CALIFORNIA PUBLIC UTILITIES COMMISSION

Report
To the
Legislature

SB 1038/Public Utilities Code Section 383.6:

Electric Transmission Plan for Renewable Resources in California

Prepared by the CPUC Energy Division

December 1, 2003

CALIFORNIA PUBLIC UTILITIES COMMISSION

Respectfully Submitted
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Executive Summary

This report satisfies the California Public Utilities Commission's (CPUC) statutory responsibility, pursuant to Public Utilities Code Section 383.6, to prepare by December 1, 2003, a comprehensive transmission plan (Plan) for renewable electricity generation facilities to meet California's renewable energy goals. The Plan has two sections: a policy text that describes key issues emerging from the development of the Plan, and a Transmission Plan detailing the lines, facilities and costs by California county group under the two scenarios of renewables generation identified by the California Energy Commission (CEC) in its Renewable Resources Development Report in pursuant Code Section 383.5

Key policy issues raised by this study include coordinating transmission development across Investor-owned Utility (IOU) service territories to maximize the return on ratepayer investments and avoid unnecessary duplication of facilities; coordinating with the ISO to enable a state total-resource perspective and to better understand the impact of intermittent resources on the grid; grouping, where possible, on a transmission facility renewable resources having complementary time profiles of production in order to maximize transmission capacity utilization; utilizing transmission capacity made available when non-renewable resources are displaced by Renewable Portfolio Standard (RPS) generation; and developing a new method of transmission financing that allows small renewable generators to participate in the RPS.

The detailed Transmission Plan describes transmission line and substation additions and modifications necessary to attain the legislative target of 20% RPS in 2017, as well as in 2010, as envisioned under the joint-agency Energy Action Plan. Generation potential as estimated by the CEC is paired with IOU estimates of the infrastructure needed to bring that potential on-line, with associated costs, all at the county-level. While this information cannot now be considered the basis for cost-effective transmission investments in the best interest of ratepayers – missing is the key ingredient of successful competitive bids, as envisioned by the legislature, as well as cost reductions after optimization of statewide transmission facilities across IOU boundaries – the Transmission Plan does accommodate the CEC's overview of renewable energy potential.

This Plan is not intended to directly integrate with the related renewables procurement process of Code Section 399.15. Instead the transmission requirements for the renewable resources procured under the "least cost, best fit" criterion of Code Section 399.15 will be assessed separately for each generation project bid.

The Plan also describes the CPUC's proposed reforems to California's system of transmission needs assessment, which will develop a collaborative process with the ISO to eliminate duplicative effort, while keeping this process coupled to the CPUC's ongoing resource planning and procurement efforts. The future course of action in two key CPUC dockets, Transmission and RPS Procurement, is also described. These reforms, and the RPS implementation steps to be undertaken in the coming months, position the CPUC and its collaborating agencies well to continue building the world's renewable energy economy

SECTION 1

I. OVERVIEW AND RECOMMENDATIONS

The California Public Utilities Commission (CPUC) is charged with formulating a plan for the transmission of potential renewable generation as identified by the California Energy Commission (CEC), and with submitting this plan to the Legislature by December 1, 2003. This document satisfies this legislative mandate, and represents, in broad strokes, the approach the CPUC will take in planning for the cost-effective development of transmission capacity to deliver renewable resources. This will be a complex, multi-year effort, the nature of which will be iterative and demanding of interagency collaboration and ongoing cooperation with the legislature. What is required, at this juncture, are solid foundational principles, a clear path to the identification and construction of optimal transmission capacity, and awareness of the potential consequences that may await the Renewable Portfolio Standard (RPS) planning effort.

The state's RPS establishes aggressive goals for the development of new renewable energy resources. As detailed by the CEC in its "Renewable Resources Development Report" (CEC document #500-03-080D), which by legislative direction forms the basis for this plan,[1] these resources are widely distributed across California and the West. While they are often bound to a particular geographic location, such as a high-quality wind area, these resources are conceptually abundant and sufficient to meet the state's renewable energy goals on a schedule that is accelerated more than the one envisioned by the legislature in SB 1078 (statutes of 2001). The resources are available and market participants are responding to California's initial efforts to revitalize its renewable energy industry.

Crucial variables exist in the RPS process for the planning and financing of sufficient, cost-effective transmission capacity to bring renewable power to the load centers it must serve. As detailed by the CEC, the renewable resources available to the California RPS are diverse in terms of their location, technology, production profile, and cost. These differences must be understood and addressed in RPS planning and procurement under the Least Cost-Best Fit process envisioned by the legislature and implemented by the CPUC. This process is described below. However, to successfully implement that process, and the entire RPS, which is more than a complex planning exercise, each resource must be connected to the electrical grid using sound engineering and financial principles. Only then will these potential resources deliver the ultimate goal of the RPS program – provide useful energy that is reliable, clean and free from reliance on fossil fuel.

This Plan draws together the CEC's assessment of renewable potential and the individual plans of the Investor-Owned Utilities (IOUs) to bring that potential on-line. Working with draft CEC assessment results made available in July 2003, the CPUC staff managed an accelerated process of turning these projections into a survey-level plan that

[1] Per Pub.Util.Code Section 383.6

demonstrates several transmission scenarios for meeting the state's renewable goals, and revealing a number of important issues for RPS transmission planning. The Plan also addresses detailed prescriptions for potential transmission investments in 11 counties to target specific renewable resources, as described in Section 2. While the Plan should not be considered a basis for immediate transmission investment – we must await the results of competitive RPS bidding to ensure that transmission dollars are well spent – the exercise of modeling the transmission needs of the state's renewable potential points the way forward to achieving renewable energy goals.

Key recommendations that emerge from this analysis include the following:

1) Coordinating Transmission Development among the IOUs

- The initial process of directing the IOUs to prepare stand-alone transmission plans for their service territories was necessary to complete this Report, and gives the CPUC an early indication of the cost assumptions the IOUs will employ.

- **Optimization of RPS transmission planning among IOUs will be essential to ensure least-cost, best-fit investments are made, a process which is best undertaken in the context of CPUC-directed long-term IOU planning.**

2) Coordinating with the ISO

- In its comments on the draft plan the California Independent System Operator (ISO) recommended taking a total-resource view of the state's generation and transmission needs, including an established reserve margin, which is consistent with the approach being taken in the CPUC's Procurement process. Once these total generation and transmission needs are known, in the ISO's view, more specific analyses of the tradeoffs between renewable and non-renewable generation can be undertaken, which will likely reveal that the cost projections represented here are conservative.[2]

- **Coordination with the ISO for RPS transmission planning will allow for total-resource optimization, and will allow the CPUC to better understand the effects of adding large-scale intermittent resources to the transmission system.**

3) Emphasizing Balanced Loading and Rational Displacement of Generation Resources

- The present IOU plans summarized here are based on the assumption that existing generation displaced by renewable generation is located at load centers. However, if displaced generation is ultimately located outside load centers, transmission capacity may become available for use by renewable generation. Determining the best transmission investments for the RPS program will require understanding the delivery profiles of the renewable resources that will utilize them, and maximizing the transmission capacity made available when fossil generation is displaced.

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[2] These costs are summarized in Part V of this plan and developed fully in the attached Appendix.

- **RPS bid selection should emphasize balanced loading and efficient displacement decisions, analyzing which non-renewable resources will be potentially displaced by RPS energy, to reveal transmission capacity that may be available to the RPS program.**

4) Designing a New Transmission Financing Mechanism

- The present method of participant funding of transmission upgrades may be incompatible with the small scale of many renewable developers; cooperation with the ISO and IOUs, using flexibility recently provided by FERC, may allow for development of a new method.

- **Conditioning IOU investment of ratepayer funds in transmission upgrades on the successful bidding of a threshold amount of potential in a resource area will ensure that the RPS program promotes sufficient development without incurring unnecessary sunk costs, to the detriment of California ratepayers.**

II. FOUNDATIONS OF THE PLAN

CEC Renewable Resources Development Report

The CEC issued a Draft "Renewable Resources Development Report" on July 1, 2003, describing the renewable generation potential identified to that date, to provide a basis for the CPUC to prepare this plan. The CEC assessment identifies the renewable generation needed to conform to the provisions of SB 1078 for the years 2005, 2008, and 2017 to meet the RPS goal.[3] The CEC's July 1st draft presented resource potential estimates for the IOUs only; a subsequent draft, made available to the CPUC on September 30th, was more comprehensive, presenting available generation for other California load-serving entities. This document incorporates these later estimates by the CEC, providing one estimate of the total transmission needed to utilize the renewable resources available to California.

Energy Action Plan

The Energy Action Plan (EAP) is a joint effort of the CPUC, the CEC, and the California Power Authority to ensure the reliability and affordability of electricity and natural gas supplies in California. Crucially from the RPS perspective, the EAP includes the goal of accelerating attainment of the RPS goals from 2017 to 2010. In accordance with the EAP, this report describes transmission expansion needs for RPS attainment in both 2010 and 2017.

Achievement of the EAP's goals affects both the transmission requirement and total cost:

[3] For transmission planning, generated power rather than energy is needed, so the CEC converted consumed energy values (gigawatt-hours) to power (megawatts) by applying plant factors of 90% for geothermal generation, 80% for biomass, 35% for wind and 15% for solar.

- Because the full 20% development is accomplished earlier, the grid will be less developed and therefore the amount of incremental transmission required is greater.
- The cost will be greater for two reasons: First, as stated above, the transmission requirement is greater. Second, from the net present value perspective, the cost for the same upgrade will be greater due to the decreased discounting period.
- For example: In the case of the renewable generation in Modoc and Siskiyou Counties in 2017, three transmission lines would have to be built for delivery of the power in 2010, which would not be needed in 2017. The reason is that in 2010 the lines would be necessary to transmit the generation south to a load center, whereas by 2017 the CEC projects that local load will have grown sufficiently to absorb the incremental power.

Procedure for Plan Development

The initial step in the formulation of the transmission plan was to have the three IOUs prepare individual plans, based on criteria stipulated by the CPUC for transmission of the renewable generation in their service territories. These plans were then distributed to the service list of the CPUC transmission planning docket (I.00.11.001), and a public stakeholder meeting was held to obtain comments from interested parties. The CPUC staff then prepared this document based on the individual IOU plans, as modified by relevant stakeholder comment.

Timeframe of the Plan

The plan identifies the upgrades to the transmission grid required to accommodate the renewable generation identified by the CEC for the years 2005, 2008, 2017, plus, for the accelerated plan, the year 2010. The detailed Section 2 of this report contains county-level analyses of the specific resources identified by the CEC.

Scope of Upgrades Included in the Plan

The transmission needed to connect a generating plant to the electrical load is generally considered to have three components:

- The transmission line from the generating plant to the point of connection to the utility grid, called the "direct assignment facility" or "gentie";
- Facilities within the grid to maintain reliability with the added burden of the new generation, called the "reliability upgrade";
- New facilities within the grid to transmit the new generation from the point of interconnection to the grid to the load center, called the "delivery upgrade".

Only the third type of upgrade is considered in this plan. Genties are the responsibility of the generation developer, and as determined in D.03-06-071 are to be incorporated into RPS bids. Included in the delivery upgrade are new and expanded substations and new and reconductored (with higher capacity wires) transmission lines.

Costs
All costs are based on 2003 dollars, escalated at a rate of 3% to account for inflation and discounted at a rate of 10% from the year of investment, between 2005 and 2017 to provide net present value (NPV) in 2003.

III. ASSUMPTIONS & LIMITATIONS

1) Transmission Planning Should Not Pick Technologies
In the Scope of Work for the IOUs studies the ALJ ruled that:

"The SB 1038 transmission study will not, by definition, take a position on which potential renewable generation facilities might actually be developed. The study will present a preliminary renewable transmission expansion plan that will require further refinements, once the results of the RPS solicitations are known, and specific interconnection studies have been undertaken."[4]

This is an important principle that will preserve the integrity of RPS development, allowing transmission investment choices to be made on the basis of cost-effective bids selected via an open, competitive solicitation, as envisioned by the RPS statutes.

2) Wheeling of Renewable Energy is Beyond the Scope of this Plan
The largest source of renewable generation lies in the SCE service territory, and is far beyond what SCE will need to meet its RPS goals. Consequently, much of this power is likely to be wheeled to load in other service territories. Defining the transmission needed to accomplish this will require the investigation of a number of alternatives, including another extra-high voltage line between SCE and Pacific Gas and Electric Company (PG&E), and is beyond the scope of this transmission plan. The CPUC will pursue coordination between the IOUs to make these generation resources available statewide.

3) Certain Factors are Necessarily Omitted from the Plan
This transmission plan provides for the transmission of all the generation identified by the CEC, from the point of connection at the grid to load centers in California. The scale of this undertaking, and the lack of specificity regarding particular generation resources, requires that certain factors be ignored at this time. These factors include:

- Resource type: geothermal, biomass, wind, solar
- Status in CAISO queue for analysis of integration effects and costs
- The need of the utility for power: it is assumed that the generation identified by the CEC for each of the years 2005, 2008, and 2017 to fulfill the SB1078 requirement of at least 1% yearly increases will be utilized even if the utility has sufficient power from non-renewable resources.[5]

[4] ALJ Ruling Clarifying Transmission Cost Studies, I.00-11-001, March 27, 2003, Attachment A, p.1
[5] There is some geothermal, biomass and wind generation originating in the Imperial Irrigation District's (IID) service area. It is not known how much of this generation would be taken by the District and how much by SCE and how much by SDG&E. Therefore, for the purpose of this plan, the simplifying

- Transmission is planned for all the identified generation without the screen of generation project cost-effectiveness.

More detailed studies are needed, on a project-specific basis, to identify reliability upgrade needs. Short-circuit and stability studies may be required to identify some reliability upgrades. Due to the time and resource constraints of this study, as well as the fact that these upgrades are very queue-sensitive and information regarding the queue position of potential renewable generation is limited or nonexistent, these short-circuit and stability studies were not performed. Therefore, there may be reliability upgrades, such as breaker replacement, that are needed but not identified in this plan. In most cases of generator connection to the grid, the cost of reliability upgrades will be small compared to the cost of delivery upgrades.

4) Environmental Issues

Based on preliminary environmental evaluation, no insurmountable environmental impediments to the identified transmission upgrades have been found. However, the emergence of right-of-way limitations due to biological, cultural and land-use issues would require a more detailed analysis of these transmission facilities and any possible alternatives. Significant routing challenges may be encountered for line segments crossing federal and Native American lands, and visual and construction impact issues may arise. Any environmental challenges to selected rights-of-way may be mitigated either by rerouting of the transmission segment or through other mitigation options, although these may add significantly to project costs.

IV. INTEGRATING THE PLAN WITH RPS PROCUREMENT

This section of the report addresses four issues in relation to transmission planning for the RPS. First, it describes the process of RPS bidding and project selection as it has been established thus far, emphasizing the evaluation of transmission costs imposed by an individual renewable project. Second, the current process of transmission planning and construction is described, followed by the CPUC's plan for reforming that process, with the special case of the RPS program highlighted. Third, the question of cost assessment and recovery is discussed, to be developed more fully in the following section on FERC issues. Finally, key issues and challenges for the RPS program and transmission planning are highlighted by way of summary, with a discussion of next steps the CPUC will undertake.

Project Evaluation in the RPS Bidding Process

CPUC decision D.03-06-071 established key RPS policies as required by statute. Among these is the process whereby the RPS-obligated entity will evaluate responses to competitive solicitations for renewable power, known as the Least Cost-Best Fit ranking process. This methodology considers a broad range of factors, many of which are not directly relevant to the question of transmission planning. Two elements require

assumption was made that all necessary transmission upgrades would be made by SCE. This may not be borne out as RPS bidding develops; wheeling across IOU territories may be optimal.

consideration here: analysis of the location, magnitude and cost of particular resources, which involves the CEC's Renewable Resources Development Report, and development of the transmission cost "adder" to be applied to each renewable bid. While the development of this adder is a separate process from the planning required in this report, they are linked in key respects, as described below.

The Least Cost-Best Fit Process (LCBF)

The RPS process will begin each year with the filing of an RPS Procurement Plan by each obligated entity, which, in the case of the IOUs, will be coordinated with general integrated resource planning. This plan will describe the status of each obligated entity in relation to its RPS goals, and will detail the type and quantity of renewable power that will be solicited in the year's RPS procurement round. Following CPUC staff review and approval of the Plan, the RPS solicitation will be issued by the obligated entity. Review and approval of proposed RPS contracts will follow, in accordance with standard CPUC practice.

The Legislature directed the CPUC to establish standard bid ranking procedures via the LCBF process. As developed in D.03-06-071, the LCBF rank-ordering considers fit with the obligated entity's need for power, all-in costs for energy and capacity, costs of integrating a specific resource into the grid, costs associated with expanding the transmission system, and benefits provided to minority and low-income populations. Bids are judged against each year's Market Price Referent (MPR), which will not be revealed until after the solicitation has closed. Winning bidders will be eligible for Supplemental Energy Payments to cover costs above the MPR, as determined by the CEC.

Developing the Transmission Cost "Adder" for RPS Projects

Most transmission additions to accommodate the RPS program will ultimately be funded by ratepayers, but, as with fossil generation additions, the initial financing for a transmission project may be provided by the generator or the RPS-obligated entity. Transmission financing may present insurmountable obstacles for some smaller renewable developers, as discussed below. Regardless of who provides the up-front financing, it is important to evaluate transmission costs as part of the all-in cost of a proposed renewable project, and to select the most cost-effective resources to meet RPS needs. To accomplish this, each RPS bidder must include an estimate of the costs of connecting the proposed project to the transmission system.

This report is not the vehicle for developing these adders, and the underlying IOU cost estimates prescribed here will not become the basis for ultimately establishing them. Through a collaborative process with the ISO, we will incorporate the results of standardized System Integration Studies and Facility Studies for projects that have commissioned them, or perform an independent calculation for the same purpose following an established methodology. Each prospective RPS bidder will have a clear opportunity to appear in a CPUC forum and have cost assessments performed in a transparent and fair manner. These assessments will then be incorporated in the RPS bid, placing all prospective projects on the same footing, allowing the CPUC and the IOUs to make the most cost-effective judgment in the interest of ratepayers. However, these detailed assessments cannot be undertaken using either the CEC's estimates of renewable potential or the transmission cost projections presented here. They must instead reflect the project-specific characteristics of individual RPS bids.

Location, Cost, and Magnitude of RPS-Eligible Resources

As many parties have noted, the CEC has done a commendable job of assessing the renewable resource potential available to the RPS program in its Renewable Resources Development Report. As required by statute, the CEC's assessment forms the basis for this RPS transmission plan, which brings together into one document the IOUs' analyses of potential transmission needs arising from RPS procurement.

It is important to emphasize, however, the considerable uncertainty that necessarily remains regarding the precise cost of the resources identified by the CEC and the ultimate magnitude of those resources that can conceivably be developed for the California consumer. Renewable energy technologies are changing rapidly, and markets for renewable power are developing throughout the West. Consequently, it is impossible to say with certainty how much a resource will ultimately cost California's ratepayers, or whether a particular resource will ultimately serve California or some other geographic area.

Transmission expansion requires substantial investment of time and capital, and can be disruptive to both developed and undeveloped environments. Undertaking these investments without sufficient certainty regarding the cost and availability of specific renewable resources would be an unwise expenditure of ratepayer dollars. Consequently, CPUC staff considers the resource assessment undertaken by the CEC to provide a general indication of the likely course of RPS development over the program's lifetime, rather than the basis for investment of ratepayer dollars in specific transmission projects. Before undertaking the cost and disruption of a new transmission project, California should seek considerable certainty that the project will connect to a viable source of renewable generation that is committed to serve California, certainty that is best achieved via the real-world test of bid solicitation in the RPS process.

This certainty regarding utilization of transmission investments must be balanced against the fact that renewable energy projects are frequently small-scale, and must therefore be aggregated in a rational fashion to arrive at an amount of generation sufficient to justify a transmission investment. Balancing these concerns may be the central challenge facing transmission planning for the RPS.

The aggregation of winning RPS bids from a particular resource area can serve as a "trigger mechanism" for the expenditure of ratepayer funds to build a new transmission facility. Possible means of designing this trigger mechanism for RPS transmission investment are discussed below.

Current Transmission Planning and CPUC-Proposed Reforms

Pursuant to guidance outlined in the Energy Action Plan, the CPUC is developing reforms to its transmission planning process, specifically to eliminate redundancies that exist in the ISO's and CPUC's transmission need assessment.[6] The CPUC has developed a proposal that will establish, in collaboration with the ISO, a methodology for assessing the economic or reliability need for a proposed transmission project.

The CPUC's procurement proceeding is the most appropriate venue to conduct a comprehensive evaluation of IOU resource options for meeting customer demand. Once the CPUC determines the appropriate mix of IOU resources in the procurement process, the IOUs will incorporate the transmission components of this resource mix in their annual transmission plans submitted to the ISO. The ISO will subsequently make a determination of need and evaluate specific transmission projects. Once the ISO has identified a preferred project, it will ask the IOU to sponsor the project going forward.

If the IOU requires a Certificate of Public Convenience and Necessity, as outlined in PU Code Section 1001 and General Order 131-d, the IOU will submit an application to the CPUC. Once it has determined that the approved economic methodology and reliability criteria were applied, the CPUC will utilize the ISO determination of need, and will conduct California Environmental Quality Act (CEQA) review. Eliminating a redundant determination of project need will significantly improve and streamline the current process while keeping transmission planning firmly linked with the larger process of generation planning and procurement.

Transmission Cost Assessment and the RPS Case

In enacting Pub.Util.Code 399.25 as part of SB 1078 in 2002, the Legislature recognized the difficulty of reconciling traditional methods of transmission expansion with the characteristics of renewable generation, which often include geographic dependence, a smaller scale than that associated with modern fossil power plants, and an industry comprised of multiple, often-entrepreneurial players. These characteristics fit poorly with the standard method of transmission finance, which is a key component in transmission planning for renewable generation.

Typically, either the generator or the load-serving entity finances the entirety of a needed transmission upgrade up-front, prior to the generation of electricity and the attendant stream of revenue associated with it. Assuming an affirmation by the FERC of the upgrade's benefit to ratepayers and the grid, this up-front investment is repaid to the utility or the generator from rates associated with the consumption of generated electricity. Over time, typically five years, this substantial up-front investment is recovered.

[6] In Decision (D.) 01-10-070, the CPUC established a collaborative relationship with the ISO to establish a common methodology for evaluating the economic benefits of a transmission project.

Several key assumptions are embedded in this method. The first is that the developer of generation is willing and able to make this substantial up-front investment, or that the contracting utility will step in and do so. The second and crucial assumption is that a substantial transmission investment will be justified by the addition of the first generator into a resource area, even if that generator is relatively small, or represents only a fraction of the total potential generation to be extracted from an area. Neither of these assumptions will necessarily hold in the RPS case, presenting a potentially confounding free-rider problem that will impede RPS progress. We must develop a method of transmission planning and financing that adequately protects the financial interests of all parties involved, and will overcome this deadlock at the initial stage of renewable development.

Funding of Transmission Expansion to Accommodate RPS Developers

In adopting SB 1078 in 2002, the Legislature made it clear that the CPUC should facilitate the construction of new transmission facilities necessary to accommodate the development of renewable resources in the state. In particular, Public Utilities Code Section 399.25, adopted as part of SB 1078, directs the CPUC to approve certificates authorizing the construction of transmission facilities that facilitate the achievement of the renewable power goals established by that law, and further directs the CPUC to support actions that are necessary to assure that the costs of such transmission facilities are included in retail electricity rates.

Since the implementation of AB 1890 in the mid-1990s, when a new power plant is built, the transmission system upgrades necessary to accommodate the generation from that plant are paid for upfront by the generator. The generator is then reimbursed over a period of time (typically five years) once the new power plant is built and providing power to the grid. The Federal Energy Regulatory Commission (FERC), which has jurisdiction over wholesale transmission rates, has, until recently, implemented this policy on a case-by-case basis. Moreover, in its recently adopted Final Rule on the Standardization of Generator Interconnection Agreements and Procedures (hereafter, "the FERC Interconnection Rule",)[7] FERC explicitly endorsed this existing policy with respect to interconnections to utility-operated transmission systems.[8]

As discussed above, if this policy were to be strictly applied to transmission upgrades necessary to accommodate new renewable resources, it could have the effect of undermining the feasibility of developing those resources.[9] For example, in a remote

[7] See 104 FERC ¶ 61,103, issued July 24, 2003.

[8] See Paragraph 693 of the FERC Interconnection Rule.

[9] The transmission system upgrades necessary to accommodate new generation fall into three categories: (1) "gen ties," *i.e.*, transmission that runs from the generator's facilities up to the first point of interconnection with the existing transmission system; (2) reliability upgrades, *i.e.*, upgrades to the existing transmission system that are necessary to maintain the same of level of reliability performance in the existing transmission system as existed prior to the new interconnection; and (3) deliverability upgrades, *i.e.*, upgrades to the existing transmission system that are necessary to assure delivery to the market of the full output of the new generator. The cost reimbursement policies endorsed by the FERC Interconnection Rule apply to categories (2) and (3). By contrast, the cost of installing "gen ties" is the exclusive responsibility of the new generator being interconnected. However, it is important to note that the FERC

area where there were significant wind resources and a large number of small developers, and these resources were to be developed over a period of years, the cost of building the transmission system upgrades necessary to accommodate the development of those resources would almost certainly be beyond the financial capabilities of any one of those developers. If the FERC policy were applied in this instance, the first developer whose project would trigger the need for significant transmission upgrades would be responsible for paying the upfront costs of these upgrades. In this case, the cost of the needed transmission upgrades could equal or exceed the capital costs of the developer's project, thereby making it practically impossible for the developer to proceed.

This problem might be somewhat mitigated in certain cases by aggregating a number of planned renewable resource projects and spreading the costs of the necessary transmission upgrades to accommodate those projects across the projects as a group. However, this is, at best, a very limited solution, because the development of renewable projects is expected to take place over an extended period of time. In a given wind resource area, some projects may be well advanced, whereas others are merely planned for development five or 10 years down the line. Under this approach, therefore, it is virtually unavoidable that a significant percentage of the costs of the necessary transmission upgrades to allow the full development of a given wind resource area will disproportionately impact (and impose burdensome, and possibly unmanageable, costs on) a small number of the developers. At the same time, other developers, whose projects would come on line at some years later on, would unduly benefit from the fact that previous developers had to carry the costs of major transmission system upgrades.

The fact that some developers in a given renewable resource area would bear disproportionate financial responsibility for required transmission upgrades, while other developers would escape such costs, creates a serious obstacle to the systematic and planned development of renewable resources that is contemplated by the renewable portfolio standard that the legislature adopted in SB 1078. Fortunately, there are several legal mechanisms available to deal with this cost allocation problem.

Most importantly, although the FERC Interconnection Rule re-states the established policy that the interconnection customer (i.e., the generator) pays the upfront costs of the transmission system upgrades necessary to accommodate the interconnection, the Rule also <u>allows</u> a transmission provider (i.e., the utility to whose transmission system the new power plant will be interconnected) to "elect" to fund these upgrades itself, with no advance payment by the new generator.[10] Thus, there does not appear to be a legal

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Interconnection Rule provides for reliability-only interconnections to the existing grid; it does not mandate deliverability upgrades, although it does allow for them. In this regard, we note that in many instances, the cost of deliverability upgrades to accommodate a given new interconnection will be dramatically larger than the costs of reliability.

[10] See Article 11.3 of the Standard Large Generator Interconnection Agreement, which was adopted as part of the FERC Interconnection Rule. It should be noted that this Standard Agreement only applies to generating facilities larger than 20 megawatts in capacity. It is possible that certain renewable resource projects will be smaller than 20 megawatts. Until FERC takes action on small generator interconnection procedures and agreements, which are currently under review in FERC Docket RM02-12-000, it is unclear what federal rules, if any, will apply to such small facilities. In the meanwhile, such facilities remain

impediment in federal law to utility funding of the upfront costs of transmission system upgrades necessary to achieve the renewable power goals that the Legislature established in SB 1078.

However, the lack of a legal impediment to utility funding of such upgrades does not guarantee that such funding will be automatic. A given utility may not want to fund transmission system upgrades to accommodate the development of particular renewable resource options, because, among other reasons, utilities have limited budgets for capital improvements, and a transmission development project to accommodate renewables may not be a priority element of a given utility's capital budget. In such cases, the CPUC may compel a utility under its jurisdiction to "reprioritize" its capital spending plans in order to fund transmission system upgrades necessary to accommodate the development of certain renewable resources addressed in this Report. Thus, the development of utility-funded transmission system upgrades necessary to accommodate the development of renewable resources is part of the balance in procurement plans, building incentives, and mandates.

In this regard, it should be noted that there are many cases in which FERC policy actually supports the use of utility funding of transmission system network upgrades. Such upgrades typically provide system-wide benefits, and FERC has consistently found that their cost should be borne by all users of the system.[11] The specific language of, and the larger public policy purpose behind, both SB 1078 in general and §399.25 in particular clearly support the principle that transmission upgrades necessary to accommodate new renewable generation provide system-wide benefits. In this light, CPUC staff believes that FERC would endorse the use of utility-funded transmission system upgrades necessary to accommodate the development of renewable resources.

In addition to the fact that there appears to be no legal impediment to upfront utility funding for transmission system upgrades necessary to accommodate the development of renewable resources, as is noted above, the policy set forth in the FERC Interconnection Rule that the developer pays the upfront costs of necessary transmission system upgrades is mandatory only with respect to interconnections to utility-operated transmission systems. In California, by contrast, as a result of AB 1890, the operation of the transmission grid was handed over to the California ISO, and while California's IOUs continue to own their transmission systems, they no longer control the operation of those systems.

This is important, because FERC has encouraged the formation of "Regional State Committees" in those parts of the country where control over the transmission grid has passed to independent operators such as the CAISO.[12] Once established, such "Regional

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subject to the applicable rules in the state-approved tariffs of the utilities to whose transmission systems these facilities would interconnect. California's electric utilities do have such rules, which have been approved by the CPUC.

[11] See, e.g., *San Diego Gas & Electric Company*, 98 FERC ¶ 61,332 (2002).

[12] In California, a "Regional State Committee" would consist of representatives of the CAISO and of the State.

State Committees" would allow states to work together to identify beneficiaries of transmission expansion projects and make recommendations on pricing proposals and cost recovery, which may include utility funding of such projects.[13] In this regard, the FERC Interconnection Rule explicitly states that FERC

> " . . . continues to allow flexibility regarding the interconnection pricing policy that each independent entity [such as the ISO] chooses to adopt, subject to [FERC] approval. We invite a Regional State Committee to establish criteria that an independent entity would use to determine which Transmission System upgrades, including those required for generator interconnections, should be participant funded and which should not."[14]

The question of "who pays" for the necessary transmission system upgrades to accommodate the full development of the renewable resources addressed in this Report remains problematic, in no small measures because the utilities may object to funding of the upfront costs of those upgrades themselves. However, there do appear to be available legal mechanisms to allow for direct funding of these necessary transmission upgrades by the utilities themselves. Such funding would, of course, require CPUC approval, and in a given case, would only be mandated after a public proceeding in which all interested parties, including the CAISO, the utilities, the renewable project developers and the interested public were able to participate. Moreover, such cost allocation would have to be justified by legal findings and conclusions to the effect that the resources necessitating the transmission system upgrades in question were a preferred alternative to meet resource needs and were necessary to enable the utilities to meet the requirements of the renewable portfolio standard in the most economic manner.

These areas of flexibility provided by FERC allow the CPUC, in conjunction with the ISO and other interested parties, to design a mechanism of transmission financing that balances the need for ratepayer protection against the inability of many potential renewable developers to fund large transmission projects on their own. One possible method would be to design a "trigger mechanism" whereby a specified number of successful RPS bids from an untapped resource area would result in a CPUC order directing the IOU to construct a transmission expansion. The precise amount of potential generation selected in the bidding process required to trigger an IOU investment – i.e. 40%, 50%, or 60% of total potential - will be the subject of deliberations in the CPUC's RPS and Transmission dockets, in collaboration with the ISO. The essential point at this time is that the nature of RPS development will likely require a change from the status quo, and the ongoing reforms at FERC and the ISO seem poised to allow for such a change. Given the substantial public interest in developing California's renewable

[13] See Paragraph 679 of the FERC Interconnection Rule.

[14] See Paragraph 698 of the FERC Interconnection Rule.

resources, awareness of which underpins the entire RPS program, a new method of burden-sharing in transmission development is warranted.

Next Steps for CPUC Action

RPS policy development is ongoing in the Commission's Procurement (R.01-10-024) and Transmission (I.00-11-001) dockets and their successors. Key next steps in each part of this process are outlined below:

- The Transmission docket will now turn to developing the process of calculating transmission cost adders for RPS bids, which will then be linked to RPS bidding in Procurement via the Least Cost-Best Fit process.
- RPS policy development will soon be given its own docket, emphasizing the annual filing of RPS procurement plans and other outstanding issues, with the goal of initiating the first RPS solicitation in Q2 2004.

The Transmission and new RPS dockets will coordinate to resolve the question of participant funding of new transmission facilities for renewable generation, in coordination with the ISO, and in conjunction with the developing Regional State Committee concept.

V. SUMMARY TABLES - Results of the Renewables Transmission Plan Study

The following are the salient features of the Transmission Plan of this Report:

- Two sets of transmission upgrades are provided: one to meet the standard of 20% by 2017 and the other to meet the accelerated EAP goal of 20% by 2010.
- The transmission plan consists of new and upgraded 60kV, 115kV, 230kV and 500kV transmission lines and new and modified substations of the same voltages.
- Two sets of costs are given for every element of the upgrades: first, in terms of undiscounted 2003 dollars, and second, in terms of the net present value (NPV) in 2003 based on the assumption of 3% annual inflation and a 10% discount rate.
- The costs of the plan are given in three tables for each County group:
  A: 2017 schedule, 2003 undiscounted dollars;
  B: 2017 schedule, NPV dollars; and
  C: 2010 schedule, NPV dollars.

According to the CEC generation plan, one-half of the increase in generation required to meet the goal of 20% electricity consumption from renewable generation in 2017 consists of some 4,000 MW of wind power in the Tehachapi Mountains. To meet the same goal under the EAP accelerated schedule a little more than half comes from wind power in the Tehachapis. The cost of the required transmission upgrades for this power is two-thirds of the total cost of the Transmission Plan. From the engineering and planning point of view sought by Section 383.6 it should be noted that the concentrated development of this amount of power with associated transmission in the Tehachapi area by 2010 calls for lead times, or mandates and incentives, not yet in place.

With respect to the transmission cost estimates, costs will be incurred for new transmission due to load growth whether the generation is renewables based or not. Thus the level of the transmission cost estimates herein is not due solely to the choice of renewable technologies for generation. However, to estimate a net cost difference due to the choice of renewables would require making assumptions about the size, timing and location of non-renewables generation, that is beyond the scope of the work mandated by the Legislature.

The transmission upgrades necessary to deliver renewable energy from largely rural locales where it is generated to the more urban electric load centers are identified and summarized on the following graphs and tables.

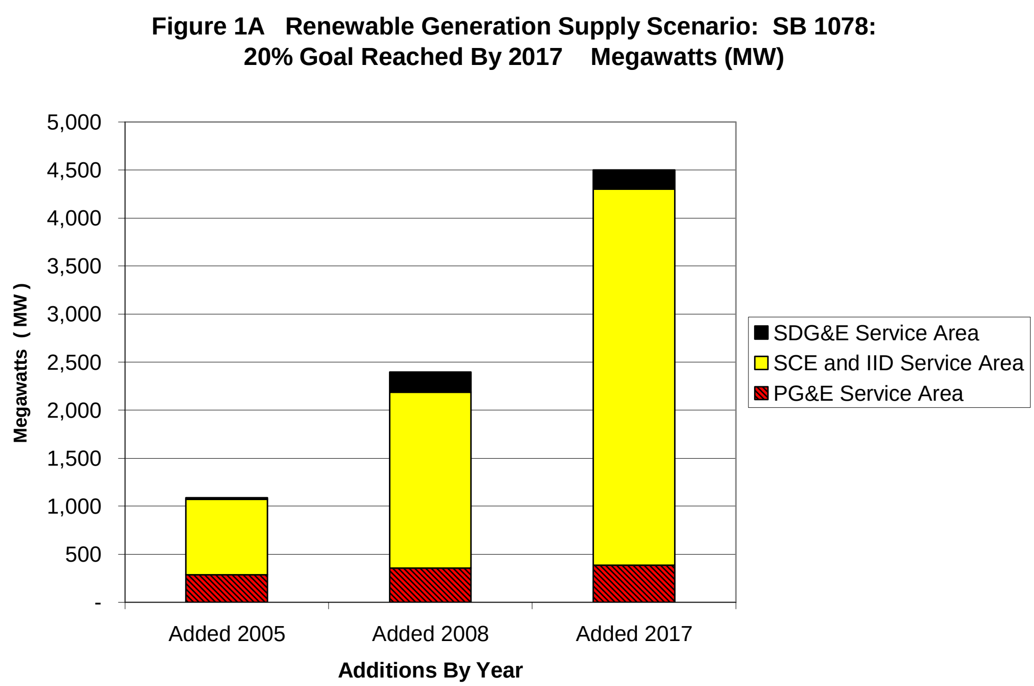
- FIGURE 1 shows the renewable generation identified by the CEC for both the SB1078 schedule to achieve 20% by 2017 and the Energy Action Plan schedule to achieve 20% by 2010. TABLES 1A and 1B give the same information broken down into California county groups.

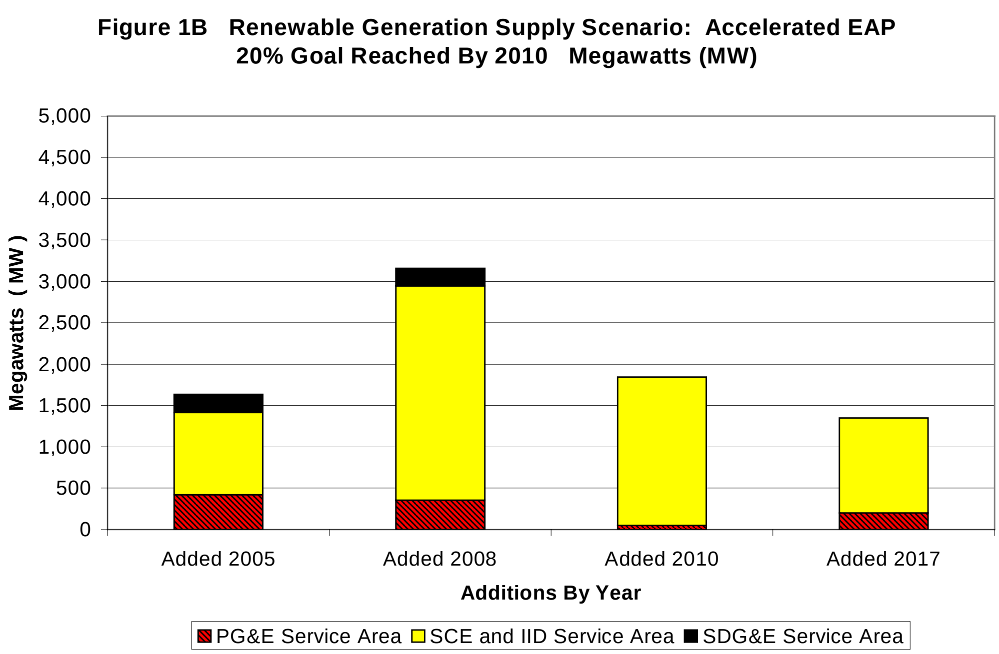
- FIGURE 2 shows the costs of the transmission upgrades for the years of interest. TABLE 2 gives the same information broken down into California county groups.

- TABLE 3 summarizes by geographical area the actual transmission facilities, lines, transformers and circuit breakers, which constitute the Transmission Plan. The information is segregated by year of interest: for the SB1078 schedule, 2005, 2008, and 2017, and for the EAP schedule, 2005, 2008, and 2010 or 2017.

FIGURE 1

Renewable Generation Supply Scenarios





The cumulative supply added by 2017 is 7,987 MW as shown in Table 1A.

TABLE 1A
Supply Scenario

SB 1078 Schedule

Megawatts (MW)

Source: CEC Table 13 Renewable Resource Assessment September 30, 2003

Location Statewide	County / Resource	Added 2005 (MW)	Added 2008 (MW)	Added 2017 (MW)
PG&E Service Area	Modoc / geothermal			105
	Siskiyou / geothermal		100	90
	Solano / wind	215	100	85
	Alameda / wind	50	110	50
	Location total	**265**	**310**	**330**
	Other biomass	20	45	55
	Other total	**20**	**45**	**55**
Area Totals		**285**	**355**	**385**
SCE and IID Service Area	Imperial / geothermal	120	60	190
	Imperial / biomass			80
	Kern / wind	285	1,410	2,365
	Mono / geothermal		50	300
	Riverside / wind	200	190	140
	San Bernardino / wind	50	40	310
	San Bernardino / solar			180
	Los Angeles / biomass	15	65	
	Los Angeles / wind	100		315
	Location total	**770**	**1,815**	**3,880**
	Other wind			30
	Other biomass	15	17	5
	Other total	**15**	**17**	**35**
Area Totals		**785**	**1,832**	**3,915**
SDG&E Service Area	San Diego / wind		200	200
	San Diego / biomass	20	10	
Area Totals		**20**	**210**	**200**
Statewide Totals		**1,090**	**2,397**	**4,500**
Cumulative Totals		**1,090**	**3,487**	**7,987**

TABLE 1B

Supply Scenario

Accelerated Energy Action Plan Schedule

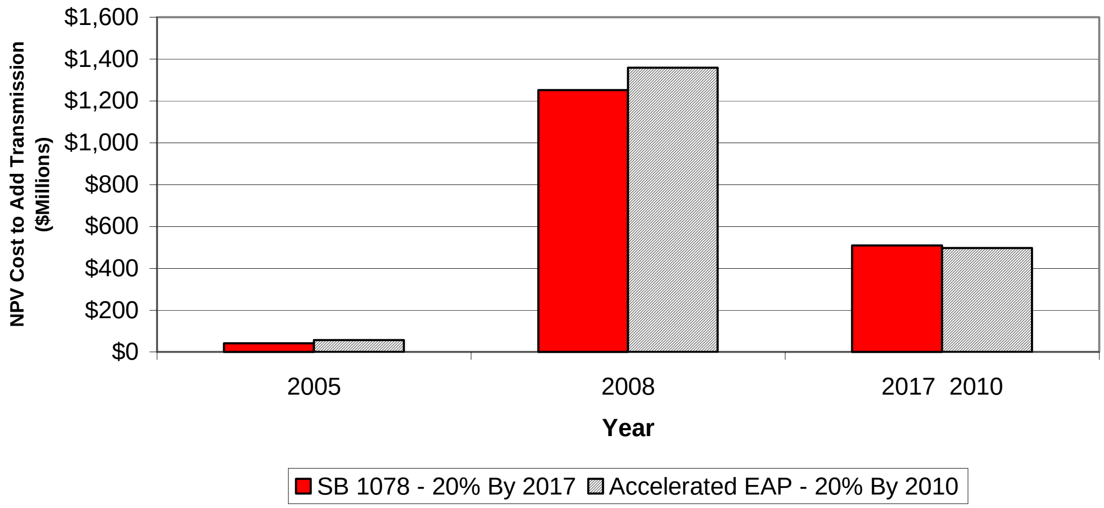
Megawatts (MW)

Source: CEC Table 15 Renewable Resource Assessment September 30, 2003

Location Statewide	County / Resource	Added 2005 (MW)	Added 2008 (MW)	Added 2010 (MW)	Added 2017 (MW)
PG&E Service Area	Siskiyou / geothermal		100	30	60
	Solano / wind	315	85		
	Modoc / geothermal		15	15	75
	Alameda / wind	50	135	5	20
	Location total	**365**	**335**	**50**	**155**
	Other wind				
	Other geothermal				
	Other biomass	55	20		45
	Other total	**55**	**20**		**45**
Area Totals		**420**	**355**	**50**	**200**
SCE and IID Service Area	Imperial / geothermal	120	90	120	40
	Imperial / biomass		50	30	
	Imperial / wind				
	Kern / wind	395	1,910	1,425	330
	Mono / geothermal		100	100	150
	Riverside / wind	250	280		
	San Bernardino / wind	50	60		290
	San Bernardino / solar			120	60
	Los Angeles / biomass	25	55		
	Los Angeles / wind	100	35		280
	Location total	**940**	**2,580**	**1,795**	**1,150**
	Other wind	30			
	Other geothermal				
	Other biomass	25	12		
	Other total	**55**	**12**	**0**	**0**
Area Totals		**995**	**2,592**	**1,795**	**1,150**
SDG&E Service Area	San Diego / wind	200	200		
	San Diego / biomass	20	10		
Area Totals		**220**	**210**	**0**	**0**
Statewide Totals		**1,635**	**3,157**	**1,845**	**1,350**
Cumulative Totals		**1,635**	**4,792**	**6,637**	**7,987**

IOU Estimates of the Costs of Transmission Upgrades
FIGURE 2 shows costs for the years of interest. TABLE 2 gives the same information broken down into geographical areas, including statewide total costs.

FIGURE 2 Accelerating the 20% Goal Year from 2017 to 2010 Raises Renewable Transmission Costs in 2005 and 2008



The total cumulative cost statewide by 2017 under the SB 1078 schedule is estimated to be $1,799 million as shown in TABLE 2. Accelerating the Goal Year under the Energy Action Plan from 2017 to 2010 would increase the Statewide cost estimate to $1,921 million also shown in TABLE 2. Thus only $118 million or 7% of NPV transmission costs are estimated saved by moving the 20% Goal Year from 2010 under the accelerated EAP to 2017 as contained in the original legislation.

Reaching the 20% Goal in 2010 however, does not require as much infrastructure to be added because overall energy consumption has not yet grown to 2017 levels. FIGURE 1 and TABLE 1 indicated the added 1,350 MW of supply the CEC estimated would be needed by 2017 to maintain the 20% of consumption renewable generation target. Estimated incremental costs between 2010 and 2017 appear by county group in the Tables of the Transmission Plan of Section 2.

TABLE 2

Cost Comparison

Renewable Transmission Additions

Original vs. Accelerated Schedules

Net Present Value

($Millions)

SB 1078 - 20% By 2017

Service Area	Counties	Added for 2005 ($MM)	Added for 2008 ($MM)	Added for 2017 ($MM)	Total for 2017 ($MM)
PG&E	Modoc & Siskiyou	$0	$6	$6	$12
	Solano & Alameda	$35	$101	$8	$144
SCE	Kern & Los Angeles	$0	$809	$357	$1,166
	Mono & San Bernardino	$0	$213	$69	$281
	Riverside & Imperial	$7	$105	$55	$166
SDG&E	San Diego	$0	$19	$11	$29
STATEWIDE		$42	$1,252	$505	$1,799

Accelerated EAP - 20% By 2010

Service Area	Counties	Added for 2005 ($MM)	Added for 2008 ($MM)	Added for 2010 ($MM)	Total for 2010 ($MM)
PG&E	Modoc & Siskiyou	$0	$14	$6	$20
	Solano & Alameda	$44	$101	$0	$145
SCE	Kern & Los Angeles	$0	$821	$352	$1,173
	Mono & San Bernardino	$0	$287	$39	$326
	Riverside & Imperial	$13	$117	$83	$213
SDG&E	San Diego	$0	$19	$17	$36
STATEWIDE		$57	$1,358	$497	$1,912

Facilities Constructed for the Estimated Expenditures

TABLE 3 in three sheets, one for each year shown, summarizes by California county group the actual transmission facilities, lines, transformers, circuit breakers, which the IOUs have identified, corresponding to the expenditures shown in TABLE 2 above. The information is segregated by year of interest, with expenditures under the SB1078 schedule compared to those under the Accelerated Energy Action Plan Schedule, for each year: 2005, 2008, and 2017 or 2010.

TABLE 3 for Year: 2005

TABLE 3

TRANSMISSION FACILITY UPGRADES

To Reach 20% Renewable Energy By Year Shown

2005

SB 1078 Goal: Reach 20% By 2017

County Group	Transmission Line			Substation			
	Item	Voltage (kV)	Total Length (miles)	Item	Number	Voltage (kV)	Total Capacity (MVA)
Modoc & Siskiyou	None			None			
Solano & Alameda	None			Dynamic Reactive Support			130
Kern & Los Angeles	None			None			
Mono & San Bernardino	None			None			
Riverside & Imperial	New Lines	115	10	Circuit Breakers	1	115	N/A
San Diego	None						

Energy Action Plan Accelerated Goal: Reach 20% By 2010

County Group	Transmission Line			Substation			
	Item	Voltage	Total Length (miles)	Item	Number	Voltage (kV)	Total Capacity (MVA)

Same Facilities Required As Those Above

Modoc & Siskiyou
Solano & Alameda
Kern & Los Angeles
Mono & San Bernardino
Riverside & Imperial
San Diego

TABLE 3

TRANSMISSION FACILITY UPGRADES

To Reach 20% Renewable Energy By Year Shown

2008

SB 1078 Goal: Reach 20% By 2017

County Group	Transmission Line			Substation			
	Item	Voltage (kV)	Total Length (miles)	Item	Number	Voltage (kV)	Total Capacity (MVA)
Modoc & Siskiyou	None			Dynamic Reactive Support			40
Solano & Alameda	New Line	230	30	Dynamic Reactive Support			110
Kern & Los Angeles	New Lines	500	95	Transformers	9	500/230	10,080
	New Lines	230	45	Transformers	15	230/66	4200
	New Lines	66 (double circuit)	100	Circuit Breakers	29	500	N/A
	Incease voltage	230 to 500	85	Circuit Breakers	82	230	N/A
				Circuit Breakers	88	66	N/A
				Capacitor Bank	18	230	810
				Capacitor Bank	11	66	319
				Stat Var Comp	1	230	200
Mono & San Bernardino	New Lines	230	125	Transformers	3	230/115	840
	New Lines	115	117	Circuit Breakers	16	230	N/A
				Circuit Breakers	21	115	N/A
				Capacitor Bank	1	230	45
Riverside & Imperial	New Lines	230	50	Circuit Breakers	7	230	N/A
	New Lines	115	10	Circuit Breakers	1	115	N/A
San Diego	New Line	138	35	Connection	1	138	N/A
	Reconductor	138	N/A	Switchyard	1	138	N/A
				Circuit Breakers	8	138	N/A

Energy Action Plan Accelerated Goal: Reach 20% By 2010

County Group	Transmission Line			Substation			
	Item	Voltage (kV)	Total Length (miles)	Item	Number	Voltage (kV)	Total Capacity (MVA)
Facilities Required That Are DIFFERENT FROM Those for 2008 Above							
Modoc & Siskiyou	None			Dynamic Reactive Support			10
Solano & Alameda	None			None			
Kern & Los Angeles	None			None			
Mono & San Bernardino	New Lines	230	174	Circuit Breakers	21	230	N/A
	New Lines	115	127	None			
Riverside & Imperial	None			None			
San Diego	None			None			

TABLE 3
TRANSMISSION FACILITY UPGRADES

To Reach 20% Renewable Energy By Year Shown

GOAL YEAR: 2017 or 2010

SB 1078 Goal: Reach 20% By 2017

County Group	Transmission Line			Substation			
	Item	Voltage (kV)	Total Length (miles)	Item	Number	Voltage (kV)	Total Capacity (MVA)
Modoc & Siskiyou	None			Dynamic Reactive Support			80
Solano & Alameda	None			Dynamic Reactive Support			70
Kern & Los Angeles	New Lines	500	130	Transformers	1	500/230	1120
	New Lines	230	53	Transformers	5	230/66	1400
	New Lines	66	250	Circuit Breakers	7	500	N/A
				Circuit Breakers	22	230	N/A
				Circuit Breakers	29	66	N/A
				Capacitor Bank	6	230	270
				Capacitor Bank	4	66	116
				Series Capacitors	3	500	4500
Mono & San Bernardino	New Lines	230	174	Transformers	1	230/115	280
	New Lines	115	58	Circuit Breakers	14	230	N/A
				Circuit Breakers	6	115	N/A
				Circuit Breakers	4	60	N/A
Riverside & Imperial	New Lines	115	10	Transformers	1	500/230	1120
	Reconductor	230	88	Circuit Breakers	1	115	N/A
San Diego	New Line	138	35	Connections	2	138	N/A
	Reconductor	230	1 Line	Switchyard	1	138	N/A
	Reconductor	138	2 Lines	Transformers	2	138/69	400
	Reconductor	69	3 Lines				

Energy Action Plan Accelerated Goal: Reach 20% By 2010

County Group	Transmission Line			Substation			
	Item	Voltage	Total Length (miles)	Item	Number	Voltage (kV)	Total Capacity (MVA)
Facilities Required for 2010 That Are DIFFERENT FROM Those for 2017							
Modoc & Siskiyou	None			Dynamic Reactive Support			50
Solano & Alameda	None			Dynamic Reactive Support			40
Kern & Los Angeles	None			Transformers	0	500/230	1120
				Circuit Breakers	17	230	N/A
Mono & San Bernardino	New Lines	230	125	Circuit Breakers	9	230	N/A
	New Lines	115	0	Circuit Breakers	3	115	N/A
Riverside & Imperial	New Lines	115	0	Circuit Breakers	0	230	N/A
				Circuit Breakers	0	115	N/A
San Diego	None			None			

VI. CONCLUSIONS

The Legislature's direction in preparing this plan emphasized transmission development for renewable generation in a process that is "orderly, rational and cost-effective." In pursuit of these objectives, this report emphasizes foundational principles for RPS transmission development, describes the CPUC's proposed path to identifying and financing new transmission facilities, and illustrates important potential challenges that may occur. To summarize:

Foundational Principles for RPS Transmission

-*Transmission must be coordinated between IOU service territories, and with the ISO*.

> Treating each service territory in an isolated fashion will add needless cost and inefficiency. Taking a state-level view of total resource needs allows for targeted investment in generation and transmission assets, and for optimal utilization of all renewable potential

-*Coordinated transmission of resource types, and rational displacement of fossil resources, maximizes available capacity on transmission facilities.*

> Where possible, resources should be grouped on a transmission facility to maximize its capacity utilization, and transmission capacity created by the displacement of non-renewable generation should be utilized for RPS purposes.

-*Results of competitive RPS bidding should drive transmission development.*

> The viability of a generation project should be assessed before the cost and disruption of transmission expansion is undertaken.

Identifying and Financing Necessary Facilities

-*The annual RPS procurement plan begins the solicitation process***.**

> Each year's filing identifies needed renewable generation and updates progress to meet the RPS goal.

-*Transmission costs are assessed in the bid ranking process via Least Cost-Best Fit.*

> Either via ISO studies or through a CPUC-approved process, each renewable developer's impact on the transmission system will be known before RPS bids are selected.

-*Recent FERC rulings allow for more options in financing transmission facilities.*

> The CPUC is exploring these options to lessen the financial burden on small renewable generator developers.

Avoiding Pitfalls in RPS Transmission Development

-*Reliance on participant funding creates a "free rider" problem.*

> If the first renewable developer in a resource area must finance the entire cost of a transmission upgrade, all developers will prefer to wait and be second, taking advantage of another developer's investment.

-Developing a transmission finance mechanism that minimizes uneconomic sunk costs.

Directing the IOUs to finance necessary upgrades without assurance of adequate generation in the resource area runs the risk that viable generation developers will not connect to the grid in a timely manner.

-Balancing these concerns with a bid-based "trigger mechanism" may provide a workable solution.

The IOU may ultimately prove to be the best source of transmission funding, but contingent upon the successful bidding of a threshold amount of generation in a new resource area. This should help ensure that transmission investments are utilized and the best resource areas developed first. The precise amount of generation required to trigger this IOU investment – i.e. 40%, 50%, or 60% of resource potential – will be considered at the CPUC, along with other methods to promote efficient transmission development.

SECTION 2

The Transmission Plan

The Renewables Transmission Plan is a High Level Snapshot

CEC Generation Data is Used As a Basis for the Plan

Parties Commented on IOU Transmission Plans at a CPUC Workshop

The Transmission Plan is a High Level Snapshot

This Transmission Plan describes the upgrades to the transmission grid required to accommodate the renewables generation identified by the CEC for the years 2005, 2008, 2017, and for accelerated generation by the year 2010. It is a compilation of individual plans prepared by each of the three principal utilities in California. The specific transmission upgrades are identified by counties for each of the IOUs. The costs associated with each of these transmission upgrades are also compiled and tabulated.

The CPUC considered directing the IOUs to conduct fully detailed transmission line engineering studies including upgrades for both deliverability and reliability. Some reliability upgrades and costing however, were not conducted since specific generating machine data needed for them was not required or provided in the generalized renewable resource data available in the CEC report. In most cases of generator connection to the grid, the cost of the reliability upgrade (for example switchgear) will be small compared to that of the deliverability upgrade (generally the wire).

The results presented are based on assumptions and limitations that Energy Division staff consider reasonable and justifiable. The transmission grid does not differentiate among the types of renewable generation whether geothermal, biomass, wind, or solar. Other factors outside the study scope include:

- Which existing plants the renewable generation will displace (how the renewable generation can be integrated with non-renewable power sources);
- The position of the generation source on the load curve (for example, base loading versus intermittent);
- Whether a source can be dispatched, or its reliability (for example, availability of wind and of operating turbine machinery); and
- Whether it is possible to develop the resources and the necessary transmission in the time frame of the Accelerated Energy Action Plan.

Changes to any of the assumptions or limitations used in the generation plan or information received from the utilities would affect the results of the CPUC staff renewables transmission plan. While recognizing the benefits of future work on the plans of the three IOUs and others, staff accepted the utility information as a reasonable first step in order to prepare its overall transmission plan for the state. Staff presents the diverse utility information in a comparable manner but time precluded further engineering studies. Analytical evaluations or sensitivity studies were outside the scope of the intended transmission plan.

Thus this report is a snapshot in time based on the combined engineering judgment of the CEC, IOUs, merchant generators, and Energy Division staff regarding the transmission upgrades and cost needed to support SB 1078 and the Energy Action Plan.

CEC Generation Data is Used As a Basis for the Plan

Because SB1038 requires both the CEC generation plan and the CPUC transmission plan to be submitted to the Legislature on the same date and because the transmission plan takes as its starting point the generation identified by the CEC, a CPUC administrative law judge, in a ruling issued on February 26, 2003, requested the CEC to "develop a renewables resource assessment and issue a draft assessment by July 1, 2003…"

Accordingly, the CEC issued its "Preliminary Renewable Resource Assessment" on that date and the IOUs and the CPUC proceeded with the formulation of the transmission plan based on the data contained therein. The data included generation scheduled to come on line in the years 2005, 2008, 2017 (intended to fulfill the mandate of SB1078 for 20% of electrical consumption in California to come from renewable resources by 2017) plus an amount of generation greater than the total for 2017, which was designated "remaining potential". The generation required to meet the Energy Action Plan goal of 20% of consumption from renewables by the year 2010 was not given.

In an administrative law judge ruling issued on July 21, 2003, the IOUs were instructed to formulate plans to meet the accelerated schedule in the Energy Action Plan (EAP) in addition to the schedule in SB1078, and to formulate conceptual designs without costs for the "remaining potential" identified by the CEC. On August 29, 2003 the IOUs submitted their draft plans based on these instructions and the CPUC started its preparation of a comprehensive transmission plan for all of California.

On September 30, 2003, the CEC issued a draft final assessment, which differs from the July draft in three essential respects:

- The generation specified to come on line in the years 2005, 2008 and 2017 in the July report covered the renewables requirements of the IOUs only; in the September report these values are increased to cover the requirements of non-IOUs such as publicly owned utilities (municipals) and Electric Service Providers and CCAs, as well as investor owned utilities. The amount of the increase in 2017 is 42%.
- The generation needed to meet the accelerated EAP schedule by 2010 is specified.
- The "remaining potential" generation is no longer listed on the tables with the annual (2005, 2008, and 2017) values.

The CPUC and the IOUs have incorporated the effects of these changes on the transmission requirements while maintaining the schedule for the submittal of the plan to the Legislature. Part of the transmission that had been identified to transmit the CEC "remaining potential" generation is now applied to transmit the greater generation due to transmission of non-IOU required generation.

Parties Commented on IOU Plans

In the February 26, 2003, Ruling in this proceeding the ALJ adopted a process and schedule including a workshop and the submission of written comments following the IOUs' filing of their final renewable transmission plan reports. Accordingly on September 23, 2003, CPUC Staff hosted a workshop at the Commission for parties to present and discuss comments on the transmission plans filed on August 29, 2003, by the three investor-owned utilities PG&E, SCE, and SDG&E.

The following parties presented comments on the IOU studies at the workshop:

- California ISO
- Solargenix
- CEERT (Center for Energy Efficiency and Renewable Technologies)
- Oak Creek
- Vulcan and Silvan Power.

CAISO'S comments come in two parts:
Comments on the IOU August 18th preliminary submittals
CAISO power flow analysis to investigate the effect of the 2017 renewables generation on path flows at California-Oregon intertie (COI), east of river (EOR: Arizona border) and Path 26.

Comments on the IOU August 18th Submittals
Recommends that a study be made to determine the transmission upgrades necessary to meet "resource adequacy", that is, the ordinary non-renewables generation needed to meet load plus reserves, to provide a benchmark for comparison with the renewables generation transmission identified in the IOU plans.
The economic benefits of low-priced renewables generation could offset the renewables generation transmission costs.
Recommends coordination of transmission development between IOUs
Recommends coordination of transmission plans with on-going transmission studies, such as STEP.
Recommends evaluation of a 500kV line from Tehachapi to PG&E's Midway Substation (the same recommendation as made by the Tehachapi developer Oak Creek).
The cost effectiveness of the elements of the transmission plans is not given.
SCE has 39% more renewables than needed to meet its goal. The means for exporting this excess to neighboring utilities should be investigated.

CAISO Power Flow Analysis Results
Maximum flows at COI, EOR and Path 26 do not change appreciably.
Constrained flows in the north-south direction in Path 26 are slightly reduced.
Constrained flows in the south-north direction are increased from 6% to 16%.

Solargenix filed two sets of comments.[15] In its first set, Solargenix commented on SCE's August 29, 2003, filing, but did not raise these issues again at the workshop, instead devoting all its time to SCE's Harper Lake study. Solargenix's comments on SCE's August 29, 2003, filing emphasized that solar development should be concentrated at an identified best geographical location in the state. Doing so would reduce generation costs from gas-assisted solar thermal technology to a range competitive with peaking combustion turbines, and would reduce transmission costs due to scale economies.

At the workshop, Solargenix presented its "point source," gas-assisted solar project north of Lugo at Harper Lake. The project did not appear in the July 1, 2003, Preliminary Renewable Resource Assessment by the CEC, on which SCE and all IOU renewable transmission plans are based.

Solargenix states that its project is to be developed in three phases, topping out at 1000MW in 2017, although the schedule could be accelerated to meet the Energy Action Plan goal for the year 2010. The site has great insolation (90% of US maximum) and produces 5MW per acre with a 23 to 27% capacity factor. Solargenix stated it has secured land and water rights for the project and the site has multiple gas lines nearby. It believes its interconnection cost is lower than average and the energy price is competitive with combustion turbines. Solargenix urged the CPUC to include its project in its report to the legislature.

CEERT provided a comprehensive critique of the IOU studies. Specifically, CEERT stated:

- SCE and PG&E transmission plans are fatally flawed and cannot be used to estimate RPS bid adders.
- Alternative plans with different assumptions and grid enhancements must be considered to achieve best statewide solutions.
- Plans are based on the assumption that existing generation displaced by renewables generation is located at the load centers, whereas if the displaced generation were located outside the load centers the freed-up transmission capacity could be used by the renewables generation.
- SCE assumes all the renewables generation in its service area would be used in its area, ignoring the PG&E market.
- SCE and PG&E plans represent unrealistic worst-case scenarios with highest costs; plans have no coordination with each other or with non-IOU transmission line owners and fail to consider grid on a statewide basis.
- Utility assumptions regarding dispatch decisions and load center reliability requirements should be checked.
- Alternatives that accommodate flows of renewable energy between IOU service territories should be identified and considered. Non-IOU transmission owners

[15] Solargenix filed comments on September 16, 2003, which included comments on the August 29, 2003, filings at the CPUC as well as comments on the IOUs presentations made on August 18, 2003, at the ISO regarding their upcoming filings at the CPUC. Solargenix filed a second set on September 24, 2003, attaching SCE's 34-page transmission study of Solargenix's proposal for generation at Harper Lake.

should be brought into the discussion. Alternatives that provide system benefits in addition to renewable access should be identified and given priority.

- A joint agency approach involving the CPUC, CEC, and CAISO should be used in transmission planning.

The IOUs responded to the criticism by pointing out that the CPUC administrative law judge ruled that transmission adders would not be developed based on these reports for the renewables generation procurement process.

Oak Creek

Oak Creek's position is very close to that of CEERT, but focused on Tehachapi.

- Proposed that a 500kV line be built from Vincent to Tehachapi to Magunden to Midway. This line would relieve Path 26 congestion as well as transmit Tehachapi wind generation.
- Proposed making use of LADWP's 230kV line out of Rinaldi.
- Said that some of Tehachapi power should go into PG&E's system.

Vulcan and Silvan Power

Described four "Green Line" projects, two north and two south of Path 15. On November 20, 2003, Vulcan emailed additional material including five pages attached here as Appendix B.

Vulcan states it suggested another transmission planning meeting was needed as did others at the meeting. Vulcan agreed with CEERT that alternative renewable transmission plans with different assumptions and grid enhancements must be considered.

Vulcan, a geothermal developer, and Silvan Power its biomass subsidiary presented four transmission plans designed to provide in the aggregate up to 1,500 MW of baseload power to California from a variety of aggregated in-state and near-border sites. The projects vary in cost from about $ 28 million to about $ 365 million each and in the aggregate about $ 530 million for 1,500 MW or more of new baseload transmission.

Vulcan commented it is important that as transmission options are compared that wind will cost about three times as much per unit output as baseload, all other things being equal due to the intermittent nature of wind. Three of the transmission options appear very cost effective compared to other known options. It mentioned wildfire risk reduction benefits of biomass power and the low visibility aspects of baseload geothermal.

Vulcan states it presented plans utilizing data provided from an SCE conceptual study named North of Lugo and a PG&E conceptual study named North of Cottonwood. Both of those studies were provided in full to the CEC.

Transmission policy planners should consider the two SP 15 transmission plans as alternatives for planning consideration. Both are not needed. They inform the planning process with available planning choices and cost estimates not otherwise included.

1. TRANSMISSION PLAN FOR MODOC & SISKIYOU COUNTIES

REGION & RESOURCES

Modoc & Siskiyou Counties are located in the northeast and northwest corners of the state, respectively. The renewable resources identified by the CEC in the area consist of 105 MW of geothermal in Modoc County and 190 MW of geothermal in Siskiyou County.

Maps 1-1 and 1-2 show renewable resources in Modoc and Siskiyou Counties and transmission upgrades, respectively. The generation capacity of these resources and the dates they could come on line are tabulated in Table 1-1.

AREA-SPECIFIC CHARACTERISTICS

The area is partially served by PG&E. The northern California region is rural, national forest lands and sparely populated. Geothermal resources in Modoc County are assumed connected to the 230kV bus at Round Mountain Substation and geothermal resources in Siskiyou County are connected to the 230kV bus at Cottonwood Substation. No environmental impact is expected if all reactive support devices can be located within the existing substations.

TRANSMISSION ADDITIONS

The transmission additions required to accommodate the renewable resource generation through 2017 consist of dynamic reactive supports at Cottonwood and Vaca-Dixon substations. Accelerating the Renewable Transmission from 2017 to 2010 would require dynamic reactive support at Cottonwood, Cortina, and Vaca-Dixon substations at slightly different amounts. The additions for the SB1078 schedule are tabulated for each year with corresponding costs on Table 1-A with costs in 2003 dollars and Table 1-B with net present value (NPV) costs. The additions for the EAP schedule are tabulated for each year with corresponding costs on Table 1-C with NPV costs. Where the cost range is shown, the median and percent spread are shown as well.

MAP 1-1

Renewable Resources in Modoc County

MAP 1-2
Renewable Resources in Siskiyou County

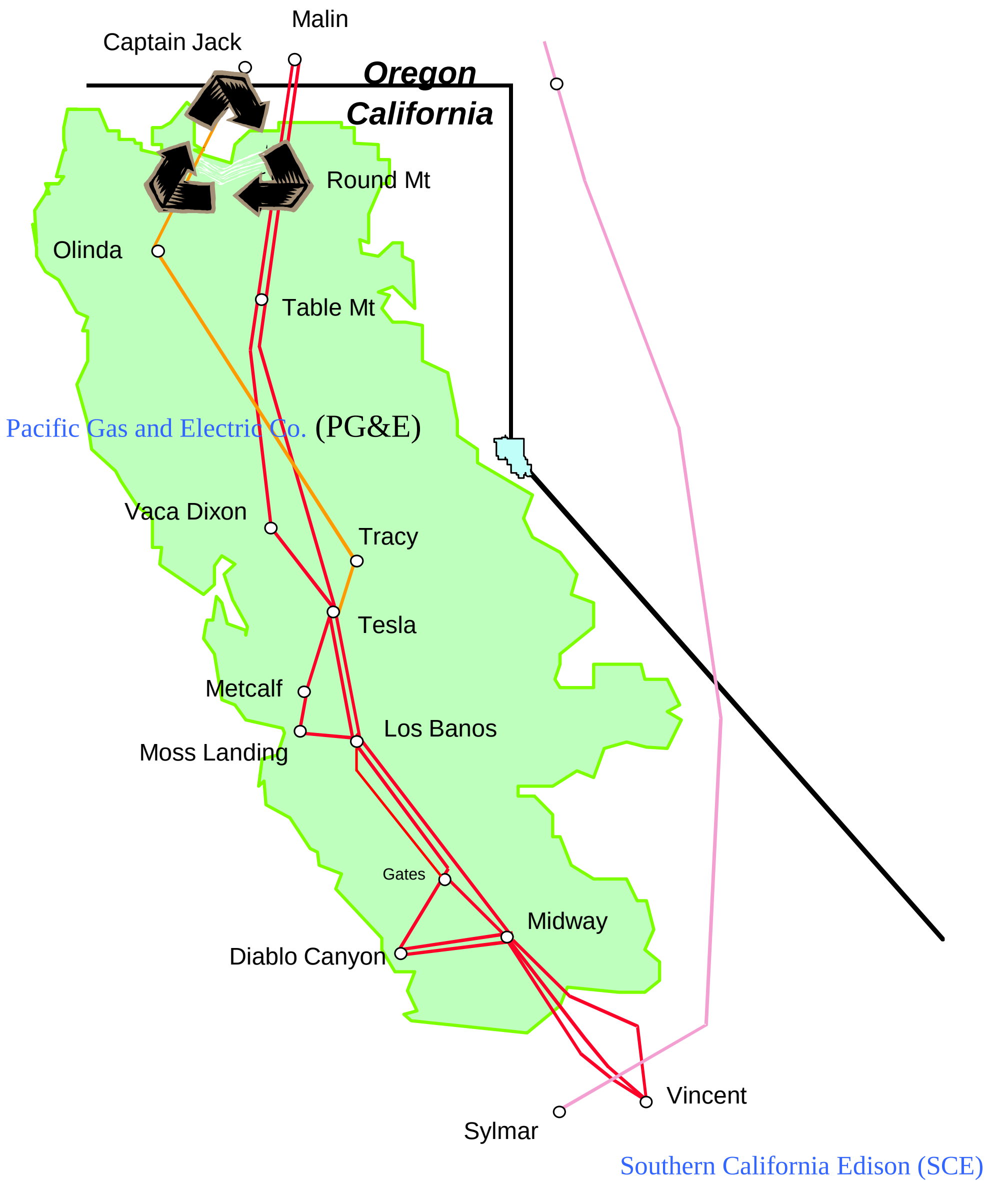


TABLE 1

RENEWABLE RESOURCE

GENERATION

MEGAWATTS (MW)

MODOC & SISKIYOU COUNTIES

SB 1078 Schedule

COUNTY	TYPE OF GENERATION	YEAR					
		Added 2005	Added 2008	Added 2010	Total 2010	Added 2017	Total 2017
Modoc	geothermal	0	0	N/A	N/A	105	105
Siskiyou	geothermal	0	100	N/A	N/A	90	190

Accelerated EAP Schedule

COUNTY	TYPE OF GENERATION	YEAR					
		Added 2005	Added 2008	Added 2010	Total 2010	Added 2017	Total 2017
Modoc	geothermal	0	15	15	30	75	105
Siskiyou	geothermal	0	100	30	130	60	190

TABLE 1-A

TRANSMISSION ADDITIONS

MODOC & SISKIYOU COUNTIES

SB1078 SCHEDULE 2003 DOLLARS

YEAR	TRANSMISSION LINES						SUBSTATIONS		TOTAL
	ACTION	TERMINAL A	TERMINAL B	MILES	VOLTAGE (KV)	COST (K$)	ACTION	COST (K$)	COST (K$)
Added 2005	NONE					0	NONE	$0	$0
								TOTAL	$0
Added 2008	NONE						40 MVAR NEW DYNAMIC REACTIVE SUPPORT AT ROUND MOUNTAIN	$10,000	$10,000
								TOTAL	$10,000
Added 2017	NONE						80 MVAR NEW DYNAMIC REACTIVE SUPPORT AT COTTONWOOD	$20,000	$20,000
								TOTAL	$20,000
								TOTAL	**$30,000**

TABLE 1-B

TRANSMISSION ADDITIONS

MODOC & SISKIYOU COUNTIES

SB1078 SCHEDULE NPV DOLLARS

YEAR	TRANSMISSION LINES						SUBSTATIONS		TOTAL
	ACTION	TERMINAL A	TERMINAL B	MILES	VOLTAGE (KV)	COST (K$)	ACTION	COST (K$)	COST (K$)
Added2 005	NONE					0	NONE	$0	$0
								TOTAL	$0
Added 2008	NONE						+40,-30 MVAR NEW DYNAMIC REACTIVE SUPPORT AT COTTONWOOD	$7,198	$7,198
								TOTAL	$7,198
Added 2017	NONE						+80,-60 MVAR NEW DYNAMIC REACTIVE SUPPORT AT VACA-DIXON	$7,966	$7,966
								TOTAL	$7,966
								TOTAL	$15,164

TABLE 1-C

TRANSMISSION ADDITIONS

MODOC & SISKIYOU COUNTIES

EAP ACCELERATED SCHEDULE NPV DOLLARS

YEAR	TRANSMISSION LINES						SUBSTATIONS		TOTAL
	ACTION	TERMINAL A	TERMINAL B	MILES	VOLTAGE (KV)	COST (K$)	ACTION	COST (K$)	COST (K$)
Added2 005	NONE					0	NONE	$0	$0
								TOTAL	$0
Added 2008	NONE						+40,-25 MVAR NEW DYNAMIC REACTIVE SUPPORT AT COTTONWOOD [Note 1]	$7,198	$7,198
							+10,-5 MVAR NEW DYNAMIC REACTIVE SUPPORT AT CORTINA [Note 1]	$7,198	$7,198
								TOTAL	$14,397
Added 2010	NONE						+20,-10 MVAR NEW DYNAMIC REACTIVE SUPPORT AT VACA-DIXON [Note 1]	$6,311	$6,311
								TOTAL	$6,311
Added 2017	NONE						+20,-10 MVAR NEW DYNAMIC REACTIVE SUPPORT AT VACA-DIXON [Note 1]	$3,983	$3,983
								TOTAL	$3,983
								TOTAL	$24,691

Notes:
1. Estimated cost in 2003 dollars is $10,000,000.

2. TRANSMISSION PLAN FOR SOLANO & ALAMEDA COUNTIES

REGION & RESOURCES

Solano and Alameda Counties are located in the San Francisco Bay Area of the state. The renewable resources identified by the CEC in the area consist of wind in both counties. The two counties possibly have the greatest concentration of developed wind generation in Northern California.

Maps 2-1 and 2-2 show the renewable resources in Solano and Alameda Counties and transmission upgrades, respectively. The generation capacity of these resources and the dates they could come on line are tabulated in Table 2-1.

AREA-SPECIFIC CHARACTERISTICS

The area is mainly served by PG&E. The northern California region is urban with open green belt, range land, developed, commercial areas and has concentrations of population in suburbs. Wind resources in Solano are assumed connected to 230kV buses at Vaca–Dixon Substation and those in Alameda are connected to the 230kV bus at Tesla Substation. Although environmental impact is expected to be minor, some of the transmission routes would require some form of environmental mitigation.

TRANSMISSION ADDITIONS

The transmission additions required to accommodate the renewable resource generation through 2017 consist of two upgrades: 1) A new 30 mile long 230kV line would be built from Vaca-Dixon to the Contra Costa Power Plant Switchyard. 2) Reactive support devices would need to be installed at the respective substations of Vaca-Dixon, Tesla, Lakeville, San Mateo, Ravenswood, Monta Vista, and Ignacio. Accelerating the Renewable Transmission from 2017 to 2010 would require a slight change of reactive support. The additions for the SB1078 schedule are tabulated for each year with corresponding costs on Table 2-A with costs in 2003 dollars and Table 2-B with net present value (NPV) costs. The additions for the EAP schedule are tabulated for each year with corresponding costs on Table 2-C with NPV costs. Where the cost range is shown, the median and percent spread are shown as well.

MAP 2-1
Renewable Resources in Solano County

MAP 2-2
Renewable Resources in Alameda County

TABLE 2

RENEWABLE RESOURCE

GENERATION

MEGAWATTS (MW)

SOLANO & ALAMEDA COUNTIES

SB 1078 Schedule

COUNTY	TYPE OF GENERATION	YEAR					
		Added 2005	Added 2008	Added 2010	Total 2010	Added 2017	Total 2017
Solano	wind	215	100	N/A	N/A	85	400
Alameda	wind	50	110	N/A	N/A	50	210

Accelerated EAP Schedule

COUNTY	TYPE OF GENERATION	YEAR					
		Added 2005	Added 2008	Added 2010	Total 2010	Added 2017	Total 2017
Solano	wind	315	85	0	400	0	400
Alameda	wind	50	135	5	190	20	210

TABLE 2-A

TRANSMISSION ADDITIONS

SOLANO & ALAMEDA COUNTIES

SB1078 SCHEDULE 2003 DOLLARS

YEAR	TRANSMISSION LINES						SUBSTATIONS		TOTAL
	ACTION	TERMINAL A	TERMINAL B	MILES	VOLTAGE (KV)	COST (K$)	ACTION	COST (K$)	COST (K$)
Added 2005	NONE						+25,-20 MVAR NEW DYNAMIC REACTIVE SUPPORT AT LAKEVILLE	$10,000	$10,000
							+25,-20 MVAR NEW DYNAMIC REACTIVE SUPPORT AT IGNACIO	$10,000	$10,000
							+50,-40 MVAR NEW DYNAMIC REACTIVE SUPPORT AT TESLA	$10,000	$10,000
							+30,-20 MVAR NEW DYNAMIC REACTIVE SUPPORT AT NEWARK	$10,000	$10,000
								TOTAL	$40,000
Added 2008	NEW LINE	VACA-DIXON	CONTRA COSTA	30	230	$80,000-$140,000			$80,000-$140,000
							+40,-30 MVAR NEW DYNAMIC REACTIVE SUPPORT AT TESLA	$10,000	$10,000
							+70,-50 MVAR NEW DYNAMIC REACTIVE SUPPORT AT SAN MATEO	$20,000	$20,000
								TOTAL	$110,000-$170,000
								Median +/- 18%	$140,000
Added 2017							+30,-20 MVAR NEW DYNAMIC REACTIVE SUPPORT AT RAVENSWOOD	$10,000	$10,000
							+40,-30 MVAR NEW DYNAMIC REACTIVE SUPPORT AT MONTA VISTA	$10,000	$10,000
								TOTAL	$20,000
								TOTAL	**$200,000**

TABLE 2-B

TRANSMISSION ADDITIONS

SOLANO & ALAMEDA COUNTIES

SB1078 SCHEDULE NPV DOLLARS

YEAR	TRANSMISSION LINES						SUBSTATIONS		TOTAL
	ACTION	TERMINAL A	TERMINAL B	MILES	VOLTAGE (KV)	COST (K$)	ACTION	COST (K$)	COST (K$)
Added 2005	NONE					0	+25,-20 MVAR NEW DYNAMIC REACTIVE SUPPORT AT LAKEVILLE	$8,768	$8,768
							+25,-20 MVAR NEW DYNAMIC REACTIVE SUPPORT AT IGNACIO	$8,768	$8,768
							+50,-40 MVAR NEW DYNAMIC REACTIVE SUPPORT AT TESLA	$8,768	$8,768
							+30,-20 MVAR NEW DYNAMIC REACTIVE SUPPORT AT NEWARK	$8,768	$8,768
								TOTAL	$35,071
Added 2008	NEW LINE	VACA-DIXON	CONTRA COSTA	30	230	$57,585-$100,775			$57,585-$100,775
							+40,-30 MVAR NEW DYNAMIC REACTIVE SUPPORT AT TESLA	$7,198	$7,198
							+70,-50 MVAR NEW DYNAMIC REACTIVE SUPPORT AT SAN MATEO	$14,397	$14,397
								TOTAL	$79,180-$122,370
								Median +/- 20%	$100,775
Added 2017							+30,-20 MVAR NEW DYNAMIC REACTIVE SUPPORT AT RAVENSWOOD	$3,983	$3,983
							+40,-30 MVAR NEW DYNAMIC REACTIVE SUPPORT AT MONTA VISTA	$3,983	$3,983
								TOTAL	$7,966
								TOTAL	**$143,812**

TABLE 2-C

TRANSMISSION ADDITIONS

SOLANO & ALAMEDA COUNTIES

EAP ACCELERATED SCHEDULE NPV DOLLARS

YEAR	TRANSMISSION LINES						SUBSTATIONS		TOTAL
	ACTION	TERMINAL A	TERMINAL B	MILES	VOLTAGE (KV)	COST (K$)	ACTION	COST (K$)	COST (K$)
Added 2005	NONE						+35,-28 MVAR NEW DYNAMIC REACTIVE SUPPORT AT LAKEVILLE [Note 1]	$8,768	$8,768
							+35,-28 MVAR NEW DYNAMIC REACTIVE SUPPORT AT IGNACIO [Note 1]	$8,768	$8,768
							+70,-54 MVAR NEW DYNAMIC REACTIVE SUPPORT AT TESLA [Note 2]	$17,535	$17,535
							+30,-20 MVAR NEW DYNAMIC REACTIVE SUPPORT AT NEWARK [Note 1]	$8,768	$8,768
								TOTAL	$43,838
Added 2008	NEW LINE	VACA-DIXON	CONTRA COSTA	30	230	$57,585-$100,775			$57,585-$100,775
							+30,-20 MVAR NEW DYNAMIC REACTIVE SUPPORT AT NEWARK [Note 1]	$7,198	$7,198
							+70,-50 MVAR NEW DYNAMIC REACTIVE SUPPORT AT SAN MATEO [Note 2]	$14,397	$14,397
								TOTAL	$79,180-$122,370
								Median +/- 18%	$100,775
Added 2010	NONE					0	NONE	$0	$0
Total 2010								**TOTAL**	$0
Added 2017	NONE					0	+40,-30 MVAR NEW DYNAMIC REACTIVE SUPPORT AT MONTA VISTA [Note 1]	$3,983	$3,983
								TOTAL	$3,983
								TOTAL	**$148,596**

Notes:
1. Estimated cost in 2003 dollars is $10,000,000.
2. Estimated cost in 2003 dollars is $20,000,000.

3. TRANSMISSION PLAN FOR KERN & LOS ANGELES COUNTIES

REGION & RESOURCES

Kern County is located just to the north of Los Angeles County, whose principal city is Los Angeles. In Kern County are located the Tehachapi Mountains, which are the source of the largest wind generation potential in the state. Approximately 4000 MW plus 400 MW of wind power nearby in Los Angeles County have been identified for development by 2017. This power would be transmitted to Los Angeles.

Wind power is intermittent (available only when the wind blows) and consequently non-dispatchable; that is, the CAISO system operator cannot call upon this source in time of need. On the contrary, when using wind power, large reserves of other types generation must be kept available in case the wind stops blowing. Therefore, how much of the 4500 total megawatts would be procured under competitive bidding on the basis of the SB1078 criterion of "least cost, best fit" is not known. Nonetheless, the transmission plan presented herein accommodates the full amount identified by the CEC.
Map 3 shows the general area covered by this section. The capacity of the resource for each of the dates it could come on line is tabulated in Table 3-1.

AREA-SPECIFIC CHARACTERISTICS

The Tehachapi Mountains are close to the load center, Los Angeles, and near a major transmission hub, the Vincent substation, to which terminate five 500kV and seven 230kV transmission lines. The area is served by SCE, but there are two nearby 230kV transmission lines not owned by SCE: one by a qualifying facility (privately owned generation) and the other by the LADWP.

TRANSMISSION ADDITIONS

On the basis of the CEC's July 1 assessment of 3000MW at Tehachapi, SCE evaluated two options for delivery of the power: the first makes use of 230kV transmission lines between the new facilities at Tehachapi and the existing substations in the area; the second uses 500kV transmission lines. On the basis of both 2003 costs added arithmetically over 14 years and in terms of net present value of escalated costs discounted to 2003, the two options are very close. However, based on the revised assessment of 4100 MW from Tehachapi and 400 MW from Los Angeles County, the 500kV option is required.

The transmission additions required to deliver Tehachapi and Los Angeles County wind power in 2017 consist of:

- 66kV collector lines that connect the generators' 66kV substations to the utility's 66/230kV step-up substations
- Five 66/230kV step-up substations.
- Two 66/230/500kV step-up substations

- Three 500kV transmission lines with series compensation from Tehachapi to existing substations on the grid.
- Four 500kV transmission lines within the grid.

The development of the transmission is shown on Figures 3-1 and 3-2 for the years 2008 and 2017 under the SB 1078 development schedule and Figure 3-3 for the year 2010 under the EAP accelerated schedule. The transmission additions are tabulated for each year with corresponding costs on Table 3-A, with costs in 2003 dollars, and Tables 3-B and 3-C with net present value costs for the SB1078 schedule and the EAP accelerated schedule, respectively.

MAP 3

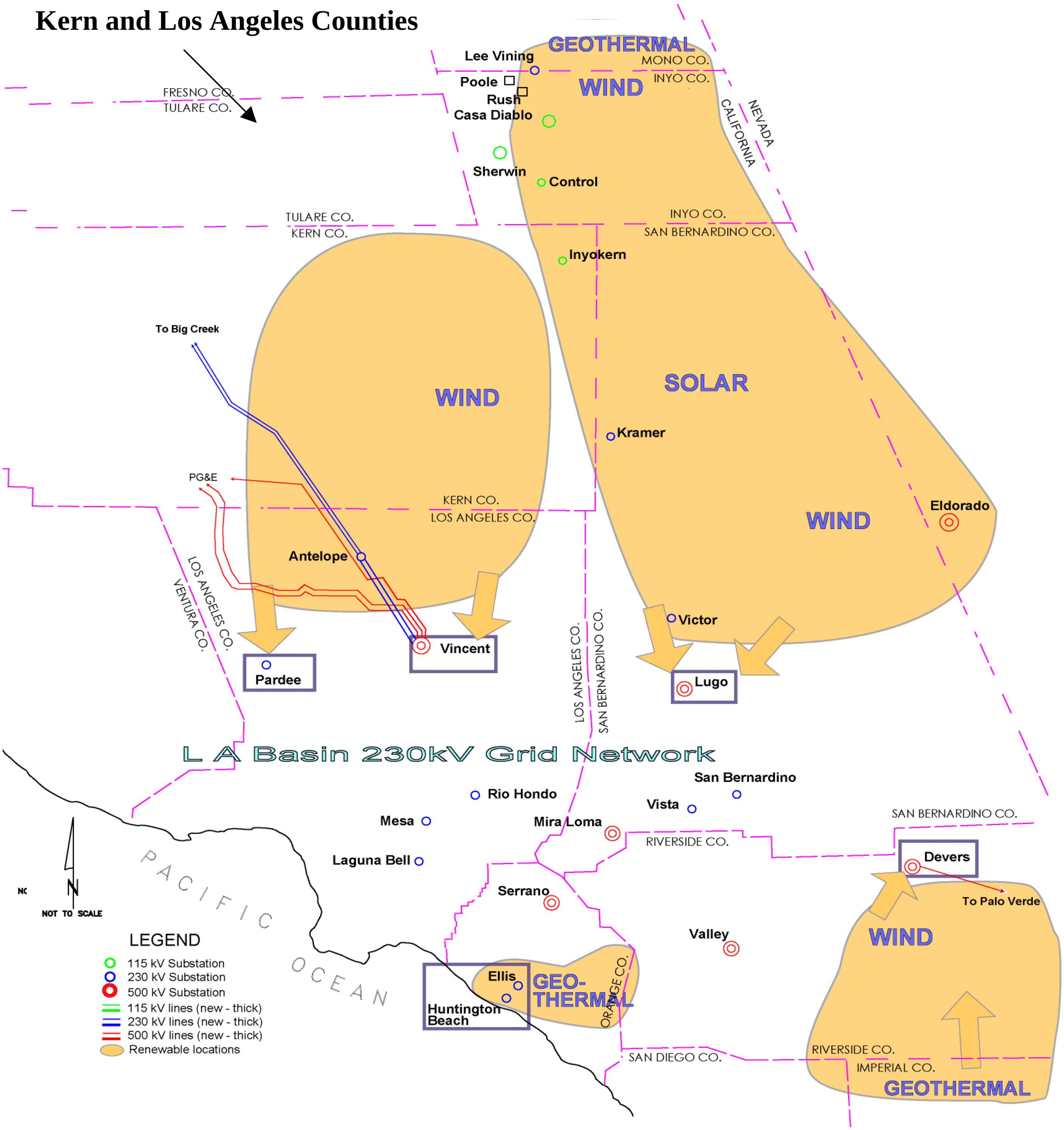

Kern and Los Angeles Counties
GEOTHERMAL
MONO CO.
INYO CO.
WIND
Lee Vining
Poole
Rush
Casa Diablo
Sherwin
Control
FRESNO CO.
TULARE CO.
NEVADA
CALIFORNIA
TULARE CO.
KERN CO.
INYO CO.
SAN BERNARDINO CO.
Inyokern
To Big Creek
WIND
SOLAR
Kramer
PG&E
KERN CO.
LOS ANGELES CO.
WIND
Eldorado
Antelope
LOS ANGELES CO.
VENTURA CO.
Victor
Vincent
Pardee
LOS ANGELES CO.
SAN BERNARDINO CO.
Lugo
L A Basin 230kV Grid Network
San Bernardino
Rio Hondo
Vista
Mesa
Mira Loma
SAN BERNARDINO CO.
RIVERSIDE CO.
Laguna Bell
Devers
To Palo Verde
NOT TO SCALE
PACIFIC
Serrano
WIND
LEGEND
115 kV Substation
230 kV Substation
500 kV Substation
115 kV lines (new - thick)
230 kV lines (new - thick)
500 kV lines (new - thick)
Renewable locations
OCEAN
Valley
Ellis
GEO-THERMAL
ORANGE CO.
Huntington Beach
SAN DIEGO CO.
RIVERSIDE CO.
IMPERIAL CO.
GEOTHERMAL

TABLE 3

RENEWABLE RESOURCE

GENERATION

MEGAWATTS (MW)

KERN & LOS ANGELES COUNTIES

SB 1078 Schedule

COUNTY	TYPE OF GENERATION	YEAR					
		Added 2005	Added 2008	Added 2010	Total 2010	Added 2017	Total 2017
KERN	WIND	285	1410	N/A	N/A	2365	4060
LOS ANGELES	WIND	100	0	N/A	N/A	315	415

Accelerated EAP Schedule

COUNTY	TYPE OF GENERATION	YEAR					
		Added 2005	Added 2008	Added 2010	Total 2010	Added 2017	Total 2017
KERN	WIND	395	1910	1425	3730	330	4060
LOS ANGELES	WIND	100	35	0	135	280	415

TABLE 3-A

TRANSMISSION ADDITIONS

KERN & LOS ANGELES COUNTIES

SB1078 SCHEDULE 2003 DOLLARS

YEAR	TRANSMISSION LINES						SUBSTATIONS		TOTAL
	ACTION	TERMINAL A	TERMINAL B	MILES	VOLTAGE (KV)	COST (K$)	ACTION	COST (K$)	COST (K$)
2005						0			0
								TOTAL	$0
2008	COLLECTOR SYSTEM	WIND FARM SUBSTATIONS	TEHACHAPI SUBSTATIONS	100 DOUBLE CIRCUIT	66	67,300			67,300
	NEW LINE (ANTELOPE-TEHACHAPI #1)	PARDEE SUBSTATION	TEHACHAPI SUBSTATION 1 (VIA ANTELOPE JUNCTION)	60	500	92,700	PARDEE SUBSTATION: TWO 500KV BREAKER & 1/2 CIRCUIT BREAKER POSITIONS (6 BREAKERS); TWO 1120MVA, 500/230KV TRANSFORMERS; TWO 230KV DOUBLE BREAKER CIRCUIT BREAKER POSITIONS (5 BREAKERS); TWO 79MVAR, 230KV CAPACITOR BANKS	68,600	161,300
	NEW LINE (ANTELOPE-TEHACHAPI #2)	ANTELOPE JUNCTION	TEHACHAPI SUBSTATION 1	35	500	46,600	TEHACHAPI SUBSTATION 1: FOUR 500KV BREAKER & 1/2 CIRCUIT BREAKER POSITIONS (10 BREAKERS); FOUR 1120MVA, 500/230KV TRANSFORMERS; EIGHT 230KV BREAKER & 1/2 CIRCUIT BREAKER POSITIONS (27 BREAKERS); SIX 45MVAR, 230KV CAPACITOR BANKS; ONE 200MVAR 230KV SVC; FOUR 280MVA, 230/66KV TRANSFORMERS; EIGHT 66KV BREAKER & 1/2 CIRCUIT BREAKER POSITIONS (29 BREAKERS); FOUR 66KV, 29MVAR CAPACITOR BANKS	276,500	323,100
	UPGRADE EXISTING 230KV LINES	ANTELOPE JUNCTION	VINCENT SUBSTATION	20	500	79,200	VINCENT SUBSTATION: TWO 500KV BREAKER & 1/2 CIRCUIT BREAKER POSITIONS (5 BREAKERS)	15,200	94,400

YEAR	TRANSMISSION LINES						SUBSTATIONS		TOTAL
	ACTION	TERMINAL A	TERMINAL B	MILES	VOLTAGE (KV)	COST (K$)	ACTION	COST (K$)	COST (K$)
	NEW LINE	ANTELOPE JUNCTION	TEHACHAPI SUBSTATION 6	5	230	4,100	TEHACHAPI SUBSTATION 6: TWO 230KV BREAKER & 1/2 CIRCUIT BREAKER POSITIONS (6 BREAKERS); TWO 280MVA, 230/66KV TRANSFORMERS; TWO 45MVAR, 230KV CAPACITOR BANKS; TWO 66KV BREAKER & 1/2 CIRCUIT BREAKER POSITIONS (6	39,700	43,800
	NEW LINE	TEHACHAPI SUBSTATION 1	TEHACHAPI SUBSTATION 2	10	230	18,200	TEHACHAPI SUBSTATION 2: FOUR 230KV BREAKER & 1/2 CIRCUIT BREAKER POSITIONS (12 BREAKERS); THREE 280MVA, 230/66KV TRANSFORMERS; TWO 45MVAR, 230KV CAPACITOR BANKS; FIVE 66KV BREAKER & 1/2 CIRCUIT BREAKER POSITIONS (18 BREAKERS); THREE 66KV, 29MVAR CAPACITOR BANKS	55,800	74,000
	UPGRADE EXISTING 230KV LINES	VINCENT SUBSTATION	RIO HONDO SUBSTATION	32	500	65,300	RIO HONDO SUBSTATION: THREE 500KV BREAKER & 1/2 CIRCUIT BREAKER POSITIONS (8 BREAKERS); THREE1120MVA, 500/230KV TRANSFORMERS; FIVE 230KV BREAKER & 1/2 CIRCUIT BREAKER POSITIONS (13 BREAKERS)	88,800	154,100
	UPGRADE EXISTING 230KV LINE	PARDEE SUBSTATION	VINCENT SUBSTATION	33	500	900			900
	NEW LINE	TEHACHAPI SUBSTATION 1	TEHACHAPI SUBSTATION 4	10	230	19,100	TEHACHAPI SUBSTATION 4: FIVE 230KV BREAKER & 1/2 CIRCUIT BREAKER POSITIONS (16 BREAKERS); FOUR 280MVA, 230/66KV TRANSFORMERS; FOUR 45MVAR, 230KV CAPACITOR BANKS; EIGHT 66KV BREAKER & 1/2 CIRCUIT BREAKER POSITIONS (29 BREAKERS); FOUR 66KV, 29MVAR CAPACITOR BANKS	69,800	88,900
	NEW LINE	TEHACHAPI SUBSTATION 1	TEHACHAPI SUBSTATION 5	20	230	35,900	TEHACHAPI SUBSTATION 5: TWO 230KV BREAKER & 1/2 CIRCUIT BREAKER POSITIONS (6 BREAKERS); TWO 280MVA, 230/66KV TRANSFORMERS; TWO 45MVAR, 230KV CAPACITOR BANKS; TWO 66KV BREAKER & 1/2 CIRCUIT BREAKER POSITIONS (6	41,800	77,700
								TOTAL	$1,085,500

YEAR	TRANSMISSION LINES						SUBSTATIONS		TOTAL
	ACTION	TERMINAL A	TERMINAL B	MILES	VOLTAGE (KV)	COST (K$)	ACTION	COST (K$)	COST (K$)
2017/ 2010	COLLECTOR SYSTEM	WIND FARM SUBSTATIONS	TEHACHAPI SUBSTATIONS	250 DOUBLE CIRCUIT	66	87,400			87,400
	NEW LINE	TEHACHAPI SUBSTATION 2	TEHACHAPI SUBSTATION 4	15	230	28,500			28,500
	NEW LINE	TEHACHAPI SUBSTATION 4	TEHACHAPI SUBSTATION 3	38	230	43,900	TEHACHAPI SUBSTATION 3: THREE 230KV BREAKER & 1/2 CIRCUIT BREAKER POSITIONS (9 BREAKERS); THREE 280MVA, 230/66KV TRANSFORMERS; FOUR 45MVAR, 230KV CAPACITOR BANKS; FIVE 66KV BREAKER & 1/2 CIRCUIT BREAKER POSITIONS (18 BREAKERS)	51,700	95,600
	NEW LINE	VINCENT SUBSTATION	TEHACHAPI SUBSTATION 4	60	500	54,900	VINCENT SUBSTATION: ADD ONE 500KV BREAKER & 1/2 CIRCUIT BREAKER POSITION (2 BREAKERS)	22,900	77,800
							TEHACHAPI SUBSTATION 4: ADD ONE 500KV BREAKER & 1/2 CIRCUIT BREAKER POSITIONS (3 BREAKERS); ONE 1120MVA, 500/230KV TRANSFORMER; ONE 230KV BREAKER & 1/2 CIRCUIT BREAKER POSITION (2 BREAKERS)	206,600	206,600
	NEW LINE	VINCENT SUBSTATION	STAGECOACH SUBSTATION	70	500	109,900	STAGECOACH SUBSTATION: ADD ONE 500KV BREAKER & 1/2 CIRCUIT BREAKER POSITION (2 BREAKERS)	22,900	132,800
	LOOP SUB 2 TO SUB 4 230KV LINES INTO NEW SUBSTATION	TEHACHAPI SUBSTATION 7	TEHACHAPI SUBSTATION 7		230		TEHACHAPI SUBSTATION 7: FOUR 230KV BREAKER & 1/2 CIRCUIT BREAKER POSITIONS (11 BREAKERS); TWO 280MVA, 230/66KV TRANSFORMERS; TWO 45MVAR, 230KV CAPACITOR BANKS; THREE 66KV BREAKER & 1/2 CIRCUIT BREAKER POSITIONS (11 BREAKERS); FOUR 29MVA, 66KV CAPACITOR BANKS	69,800	69,800
	SERIES COMPENSATION	PARDEE SUBSTATION	TEHACHAPI SUBSTATION 1		500	36,600			36,600
	SERIES COMPENSATION	VINCENT SUBSTATION	TEHACHAPI SUBSTATION 1		500	36,600			36,600
	SERIES COMPENSATION	VINCENT SUBSTATION	TEHACHAPI SUBSTATION 4		500	36,600			36,600
								TOTAL	$808,300
							TOTAL FOR PROJECT: 2005, 2008, 2017		$1,893,800

TABLE 3-B

TRANSMISSION ADDITIONS

KERN & LOS ANGELES COUNTIES

SB1078 SCHEDULE NPV DOLLARS

YEAR	TRANSMISSION LINES						SUBSTATIONS		TOTAL
	ACTION	TERMINAL A	TERMINAL B	MILES	VOLTAGE (KV)	COST (K$)	ACTION	COST (K$)	COST (K$)
2005						0		**TOTAL**	0 $0
2008	COLLECTOR SYSTEM	WIND FARM SUBSTATIONS	TEHACHAPI SUBSTATIONS	100 DOUBLE CIRCUIT	66	51,300			51,300
	NEW LINE (ANTELOPE-TEHACHAPI #1)	PARDEE SUBSTATION	TEHACHAPI SUBSTATION 1 (VIA ANTELOPE JUNCTION)	60	500	75,600	PARDEE SUBSTATION: TWO 500KV BREAKER & 1/2 CIRCUIT BREAKER POSITIONS (6 BREAKERS); TWO 1120MVA, 500/230KV TRANSFORMERS; TWO 230KV DOUBLE BREAKER CIRCUIT BREAKER POSITIONS (5 BREAKERS); TWO 79MVAR, 230KV CAPACITOR BANKS	52,300	127,900
	NEW LINE (ANTELOPE-TEHACHAPI #2)	ANTELOPE JUNCTION	TEHACHAPI SUBSTATION 1	35	500	39,200	TEHACHAPI SUBSTATION 1: FOUR 500KV BREAKER & 1/2 CIRCUIT BREAKER POSITIONS (10 BREAKERS); FOUR 1120MVA, 500/230KV TRANSFORMERS; EIGHT 230KV BREAKER & 1/2 CIRCUIT BREAKER POSITIONS (27 BREAKERS); SIX 45MVAR, 230KV CAPACITOR BANKS; ONE 200MVAR 230KV SVC; FOUR 280MVA, 230/66KV TRANSFORMERS; EIGHT 66KV BREAKER & 1/2 CIRCUIT BREAKER POSITIONS (29 BREAKERS); FOUR 66KV, 29MVAR CAPACITOR BANKS	204,100	243,300
	UPGRADE EXISTING 230KV LINES	ANTELOPE JUNCTION	VINCENT SUBSTATION	20	500	58,400	VINCENT SUBSTATION: TWO 500KV BREAKER & 1/2 CIRCUIT BREAKER POSITIONS (5 BREAKERS)	10,800	69,200

YEAR	TRANSMISSION LINES						SUBSTATIONS		TOTAL
	ACTION	TERMINAL A	TERMINAL B	MILES	VOLTAGE (KV)	COST (K$)	ACTION	COST (K$)	COST (K$)
	NEW LINE	ANTELOPE JUNCTION	TEHACHAPI SUBSTATION 6	5	230	3,100	TEHACHAPI SUBSTATION 6: TWO 230KV BREAKER & 1/2 CIRCUIT BREAKER POSITIONS (6 BREAKERS); TWO 280MVA, 230/66KV TRANSFORMERS; TWO 45MVAR, 230KV CAPACITOR BANKS; TWO 66KV BREAKER & 1/2 CIRCUIT BREAKER POSITIONS (6	30,300	33,400
	NEW LINE	TEHACHAPI SUBSTATION 1	TEHACHAPI SUBSTATION 2	10	230	13,900	TEHACHAPI SUBSTATION 2: FOUR 230KV BREAKER & 1/2 CIRCUIT BREAKER POSITIONS (12 BREAKERS); THREE 280MVA, 230/66KV TRANSFORMERS; TWO 45MVAR, 230KV CAPACITOR BANKS; FIVE 66KV BREAKER & 1/2 CIRCUIT BREAKER POSITIONS (18 BREAKERS); THREE 66KV, 29MVAR CAPACITOR BANKS	42,600	56,500
	UPGRADE EXISTING 230KV LINES	VINCENT SUBSTATION	RIO HONDO SUBSTATION	32	500	46,600	RIO HONDO SUBSTATION: THREE 500KV BREAKER & 1/2 CIRCUIT BREAKER POSITIONS (8 BREAKERS); THREE1120MVA, 500/230KV TRANSFORMERS; FIVE 230KV BREAKER & 1/2 CIRCUIT BREAKER POSITIONS (13 BREAKERS)	63,300	109,900
	UPGRADE EXISTING 230KV LINE	PARDEE SUBSTATION	VINCENT SUBSTATION	33	500	700			700
	NEW LINE	TEHACHAPI SUBSTATION 1	TEHACHAPI SUBSTATION 4	10	230	13,600	TEHACHAPI SUBSTATION 4: FIVE 230KV BREAKER & 1/2 CIRCUIT BREAKER POSITIONS (16 BREAKERS); FOUR 280MVA, 230/66KV TRANSFORMERS; FOUR 45MVAR, 230KV CAPACITOR BANKS; EIGHT 66KV BREAKER & 1/2 CIRCUIT BREAKER POSITIONS (29 BREAKERS); FOUR 66KV, 29MVAR CAPACITOR BANKS	48,100	61,700
	NEW LINE	TEHACHAPI SUBSTATION 1	TEHACHAPI SUBSTATION 5	20	230	25,600	TEHACHAPI SUBSTATION 5: TWO 230KV BREAKER & 1/2 CIRCUIT BREAKER POSITIONS (6 BREAKERS); TWO 280MVA, 230/66KV TRANSFORMERS; TWO 45MVAR, 230KV CAPACITOR BANKS; TWO 66KV BREAKER & 1/2 CIRCUIT BREAKER POSITIONS (6	29,800	55,400
								TOTAL	$809,300

YEAR	TRANSMISSION LINES						SUBSTATIONS		TOTAL
	ACTION	TERMINAL A	TERMINAL B	MILES	VOLTAGE (KV)	COST (K$)	ACTION	COST (K$)	COST (K$)
2017/ 2010	COLLECTOR SYSTEM	WIND FARM SUBSTATIONS	TEHACHAPI SUBSTATIONS	250 DOUBLE CIRCUIT	66	31,800			31,800
	NEW LINE	TEHACHAPI SUBSTATION 2	TEHACHAPI SUBSTATION 4	15	230	17,700			17,700
	NEW LINE	TEHACHAPI SUBSTATION 4	TEHACHAPI SUBSTATION 3	38	230	25,600	TEHACHAPI SUBSTATION 3: THREE 230KV BREAKER & 1/2 CIRCUIT BREAKER POSITIONS (9 BREAKERS); THREE 280MVA, 230/66KV TRANSFORMERS; FOUR 45MVAR, 230KV CAPACITOR BANKS; FIVE 66KV BREAKER & 1/2 CIRCUIT BREAKER POSITIONS (18 BREAKERS)	30,100	55,700
	NEW LINE	VINCENT SUBSTATION	TEHACHAPI SUBSTATION 4	60	500	27,900	VINCENT SUBSTATION: ADD ONE 500KV BREAKER & 1/2 CIRCUIT BREAKER POSITION (2 BREAKERS)	10,200	38,100
							TEHACHAPI SUBSTATION 4: ADD ONE 500KV BREAKER & 1/2 CIRCUIT BREAKER POSITIONS (3 BREAKERS); ONE 1120MVA, 500/230KV TRANSFORMER; ONE 230KV BREAKER & 1/2 CIRCUIT BREAKER POSITION (2 BREAKERS)	97,300	97,300
	NEW LINE	VINCENT SUBSTATION	STAGECOACH SUBSTATION	70	500	39,900	STAGECOACH SUBSTATION: ADD ONE 500KV BREAKER & 1/2 CIRCUIT BREAKER POSITION (2 BREAKERS)	9,500	49,400
	LOOP SUB 2 TO SUB 4 230KV LINES INTO NEW SUBSTATION	TEHACHAPI SUBSTATION 7	TEHACHAPI SUBSTATION 7		230		TEHACHAPI SUBSTATION 7: FOUR 230KV BREAKER & 1/2 CIRCUIT BREAKER POSITIONS (11 BREAKERS); TWO 280MVA, 230/66KV TRANSFORMERS; TWO 45MVAR, 230KV CAPACITOR BANKS; THREE 66KV BREAKER & 1/2 CIRCUIT BREAKER POSITIONS (11 BREAKERS); FOUR 29MVA, 66KV CAPACITOR BANKS	21,700	21,700
	SERIES COMPENSATION	PARDEE SUBSTATION	TEHACHAPI SUBSTATION 1		500	16,300			16,300
	SERIES COMPENSATION	VINCENT SUBSTATION	TEHACHAPI SUBSTATION 1		500	15,200			15,200
	SERIES COMPENSATION	VINCENT SUBSTATION	TEHACHAPI SUBSTATION 4		500	14,200			14,200
								TOTAL	$357,400
							TOTAL FOR PROJECT: 2005, 2008, 2017		$1,166,700

TABLE 3-C

TRANSMISSION ADDITIONS

KERN & LOS ANGELES COUNTIES

EAP ACCELERATED SCHEDULE NPV DOLLARS

YEAR	TRANSMISSION LINES						SUBSTATIONS		TOTAL
	ACTION	TERMINAL A	TERMINAL B	MILES	VOLTAGE (KV)	COST (K$)	ACTION	COST (K$)	COST (K$)
2005						0		0	0
								TOTAL	$0
2008	COLLECTOR SYSTEM	WIND FARM SUBSTATIONS	TEHACHAPI SUBSTATIONS	100 DOUBLE CIRCUIT	66	67,400			67,400
	NEW LINE (ANTELOPE-TEHACHAPI #1)	PARDEE SUBSTATION	TEHACHAPI SUBSTATION 1 (VIA ANTELOPE JUNCTION)	60	500	75,600	PARDEE SUBSTATION: TWO 500KV BREAKER & 1/2 CIRCUIT BREAKER POSITIONS (6 BREAKERS); TWO 1120MVA, 500/230KV TRANSFORMERS; TWO 230KV DOUBLE BREAKER CIRCUIT BREAKER POSITIONS (5 BREAKERS); TWO 79MVAR, 230KV CAPACITOR BANKS	52,300	127,900
	NEW LINE (ANTELOPE-TEHACHAPI #2)	ANTELOPE JUNCTION	TEHACHAPI SUBSTATION 1	35	500	33,200	TEHACHAPI SUBSTATION 1: FOUR 500KV BREAKER & 1/2 CIRCUIT BREAKER POSITIONS (10 BREAKERS); FOUR 1120MVA, 500/230KV TRANSFORMERS; EIGHT 230KV BREAKER & 1/2 CIRCUIT BREAKER POSITIONS (27 BREAKERS); SIX 45MVAR, 230KV CAPACITOR BANKS; ONE 200MVAR 230KV SVC; FOUR 280MVA, 230/66KV TRANSFORMERS; EIGHT 66KV BREAKER & 1/2 CIRCUIT BREAKER POSITIONS (29 BREAKERS); FOUR 66KV, 29MVAR CAPACITOR BANKS	204,100	237,300
	UPGRADE EXISTING 230KV LINES	ANTELOPE JUNCTION	VINCENT SUBSTATION	20	500	58,400	VINCENT SUBSTATION: TWO 500KV BREAKER & 1/2 CIRCUIT BREAKER POSITIONS (5 BREAKERS)	10,800	69,200
	NEW LINE	ANTELOPE JUNCTION	TEHACHAPI SUBSTATION 6	5	230	3,100	TEHACHAPI SUBSTATION 6: TWO 230KV BREAKER & 1/2 CIRCUIT BREAKER POSITIONS (6 BREAKERS); TWO 280MVA, 230/66KV TRANSFORMERS; TWO 45MVAR, 230KV CAPACITOR BANKS; TWO 66KV BREAKER & 1/2 CIRCUIT BREAKER POSITIONS (6 BREAKERS)	30,300	33,400

YEAR	TRANSMISSION LINES						SUBSTATIONS		TOTAL
	ACTION	TERMINAL A	TERMINAL B	MILES	VOLTAGE (KV)	COST (K$)	ACTION	COST (K$)	COST (K$)
	NEW LINE	TEHACHAPI SUBSTATION 1	TEHACHAPI SUBSTATION 2	10	230	13,900	TEHACHAPI SUBSTATION 2: FOUR 230KV BREAKER & 1/2 CIRCUIT BREAKER POSITIONS (12 BREAKERS); THREE 280MVA, 230/66KV TRANSFORMERS; TWO 45MVAR, 230KV CAPACITOR BANKS; FIVE 66KV BREAKER & 1/2 CIRCUIT BREAKER POSITIONS (18 BREAKERS); THREE 66KV, 29MVAR CAPACITOR BANKS	42,600	56,500
	UPGRADE EXISTING 230KV LINES	VINCENT SUBSTATION	RIO HONDO SUBSTATION	32	500	46,600	RIO HONDO SUBSTATION: THREE 500KV BREAKER & 1/2 CIRCUIT BREAKER POSITIONS (8 BREAKERS); THREE1120MVA, 500/230KV TRANSFORMERS; FIVE 230KV BREAKER & 1/2 CIRCUIT BREAKER POSITIONS (13 BREAKERS)	63,300	109,900
	UPGRADE EXISTING 230KV LINE	PARDEE SUBSTATION	VINCENT SUBSTATION	33	500	700			700
	NEW LINE	TEHACHAPI SUBSTATION 1	TEHACHAPI SUBSTATION 4	10	230	13,600	TEHACHAPI SUBSTATION 4: FOUR 230KV BREAKER & 1/2 CIRCUIT BREAKER POSITIONS (13 BREAKERS); FOUR 280MVA, 230/66KV TRANSFORMERS; FOUR 45MVAR, 230KV CAPACITOR BANKS; EIGHT 66KV BREAKER & 1/2 CIRCUIT BREAKER POSITIONS (29 BREAKERS); FOUR 66KV, 29MVAR CAPACITOR BANKS	49,700	63,300
	NEW LINE	TEHACHAPI SUBSTATION 1	TEHACHAPI SUBSTATION 5	20	230	25,600	TEHACHAPI SUBSTATION 5: TWO 230KV BREAKER & 1/2 CIRCUIT BREAKER POSITIONS (6 BREAKERS); TWO 280MVA, 230/66KV TRANSFORMERS; TWO 45MVAR, 230KV CAPACITOR BANKS; TWO 66KV BREAKER & 1/2 CIRCUIT BREAKER POSITIONS (6 BREAKERS)	29,800	55,400
								TOTAL	$821,000

YEAR	TRANSMISSION LINES						SUBSTATIONS		TOTAL
	ACTION	**TERMINAL A**	**TERMINAL B**	**MILES**	**VOLTAGE (KV)**	**COST (K$)**	**ACTION**	**COST (K$)**	**COST (K$)**
2010	COLLECTOR SYSTEM	WIND FARM SUBSTATIONS	TEHACHAPI SUBSTATIONS	250 DOUBLE CIRCUIT	66	31,800			31,800
	NEW LINE	TEHACHAPI SUBSTATION 2	TEHACHAPI SUBSTATION 4	15	230	17,700			17,700
	NEW LINE	TEHACHAPI SUBSTATION 4	TEHACHAPI SUBSTATION 3	38	230	27,400	TEHACHAPI SUBSTATION 3: THREE 230KV BREAKER & 1/2 CIRCUIT BREAKER POSITIONS (9 BREAKERS); THREE 280MVA, 230/66KV TRANSFORMERS; FOUR 45MVAR, 230KV CAPACITOR BANKS; FIVE 66KV BREAKER & 1/2 CIRCUIT BREAKER POSITIONS (18 BREAKERS)	32,200	59,600
	NEW LINE	VINCENT SUBSTATION	TEHACHAPI SUBSTATION 4	60	500	34,200	VINCENT SUBSTATION: ADD ONE 500KV BREAKER & 1/2 CIRCUIT BREAKER POSITION (2 BREAKERS)	14,300	48,500
							TEHACHAPI SUBSTATION 4: ADD ONE 500KV BREAKER & 1/2 CIRCUIT BREAKER POSITIONS (3 BREAKERS); ONE 1120MVA, 500/230KV TRANSFORMER; ONE 230KV BREAKER & 1/2 CIRCUIT BREAKER POSITION (2 BREAKERS)	49,900	49,900
	NEW LINE	VINCENT SUBSTATION	STAGECOACH SUBSTATION	70	500	39,900	STAGECOACH SUBSTATION: ADD ONE 500KV BREAKER & 1/2 CIRCUIT BREAKER POSITION (2 BREAKERS)	14,300	54,200
	LOOP SUB 2 TO SUB 4 230KV LINES INTO NEW SUBSTATION				230		TEHACHAPI SUBSTATION 7: THREE 230KV BREAKER & 1/2 CIRCUIT BREAKER POSITIONS (8 BREAKERS); TWO 280MVA, 230/66KV TRANSFORMERS; TWO 45MVAR, 230KV CAPACITOR BANKS; THREE 66KV BREAKER & 1/2 CIRCUIT BREAKER POSITIONS (11 BREAKERS); FOUR 29MVA, 66KV CAPACITOR BANKS	21,700	21,700
	SERIES COMPENSATION	PARDEE SUBSTATION	TEHACHAPI SUBSTATION 1		500	22,800			22,800
	SERIES COMPENSATION	VINCENT SUBSTATION	TEHACHAPI SUBSTATION 1		500	22,800			22,800
	SERIES COMPENSATION	VINCENT SUBSTATION	TEHACHAPI SUBSTATION 4		500	22,800			22,800
								TOTAL	$351,800
2017							TEHACHAPI SUBSTATION 4: ADD 230KV BREAKER & 1/2 CIRCUIT BREAKER POSITION (3 BREAKERS)	12,900	12,900
							TEHACHAPI SUBSTATION 4: ADD 230KV BREAKER & 1/2 CIRCUIT BREAKER POSITION (3 BREAKERS)	14,500	14,500
								TOTAL	$27,400
							TOTAL FOR PROJECT: 2005, 2008, 2010, 2017		$1,200,200

Figure 3-1
KERN AND LOS ANGELES COUNTIES - 2008

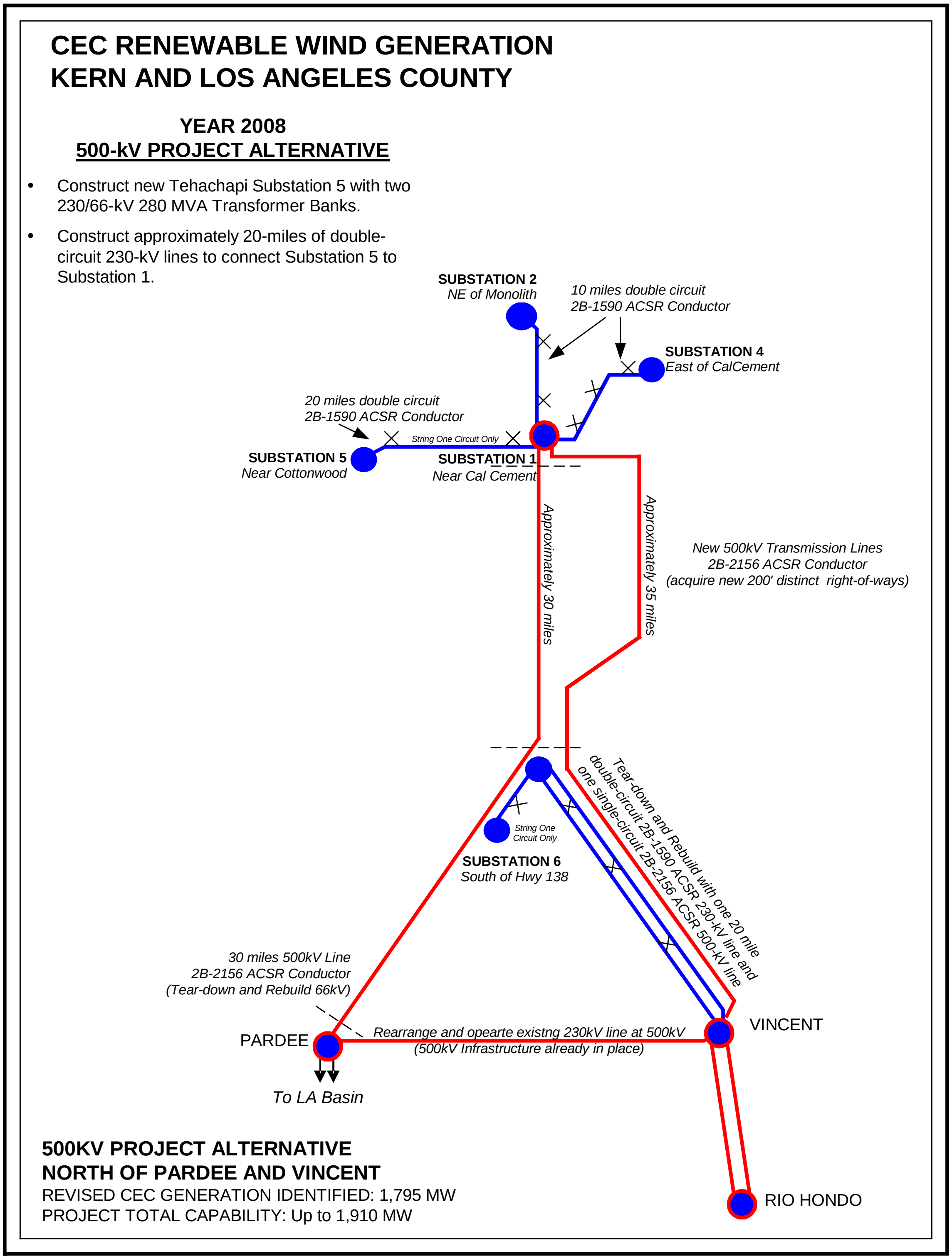


Figure 3-2

KERN AND LOS ANGELES COUNTIES – 2017

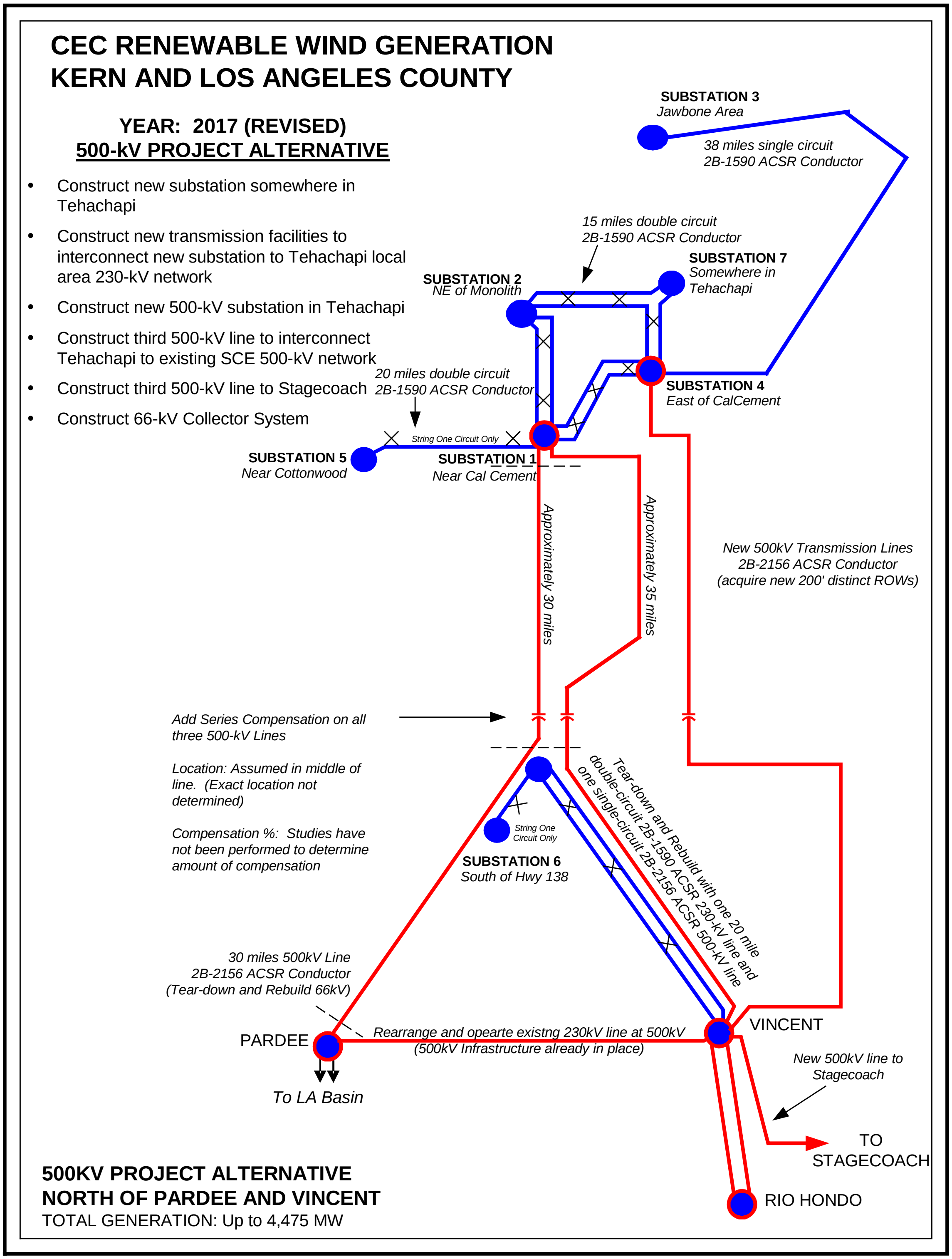
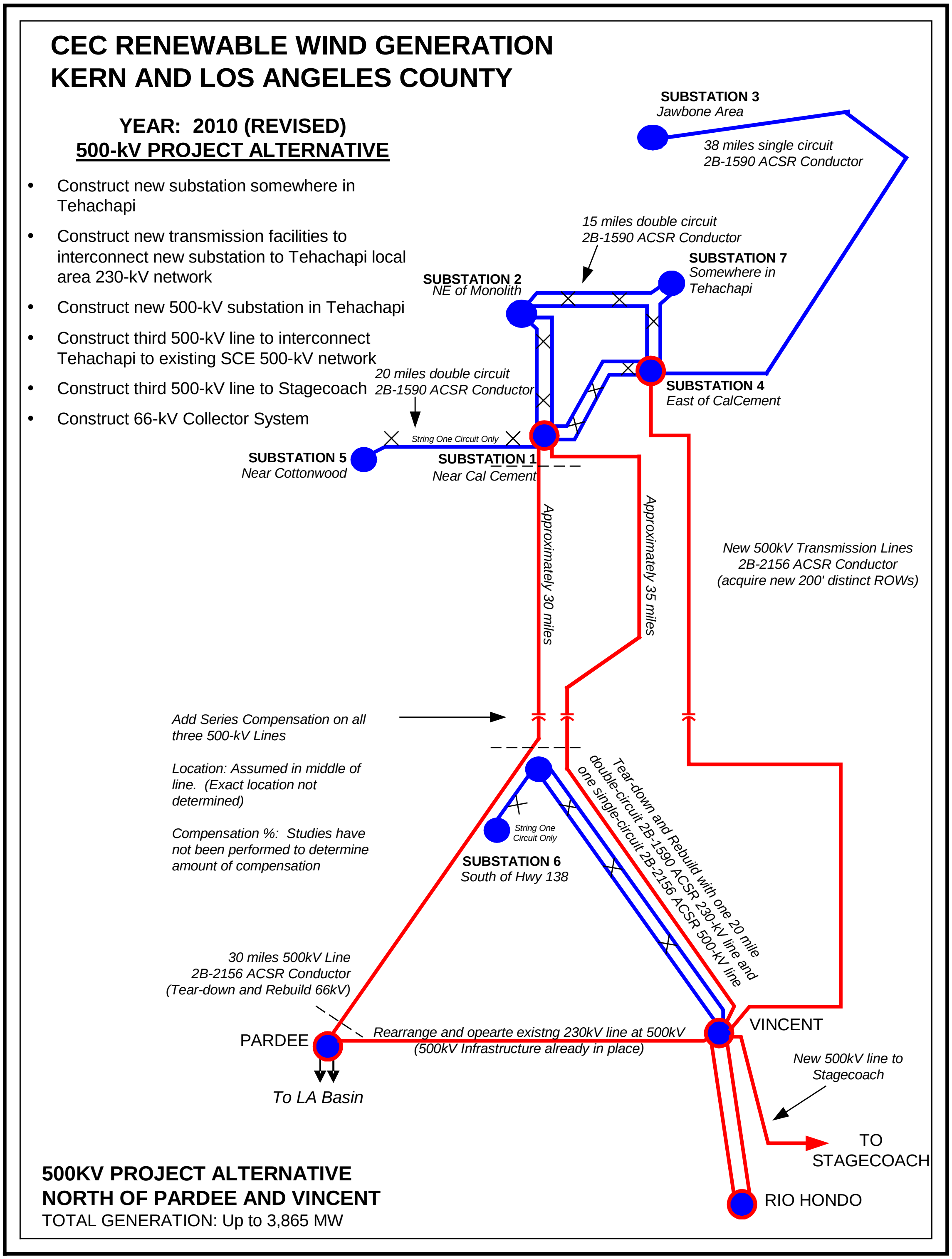


Figure 3-3
KERN AND LOS ANGELES COUNTIES – 2010 ACCELERATED



4. TRANSMISSION PLAN FOR MONO & SAN BERNARDINO COUNTIES

REGION & RESOURCES

Mono County is located in the central eastern part of the state, east of the Sierra Nevada Mountains, and separated from San Bernardino County to the south by Inyo County. Mono County is the furthest north of the SCE service area. It has hydroelectric power, which is transmitted south in the spring and summer over a 115kV transmission line. San Bernardino County, northeast of Los Angeles, is a corridor for seven 500kV transmission lines, five of which are owned by the LADWP and two by SCE, to sources of generation in Nevada.

The renewable resources identified by the CEC in Mono County consist of wind and geothermal; in San Bernardino County there is wind and solar.

Map 4 shows the general area covered by this section. The capacity of the resources and the dates they could come on line are tabulated in Table 4-1.

AREA-SPECIFIC CHARACTERISTICS

The area is served by SCE. The electrical hub is the Lugo Substation, to which terminate eight 500kV and six 230kV transmission lines. From this substation two 500kV and two 230kV transmission lines run east 177 miles to the El Dorado Substation in Nevada. Transmission to the north starts with four 230kV lines and ends with one 115kV line at Lee Vining, just east of Yosemite 278 miles away. New generation connected to the El Dorado Substation would not require additional lines for transmission to Los Angeles, but new generation connected in the north would require considerable upgrades described below.

TRANSMISSION ADDITIONS

The transmission additions required to accommodate the renewable resource generation through 2017 consist of:

- New substation, Mountain Pass 2, west of El Dorado Substation to receive wind power
- One 115kV transmission line between Mountain Pass 2 and El Dorado Substations
- One 230kV transmission line from Control Substation to LADWP's Inyo Substation
- Two 230kV transmission lines between Control and Inyokern Substations
- Augment capacity of one transmission line between Inyokern and Kramer Substations
- A loop Bureau of Land Management (BLM) 230kV transmission line that terminates at Kramer Substation into Inyokern Substation to increase transmission capacity between Inyokern and Kramer

- One 230kV transmission line between Kramer Substation and Lugo Substation
- Upgrade El Dorado, Lee Vining, Control, Fish Lake Valley, Inyokern, Kramer and Lugo Substations.

The transmission in the area, including the renewables additions, is shown for the years 2008 and 2017 on Figures 4-1 and 4-2, and for the years 2008 and 2010 under the EAP schedule in Figures 4-3 and 4-4. The additions are tabulated for each year with corresponding costs on Table 4-A with costs in 2003 dollars, and Table 4-B with net present value costs. Net present value costs for the accelerated schedule are shown in Table 4-C.

MAP 4

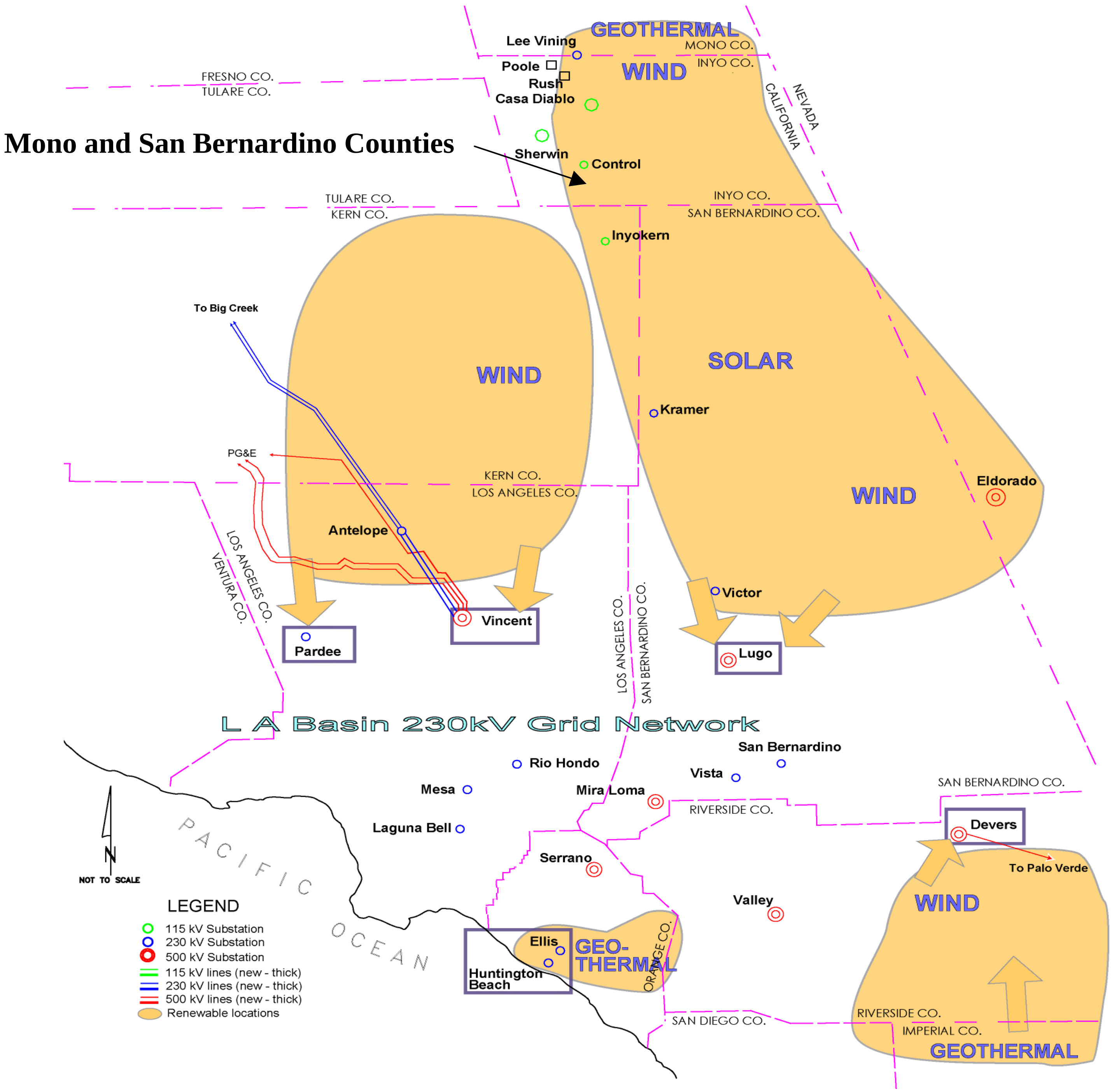

Mono and San Bernardino Counties
GEOTHERMAL
MONO CO.
INYO CO.
WIND
Lee Vining
Poole
Rush
Casa Diablo
Sherwin
Control
FRESNO CO.
TULARE CO.
NEVADA
CALIFORNIA
TULARE CO.
KERN CO.
INYO CO.
SAN BERNARDINO CO.
Inyokern
To Big Creek
WIND
SOLAR
Kramer
PG&E
KERN CO.
LOS ANGELES CO.
WIND
Eldorado
Antelope
LOS ANGELES CO.
VENTURA CO.
Victor
Vincent
Pardee
LOS ANGELES CO.
SAN BERNARDINO CO.
Lugo
L A Basin 230kV Grid Network
San Bernardino
Rio Hondo
Vista
SAN BERNARDINO CO.
Mesa
Mira Loma
RIVERSIDE CO.
Laguna Bell
Devers
N
NOT TO SCALE
PACIFIC
Serrano
To Palo Verde
WIND
Valley
LEGEND
115 kV Substation
230 kV Substation
500 kV Substation
115 kV lines (new - thick)
230 kV lines (new - thick)
500 kV lines (new - thick)
Renewable locations
OCEAN
Ellis
Huntington Beach
GEO-THERMAL
ORANGE CO.
SAN DIEGO CO.
RIVERSIDE CO.
IMPERIAL CO.
GEOTHERMAL

TABLE 4

RENEWABLE RESOURCE

GENERATION

MEGAWATTS (MW)

MONO & SAN BERNARDINO COUNTIES

SB 1078 Schedule

COUNTY	TYPE OF GENERATION	YEAR					
		Added 2005	Added 2008	Added 2010	Total 2010	Added 2017	Total 2017
MONO	WIND	0	0	N/A	N/A	30	30
	GEOTHERMAL		50	N/A	N/A	300	350
SAN BERNARDINO	WIND	50	40	N/A	N/A	310	400
	SOLAR	0	0	N/A	N/A	180	180

Accelerated EAP Schedule

COUNTY	TYPE OF GENERATION	YEAR					
		Added 2005	Added 2008	Added 2010	Total 2010	Added 2017	Total 2017
MONO	WIND	30	0	0	30	0	30
	GEOTHERMAL		100	100	200	150	350
SAN BERNARDINO	WIND	50	60	0	110	290	400
	SOLAR	0	0	120	120	60	180

TABLE 4-A

TRANSMISSION ADDITIONS

MONO & SAN BERNARDINO COUNTIES

SCHEDULE SB1078 2003 DOLLARS

YEAR	TRANSMISSION LINES						SUBSTATIONS		TOTAL
	ACTION	TERMINAL A	TERMINAL B	MILES	VOLTAGE (KV)	COST (K$)	ACTION	COST (K$)	COST (K$)
2005	NONE					0	NONE	0	0
								TOTAL	$0
2008	NEW LINE	WIND FARM COLLECTOR	MOUNTAIN PASS 2 SUBSTATION	10	115	2800	MOUNTAIN PASS 2 SUBSTATION: NEW 115KV SUBSTATION, MAIN & TRANSFER BUS, WITH 3 CIRCUIT BREAKERS	4700	7500
	NEW LINE (FIRST LINE)	MOUNTAIN PASS 2 SUBSTATION	EL DORADO SUBSTATION	38	115	13,200	EL DORADO SUBSTATION: ADD TWO 230KV, BREAKER & 1/2 CIRCUIT BREAKER POSITIONS (4 BREAKERS); ONE 280MVA, 230/115KV TRANSFORMER; TWO 115KV BREAKER & 1/2 CIRCUIT BREAKER POSITIONS (6 BREAKERS)	16,000	29,200
	NEW LINE	LEE VINING SUBSTATION	CONTROL SUBSTATION	69	115	31,900	LEE VINING SUBSTATION: ADD 115 KV SWITCHRACK WITH FOUR DOUBLE BREAKER CIRCUIT BREAKER POSITIONS (8 BREAKERS)	9,400	41,300
	NEW LINE (FIRST LINE)	CONTROL SUBSTATION	INYOKERN SUBSTATION	125	230	176,200	CONTROL SUBSTATION: ADD TWO 230KV BREAKER & 1/2 CIRCUIT BREAKER POSITIONS (6 BREAKERS); ONE 280MVA, 230/115KV TRANSFORMER; THREE 115 KV CIRCUIT BREAKERS; ONE 45MVAR 115KV CAPACITOR BANK	12,100	188,300
							INYOKERN SUBSTATION: ADD TWO 230KV BREAKER & 1/2 CIRCUIT BREAKER POSITIONS (6 BREAKERS); ONE 280MVA, 230/115KV TRANSFORMER; ONE 115 KV CIRCUIT BREAKER	8,400	8,400
								TOTAL	$274,700

YEAR	TRANSMISSION LINES						SUBSTATIONS		TOTAL
	ACTION	**TERMINAL A**	**TERMINAL B**	**MILES**	**VOLTAGE (KV)**	**COST (K$)**	**ACTION**	**COST (K$)**	**COST (K$)**
2017/ 2010	NEW LINE	WIND FARM COLLECTOR	LEE VINING SUBSTATION	10	115	4,100	LEE VINING SUBSTATION: ADD 230KV SWITCHRACK WITH ONE BREAKER & 1/2 CIRCUIT BREAKER POSITION (3 BREAKERS) ONE 240MVA, 230/115KV TRANSFORMER, ONE 115KV BREAKER & 1/2 POSITION (3 BREAKERS)	7,300	11,400
	NEW LINE	WIND FARM COLLECTOR	MOUNTAIN PASS 2 SUBSTATION	10	115	2,800	MOUNTAIN PASS 2 SUBSTATION: ADD TWO 115KV CIRCUIT BREAKERS	1,000	3,800
	NEW LINE (SECOND LINE)	MOUNTAIN PASS 2 SUBSTATION	EL DORADO SUBSTATION	38	115	13200	EL DORADO SUBSTATION: ADD ONE 230KV CIRCUIT BREAKER	3,100	16,300
	NEW LINE (SECOND LINE)	CONTROL SUBSTATION	INYOKERN SUBSTATION	125	230	40,900	INYOKERN SUBSTATION: ADD ONE 230KV BREAKER & 1/2 CIRCUIT BREAKER POSITION (3 BREAKERS)	5,600	46,500
	NEW LINE	CONTROL SUBSTATION	INYO SUBSTATION	3	230	6,200	INYO SUBSTATION MODIFICATIONS NOT KNOWN (OWNED BY LADWP)	N/A	6,200
							FISH LAKE VALLEY SUBSTATION: ADD FOUR 60KV MAIN & TRANSFER BUS CIRCUIT BREAKER POSITIONS (FOUR BREAKERS)	2,200	2,200
							CASA DIABLO SUBSTATION: ADD ONE 115KV CIRCUIT BREAKER	1,200	1,200
	NEW LINE	KRAMER SUBSTATION	LUGO SUBSTATION	46	230	66,000	KRAMER SUBSTATION: ADD TWO 230KV BREAKER & 1/2 CIRCUIT BREAKER POSITIONS (5 BREAKERS)	7400	73,400
							LUGO SUBSTATION: ADD ONE 230KV BREAKER & 1/2 CIRCUIT BREAKER POSITION (3 BREAKERS)	2,400	2,400
	LOOP BLM WEST 230KV TRANSMIS SION LINE INTO SUB	INYO KERN SUBSTATION	INYO KERN SUBSTATION	0	230	700			700
								TOTAL	$164,100
							TOTAL FOR PROJECT: 2005, 2008, 2017		$438,800

TABLE 4-B

TRANSMISSION ADDITIONS

MONO & SAN BERNARDINO COUNTIES

SCHEDULE SB1078 NPV DOLLARS

YEAR	TRANSMISSION LINES						SUBSTATIONS		TOTAL
	ACTION	TERMINAL A	TERMINAL B	MILES	VOLTAGE (KV)	COST (K$)	ACTION	COST (K$)	COST (K$)
2005	NONE					0	NONE	0	0
								TOTAL	$0
2008	NEW LINE	WIND FARM COLLECTOR	MOUNTAIN PASS 2 SUBSTATION	10	115	2,100	MOUNTAIN PASS 2 SUBSTATION: NEW 115KV SUBSTATION, MAIN & TRANSFER BUS, WITH 3 CIRCUIT BREAKERS	3,400	5,500
	NEW LINE (FIRST LINE)	MOUNTAIN PASS 2 SUBSTATION	EL DORADO SUBSTATION	38	115	10,100	EL DORADO SUBSTATION: ADD TWO 230KV, BREAKER & 1/2 CIRCUIT BREAKER POSITIONS (4 BREAKERS); ONE 280MVA, 230/115KV TRANSFORMER; TWO 115KV BREAKER & 1/2 CIRCUIT BREAKER POSITIONS (6 BREAKERS)	11,400	21,500
	NEW LINE	LEE VINING SUBSTATION	CONTROL SUBSTATION	69	115	25,200	LEE VINING SUBSTATION: ADD 115 KV SWITCHRACK WITH FOUR DOUBLE BREAKER CIRCUIT BREAKER POSITIONS (8 BREAKERS)	6,700	31,900
	NEW LINE (FIRST LINE)	CONTROL SUBSTATION	INYOKERN SUBSTATION	125	230	139,200	CONTROL SUBSTATION: ADD TWO 230KV BREAKER & 1/2 CIRCUIT BREAKER POSITIONS (6 BREAKERS); ONE 280MVA, 230/115KV TRANSFORMER; THREE 115 KV CIRCUIT BREAKERS; ONE 45MVAR 115KV CAPACITOR BANK	8,600	147,800
							INYOKERN SUBSTATION: ADD TWO 230KV BREAKER & 1/2 CIRCUIT BREAKER POSITIONS (6 BREAKERS); ONE 280MVA, 230/115KV TRANSFORMER; ONE 115 KV CIRCUIT BREAKER	6,000	6,000
								TOTAL	$212,700
2017	NEW LINE	WIND FARM COLLECTOR	LEE VINING SUBSTATION	10	115	1,800	LEE VINING SUBSTATION: ADD 230KV SWITCHRACK WITH ONE BREAKER & 1/2 CIRCUIT BREAKER POSITION (3 BREAKERS) ONE 240MVA, 230/115KV TRANSFORMER, ONE 115KV BREAKER & 1/2 POSITION (3 BREAKERS)	2,800	4,600

YEAR	TRANSMISSION LINES						SUBSTATIONS		TOTAL
	ACTION	TERMINAL A	TERMINAL B	MILES	VOLTAGE (KV)	COST (K$)	ACTION	COST (K$)	COST (K$)
	NEW LINE	WIND FARM COLLECTOR	MOUNTAIN PASS 2 SUBSTATION	10	115	1,200	MOUNTAIN PASS 2 SUBSTATION: ADD TWO 115KV CIRCUIT BREAKERS	400	1,600
	NEW LINE (SECOND LINE)	MOUNTAIN PASS 2 SUBSTATION	EL DORADO SUBSTATION	38	115	5500	EL DORADO SUBSTATION: ADD ONE 230KV CIRCUIT BREAKER	1,200	6,700
	NEW LINE (SECOND LINE)	CONTROL SUBSTATION	INYOKERN SUBSTATION	125	230	17,000	INYOKERN SUBSTATION: ADD ONE 230KV BREAKER & 1/2 CIRCUIT BREAKER POSITION (3 BREAKERS)	2,200	19,200
	NEW LINE	CONTROL SUBSTATION	INYO SUBSTATION	3	230	2,700	INYO SUBSTATION MODIFICATIONS NOT KNOWN (OWNED BY LADWP)	N/A	2,700
							FISH LAKE VALLEY SUBSTATION: ADD FOUR 60KV MAIN & TRANSFER BUS CIRCUIT BREAKER POSITIONS (FOUR BREAKERS)	900	900
							CASA DIABLO SUBSTATION: ADD ONE 115KV CIRCUIT BREAKER	500	500
	NEW LINE	KRAMER SUBSTATION	LUGO SUBSTATION	46	230	28,400	KRAMER SUBSTATION: ADD TWO 230KV BREAKER & 1/2 CIRCUIT BREAKER POSITIONS (5 BREAKERS)	2,900	31,300
							LUGO SUBSTATION: ADD ONE 230KV BREAKER & 1/2 CIRCUIT BREAKER POSITION (3 BREAKERS)	900	900
	LOOP BLM WEST 230KV TRANSMIS SION LINE INTO SUB	INYO KERN SUBSTATION	INYO KERN SUBSTATION	0	230	300			300
								TOTAL	$68,700
							TOTAL FOR PROJECT: 2005, 2008, 2017		$281,400

TABLE 4-C

TRANSMISSION ADDITIONS

MONO & SAN BERNARDINO COUNTIES

EAP ACCELERATED SCHEDULE NPV DOLLARS

YEAR	TRANSMISSION LINES						SUBSTATIONS		TOTAL
	ACTION	TERMINAL A	TERMINAL B	MILES	VOLTAGE (KV)	COST (K$)	ACTION	COST (K$)	COST (K$)
2005	NONE					0	NONE	0	0
								TOTAL	$0
2008	NEW LINE	WIND FARM COLLECTOR	MOUNTAIN PASS 2 SUBSTATION	10	115	2,100	MOUNTAIN PASS 2 SUBSTATION: NEW 115KV SUBSTATION, MAIN & TRANSFER BUS, WITH 3 CIRCUIT BREAKERS	3,400	5,500
	NEW LINE	WIND FARM COLLECTOR	LEE VINING SUBSTATION	10	115	3,100	LEE VINING SUBSTATION: ADD 115 KV SWITCHRACK WITH FOUR DOUBLE BREAKER CIRCUIT BREAKER POSITIONS (8 BREAKERS)	6,300	9,400
	NEW LINE (FIRST LINE)	MOUNTAIN PASS 2 SUBSTATION	EL DORADO SUBSTATION	38	115	10,100	EL DORADO SUBSTATION: ADD TWO 230KV, BREAKER & 1/2 CIRCUIT BREAKER POSITIONS (4 BREAKERS); ONE 280MVA, 230/115KV TRANSFORMER; TWO 115KV BREAKER & 1/2 CIRCUIT BREAKER POSITIONS (6 BREAKERS)	11,400	21,500
	NEW LINE	LEE VINING SUBSTATION	CONTROL SUBSTATION	69	115	26,000	CONTROL SUBSTATION: ADD ONE 230KV BREAKER & 1/2 CIRCUIT BREAKER POSITION (3 BREAKERS); ONE 280MVA, 230/115KV TRANSFORMER; THREE 115 KV CIRCUIT BREAKERS; ONE 45MVAR 115KV CAPACITOR BANK	8,600	34,600
	NEW LINE (FIRST LINE)	CONTROL SUBSTATION	INYOKERN SUBSTATION	125	230	143,800	INYOKERN SUBSTATION: ADD TWO 230KV BREAKER & 1/2 CIRCUIT BREAKER POSITIONS (6 BREAKERS); ONE 280MVA, 230/115KV TRANSFORMER; ONE 115 KV CIRCUIT BREAKER	8,000	151,800

YEAR	TRANSMISSION LINES						SUBSTATIONS		TOTAL
	ACTION	TERMINAL A	TERMINAL B	MILES	VOLTAGE (KV)	COST (K$)	ACTION	COST (K$)	COST (K$)
	NEW LINE	CONTROL SUBSTATION	INYO SUBSTATION	3	230	4,900	INYO SUBSTATION MODIFICATIONS NOT KNOWN (OWNED BY LADWP)	N/A	4,900
	NEW LINE	KRAMER SUBSTATION	LUGO SUBSTATION	46	230	52,100	KRAMER SUBSTATION: ADD TWO 230KV BREAKER & 1/2 CIRCUIT BREAKER POSITIONS (5 BREAKERS)	5,300	57,400
							LUGO SUBSTATION: ADD ONE 230KV BREAKER & 1/2 CIRCUIT BREAKER POSITION (3 BREAKERS)	1,700	1,700
	LOOP BLM WEST 230KV TRANSMISSION LINE INTO SUB	INYO SUBSTATION	INYO SUBSTATION	0	230	600			600
								TOTAL	287,400
2010	NEW LINE (SECOND LINE)	CONTROL SUBSTATION	INYOKERN SUBSTATION	125	230	27,300	CONTROL SUBSTATOIN: ADD ONE 230KV BREAKER & 1/2 CIRCUIT BREAKER POSITION (3 BREAKERS)	3,000	30,300
							INYOKERN SUBSTATION: ADD ONE 230KV BREAKER & 1/2 CIRCUIT BREAKER POSITION (3 BREAKERS)	1,700	1,700
							LEE VINING SUBSTATION: ADD 230KV SWITCHRACK WITH ONE BREAKER & 1/2 CIRCUIT BREAKER POSITION (3 BREAKERS) ONE 240MVA, 230/115KV TRANSFORMER, ONE 115KV BREAKER & 1/2 POSITION (2 BREAKERS)	4,600	4,600
							FISH LAKE VALLEY SUBSTATION: ADD FOUR 60KV MAIN & TRANSFER BUS CIRCUIT BREAKER POSITIONS (FOUR BREAKERS)	1,400	1,400
							CASA DIABLO SUBSTATION: ADD ONE 115KV CIRCUIT BREAKER	700	700
								TOTAL	$38,700
2017	NEW LINE	WIND FARM COLLECTOR	MOUNTAIN PASS 2 SUBSTATION	10	115	1,200	MOUNTAIN PASS 2 SUBSTATION: ADD TWO 115KV CIRCUIT BREAKERS	400	1,600
	NEW LINE (SECOND LINE)	MOUNTAIN PASS 2 SUBSTATION	EL DORADO SUBSTATION	38	115	5400	EL DORADO SUBSTATION: ADD ONE 230KV CIRCUIT BREAKER	1,200	6,600
								TOTAL	$8,200
							TOTAL FOR PROJECT: 2005, 2008, 2010, 2017		$334,300

Figure 4-1
MONO AND SAN BERNARDINO COUNTIES 2008

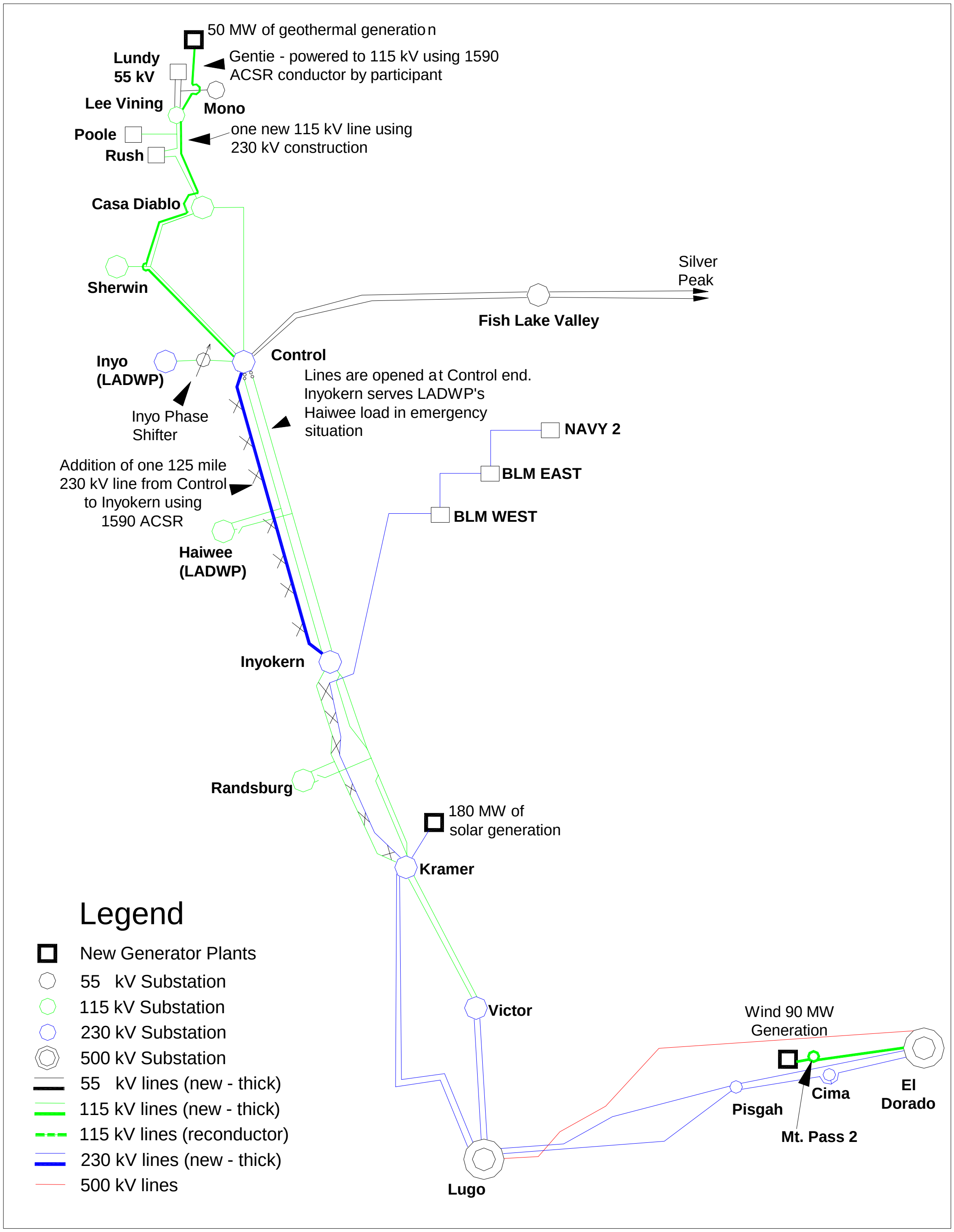


Figure 4-2

MONO AND SAN BERNARDINO COUNTIES 2017

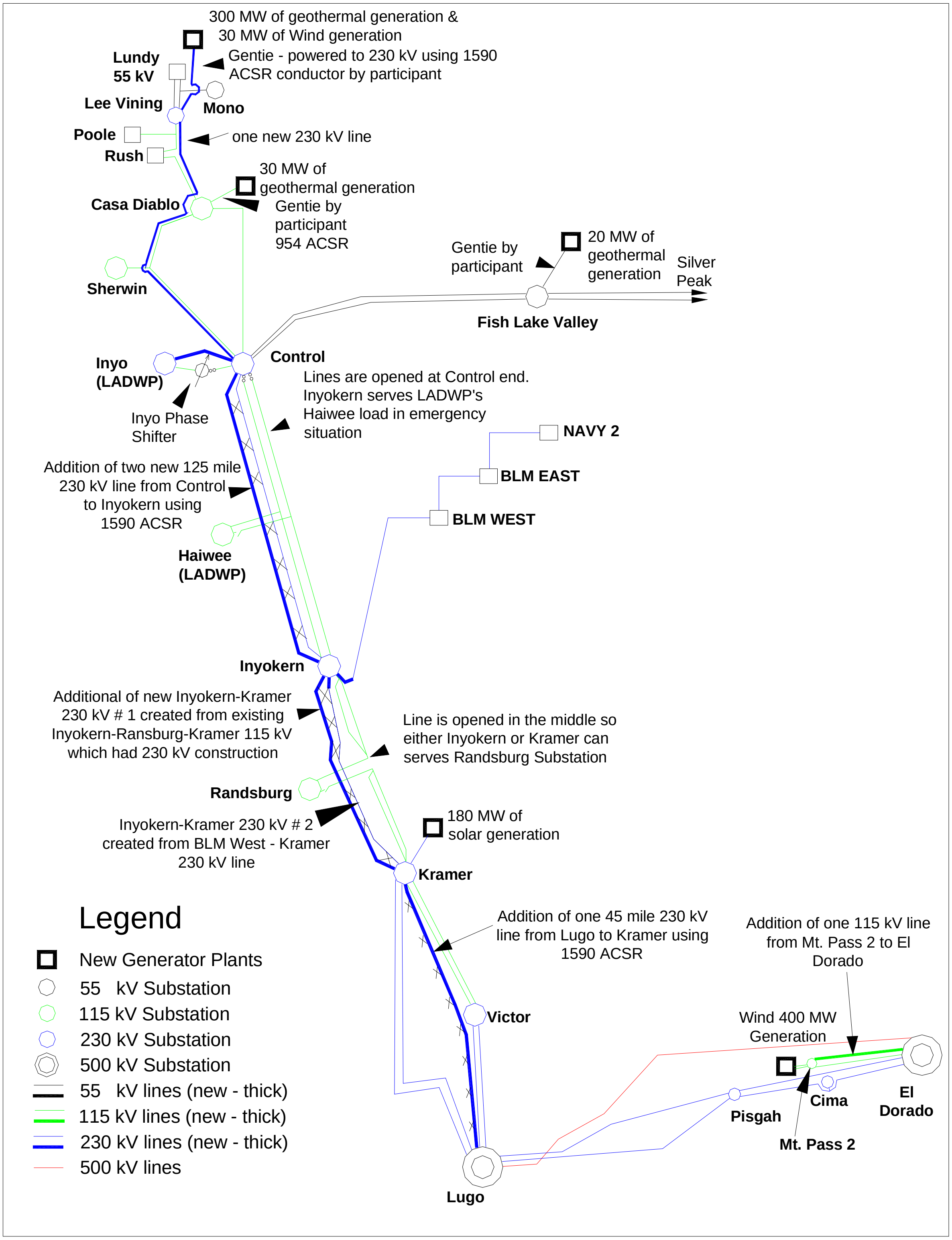


Figure 4-3

MONO AND SAN BERNARDINO COUNTIES – 2008 ACCELERATED SCHEDULE

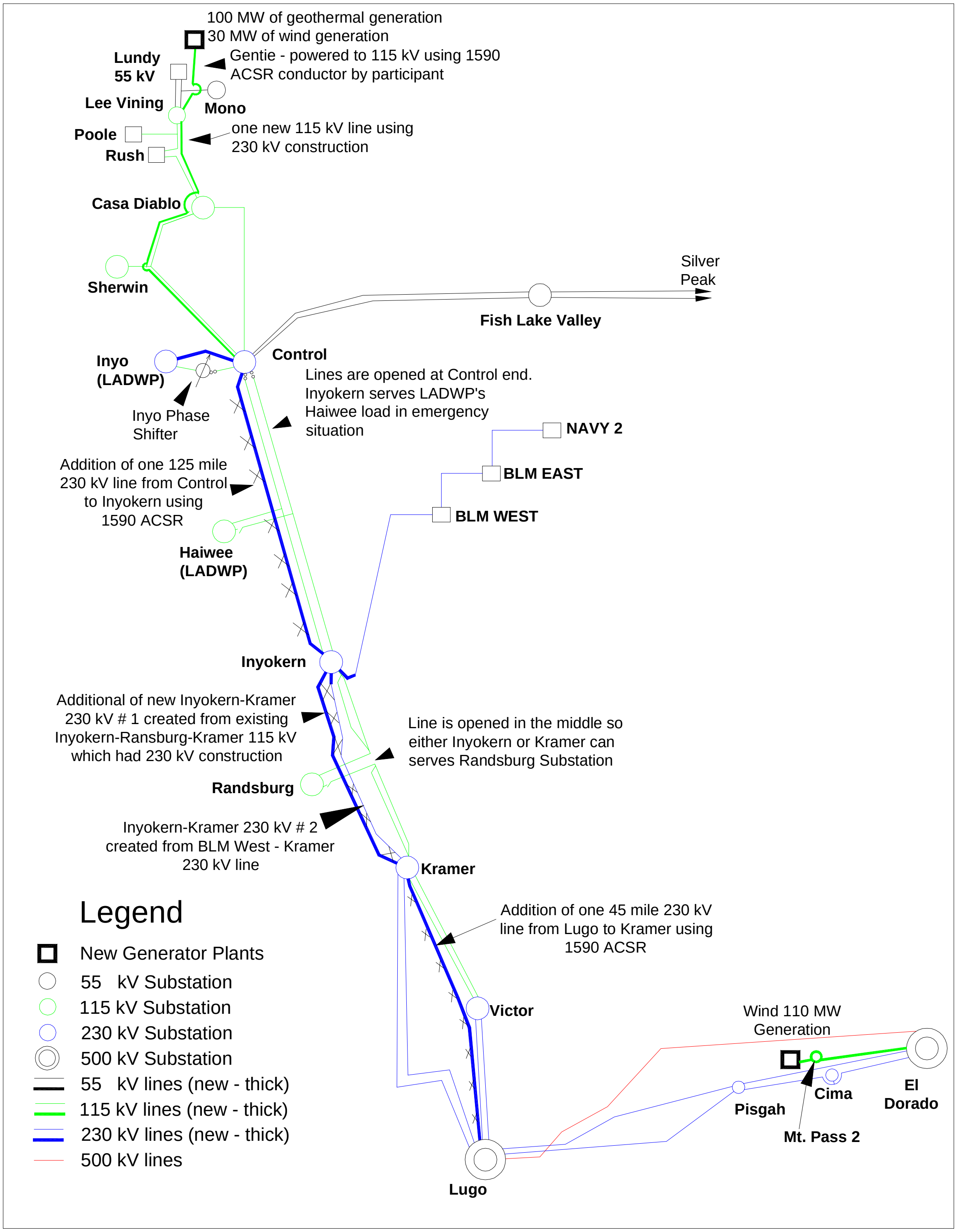
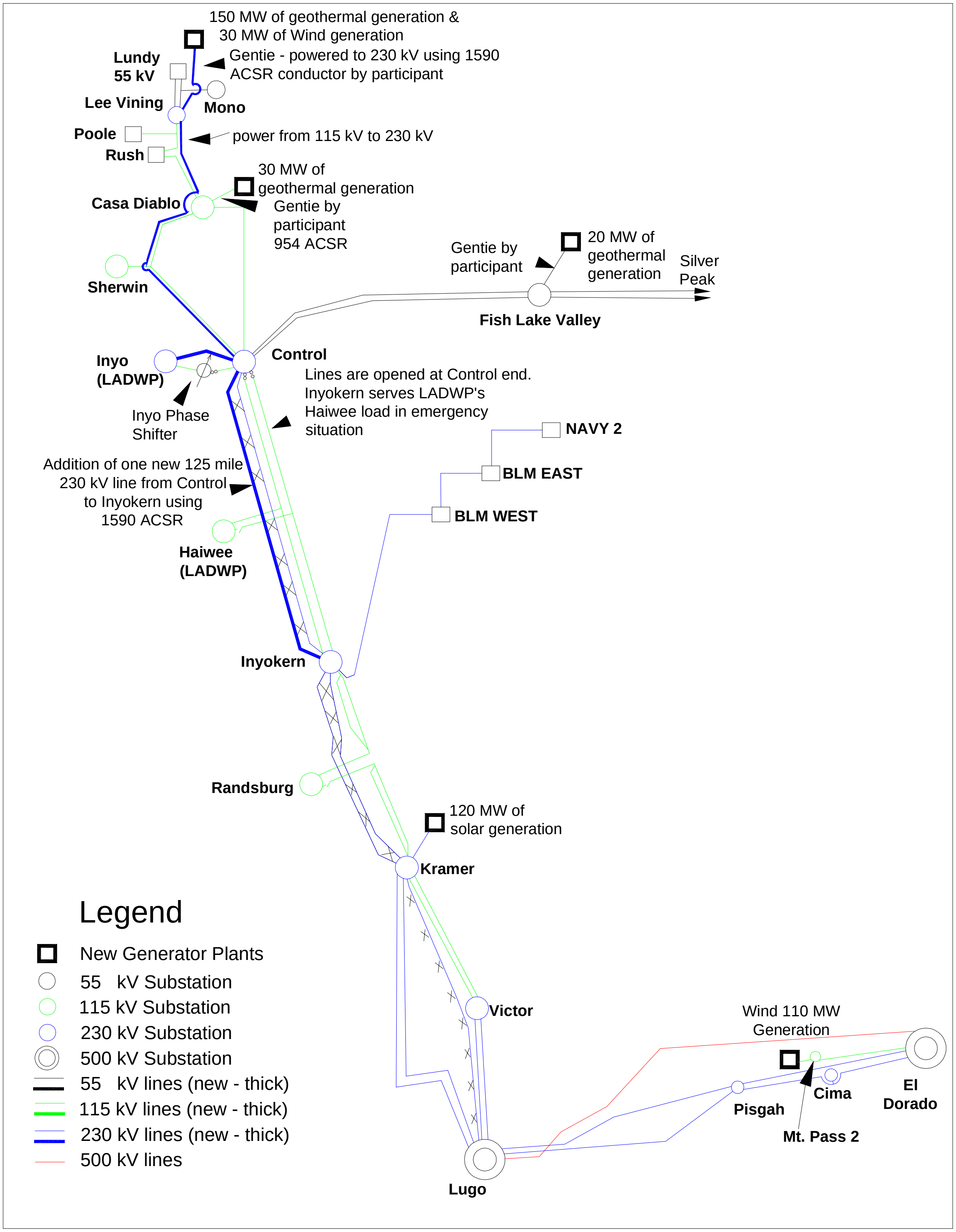


Figure 4-4

MONO AND SAN BERNARDINO COUNTIES – 2010 ACCELERATED SCHEDULE



5. TRANSMISSION PLAN FOR RIVERSIDE & IMPERIAL COUNTIES

REGION & RESOURCES

Riverside and Imperial Counties are located in the southeast corner of the state, adjoining Arizona on the east and Mexico on the south. Power is imported from Arizona to Los Angeles by means of a 500kV transmission line through Riverside County, and to San Diego by another 500kV transmission line which runs just north of the border with Mexico. Merchant electricity plants in Mexico also transmit their output to San Diego over this line. Means for increasing import capacity from Arizona are presently the subject of the “Southwest Transmission Expansion Planning” (STEP) study.

The renewable resources identified by the CEC in the area consist of wind in Riverside County, and wind, geothermal and biomass in Imperial County as shown in Map 5. The capacity of these resources and the dates they could come on line are tabulated in Table 5-1.

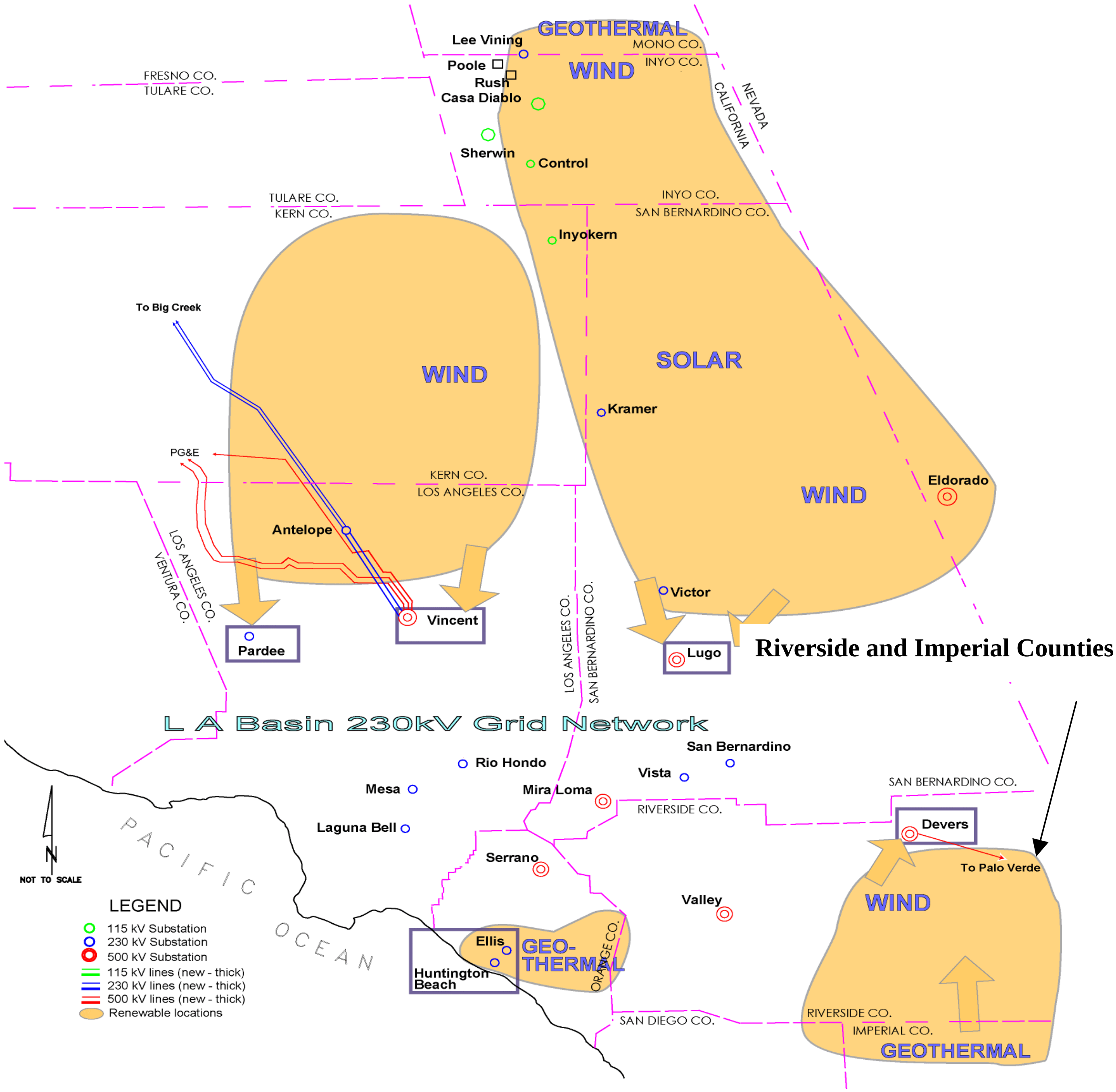
AREA-SPECIFIC CHARACTERISTICS

The area is served by three utilities: SCE, SDG&E and the Imperial Irrigation District (IID). The renewable resources in Imperial County would be connected to the IID network. It is not now known whether this generation would serve IID customers or be transmitted to SCE or to SDG&E or a combination of the foregoing. Therefore, the simplifying assumption was made that all the power would be delivered to SCE’s Devers Substation, initially from IID’s Coachella Substation and subsequently from a new substation arbitrarily designated “Geo”.

TRANSMISSION ADDITIONS

The transmission additions required to accommodate the renewable resource generation through 2017 consist of a new substation in Southeast Riverside County, the “Geo”, and a 230kV transmission line from there to Devers Substation. The transmission in the area, including the renewables additions, are shown for the existing condition, which is unchanged in 2005, and for the years 2008 and 2017 on Figures 5-A, 5-B, and 5-C for the SB 1078 development schedule and Figure 5-D for the year 2010 under the EAP accelerated schedule. The additions are tabulated for each year with corresponding costs on Table 5-A with costs in 2003 dollars, and Table 5-B and 5-C with net present value costs for the SB 1078 schedule and the accelerated schedule respectively.

MAP 5



GEOTHERMAL
Lee Vining
MONO CO.
INYO CO.
Poole
Rush
Casa Diablo
WIND
FRESNO CO.
TULARE CO.
NEVADA
CALIFORNIA
Sherwin
Control
TULARE CO.
KERN CO.
INYO CO.
SAN BERNARDINO CO.
Inyokern
To Big Creek
WIND
SOLAR
Kramer
PG&E
KERN CO.
LOS ANGELES CO.
WIND
Eldorado
Antelope
LOS ANGELES CO.
VENTURA CO.
Victor
Vincent
Pardee
LOS ANGELES CO.
SAN BERNARDINO CO.
Lugo
Riverside and Imperial Counties
L A Basin 230kV Grid Network
San Bernardino
Rio Hondo
Vista
Mesa
Mira Loma
SAN BERNARDINO CO.
RIVERSIDE CO.
Laguna Bell
Devers
N
NOT TO SCALE
PACIFIC
Serrano
To Palo Verde
Valley
WIND
LEGEND
115 kV Substation
230 kV Substation
500 kV Substation
115 kV lines (new - thick)
230 kV lines (new - thick)
500 kV lines (new - thick)
Renewable locations
OCEAN
Ellis
GEO-
THERMAL
ORANGE CO.
Huntington
Beach
RIVERSIDE CO.
IMPERIAL CO.
SAN DIEGO CO.
GEOTHERMAL

TABLE 5

RENEWABLE RESOURCE

GENERATION

MEGAWATT (MW)

RIVERSIDE & IMPERIAL COUNTIES

SB 1078 Schedule

COUNTY	TYPE OF GENERATION	YEAR					
		Added 2005	Added 2008	Added 2010	Total 2010	Added 2017	Total 2017
RIVERSIDE	WIND	200	190	0	390	140	530
IMPERIAL	GEOTHERMAL	120	60	0	180	190	370
	BIOMASS	0	0	0	0	80	80

Accelerated EAP Schedule

COUNTY	TYPE OF GENERATION	YEAR					
		Added 2005	Added 2008	Added 2010	Total 2010	Added 2017	Total 2017
RIVERSIDE	WIND	250	280	0	530	0	530
IMPERIAL	GEOTHERMAL	120	90	120	330	40	370
	BIOMASS	0	50	30	80	0	80

TABLE 5-A

TRANSMISSION ADDITIONS

RIVERSIDE & IMPERIAL COUNTIES

SB1078 SCHEDULE 2003 DOLLARS

YEAR	TRANSMISSION LINES						SUBSTATIONS		TOTAL
	ACTION	**TERMINAL A**	**TERMINAL B**	**MILES**	**VOLTAGE (KV)**	**COST (K$)**	**ACTION**	**COST (K$)**	**COST (K$)**
2005	NEW LINE	WIND FARM COLLECTOR	DEVERS SUBSTATION	10	115	5,900	DEVERS SUBSTATION: ADD ONE 115 KV BREAKER IN EXISTING BREAKER & 1/2 CIRCUIT BREAKER POSITION	1,200	7,100
								TOTAL	$7,100
2008	NEW LINE	GEO SUBSTATION	DEVERS SUBSTATION	50	230	93,600	GEO SUBSTATION: NEW 230KV SUBSTATION WITH 3 DOUBLE BREAKER CIRCUIT BREAKER POSITIONS (6 BREAKERS)	12,700	116,200
							DEVERS SUBSTATION: ADD ONE 230 KV BREAKER IN EXISTING BREAKER & 1/2 CIRCUIT BREAKER POSITION	9,900	
	NEW LINE	WIND FARM COLLECTOR	DEVERS SUBSTATION	10	115	5,900	DEVERS SUBSTATION: ADD ONE 115 KV BREAKER IN EXISTING BREAKER & 1/2 CIRCUIT BREAKER POSITION	1,200	7,100
								TOTAL	$123,300
2017/ 2010	NEW LINE	WIND FARM COLLECTOR	DEVERS SUBSTATION	10	115	5,900	DEVERS SUBSTATION: ADD ONE 115 KV BREAKER IN EXISTING BREAKER & 1/2 CIRCUIT BREAKER POSITION	1,200	7,100
	RECON-DUCTOR	DEVERS SUBSTATION	VISTA & SAN BERNARDINO SUBSTATIONS (2 CIRCUITS EACH)	45 & 43	230	101,900	DEVERS SUBSTATION: ADD SECOND 1120MVA, 500/230KV TRANSFORMER	22,900	124,800
								TOTAL	131,900
							TOTAL FOR PROJECT: 2005, 2008, 2017		$262,300

TABLE 5-B

TRANSMISSION ADDITIONS

RIVERSIDE & IMPERIAL COUNTIES

SB1078 SCHEDULE NPV DOLLARS

YEAR	TRANSMISSION LINES						SUBSTATIONS		TOTAL
	ACTION	TERMINAL A	TERMINAL B	MILES	VOLTAGE (KV)	COST (K$)	ACTION	COST (K$)	COST (K$)
2005	NEW LINE	WIND FARM COLLECTOR	DEVERS SUBSTATION	10	115	5,500	DEVERS SUBSTATION: ADD ONE 115 KV BREAKER IN EXISTING BREAKER & 1/2 CIRCUIT BREAKER POSITION	1,100	6,600
								TOTAL	$6,600
2008	NEW LINE	GEO SUBSTATION	DEVERS SUBSTATION	50	230	81,700	GEO SUBSTATION: NEW 230KV SUBSTATION WITH 3 DOUBLE BREAKER CIRCUIT BREAKER POSITIONS (6 BREAKERS)	9,700	91,400
							DEVERS SUBSTATION: ADD ONE 230 KV BREAKER IN EXISTING BREAKER & 1/2 CIRCUIT BREAKER POSITION	7,500	7,500
	NEW LINE	WIND FARM COLLECTOR	DEVERS SUBSTATION	10	115	4,800	DEVERS SUBSTATION: ADD ONE 115 KV BREAKER IN EXISTING BREAKER & 1/2 CIRCUIT BREAKER POSITION	900	5,700
								TOTAL	$104,600
2017	NEW LINE	WIND FARM COLLECTOR	DEVERS SUBSTATION	10	115	2,400	DEVERS SUBSTATION: ADD ONE 115 KV BREAKER IN EXISTING BREAKER & 1/2 CIRCUIT BREAKER POSITION	500	2,900
	RECON-DUCTOR	DEVERS SUBSTATION	VISTA & SAN BERNARDINO SUBSTATIONS (2 CIRCUITS EACH)	45 & 43	230	42,300	DEVERS SUBSTATION: ADD SECOND 1120MVA, 500/230KV TRANSFORMER	9,500	51,800
								TOTAL	$54,700
							TOTAL FOR PROJECT: 2005, 2008, 2017		$165,900

TABLE 5-C

TRANSMISSION ADDITIONS

RIVERSIDE & IMPERIAL COUNTIES

EAP ACCELERATED SCHEDULE NPV DOLLARS

YEAR	TRANSMISSION LINES						SUBSTATIONS		TOTAL
	ACTION	**TERMINAL A**	**TERMINAL B**	**MILES**	**VOLTAGE (KV)**	**COST (K$)**	**ACTION**	**COST (K$)**	**COST (K$)**
2005	NEW LINE (2 CIRCUITS)	WIND FARM COLLECTOR	DEVERS SUBSTATION	10	115	11,100	DEVERS SUBSTATION: ADD TWO 115 KV BREAKERS IN EXISTING BREAKER & 1/2 CIRCUIT BREAKER POSITIONS	2,200	13,300
								TOTAL	$13,300
2008	NEW LINE	WIND FARM COLLECTOR	DEVERS SUBSTATION	10	115	6,600	DEVERS SUBSTATION: ADD ONE 115 KV BREAKER IN EXISTING BREAKER & 1/2 CIRCUIT BREAKER POSITION	900	7,500
	NEW LINE	GEO SUBSTATION	DEVERS SUBSTATION	50	230	91,600	GEO SUBSTATION: NEW 230KV SUBSTATION WITH 3 DOUBLE BREAKER CIRCUIT BREAKER POSITIONS (6 BREAKERS)	10,600	102,200
							DEVERS SUBSTATION: ADD ONE 230 KV BREAKER IN EXISTING BREAKER & 1/2 CIRCUIT BREAKER POSITION	7,500	7,500
								TOTAL	$117,200
2010	RECON-DUCTOR	DEVERS SUBSTATION	VISTA & SAN BERNARDINO SUBSTATIONS (2 CIRCUITS EACH)	45 & 43	230	67,900	DEVERS SUBSTATION: ADD SECOND 1120MVA, 500/230KV TRANSFORMER	15,200	83,100
								TOTAL	$83,100
2017	NEW LINE	WIND FARM COLLEC	DEVERS SUBSTATION	10	115	3,700	DEVERS SUBSATION: ADD ONE 115 KV BREAKER IN EXISTING BREAKER & 1/2 CIRCUIT BREAKER POSITION	700	4,400
								TOTAL	$4,400
							TOTAL FOR PROJECT: 2005, 2008, 2010, 2017		$218,000

Figure 5-1

RIVERSIDE AND IMPERIAL COUNTIES - 2005

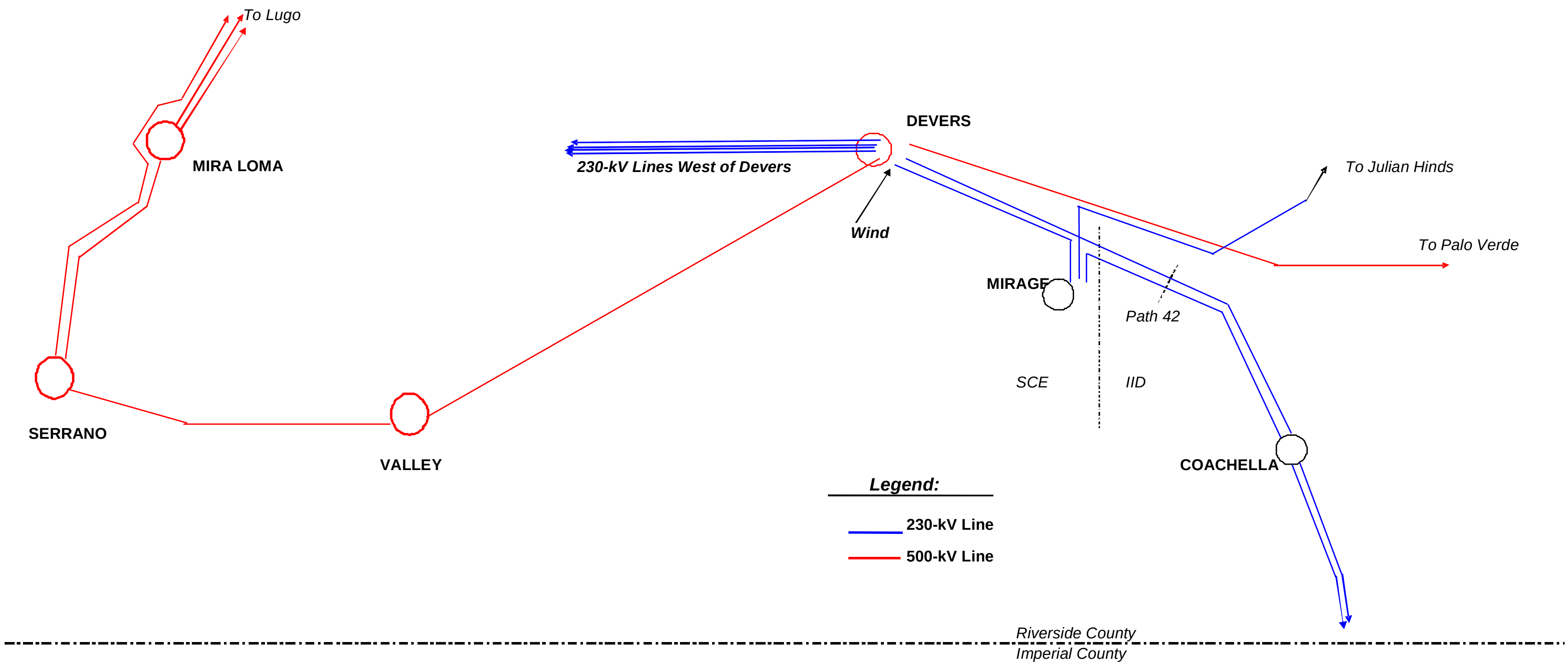


Figure 5-2
RIVERSIDE AND IMPERIAL COUNTIES - 2008

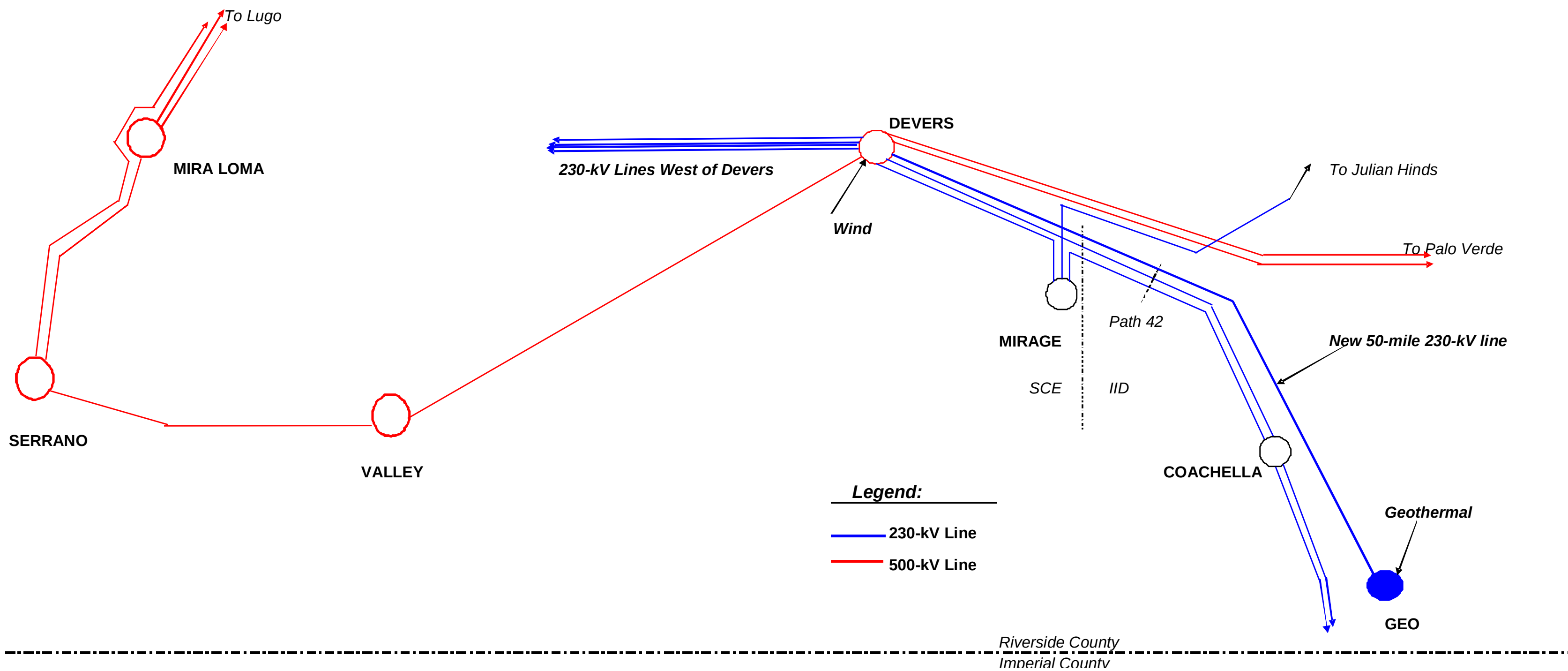


Figure 5-3
RIVERSIDE AND IMPERIAL COUNTIES - 2017

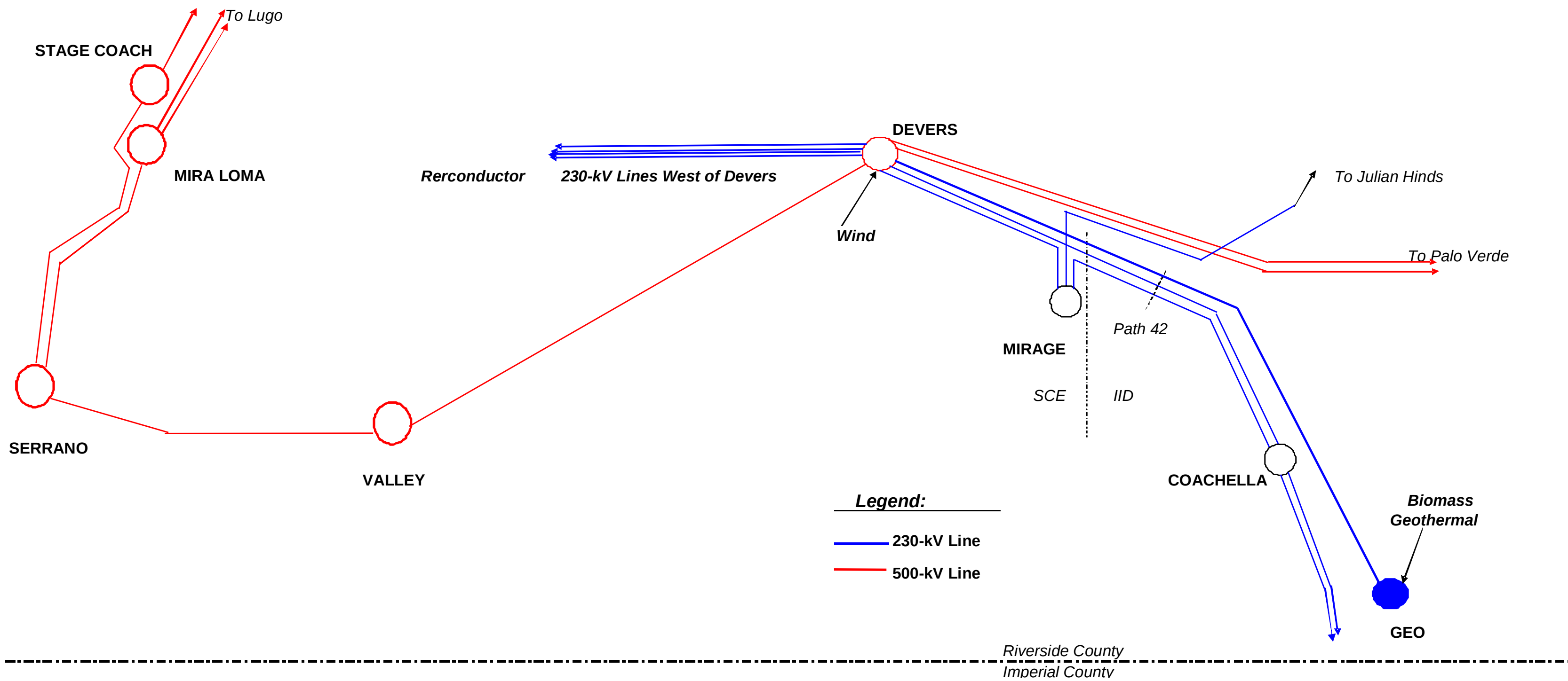
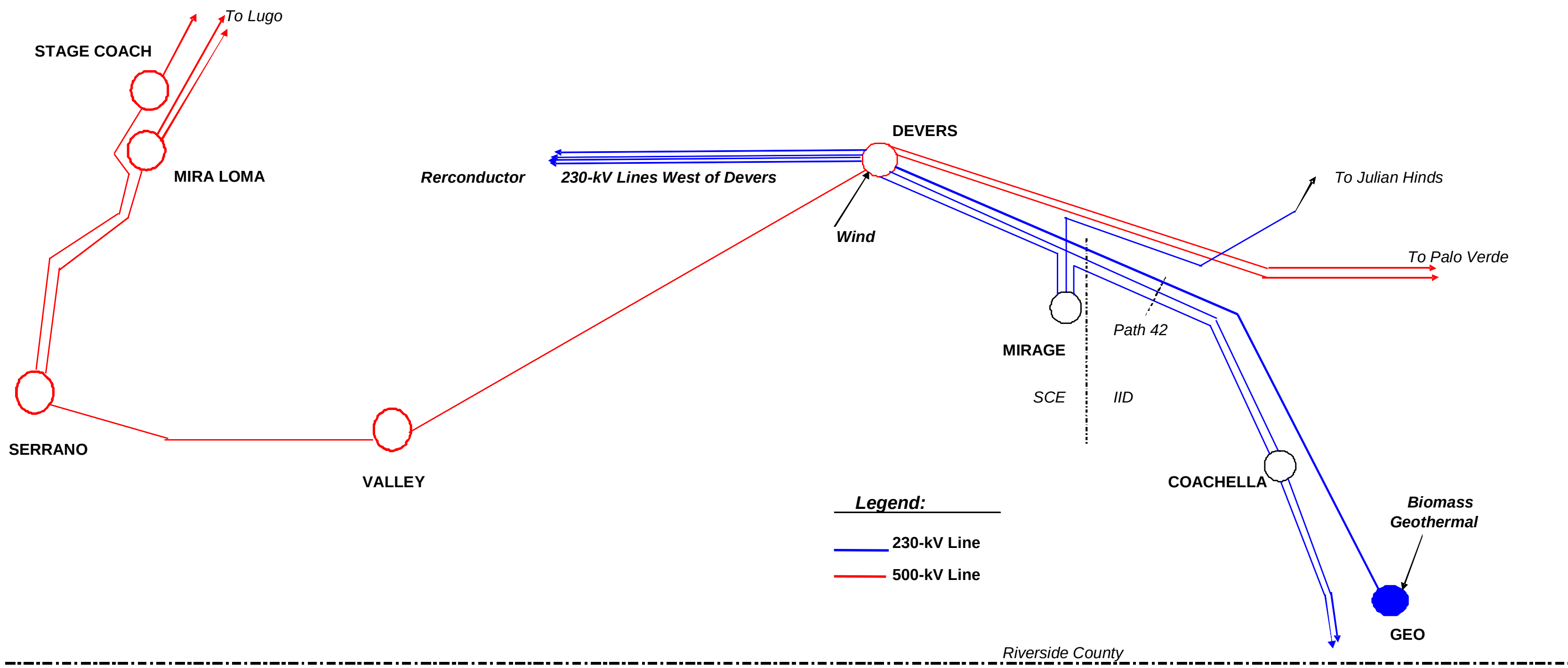


Figure 5-4
RIVERSIDE AND IMPERIAL COUNTIES – 2010 ACCELERATED



6. TRANSMISSION PLAN FOR SAN DIEGO COUNTY

REGION & RESOURCES

San Diego County is located in the southwest corner of the state, adjoining Riverside and San Bernardino Counties in the east and Mexico on the south. Power is imported from Arizona to San Diego by a 500kV transmission line, which runs just north of the border with Mexico. Merchant electricity plants in Mexico also transmit their output to San Diego over this line. Means for increasing import capacity from Arizona are presently the subject of the "Southwest Transmission Expansion Planning" (STEP) study.

The renewable resources identified by the CEC in the area consist of wind and biomass in eastern San Diego County as shown in Maps 6-A and 6-B. The generation capacity of these resources and the dates they could come on line are tabulated in Table 6.

AREA-SPECIFIC CHARACTERISTICS

The area is served by SDG&E with import capability to SCE and the Imperial Irrigation District (IID). This area in eastern San Diego County is very rural and sparsely populated. There is minor impact for environmental issues on protected species and habitat and visual impact. Existing rights of way cross Federal lands. Any changes to existing transmission lines could trigger underground or relocation off Federal lands.

TRANSMISSION ADDITIONS

The transmission additions required to accommodate the renewable resource generation through 2017 consist of two alternatives:

Alternative 1 (preferred due to less cost) - An upgrade to Los Cochos substation in San Diego County, a new 138kV transmission line from New 138kV Collector Site for CEC Wind Resource Area.

Alternative 2 **–** New 230 kV transmission line connecting a New 230 kV Collector Site with another New 230/500kV Collector Site.

CPUC staff agrees that Alternative 1 is the cost effective choice because Alternative 2 cannot be built in two phases and it could potentially impact the reliability of the 500kV system. The transmission in the area, including the renewable additions, is shown for the existing condition, which is unchanged in 2005, and the years 2008 and 2017 on Maps 6-A and 6-B. The additions are tabulated for each year with corresponding costs on Table 6-A with costs in 2003 dollars, and Table 6-B with net present value (NPV) costs. Costs for the accelerated schedule are shown in Table 6-C.

TABLE 6

RENEWABLE RESOURCE

GENERATION

MEGAWATTS (MW)

SAN DIEGO COUNTY

SB 1078 Schedule

COUNTY	TYPE OF GENERATION	YEAR					
		Added 2005	Added 2008	Added 2010	Total 2010	Added 2017	Total 2017
SAN DIEGO	WIND	0	200	N/A	N/A	200	400
SAN DIEGO	BIOMASS	20	10	N/A	N/A	0	30

Accelerated EAP Schedule

COUNTY	TYPE OF GENERATION	YEAR					
		Added 2005	Added 2008	Added 2010	Total 2010	Added 2017	Total 2017
SAN DIEGO	WIND	200	200	0	400	0	400
SAN DIEGO	BIOMASS	20	10	0	30	0	30

TABLE 6-A

TRANSMISSION ADDITIONS

SAN DIEGO COUNTY

SB 1078 SCHEDULE 2003 DOLLARS

YEAR	TRANSMISSION LINES						SUBSTATIONS		TOTAL
Added by	**ACTION**	**TERMINAL A**	**TERMINAL B**	**MILES**	**VOLTAGE (KV)**	**COST (K$)**	**ACTION**	**COST (K$)**	**COST (K$)**
2005	NONE					0	NONE	$0	$0
								TOTAL	$0
2008 ALT 1	NEW LINE	COLLECTOR SITE	LOS COCHOS SUBSTATION	35	138	$16,047	NEW 138kV LINE POSITION AT LOS COCHOS SUBSTATION	$943	$16,990
							NEW 138kV SWITCHYARD/COLLECTOR STATION	$3,809	$3,809
							REPLACE OVERSTRESSED BREAKERS AT LOS COCHOS SUB AND RECONDUCTOR MAIN ST - SOUTHBAY 138KV	$3,911	$3,911
								TOTAL	$24,710
2017/2010 ALT 1	ADD LINE	COLLECTOR SITE	LOS COCHOS SUBSTATION	35	138	$7,538	NEW 138kV LINE POSITION AT LOS COCHOS SUBSTATION	$2,361	$9,899
							NEW 138kV SWITCHYARD/COLLECTOR STATION	$1,113	$1,113
							SYSTEM UPGRADES OF ADDITIONAL NEW LINES AND LINE RECONDUCTORING	$14,900	$14,900
								TOTAL	$25,912
								TOTAL	**$50,622**
2017 ALT 2	NEW GEN TIE LINE	COLLECTOR SITE	SWPL SUBSTATION	20	230	$28,741	NEW 500/230kV SUBSTATION AT SWPL	$18,165	$46,906
							NEW 230kV SWITCHYARD/COLLECTOR STATION	$9,892	$9,892
							SUBSTATION INTERCONNECTION COSTS	$2,731	$2,731
								TOTAL	$59,529
								TOTAL	**$84,239**

TABLE 6-B

TRANSMISSION ADDITIONS

SAN DIEGO COUNTY

SB 1078 SCHEDULE NPV DOLLARS

YEAR	TRANSMISSION LINES						SUBSTATIONS		TOTAL
Added by	ACTION	TERMINAL A	TERMINAL B	MILES	VOLTAGE (KV)	COST (K$)	ACTION	COST (K$)	COST (K$)
2005	NONE					0	NONE	$0	$0
								TOTAL	$0
2008 ALT 1	NEW LINE	COLLECTOR SITE	LOS COCHOS SUBSTATION	35	138	$12,027	NEW 138kV LINE POSITION AT LOS COCHOS SUBSTATION	$707	$12,734
							NEW 138kV SWITCHYARD/COLLECTOR STATION	$2,855	$2,855
							REPLACE OVERSTRESSED BREAKERS AT LOS COCHOS SUB AND RECONDUCTOR MAIN ST - SOUTHBAY 138KV	$2,931	$2,931
								TOTAL	$18,520
2017 ALT 1	ADD LINE	COLLECTOR SITE	LOS COCHOS SUBSTATION	35	138	$3,126	NEW 138kV LINE POSITION AT LOS COCHOS SUBSTATION	$979	$4,105
							NEW 138kV SWITCHYARD/COLLECTOR STATION	$462	$462
							SYSTEM UPGRADES OF ADDITIONAL NEW LINES AND LINE RECONDUCTORING	$6,180	$6,180
								TOTAL	$10,746
								TOTAL	**$29,266**
2017 ALT 2	NEW GEN TIE LINE	COLLECTOR SITE	SWPL SUBSTATION	20	230	$11,920	NEW 500/230kV SUBSTATION AT SWPL	$7,534	$19,454
							NEW 230kV SWITCHYARD/COLLECTOR STATION	$4,103	$4,103
							SUBSTATION INTERCONNECTION COSTS	$1,133	$1,133
								TOTAL	$24,689
								TOTAL	**$43,209**

TABLE 6-C

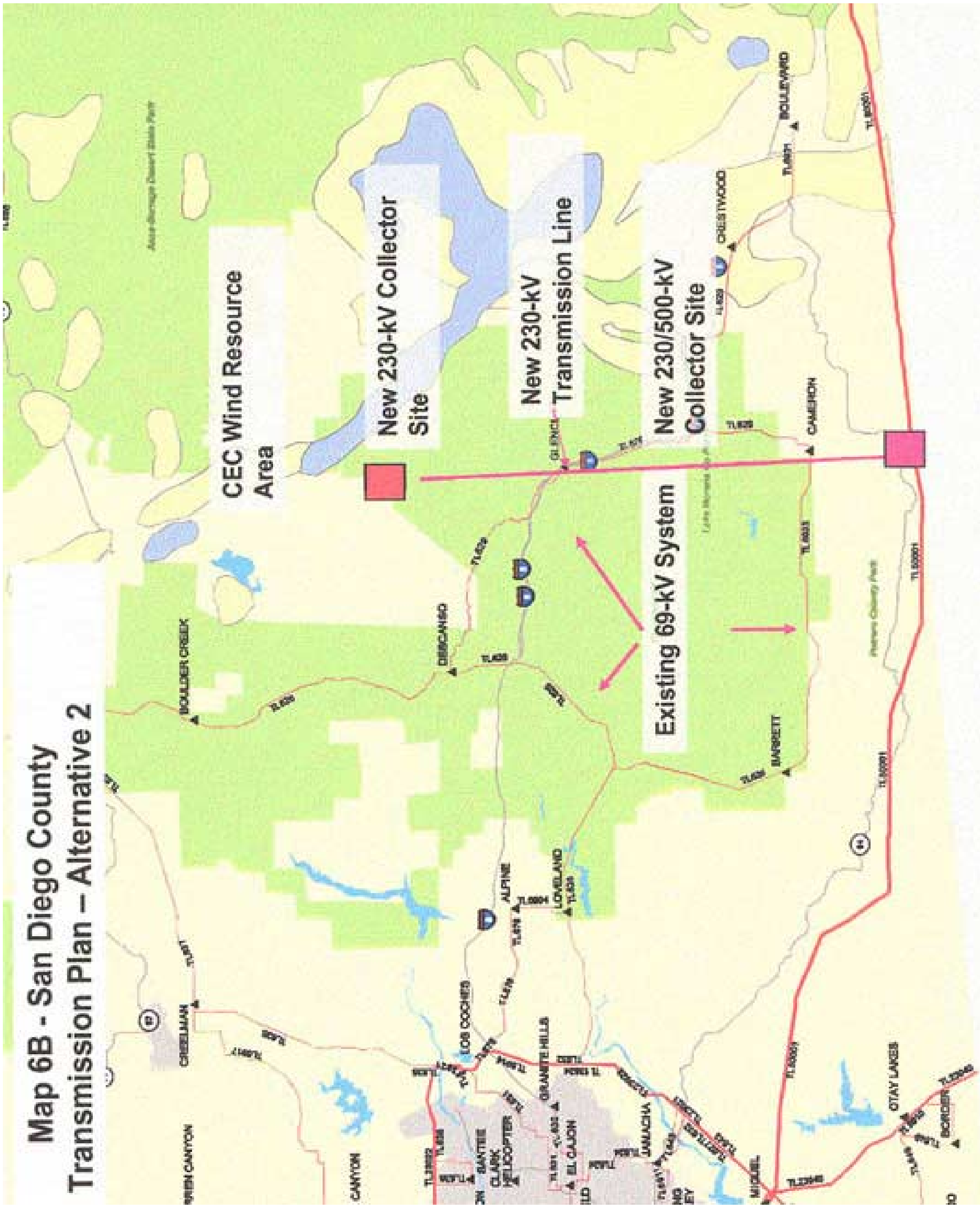
TRANSMISSION ADDITIONS

SAN DIEGO COUNTY

EAP ACCELERATED SCHEDULE NPV DOLLARS

YEAR	TRANSMISSION LINES						SUBSTATIONS		TOTAL
Added by	**ACTION**	**TERMINAL A**	**TERMINAL B**	**MILES**	**VOLTAGE (KV)**	**COST (K$)**	**ACTION**	**COST (K$)**	**COST (K$)**
2005	NONE					0	NONE	$0	$0
								TOTAL	$0
2008 ALT 1	NEW LINE	COLLECTOR SITE	LOS COCHOS SUBSTATION	35	138	$12,027	NEW 138kV LINE POSITION AT LOS COCHOS SUBSTATION	$707	$12,734
							NEW 138kV SWITCHYARD/COLLECTOR STATION	$2,855	$2,855
							REPLACE OVERSTRESSED BREAKERS AT LOS COCHOS SUB AND RECONDUCTOR MAIN ST - SOUTHBAY 138KV	$2,931	$2,931
								TOTAL	$18,520
2010 ALT 1	ADD LINE	COLLECTOR SITE	LOS COCHOS SUBSTATION	35	138	$4,954	NEW 138kV LINE POSITION AT LOS COCHOS SUBSTATION	$1,551	$6,505
							NEW 138kV SWITCHYARD/COLLECTOR STATION	$732	$732
							SYSTEM UPGRADES OF ADDITIONAL NEW LINES AND LINE RECONDUCTORING	$9,791	$9,791
								TOTAL	$17,028
								TOTAL	**$35,548**
2010 ALT 2	NEW GEN TIE LINE	COLLECTOR SITE	SWPL SUBSTATION	20	230	$18,887	NEW 500/230kV SUBSTATION AT SWPL	$11,937	$30,824
							NEW 230kV SWITCHYARD/COLLECTOR STATION	$6,501	$6,501
							SUBSTATION INTERCONNECTION COSTS	$1,795	$1,795
								TOTAL	$39,119
								TOTAL	**$57,639**


Map 6A - San Diego County
Transmission Plan – Alternative 1
SANTA YSABEL
CREELMAN
BOULDER CREEK
CEC Wind Resource
Area
New 138-kV
Transmission Line
Los Coches 138-kV
New 138-kV Collector
Site
LOS COCHES
SANTEE
ALPINE
GRANITE HILLS
LOVELAND
EL CAJON
JAMACHA
GLENCLIFF
Existing 69-kV
System
CRESTWOOD
BARRETT
CAMERON
BOULEVARD
OTAY LAKES
BORDER


Map 6B - San Diego County
Transmission Plan – Alternative 2
CEC Wind Resource Area
New 230-kV Collector Site
New 230-kV Transmission Line
New 230/500-kV Collector Site
Existing 69-kV System
BOULDER CREEK
DESCANSO
ALPINE
LOVELAND
BARRETT
CAMERON
CRESTWOOD
BOULEVARD
LOS COCHES
GRANITE HILLS
CREELMAN
SANTEE
EL CAJON
JAMACHA
OTAY LAKES

APPENDIX A

SOLARGENIX GENERATION PLAN

The Solargenix (Solargenix) Generation plan describes a proposal to add 1000 MWs of solar generation in the Southern California Edison (SCE) territory. The plan was not prepared in time to be included in the CEC report (Resource Assessment shown here as Table 1A), and is not reflected in SCE's transmission study based on that report. SCE, however, accepted the proposal as the subject of a separate transmission study, delivered to and filed by Solargenix on September 15, 2003, and described briefly in this section.

The plan is based on the competitive cost of solar versus combustion turbines when used in meeting "peaking" loads.

SCE has provided a conceptual transmission facilities study to accommodate the additional generation with the following schedule:

2005 – 100MW
2008 – 400 MW
2017 – 500 MW

The following planned phases identified by the SCE Conceptual Transmission study would be interconnected to the Kramer substation, which could interconnect 100MWs in 2003 without any new facilities (other than work in the Kramer Substation). The other phased additions need further analysis covered in a System Impact Study, which may need the additional 500kV transmission lines to Los Angeles Basin in 2002 CAISO Annual Assessment. Facility upgrades indicate new 230kV lines connecting Lugo and Kramer substation are needed to deliver the renewables to the load centers as well. The Conceptual Study identified there are licensing and environmental requirements and limitations for the new lines right of ways and substation sites.

This could represent about 10% of the total renewables that would be considered in the transmission study.

Due to the limited time and changing nature of renewable resource development, this section recognizes the Solargenix plan as an option that may warrant further consideration.

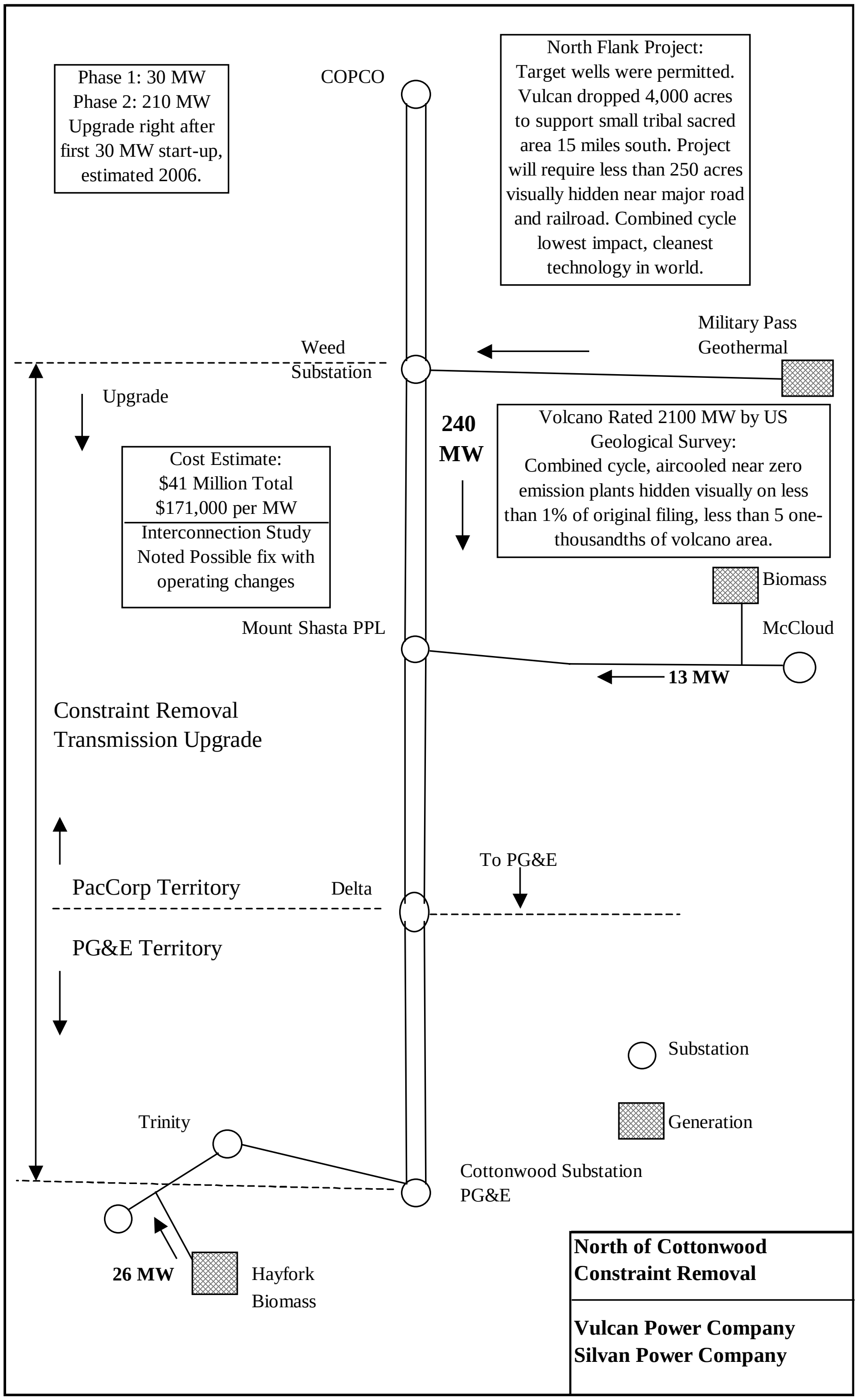
APPENDIX B

Vulcan Proposals:

- North of Cottonwood
- Northeast Green Line
- Green Tap Project
- North of Lugo

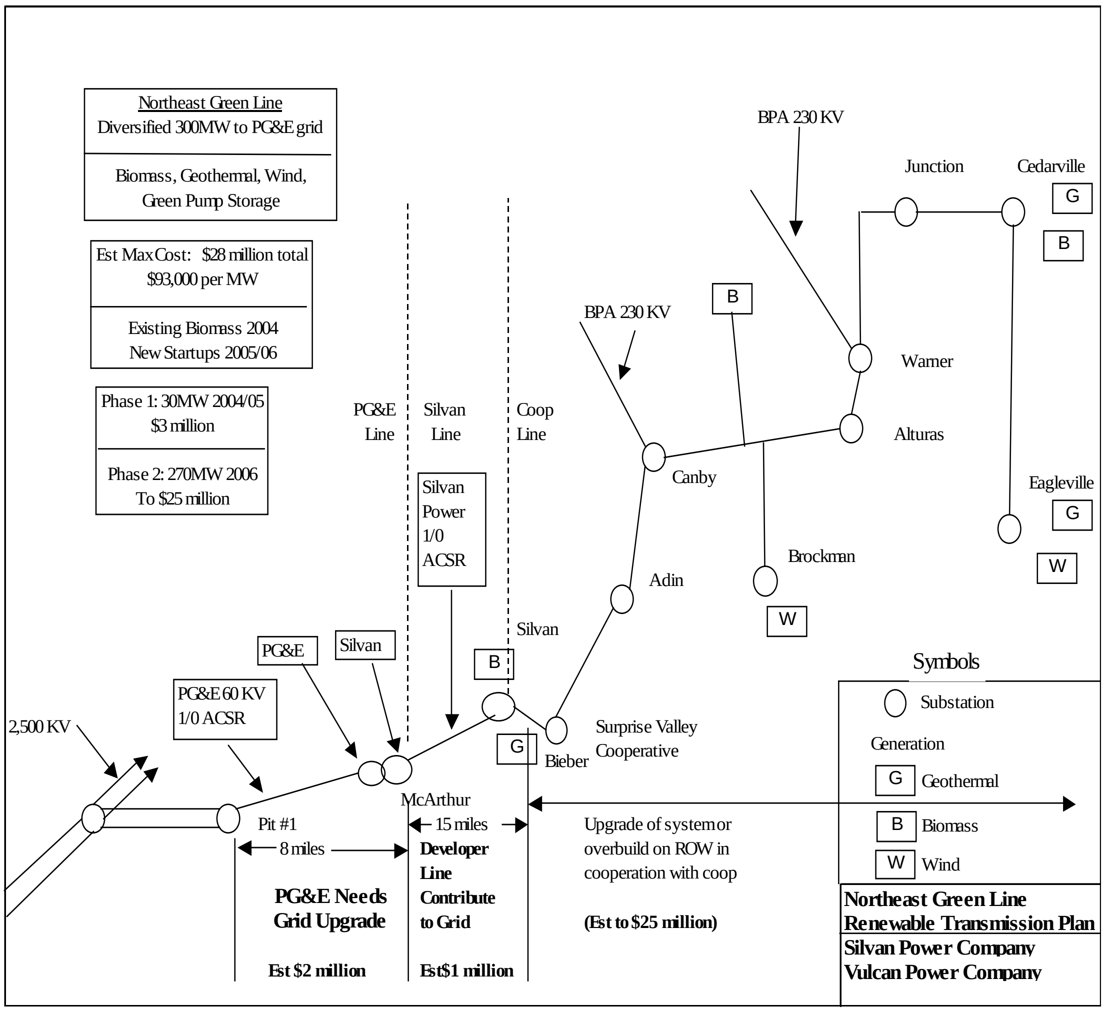
North of Cottonwood Green Line
Siskiyou and Shasta Counties, California
Transmission Constraint Removal Plan
240 MW Baseload For PG&E Territory

Data Sources: CPUC Transmission Docket PG&E Conceptual Study for Vulcan Power Company and developer project work.



Northeast Green Line
Modoc and Lassen Counties, California
300 MW Diversified Renewables Upgrade
Existing Developer-owned Line to PG&E

Data Sources: Developer-owned line data, consultants, coop preliminary discussions.



Data Sources: Electranix consultant comments on CEC Project: "Feasibility of Connecting to Pacific HVDC Intertie" technical and cost sections of draft dated 2/24/03, and Vulcan discussions with Sierra Pacific Power Company, other consultants and utilities. Terminal upgrades now underway will fix line problems and re-rate PDCI to 3,200 MW. The terminal upgrades reportedly benefit the tap since little if any new terminal cost will now be required above actual tap costs.

Background Data: Vulcan was selected to provide up to 240 MW across PDCI by LADWP renewables-only RFP 3 years ago. Action to advance selection to PPA contracts in support of RPS muni goals was refused by LADWP generation group which states they prefer to build coal and gas plants instead of honoring the significant baseload green power selections.

Vulcan also proposed 240 MW of its near border Nevada geothermal power to SCE in response to recent renewable-only RFP after LADWP generation group managers delayed for nearly two years. Vulcan has also notified Caithness, a geothermal developer in Dixie Valley, Nevada and owner of the Dixie Valley Line that the companies might cooperatively deliver new power to California utilities across the Vulcan Aurora Green Tap substation and jointly utilize the Dixie Valley Line as a gentie to mutual benefit.

If Caithness does not want to cooperate in use of Dixie Valley line, FERC previously specifically ruled this line is subject to open access tariff requirements for entities seeking service over the line.

Two Routes: SP 15 South to Sylmar Terminal Los Angeles
NP 15 North to Celilo Terminal Thence South to COB

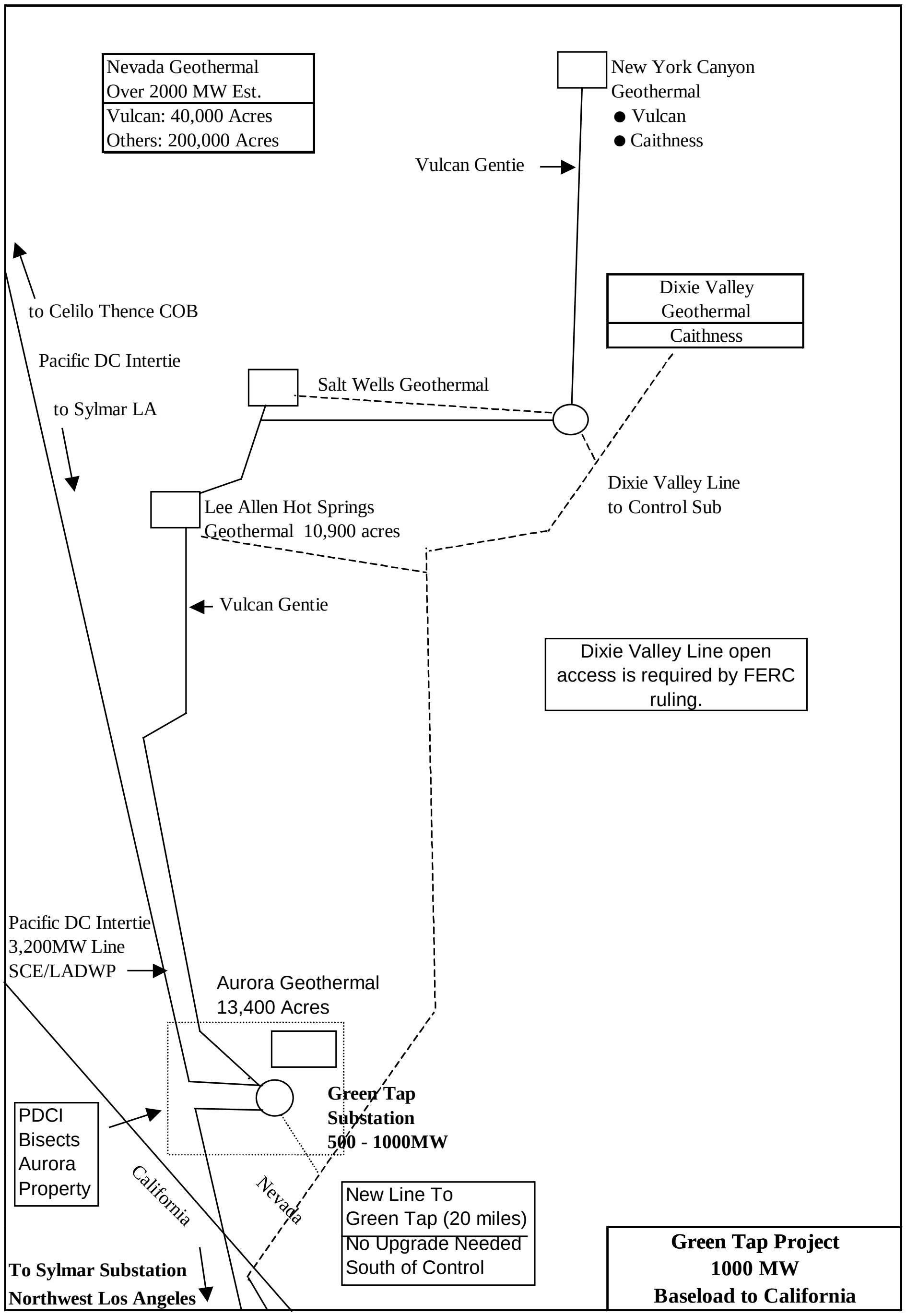
Preliminary Cost Estimates:

Cal Power Tap Size (MW)	Estimated Total Cost	Cost per MW (1)
500	$100 million	$200,000
1,000	$150 million	$150,000

Note: (1) This is for 95-98% available baseload geothermal power. If used for wind, the cost per MW is about 3x higher.

Green Tap Project
500 MW to 1,000 MW Renewable Grid Plan
Delivery At 3,200 MW Pacific DC Intertie Line New Substation
On Vulcan Aurora Geothermal Property: 5 Miles East of California Border

SP 15 Delivery: South to Sylmar Terminal Los Angeles
NP 15 Delivery: North to Celilo Terminal Thence to COB



Alternate Gentie Plans:

(1) New Vulcan gentie from 3 properties to Aurora (solid line ___)

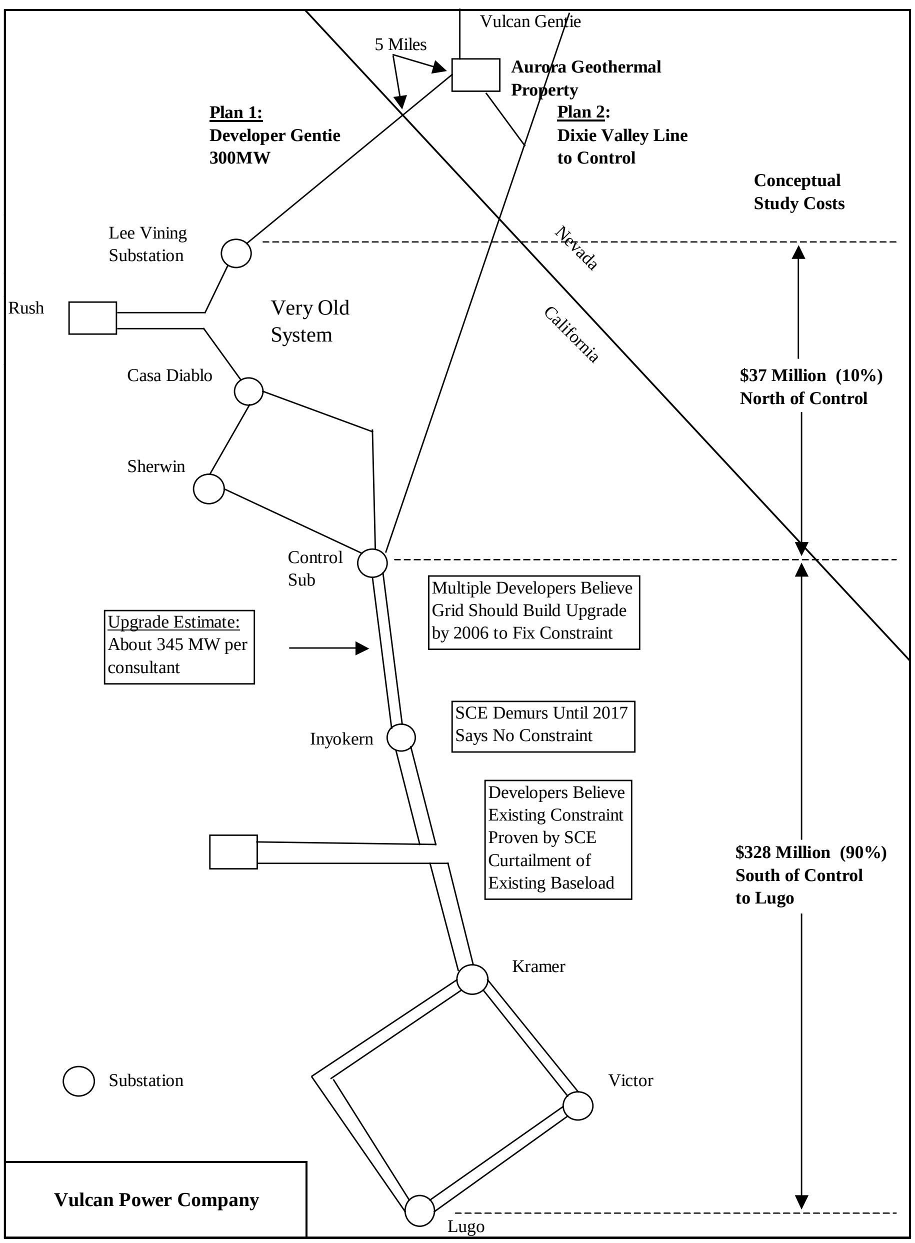
(2) Vulcan property gentie to Dixie Valley line then connect it to Green Tap (dashed line -----)

(PDCI owned 50/50 in Nev-Cal by SCE/LADWP and by BPA in Oregon.)

North of Lugo / North of Control Plan
Mono and Inyo Counties, California
300 MW Delivery to SCE At Control Sub

Data Sources: Vulcan sponsored SCE conceptual study under CPUC Transmission docket, experienced transmission consultants, developer evaluation, FERC ruling on Dixie Valley Line. SCE study provided to CEC for transmission plan input. That study did not include Dixie Valley Line because CEC had not yet approved out of state renewables for RPS.

Comparative Note: This cost is much higher per unit output than Green Tap project and both Northeast Green Line and North of Cottonwood Upgrade. Option is likely to build Green Tap Project or North of Lugo upgrade but not both.



Alternate Plans (1):

(1) Aurora Gentie to Lee Vining Sub thence to Control (300 MW).

Cost: $365 million
$1.22 million per MW for 300 MW

(2) Project Genties to Dixie Valley Line to Control (300 MW)

Cost: $328 million
$1,093,000 per MW for 300 MW and $950,000 per MW for 345 MW

Note: (1) Plans supply baseload power. Wind supply will cost about 3 times more per MW output.