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October 1, 2001

Chair, Council on Environmental Quality
722 Jackson Place, N.W.
Washington, DC 20503

Attention: Energy Task Force

Dear Mr. Chairman:

On behalf of Calpine Corporation, I am pleased to respond to your request for comments on the nature and scope of the activities of the newly-established Energy Task Force. We strongly support the goals expressed by President Bush in Executive Order No. 13212, creating your Task Force: to expedite the federal permitting process so as to accelerate the completion of energy-related projects, while maintaining safety, public health, and environmental protections.

By way of introduction, Calpine is the fastest-growing independent power producer of electricity in the nation. We currently have approximately 47,500 megawatts of base load and peaking capacity in operation, under construction, or in announced development in 29 states, the United Kingdom, and Canada. Most of our generation facilities are fired by natural gas, producing extremely clean energy using state-of-the-art equipment. We are also the world's largest producer of renewable geothermal energy, with 850 megawatts of geothermal power at a facility in Northern California known as the Geysers.

As energy developers, we have substantial experience in seeking a wide variety of permits from federal, state, and local agencies. Not surprisingly, most of our experience is in attempting to obtain the approvals necessary for the construction of generation facilities. More recently, however, we have experienced substantial delays in our ability to interconnect our facilities with the grid and move the related power over the nation's electric transmission system.

Based on that experience, our comments are divided into three sections. First, we briefly discuss what we believe to be the essential nature of the problem of obtaining federal permits in a timely manner. Second, we suggest a process for focussing the resources of the Task Force, and for increasing the accountability of the federal agencies responsible for permit review. Finally, we describe specific problems that we recommend that the Task Force address. We have also attached information relating to two projects that merit the particular attention of the Task Force.

1. The Nature of the Problem

The nature of the problem is that each federal agency participates in the generation siting process based on its own organic statutes and institutional perspective. These statutes and perspectives are different for each agency, and no agency has as its primary goal the successful siting of an energy facility. For example, the Forest Service exists to manage public forest land, the Fish & Wildlife Service exists to protect fish and wildlife, and the EPA Environmental Justice unit exists to protect minorities from disproportionate environmental harm. Because none of these agencies have any statutory mandate or institutional incentive to see generation facilities sited, and often have an institutional incentive to delay or kill the siting of such facilities, the current slow pace of permit review and approval is entirely unsurprising.

In response to nearly any problem in government, it is tempting to recommend a new statute to revise the statutory missions of the various agencies, or to create a new federal generation siting agency. In this case, however, that is probably the wrong approach. Different federal agencies have different missions for good reason, and there is no need to compromise those missions in order to site well-considered generation facilities in a timely manner.

What we need is a champion within the federal government who will "ride herd" on the agencies participating in the permitting process. Although the creation of a federal generation siting agency by statute might have some benefits, it could not possibly happen within a reasonable timeframe. That is why we so much appreciate the President's initiative in creating the Task Force by Executive Order.

2. A Suggested Process

The Task Force should now take the initiative by directing the head of each federal agency to establish a relatively small, interdisciplinary energy facility siting team within that agency. Each team would be given a certain period of time (e.g., 60 days) to prepare and submit to the Task Force a list of all proposed energy facilities for which approval is pending at that agency.

For each facility on the list, the team would: (1) describe the proposed facility and its relative significance; (2) describe the current status of the proposed facility in the agency's approval process; (3) provide a projected deadline for final action by the agency; (4) identify any unusual barriers to achieving final action by the deadline; (5) determine whether the agency is currently meeting all decisionmaking benchmarks and deadlines contained in statute, regulations, or internal agency guidance documents; and (6) identify approvals needed from other agencies before the facility may proceed. The

Task Force should require that the list be updated by the team on a periodic basis (e.g., every 30 days).

This list would allow the Task Force to focus its efforts on solving the most pressing bottlenecks in the agency approval process. Working with the agency teams, the Task Force should act as a roving champion for expeditious action. The Task Force could be particularly helpful in resolving conflicts among agencies involved in the permitting of the same project. As the Task Force gains experience in helping agencies cut processing time, it should make the "best practices" readily available to all agency teams.

Perhaps more importantly, the Task Force should create accountability for performance. The Task Force should publish a regular scorecard for each agency, available to the public and the media on a website. It should also develop an awards program for individuals who have demonstrated outstanding leadership in facilitating the coordination and acceleration of the review process.

The Task Force should invite states and tribes to adopt a similar approach to expediting the siting of generation facilities. States and tribes seeking to expedite the review of generation facilities within their borders could, by executive action, create Task Forces and agency teams that would work directly with their federal counterparts in resolving problems regarding projects that require some combination of federal, state, and tribal approval. Where a state or tribe has created an agency to lead its siting effort, that agency could serve in lieu of a Task Force. A scorecard and individual award program at the state and tribal level would similarly increase accountability.

These recommendations are included in an article I recently co-authored, to be published this Fall by the Rocky Mountain Mineral Law Foundation. For your information, I am including a copy of the galley proofs of the article, entitled "Keeping the Lights On: Siting Power Generation Projects in the West During the Energy Crisis."

3. Specific Problems

A. The BPA Problem

The Bonneville Power Administration (BPA) owns and operates over 75 percent of the high-voltage transmission system in the Northwest. As a result, many generation projects being developed in the Northwest can only go forward if they can interconnect to, and receive transmission service from, BPA. BPA's current process of review has the unfortunate effect of delaying viable projects, while spending time and resources on projects that are unlikely to move forward. Because the BPA transmission system is part of the larger transmission system that serves the 11 Western States, any delay in energizing these viable projects simply extends the current power shortages throughout the West.

Pursuant to its Open Access Transmission Tariff (OATT) filed at the Federal Energy Regulatory Commission (FERC), BPA currently considers requests for interconnection and transmission service on a "first-come, first-served" basis. Although this approach enjoys an element of fairness, it ignores the reality that some projects in the queue are very unlikely to ever be built. For example, the developer may not be able to secure adequate natural gas for a gas-fired generation facility, may not be able to secure the generation equipment itself, or may have little likelihood of receiving the necessary land use and environmental approvals.

This means that nonviable projects are occupying positions in the queue ahead of other, viable projects. Instead of requiring any showing of viability, BPA simply studies the need for interconnection facilities and transmission upgrades at each proposed generation project, in queue order. To keep its place in the queue, the developer must only make a relatively small payment to BPA to cover the costs of the study.

Consequently, BPA's limited staff resources are being spent studying the transmission needs of generation facilities that will never be built, while other, viable projects wait in line for months or even years. In order to cure this problem, Calpine has suggested two possible solutions to BPA: (1) require that projects that fail to meet certain development milestones (e.g., securing financing, equipment, land use permits) within prescribed periods of time be removed from the queue; or (2) provide that BPA need not study the interconnection needs of a generation facility until BPA is provided with adequate assurance of project viability. Attached is a September 21, 2001 letter from Calpine to BPA that provides more detail on this issue.

It is important to note that BPA is well aware of this problem, and has invited proposed solutions. The difficulty is that fixing the problem will require a revision to the first come, first served language in BPA's OATT. In order to do so, BPA will first have to engage in some sort of public process with its transmission customers to arrive at a proposed solution, and then will need to file an OATT amendment with FERC for consideration and approval.

We ask that the Task Force work with BPA and FERC to expedite this process to the greatest extent possible. Otherwise, generation projects in the Northwest that could help solve the supply problem for the entire West will not achieve commercial operation in a timely manner.

B. The TVA Problem

The Tennessee Valley Authority (TVA) should be required to provide independent power producers with timely and non-discriminatory access to its transmission grid. Calpine is currently constructing two 800 megawatt cogeneration facilities in TVA's territory, and has experienced significant delays and unreasonable obstacles in attempting to interconnect to TVA's transmission system. Although we applied to TVA for interconnection in the Fall of 1999, and construction of these power plants will be completed in time to meet the peak demand of Summer 2002, TVA says that it will not be able to provide interconnection until 2003. Most other transmission owners complete this process in half the time.

TVA has repeatedly proposed interconnection schemes that are larger and costlier than required. For example, TVA demanded that Calpine pay for system upgrades that were required based on an assumption that a nuclear facility mothballed in 1984 would become operational. TVA also initially demanded that Calpine pay over $29 million in reactive power losses, a request that is unprecedented and in violation of FERC policy. TVA has also refused to provide back-up technical information regarding the system impacts and basis for proposed upgrades, despite the fact that such information is routinely provided by other transmission owners. The Task Force should insist that TVA act in a more timely and transparent manner in responding to interconnection requests, and that it comply with all FERC regulations. In particular, the Task Force should seek assurances from all future nominees to the TVA Board of Directors that they will support TVA compliance with such regulations, including joining the Southeast Regional Transmission Organization planned by FERC.

C. The Need for FERC to Establish Uniform Rules Regarding Interconnection

The interconnection problems at BPA and TVA are but two examples of a national problem regarding interconnection. Although we need to move forward to expeditiously address problems with individual entities, the larger answer is that FERC should initiate a rulemaking proceeding that would allow it to establish uniform interconnection rules on a nationwide basis.

Independent power producers need the assurance that there is a right to interconnect with the existing transmission grid. Uniformity in the rules will send the correct signals to the investment community that if new plants are built, access to the market will be timely and predictable.

Some transmission-owning entities have recognized the benefits of expeditious interconnections, as this allows more power to reach the grid sooner, thereby increasing reliability and providing downward price pressure for their retail customers. Others, however, have stymied new generation through delaying tactics and unreasonable financial burdens.

FERC has considered initiating a rulemaking on this subject in the past, but has deferred. However, we are now encouraged by the September 26, 2001, statements of Chairman Pat Wood that this issue may be a major priority of the Commission in the near future. There could be opposition to FERC's approach, so we strongly encourage the Task Force to support Chairman Wood and the other members of FERC when they address this issue.

D. FERC Needs Authority Over All Transmission Lines

In order to avoid discrimination in the use of the transmission system, FERC needs statutory authority over all transmission lines, including those owned and operated by federal agencies and publicly-owned utilities. Presently, FERC has clear authority over the portion of the transmission system owned by investor-owned utilities, but the agency's authority over the portions owned by federal agencies and publicly-owned utilities is unclear. We recognize that FERC may need to regulate these other entities somewhat differently because they are either government-owned or consumer-owned, but comparable standards that allow for non-discriminatory access and comparable provisions regarding rates, terms, and conditions is essential to allow the wholesale market to work.

Without this uniformity, the nation's transmission system will continue as a patchwork of different policies, exacerbating problems with reliability and transmission bottlenecks. This is an area in which statutory changes are needed, and the Task Force should make those recommendations to Congress, in cooperation with the Department of Energy.

E. The Environmental Appeals Board Problem

The procedural rules of the EPA Environmental Appeals Board (EAB) should be amended to eliminate the automatic stay of construction pending an appeal. Under the Clean Air Act, new power plants are required to obtain a Prevention of Significant Deterioration (PSD) permit prior to construction, in order to maintain national air quality standards. Although the Act mandates that a completed PSD permit "be granted or denied not later than one year after the date of filing", electric generation companies have experienced lengthy and needless delays that have added millions in unnecessary project costs and have impeded the addition of urgently needed new power supplies. These delays have occurred, in part, because opponents can file meritless, last minute appeals to the EAB that, under current EAB procedures (40 C.F.R. Part 124), automatically require a stay of construction, despite the fact that the same issues have been fully considered and rejected in prior proceedings.

We recommend that EPA revise the Part 124 regulations so that a stay of construction would only be ordered if the petitioner were able to satisfy the same type of heightened scrutiny that is used by a court when considering whether to issue a temporary restraining order. If that standard is not met, the developer would be able to proceed with early construction activities, pending the outcome of the appeal. These early activities pose no threat to the environment, and the developer would bear all financial risk that the appeal would later be granted.

We also recommend that the EAB self-impose a strict 60-day timetable for completing such reviews. In a very recent EAB case involving an appeal of a proposed PSD permit for a new power plant, the Board was able to complete its review in less than 60 days, which suggests that such a time limit is practicable.

F. The EPA New Source Review Problem

EPA needs to revise its New Source Review program to encourage development of new, cleaner forms of generation in a timely manner. Under the current process, new facilities that are installing some of the most advanced clean up technologies available still face lengthy delays in obtaining air permits. New, clean projects are also disadvantaged, vis a vis older, dirtier power plants, in areas with emissions allowance trading programs.

First, Calpine recommends the establishment of clear criteria for receiving pre-construction air permits on an accelerated basis. Currently, such permits take 6-9 months. For those projects that are capable of meeting performance-based criteria that assures a pre-approved level of environmental protection, it should be possible to reduce this review process to 90 days. The Task Force should also encourage EPA to develop a standard list of requirements that defines a completed permit application.

Second, where new generating projects are subject to market-based emission allowance trading programs, the Task Force should propose those legislative or regulatory changes needed to allow such projects an appropriate allocation of emission credits. Under many trading schemes, new, clean generators do not receive allocations, but must purchase them from their competitors that own older, dirtier facilities.

All new projects meeting the criteria for accelerated permitting suggested above, and new generating projects that undergo the regular review process, but meet the most stringent of emission limits, should receive emission allowances. At a minimum, such allocations should be sufficient to cover the project's anticipated emissions of regulated pollutants; ideally, all generation should receive equal allowances based on output. We recognize that the NSR program is currently under review at EPA, but would like the Task Force to urge EPA's consideration of output based emission regulation and a fair allocation of trading credits for new generation.

G. The Federal Land Problem

Federal land managers need to expedite the siting of energy projects on federal lands, especially renewable projects such as geothermal, which is disproportionately found on federal land. Calpine's Fourmile Hill project in the Glass Mountain Known Geothermal Resource Area of northern California has been mired in the federal permitting and appeal process for approximately 5 years. The 50 megawatt project was initiated in 1996 on Federal leases in an area that was specifically identified by the Federal government as viable for geothermal development. After spending 2.5 years developing an extensive environmental impact statement at Calpine's expense, the Forest Service and Bureau of Land Management (BLM) took an additional 20 months to arrive at its decision approving the project. The decision was then appealed to the Interior Board of Land Appeals (IBLA), which has a 2-year backlog of cases. In late summer

2000, the IBLA issued a stay on construction of the project until it could rule on the appeal. The stay has been in place for 13 months so far.

We recommend that timeframes and milestones be established for all federal and state agencies involved to complete environmental reviews and make decisions in a fair and timely fashion. We further recommend that the Task Force strongly encourage the IBLA to eliminate its backlog, reforming its process if necessary. Current Forest Service regulations require that agency to decide appeals in a matter of weeks, while appeals of BLM decisions can take over two years before the IBLA.

We hope that these comments are helpful, and would like to work with you in implementing these suggestions. I will be calling in the next week to arrange a meeting at your convenience.

Sincerely Yours,

Joseph E. Ronan, Jr.

Joseph E. Ronan, Jr.
Vice President – Government and Regulatory Affairs

Fourmile Hill Geothermal Project

Name: Fourmile Hill Geothermal Project

Proposing Entity: Calpine Corporation

Category of Project: electricity generation (renewable)

Description of Project: Fourmile Hill is a 50-megawatt geothermal project in the Glass Mountain Known Geothermal Resource Area of northern California.

Agencies involved: The Forest Service and Bureau of Land Management.

Reason for Listing: Federal land managers need to expedite the siting of energy projects on federal lands, especially renewable projects such as geothermal, which are disproportionately found on federal land. The Fourmile Hill project has been mired in the federal permitting and appeal process for approximately 5 years. The project was initiated in 1996 on Federal leases in an area that was specifically identified by the Federal government as viable for geothermal development. After spending 2.5 years developing an extensive environmental impact statement at Calpine's expense, the Forest Service and Bureau of Land Management (BLM) took an additional 20 months to arrive at their decision approving the project. The decision was then appealed to the Interior Board of Land Appeals (IBLA), which has a 2-year backlog of cases. In late summer 2000, the IBLA issued a stay of construction on the project until it could rule on the appeal. The stay has been in place for 13 months so far.

Suggestions for Improving the Process: We recommend that timeframes and milestones be established for all federal and state agencies involved in environmental review, so that decisions are made in a fair and timely fashion. We further recommend that the Task Force strongly encourage the IBLA to eliminate its backlog of appeals, reforming its procedures if necessary. Current Forest Service regulations require that agency to decide appeals in a matter of weeks, while appeals of BLM decisions can take over two years before the IBLA.

Tennessee Valley Authority (TVA) Project

Name: Morgan Energy Center

Proposing Entity: Calpine Corporation

Category of Project: electricity cogeneration

Description of Project: The Morgan Energy Center is an 800 megawatt cogeneration power plant currently being constructed in northern Alabama in TVA's jurisdiction. It will provide both power to BP Amoco's facility in Decatur, AL as well as clean, efficient power to other consumers in the area.

Calpine applied to TVA for interconnection to the grid in November, 1999, but the system impact study was not completed until February 2001. The process was further delayed for months by two unreasonable demands from TVA, one of which Calpine eventually accepted (the assumption that a TVA nuclear facility that is mothballed and has not run since 1984 would be up and running) and one which TVA eventually retracted (TVA requested almost $30 million in reactive power losses, a claim which was unprecedented and violated FERC policy).

The final interconnection plan and scope of work proposed by TVA was much larger and more costly than needed. Calpine has proposed several alternatives that would meet TVA's reliability requirements, but has not yet been able to reach agreement. At this point, if TVA's plan prevails, the plant will be fully constructed and ready to supply power in July 2002 to meet peak summer demand, but the interconnection will not be completed until November 2002, delaying the operation date to February 2003.

The Morgan Energy Center will provide new jobs (up to 400 during construction and 25 direct and 100 support positions permanently), secure existing jobs at BP Amoco, spur economic development in the area (average annual payroll will be $1,375,000) and add needed funds to government tax revenues (during construction, the sales and use taxes for Morgan County will be approximately $3 million and property taxes will be $350,000 to $550,000 annually).

Agencies involved: TVA is a unique federal entity in that its' decisions are not reviewed by any other agency, giving it wide-ranging power to control the entrance of new power generation in its' territory.

Reason for Listing: Calpine Corporation is bringing this project to the Task Force's attention because we believe that it is a prime example of why TVA should be brought under FERC's jurisdiction so that there is oversight of the interconnection process to assure fair and non-discriminatory access to the grid.

Suggestions for Improving TVA Process: TVA should develop clear and fair interconnection standards that are reviewed and approved by FERC with specific time deadlines for completion of the system impact study and interconnection.

CALPINE

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September 21, 2001

Mr. Stephen J. Wright
Acting Administrator/CEO
Bonneville Power Administration
905 NE 11th Avenue
Portland, OR 97232

Dear Steve:

On behalf of Calpine Corporation, I am writing to propose a solution to assist the Bonneville Power Administration (BPA) in processing the unprecedented amount of applications for the interconnection of new electric generation plants on the BPA Federal Columbia River Transmission System (FCRTS).

As you know, much-needed new power plants are being delayed due to their position in the lengthy "interconnection queue" administered under the requirements of BPA's Open Access Transmission Tariff (OATT). As the largest transmission owner in the Northwest Power Pool ("NWPP"), the BPA's interconnection queue is an integral component to facilitate bringing such new generation online.

Many proposed projects that have a relatively high position in the queue are unlikely to ever be built due to the developer's inability to obtain financing, generation equipment, easements, environmental permits, and other prerequisites. Nevertheless, these less viable generation projects effectively delay progress on the interconnection of far more viable projects that are otherwise poised to begin construction/operation. This is due to the fact that BPA's OATT provision is strictly first come, first served. Once a proposed project obtains a position in the queue, BPA's requirements to maintain that position are modest, and can be met by proposed projects that are unlikely to become commercial.

It has come to our attention that the Federal Energy Regulatory Commission (FERC) has approved OATT amendments by transmission owners that require developers to meet a variety of non-discriminatory project development milestones. These milestones are agreed upon by the transmission owner and the developer, and failure to meet them causes the project to lose its place in the interconnection queue. This results in less viable projects being set aside in favor of more viable projects, allowing the transmission owner to reduce and rationalize its workload relating to interconnection.

Attached for your review is a background paper on this matter, as well as a draft tariff for discussion purposes. Calpine strongly urges Bonneville to submit a tariff amendment along these lines to the FERC as soon as possible. If properly implemented, such a tariff amendment would be a powerful tool for accelerating the interconnection of electric generation needed to serve the West.

We would be pleased to meet with you and your staff to discuss this proposal at your convenience.

Sincerely,

Peter Blood
Director – Marketing & Transmission

cc: Mark Maher
Charles Meyer
Michael Raschio

BACKGROUND PAPER ON SOLVING THE BPA INTERCONNECTION QUEUE PROBLEM

Under the BPA OATT that will go into effect as of October 1, 2001, the only way for BPA to remove a project from the queue is for "failure to timely return an executed study, construction and interconnection agreement or Service Agreement after it has been tendered...." Generation projects with little or no prospect of obtaining the necessary equipment or financing or regulatory approvals can meet this requirement with relatively little difficulty, simply by tendering approximately $40,000 to $70,000 to pay for a system impact study. As a consequence, in the midst of a West-wide power shortage, BPA is expending scarce resources preparing to interconnect non-viable generation projects while viable projects are not being provided the interconnection services they need to commence construction or operation.

Relevant FERC Precedent

In a number of recent orders, the FERC has upheld efforts by transmission owners to require generation plant developers to meet a variety of project development milestones and, if they cannot do so, move them to the back of the interconnection queue. A new BPA interconnection approach based on this precedent would, if properly implemented, accelerate the interconnection of new generation in the Northwest. It also would likely reduce and rationalize BPA's workload associated with interconnection, allowing its highly skilled staff to focus on the most viable projects.

In Commonwealth Edison Company, 91 FERC ¶61,083 (Apr. 26, 2000), FERC approved OATT revisions that allow Com Ed to remove a project from the interconnection queue if certain project milestones are not met. The Electric Power Supply Association (EPSA) agreed that reasonable milestone dates are appropriate, but argued that Com Ed should not be permitted to unilaterally determine what milestones are appropriate for each interconnecting generator.

In response, FERC stated:

> As a general matter, we agree with Commonwealth Edison that milestones are appropriate in an IA. However, Commonwealth Edison should adjust the milestones, where applicable, through negotiation. ... Failing agreement, parties are free to contest the reasonableness of the specific milestones provisions at the time the IA is filed with the Commission.

Id. at 61,299. The FERC also upheld a Com Ed requirement to request reasonable credit support from applicants as consistent with the FERC's *pro forma* OATT.

In Carolina Power & Light Company, 93 FERC ¶61,032 (Oct. 11, 2000), the Commission approved OATT amendments that require a developer to make reasonable progress toward placing a generator in service or lose its place in the queue. The Commission stated, "We find that CP&L's commitment to develop a set of milestones to track the generators progress in prospective interconnection agreements is generally consistent with the above-mentioned policy articulated in *Commonwealth Edison*." *Id.* at 61,071. It should be noted that Portland General Electric Company has adopted the CP&L interconnection queue rules and process.

In Consumers Energy Company, 94 FERC ¶61,230 (Feb. 28, 2001), Duke Energy North America (DENA) requested rehearing on the Commission's prior approval of a tariff amendment requirement that a generator must reapply for interconnection if the generator increases plant size by 15 percent or more or ,more importantly, the generator's in-service date is delayed by more than six months from the in-service date set forth in its initial interconnection request.

DENA argued that such changes or delay should not result in an automatic loss of queue position and that a loss in queue position should only occur if the change in generator plans will adversely or materially affect another project in the queue. The Commission rejected DENA's position:

> We reject DENA's contention that Consumers' interconnection reapplication requirement is unreasonable. As we made clear in the December 29 Order, significant changes in the size of a generator, its location on the transmission provider's system, or in the in-service date may adversely affect other generators seeking interconnection. We believe that these criteria established by Consumers are reasonable.

Id. at 61,834 (footnote omitted).

In another recent order, Arizona Public Service Company, 95 FERC ¶61,070 (Apr. 13, 2001), the Commission accepted a requirement that the generator seeking interconnection provide the utility, by a date certain, with appropriate proof that it has secured the necessary capital to finance construction of its proposed generation facility.

In summary, the FERC has supported the approach of using the achievement of reasonable project development milestones to determine whether or not a developer seeking interconnection should maintain its position in the interconnection queue. FERC has also made it clear that the transmission owner does not have the authority to unilaterally set milestones not specified in a FERC approved tariff or procedure. It urges parties to resolve differences over milestones through negotiation and, failing agreement, bring these disputes to the FERC for resolution.

Tariff Amendment Should Apply Equally to All Projects

Any tariff amendment submitted by the BPA to the Commission should apply in an equal and non-discriminatory basis to both new projects and those that already have a position in the BPA interconnection queue. For example, if a tariff amendment provides that a project loses its place in the interconnection queue if it is unable to contract for necessary generation equipment within 6 months of its initial placement in the queue, such a requirement would apply equally to all projects, regardless of whether they had obtained their queue position under the old tariff or the new amended tariff. Consequently, all projects in the queue, whether they had been in the queue for a day, or two years, would have six months from the date of the application of the tariff amendment to meet the new requirements. Such a transition mechanism would assure that no project with an existing queue position would immediately lose such position upon implementation of the tariff amendment.

Draft tariff amendment

For discussion purposes, we offer the following two options as tariff language:

<u>Option 1</u>:

Within 60 days after an application for interconnection service is submitted, the Transmission Provider and Applicant shall negotiate and agree upon reasonable project milestone dates. Such milestones may include securing adequate financing, necessary generation equipment, easements, necessary environmental and land use permits and certifications, and similar events to ensure successful completion and energization of the project. If the Applicant does not achieve any one of the the agreed-upon milestones, it, the Applicant, shall be deemed to have abandoned its application, and Transmission Provider shall be relieved of the requirement to study, construct and/or install any interconnection facilities or system upgrades, or Transmission Provider may suspend such study, construction and/or installation until such milestones are achieved. If the Transmission Provider suspends any such study, construction and/or installation, recommencement thereof shall be subject to the Transmission Provider's then-existing interconnection commitments to other Applicants. The Transmission Provider may reasonably extend any such milestone dates in the event of delays not caused by the Applicant, such as unforeseen regulatory or construction delays that could not have been remedied by the Applicant through the exercise of due diligence. Abandonment of an application under this section shall not relieve the Applicant of the obligation to reimburse Transmission Provider for the costs incurred prior to such abandonment.

Option 2:

The Transmission Provider shall not be obligated to study, construct and/or install any interconnection facilities or system upgrades, until the Applicant has provided adequate assurance that it has secured adequate financing, necessary generation equipment, easements, necessary environmental and land use permits and certifications, and similar events to ensure successful completion and energization of the project.

Chapter 11
KEEPING THE LIGHTS ON: SITING POWER GENERATION PROJECTS IN THE WEST DURING THE ENERGY CRISIS

Joseph E. Ronan, Jr.
Calpine Corporation
Pleasanton, California

Craig Gannett
Davis Wright Tremaine
Seattle, Washington

Synopsis

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§ 11.01 Scope[1]

This paper focuses on the siting of power plants in the West. Section 11.02 provides an overview of changes in demographics and power consumption in the West that have drastically increased the need for new plant siting. Section 11.03 discusses the constellation of issues that are unique to the siting of generating facilities in the West: (1) pervasive federal ownership of land, (2) extensive tribal lands, (3) local environmental and land use issues, (4) competition for scarce water; and (5) the fact that many of the high-voltage transmission lines in the West are owned and operated by the federal government.

Although some of the same problems arise in the siting of natural gas pipelines and electric transmission lines, those related infrastructure improvements are beyond the scope of this paper. Similarly, this paper does not address the siting of all types of power plants. The examples used consist of power plants fueled by natural gas or geothermal steam. Natural gas, which currently provides about 16% of U.S. electricity generation, is projected to fuel about 90% of the capacity

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[1]Mr. Ronan is the Vice President for Government and Regulatory Affairs for the Calpine Corporation. Mr. Gannett is a partner in the law firm of Davis Wright Tremaine, LLP, Seattle, Washington office. Mr. Ronan and Mr. Gannett gratefully acknowledge the assistance of Jennifer Schubert, Patricia Thompson, and Dan Adamson of Davis Wright Tremaine; Doug Nelson of Phoenix, Arizona; and Jeff Stahlhut of Holland and Hart, Denver, Colorado.

additions over the next 20 years.[2] Geothermal steam provides a useful example because it tends to be present on or near federal lands in the West.

Section 11.04 discusses power projects that illustrate how the five West-specific obstacles to development have manifested themselves. Section 11.05 suggests measures to overcome these obstacles and thereby fulfill the West's need for new generation in a more timely manner. Section 11.06 concludes the chapter by surveying briefly the state siting statutes of Washington, Oregon, Arizona, California, and Colorado, with an emphasis on potential sources of delay.

§ 11.02 Overview

The United States is facing a profound electricity shortage. California has suffered rolling blackouts that have cost businesses hundreds of millions of dollars, New York attempted to avert similar problems the summer of 2001, and Nevada experienced its first-ever blackout in July 2001.

Although the solution lies in a balanced approach, including conservation, energy efficiency, and renewable energy sources, it is clear that a new generation of large power plants will be essential. This is a central point of the report of Vice President Cheney's National Energy Policy Development Group (Cheney Report), submitted to President Bush on May 16, 2001. The Cheney Report estimates that between 1,300 and 1,900 new electric generation facilities will be needed over the next 20 years in order to meet projected demand.[3] By comparison, there are approximately 5,000 power plants in the United States today.[4]

In response to the recommendations of the Cheney Report, President Bush issued two Executive Orders on May 18, 2001. The first, Executive Order 13211, requires federal agencies to prepare and submit a Statement of Energy Effects to the Administrator of the Office of Information and Regulatory

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[2]Report of the National Energy Policy Development Group, May 2001, at 5-18 [hereinafter Cheney Report].

[3]*Id.* at xi.

[4]*Id.* at 7-5.

Affairs (OIRA), within the Office of Management and Budget (OMB), for those matters identified as significant energy actions. A significant energy action is defined essentially as any energy-related regulation that would have an annual effect on the economy of $100 million or more.[5] The Statement of Energy Effects is to be a detailed statement by the agency of any adverse effects on energy supply, distribution, or use should the proposed energy action be implemented, as well as reasonable alternatives to the action and the expected effects of such alternatives.

The second, Executive Order 13212, requires federal agencies to expedite their review of permits or take other actions as necessary to accelerate the completion of energy-related projects. It also establishes an Interagency Task Force to monitor and assist agencies in their efforts to expedite permit review, and to monitor and assist agencies in setting up appropriate mechanisms to coordinate federal, state, tribal, and local permitting in geographic areas where increased permitting activity is expected. The Task Force consists of representatives of 20 departments, agencies, and councils,[6] is to be chaired by the Chairman of the Council on Environmental Quality, and is housed at the Department of Energy for administrative purposes.

Power plants are but one key component in an overall energy infrastructure that is both inadequate and antiquated.

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[5]Exec. Order No. 13,211, § 4(b), 66 Fed. Reg. 28,355 (May 18, 2001). Section 4(b) of Executive Order No. 13,211 defines "significant energy action" as any regulatory action that is a "significant regulatory action" under Executive Order No. 12,866 (the seminal 1993 Executive Order on federal regulatory planning and review) and that is likely to have a significant adverse effect on the supply, distribution, or use of energy. Executive Order No. 12,866 defines "significant regulatory action" essentially as any regulation that may have an annual effect on the economy of $100 million or more. Exec. Order No. 12,866, § 3(f), 58 Fed. Reg. 51,735 (Sept. 30, 1993).

[6]The Task Force includes representatives of the Departments of State; the Treasury; Defense; Agriculture; Housing and Urban Development; Justice; Commerce; Transportation; the Interior; Labor; Education, Health and Human Services; Energy; Veterans Affairs; and also of the Environmental Protection Agency; the Central Intelligence Agency; the General Services Administration; the Office of Management and Budget; the Council of Economic Advisors; the Domestic Policy Council; the National Economic Council; and such other representatives as may be determined by the Chairman of the Council on Environmental Quality. Exec. Order No. 13,212, § 3, 66 Fed. Reg. 28,357 (May 18, 2001).

In addition, thousands of miles of natural gas pipelines and power transmission lines will have to be sited if a durable solution is to be found to the crisis. According to the Cheney Report, the current domestic natural gas transmission capacity of approximately 23 trillion cubic feet will be insufficient to meet the projected 50% increase in consumption projected for 2020.[7] Similarly, over the next 10 years, U.S. demand for electric power is expected to increase by 25%, while transmission capacity is expected to increase by only 4%.[8]

The West is currently the epicenter of the energy crisis due to the continuing drought in the Northwest and the way that electricity restructuring was implemented in California. The fundamental problem in the West is that a fast-growing population has been enjoying economic growth without simultaneously building the electrical infrastructure to support continued prosperity.

In the 1990s, the West experienced the highest population growth rate (19.7%) of any region of the country, followed by the South (17.3%), the Midwest (7.9%), and the Northeast (5.5%).[9] This is the continuation of a trend in recent decades. Between 1950 and 2000, the West's share of the nation's population has increased from 13% to 22%, and the South has increased from 31% to 36%. Meanwhile, the Midwest's share fell from 29% to 23%, and the Northeast's portion declined from 26% to 19%.[10] The bar chart below provides a sense of how population growth and the installation of new generating capacity are seriously out of alignment in the West.

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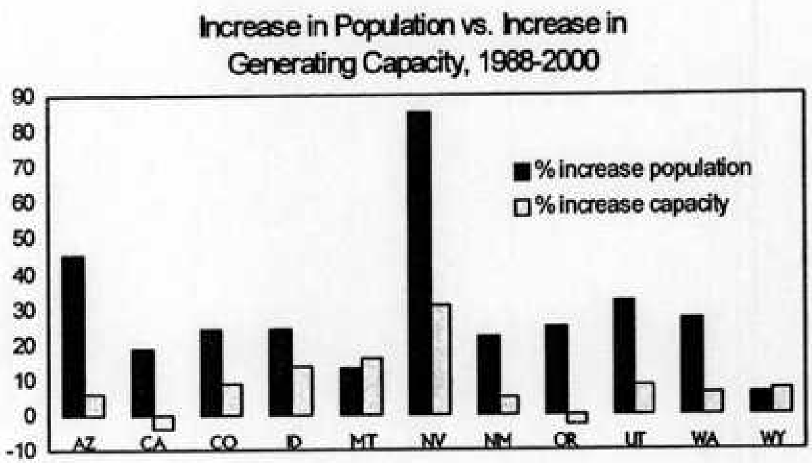
[7]Cheney Report, *supra* note 2, at 7-11.

[8]*Id.* at 7-8.

[9]U.S. Census Bureau, Economics & Statistics Admin., U.S. Dep't of Commerce, *Population Change and Distribution, 1990 to 2000, Census 2000 Brief* (Apr. 2001).

[10]Cheney Report, *supra* note 2, at 2-3.



California and the Pacific Northwest are particularly in need of new generation. Since 1995, California's peak summer demand has risen by at least 5,500 megawatts (MW), while in-state generation has failed to keep pace.[11] In fact, California did not add a single new major power plant during the 1990s.[12] In the Northwest, demand for electricity has grown by 24% in the last decade while generating capacity has grown by only 4%.[13] To make matters worse, the hydroelectric system, upon which the region historically has depended, has lost significant flexibility of operation due to the Endangered Species Act, effectively derating it by about 1,000 MW.[14]

The shortage in the West is having devastating financial consequences. In 1999, Californians paid approximately $7 billion for electricity; in 2000, $28 billion; in 2001, the expectation is a whopping $70 billion. Pacific Gas and Electric is in bankruptcy, and Southern California Edison may not be

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[11] *Id.* at 1-3.

[12] *Id.* at viii.

[13] Testimony of Councilmember Tom Karier, on behalf of the Northwest Power Planning Council, to the U.S. Senate Energy & Natural Res. Comm., Feb. 1, 2001.

[14] *Id.*

far behind. The result is that this crisis will harm California's economy—the fifth largest in the world—for years to come.

§ 11.03 Siting in the West Involves a Unique Set of Challenges

The West confronts a unique constellation of obstacles that delay the siting of new facilities. As a result, the siting process in the West is generally longer, less predictable, and more expensive than in other regions of the country. At least five distinctly Western factors are at play:

[1] Pervasive Federal Land Ownership

The federal government owns a much higher percentage of land in the West than it does in other regions of the country. Of the 48 contiguous states, federal land ownership in the 11 western-most states ranges from 27.6% in Montana to 82.9% in Nevada, while most states in other regions are well below 10%.[15] Thus, potential sites for generation facilities are more likely to be on or near federal land in the West. When federal land is involved, the permitting process is more likely to require the approval of one or more federal agencies (in addition to state and local agencies) than when a project is located on private land.

[2] Extensive Tribal Lands

Potential sites in the West are more likely to be located near Indian lands. There are about 275 Indian reservations in the United States, consisting of approximately 56.2 million acres of land.[16] Most of the reservations are in the West, including the largest, the 16 million-acre Navajo Reservation in Arizona, New Mexico, and Utah.[17] The presence of such land anywhere near the proposed site can cause delay due to the increased involvement of federal agencies and tribal members in the siting process. Executive Order 13175, issued on November 6, 2000, further complicates this issue by requiring

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[15] 185 *Public Lands Statistics 2000* (Mar. 2001), *at* http://www.blm.gov/natacq/pls00/contents.html.

[16] U.S. Dep't of the Interior, Bureau of Indian Affairs, "Frequently Asked Questions," *at* http://www.doi.gov/bia/oirm/faq.htm.

[17] *Id.*

extensive consultation with tribal officials in the development of federal policies that have substantial direct effects on Indian tribes.[17.1]

[3] Local Environmental Opposition (NIMBYs, BANANAs, and NOPEs)[18]

The Not-in-My-Back-Yard (NIMBY) response to new power plants is thriving in the West. Aided by both federal and state law, local environmental opponents have many opportunities to stall projects for long periods of time.[18.1] Among other things, this helps explain why no major power plants were built in California in the 1990s.

[4] Competition for Scarce Water

Water issues loom large in the West. In the Southwest, burgeoning populations are outstripping existing water supplies, making it increasingly difficult to secure water for power production. In the Northwest, the listing of endangered species of fish has caused state and federal agencies to stringently guard in-stream flow. Large power plants can consume enough water to supply a small city, utilizing up to 40,000 acre-feet of fresh water per year. In Arizona, 9 of the 14 plants currently in licensing will use fresh-water cooling, and in California 14 of 28 also will tap this resource. California water officials estimate that the state's current demand for water already outstrips supply by more than 1.6 million acre-feet per year without taking into account the proposed use by new power plants.

[5] The Dominance of Federal Power Marketing Administrations

A high percentage of the West is served by two federal power marketing administrations (PMAs): the Bonneville Power Administration (BPA) and the Western Area Power

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[17.1] Exec. Order No. 13,175, 65 Fed. Reg. 67,249 (Nov. 6, 2000).

[18] NIMBY is an acronym for "Not In My Back Yard," BANANA stands for "Build Absolutely Nothing Anywhere Near Anything," and NOPE stands for "Not On Planet Earth."

[18.1] See *infra* § 11.04 for case studies.

Administration (WAPA). BPA is the more prominent of the two, owning and operating more than 70% of the high-voltage transmission lines in the Northwest. Although both BPA and WAPA have voluntarily submitted open-access transmission tariffs to the Federal Energy Regulatory Commission (FERC), neither was legally bound to do so. Because they are not subject to the full extent of FERC jurisdiction that is applied to investor-owned transmission owners, and because they serve in the dual role of transmission provider and governmental policymaker, interconnecting new generation facilities to the PMAs can be a source of delay.

§ 11.04 Siting of Energy Facilities in the West—Case Studies

[1] Siting Obstacles Due to Project's Location on Federal Land and its Proximity to Tribal Land—Fourmile Hill Geothermal Project

The Fourmile Hill Geothermal Project is an example of the problems that can arise when developing an energy project on federal land that is located near tribal land. For more than six years, this project has been in the permitting process. It lies in the Klamath and Modoc National Forests in Northern California, approximately 30 miles south of the Oregon border, within the Glass Mountain Known Geothermal Resource Area (KGRA).

The Bureau of Land Management (BLM) issued geothermal leases to the project developers for the development of the Glass Mountain KGRA approximately 15 years ago. The projects are located entirely on federal land. It is estimated that the Glass Mountain KGRA is capable of generating up to 1,000 MW, enough to meet the electricity needs of a city the size of Seattle.

Calpine Corporation and California Energy General Corporation (CalEnergy) have been attempting to develop this resource under a program initially sponsored by BPA, which, in turn, has agreed to purchase a portion of the power generated from the KGRA. In addition, the Fourmile Hill project was awarded a $20 million grant from the California

Energy Commission's Renewable Energy Program to encourage the development of the project.

The environmental impact statement (EIS) process was initiated by Calpine in 1996, and the final EIS was published in October 1998. Nineteen months later, on May 31, 2000, the Records of Decision (RODs) were issued by BLM and the U.S. Forest Service (Forest Service). Although the RODs approved the Calpine plan of operation, the agencies imposed significant conditions on the construction of the project. (The CalEnergy application was denied by the agencies, and CalEnergy has filed a "takings" claim in the U.S. Court of Federal Claims.[18.2]) In addition, BLM placed a moratorium on further geothermal development in the Glass Mountain KGRA for a minimum of five years, effectively preventing the production of electricity for nearly an additional decade. Calpine has appealed the conditions imposed in the ROD and the imposition of the moratorium to the Interior Board of Land Appeals (IBLA). Experience has demonstrated that an appeal to IBLA averages nearly 22 months before a decision is issued.

At least four factors significantly affected the timing of permitting this project:

[a] NEPA Review Significantly Impacted by Involvement of Nearby Native American Tribes

As part of the National Environmental Policy Act (NEPA) review, the project developer, Calpine, funded an ethnographic study as a mitigation measure and as a goodwill gesture to the local tribes. The study sought to establish and record tribal customs and historical uses of the area near Glass Mountain known as the Medicine Lake Highlands. Calpine recognized the importance of Native American concerns regarding the project, and met extensively with the three tribes identified in the ethnographic study as having historically used the Medicine Lake Highlands. Calpine

[18.2] Cal. Energy Gen. Corp. v. United States, No. 00-619C (Fed. Cl. filed Oct. 17, 2000). The action also includes a breach of contract claim based on the BLM leases.

ultimately entered into agreements with two of the tribes. A third tribe, the Pit River Tribe, whose lands are located about 35 miles from the Glass Mountain KGRA, remains opposed to the project.

Nevertheless, the final EIS indicated that the project would have an adverse effect on Native American traditional cultural values with respect to noise and landscape views, because the geothermal development would degrade the spiritual significance of Medicine Lake Highlands as a sacred site. Significantly, the Medicine Lake Highlands contain paved roads, a campground, cabins, a boat ramp, motorboats, a snowmobile park, and an active pumice mine. At one time, the entire area was logged.

[b] Consultations with the State Historic Preservation Office Caused Additional Delay

As a result of the adverse effect determination, the Forest Service and BLM completed consultations with the State Historic Preservation Office (SHPO) and the Advisory Council on Historic Preservation before issuing their RODs. Because the SHPO and the Advisory Council consultations were not concluded expeditiously, and the Forest Service did not press for a conclusion, the RODs approving the project were not signed until almost 20 months after completion of the final EIS.

[c] The Involvement of EPA Environmental Justice Unit Exacerbated Delay

Very late in the process, after the comment period for the final EIS had expired, the Environmental Justice staff of EPA Region IX became involved at the request of the Pit River Tribe. EPA requested the lead federal agencies to issue a negative ROD,[18.3] even though EPA had been a cooperating agency in the NEPA review process. EPA also wrote to the California Energy Commission seeking delay in signing final

[18.3] Letter from Enrique Manzanilla, Director, Cross Media Division, U.S. EPA Region IX, to Randall Sharp, BLM/USFS Project Coordinator, Alturas, California (Apr. 5, 1999).

agreements for state funding of the project.[18.4] Such involvement resulted in meetings between the agencies and the Pit River Tribe that took months to resolve.

[d] The Department of the Interior's Lengthy Administrative Appeals Process Compounded Delay

After the RODs approving the project were issued, project opponents filed appeals that sought to overturn the decision. The Forest Service promptly denied all appeals. However, as noted above, BLM decisions are appealed to IBLA, which presently has a 22-month backlog of cases. When project opponents requested a stay of project development pending the outcome of the appeal, IBLA granted it.

With the change in the Administration in Washington, D.C., and the subsequent issuance of the two Executive Orders, the official attitude toward development of this resource may be changing dramatically. On June 15, 2001, BLM lifted the five-year moratorium previously imposed, citing the energy policy outlined in the Cheney Report and Executive Order 13212.

[2] The "Poster Child" for NIMBYism—Metcalf Energy Center

Calpine's $400 million, 600-megawatt Metcalf project in California's Silicon Valley is intended as a "showcase" project, cleaner than any plant its size ever licensed in California. Extraordinary care has been taken in the design of the project to minimize aesthetic impact. Moreover, the site currently is a junkyard unsuitable for most development, and is located directly across the street from the Pacific Gas and Electric Company's 40-acre Metcalf substation, the main hub for electricity in the South Bay. The need for the project is pressing, as the Silicon Valley has no major power plants, while its population has grown by more than 50% since 1970, and its electricity usage has been expanding at approximately 13% per year.

[18.4] Letter from Enrique Manzanilla, Director, Cross Media Division, U.S. EPA Region IX, to Michael Moore, Presiding Member for Renewable Energy, Cal. Energy Comm'n (undated).

The California Energy Commission deemed the project data adequate on June 23, 1999, and conducted its first public hearing on July 12, 1999. In the most contested and controversial power plant application proceeding in the 27-year history of the Commission, the Commission issued 50 Orders and Rulings, and held 20 public hearings and 30 workshops. Finally, on June 18, 2001, the Commission issued its final recommendation of approval, with final Commission action expected in August 2001, 26 months after the data adequacy finding.

The project was delayed on a number of local, state, and federal fronts. Some of the most significant roadblocks have involved federal regulatory approvals.

[a] Delay in Processing of Biological Opinion

Although the U.S. Fish and Wildlife Service (USF&WS) is required by statute and regulation to provide a "biological opinion" within 135 days of the date formal consultation is initiated (with provisions for extension in certain circumstances),[18.5] in practice securing a biological opinion from the USF&WS has presented significant potential for delay. Delay in issuance of the biological opinion in this case contributed to the delay in development of the project.

[b] Lack of Coordination or Double-Tracking of Federal Agency Review Magnifies the Delay

The Metcalf project has also been seriously affected by EPA's apparent inability to move forward on the required Prevention of Significant Deterioration (PSD) air permit as a result of the USF&WS' delays. Processing of an application would be much more timely if the analyses required under these two permitting procedures were managed simultaneously. Following the issuance of the PSD permit by EPA, an appeal was filed immediately with the EPA Environmental Appeals Board (EAB), where the matter now rests. Just as in the case of the Four Mile Hill Project, construction of the project cannot begin until the appeal is decided by the EAB.

[18.5] 16 U.S.C.A. § 1536(b)(1)(A) (2000), 50 C.F.R. § 402.14(e) (2000).

[c] Federal Agency Delay Creates Opportunities for Special Interests to Stall the Process

Federal delays also tend to foster local delays by providing additional time for project opponents to mobilize and encourage other NIMBY complaints. Since early 1999, Calpine has participated in over 50 public meetings or hearings regarding the Metcalf project, and has responded to more than 300 written data requests. During this period the Mayor and City Council of San Jose, with the active support of Cisco Systems, Inc., and a neighborhood group opposed the project, resulting in a denial of a rezoning request by an 11-0 vote of the San Jose City Council on November 28, 2000.[18.6] The Mayor and City Council subsequently reversed their position, in June 2001, and construction of the project is expected to be completed in the summer of 2003.

[3] Opportunities for Even a Single Individual to Cause Substantial Delay—Sutter Power Project

Calpine's Sutter Power Project, a $350 million, 540-megawatt natural gas-fueled power plant near Yuba City, California, is now providing power to more than 500,000 households in the greater Sacramento Valley, having gone on line on July 2, 2001. Coincidentally, Northern California experienced a severe heat wave that day, nearly causing a blackout. State officials credited energy from the Sutter facility on that day for preventing the blackout. It was the first thermal power plant approved by the California Energy Commission since it came into existence in 1974.

This project was delayed five months and Calpine incurred substantial expense as a result of a single individual appealing the facility's PSD permit to the EAB. Any such appeal to EAB effectively creates an automatic stay of any construction until the appeal has been decided. Due to the EAB's considerable backlog of cases, this single appeal

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[18.6] For reports on the events and background surrounding this controversy, see Chris Gaither, "Silicon Valley's Achilles' Heel is Exposed," *N.Y. Times*, Jan. 12, 2001; John Greenwald, "The New Energy Crunch," *Time Mag.*, Jan. 29, 2001, at 36; Mark Arax & Terence Monmoney, "The California Energy Crisis, Power Plant Juggernaut Slowed by Internet Giant," *L.A. Times*, Jan. 10, 2001, Home Edition, pt. A, at A-1.

consumed five months of construction time before it was denied on December 2, 1999. Construction started immediately, but eight months after final approval was received from the State of California, meaning that the plant was not operational during a period when the state experienced numerous rolling blackouts.

[4] Delay Due to State Siting Agency Insistence on Sale of Power Within the State—Sumas Energy 2 Generation Facility

The proposal to build a 660-MW gas-fired facility in Sumas, Washington, illustrates the obstacle to facility siting presented when the state siting agency requires that power from the project be sold within the state.

The Washington State Energy Facility Site Evaluation Council (Council) recommended against the application of Sumas Energy 2, Inc. (SE2) on February 16, 2001. That recommendation was based in part on the Council's conclusion that the environmental costs of the generation facility would not be adequately counterbalanced by benefits to consumers in Washington State because the facility owners might sell power to out-of-state purchasers.

This conclusion ignores the fact that the West is one electricity market, consisting of all customers served by the transmission system known as the Western interconnection. Power generated anywhere in the Western interconnection benefits all customers on that system by increasing supply.

SE2 moved the Council for reconsideration of its recommendation. In doing so, SE2 offered to agree to long-term contracts to sell much of the output in Washington State. The Council denied the motion, thereby necessitating the submittal of a revised application and the taking of additional evidence, but indicated that it would consider favorably the revised application now that SE2 had committed to the in-state sales.

[5] The Dominance of Federal Power Marketing Administrations in the West Creates Potential Delays Regarding Interconnection and Transmission Services for New Generation Facilities

Two agencies within the Department of Energy, BPA and WAPA, own much of the transmission system in the West. BPA owns and operates about 75% of the high-voltage transmission lines in the Northwest, and WAPA owns and operates nearly 17,000 miles of transmission lines that stretch across 15 states. Although BPA and WAPA each have voluntarily filed an open-access transmission tariff (OATT) with FERC, they are not subject to complete FERC jurisdiction, and they enjoy considerable discretion as federal agencies. This discretion can lead to delays when seeking interconnection and transmission services for a new generation facility.

The best example is currently pending at BPA. Since early 2001, BPA has ceased entering into transmission interconnection agreements while it conducts an assessment of the cumulative impacts on air quality of more than 40 generation projects seeking interconnection to the BPA system. The study, which BPA expects to complete by the end of 2001, apparently was undertaken in response to concerns from local federal land managers from the Forest Service and Park Service regarding air quality in the Columbia Gorge and other areas, rather than any regulatory requirement.

Through this study, BPA has effectively assumed shared responsibility with EPA for air emissions, despite the fact that BPA has no statutory responsibility for air quality. Not only does this lead to delay, but it also creates the potential for BPA and EPA to reach contradictory conclusions regarding both the actual air impacts of the generation facilities and the regulatory consequences of those air impacts.

Such contradictory conclusions seem likely to occur because BPA's study, instead of utilizing EPA-approved methods, is based on very conservative assumptions. When it was first announced, critics argued that the study would find that all proposed projects would cause significant impacts, even where EPA-approved air impact models would not. On July 16, 2001, the critics' fears were substantiated. BPA issued the results of Phase 1 of the study, finding that every facility studied would have a significant impact on visibility in a Class 1 area or scenic area.[18.7]

It is understood that BPA is now preparing to seek monetary "mitigation" as a condition of issuing interconnection RODs.

It is submitted that BPA lacks regulatory or statutory authority to demand monetary payments of this kind, and that not even EPA could demand such mitigation from most of the proposed facilities because the emissions from them fall below relevant triggering thresholds.

BPA has stated that its air study is required by NEPA as a prerequisite to taking a federal "action" (i.e., signing an interconnection agreement) that would affect the quality of the environment, and cites the Department of Energy's regulation implementing NEPA.[19] But those same regulations make clear that an "action" sufficient to trigger environmental analysis means "a project, program, plan, or policy . . . that is subject to DOE's control and responsibility."[20] Because the decision to build these generation facilities is beyond the control and responsibility of BPA, that agency logically is not required by NEPA to analyze the air quality impacts of new facilities that seek interconnection to its transmission system.

This is closely analogous to the NEPA review conducted by FERC when it is asked to approve a gas pipeline lateral to serve a power plant. Applying FERC's NEPA regulations, FERC generally does not consider the environmental impacts of the power plant itself when reviewing an application to construct a pipeline lateral that interconnects the plant to the

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18.7 *See* http://www.efw.bpa.gov/cgi-bin/PSA/NEPA/SUMMARIES/air2.

19 10 C.F.R. pt. 1021 (2000).

20 10 C.F.R. § 1021.104(b) (2000).

main gas pipeline.[21] The thrust of FERC's regulations is that where a lateral provides "merely a link" to a nonjurisdictional facility (the generation facility), over which there is little federal control or responsibility, the application generally will not trigger environmental review by FERC.

Although these FERC regulations do not apply directly to DOE, the FERC and DOE regulations share the same central consideration: whether the nonjurisdictional facility is subject to the "control and responsibility" of the reviewing agency. Furthermore, the limitation contained in these regulations is simply a codification of a well-recognized line of NEPA cases that apply to all federal agencies, including BPA.

The seminal case is *Winnebago Tribes v. Ray*[21.1] In that case, a proposed 67-mile long transmission line needed a permit from the Corps of Engineers to cross the Missouri River.[22] Pursuant to its authority over areas in and affecting navigable waters, the Corps reviewed the 1.25-mile river-crossing portion of the line, and concluded that no environmental impact statement was required.[23] Opponents of the project argued that the Corps should have considered the environmental impacts of the entire transmission line, but the Eighth Circuit disagreed, stating that "while the Corps has broad discretion to consider environmental impacts, that

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[21] 18 C.F.R. § 380.12(c)(2)(ii) (2000) provides that an applicant to FERC for pipeline construction must:

> Address each of the following factors and indicate which ones, if any, appear to indicate the need for the Commission to do an environmental review of project-related nonjurisdictional facilities.
>
> (A) Whether or not the regulated activity comprises "merely a link" in a corridor type project (e.g., a transportation or utility transmission project).
>
> (B) Whether there are aspects of the nonjurisdictional facility in the immediate vicinity of the regulated activity which uniquely determine the location and configuration of the regulated activity.
>
> (C) The extent to which the entire project will be within the Commission's jurisdiction.
>
> (D) The extent of cumulative Federal control and responsibility.

[21.1] 621 F.2d 269 (8th Cir. 1980).

[22] *Id.* at 270.

[23] *Id.*

discretion must be exercised within the scope of the agency's authority."[24]

In doing so, the court applied a three-part test to determine if the federal agency has sufficient control over the entire project to warrant an environmental review of the nonfederal portion: (1) the degree of discretion exercised by the agency over the federal portion of the project, (2) whether the federal government has given any direct financial aid to the project, and (3) whether the overall federal involvement with the project is sufficient to turn essentially private action into federal action.[25]

Applying these factors to BPA's situation clearly leads to the same conclusion as was reached in *Winnebago*. First, BPA is exercising only limited discretion because the OATT it filed with FERC requires non-discriminatory first-come, first-served treatment for those seeking interconnection. Second, no federal aid has been given to most of the generating projects seeking interconnection. Finally, the generation facilities at issue are completely private in nature. Thus, there is no need for BPA to engage in analysis of the air quality impacts of the generation facilities.

In response, BPA cites *Port of Astoria, Oregon v. Hodel*[25.1] for the proposition that it must conduct the cumulative air impact study before allowing interconnection. *Port of Astoria*, however, was a very different case. There, plaintiffs sought an environmental impact statement regarding a contract by BPA to sell 320 megawatts to a proposed aluminum plant and build the transmission lines necessary to service the plant. The court held that the contract required an EIS because it "creates a new commitment of BPA's energy resources" and "sets the stage for the initiation of" a region-wide power program known as Phase 2 of the Hydro Thermal Power Program.[26] Under Phase 2, BPA was to purchase power from

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[24] *Id.* at 272.

[25] *Id.*

[25.1] 595 F.2d 467 (9th Cir. 1979).

[26] *Id.* at 477.

new power plants built by non-federal utilities, meld that power with BPA's hydroelectric resources, and then sell it back to customers at a pooled rate. The court noted that the contract would be integral to Phase 2, and rejected BPA's argument that Phase 2 was not a federal program.[27]

The current issue of interconnection requests is clearly distinguishable from the *Port of Astoria* situation. Many of these interconnection requests do not involve BPA commitments for power, funding, or commitments to build transmission facilities. BPA is involved solely due to the request to transmit power over the BPA system under BPA's tariff, which requires BPA to provide open access. Instead, the current requests are far more analogous to the *Winnebago* situation where the Corps had little jurisdiction over the project, and its review was limited to that jurisdictional scope. In this case, BPA has jurisdiction only over the interconnection. It neither permits nor approves any aspect of the generating plant. Thus, its review should be limited to the interconnection and not extend to the entire project. In conducting this cumulative impact assessment, it is submitted that BPA has gone far beyond examining a project outside its scope and authority (i.e., the generating plant) to co-opting an entire regulatory arena over which it has no statutory jurisdiction.

§ 11.05 Recommendations

[1] The Problem

In the absence of substantial reform of the current federal, state, and tribal processes, the prospects for building enough new generation to meet the country's growing needs appear slim. Unless agencies are given appropriate incentives to

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[27] *Id.* at 477-78. The court wrote:

> BPA also asserts that Phase 2 is not a federal program. However, although Phase 2 is a cooperative enterprise involving BPA and nonfederal participants, it is BPA's participation that integrates the entire program. BPA will act as the agent for power produced by thermal plants and will to a large extent assure the success of these plants by direct sales of power to its own direct-service industrial customers. Without BPA, it is doubtful that Phase 2 would ever have been developed or, if developed, would have become feasible.

Id. at 478.

expedite their processes, the permitting process will continue to take years instead of months.

As illustrated in the case studies above, a central problem is that each federal agency participates in the generation-siting process based on its own organic statutes and institutional perspective; these statutes and perspectives are different for each agency, and no agency has as its primary goal the successful siting of an energy facility. The Forest Service exists to manage public forest land, the USF&WS exists to protect fish and wildlife, and the EPA Environmental Justice unit exists to protect minorities from disproportionate environmental harm. Because none of these agencies have any statutory mandate or institutional incentive to see generation facilities sited, and often have an institutional incentive to delay or prevent the siting of such facilities, the current pace of permit review and approval is entirely unsurprising.

In fact, there is no agency or individual in the federal government charged with championing the siting of generation facilities. Without such a champion, or at least clear leadership on this issue, the uncoordinated participation of various federal agencies will continue to slow the generation-siting process.

[2] A Partial Solution

As in all cases where a problem in government has been identified, it is tempting to recommend a new statute. In this case, however, that is probably the wrong approach. Different federal agencies have different statutory missions for good reason, and there is no need to compromise those missions in the course of siting well-considered generation facilities. Creating a new federal agency to coordinate the involvement of federal agencies in generation siting might be a good idea, but a simpler, faster approach would be to vigorously utilize the Task Force created in President Bush's Executive Order 13212.

That Executive Order provides a broad mandate to the Task Force. It is to

> monitor and assist the [federal] agencies in their efforts to expedite their review of permits or similar actions, as necessary, to accelerate the completion of energy-related projects, increase energy production and conservation, and improve transmission of energy. The Task Force also shall monitor and assist agencies in setting up appropriate mechanisms to coordinate Federal, State, tribal, and local permitting in geographic areas where increased permitting activity is expected.[28]

This "monitor and assist" role of the Task Force is coupled with a mandate to each agency to expedite its review of permits or take such actions as necessary to accelerate the completion of energy-related projects, while maintaining safety, public health, and environmental protections.[29]

The Task Force should take the initiative by directing the head of each federal agency to establish a relatively small, interdisciplinary energy facility-siting team within that agency. Each team would be given a certain period of time (e.g., 60 days) to prepare and submit to the Task Force a list of all proposed energy facilities for which approval is pending at that agency. For each facility on the list, the team would: (1) describe the proposed facility and its relative significance; (2) describe the current status of the proposed facility in the agency's approval process; (3) provide a projected deadline for final action by the agency; (4) identify any unusual barriers to achieving final action by the deadline; (5) determine whether the agency is currently meeting all decisionmaking benchmarks and deadlines contained in statutes, regulations, or internal agency guidance documents; and (6) identify approvals needed from other agencies before the facility may proceed. The Task Force should require that the list be updated by the team on a periodic basis (e.g., every 30 days).

This list would allow the Task Force to focus its efforts on solving the most pressing bottlenecks in the agency-approval process. Working with the agency teams, the Task Force should act as a roving champion for expeditious action. The Task Force could be particularly helpful in resolving conflicts

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[28] Exec. Order No. 13,212, *supra* note 6, § 3.

[29] *Id.* § 2. Section 2 of the Executive Order also provides that the "agencies shall take such actions to the extent permitted by law and regulation, and where appropriate."

among agencies involved in the permitting of the same project. As the Task Force gains experience in helping agencies cut processing time, it should make the "best practices" readily available to all agency teams.

Perhaps more importantly, the Task Force should create accountability for performance. The Task Force should publish a regular scorecard for each agency, available to the public and the media on a website. It should also develop an awards program for individuals who have demonstrated outstanding leadership in facilitating the coordination and acceleration of the review process.

The Task Force should invite states and tribes to adopt a similar approach to expediting the siting of generation facilities. States and tribes seeking to expedite the review of generation facilities within their borders could create, by executive action, Task Forces and agency teams that would work directly with their federal counterparts in resolving problems regarding projects that require some combination of federal, state, and tribal approval. Where a state or tribe has created an agency to lead its siting effort, that agency could serve in lieu of a Task Force. A scorecard and individual award program at the state and tribal level would similarly increase accountability.

§ 11.06 A Survey of Siting Laws and Procedures From Selected Western States

[1] Washington

Faced with a fast-growing demand for energy, the Washington state legislature created the Energy Facility Site Evaluation Council (EFSEC or Council) in 1970. In the 2001 session, the legislature mandated EFSEC to "avoid costly duplication in the siting process and ensure that decisions are made timely and without unnecessary delay."[30] It is charged with making recommendations to the governor regarding the

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[30] E.H.B. 2247, § 1, 2001 Leg., 57th Sess. (Wash. 2001) (to be codified at Wash. Rev. Code § 80.50.010).

siting of generation facilities of 350 megawatts or more.[31] EFSEC consists of a chair appointed by the governor, the directors of five departments or agencies of the state, and an appointee from each city and county where a proposed facility is to be located.[32]

After receiving an application for energy facility siting, EFSEC investigates its sufficiency by commissioning an independent study and conducting a series of hearings.[33] Under limited circumstances, expedited review is available.[34] As part of its effort to expedite the approval process, the Washington legislature in 2001 provided for early consultation between the applicant and the Council.[35]

The Council has broad preemptive authority and oversees permitting under the State Environmental Protection Act (SEPA), the Washington Clean Air Act, and the National Pollutant Discharge Elimination System (NPDES) process.[36]

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[31] E.H.B. 2247, § 3, 2001 Leg., 57th Sess. (Wash. 2001) (to be codified at Wash. Rev. Code §§ 80.50.010, 80.50.020(14)(a)).

[32] Five departments have permanent representatives on the Council: the Department of Ecology; the Department of Fish and Wildlife; the Department of Community, Trade and Economic Development; the Utilities and Transportation Commission; and the Department of Natural Resources. E.H.B. 2247, § 3, 2001 Leg., 57th Sess. (Wash. 2001) (to be codified at Wash. Rev. Code § 80.50.030(3)).

[33] Wash. Rev. Code §§ 80.50.040, 80.50.090 (2001); Wash. Admin. Code § 463-14-030 (2001).

[34] The Council can grant expedited review if it finds that the environmental impact, the area potentially affected, the cost and magnitude, and the degree to which the proposed facility represents a change in use of the site are not significant enough to warrant full review. Wash. Rev. Code § 80.50.075 (2001); Wash. Admin. Code § 463-43-010 to 463-43-080 (2001). If the Council grants expedited processing, it is not required to commission an independent study, or hold an adjudicative proceeding.

[35] E.H.B 2247, § 5, 2001 Leg., 57th Sess. (Wash. 2001). After the Council has received a site application, the Council staff confer with the applicant to identify issues presented by the application and recommend resolutions that would allow site approval. At this time, Council staff also reports its recommendations of conditions that would permit site approval to the Council.

[36] When the Council receives an application, it determines whether the proposal is "categorically exempt" from SEPA, or whether the applicant must complete an environmental checklist. The Council must determine whether it or another agency is a SEPA lead agency within five working days. If it believes another agency is the lead, it must send the application and checklist on to such agency with an explanation. Wash. Admin. Code § 463-47-060 (2001). Either the Council or an

Although an applicant must first pursue land use permit approval through local processes,[37] if the applicant cannot resolve the project's incompatibility with local zoning, the Council can preempt local ordinances and processes.[38] After conducting an adjudicatory hearing, the Council is authorized to recommend approval of the project in its final order, in spite of the noncompliance.[39]

The Council issues an order at the end of the review process that recommends approval, approval with conditions, or denial of the application to the governor. The governor must act on the application within 60 days.[40] Washington's siting statute preempts all matters related to energy facility siting; certification is in lieu of any permit, certificate, or similar document that might otherwise be required. Thus,

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outside party under its direction prepares a draft and final EIS unless it is unable to prepare these documents due to other commitments or constraints. Wash. Admin. Code § 463-47-090 (2001). The Council issues an NPDES permit based on compliance with all water quality standards and effluent limitations required for permits under the act. Wash. Admin. Code § 463-38-053 (2001). Wash. Admin. Code § 463-38-020 (2001) establishes regulations specifying procedures and other rules to be utilized by EFSEC to implement § 402 of the Federal Water Pollution Control Act, 33 U.S.C.A. §§ 1251-1387 (2001), and to integrate the NPDES permit program into the existing Council procedures for processing applications. An applicant may submit an NPDES permit when it submits its application to the Council. Wash. Admin. Code § 463-38-031 (2001). Within six months of submission of a complete application, the Council should formulate a tentative determination with respect to the NPDES application. *Id.* When the Council announces an intent to issue a permit under an NPDES application, any state, interstate agency, county, or interested agency or person or group that would be affected by the application, or the EPA regional administrator, may petition for a public hearing. Wash. Admin. Code § 446-30-400 (2001). The Council also must relay the proposed permit to the EPA regional administrator, who may prevent its issuance by objecting to it within 90 days. Wash. Admin. Code § 463-38-064 (2001). Permits for energy facilities are issued by the Council under the Washington Clean Air Act. Wash. Rev. Code § 70.94.422 (2001). They become effective only if the governor approves the application for certification and the certification agreement is executed. *Id.*

[37]The Council holds a public hearing to determine if the site is in compliance with existing land use plans or zoning ordinances. Wash. Rev. Code § 80.50.090 (2001). If it is not, the applicant must make application for change in or permission under those plans or ordinances. Wash. Admin. Code § 463-28-030 (2001).

[38]Wash. Rev. Code § 80.50.010 (2001), Wash. Admin. Code §§ 463-28-020 & 463-28-040 (2001).

[39]Wash. Admin. Code § 463-28-060 to 463-28-080 (2001).

[40]Wash. Rev. Code § 80.50.100 (2001).

certification of an application binds the state and all relevant departments to approval of the site, and authorizes the developer to construct and operate the facility subject only to conditions set forth therein.[41] A certification is a binding agreement between the applicant and the state that embodies compliance with siting guidelines adopted by the Council.[42] After an application is approved, EFSEC has the power to monitor the effects of construction and operation to assure continued compliance with the certification and/or permits.

Water considerations are a significant factor in the siting of power plants in Washington. Lack of available water at an affordable price may doom an otherwise promising project. In the populated areas of western Washington, municipal water and its attendant infrastructure are more readily available than in eastern Washington.[43] In less populated and arid eastern Washington, on the other hand, water is a valuable[44] and scarce commodity. Several major users—agriculture, municipalities, industries, and hydropower—compete for water provided by deep aquifers and substantial rivers (e.g., the Columbia and Snake Rivers). The demands of competing users are further complicated by recent in-stream flow requirements to protect endangered fish.

Exacerbating this scarcity of water has been an archaic and convoluted process of administering water rights applications. Washington appropriates water rights giving seniority to those first in time and first in use. The Department of Ecology (Ecology) issues certificates or permits that evidence water rights and authorize holders to withdraw and use a fixed

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[41]Wash. Rev. Code § 80.50.120 (2001), Wash. Admin. Code § 463-14-050 (2001).

[42]Wash. Rev. Code §§ 80.50.040 & 80.50.020 (2001).

[43]Although developers may be required to upgrade utilities and lines, pay latecomers or development fees (to compensate other developers or municipalities for earlier upgrades), or pay surcharges for increased water use, at least water is often available.

[44]In some recent acquisitions, the cost of water has reached $1,000 per acre-foot. Depending upon plant size and water needs, this fact alone may decide plant location.

amount of groundwater or surface water.[45] Until recently, requests to transfer existing rights were processed in the same queue as requests for new rights,[46] causing a backlog that could result in several years' delay of the more straightforward applications to transfer the location, use, and ownership of existing rights. To streamline this process, in May 2001, the governor signed House Bill 1832, which effectively places transfer requests in a separate queue from new requests and allows Ecology to process them independently.[47] Ideally, this two-queue arrangement allows a developer to avoid the delay inherent in acquiring new water rights by acquiring and transferring existing water rights. Nevertheless, the queue for transfers alone may still be quite long in certain water resource areas.

[2] Oregon

The Oregon Energy Facility Siting Council (Council) is charged to cooperate with the federal government and implement a streamlined, comprehensive system for the siting of all energy facilities in Oregon, but it lacks the preemptive authority vested in the Washington Council.[48] The jurisdiction of the Council includes all electric power generating plants with an electric generating capacity of 25 megawatts or more.[49] Unlike Washington, federally-delegated permits, such as the Air Contaminant Discharge and NPDES permits, are outside of the Council's jurisdiction, and must be obtained through the Oregon Department of Environmental Quality. The role of the Council is largely that of coordinator, directing the flow of information and requiring that state and federal

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[45] Wash. Rev. Code § 90.14.130 to 90.14.180 (2001). Such holders must beneficially use their water or lose it. The impetus to relinquish such rights is strong. Non-use for five consecutive years can result in relinquishment of all or part of the right. *Id.*

[46] Wash. Admin. Code § 173-152-050 (2001).

[47] H.B. 1832, § 5. Under the new scheme, Ecology may still prioritize those applications that meet the enumerated exceptions (e.g., alleviate public health or safety concerns, enhance the quality of the environment, etc.).

[48] Or. Rev. Stat. § 469.310 (1999).

[49] Or. Rev. Stat. § 469.300 (1999).

agencies adhere to common schedules in reviewing permit applications.[50]

In contrast to Washington, where EFSEC consists almost exclusively of state officials, Oregon's Council consists of citizen volunteer appointees. Council members are appointed by the governor and confirmed by the senate, and must be geographically representative of the state. Although the Council oversees the review of the process and makes the final certification decision, employees of the Oregon Office of Energy, acting as Council staff members actually research the application, hold hearings, and make the ultimate recommendation to the Council for its consideration.

The review process begins with the applicant's submission of a notice of intent (NOI) to build a facility to the Office of Energy.[51] The applicant must circulate copies of the NOI to a

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[50]The Oregon Office of Energy's role with respect to the permit review process is to monitor the review and impose deadlines. The Office of Energy, whose employees act as Council staff members, prepares a memorandum to accompany the application when it is distributed to agencies and tribes that requests return of comments and recommendations and final land use decisions by a specified deadline. Or. Admin. R. 345-015-0180 & 345-015-0200 (2001). Each reviewing agency must mail the applicant and the Office of Energy a report on the status of any permit applications, assess compliance, and list proposed conditions before that deadline. Or. Admin. R. 345-021-0060 (2001). Each reviewing agency is encouraged to conduct its review of the application and other permits applications on a time line and in a manner that enables it to make recommendations to the Office of Energy and Council on compliance and conditions, present testimony and evidence at the contested case hearing, and consolidate all its public hearings and written comment periods with the Office of Energy's siting review procedures. Or. Admin. R. 345-021-0080 (2001). After the deadline for agency reports, the Office of Energy may convene a meeting of reviewing agency personnel to coordinate review of the application and other permit applications. *Id.* The Council is to eliminate duplicative application, study, and reporting requirements; use information and documents prepared for federal review; develop reliance on a joint record; conduct joint hearings, on a time frame consistent with federal agency review; and establish conditions consistent with conditions established by federal agencies (to the extent consistent with applicable state standards). Or. Rev. Stat. § 469.370 (1999). State agencies are charged to review the permit simultaneously with the Council's review of the site certification application and consolidate the required permit application hearing with hearings under the siting statute whenever feasible. Or. Rev. Stat. § 469.505 (1999). Agency reports and final land use decisions are part of the Office of Energy's decision record for the application. Or. Admin. R. 345-015-0200 (2001).

[51]Or. Rev. Stat. § 469.330 (1999), Or. Admin. R. 345-020-0011 (2001). The NOI is an extensive collection of information concerning the applicant, the proposed facility, the state, federal, and local permits needed and various agencies involved, potential

list of agencies, officers, and tribes, which are required to submit comments and recommendations to the Office of Energy.[52] For a facility with a nominal electric generating capacity of less than 100 MW, the applicant can request expedited review.[53] In contrast to Washington, the applicant cannot submit an application until the Office of Energy has issued a project order,[54] listing the state statutes and administrative rules that must be met, all local government ordinances, all application requirements, all state and local permits, and public concerns that the applicant should address.[55] The application is not complete until each responsible agency has notified the Council that it has enough information for a permit decision or has stipulated what additional information is necessary, and has estimated a date when it will complete its review and issue a permit decision.[56] Thus, because there is no preemption of responsible agencies, there is potential for any agency to hold up the process by requesting additional information or delaying its review.

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adverse impacts and proposed mitigation, and projected water use and carbon dioxide emissions. Or. Rev. Stat. § 469.330 (1999), Or. Admin. R. 345-020-0011 (2001). If federal land is involved, the applicant should include documents prepared for an Environmental Assessment or EIS under NEPA and may copy relevant sections or cross-reference them in the NOI to avoid duplication. *Id.* The applicant must provide evidence in the NOI that it has consulted with the State Commission on Indian Services to identify each tribe appropriate for consultation as to the potential effects on Indian historical and cultural resources. Or. Admin. R. 345-020-0011 (2001).

[52]Or. Admin. R. 345-020-0040 (2001).

[53]Or. Admin. R. 345-015-0300 (2001). Expedited review means that the NOI phase of the application process can be bypassed, and the applicant can proceed directly to submit an initial application. The Council will issue a project order (an order listing the rules, ordinances, and permits that apply to the project) after reviewing the initial application and continue the process just as with regular review.

[54]Or. Admin. R. 345-021-0000 (2001). The Office of Energy issues the project order after it reviews the NOI and the comments submitted in response to the public notice. Or. Admin. R. 345-015-0160 (2001).

[55]Or. Admin. R. 345-015-0160 (2001). During its review it may convene meetings between the applicant and any reviewing agency. Or. Admin. R. 345-015-0140 (2001). When review of the NOI is complete, the Office of Energy sends a project order to the applicant. Or. Admin. R. 345-015-0160 (2001), Or. Rev. Stat. § 469.330 (1999). The Office of Energy is required to the extent practicable to issue the project order within 140 days of the submission of the notice of intent. *Id.* It is not a final order, and therefore is not appealable. *Id.*

[56]Or. Admin. R. 345-021-0000 (2001).

As in Washington, an applicant can look to the Council for a determination of compliance with respect to local land use standards. Unlike Washington, Oregon provides the option of choosing a Council determination of compliance at the beginning of the process, rather than requiring the applicant to attempt to obtain local approval first. In Oregon, an applicant can establish initial compliance with zoning and statewide planning goals (1) if the applicant has gone through local processes and has received local land use approval, or (2) if the Council makes a finding that it complies with substantive criteria from the local comprehensive plan and state planning goals and statutes, identified by the local land use planners. If the applicant chooses the Council determination of compliance route, the Council may grant an exemption from compliance with planning criteria under certain circumstances.[57] Although the Council will not approve a project that has been denied approval in the local process, it can effectively preempt that process when it acts to approve a project that it has exempted from compliance.[58]

The Council reviews the application for compliance with standards that it promulgated to reflect other agencies' standards and requirements under applicable permits. Unlike other states, Oregon does not have SEPA requirements and no state EIS is required.[59] The coordinated review process culminates in the Council's decision to issue or not issue a site certificate. The Council must issue a site certificate if it finds that the application meets its specific environmental and

[57]The Council may determine that an exception is justified because changed circumstances make the planning goal with respect to that parcel impracticable, or determine that reasons justify not applying that state policy, that adverse consequences will be mitigated, and the facility is compatible with adjacent uses. Or. Rev. Stat. § 469.504 (1999), Or. Admin. R. 345-022-0030 (2001).

[58]If the Council determines that an exception is justified, "[o]n or before its next periodic review, each affected local government shall amend its comprehensive plan and land use regulations as necessary to reflect the decision of the council pertaining to a site certificate or amended site certificate." Or. Rev. Stat. § 469.504 (1999).

[59]Oregon Office of Energy: Comparison of Energy Facility Siting Requirements, http://www.energy.state.or.us/siting/sitecom.httm (visited May 14, 2001).

social standards[60] and is in compliance with statewide planning goals adopted by the Oregon Land Conservation and Development Commission.[61] Failure to comply with the standards will result in denial unless the Council determines that the overall public benefits outweigh the damage to the resources protected by the standards the facility does not meet.[62]

Satisfaction of the Oregon carbon dioxide standard represents an important milestone in the process of obtaining certification for a project in Oregon.[63] The imposition of a carbon dioxide standard and the options stipulated in Oregon law for compliance with the standard may represent the wave of the future for other states' application processes. Oregon requires an emissions rate that is below that achieved by any

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[60] Social standards include impacts on historic, cultural, or archaeological resources; protection of public health and safety; impacts of the facility on recreation, scenic, and aesthetic values; ability of the communities in the affected area to provide sewers and sewage treatment, housing, traffic safety, police and fire protection, health care, and schools; and protection of public health and safety.

[61] Or. Rev. Stat. § 469.501 (1999) accomplishes the following: The Council is charged with adopting standards that protect the environment and natural resources. It may not adopt a standard requiring a showing of need or cost-effectiveness for energy facilities. The Council reviews permits and agency standards under its general standard, including noise standard, wetlands removal/fill permits, water pollution control facility permits, and water rights. Other standards enforced by the Council are promulgated in Or. Admin. R. 345-022-0010 to 345-022-0130 (2001).

[62] Or. Rev. Stat. § 469.503 (1999). To determine that a facility that does not meet standards under Or. Rev. Stat. § 469.501 confers overall public benefits that outweigh the damage to the protected resource, the Council considers (1) if the damage is acceptable (weighing the uniqueness of the resource, the degree to which it is already affected by development, and whether there are reasonable alternatives), and (2) the nature of the public benefit from construction at the proposed site (weighing the contribution toward maintaining reliable energy delivery to an area in the state, the expected effect of the proposed facility on total resource cost and average delivered price of energy to end uses, overall environmental effects, consistency of the facility with state energy policy under Or. Rev. Stat. § 469.010 (1999), and recommendations from any special advisory group). Or. Admin. R. 345-022-0000 (2001). The Council has not used its authority to waive a standard to date. *Oregon Office of Energy—Facility Siting Process*, http://www.energy.state.or.us./siting/process.htm.

[63] Or. Rev. Stat.§ 469.503 (1999).

[64] Reserved.

currently operating plant.[65] Thus, a developer is unlikely to be able to completely satisfy the carbon dioxide reduction target through plant efficiency alone, and will need to take measures to offset the facility's emissions.[66]

The applicant can meet the carbon dioxide standard either through cogeneration that offsets fossil fuel emissions that otherwise would have occurred, or through offset projects. To meet the standard through offset projects, an applicant may either implement offset projects or provide offset funds.[67] If an applicant proposes to implement or sponsor an offset project, rather than providing offset funds, that project must withstand detailed examination by the Council during the hearing process.[68]

Under the "monetary path" option, the applicant provides a calculated amount of offset funds to meet the carbon dioxide standard. The funds are then channeled to a qualified organization that implements the offsets.[69] The Council determines the amount of carbon dioxide reductions necessary to meet the standard based on the likely emissions of the facility given its proposed design. Then it calculates the

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[65]For base load gas plants (natural-gas-fired plants), the standard sets the net emissions rate at 0.675 lb. carbon dioxide per kilowatt-hour. For non-base load plants (all fuels), the net emissions rate is 0.70 lb. carbon dioxide per kilowatt-hour. For nongenerating facilities, the rate is 0.522 lb. carbon dioxide per horsepower-hour. A non-base load plant is a fossil-fuel generating facility that is limited by the site certificate to an average of not more than 6,600 hours of operation annually (75% capacity) (over 5 years), and is a peaking, or load-following plant. A base load plant is a generating facility fueled by natural gas, and is not limited in its site certificate to hours of operation below 100% capacity.

[66]Or. Rev. Stat. § 469.501 (1999).

[67]*Id.* An applicant can implement offsets directly or through a third party, or provide offset funds directly or through a third party.

[68]The Council will consider (in the contested case hearing stage of the approval process) the certainty that the projected offsets will be achieved, the ability of the Council to monitor and confirm reductions from the projects, and the extent to which the reductions would have occurred in the absence of the offset project.

[69]The Council has established criteria for identifying qualifying organizations, including nonprofit status and board membership. The organization's board must consist of three members appointed by the Council, three appointed by an environmental non-profit group, and one appointed by the applicant. The Oregon Climate Trust was formed as a qualified organization, and may be used at the applicant's choice or if the applicant is unable to find a qualified organization.

amount of offset funds that the applicant should provide, at a rate of $0.57 per ton of stipulated carbon dioxide reductions.[70] Because payment of the funds automatically satisfies the offset obligation, this option relieves the applicant of the obligation to prove projected carbon dioxide offsets in a contested case hearing and frees it from management of offset projects.

Water supply for the project may be secured either through purchase from a water utility in whose service area the project is located or through the state water rights permit process. Oregon is among 19 other Western states that have adopted the prior appropriation doctrine by means of a permit process, administered by the Oregon Water Resources Department (WRD).[71] An application submitted to the WRD[72] is evaluated for technical sufficiency, to confirm whether water is available for appropriation, and whether the project would impair or be detrimental to the public interest.[73] If so, a proposed final order is issued and public notice given, typically followed by mediation or hearings.[74] The permit is not itself a "water right," but an inchoate right that authorizes the permittee to apply water to a beneficial use.

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[70]The applicant must also pay contracting and selection funds for the qualified organization. The organization must use at least 80% of the funds to purchase offsets and may use the remaining funds to perform administrative functions. The contracting and selection funds are 10% of the first $500,000 of offset funds and 4.286% of any additional offset funds.

[71]Or. Rev. Stat. §§ 537.110 to 537.330 (1999). The permit process was established for surface water in the Water Rights Act of 1909. Oregon law recognizes water rights secured by other means prior to 1909, and provides for an adjudication process to determine such rights. Or. Rev. Stat. §§ 539.005 to 539.240 (1999). Few Oregon streams have been adjudicated, but the existence of old water rights might be a limiting factor on availability of water for new rights. Rights to use groundwater are also subject to a permit process, as of 1955. Or. Rev. Stat. §§ 537.505 to 537.796 (1999). Adjudication of groundwater rights is pursuant to Or. Rev. Stat. §§ 537.670 to 537.700 (1999).

[72]Or. Rev. Stat. § 537.140 (1999).

[73]Or. Rev. Stat. § 537.150 (1999).

[74]Contested case hearings or mediation are conducted if there are protests in response to the proposed final order. If no protests are received, the permit must issue within 180 days of filing the application. Or. Rev. Stat. § 537.175 (1999).

Once the permittee can prove that the water has been so applied, a water rights certificate is issued.[75]

Because many Oregon streams are considered to be "over-appropriated" and because of heightened concern for maintaining in-stream flows for listed protected species, new water rights applications are often protested and permits are difficult to obtain. One alternative is to purchase water or water rights from another water rights holder at a negotiated market price. Such a transaction involves an administrative process before the WRD to "transfer" the point of diversion, place of use, or nature of use. The test for transfers is whether the change would injure existing water users. Transfers are not subject to a general public interest test.[76]

[3] Arizona

Arizona's siting statute covers facilities with generation capacity of 100 MW or more. In Arizona's two-tiered siting review process, the Arizona Corporation Commission (Corporation Commission) has siting authority, but the application review process is carried out by the Power Plant and Transmission Line Siting Committee (Siting Committee) under the oversight of the Corporation Commission.[77] The Corporation Commission must approve the Siting Committee's recommendation unless a party to the certification proceeding requests the Corporation Commission to review the recommendation through a second series of hearings.[78] The 11-member Siting Committee consists of

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[75] Or. Rev. Stat. § 537.250 (1999).

[76] Or. Rev. Stat. §§ 540.505 to 540.580 (1999).

[77] The Arizona Legislature created a two-tiered framework for power plant and transmission line siting. The Arizona Corporation Commission independently regulates "public service corporations" that generate or deliver electricity and it has siting authority. Ariz. Rev. Stat. §§ 40-360 to 40-360.13 (1996). The Power Plant and Transmission Line Siting Committee is responsible for most of the research and investigation and much of the application review process. Ariz. Rev. Stat. § 40-360.04 (1996).

[78] Arizona uses a two-step certification process in reviewing power plant and transmission line applications. First, the Siting Committee conducts hearings after public notice of the application. Typically, the Siting Committee imposes conditions before issuing the certificate. Within 60 days of the Siting Committee's decision, the Corporation Commission must "affirm and approve" the certificate unless a party to

agency representatives and Corporation Commission appointees representing the public and local jurisdictions potentially affected by the facility.[79] The Corporation Commission makes a final decision, without need for the governor's approval.[80] Usually, the Corporation Commission imposes additional conditions to the Siting Committee's approval.[81]

The applicant must comply with local zoning ordinances and must obtain all relevant local permits without the benefit of Corporation Commission preemption or streamlining of those processes. The Corporation Commission does not have the ability to preempt state permit processes, nor does it coordinate federal permits delegated to the state. In the absence of a SEPA process, the Corporation Commission augments those federally-delegated, state, and local permitting processes with its own separate regulation, ensuring that environmental and social impacts are minimized by imposing conditions on siting permit applications. As conditions of approval, the Siting Committee has regularly imposed air quality conditions and emissions offsets, required new plants to commit to future technology

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the certification requests the Corporation Commission to review the Siting Committee's decision. Ariz. Rev. Stat. § 40-360.07(A) (1996). If the Committee's decision is challenged, the Corporation Commission may "either confirm, deny or modify" the certificate within 60 days of a challenge. Ariz. Rev. Stat. § 40-360.07(B) (1996). The second step is a series of public hearings and review of the Siting Committee's record by the three-member Corporation Commission. *Id.*

[79] An attorney from the State Attorney General Office chairs the Siting Committee, comprised of representatives from the Arizona Department of Environmental Quality, Department of Water Resources, Energy Office (in the Department of Commerce), and the Corporation Commission chairman or his designee. The Corporation Commission appoints six additional members for two-year terms, of which three represent the public and one member each represents cities and towns, counties, and agriculture. Ariz. Rev. Stat. § 40-360.01 (1996).

[80] Ariz. Rev. Stat. § 40-360.06 (1996).

[81] No application has been denied in recent times. However, the number of conditions has increased for recent applications. For example, the Siting Committee approved the Santan Expansion Project of the Salt River Project (SRP) with 34 conditions, and the Corporation Commission added 7 more, for a total of 41 conditions.

improvements, and required energy generated be available to the Arizona market.[82]

Arizona law prohibits the Siting Committee from imposing more stringent air quality conditions than existing law and regulations.[83] Nevertheless, for facilities proposed in areas that are attaining air quality standards, the Corporation Commission has conditioned approval on meeting the more rigorous emissions standards required in non-attainment areas. In obtaining air emission offsets, the Siting Committee requires the plant owner to use its "best efforts" to obtain those offsets as close as possible to the plant site.[84] In addition, the Corporation Commission has begun requiring new plants to commit to scheduled future technology improvements. Continued operation of the facility has been conditioned on the Corporation Commission's approval of those improvements.[85]

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[82] *See infra* notes 83-86.

[83] Ariz. Rev. Stat. § 40-360.06(C) (1996) states:

> Notwithstanding any other provision of this article, the committee shall require in all certificates for facilities that the applicant comply with all applicable nuclear radiation standards and air and water pollution control standards and regulations, but shall not require compliance with performance standards other than those established by the agency having primary jurisdiction over a particular pollution source.

[84] A number of requirements were imposed as conditions of approval of the application of the Salt River Project Agricultural Improvement and Power District (SRP) to construct the Santan Expansion Project. The Corporation Commission required SRP to meet the lowest achievable emission rate (LAER) for carbon monoxide (CO), nitrogen oxides (NOx), volatile organic carbons (VOCs), and particulate matter less than 10 microns in aerodynamic diameter. In addition, no diesel fuel may be used at that site, which has an existing 300-megawatt generator. The Siting Committee also required the Salt River Project to contribute $330,000 for the conversion of school buses to green diesel or other alternative fuel, to contribute $400,000 to the regional mass transit authority, and to replace all of the city's street sweepers with certified PM10 efficient equipment. *See* Certificate of Environmental Compatibility, Docket No. L-00000B-00-0105.

[85] For example, when it approved the Santan Expansion Project, it required the Salt River Project to review its plant operations every five years. SRP must file a report with the Corporation Commission, within 120 days of that review, listing all improvements that would reduce plant emissions and their associated costs. Corporation Commission staff will then review that report and must issue findings (including an economic feasibility study) to the Corporation Commission within 60 days. Within 24 months of SRP filing its report, it must install the improvements, unless the Corporation Commission directs otherwise. *Id.*

The Corporation Commission in Arizona has engaged in regional market protectionism similar to that demonstrated by the Energy Facility Siting Council in Washington State. Citing the need to guarantee Arizona consumers market access to energy generated at new facilities, it has required power plant applicants to commit to initially making some of the energy available to the Arizona market.[86] It also has begun issuing certificates that expire after five years if the project has not been completed.

The Arizona siting statute gives the Siting Committee a narrow mandate for dealing with water issues when evaluating a proposed facility's cooling water use. It must consider the impact of use on endangered species, and, in certain circumstances, may consider the impact of use on water supply.[87] Siting law requires the Committee to consider fish, wildlife, and plant life and "give special consideration to the protection of areas unique because of biological wealth or because they are habitats for rare and endangered species.[88]

With respect to water supply, most water sources are controlled and regulated outside the jurisdiction of the siting statute. Only groundwater use is to a limited degree under the purview of the Siting Committee. If a proposed site is inside a designated active management area (AMA) and within the water service area of a city or town, it is subject to the regulation of the Siting Committee, and must comply with the AMA. Outside these areas, the siting statute does not grant the Siting Committee the authority to consider a proposed facility's effect on water supply, or to deny an application on the ground that it negatively impacts water supply available to other users. The Siting Committee is

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[86]The Siting Committee required SRP to operate the plant consistent with its obligation to serve its retail load to maintain a reliable transmission system within Arizona, recognizing generation shortages and "the attendant price volatility that California is now experiencing." Although SRP, as a municipal utility, is not under the jurisdiction of the Commission except as to plant and line siting, the Corporation Commission was able to dictate SRP's distribution and transmission system in approving this certificate.

[87]Ariz. Rev. Stat. §§ 40-360.06(B) & 40-360.13 (1996).

[88]*Id.*

charged only to consider the effects of the proposal on existing plans for other development rather than considering the adequacy of supply.[89] However, the Siting Committee indirectly influences the water use proposed in a siting application because developers are sensitive to water use as a political issue. Developers typically choose to demonstrate adequacy of water supply in their applications by purchasing water rights, e.g., through retirement of agricultural uses, in order to minimize opposition to the project by assuaging local users' concerns about the adequacy of the remaining water supply. Developers also take this step to overcome opponents' charge that Arizona water is being used by merchant plants to export power to California, at the expense of Arizona citizens who are left with a diminished supply of water.

[4] California

In 1974, the California legislature passed the Warren-Alquist Act,[90] creating the State Energy Resources Conservation and Development Commission, more commonly known as the California Energy Commission (the Commission).

The Commission has the exclusive authority to certify the construction and operation of thermal electric power plants 50 megawatts or larger and all related facilities in the state. The Commission's site certification process provides a review and analysis of all aspects of a proposed project, including needs, public health and environmental impacts, safety, efficiency, and reliability.

The governor appoints the five members of the Commission. By law, four members of the Commission have professional training in specific areas—engineering and physical science, environmental protection, economics, and law. The fifth commissioner is from the public at large.

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[89] Unless the proposed facility is in a water service area within an AMA, the Siting Committee may only consider whether that water use will affect "existing plans of the state, local government and private entities for other developments at or in the vicinity of the proposed site." Ariz. Rev. Stat. § 40-360.06(A)(1) (1996).

[90] Cal. Pub. Res. Code §§ 25000 to 25009 (1996).

During the energy facilities certification process, two commissioners are chosen to oversee all hearings, workshops, and related proceedings on a specific project. This two-member "committee" will make recommendations to the other commissioners before final action for certification is determined at a public hearing(s) of the full five-member Commission. The staff relies on the Commission's regulations[91] for direction on staff's particular responsibilities in a siting case. The Commission's siting process has been determined to be a certified regulatory program under the California Environmental Quality Act (CEQA) and the functional equivalent of preparing environmental impact reports. Consequently, while the Commission is the lead agency for all projects under its jurisdiction and meets the intent of CEQA, the Commission is not required to prepare environmental impact reports but instead prepares staff assessments.

The standard licensing process is intended to be conducted in 12 months, starting from the day the application (the AFC) is deemed adequate by the Commission. However, very few major power plant licenses have been issued in less than two years. After the onset of the energy crisis in California the summer of 2000, Governor Davis issued a series of executive orders designed to streamline the siting process. As a result, in certain circumstances, an application may qualify for an expedited six-month review process, as well as a four-month review process for "peaker" power plants.[92] A number of peaker plants have been approved within four months, but no significant power plant has qualified for the six-month review to date. In a further attempt to expedite the review of applications to construct power plants, the California legislature passed Senate Bill 28X on February 5, 2001. The purpose of this bill is to set firm time lines on local jurisdictions to avoid the delays in these jurisdictions in submitting information in the licensing process.

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[91] Cal. Code Regs. tit. 20, § 1701.

[92] Cal. Pub. Res. Code § 25000(a) (1996).

The initial portion of the certification process is weighted heavily toward ensuring public awareness of the proposed project and obtaining such further technical information as necessary. The Office of the Public Adviser is available to inform members of the public concerning the certification proceedings, and to assist those interested in participating. During this phase, the Commission staff sponsors numerous public workshops at which intervenors, agency representatives, and members of the public meet with staff and the applicant to discuss, clarify, and negotiate pertinent issues. Staff publishes its initial technical evaluation of a proposed project in the preliminary staff assessment (PSA), which is made available for public comment. Staff's responses to public comment on the PSA and its complete analysis are published in the Final Staff Assessment (FSA).

The Commission also conducts various public events to assess the adequacy of available information, identify issues, and determine the positions of the various participants. Information gleaned from these events forms the basis for a hearing order organizing and scheduling formal evidentiary hearings. At these hearings, all formal parties are able to present testimony, under oath or affirmation, which is subject to cross-examination by other parties and to questions by the Commission. The public also may comment on a proposed project at these hearings. Evidence adduced during these hearings provides the basis for the decisionmakers' analysis. Typically, a power plant application may undergo 20 to 30 public hearings before final approval.

Until July 2, 2001, no major power plants other than nuclear plants had been built in California since 1972. In the early 1990s before the state's electricity generation industry was restructured, the Commission certified 11 power plants, none larger than 240 MW. Of these, three were never built due to market conditions. The remaining eight plants are now generating 952 MW of electricity. No power plant applications were filed with the Commission between 1994 and 1997, in part because there was so much uncertainty concerning the restructuring of the electricity industry.

Electricity deregulation occurred in March 1998.[92.1] The Commission has approved 16 large-scale (over 300 MW) plants since April 1999. Three plants totaling 2300 MW have become operational since July 2001. An additional 13 plants totaling 8,000 MW are under construction, and will come online over the next 30 months. In addition to the rather lengthy permitting process within the state, California is a prime example of the impact of federal permit constraints on a state licensing process. As experienced in almost all recent cases, the timing of some federal permits (and their requirements for the siting, construction, and operation of power plants) can impact the licensing process in a variety of ways, including delaying important federal permit decisions until after the Commission's decision. Such federal permits may be subject to further appeals processes over which the Commission may have limited influence.

On March 13, 2001, the Commission identified the following federal permit processes that have the greatest potential to cause significant delays and add substantial uncertainties to power plant licensing. These are:

The Endangered Species Act. The USF&WS and the National Marine Fisheries Service (NMFS) administer the Endangered Species Act (ESA), under the consultation requirements of section 7 of the Act. Section 7 typically requires that a federal agency whose action is likely to affect a listed species submit a biological assessment (BA) to the USF&WS for formal consultation and a biological opinion (BO). The USF&WS, upon accepting the BA, is required by statute and regulation to provide the BO within 135 days (with certain exceptions), a schedule that is rarely adhered to.[92.2]

Prevention of Significant Deterioration (PSD) Permits Under the Clean Air Act. This permit is administered by EPA or delegated to local air districts. EPA may conduct its reviews of PSD permits very late in the licensing process and approval

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[92.1] Cal. Pub. Util. Code § 365(b)(i) (2001).

[92.2] *See* § 11.04[2][a] *supra*.

may be well after the AFC is certified. Such permits may be appealed to the EAB, and if an appeal is filed, the applicant must stop construction until the appeal is resolved. The EAB has interpreted broadly the scope of the issues that it may review (including compliance with Executive Order 12898 regarding environmental justice)[92.3] and, as a result, such reviews can often require six months to a year to resolve, with no mandatory upper limit.

National Pollutant Discharge Elimination System (NPDES). This permitting program causes uncertainties in the licensing process due to changing EPA regulations and regulatory guidance. With the new California Toxics Rule and the promulgation of new EPA regulations governing discharges from construction sites, the regulatory requirements of the California Regional Water Quality Control Boards as they pertain to individual projects are in a state of flux.

Federal Land Use Entitlements. Federal land management agencies have lengthy and involved review processes governing such actions as the grant of rights-of-way (ROWs) and special use permits for pipelines and transmission lines, which typically require the preparation of an EIS pursuant to NEPA, and may extend beyond the 6- or 12-month Commission process.

Tribal Lands and Native American Concerns. For actions involving use of Indian lands, the U.S. Bureau of Indian Affairs (BIA) is the lead federal agency. Like the federal land management agencies described above, the BIA has comprehensive review processes and NEPA compliance requirements. This involves extensive tribal consultation, as do projects that could affect resources protected by tribal treaty rights or cultural resources of significance to Native Americans.

[5] Colorado

In contrast to the other states reviewed in this paper, Colorado does not have a state power plant siting agency. Siting decisions are made at the county or municipal level,

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[92.3] 59 Fed. Reg. 7629 (Feb. 11, 1994).

with the environmental permits primarily for air emissions and water discharge issued by state agencies, primarily the Colorado Department of Public Health and Environment (CDPHE). There is no Colorado NEPA equivalent. Therefore, unless the development of the project constitutes "a major Federal action" under federal law, there is no requirement that an environmental impact statement be prepared under state law.

Local land use codes describe the requirements applicable to land within a given jurisdiction. If the power plant site is located within town or city limits, the current municipal zoning and/or land use code will apply. Many of these codes are now available online.[93] If the power plant site is not located within a municipality and is in an unincorporated area of a county, the county land use code will apply, unless annexation of the power plant site is pursued.

If the power plant site is not located in a town or city, municipal annexation may be considered. Reasons for annexing into a city or town may include the fact that municipalities may have desirable services needed for the operation of the power plant (water, wastewater treatment, fire protection, etc.). However, annexation may result in additional liability. If annexation is pursued, the Colorado Municipal Annexation Act of 1965 will apply.[94] In addition, the land use codes of most municipalities include their own annexation requirements, and may require a vote, either by the relevant city council or by citizens.[95]

Annexations are appealable and reviewable. Judicial review may be sought by (1) any landowner or qualified elector of the annexed area, (2) the board of county commissioners, or (3) a

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[93] For example, the City of Arvada has a website at http://www.ci.arvada.co.us that contains links to the land use code.

[94] Colo. Rev. Stat. Ann. §§ 31-12-101 to 31-12-123 (2001).

[95] Colo. Rev. Stat. Ann. §§ 31-12-107(2) & 31-12-110 (2001); Minch v. Town of Meade, 957 P.2d 1054 (Colo. Ct. App. 1998) (where town passed ordinance requiring vote of electors for any annexation into the town) pursuant to Colo. Rev. Stat. Ann. § 31-12-107(1) (2001).

municipality within one mile of the proposed annexation.[96] Such action must be brought within 60 days, and review is limited to the question of whether the annexing municipality exceeded its jurisdiction or abused its discretion.

Even if the municipality approves the siting of the power plant, the decision may still be subject to a vote of the local electorate. This may be one reason for choosing not to annex, especially if the annexing municipality has a small population, which could obtain easily the votes necessary to reject the siting of the power plant.

Any ordinance passed by the municipality, including ordinances approving the annexation, zoning, or rezoning, are subject to referendum or initiative procedures that could put the issue to the vote of the local electorate. This process requires either a petition signed by 5% of the electorate, or a decision by the legislative body to refer the ordinance to the electorate.[97]

If the power plant site is annexed into a municipality, the property will need to be zoned in a district that permits power plant usage. Some municipalities have zone districts (usually industrial) that permit power plants as a use by right, while others have zone districts that allow power plants as a permitted use subject to review. Initial zoning is considered legislative and therefore is not subject to judicial review.

On the other hand, if the power plant site is located in a municipality but is not in an industrial zone district or is in an unincorporated portion of a county, it is likely that a request for a zoning change for the property will be required. Zoning changes for specific properties are considered both legislative and quasi-judicial. Therefore, even if the rezoning request is granted, it still may be challenged by the electorate through a referendum procedure or may be subject to judicial review for abuse of discretion or jurisdictional challenges.

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[96] Colo. Rev. Stat. Ann. § 31-12-116 (2001).

[97] The referendum and initiative procedures are established pursuant to art. V, § 1 of the Colorado Constitution, and the procedures are set forth in Colo. Rev. Stat. Ann. §§ 31-11-101 to 31-11-118 (2001).

Many jurisdictions provide a conditional use permit procedure (or some variation thereof) for uses such as a power plant. A conditional use permit procedure may be in addition to, or in lieu of, zoning action.[96]

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[96]*See, e.g.*, Weld County Zoning Ordinance § 23-2-200 *et seq.* "Use by Special Review Permit." Calpine is using the Weld County Use by Special Review Permit process for its proposed power plant located near Hudson, Colorado. The land selected for the Rocky Mountain Energy Center is zoned agricultural, but a power plant is a permitted use if a Use by Special Review Permit is obtained. Thus, Calpine does not need to re-zone the land, but it does need to comply with rigorous standards of review involved in the Use by Special Review Permit approval process.