4. Regulatory and Institutional Environment

The regulatory framework applicable to energy markets in the West is composed of a complex interaction of federal and state requirements related to energy and the environment.[1] As described below, in California, restructured markets were designed through a political process involving state, federal, and stakeholder inputs. The result of this process was an extremely complicated market design, with continued state and federal oversight at every organizational level. Furthermore, the new market entities created to implement restructured markets in California, the California Independent System Operator Corporation (Cal-ISO) and the California Power Exchange Corporation (PX), are governed by interested stakeholder boards which are charged with sorting through these political and market complexities, while maintaining a fiduciary duty to the Cal-ISO and PX. These are further overseen by an Electricity Oversight Board. All of this is in addition to the traditional regulatory oversight of the Federal Energy Regulatory Commission and the California Public Utilities Commission (CPUC).

Environmental regulation in California affects the siting and operation of generation and transmission projects. As discussed below, the regulatory structure is complicated and involves many layers of state and federal regulation. Local air quality factors have become of particular importance. Consequently, the review process for siting new transmission or generation facilities is frequently very lengthy; and, once constructed, environmental standards can significantly affect operations and generation costs.

A. Economic Regulation of Utilities

1. Federal Economic Regulation

The Federal Energy Regulatory Commission (Commission) is the principal federal regulatory agency responsible for electric regulation in the Western Systems Coordinating Council (WSCC) region.[2] The Commission regulates the rates, and terms and conditions governing the sale and

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[1] While other states in the West have passed restructuring initiatives, they have not been fully implemented and do not pose the regulatory complexities observed in California. Therefore, our primary focus is on the regulatory structures in California.

[2] The Commission also regulates: (1) the licensing, operations, and safety of all non-federal hydroelectric facilities located on navigable streams and facilities constructed after 1935 which are located on waters over which Congress has Commerce Clause jurisdiction and which affect the interests of interstate or foreign commerce; (2) the rates, terms and conditions for the transportation and sale for resale of gas in interstate commerce; and (3) the siting, construction and abandonment of interstate pipelines.

transmission of bulk power in interstate commerce under the Federal Power Act.[3] The Commission's mandate under the FPA is to assure that rates and terms and conditions are just and reasonable and not unduly discriminatory or preferential. The Commission's authority extends to the structure of both ISOs and the RTOs.[4] The Commission has limited authority over municipal, state, or federally owned generating and transmission facilities under the Federal Power Act. The Commission has permitted many generating entities in the west to charge market-based rates for the power they sell.

2. Economic Regulation of Electric Utilities in California

The State Regulatory Structure

Economic regulation of electric utilities in California is conducted by several agencies. Electric restructuring in California was initiated by the CPUC, which issued a series of policy decisions in 1994 and 1995. These decisions were followed by legislative enactment of Restructuring Legislation, under Assembly Bill 1890 (AB 1890). These state actions were taken in conjunction with a massive stakeholder process in which all segments of the California electric industry participated in developing the new market structure. Ultimately, the fruits of this process were submitted to the Commission for review.

Among other things, the new regime provided for establishment of two new entities, the California ISO and PX, to reliably operate the California transmission grid and to provide a spot market for electric energy; mandatory divestiture by California IOUs of significant portions of their generation; transfer of operational control of IOU transmission facilities to the Cal-ISO; implementation of retail access as of January 1, 1998, a non-bypassable Competition Transition Charge (CTC) which will allow IOUs to recover stranded costs through March 2002, a rate freeze to remain in place until the IOUs recover their stranded costs; a mandatory buy-sell requirement to ensure that the PX is a viable market entity; market monitoring within the ISO and PX; and oversight by several state agencies.

The CPUC regulates the retail rates of all privately owned electric utilities in California, but does not regulate municipal electrical corporations, which include some 14 municipal power companies,

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[3] Federal Power Act, Part II, 16 USC § 824, et seq; Pacific Gas and Electric Co., et al., 77 FERC ¶ 61,818 (1996).

[4] *See, e.g.*, Regional Transmission Organizations, Order No. 2000, 65 Fed. Reg. 809 (January 6, 2000), FERC Statutes and Regulations ¶ 31,089 at 30,994 and 31,037 (2000). In reviewing ISO or RTO filings, the Commission considers: the tariffs of such organizations, the terms for access to the interstate grid, the structure of their governing boards, delegated enforcement activities, and provisions such as an OASIS designed to assure non-discriminatory access to information regarding the operation of the electricity grid.

1 cooperative, and 4 state power authorities. The CPUC is responsible for evaluating the economic need for additional transmission capacity and reviews the reasonableness of proposed construction costs for rate making purposes once construction has been completed. Under AB 1890, the CPUC is charged with implementing direct retail access, regulating retail rates and services of state-regulated IOUs, retail distribution operation and reliability, IOU mergers, consumers protection and education programs regarding retail electricity services, administration of IOU contracts with qualifying facilities, examination of market behavior of IOUs and their affiliate transactions, and implementing the CTC mechanism as a non-bypassable charge on all customers.[5]

AB 1890 created a new regulatory entity, the California Electricity Oversight Board (EOB), to provide an oversight function over the ISO and PX. As modified by Senate Bill 96, the EOB's functions include monitoring, evaluating and representing state interests concerning the operation and reliability of the interconnected electric transmission system and the markets for generation and bulk energy including the ISO and PX and similar entities, and the rules and policies affecting these entities.[6] In addition, the EOB has the right to approve procedures and qualifications of, and to confirm the appointments of, Cal-ISO and PX governing board members representing retail and end-use classes.[7] Furthermore, the EOB has the right to serve as an appeal body for majority decisions of the ISO governing board related to matters exclusively within California's jurisdiction. The EOB consists of three voting members appointed by the Governor of California, and two non-voting members appointed by the California House and Senate, respectively, plus a professional staff of analysts and lawyers.

Under the AB 1890, two new entities were established to operate and to maintain the reliability of the interstate transmission grid and to operate a spot market for electric energy. The Cal-ISO is responsible for operating most of the transmission system in California. The ISO-controlled grid excludes local distribution facilities and facilities owned by municipalities that have not joined the ISO. The ISO controls, but does not own the network which remains titled in the name of its member companies. The ISO receives balanced operating schedules from the various scheduling coordinators to transmit power throughout the state. The ISO is responsible for resolving congestion issues within its system, for purchasing power needed to maintain system reliability, and for evaluating and determining the need for transmission system upgrades of the network it is responsible for operating. The authority of the ISO to require upgrades of the network it is charged with operating is subject to the concurrence of the owning utility. The ISO also operates a real time balancing market and ancillary services markets, and is responsible for all coordinating and regional reliability obligations involving the WSCC.

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5 *See* Draft Memorandum of Understanding between the EOB and CPUC, January 20, 1999.

6 *Id.*

7 The EOB has the exclusive right to decline to confirm representatives of the agricultural end-user, industrial end-user, commercial-end-user, residential end-user, end-user at large, nonmarket participant and public interest group classes.

The ISO is governed by a 26-member stakeholder board, consisting of representatives of the following classes: CEO and President; Investor-Owned Utility Transmission Owners (3 members); Municipal Utilities (4 members); Government Market Participant Entities (1 member); Non-Utility Electric Sellers (2 members); Public Byers and Sellers (1 member); Private Buyers and Sellers (1 member); Agricultural End-Users (1 member); Industrial End-Users (1 member); Commercial End-Users (1 member); Residential End-Users (2 members); End-User at Large (4 members); Public Interest Groups (2 members); Non-Market Participants (2 members); plus several non-voting Advisory representatives. The ISO bylaws and structure require at least a majority vote to pass motions. This structure ensures that no two classes of customers can combine to dominate ISO Board decision making. The Cal-ISO has a market monitoring unit, called the Department of Market Analysis, and an external Market Surveillance Committee.

The PX was created under AB 1890 to function as the principal power market in California. The PX establishes prices for a day-ahead market based on demand quantities and prices it receives from parties trading through the PX. These prices incorporate the amount that parties are willing to pay as congestion relief charges. The PX is also a scheduling coordinator in the ISO. Once the day-ahead price and quantities are established, the PX submits the balanced schedules to the ISO. If congestion develops, another round of schedules, which incorporates congestion charges, is developed and submitted to the ISO. The PX also acts as a clearing house for the daily and hourly markets. Under AB 1890, the three major electric utility companies in California (SDG&E, SoCal Edison and PG&E) are required to make all of their purchases through the PX. Since 1999, the PX has operated a block-forward market in an attempt to provide greater depth and to allow participants to hedge against price volatility. The PX has both an internal market monitoring compliance unit and an external Market Monitoring Committee to maintain vigilance against market abuses in the newly restructured environment.

Like the ISO Governing Board, the PX Governing Board is a stakeholder board, representing the following classes: CEO and President; Privately Owned Distribution Companies (3 members); Publicly Owned Distribution Companies (3 members); Public Buyers and Sellers (2 members); Private Buyers and Sellers (2 members); Non-Utility Generators (3 members); Agricultural End-Users (1 member); Industrial End-Users (1 member); Commercial End-Users (1 member); Residential End-Users (2 members); End-User at Large (3 members); Public Interest Groups (2 members); Non-Market Participants (2 members); plus several non-voting Advisory representatives. Like the ISO, the PX Governing Board has structural checks against dominance by any one or two voting classes.

The CPUC and EOB recently have recommended that the stakeholder boards should be eliminated and replaced with boards appointed by the Governor.[8] They have also recommended that the EOB's authority over the PX and Cal-ISO should be clarified and that either the CPUC or the

[8] EOB/CPUC Report to the Governor, at 46-47.

EOB should be given authority to sanction power plant owners, electricity sellers or scheduling coordinators.

CPUC Policies for IOU Generation and Purchases

The California Commission's Preferred Policy Decision, 64 CPUC2d, 1 (1994) required PG&E, SoCal Edison and SDG&E to bid all of their generation into the PX and to procure electric energy for their full service customers by purchases from the PX. (*Id*. at 95). This "buy/sell requirement" remains in effect for a period consistent with the rate freeze and the IOUs' collection of stranded costs through the CTC.

The CPUC's stated rationale for the buy/sell requirement was to provide price transparency, mitigate market power and reduce regulatory burdens, to ensure that customers relying on their distribution utility to procure their electric energy would receive the benefits of competitive market prices, and to provide sufficient depth to the PX that its market signals may be relied upon as a benchmark for choices to opt for contracts for differences or direct access arrangements. (64 CPUC 2d 1, at 38).

In its initial orders on the proposed restructuring, the Commission independently adopted the California buy/sell requirement. Although the Commission stated that it might be concerned if this was a long-term requirement, it found that the buy/sell requirement was important to the entire restructuring proposal and that it was acceptable as a transition mechanism that would be in place for a limited, 5-year period. [9] Until the PX implemented the block-forward market, the buy/sell requirement limited the IOUs to the PX day-ahead market for their supply, and precluded the use of forward contracts to hedge the risk of price spikes in the spot market.

As originally proposed and authorized, the PX block-forward market was limited to bilateral energy transactions up to 12 months in advance of delivery.[10] The California IOUs were required to secure permission from the California Commission to participate in the PX block-forward market. Prior to the implementation of the block-forward market, the CPUC gave very limited authority to the IOUs to engage in hedging.[11]

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9 Pacific Gas and Electric Company, et al., 77 FERC ¶ 61,265 at p. 62,088-89 (1996).

10 California Power Exchange Corp., 87 FERC ¶ 61,203 (1999);

11 The decisions of the CPUC are reported in the following cases: PG&E, D.97-08-058(1997)(denied request to use financial instruments to hedge); PG&E, D.98-06-076(1998)(granted, with conditions, request to use gas-indexed financial instruments to hedge gas costs for power production); SoCal Edison, D.99-07-018(1999)(dismissed request to implement pilot program for bilateral agreements for energy and capacity purchases up to 2000MW); SDG&E, D.97-12-088(1996)(denied request to purchase power in bilateral market which would then be bid into the PX

The IOUs sought authority to participate in the block-forward market in April and May 1999. On July 8, 1999, the CPUC granted the IOUs permission to use the PX block-forward market through October 2000, for up to one third of their respective hourly loads per month. [12] For the summer of 2000, these limits were: 300-400 MW for SDG&E; 2,000 MW for PG&E; and 1,800-2,000 MW for SoCal Edison. The CPUC also conditioned such hedging on reasonableness reviews. [13]

The PX began offering expanded block-forward market products in the spring of 2000, including super peak and shoulder peak energy products and peak energy products from surrounding states. The PX also proposed to offer a block-forward market for ancillary services effective May 1, 2000. In January 2000, SoCal Edison and PG&E requested permission to participate in the new PX markets, an extension of the termination date from October 2000 to March 2002, and expanded hedging limits. SoCal Edison requested that the limits be increased to the following quarterly levels: 2,000 MW (1st and 2nd Qtr); 5,200 MW (3rd Qtr); and 3,000 MW (4th Qtr).

On March 16, 2000, the CPUC granted SoCal Edison and PG&E's requests to purchase new PX energy products.[14] The hedging limits were revised to PG&E and SoCal Edison's respective "net short positions," or the utilities' total bundled service hourly demand less the amount of generation the utility provides in that hour, through the end of the rate freeze. Specifically, SoCal Edison's limit was increased to 5,000 MW per month, while PG&E's limit was increased to approximately 3,000 MW. PG&E and SoCal Edison subsequently received permission to participate in the PX block-forward market for ancillary services.[15] SDG&E requested similar expansion of its participation in the PX new products markets in July 2000. The CPUC granted this request in August 2000.[16]

In addition, on July 6, 2000, the CPUC authorized SoCal Edison and PG&E to purchase energy in the PX daily and balance of the month block-forward markets, and allowed further increases

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day-ahead market); SDG&E, D.00-96-034(2000)(denied request for limited authority to purchase outside the PX and to use financial instruments outside the PX in connection with an Electric Commodity PBR to be implemented at the end of the rate freeze).

12According to the California Commission, limitation is necessary to ensure that the IOUs do not over-procure supply, and to reduce opportunities for speculation and the exercise of market power. CPUC Resolution E-3618, issued July 8, 1999.

13*Id*.

14Resolution E-3658, issued March 16, 2000.

15Resolutions E-3666 and E-3672, issued May 4 and June 8, 2000.

16D.00-08-021 (2000).

in daily (but not monthly) block-forward trading levels, through the end of the rate freeze.[17] On July 21, 2000, PG&E filed an emergency motion requesting authority to enter into bilateral contracts through December 31, 2005. The CPUC granted this request on August 3, 2000, up to the existing block-forward market limits.[18] SDG&E filed a request for similar authority on August 9, 2000.

During the summer of 2000, SDG&E, PG&E and SoCal Edison did not fully utilize their authorized hedging limits. In response to staff queries, PG&E reported that it purchased approximately 1,100 MW in the block-forward market in June and about 1,800 MW in July and August. For the 6-month period ending August 2000, PG&E stated that it hedged approximately 90 percent of its total average load of 40,783,831 MWh, primarily through its own generation (31,857,241 MWh) and block-forward market contracts (4,682,496 MWh). SoCal Edison hedged about 1,750 MW of its 2,200 MW in June and about 3,000 to 3,500 MW of its 5,200 MW limit for July through September.[19] SoCal Edison requested confidential treatment for its hedging strategies and levels. SDG&E responded that it used the authority for a 100-MW transaction for September 1999. SDG&E also pointed out that the block-forward market is not a hedge, as the term is used in trading, and that pursuant to CPUC determinations, it has not used any financial hedges.

3. Economic Regulation of Electric Utilities in Other Western States

In the other western states, utilities are generally regulated by public utility commissions which regulate rates, terms and conditions of service, and which also may issue certificates for the construction of power plants and transmission facilities by investor-owned utilities. These regulatory commissions generally have only limited jurisdiction over cooperatives and none over municipal electricity operations. Open- access programs have been enacted by the states of Arizona (effective on January 1, 2001); New Mexico (phased-in between January 1, 2001, and January 1, 2002); Nevada (retail access delayed since January 1, 1999); Oregon (effective October 1, 2001); Idaho; and Montana (phased in between July 1, 1998 and July 1, 2006). The states of Utah, Washington, South Dakota, Colorado, Nebraska, and Wyoming have not enacted open access or retail competition programs.

B. Environmental Regulation of Electric Utilities

1. Federal Environmental Regulation of Electric Utilities

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17 Resolution E-3683, issued July 6, 2000.

18 D.00-08-023 (2000).

19 *Report on California Energy Market Issues and Performance: May-June 2000,* California ISO Department of Market Analysis, August 10, 2000, p. 20.

The Commission is the primary agency involved in the environmental review of licensing and construction of jurisdictional hydroelectric facilities. In the West a significant amount of the hydroelectric resources are from federally run projects that are not subject to the Commission's jurisdiction. These are subject to federal environmental laws, and their power output can be significantly affected by their need to comply with environmental requirements, such as Endangered Species Act requirements to protect endangered fish in the Northwest. Federal reviews of electric transmission or generation siting proposals may involve the U.S. Army Corps of Engineers if wetlands are involved, the Department of Interior if a historical site is involved, and/or review by the Fish and Wildlife Agency of the Department of the Interior if federal lands or a protected species is involved. In all cases, the project must comply with the minimum requirements administered by the Environmental Protection Agency (EPA) for clean air and water discharge standards, which usually are enforced through a permitting process at the state and local level.

Minimum EPA standards also apply to projects involving the disposition of certain types of hazardous waste and chemicals. Economic and safety review of proposed nuclear power plants (including site safety matters and disposition of hazardous waste) is vested in the Nuclear Regulatory Commission and DOE, respectively, with most other environmental and land use issues reserved to the states or local jurisdictions.

Utility operations are also governed by minimum federal standards for clean air under Title V of the Clean Air Act. Regional air quality plans are developed under EPA supervision and administered by the states. Most important among the standards are ozone, sulfur, particulate, and nitrogen dioxide (NOx), and carbon dioxide emissions.

2. Environmental Regulation of Utilities in California

California environmental regulations are based on: (1) related federal air quality and water quality requirements of the Clean Air Act and the Clean Water Act administered by the EPA; (2) the California Environmental Quality Act (CEQA), (3) several California Clean Air Acts, (4) local air quality standards; and (5) local land use planning and zoning regulations.

Siting Requirements

The siting process for new generation in excess of 50 MW or related transmission facilities is administered by the California Energy Commission (CEC). This review includes a determination of whether the proposed facility is consistent with the state's energy needs and plans and whether it conforms to environmental requirements. The siting process is complex and requires the applicant to select at least three possible sites for the facility, including at least one that is not a coastal site. Certain wetland, conservation, and shore sites are excluded by statute and others have a higher level of protection unless the Commission finds that mitigation will be effective. CEC also must evaluate possible alternative sites that are not listed by the applicant. CEC review involves input from local air quality agencies, which provide a report which is reviewed by the California Air Review Board.

Local jurisdictions such as cities, towns and counties have extensive land use and zoning authority under California law. If a proposed project is inconsistent with a local land use plan or related zoning provision, then a special exception or variance must be obtained at the local level. Individuals and localities are given extensive opportunities to participate in siting decisions. The CEC may override local land use and zoning regulations only if it finds that the facility is required by the public convenience and necessity and that there are not any prudent and feasible alternatives.

On September 7, 2000, the California assembly passed AB 970, to address the immediate need for certain additional generating capacity in the state. AB 970 created an interagency task force of not more than 15 members appointed by the Governor from the various California regulatory agencies, related federal agencies, and local governments to compile and provide all guidance documents and procedures to parties desiring to construct power plants, including best available technology, to provide assistance in processing applications, without compromising public participation or environmental protection, and to help applicants obtain essential inputs such as gas and water supplies, and emission offsets. The bill expires on January 1, 2004, unless extended.

AB 970 also provides for expedited review of new powerplants meeting certain criteria by local clean air districts,[20] and limits these districts in the use of their discretion to require more stringent controls than are required by federal and state minimums in light of the current shortage of generation capacity in California. AB 970 also requires the CEC to establish an expedited process to issue its final certification of any application on the basis of an initial review that shows that there is substantial evidence that the proposed thermal power plant will not cause a significant adverse impact on the environment or electrical system and will comply with all applicable standards, ordinances, or laws. However, all of the information requirements for applications, including compliance with local laws and regulations, must still be included in the application. Further, the CEC may not issue an expedited certificate if it determines, based on substantial evidence, that the project would result in a significant adverse impact on the environment or electric system or does not comply with an applicable standard, ordinance or law. All agencies that would otherwise have jurisdiction are required to submit their comments within 100 days after the application is filed.

[20] Specifically, a proposed powerplant may not emit more than five parts per million of NOx over a 3-hour period, must displace electric generation that has a higher emission rate, must be connected to the grid at a point that urgently needs generation in order to provide reliable electrical generation, and must contract with the ISO for all of its output. Second, the proposal to install a power plant must not be inconsistent with federal clean air requirements, and the proposed power plant must cease operations within 3 years and be modified, replaced, or removed within 3 years with a combined-cycle plant that complies with all applicable laws and regulations.

AB 970 also requires the CEC to institute a proceeding, consistent with the Clean Air Act and California environmental law, for the expedited siting of simple cycle thermal plants, including a determination within 25 days of whether the application qualifies with this portion of the statute. It must make its determination within four months for all projects likely to be in service on or before August 2001. The required certificate will issue if the plant is not a major stationary source or a modification to a stationary source as defined the Clean Air Act, will not have a significant adverse impact on the environment from operations or construction, assures protection of the public health and safety, complies with a federal, state, and local laws ordinances and standards, will cease operations within 3 years and will be modified within 3 years to a combined-cycle plant using best available technology and complies with all laws and ordinances. The plant is also required to obtain pollution offsets or to pay the required environmental mitigation fees.

Emissions Requirements

In California the principal environmental issues involved in electric generation and transmission are related to air quality. The California Air Review Board (CARB) is responsible for developing state air pollution standards from all sources. It oversees the operation of 35 air quality districts within the state. These districts are responsible for implementing state and federal clean air standards and plans, particularly the regional air quality attainment plans required by federal law. Based on these standards, these districts (1) advise the CARB whether a proposed generation or transmission project will comply with the air quality standards for the district, within which it will be located, and (2) regulate the level of pollutants allowed for a given site.

The federal and California standards address six pollutants: ozone (O_3), nitrogen dioxide (NO_2), sulfur dioxide (SO_2) carbon monoxide (CO), fine particulate matter (PM10), and lead. California also has standards for sulfates, hydrogen sulfide, vinyl chloride, and visibility. Local areas which exceed standards for any of these pollutants are designated as "non-attainment" areas, and are subject to increasingly stringent regulations, depending on the severity of the pollution. Areas with air quality better than the federal standards are regulated under Prevention of Significant Deterioration rules, which are intended to keep air quality from reaching unhealthful levels.

Under these rules, new sources of air emissions, including power plants, must have pollution control devices that meet "Best Available Control Technology" and must obtain pollution offsets before beginning operations. In addition, existing power plants must reduce their emissions according to pre-set schedules by retrofitting old plants, adding new controls, or reducing total emissions by purchasing credits from other sources. For older plants, emission control presents a conflict between maximum power production and compliance with the air attainment quality standards in a particular air attainment area. Maximum operations may delay the conversion to more efficient equipment or result in fines if the maximum standards for a given area are exceeded. When power plants produce excessive NOx emissions, this restricts the possible use of emergency generators when generating capacity is short.

All local air quality management districts and air pollution control districts must adopt emission reduction credit banking programs. Within each district, applicants may obtain credits for permanent, real and quantifiable emissions reductions, through facility shutdowns or emissions controls. The districts issue Banking Certificates which may then be traded with other parties at market prices. The program requires that offsets be at a one-to-one ratio or greater. These may then be traded through transfers of Banking Certificates.

The local districts also collect relevant information about offset transactions and publish this information annually. The CARB then compiles this information from all 35 districts and issues a report summarizing these transactions. The CARB's 1999 Report indicates that both the number of NOx transactions and highest price paid for transactions increased substantially since reporting began in 1993. In 1999, the average price paid was $13,884 per ton, or $6.94 per lb. This level had increased dramatically, by the end of the summer of 2000.