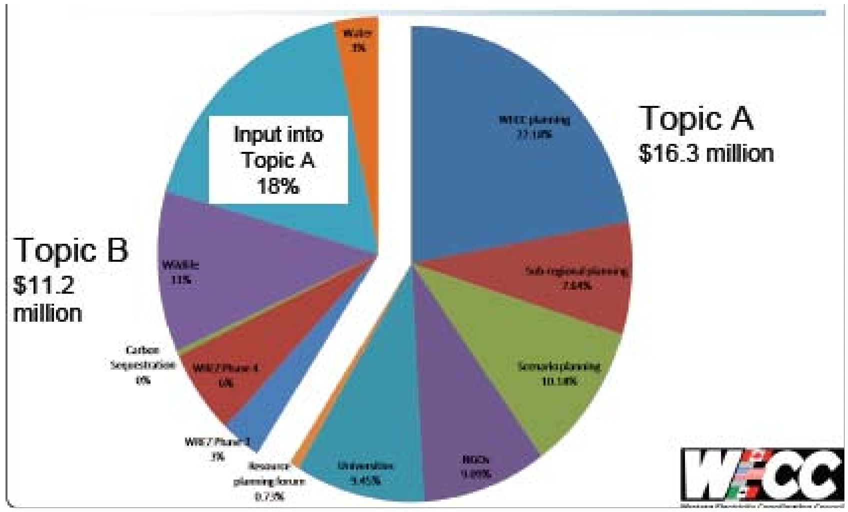
Figure B-2: Organization of Tasks Under US DOE Regional Planning FOA Topic B



Source: Doug Larson, WIEB Staff Presentation to WECC Board of Directors, July 30, 2009 Loveland, Colorado

As can be seen in Figure B-2, WREZ Phases 3 and 4 will be explicitly funded by the FOA awards and will be overseen by the WGA Staff Council. A new entity, a 24-member state/provincial steering committee will be formed to oversee work that provides input into the Topic A work to be undertaken as proposed by the WECC. Major new work on a decision support system for wildlife habitat corridors, mapping carbon sequestration, and exploring the water-energy nexus is proposed, all under the oversight of the Staff Council. WGA has requested $14 million in funding over 2010-2014. A summary of proposed allocations for both parts is provided in Figure B-3 (note: the graphic shows $11.2 million for Topic B, based on an earlier projection of funding.)

Figure B-3: Illustration of Proposed Funding Regional Planning Topics A and B



Source: Doug Larson, WIEB Staff Presentation to WECC Board of Directors, July 30, 2009, Loveland, Colorado

APPENDIX C:
Summary of Projects Supported in 2005 and 2007 Strategic Transmission Investment Plans

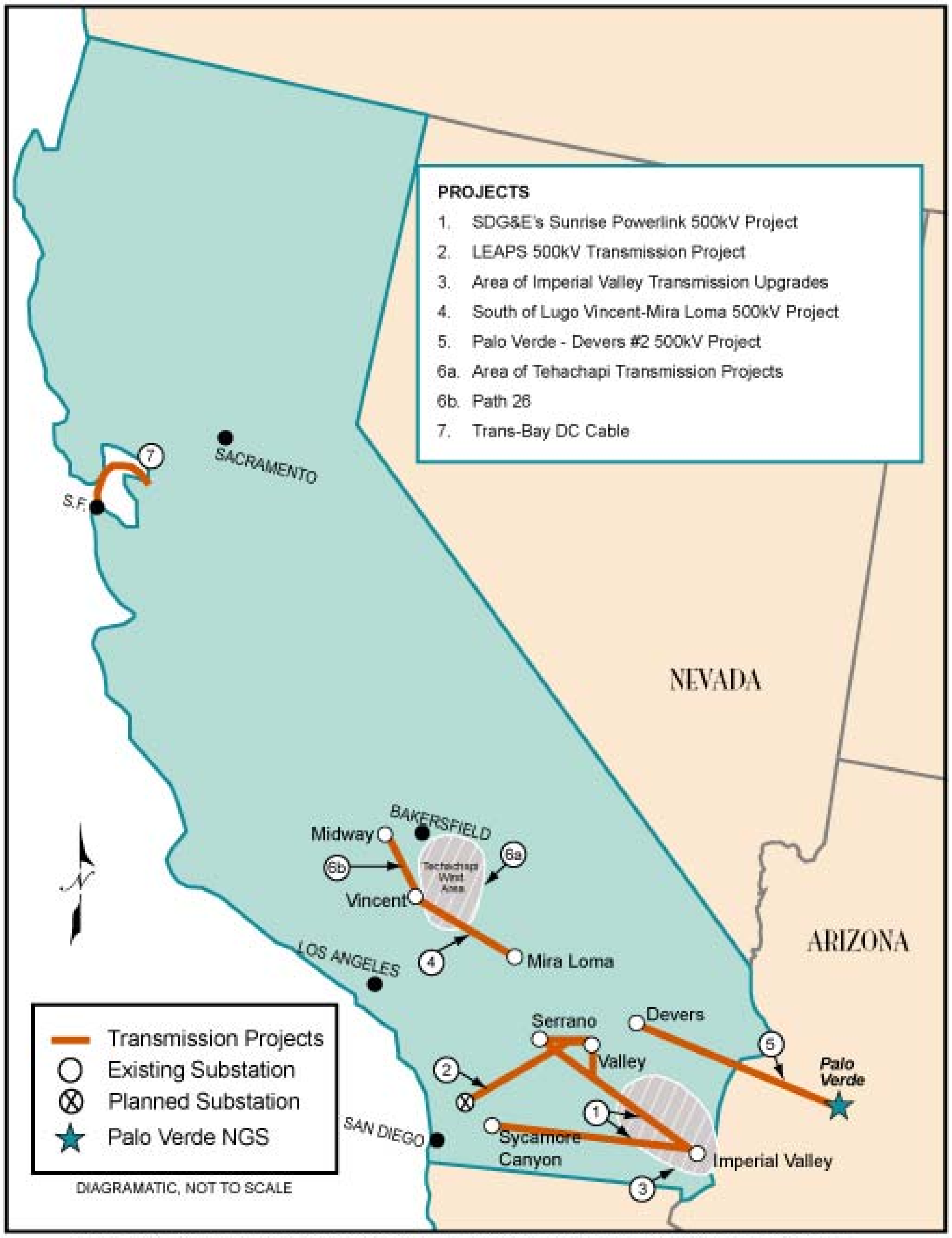
2005 Strategic Plan Energy Commission Supported Projects

The California Energy Commission (Energy Commission) recommended five projects in its *2005 Strategic Transmission Investment Plan* (*2005 Strategic Plan*). These five projects were summarized in "Chapter 1: Introduction" and are described in greater detail below. See Figure C-1 for a map of the five projects.[112]

1. Palo Verde-Devers No. 2 500 kilovolt (kV) Transmission Project
2. Sunrise Powerlink 500 kV Project
3. Tehachapi Transmission Plan, Phase I: Antelope Transmission Project
4. Imperial Valley Transmission Upgrades
5. Trans Bay Cable Project

[112] Figure D-1 includes two other projects (South of Lugo Vincent-Mira Loma and Path 26), which were considered by the Energy Commission but were not included in the final recommendations.

Figure C-1: Recommended Projects of Statewide Significance (2005)



CALIFORNIA ENERGY COMMISSION, SYSTEMS ASSESSMENT & FACILITIES SITING DIVISION, AUGUST 2005
SOURCE: CEC Staff

2007 Strategic Plan Energy Commission Supported Projects

The Energy Commission recommended five additional projects in its *2007 Strategic Plan*, while continuing to endorse the five 2005 projects. The five additional projects were summarized in "Chapter 1: Introduction" and are described in greater detail below. See Figure C-2 for a map of the five additional projects.

6. PG&E Central California Clean Energy Transmission Project (C3ETP)
7. The Lake Elsinore Advanced Pumped Storage (LEAPS) Project
8. The Green Path Coordinated Projects
9. LADWP Tehachapi Transmission Project
10. SCE Tehachapi Renewable Transmission Project.

1. Palo Verde-Devers No. 2 Transmission Project

Southern California Edison Company (SCE) filed applications in 2005 and 2006 with the California Public Utilities Commission (CPUC) and the Arizona Corporation Commission (ACC) for approval to construct the Devers-Palo Verde No. 2 (DPV2) transmission project. The original scope of this project included 225 miles of 500 kV transmission line between Arizona and California and a 42-mile 230 kV transmission line between SCE's Devers and Valley substations in California. The CPUC approved the project in January 2007 (Decision No. 07-01-040), but the ACC denied the Arizona portion in June 2007. SCE continued to pursue approval of the Arizona portion of the project, believing at the time that it would provide important economic benefits to both California and Arizona. SCE was never able to get approval for the Arizona portion of the project. Since the ACC's denial of the project, SCE had been simultaneously pursuing three approaches to secure complete regulatory approval:

- New ACC Filing – SCE was working with stakeholders, regional utilities and planning groups to develop a mutually acceptable alternative plan to present to the ACC.
- FERC Transmission Line Siting Process – SCE initiated pre-filing activities with FERC in May 2008. The Energy Policy Act of 2005 gave FERC the authority to review and issue an approval for a transmission line project that has been denied in a critically congested electrical corridor.

Figure C-2: Recommended Projects of Statewide Significance (2007)

Source: California Energy Commission, August 2007

- CPUC Approval to Start Construction in California – In May 2008, SCE filed a petition with the CPUC seeking permission to start construction of the project in California to satisfy interconnection requests for new renewable and conventional generation projects near Blythe, California. The California portion of the DPV2 Project includes a single-circuit 500 kV transmission line starting from the new Midpoint 500 kV substation located west of the Colorado River near Blythe, to SCE's existing Devers substation and extending it further to SCE's Valley 500 kV substation[113].

In May 2009 SCE reported that a recent update of economic analysis for the project demonstrated that the economic benefits to California customers to build the Arizona portion of the project were then reduced significantly. The analysis no longer supported SCE refiling with the ACC, at that time, for authorization of the Arizona portion of the project[114].

On May 14, 2008, SCE filed a petition to modify the original CPCN request that included a request for authorization to construct DPV2 facilities in California to allow SCE to access potential new renewable and conventional gas-fired generation in the Blythe area to help enable California to meet its renewable energy goals. As part of this modification to the DPV2 project SCE also requested authorization to construct the Midpoint Substation, near Blythe[115].

On July 18, 2008, the Assigned Commissioner and Administrative Law Judge issued a Joint Ruling that the original petition to modify failed to address adequately how the ACC's denial of a CPCN affects the economic analysis that provided the basis for the CPUC's approval of the CPCN on the basis that the project was in the public interest (D.07-01-040). The CPUC explained that under D.07-01-040 the primary rationale for the CPUC's approval of the transmission line was to bring the economic benefits of low cost Arizona power to California. Without the Arizona portion of this transmission line, these key findings fall, and – absent additional information – so does the rationale in D.07-01-040 for finding the transmission project in the public interest. However, they ruled that SCE should amend its petition to address the economic costs and benefits associated with the proposed amended project, demonstrating that the proposed action will be in the public interest and explaining why SCE believes that no further review under the California Environmental Quality Act is necessary on the amended petition.

While the original DPV2 CPCN was granted based upon the economic benefits generated by a transmission line connecting both California and Arizona, SCE's petition to modify failed to provide facts to demonstrate that ratepayer benefits accrue: (1) if only the California portion of

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[113] RETI Draft Final 2A Report, 7/22/2009, Footnote No. 22, pp. 3-68-3-70.

[114] http://www.sce.com/PowerandEnvironment/Transmission/CurrentProjects/DPV; Devers Palo-Verde No. 2 Project Update, May 2009

[115] http://docs.cpuc.ca.gov/efile/PM/82714.pdf

DPV2 is constructed, or (2) if construction of the Arizona portion of DPV2 is constructed far beyond the time frame estimated in the original CPCN decision.

The ruling suggested that, based on the multiple factors raised by SCE in its petition, there may be several ways for SCE to amend its petition to demonstrate that allowing SCE to construct the California portion of DPV2 at this time is in the public interest including demonstrating[116]:

- That the economic benefits of a California-only DPV2 exceed the costs of construction.
- That the requests for interconnection from those proposing generation facilities in the area served by the California portion of DPV2 necessitate its construction under law or are otherwise in the public interest to relieve forecasted congestion.
- That the construction of the DPV2 line in California is necessary for California to meet the Renewables Portfolio Standards adopted by California statute and therefore should be built.
- That the construction of the Arizona portion of the transmission line will be completed without major delay so that benefits associated with the project exceed its costs.
- That in light of prudent decision analysis that considers the probabilities of these disparate outcomes, construction of DPV2 in California at this time remains superior to a strategy of awaiting approval of the Arizona portion of the line.

On September 2, 2008, SCE filed to amend the original decision. SCE filed its petition to construct the California portion of DPV2, and to position itself to take advantage of potential generation sources (a significant portion of which are renewable) which have requested interconnection to the California ISO grid in the Blythe area. SCE believes that advancing the construction of the California portion of DPV2 is the best the way to deliver power this generation in the Blythe area because it uses existing right of way, has been fully analyzed from an environmental perspective, and is a direct path to the Southern California load center using SCE's most efficient voltage class for long distance electric transmission.

In May 2009, SCE updated its economic analysis of the project with new updates for gas prices, load forecast, carbon tax for coal imports, and new renewable generation development in the Western Interconnection and in California. This updated economic analysis indicates significantly reduced economic benefits to the project and no longer supports SCE refiling its application with the ACC. SCE continues to pursue the California portion of the DPV2 project and awaits CPUC authorization to begin construction to connect and deliver new and efficient thermal generation and renewables (mostly solar generation) to the ISO-Controlled Grid. [117] California ISO management recently reviewed and evaluated the proposed California portion of

[116] http://docs.cpuc.ca.gov/efile/RULINGS/85466.pdf

[117] http://www.sce.com/PowerandEnvironment/Transmission/CurrentProjects/DPV; Devers Palo-Verde No. 2 Project Update, May 2009

the DPV2 project and agreed that construction of this portion of the project is necessary to interconnect generating facilities currently in the ISO interconnection queue. On June 19, 2009, the ISO sent a letter to the CPUC Administrative Law Judge responsible for the DPV2 proceeding indicating that the California portion of the project will be important in meeting the state's Renewables Portfolio Standard and setting out the milestones needed for California ISO agreement that construction of the California portion of the project is necessary infrastructure to connect generating facilities in the ISO's interconnection queue. On June 26, SCE submitted supplemental information to the CPUC in support of its petition to begin construction of the California portion of DPV2. SCE reports that it has signed a power purchase agreement for 242 MW of solar resources in the project area.[118]

SCE stated that it is committed to find a way to proceed with permitting the Arizona portion of the project if further analysis supports the approach in the future. SCE plans to continue to review the anticipated renewable and non-renewable benefits that building DPV2 project would provide to both Arizona and California. If the required interconnection studies establish the need for new transmission in western Arizona to interconnect generation resources, SCE will seek ACC approval of necessary transmission. In the meantime, SCE will continue to pursue the California portion of the DPV2 project and is currently waiting for authorization from the CPUC to begin construction.[119]

2. *Sunrise Powerlink Transmission Project*

The CPUC approved the final decision for the Sunrise Powerlink on December 18, 2008. The final decision approves a Certificate of Public Convenience and Necessity (CPCN) for San Diego Gas & Electric to construct the environmentally superior southern transmission route and adopts a cost cap of $1.883 billion.[120] On the same date, the CPUC also certified the environmental impact report (EIR). With respect to the areas in which SDG&E owns transmission facilities, Sunrise was the only major project recommended in the Energy Commission's *2005* and *2007 Strategic Plans*.[121] The Sunrise Powerlink could be in service by June 2012.

In August 2006, the California ISO Board approved the Sunrise Powerlink project (Sunrise project) due to its reliability benefits, economic benefit, and access to renewables. The Sunrise

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118 http://www.caiso.com/23ea/23ea9c6a4e3a8.pdf; Memorandum from Laura Manz to California ISO Board of Governors, 7/10/2009

119 http://www.sce.com/PowerandEnvironment/Transmission/CurrentProjects/DPV Devers Palo-Verde No. 2 Project Update, May 2009.

120 http://docs.cpuc.ca.gov/PUBLISHED/FINAL_DECISION/95750.htm#P3066_501239

121 SDG&E F&I Response, 3/16/2009, pp. 2-3.

project received CPUC approval in December 2008[122] and U.S. Bureau of Land Management approval in January 2009.

On January 23, 2009, Utility Consumers' Action Network (UCAN) and Center for Biological Diversity, jointly with the Sierra Club (CBD/Sierra Club), filed applications for rehearing of Decision (D.) 08-12-058 which granted the application of San Diego Gas & Electric (SDG&E) for a Certificate of Public Convenience and Necessity (CPCN) to construct the Sunrise Powerlink Project. SDG&E and the California ISO filed responses on February 9, 2009, stating that the rehearing requests simply repeated arguments that were considered and rejected by the CPUC. CBD also filed a petition with the California Supreme Court for review of the CPUC's decision, arguing that it violates environmental requirements. The petition was denied on procedural grounds on February 18. The original decision approved the Final Environmentally Superior Southern Route ("Approved Route") alternative to SDG&E's proposed project because the CPUC found it to be environmentally superior to the Proposed Project and more feasible than the alternatives ranked higher environmentally in the EIR.[123] On July 9, 2009, the CPUC denied the request for but did agree to some modifications to the decision to clarify its reasoning and correct inadvertent errors.[124]

SDG&E awaits the U.S. Forest Service permit decision, anticipated in summer 2009. Detailed project engineering is expected to be completed in October 2009, with construction expected to begin in June 2010, to finish in June 2012. Early preparatory construction, including installation of foundations for 21 structures, may start as early as the fourth quarter of 2009 to reduce environmental impact to the big-horned sheep in the area.[125]

On January 20, 2009, the U.S. Bureau of Land Management (BLM) signed the Record of Decision approving the route selected by the CPUC for the Sunrise Powerlink and also certified the environmental impact statement (EIS), which is BLM's version of the EIR. The BLM's action authorizes the issuance of a right-of-way grant to SDG&E to build on approximately 70 miles of federal property included in the route. The BLM decision was published in the Federal Register on February 20, 2009, and any appeals must be filed by March 23, 2009. The next permitting step is completion of the U.S. Forest Service Plan Amendment and the issuance of its Record of Decision, which was expected by June 2009. This action will allow construction on land within the Cleveland National Forest.

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[122] http://docs.cpuc.ca.gov/PUBLISHED/FINAL_DECISION/95750.htm; Decision 08-12-058, December 18, 2008, p.292.

[123] http://www.cpuc.ca.gov/Environment/info/aspen/sunrise/toc-feir.htm; Final Environmental Impact Report / Environmental Impact Statement and Draft Land Use Plan Amendment

[124] http://docs.cpuc.ca.gov/PUBLISHED/FINAL_DECISION/104312.htm, CPUC Decision, July 9, 2009.

[125] SDG&E F&I Response, March 16, 2009, pp. 2-3.

3. Tehachapi Transmission Segments 1, 2, and 3

In January 2007, the California ISO Board approved the Tehachapi Renewable Transmission project (Tehachapi) to connect and deliver 4,350 MW of proposed renewable generation projects from the Tehachapi Wind Resources Area. This project is critical for helping load-serving entities in the California ISO footprint meet State-mandated renewable portfolio standards requirements. To date (July 2009), power purchase agreements have been signed for 1,942 MW of new wind generation in this resources area. Tehachapi includes eleven segments of bulk transmission lines and substation facilities with 230 kV and 500 kV operating voltage. Segments 1 to 3 of the project involve constructing 220 kV and 500 kV transmission line upgrades and new substations between the Tehachapi Wind Resource Area in southern Kern County and Los Angeles County. Approximately 80 miles of transmission lines will be build in the three segments approved by the CPUC.[126] The project has a proposed in-service date of 2009-2010.[127]

Transmission segments 1–3 have been granted environmental permits from the California Public Utilities Commission (CPUC) and the United States Forest Service.[128] Segment 1 was originally filed as Antelope - Pardee Transmission Line. Transmission segments 1–3 include the Antelope – Pardee 500 kV, Antelope – Vincent No. 1 500 kV, Antelope – Windhub 500 kV and Windhub – Highwind 230 kV transmission lines. Segments 2 and 3 were originally filed as Antelope Transmission Project. Upon completion, these three segments will have total transmission capability of 700 MW. Expected completion date for the 500 kV portion of Segments 1 – 3 is the fourth quarter of 2009, and summer 2010 for the 230 kV portion.[129]

4. Imperial Irrigation District Upgrades[130]

The Imperial Irrigation District (IID) has been promoting renewable energy in the Imperial Valley for many years. Nearly 20 years ago, IID upgraded its transmission system by building a 230 kV collector system to accommodate the interconnection of new geothermal generation and export this renewable energy to Southern California Edison (SCE). Currently, IID wheels

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[126] http://docs.cpuc.ca.gov/Published/News_release/65628.htm.

[127] http://www.caiso.com/23ea/23ea9c6a4e3a8.pdf; Memorandum from Laura Manz to ISO Board of Governors, July 10, 2009.

[128] U.S. Forest Service record of decision issued August 27, 2007, conditional use permit issued October 2007: http://www.fs.fed.us/r5/angeles/documents/antelope-pardee-rod.pdf#xml=http://www.fs.fed.us/cgi-bin/texis/searchallsites/search.allsites/xml.txt?query=southern+california+edison&db=allsites&id=47c3bb7a0

[129] http://www.caiso.com/23ea/23ea9c6a4e3a8.pdf; Memorandum from Laura Manz to ISO Board of Governors, July 10, 2009.

[130] Descriptions of the Imperial Valley Upgrades taken from the *RETI Phase 2A Final Report*.

approximately 550 MW of geothermal energy from Imperial Valley into the California ISO balancing authority area.[131]

IID has developed a detailed long-term transmission plan (10 years plus timeframe) to define the transmission improvements necessary to continue meeting the load service requirements in future years as well as allow for the export of renewable resources from the Imperial Valley area. The plan has primarily focused on the upgrade of certain sections of IID's 161 kV transmission system to 230 kV to integrate the existing 230 kV collector system and create a 230 kV transmission loop that will cover most of IID service area to allow for the export of renewable generation to the north, south and east of IID's service area. The individual project components of this plan are described below.

El Centro Switching Station (ECSS) to Highline Station Double-Circuit 230 kV Transmission Line

Upgrade to double-circuit 230 kV, the ECSS to Pilot Knob 161 kV and the ECSS to Drop 4 92 kV line sections (18 miles) from ECSS to one mile south of Highline station, build one mile of double-circuit 230 kV line to extend the line from ECSS into Highline station. Build one mile of double-circuit 230 kV line to interconnect the remaining 161 kV line to Pilot Knob and the 92 kV line to Drop 4 into Highline station.

Bannister Switching Station and Single-Circuit 230 kV Line to the Proposed GEO Station

Build a 230 kV switching station (Bannister) in the southwest area of the Salton Sea, build 16 miles of single-circuit 230 kV transmission line (prepared for double-circuit) from Bannister switching station to GEO station.

El Centro Switching Station (ECSS) to Dixieland Substation Single-Circuit 230 kV Transmission Line

Build 15.5 miles of single-circuit 230 kV transmission line from ECSS to the Dixieland substation.

Coachella Valley Substation (ECSS) to Proposed Devers II 500/230 kV Substation 230 kV Transmission Line

Build 35 miles of double-circuit 230 kV transmission line between Coachella Valley substation to a proposed Devers II substation.

[131] *RETI Draft Phase 2A Report*, Appendix G, pp. 13-18.

Coachella Valley Substation to Mirage Substation (Path 42) Double-Circuit 230 kV Line Upgrade From 800 MW to 1600 MW

Upgrade 20 miles of existing double-circuit single conductor 230 kV transmission line to bundle (two conductors per phase) conductors. The project will increase the thermal rating capacity of the Imperial Irrigation District to the SCE interconnection from 800 MW to 1600 MW.

El Centro Switching Station (ECSS) to Bannister Switching Station Double-Circuit 230 kV Transmission Line

Rebuild 24 miles of the ECSS to AVE 58 substation 161 kV single-circuit line to double-circuit 230 kV from ECSS to 3.5 miles west of the proposed Bannister substation (Bannister intersection), build 3.5 miles of single-circuit 230 kV (prepared to double-circuit) line, from Bannister intersection to Bannister substation. One circuit will establish the 230 kV line from ECSS to Bannister and the second circuit from ECSS to Bannister intersection will be operated at 161 kV to interconnect to the remaining 161 kV single-circuit line to Ave 58 Substation.

IID IV Sub Switching Station and to IID IV Sub to ECSS Double-Circuit 230 kV Transmission Line

Build a 230 kV switching station (IID IV Sub) adjacent to SDG&E/IID's Imperial Valley Substation (IV Sub), looping existing IV Sub to Dixieland substation and IV Sub to ECSS 230 kV lines. Establishing the IID IV Sub to Dixieland and IID IV Sub to ECSS 230 kV lines and rebuild the single-circuit 230 kV IID IV Sub to ECSS 230 kV line to double-circuit 230 KV.

Bannister SS to Coachella Valley 230 kV Transmission Line

Build 3.5 miles of single-circuit 230 kV line (prepared to double-circuit), from Bannister substation to Bannister intersection; rebuild 46.2 miles of the ECSS to Ave 58 substation single-circuit 161 kV line, from Bannister intersection to the intersection with the double-circuit 161 kV line into Ave 58 Substation (Ave 58 intersection); upgrade 11.3 miles of double-circuit 161 kV line from Ave 58 intersection to Ave 58 Substation; rebuild 6.3 miles of single-circuit line to double-circuit 230 kV, from Ave 58 intersection to Coachella Valley substation. One circuit will establish the 230 kV line from Bannister substation to Coachella Valley substation, and the second circuit will be operated at 161 kV from ECSS to Ave 58 substations and from Ave 58 to Coachella Valley Substations.

Midway Station to the Proposed GEO Station Transmission Line; Second 230 kV Circuit Addition

Add a second 16-mile 230 kV circuit to the Midway station to GEO station 230 kV transmission line.

GEO Station to Bannister Switching Station; Second 230 kV Circuit Addition

Add a second 16-mile 230 kV circuit to the GEO station to Bannister Station 230 kV transmission line.

Dixieland Substation - Bannister Switching Station (Bannister SS) - Ave 58 Substation - Coachella Valley Substation 230 kV Transmission Lines

Disconnect the ECSS to Ave 58 and Ave 58 to Coachella Valley substations 161 kV lines (prepared for 230 kV); upgrade the Ave 58 substation 161 kV bus and transformation capacity to 230 kV, reconnect the Ave 58 to Coachella Valley 230 kV transmission line. Reconnect the northern end of the ECSS to Ave 58 substation transmission line to Ave 58 230 kV bus, the southern end of the line will be rerouted to Dixieland substation using the Dixieland to ECSS 230 kV transmission line that will be disconnected from ECSS to temporary establish the Dixieland to Ave 58 230 kV line. Add a second circuit to the 3.5-mile section (Bannister intersection to Bannister SS) of the ECSS to Bannister SS and Bannister SS to Coachella Valley 230 kV lines, loop the Dixieland to Ave 58 230 kV line into Bannister SS using the two new 3.5-mile circuits to establish the Dixieland to Bannister SS and Bannister SS to Ave 58 substation 230 kV transmission line.

5. Trans Bay Cable Project

In January 2007, the California ISO Board approved the Trans Bay Cable Project (Trans Bay project) as a reliability project to support the retirement of old thermal generation in San Francisco. The city of Pittsburg municipal utility will eventually own the Trans Bay project and will apply to become a participating transmission owner. It will then turn operational control of the Trans Bay project over to the ISO, in accordance with the Transmission Control Agreement. The Trans Bay project consists of a 59-mile, 400 MW, high-voltage, direct-current transmission system running under San Francisco Bay from Pittsburg to a location adjacent to Potrero substation in San Francisco. Associated substation modifications are necessary to interconnect the project to the ISO Controlled Grid, which is scheduled to be in service by March 2010.[132] The original project proponents, Babcock & Brown, were replaced by Pattern Energy in July 2009.

Target Dates:

- Converter (reactive power available) at Pittsburg – September 2009;
- Converter (reactive power available) at Potrero – November 2009;
- Real power available – December 2009; and

[132] http://www.caiso.com/23ea/23ea9c6a4e3a8.pdf; Memorandum from Laura Manz to ISO Board of Governors, July 10, 2009.

- Commercial date – March 2010.

6. Central California Clean Energy Transmission Project

The Central California Clean Energy Transmission Project (C3ETP) would reduce costs, increase access to renewable resources, increase reliability in the Fresno area, and allow more efficient use of PG&E's Helms Pumped Storage Hydroelectric Facility. In its response to the Forms and Instructions, PG&E submitted its *2009 Electric Transmission Grid Expansion Plan* (p. 6-38) and estimated a 2013 on-line date for this project. The C3ETP includes a new 150-mile 500 kV double-circuit transmission line, a new 500/230 kV substation, and other upgrades requiring a CPCN from the CPUC that will "connect Midway Substation to the load centers in the Greater Fresno Area [and is] expected to be operational in 2013." (PG&E *2009 Electric Transmission Grid Expansion Plan*, p. 7-6). The project would require a new right-of-way and cost between $799 million and $1,023 million. See Figure C-2 for the approximate route for the proposed line and location of the new substation. The proposed project would provide many benefits to California and is not a single purpose line. The C3ETP therefore meets all four criteria needed for inclusion in the *2007 Strategic Plan*.[133]

The C3ETP is a multipurpose project that could help state utilities meet policy goals, reduce congestion, and improve reliability. While further study is needed for a project of this magnitude, the C3ETP would benefit the state of California in a number of ways. First, the project would increase reliability in the Fresno area and defer the need for a new 230 kV transmission line. The project would increase the ability to move power into the Yosemite and Fresno area by about 500 MW, reducing local generation needs, which the California ISO in its 2007 Grid Plan estimated will be almost 2,300 MW in 2011. PG&E also estimates that the project will reduce [ETGEP says it would "relieve"] congestion on Path 15 (the transmission path limiting the transfer of bulk electricity from Southern and Central to Northern California) by increasing its rating by 1,250 MW and reducing the annual Path 15 congestion to less than 100 hours. Increasing the Path 15 rating will also allow more renewable generation in Southern California (including the Tehachapi region) to be delivered to Northern California. Increasing transmission into the Fresno area would also allow PG&E to more efficiently use the Helms Pumped Storage Hydroelectric Facility, which would improve the system's ability to incorporate intermittent generation resources like wind.

In January 2008 the California ISO initiated a stakeholder process to analyze the C3ETP. Since then the California ISO has held several more stakeholder meetings and a project open house.[134] The last stakeholder meeting was held in December 2008, and a California ISO analysis of the C3ETP is expected sometime in the fourth quarter of 2009.

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[133] Pacific Gas and Electric *2009 Electric Transmission Grid Plan*, March 5, 2009.

[134] http://www.caiso.com/1f42/1f42daf7415e0.html

7. Lake Elsinore Advanced Pumped Storage Project

The Lake Elsinore Advanced Pumped Storage (LEAPS) project has reached several critical permitting milestones, but there are still issues to be resolved and permits to be issued. FERC issued the final EIS for both the pumped hydroelectric and transmission components of LEAPS on January 30, 2007. The project received interconnection approval from the California ISO, for both the SCE and SDG&E interconnections, in March 2007; however, this approval was contingent upon completion of an operational study. The transmission portion of the project will require a CPCN for modifications to both the SCE and SDG&E transmission grids. On October 9, 2007, The Nevada Hydro Company, Inc. (TNHC) filed a CPCN application with the CPUC. The LEAPS CPCN application, A.09-02-012 (previously was A. 07-10-005), was dismissed without prejudice in CPUC decision D.09-04-006 on April 17, 2009, because the Proponent's Environmental Assessment (PEA) was deemed incomplete (on March 6, 2008); and the revised PEA was deemed incomplete on August 18, 2008.[135]

On February 27, 2009, the California ISO and SDG&E submitted a second compliance filing in response to FERC's order conditionally accepting the ISO's and SDG&E's prior compliance filing of revisions to the unexecuted Large Generator Interconnection Agreement (LGIA) with TNHC for its proposed LEAPS project and its associated proposed transmission interconnection between the SDG&E's and SCE's systems. This second compliance filing responded to FERC's directive to revise the milestones for the construction schedule in the LGIA.[136] It included a detailed explanation of the several factors that the California ISO and SDG&E took into account in establishing the revised milestone dates, including the use of TNHC's requested date for the in-service date to be used in the LGIA. On March 30, 2009, TNHC filed a protest of the compliance filing, seeking different dates for three other milestone dates without any explanation of their relevance and without addressing any of the considerations the ISO and SDG&E described as forming the basis for their specification of these dates in the LGIA. On April 14, 2009, the California ISO and SDG&E filed an answer to TNHC's protest, explaining further why TNHC's request for different dates should be rejected.[137]

TNHC amended its Participating Transmission Owner application to the California ISO on April 21, 2009, regarding the proposed Talega-Escondido/Valley-Serrano 500 kV transmission line. The California ISO deferred further consideration of the application until the FERC resolves the pending question of whether TNHC must subject its proposed TE/VS Interconnect to the California ISO's existing, FERC-approved transmission expansion and planning process. This matter is pending at FERC in ER06-278.[138] (Source: SCE Transmission-related Data

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[135] CPUC website, "Transmission Project Tracking Spreadsheet," June 30, 2009.

[136] Nevada Hydro Company Large Generator Interconnection Agreement (ER08-654).

[137] California ISO Memorandum from Nancy Saracino to Board of Governors, May 8, 2009, Regulatory Update, pp.5-6, http://www.caiso.com/23ab/23abe277e490.pdf.

[138] SDG&E's comments on the California ISO's May 14, 2009, Market Notice Regarding The Nevada Hydro Company Amended PTO Application.

Response Update, June 26, 2009, p.4.) The California ISO is the entity administering the LEAPS project interconnection to its grid. TNHC submitted a generator interconnection request to the California ISO for the LEAPS project under the California ISO tariff and the Large Generator Interconnection Procedure mandated by FERC. SCE is one of two participating transmission owners (PTOs) that will interconnect the project. SDG&E is the other PTO. SCE has worked with the California ISO and SDG&E on the generation interconnection request for the LEAPS project.

The proposed LEAPS project, planned jointly by the Elsinore Valley Municipal Water District and TNHC, is a combined generation and transmission project located at Lake Elsinore in Riverside County. The LEAPS project met all the requirements for inclusion in the *2007 Strategic Plan*, although there are still issues to be resolved with both the FERC and the California ISO. The transmission portion of the project, sometimes referred to as the Talega-Escondido/Valley-Serrano (TE/VS) line, would primarily be located in the Cleveland National Forest, which is located in both San Diego and Riverside counties. The 28.5-mile, 500 kV transmission component of the LEAPS project would connect to a tap on SCE's 500 kV Valley-Serrano line, as well as to a new substation near the existing Talega-Escondido 230-kV line where the line enters Camp Pendleton in northern San Diego County. This would provide an interconnection between the SDG&E and SCE service territories much like the SDG&E Valley-Rainbow Project, which was denied a CPCN by the CPUC in 2002. According to TNHC, the 500 kV line would have a nominal rating of 1,500 MW and could increase import capabilities into the San Diego area by as much as 1,000 MW, although the WECC line rating studies are not complete. Project costs are estimated at approximately $350 million for the transmission line and substations and $750 million for the pumped storage facility. SCE and SDG&E estimate that an additional $118 million in upgrades are required to reliably connect the LEAPS project to the existing transmission network. According to TNHC, the TE/VS interconnect project could be on line in 2009, while the pumped storage facility could be on-line in 2012.

The LEAPS project would deliver pumped storage hydroelectric power to the grid, reduce congestion, and improve reliability in the San Diego area. The transmission components of LEAPS would complement the Sunrise Powerlink 500 kV Project because it would form a northern interconnection between the SDG&E and SCE service territories. This would require close coordination between the project sponsors and SDG&E. LEAPS could also strengthen the California ISO grid by providing a 500 kV interconnection between the two utility service territories. The 500 kV bulk transmission "backbone" that runs from the Oregon border through SCE's service territory does not connect with the San Diego area. San Diego's system currently connects to the rest of California via 230 kV lines running north to the San Onofre Nuclear Generating Station, and via 500 kV lines running east to Imperial Valley. A northern 500 kV interconnection would both improve the reliability of California's transmission system and increase the state's overall ability to import lower-cost power from Arizona, Mexico, and the Desert Southwest. In 2004, the California ISO noted that "The transmission line proposed in association with the Lake Elsinore Pumped Storage Project would allow the San Diego area to import substantially more power from surrounding areas and would greatly enhance electric system reliability."

The FERC deferred action on the rate request for both the transmission and the pumped storage portions of the project, though FERC did find that the entire project deserves special treatment (as an advance transmission technology under the 2005 Energy Policy Act (EPAct-05)). TNHC has applied to the California ISO to recover its costs through the Transmission Access Charge (TAC); the entire project is under the control of the California ISO. In its order on the LEAPS rate request, FERC stated "…We do not have sufficient information to determine whether inclusion of the LEAPS facility in the [California] ISO's TAC is appropriate and whether the rate incentives requested by Nevada Hydro are justified and would result in just and reasonable rates for California ratepayers." FERC deferred its decision on the rate treatment for the LEAPS project and ordered the California ISO and TNHC to make recommendations on several substantive issues through the California ISO stakeholder process. After two draft white papers and stakeholder meetings, the California ISO expressed several concerns with inclusion of the pumped storage portion of LEAPS in the TAC:

- While the pumped storage project is rightfully considered to be an advanced transmission resource and should be encouraged according to EPAct-05, preferential rate treatment as complete as inclusion in the TAC is not the only form of encouragement for these projects and is not required by EPAct-05.
- Including the LEAPS in the TAC gives the project a competitive advantage over other pumped storage plants in the state that pay to use the transmission system as loads and resources.
- The LEAPS project does not provide benefits that are any different from other merchant generators and should therefore not be exempt from the risks apportioned to other generators.
- The California ISO cannot take over the operation of the pumped storage project without becoming itself a market participant.
- The pumped storage project should apply for interconnection through the California ISO's Large Generator Interconnection process.
- The transmission portion is not required for reliability but would provide other benefits and is thus a candidate for inclusion in the TAC.

The generating aspect of the LEAPS project consists of a pumped storage hydro plant with a generating capacity of 500 MW and a pump load of 600 MW. The project also consists of two 500 kV lines connecting the generator to: (i) a new substation with SCE's Valley-Serrano 500kV line and (ii) a new substation with SDG&E's Talega-Escondido 230 kV line using phase shifting transformers. SCE has completed a System Impact and Facilities Study associated with the gen-tie connecting the generator to SCE's Valley-Serrano 500 kV line. The LEAPS project sponsors and SCE are in the interconnection agreement negotiations phase. Additional information about the LEAPS project should be requested from the California ISO.

8. LADWP/IID/Citizens Energy Green Path Coordinated Projects

The Green Path Coordinated Projects have been discussed for several years and in different forms. In 2005 the Energy Commission recommended that IID pursue a series of transmission upgrades that would create a geothermal collection system and reinforce delivery of this generation to SDG&E and LADWP. The projects included four phases, which would develop geothermal collector and delivery systems for over 2,000 MW of new generation. Phase 1 of the projects would provide a basic interconnection for 600 MW of new geothermal resources and support the delivery of that generation to LADWP and SDG&E. The *2005 Strategic Plan* recommended that IID pursue its portion of Phase 1. Since the *2005 Strategic Plan*, the four projects were consolidated into three (Green Path Southwest, Green Path North and the Sunrise Powerlink) through agreements between IID, SDG&E, and LADWP.

In 2007, Green Path North was reported as a joint agency project that included IID, LADWP, Citizens Energy, and several other POUs (IID Board Agenda Memorandum, November 26, 2006). The project was essentially a new 1,200 MW to 1,600 MW connection between IID and LADWP. The project would have provided a new 500 kV or 230 kV transmission line between the IID Indian Hills Substation and a new LADWP Devers 2 substation. The overall project would have cost approximately $470 million and could be on-line as early as 2011.

While the LADWP transmission forms and instructions submission for 2007 included only the Green Path North Project, the projects' components relate to one another and are, collectively, critical to the development of renewable generation in California. All three projects met the requirements for inclusion in the *2007 Strategic Plan*: They are scheduled for completion before 2017, require permitting, provide benefits to the state, and are not single-purpose reliability projects. However, there are issues and potential barriers to the development of these projects.

However, in 2009, IID reported two elements under the Green Path North Projects: the Green Path North Project and the Coachella Valley-Devers II Project.

In 2009, IID describes the Green Path North (GPN) project as a proposed 500 kV transmission line that will carry between 1200-1600 MWs of energy between a new switching station in Hesperia near the SCE Lugo substation to a new switching station near Palm Springs and SCE's existing Devers substation. GPN will provide a transmission path for Imperial County renewable energy to reach the Los Angeles basin load centers. LADWP listed the benefit GPN:

- Supports development of geothermal, solar, and other renewable resources in the Imperial Valley.
- Helps meet the State of California's greenhouse gas (GHG) regulation that seeks to reduce dependence on fossil fuel power.
- Displaces fossil fuel power with clean, non-polluting energy.

- Provides economic stimulus for the counties of San Bernardino, Riverside, and Imperial Valley.
- Supports regional transmission network by reducing the amount of load trips with Palo Verde-Devers 2 in-service.
- Reduces congestion at West-of-Devers and Victorville-Lugo 500 kV line.

According to IID, GPN has an estimated in-service date of October 2013[139]. In 2009, IID also indicated that it is a partner with Southern California Public Power Authority in the Green Path North transmission project and is also working with SCE to increase the rating of WECC Path 42 to provide an additional 200 MW of export capability from IID's system into SCE's system[140]." The planned in-service date per LADWP is November 2013 at a cost of $700 million[141]. [Source:] IID and LADWP will have individual and joint facilities, as detailed below.

LADWP Facilities:

- Construct one 85-mile 500 kV line with 70 percent series compensation from LADWP's new Devers 2 substation near Palm Springs to LADWP's new Hesperia substation near Lugo.
- Construct one or two 500 kV tie lines from new Devers 2 substation to existing Devers substation owned by SCE and approximately one mile apart.
- Construct new Hesperia switching station, located approximately 5 miles east of the existing transmission corridor, to sectionalize one Victorville-Century 287 kV line.
- Construct one new 5-mile line from Hesperia to tap one existing Victorville-Century 287kV line on one end, creating one new 77-mile Hesperia-Century 287 kV line.
- Construct one new 17-mile line from Hesperia to Victorville 500 kV. One Victorville-Century 287 kV line remains in operation.[142]

LADWP/IID Joint Facility:

- Construct two 30-mile 230 kV or one 500 kV line from new Coachella substation to Devers 2 substation to be jointly owned and operated by LADWP and IID.

IID Facility:

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[139] Imperial Irrigation District Response to Transmission-Related Data Requests 2009, page 6.

[140] Ibid, page 3.

[141] Los Angeles Department of Water and Power Response to Transmission Related Data Requests 2009, pp. 3-7.

[142] Ibid, pp. 3-7.

- Expand existing Coachella 230 kV substation.

IID also reported on the Coachella Valley – Devers II (CV Devers II) Project under the "Green Path North Projects." IID plans to build a 35-mile transmission line that will connect the IID system in the Coachella Valley area to the LADWP and CAISO balancing authority areas near Palm Springs. The new line will carry up to 1,600 MWs of energy from IID's Coachella Valley substation to the proposed Devers II substation near SCE's existing Devers substation. The CV-Devers II project will be either a double-circuit 230 kV or single-circuit 500 kV line with an anticipated commercial operation date of 2013. The federal right-of-way has been secured. The required federal environmental analysis has been completed.[143]

9. LADWP Tehachapi Project/ Barren Ridge Renewable Transmission Project

In 2009 the LADWP Tehachapi Project was replaced by the Barren Ridge Renewable Transmission Project, a renewable resources project that will consist of a new 61-mile double-circuit 230 kV transmission line between the Barren Ridge Switching Station and a new Haskell Canyon Switching Station. The Barren Ridge Switching Station will be a newly constructed station along the existing Inyo to Rinaldi line approximately 20 miles north of the City of Mojave. The project will also reconductor the existing line from Barren Ridge to Haskell Canyon. With the construction of the new line and the reconductoring, the rating of the existing system, which is approximately 400 MW, will be increased to approximately 2,200 MW. The project is in the environmental review process and is expected to be in service by late 2013.

LADWP's 2007 transmission-related data response described a plan to increase the capacity of the transmission system that connects the Tehachapi region with LADWP's load centers. The project includes new 230 kV transmission facilities and several new substations that would essentially serve as a wind collector transmission system. The project would allow LADWP to deliver approximately 500 MW of wind generation to its load centers. A critical component of the LADWP Tehachapi Project is a direct connection to the Castaic Pumped Storage Plant, which would also increase the value of intermittent resources. The LADWP project would be developed in phases, with overall project completion in 2013. The project would increase the state's development of renewable energy and would require permitting for its new transmission facilities.[144]

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[143] Imperial Irrigation District Response to Transmission-Related Data Requests 2009.

[144] http://www.ladwp.com/ladwp/cms/ladwp009508.jsp

10. SCE Tehachapi Renewable Transmission Project

The SCE Tehachapi Renewable Transmission Project (TRTP) would provide the electrical facilities necessary to both integrate new wind generation – more than 700 MW and up to approximately 4,500 MW – in the Tehachapi Wind Resource Area and accommodate solar and geothermal projects being either planned for or otherwise expected in the future. The project would also address the reliability needs of the California ISO-controlled grid due to projected load growth in the Antelope Valley and the South of Lugo transmission constraints in Hesperia, California. The project includes both a series of new and upgraded high-voltage electric transmission lines and substations to deliver electricity (from new wind farms planned by independent power producers in Eastern Kern County) to the Los Angeles Basin.

SCE filed a CPCN application June 29, 2007, for the project, referred to as segments 4 through 11 of the Tehachapi Expansion Plan. SCE also submitted an application for a special use authorization to the U.S. Forest Service. The proposed project must be reviewed under both the California Environmental Quality Act and the National Environmental Policy Act. SCE submitted the project to the CPUC and the U.S. Forest Service for authorization to construct the project in the summer of 2007, but is awaiting approval from both agencies at this time. SCE anticipates a decision from the CPUC and the U.S. Forest Service during the summer of 2009. The expected on-line dates for the various segments range from late 2011 through late 2013.[145]

Segments 4–11 include 250 miles of new and upgraded transmission facilities and substations, primarily 500 kV facilities and one 230 kV transmission line. Currently, SCE is expecting environmental permit approval from the CPUC and the U.S. Forest Service in the summer of 2009.[146] Construction completion dates for these segments are scheduled for 2011, 2012 and 2013. Upon completion in winter 2013, the completed eleven segments of the Tehachapi project will have a total of 4,500 MW of transmission capability.[147]

- Segment 4 – Construction of the new Whirlwind Substation in Kern County west of Rosamond. This 500/220 kV substation would be connected to the proposed Cottonwind Substation 1 by a new four-mile double-circuit, 220 kilovolt (kV) transmission line and to SCE's existing Antelope Substation in west Lancaster by a new 14- mile 500 kV transmission line. Construction would be in a new ROW, parallel to the existing ROW.
- Segment 5 – Construction of a new 18- mile-long 500 kV transmission line that would connect SCE's existing Antelope Substation with SCE's existing Vincent Substation near Acton. This new line would be built next to an identical existing 500 kV line and would replace two 220 kV lines that would be removed. An existing ROW would be used. This new line would be initially energized at 220 kV.

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[145] http://www.caiso.com/23ea/23ea9c6a4e3a8.pdf; Memorandum from Laura Manz to California ISO Board of Governors, July 10, 2009.

[146] SCE Response to Transmission-Related Data Requests 2009, p. 7-8.

[147] *RETI Phase 2A Draft Report* Appendix G, p. G-23 – G-24.

- Segment 6 – Replacement of approximately 27 miles of an existing 220 kV transmission line that runs from SCE's existing Vincent Substation to the southern edge of the Angeles National Forest (ANF) near Duarte with a new 500 kV transmission line that would initially be energized at 220 kV. An existing ROW would be used. And the replacement of approximately five miles of an existing SCE 220 kV transmission line between Vincent Substation and the northern border of the ANF with a new 500 kV transmission line.
- Segment 7 – Replacement of 15 miles of the existing 220 kV line from the ANF border near the city of Duarte south to SCE's existing Rio Hondo Substation in the city of Irwindale and then continuing southwest across various San Gabriel Valley cities toward SCE's existing Mesa Substation in the Monterey Park/Montebello area with a double-circuit, 500 kV transmission line. Existing ROWs would be used, and various lower-voltage subtransmission lines between the Rio Hondo and Mesa Substations would require relocation within existing ROW or public ROW.
- Segment 8 – Replacement of existing single-circuit, 220 kV line that runs from the existing Mesa Substation area to the Chino Substation area and existing double-circuit, 220 kV line from Chino Substation to the existing Mira Loma Substation with a 32-mile double-circuit, 500 kV line. Replacement of approximately seven miles of existing 220 kV line that run from SCE's Chino Substation to its Mira Loma Substation located in Ontario with a double-circuit, 220 kV line. Existing ROWs would be used except for where approximately three miles of new ROW would be required in limited areas. Various lower-voltage sub-transmission lines in the Chino area would require relocation within existing ROW or public ROW.
- Segment 9 – Installation of equipment and upgrades at Antelope, Vincent, Windhub and Whirlwind Substations to connect new 220 kV and 500 kV transmission lines and to help maintain proper voltage levels.
- Segment 10 – Construction of a new 12- mile, single-circuit, 500kV line to connect the proposed Whirlwind Substation (Segment 4) with the Windhub 2 collector substation. New ROW would be required.
- Segment 11 – Replacement of approximately 20 miles of 220 kV transmission line between the existing Vincent Substation and Gould Substation near La Cañada Flintridge with a new, 20-mile, single-circuit, 500 kV transmission line. And the installation of a second 220 kV transmission line on the currently empty side of the transmission towers that already extend from the area of Gould Substation across various San Gabriel Valley cities to the area of Mesa Substation in Monterey Park. An existing ROW would be used.
- Cottonwind Substation is undergoing environmental review by the Kern County in conjunction with a proposed wind farm development under an existing application.
- Substation One (Windhub) was included in SCE's proposed Antelope Transmission Project Segment 2-3 application (A.04-12-008) submitted to the California Public Utilities Commission for approval in December 2004 and amended September 30, 2005.

SCE Eldorado to Ivanpah Transmission Project

On May 28, 2009, SCE filed an application for a CPCN with the CPUC for the El Dorado to Ivanpah Transmission Project (application number A.09-05-027).[148] The CPUC is the CEQA lead agency and the U.S. Bureau of Land Management (BLM) is the National Energy Policy Act (NEPA) lead agency. The project, as proposed by SCE, would provide the electrical facilities necessary to integrate new solar energy generation above 1,400 MW in the Ivanpah Dry Lake area. The project's major components include the following: (1) Construction of a new Ivanpah Substation in San Bernardino County; (2) Removal of approximately 35 miles of existing 115 kV transmission line and replacement with a new double-circuit 220 kV transmission line between the new Ivanpah Substation and the existing Eldorado Substation in Clark County, Nevada; and (3) Installation of associated telecommunication infrastructure. The project is undergoing data adequacy review.[149]

[148] http://docs.cpuc.ca.gov/published/proceedings/A0905027.htm

[149] http://www.cpuc.ca.gov/Environment/info/ene/ivanpah/Ivanpah.html

APPENDIX D: Summary of Proposed Regional Transmission Projects

Background

The Western Electricity Coordinating Council (WECC) is the regional entity responsible for coordinating and promoting bulk electric system reliability in the Western Interconnection. WECC's territory extends from Canada to Mexico, and includes Alberta, British Columbia, Northern Baja California, Mexico, and the 14 western states in between.

The Federal Energy Regulatory Commission's (FERC) Order No. 890, requires transmission service providers to participate in subregional and regional transmission planning processes. The requirement includes the performance of economic studies to identify the cost of congestion and plans to remedy it on a systemwide basis and to coordinate with other areas to ensure simultaneous feasibility of the plans. In April 2006 and in response to FERC Order No. 890, the WECC Board formed the Transmission Expansion Planning Policy Committee (TEPPC) to oversee the regional transmission planning process. In addition, subregional planning groups were formed to address common issues within a particular portion of the Western Interconnection. Each subregional group's open and transparent planning process is linked to the TEPPC process. The six subregional groups include the California Independent System Operator, Northwest Transmission Assessment Committee of the Northwest Power Pool, Columbia Grid, Northern Tier Transmission Group, WestConnect Subregional Groups, and Pacific Southwest Planning Association.

There are approximately 51 regional transmission projects currently going through the TEPPC Path Rating Process. This appendix describes seven of these projects to illustrate the number of transmission projects being built outside California with the ability to deliver renewable energy into California. One additional project, not listed in the TEPPC Path Rating Process, is being built in Mexico with the sole purpose of delivering wind energy into Southern California is also described below. All of these projects could help California meet its Renewables Portfolio Standards (RPS) by 2020 and beyond. Projects were selected from the Pacific Northwest, Inland, Desert Southwest, and Mexico. Although these projects have projected in-service dates before 2020, the renewable energy could be available in the event California chose to import more out-of-state renewable energy in lieu of in-state renewable energy and additional transmission lines.

Pacific Northwest

West Coast Cable

Description

The West Coast Cable Project is sponsored by Sea Breeze Pacific West Coast Cable. West Coast Cable is a 500 kilovolt (kV) high-voltage DC (HVDC) sea cable project approximately 650 miles in length with 1,200 megawatts (MW) of transfer capability. The point of origin is the Alston Substation near Portland, Oregon, with termination at San Francisco, California. The general route runs west down the Columbia River then south along the Pacific Coast to the San Francisco area. The projected in-service date is 2010.

Potential Benefits

The project would provide hydroelectric energy and untapped wind resources from the Pacific Northwest into California. The project will stabilize the Western transmission grid by making load flows more predictable and relieve congestion on existing transmission lines.

Project Status

The West Coast Cable project is one of four transmission alternatives under consideration by the California Independent System Operator’s Joint Stakeholder Long-Term Planning Study. The project is also under review by the WECC TEPPC, which was initiated by the Pacific Gas and Electric Company. The project is in Phase 1 of the TEPPC Path Rating Process.

Gateway West

Description

Gateway West is part of PacificCorp’s Energy Gateway Transmission Expansion Project. The project is divided up into four segments. Segment 1A is a 500 kV alternating current (AC) circuit, approximately 298 miles long, originating at the planned Windstar substation near Glenrock, Wyoming, and terminating at Jim Bridger substation near Rock Springs, Wyoming.

Segment 1B is a 500 kV AC double-circuit, approximately 191 miles, originating at Jim Bridger substation near Rock Springs and terminating at the planned Populus substation near Downey, Idaho. Segment 1C is a 500 kV AC circuit, approximately 135 miles, originating at the planned Populus substation near Downey, Idaho, and terminating at Midpoint substation near Midpoint, Idaho. Segment E is a 500 kV AC circuit, approximately 136 miles, originating at Midpoint substation near Midpoint, Idaho, and terminating at the planned Hemingway substation near Melba, Idaho. Segments 1A and 1B have an estimated in-service date of 2014, and Segments 1C and E have an estimated in-service date of 2015. The estimated transfer capability of the project is 3,000 MW.

Upon completion of Segment H, PacifiCorp is planning a single-circuit 500 kV AC circuit, approximately 375 miles, originating at the planned Hemingway substation near Melba, Idaho, and terminating at Captain Jack near Klamath Falls, Oregon. The estimated transfer capability is 1,500 MW bidirectional.

Potential Benefits

The project will enable the delivery of renewable energy resources to support the region's RPS and environmental priorities. The new transmission system will provide a stronger and less-constrained transmission network that will ease congestion throughout the West and ensure reliable and efficient service. Segment H will help deliver renewable energy to serve PacifiCorp's customers in Oregon, Washington, and California.

Project Status

Gateway West Transmission Project Segments 1A, 1B, 1C, and 1E are in Phase 2 of the TEPPC Path Rating Process. Segment 1H is in the early planning process.

Inland

Gateway South

Description

Gateway South is part of PacifiCorp's Energy Gateway Transmission Expansion Project. The project is a 500 kV AC circuit, approximately 800 miles, and is divided into two segments. Segment F is a 500 kV AC double-circuit, approximately 400 miles long, originating at the Jim Bridger substation near Rock Springs, connecting to the planned Aeolus substation near Medicine Bow, Wyoming, and terminating at the planned substation near Mona, Utah. The transmission line has a transfer capability of 3,000 MW bidirectional with an estimated on-line service date of 2016. Segment G is a 345 kV AC circuit, approximately 400 miles, originating at the planned substation near Mona and terminating at the existing Crystal substation, north of

Las Vegas. The estimated on-line service date is 2016 with a transfer capability of 1,500 MW bidirectional.

Potential Benefits

Gateway South will help maintain system reliability to the Western Interconnection, reduce transmission congestion, support delivery of renewable energy from Wyoming to Utah and Desert Southwest, and provide backup to the Gateway West project.

Project Status

Gateway South Transmission Project Segments F and G are in Phase 2 of the TEPPC Path Rating Process.

TransWest Express

Description

The TransWest Express Transmission Project is sponsored by TransWest Express LLC. TransWest Express is a 600 kV HVDC project approximately 800 miles in length with 3,000 MW of transfer capability. The transmission line will originate at the planned Aeolus substation near Medicine Bow, Wyoming, and terminate at Marketplace substation near Las Vegas. The general route will begin in south-central Wyoming, extend through Northwestern Colorado and Central Utah, turn southwest into Southern Nevada, and end near Las Vegas. The projected in-service date is 2014.

Potential Benefits

TransWest Express will provide the transmission infrastructure necessary to reliably and cost-effectively deliver high-quality, low-cost renewable energy in the form of wind from Wyoming into Arizona, Nevada, and Southern California. The project will contribute to meeting national, regional, and state environmental policies, including state-mandated RPS and greenhouse-gas reduction targets.

Project Status

TransWest Express initiated the TEPPC Path Rating process for the TransWest Express Transmission Project in 2008 and is in Phase 1 of the process.

Northern Lights Zephyr

Description

TransCanada Energy is the project sponsor for the Northern Lights Zephyr Transmission Project. Zephyr is a 500 kV HVDC project approximately 1,000 miles in length with 3,000 MW of transfer capability. The transmission line will originate near Powder River, Wyoming, and terminate in the Eldorado Valley near Las Vegas. The projected in-service date is 2015.

Potential Benefits

Zephyr will provide transmission infrastructure in the Western United States that will connect to high-quality wind generation for delivery into Southwestern United States, including California. The project will enable the development of wind projects in the West and assist several western states in achieving their RPS while helping to reduce greenhouse-gas emissions.

Project Status

The Northern Lights Zephyr Transmission Project is in the conceptual phase of the TEPPC Path Rating process.

Northern Lights Chinook

Description

TransCanada Energy is the project sponsor for the Northern Lights Chinook Transmission Project. Chinook is a 500 kV HVDC project approximately 1,000 miles in length with 3,000 MW of transfer capability. The transmission line will originate near Colstrip, Montana, and terminate in the Eldorado Valley near Las Vegas. The projected in-service date is 2015.

Potential Benefits

Chinook will provide transmission infrastructure in the Western United States that will connect to high-quality wind generation for delivery into the southwestern United States, including California. The project will enable the development of wind projects in the West and assist several Western states in achieving their RPS while helping to reduce greenhouse-gas emissions.

Project Status

The Northern Lights Chinook Transmission Project is in the conceptual phase of the TEPPC Path Rating process.

Desert Southwest

SunZia Southwest

Description

The project sponsors for the SunZia Southwest Transmission Project include Southwestern Power Group, Salt River Project, Tucson Electric Power Company, Energy Capital Partners, and Shell WindEnergy, Inc. SunZia is a 500 kV AC double-circuit project approximately 460 miles in length with 3,000 MW of transfer capability. The transmission line will originate at the SunZia East substation near Ancho, New Mexico and terminate at the Pinal Central substation near Coolidge, Arizona. The projected in-service date is 2013.

Potential Benefits

The SunZia Southwest Transmission Project will deliver renewable energy to the western power markets and enable the development of renewable energy resources including wind, solar and geothermal generation.

Project Status

The SunZia Southwest Transmission Project is in Phase 1 of the TEPPC Path Rating Process.

Mexico

Energía Sierra Juárez U.S. Transmission

Description

Energía Sierra Juárez, LLC, is a subsidiary of Sempra Generation and is the project sponsor of the Energía Sierra Juárez U.S. Transmission Project. The transmission line will be three miles in length, two miles in Baja California, Mexico, and one mile in California. The two-mile segment will either be a 230 kV AC double-circuit or a 500 kV AC single-circuit, and the one-mile segment will be a 500 kV AC circuit that will tie into the existing Southwest Powerlink transmission line near Jacumba, California. The Energía Sierra Juárez U.S. Transmission project will have a 1,250 MW transfer capability dedicated to the U.S. market with a projected in-service date of 2011.

Potential Benefits

The Energía Sierra Juárez U.S. Transmission Project will provide wind energy to Southern California. Sempra Generation has signed a 20-year power purchase agreement with Southern California Edison for the first phase of the project's output, approximately 150 to 200 MW.

Project Status

On December 20, 2007, Sempra Generation, on behalf of Energía Sierra Juárez U.S. Transmission, LLC applied for a Presidential permit for the construction of the Energía Sierra Juárez U.S. Transmission Project. On February 25, 2009, the U.S. Department of Energy announced its intention to prepare an environmental impact statement on the proposed federal action of granting a Presidential permit to Energía Sierra Juárez U.S. Transmission Project.