STAFF PAPER

Gas-Fired Generating Plants as Mitigation for Contingencies Threatening Southern California Electric Reliability

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ABSTRACT

The staffs of the California Energy Commission (Energy Commission), California Public Utilities Commission (CPUC), California Independent System Operator (California ISO) and California Air Resources Board (ARB) are working together to track resource development and electricity demand, and are identifying contingency mitigation options, should they be required, to assure electric system reliability in Southern California. Like most reliability assessments, there are risks (contingencies) and solutions (mitigation measures). The mitigation measures developed in the plan are designed to guard against the contingencies of lesser savings from preferred resource development, delays or termination of planned generation additions, or delays or poorer performance than planned of ISO-approved transmission system upgrades. This paper is a work in progress for one part of the overall contingency project. It identifies three options for developing a generating project that could serve as mitigation for a contingency that threatens reliability, and provides a preliminary assessment of the advantages and disadvantages of each option. The basic idea is to have a generating project designed, partly or fully permitted, and ready to be developed if projections for the total amount of resource capacity fall short of local capacity requirements in one or more of the local capacity areas of Southern California.

Keywords: Electricity policy, contingency, mitigation measures, power plant permitting, local capacity requirements, reliability

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EXECUTIVE SUMMARY

Immediately following Southern California Edison's June 27, 2013, announcement to close the San Onofre Nuclear Generating Station (San Onofre), Governor Brown requested that energy agencies, utilities, and air districts develop a plan for the power plant's replacement and the assurance of electric service reliability in Southern California. The staffs of the organizations developed a preliminary plan and presented it at a September 9, 2013, workshop as part of the *2013 Integrated Energy Policy Report* proceeding.

The preliminary plan was a multipronged effort to satisfy California Independent System Operator estimates of resource requirements to assure reliability, as measured by local capacity area requirements, using a rough replacement target of 50 percent preferred resources (such as energy efficiency savings, renewable generation, demand response programs) and 50 percent conventional natural gas-fired generation. The preliminary plan was not finalized or adopted by any agency, but both the California Public Utilities Commission (CPUC) and the California Independent System Operator (California ISO) examined the issue in their respective proceedings.

The CPUC has directed Southern California Edison Company and San Diego Gas & Electric Company to target preferred energy resource development in the geographic areas most helpful in satisfying system requirements. Also, the CPUC is overseeing power purchase agreements aimed at constructing new generation in desired locations. The Energy Commission is processing permits for a variety of proposed generation projects, some of which may be built if the California Public Utilities Commission approves a power purchase agreement for them. California ISO is studying and, in some cases, authorizing transmission system upgrades that address the voltage instability concerns created by the retirement of San Onofre.

If all this resource development continues as planned, reliability in Southern California would likely be assured. Reliability in Southern California, however, rests upon close coordination between retirement of large amounts of fossil-fueled, once-through-cooling power plants and the development of appropriate resources in locations needed to assure local capacity requirements are satisfied. Accordingly, the energy agencies and the California Air Resources Board have been working collaboratively to track all types of preferred resource, conventional power plant, and transmission deployment and develop a contingency plan. This report was prepared by Energy Commission staff with input from the other agencies.

Contingency mitigation measures to ensure electric service reliability need to be developed that can be triggered if resource expectations do not match requirements. A short-term measure is a possible request to the State Water Resources Control Board to defer compliance dates for specific once-through facilities for which a specific new power plant would allow retirement. (*Once-through cooling* involves water that is withdrawn from a source, circulated through the heat exchangers of the power plant, and then returned to a water body at a higher temperature.) A second but longer-term option would be conventional power plant proposals, taken as far through the permitting and procurement processes as possible, but then held in reserve to receive final approval and begin construction only if triggered.

This staff report is a work in progress that identifies three options for developing this longer-term generator mitigation measure:

- Option 1: Investor-owned utility chooses a project developer who initiates the process with specific project designed by the developer.
- Option 2: Investor-owned utility initiates project development.
- Option 3: Rely upon already-permitted projects.

All options will require a series of steps to get to the point where they would be ready for triggering if contingencies are encountered. Once triggered, any final permitting and purchase agreement approval would be completed, and construction would start as quickly as possible. The agencies may need to modify normal approval processes to accelerate review and approval should the mitigation measures need to be triggered.

Input from utilities, air permitting districts, and the public will be useful in identifying the advantages and disadvantages of each option to enable the project team to make a recommendation for implementing one of the three specific generator mitigation measure options.

The appendix provides guidelines for developers to use in preparing project applications proposed as contingency mitigation measures to assure that a project coming to the Energy Commission can be processed in the least amount of time.

Background

The staffs of the California Energy Commission (Energy Commission), California Public Utilities Commission (CPUC), California Independent System Operator (California ISO) and California Air Resources Board (ARB) are working together to track resource development and electricity demand, and are identifying contingency mitigation options, should they be required, to assure electric system reliability in Southern California. [1] [2] Like most reliability plans, there are risks (contingencies) and solutions (mitigation measures). The mitigation measures developed in the plan will be available for implementation, if needed, to guard against the contingencies of preferred resources failing to develop as planned, delays or termination of planned generation additions, or delays or poorer performance than planned of California ISO-approved transmission system upgrades. Mitigation measures will still follow approved processes for procuring electricity with appropriate transparency. Two types of mitigation measures are being developed—short-term once-through-cooling (OTC) compliance date deferral for selected facilities and a conventional generator option. The California ISO has analyzed extensively transmission alternatives in the event other electricity resources fail to materialize. If currently anticipated resources fail to materialize, other short-term mitigation plans will need to be considered to provide adequate time for transmission alternatives to be developed. The California ISO will continue to study transmission alternatives through its annual transmission planning process. Close monitoring of resource development and expectations for future development would be used to project whether local capacity requirements were likely to be satisfied, and if not, to recommend that one or more of the mitigation measures be triggered. This paper describes conventional generation options that could be developed as part of this overall contingency mitigation program. [3] The other mitigation options are briefly described in the August 20 workshop materials.

This paper is Version 3 of a work in progress for one part of the overall contingency mitigation proposal. It identifies three options for developing a generator mitigation measure. In previous drafts of this paper, other options have been described, but they have received substantial criticism from reviewers and have been dropped. Each option has some degree of permit approval but vary widely in the degree of approval for investor-owned utility (IOU)/developer power purchase agreement (PPA). All options require a series of

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1 A workshop providing an overview of the approach being developed and a status report on various elements was conducted on August 20, 2014, as part of the Energy Commission's *2014 Integrated Energy Policy Report* (IEPR) proceeding. See http://www.energy.ca.gov/2014_energypolicy/documents/#08202014.

2 The staff of the Energy Commission prepared this paper with input from CPUC, California ISO, and ARB. Chris Davis of the Energy Commission provided substantial support.

3 An initial draft dated October 2, 2014, was circulated to selected stakeholders and initial comments were obtained through a series of teleconferences. This draft incorporates some of that feedback.

steps to get them to the point where they would "sit on the shelf" waiting to be triggered by contingencies.[4] If triggered, then permits and PPAs would have to be completed. Other mitigation measures would be developed and could be triggered instead of, or in addition to, a generator option. Only some contingencies would likely justify triggering development of such new generation. Once triggered, any final permitting and PPA approval would be completed, and construction would start as quickly as possible.

Regardless of which option is selected from those described herein, one or two generating facility projects (locations and technologies) would be chosen to be developed as a potential power plant. In developing such resources, it seems essential to at least partially complete the permitting process, so that, if triggered by contingencies, substantially less time and effort (compared to a typical generating facility) would be needed to complete permitting and approve the PPA before actual construction could commence.

Depending upon the option, either the Energy Commission or CPUC, or both, would have to modify their generation review/approval processes these options to be implemented. The Energy Commission would have to modify its power plant licensing process, giving such projects special treatment as contingency mitigation resources. This modification essentially means completing as much of the permitting process as feasible, recognizing that some components and final approval would remain. Since the Energy Commission permitting process encompasses, but does not substitute for, an air quality permit, the timeline should recognize that finalizing the air permit is likely to be among the remaining steps that takes place once the project is triggered. Thus, the lead time from final approval to project ready for operation would be reduced compared to the normal permitting, procurement, and construction processes.

The CPUC might need to open a proceeding specifically to review and approve utility cost recovery associated with the contingency project. The CPUC might also need to determine whether the IOU itself would be allowed to propose a project as utility-owned generation.

Regardless of the option selected for contingent power plant development, Energy Commission staff recommends that specific projects proposed as mitigation measures follow the guidelines discussed in the appendix to this document. These guidelines would help to assure that a project coming to the Energy Commission can be processed in the least amount of time. Toward that end, and considering each of the following options, there may be some additional time savings by IOUs acting upon the language of the March 2014 Decision in the 2012 Long-Term Procurement Planning proceeding (LTPP) (D14-03-004, Section 5.4, page 102) relative to contingency (options) contracts.[5]

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4 These generator mitigation options could be viewed as an insurance policy that only would be used as a last resort in the event of contingencies.

5 CPUC D.14-03-004, Section 5.4, reviews Southern California Edison Company's (SCE) proposal for contingent contracting authority. It outlines a series of questions that the CPUC might ask if SCE submitted such a proposed contract for approval. The decision authorizes SCE and San Diego Gas &

Specific Options

Three options to accomplish the general idea of a fast-track approach to power plant development are described and evaluated in this paper. Each option is divided into two stages, with Stage 1 (creation of the option) comprising the steps to get it to the point where it would "sit on the shelf" waiting to be triggered by contingencies and Stage 2 comprising actual project development only if the option is triggered. These three options were developed using the following design approaches:

- Option 1: IOU Chooses Developer Who Initiates Process With a Specific Project
    - Maximize project definition, permitting, and procurement authorization upfront.
    - Minimize elapsed time from triggering to the on-line date for the project.
- Option 2: IOU Initiates Project Development
    - Maximize project definition, permitting, and procurement authorization upfront.
    - Rely upon IOUs to initiate process and streamline cost recovery with CPUC.
- Option 3: Rely Upon Already Permitted Projects
    - Rely upon developers to design projects and obtain permits without any guarantee of cost recovery.

Option 1: IOU Chooses Developer Who Initiates Process With a Specific Project

Concept: This option begins by the IOU selecting a project developer, perhaps through a request for offers process, and a specific location and technology for the project is known. The developer must prepare and submit an application for certification (AFC) to the Energy Commission, the IOU and the developer agree to a two-part PPA, and the IOU submits this to the CPUC for approval. This option makes limited changes to the actual Energy Commission power plant licensing process principally because the project developer initiates the normal Energy Commission licensing process, but at some point the project approval effort is suspended, and no final license is provided to the project.

The CPUC could potentially process a contingency contract between the developer and a utility for the project. A proposed PPA would split the normal costs of a generator project into two stages. The first is a project design stage covering just site control,[6] project design, and preliminary equipment purchase costs would be fully approved. The second, the

Electric Company (SDG&E) to submit contingent contracts and highlights the requirement that the utility must fully address the questions in any such application.

6 Site control is the step in the development of a project in which the developer purchases the land where the project is intended to be built, or otherwise obtains an option to acquire the land if a permit to develop the project is received.

project construction and operation stage, would cover the actual project construction costs and procurement of power production services (capacity, energy, and ancillary services)[7] from the project for some term of years and could be carried through all steps except final signoff. Creating a PPA with two stages would (1) allow sunk cost recovery for a generating company that might never have an opportunity to construct the power plant because the contingency conditions were never encountered, and (2) protect ratepayers from "double cost recovery" if the project is eventually built by assuring that costs incurred to design and permit the plant already paid for in Stage 1 are not paid for again in Stage 2.

In concept, the *project design stage* would include the costs of preparing an application to the Energy Commission, securing control of the site through an option on the land, and obtaining or "reserving" any needed emission offsets for such a contingent facility. This stage of the PPA would also recover costs of any "deposits" associated with advance ordering of necessary generating equipment and "holding a place in line" for such equipment. In effect, through the *project design stage*, the developer is paid to create a project, move it substantially through the Energy Commission and the applicable air district permitting processes, and secure a place in line with all critical equipment suppliers.

The terms, conditions, and pricing of the *project construction and operation stage* would recognize that project design costs normally included within the terms and conditions for capacity and energy products have already been paid for via a separate stage of the PPA. The developer should not be paid for these twice, so amounts paid to the developer in the *project design stage of the PPA* would be subtracted from market-based, negotiated terms and conditions for capacity and energy products under the normal power purchase agreement. In the *project construction and operation stage* of the PPA the developer would be paid for construction costs, fuel and other operating costs once the plant was operating, and customary profits.

In the normal Energy Commission power plant licensing process, a permit is good for five years. Extensions can be granted by vote of the Energy Commission.[8] Some evidence used in the decision could have become stale; it may take a supplementary analysis to determine that the approved permit is still valid, especially from an air quality perspective. Extensions typically are only for one year, and the applicant must file such a request with enough time remaining before the permit expires for the Energy Commission to thoroughly evaluate it and make the determination whether all the evidence is still relevant. It would be incorrect

7 A power plant provides multiple services that can satisfy requirements of different entities in the electricity system. End-users are interested in energy to support their electricity consumption needs. Capacity that is available to be dispatched is of interest to a load serving entity trying to cover the collective power demands of many customers and to a system operator trying to assure reliability. A system operator requires ancillary services to support the stability of the grid rather than the needs of end-users for power or energy. Services may include regulation, spinning reserve, non-spinning reserve, replacement reserve and voltage support.

8 License extensions of this kind have been approved several times by the Energy Commission.

to assume that extensions are universally granted. The authority to construct application submitted to an air district also results in a permit with a limited lifetime usually much shorter than the five years allowed by the Energy Commission. Such permits can be extended, but after a certain period, best available control technology, air quality modeling, and other aspects of the air quality permit review process would have to be reviewed and potentially revised. These reviews at both the Energy Commission and the appropriate air quality district need to be addressed in the timeline for the second stage.

Table 2 of this document lists each of the steps describing this option, whether the Energy Commission or CPUC generally has the lead for that step, and the elapsed time estimated for that step. **Table 2** identifies all steps comprising the creation of the mitigation option (Stage 1), and then the remaining steps to approve and construct the project if it is triggered (Stage 2). The elapsed time associated with Stage 1 could be shortened if the proposed site is an existing or former power generation facility as opposed to a greenfield site (undeveloped land) since one would expect such a brownfield site (a site with an existing use that has already disturbed the land) to have already encountered the development impacts explored in greater depth for a greenfield site. The high level of advance approval in Option 1 could translate into as little as 35 months from final authorization through construction to an operating power plant.

Concept Implementation Issues

Numerous implementation issues need to be overcome. Among these are:

- Clearly more than one generating company might like to obtain such a contingent permit. Utilities seem to prefer some kind of request for offer (RFO) or auction process to select from among qualified developers bringing forward evidence of site control or some other demonstration of project viability. Utilities have noted that devising an RFO that expressly requires bidders to segment costs into Stage 1 and Stage 2 could reduce litigation costs and make CPUC approval of a PPA more straightforward.
- Air permits are also necessary to secure in advance, or by some means be made available to the projects selected, for this option to be effective. The practices of South Coast Air Quality Management District (SCAQMD) and San Diego Air Pollution Control District (SDAPCD) are different, and both may be changing.[9] Initial discussions with both agencies have revealed that an air permit to construct valid for multiple years is unrealistic. At a minimum, some review would be required once a project was actually triggered. The depth of this review and the time needed to complete the Stage 2 process have not yet been established. However, the elapsed time between Stage 1 and Stage 2 is

9 In February 2014, SCAQMD's governing board authorized staff to develop a proposed Rule 1304.2 that has the intent to allow additional generating projects to access SCAQMD's internal bank of offsets. Features of this proposed rule, still in development at this writing, are compatible with contingent permitting described in this paper. SCAQMD staff has initially aimed for adoption in the second quarter of 2015, but the timeline has been extended to the fourth quarter of 2015.

critical to the determination of whether additional analyses are required. Some initial guidance was provided by the districts.

- SCAQMD staff indicated a permit to construct could be issued for longer than a year, but the district requires a valid California Environmental Quality Act (CEQA) document to issue the permit to construct. For projects of 50 megawatts (MW) and larger, the Energy Commission’s approved application for certification provides the valid CEQA document.
- SCAQMD staff commented the three months allotted for completion of the air permit to construct in **Table 1** for Stage 2 may be too abbreviated, particularly if new ambient air quality standards are approved, because required air modeling itself can take a couple of months to complete.
- SDAPCD staff indicated an authority to construct could be issued for longer than one year and up to five years with district governing board approval. An alternative is to process the project as a preapplication study where all the permitting work, except issuance of the authority to construct, is completed.
- SDAPCD staff estimated the time needed to review the project in Stage 2 at two to four months and commented that required air modeling would likely be the most time-consuming aspect.

- Generally, if completing the permitting process is infeasible for a contingent project, which portions of the permitting process can be completed in Stage 1 and not be repeated once the project is triggered? Are there other portions of the permitting process that should be completed in Stage 1 even if they have to be repeated in Stage 2 due to the passage of time? Are there portions of the permitting process that should clearly not be conducted in Stage 1 and left to be addressed in Stage 2, if the project is to be triggered by reliability needs? How can the overall permitting process be clearly delineated between these two stages so there is clarity for the developer and the agencies participating in the process?
- The permit application processing and expiration time frames for projects that require a Prevention of Significant Deterioration (PSD) permit from the United States Environmental Protection Agency (U.S. EPA) may be even more constraining than those of local air districts.[10] U.S. EPA PSD practices provide a permit that has only an 18-month life and can be extended only once for a maximum of another 18 months. Any significant modification of the project would likely trigger a restart of the permitting process. What project size and combustion technologies would avoid the US EPA PSD process altogether?
- CPUC D.14-03-004 authorized utilities to enter into contingency contracts with project developers. Few details were specified. Does the CPUC need to clarify its requirements in advance of an application from a utility, or can the CPUC accept an application and resolve any ambiguities in the process of reviewing a specific proposed project?

10 Discussions with U.S. EPA Region IX on March 23, 2015.

- Should separate, parallel project development take place for both SDG&E and SCE?

Option 2: IOU Initiates Project Development

Concept

This option includes all of the basic steps of Option 1, except the utility handles more of them before the project developer is selected and the project is handed off to this entity. **Table 3** describes the sequence of steps broken into two stages quite similar to Option 1. However, the key difference is that the IOU chooses a site and develops an initial project design rather than a developer. Only if the generator mitigation option is triggered would the IOU identify an actual project developer and update costs associated with a final project design through a modification of the original PPA.

Like Option 1, this option makes no major change to the actual Energy Commission power plant licensing process. However, instead of the generator developer, the IOU would represent the project in all regulatory proceedings with the Energy Commission and air districts. In contrast, the CPUC could potentially process a contingency contract or a utility-controlled facility for the same project being permitted by the Energy Commission. Like Option 1, the PPA for such a project could split the normal approval for a generator project into two stages. In Option 2, the CPUC could review and approve the *project design portion* of a proposed project covering just site control, project design, and preliminary equipment purchase costs. The second stage, *project construction and operation stage*, would cover the actual project construction costs and procurement of power production services (capacity, energy, ancillary services) from the project owner if the project were carried to fruition. The CPUC could evaluate Stage 1 costs of the IOU for recovery in rates and be informed of estimated costs of Stage 2, even though such costs may be revised before final approval was sought.

In concept, the Stage 1 *project design* scope would include the costs of preparing an application to the Energy Commission, securing site control through an option on the land, and purchasing or "reserving" criteria pollutant emission offsets for such a contingent power plant. Legitimate costs to be included in Stage 1 activities include any "deposits" associated with advance ordering of necessary generating equipment and "holding a place in line" for such equipment. In contrast to Option 1, in Option 2 the IOU undertakes the activities to create a project, get it permitted at the Energy Commission and the applicable air district, and secure a place in line with all critical equipment suppliers.

If the project were triggered, then the IOU would find a project developer to build and operate the project. The contract cost structure should recognize that certain project costs normally recovered by the developer in the pricing of services from the project have already been undertaken by the IOU. Barring any other restrictions, the IOU could potentially act as the owner-operator of the final plant, with costs and benefits allocated to other load-serving entities (LSEs) per the established cost allocation mechanism (CAM).[11] Therefore, the final proposed cost recovery through rates and the CPUC's review and approval of this CAM project would recognize that project design costs normally included within the terms and conditions for capacity and energy products have already been paid. Similar to Option 1, only the residual costs would be covered in the final CAM cost recovery.

The air quality permitting issues of this option are identical to those of Option 1. While an overall Energy Commission permit is good for five years and frequently has been extended, an air quality permit is normally good for a shorter period. Air districts will require some kind of review if the project is not developed after a few years, and the depth of this review and the time required are likely to be greater the longer the project has been "on the shelf."

See **Table 3** of this document for a listing of each of the steps describing this option, which of Energy Commission or CPUC generally has the lead for that step, and the elapsed time estimated for that step. **Table 3** identifies all steps comprising the creation of the mitigation option (Stage 1), and then the remaining steps to approve and construct the project if it is triggered (Stage 2). As with Option 1, the elapsed time associated with Stage 1 could be shortened if the proposed site is an existing or former power generation facility as opposed to a greenfield site.

Concept Implementation Issues

Numerous implementation issues need to be overcome. Among these are the following:

- Since this option closely parallels Option 1, it faces many of the same issues as Option 1.
- If the project is triggered, and if a developer has not already been correlated to the project, then the IOU should select an actual developer. Clearly more than one generating company might like to be this developer, especially since many of the riskier aspects of project development would not apply. It is possible that some kind of RFO or auction process could be held to select from among qualified developers, but this needs to be completed in as short a time as prudent because it is adding to the minimum time interval between triggering and getting the project operational.
- Although the IOU would have submitted a specific site and a complete project design to secure preliminary Energy Commission and air districts permits, it is possible that the developers bidding to obtain the project from the IOU would want to tweak the design. Doing so would take time for the developer and then lead to additional review by the Energy Commission and the applicable air district from a permitting perspective and from the CPUC in reviewing and finalizing the PPA between the developer and the IOU.

11 California's electricity restructuring legislation allows non-utility entities to sell energy to end-use customers. A private corporation selling energy to end-users is called an electricity service provider (ESP). A governmental entity selling energy to end-users within its jurisdiction is called a community choice aggregator (CCA). Utilities, ESPs, and CCAs are collectively referred to as load serving entities. Generating plants built for reliability purposes by a utility have the capacity costs and the capacity shares of the plant split among all LSEs benefitting from the plant.

Is it possible that concern would be alleviated by selecting from a pool of qualified bidders from a previous RFO where such tweaks were already included, or by greater control on the part of the IOU to adhere to specifications?

- Air permits are also necessary to secure in advance, or by some means be made available to the projects selected, for this option to be effective. The practices of SCAQMD and SDAPCD are different, and both may be changing. A key question is how much time will be required by an air district to review a final project design compared to the initial design, and issue a final permit? These issues are substantially the same as with Option 1.
- To what extent will a permit issued by the Energy Commission for a generator project that sits on the shelf for years still be valid at the time it is triggered? Provisions in the permitting process itself should take into account the expected use of that permit (including timing thereof) to assure continued validity.
- All the PSD issues are the same as with Option 1.
- If the process used for selected CAM projects is not used to authorize the generator development, what process could the CPUC use to authorize SCE and SDG&E to undertake such project development activities? Would IOU costs be reimbursed immediately or given some kind of balancing account treatment? With the IOU playing the Stage 1 developer role, are such costs greater or lesser than corresponding costs of Option 1?

Option 3: Rely Upon Already Permitted Projects

Option 3 is very different from Options 1 and 2 in how a project is conceived, designed, and located. Rather than purposefully developing projects to satisfy a specific reliability contingency, Option 3 relies upon the "normal" power plant development process. A developer conceives of a project, acquires site control, and initiates the permitting process with the Energy Commission or other appropriate licensing authority without direct guidance from IOUs or agencies. A limited pool of such projects exists at any point in time.

Stage 1: Project Selection and Design would be very different for this option than for Options 1 and 2. Since the project pool is, by definition, those projects that already have a final permit, the design phase is complete. Instead, a wholly different Stage 1 would be required. In this *Stage 1: Monitor Pool of Projects*, the Energy Commission staff would monitor the status of these projects and maintain and updated list. Since recent discussions with air permitting agencies has made clear that air permits have a finite life, ongoing monitoring would be necessary to determine whether, or to what extent, such permits were still valid. For those permits that have "expired," it may be necessary to request that the developer submit permit extension requests and reengage the permitting process to update the original permit. Discussions with air permitting agencies suggest that one or at the most two updates would be possible before a major review would be required. Clearly this would add to the costs that a generator has to front with no clear path to cost recovery if the project is never built.

Stage 2: Actual Project Development (if triggered) would be nearly identical to that described earlier for Option 2. However, instead of seeking through an RFO process a set of project developers to take on a project partially permitted by the IOU, the IOU would use an RFO process to select from the limited pool of already permitted projects to select a specific project to bring forward as a PPA to the CPUC for approval. Since the pool is likely to be very limited, market power concerns would have to be considered.[12]

Table 4 gives a step-by-step description of the design and approval process and an estimate of the elapsed times required for each step.

Concept Implementation Issues

Several concept implementation issues would have to be resolved:

- Is the idea of a pool of projects with permits but without PPAs a valid, ongoing concept or is it viable for a short period as an aberration from the likely project development pattern going forward? If it is an aberration, can it still be a useful approach for a few years to get Southern California back to a "normal" balance between resources and local capacity requirements?
- To what extent will a permit issued by the Energy Commission for a generator project that sits on the shelf for years still be valid at the time it is triggered? Provisions in the permitting process itself should take into account the expected use of that permit (including timing thereof) in an effort to assure continued validity.
- Will it be necessary to provide cost recovery to generators to induce them to update air permits so the projects remains fully permitted? If so, what regulatory mechanism would be used to accomplish this?
- PSD issues with the U.S. EPA would be encountered for some projects and not for others. A project that triggered the PSD process and obtained a permit from U.S. EPA would likely encounter repermitting requirements earlier than one that did not.

Preliminary Evaluation of the Options

This brief section compares and contrasts the three options.

Minimizing Stage 2 Elapsed Time

Table 1 summarizes the elapsed times for each of the three options. Option 3 has by far the least amount of time since it bypasses the entire Stage 1 project development step by limiting participation to projects with approved permits. Of the two remaining options, it is clear that Option 1 takes the approval process further than Option 2; so between these two,

12 It is possible that projects near the end of the permitting process might be worth including in the pool, since such projects could complete the permit while the PPA was being reviewed by the CPUC. Of course, since permitting conditions might not yet be finalized, costs to the developer would not be fully known.

Option 1 has the least time remaining from the date such a contingent approval is signed off until a power plant is functional. Option 2 requires an additional amount of time than Option 1 since at the triggering of the project the IOU needs to take some time to bring a project developer into the picture and negotiate the details of the modification to the PPA submitted by the IOU in Stage 1. It may also be likely that the shift from the project design used by the IOU in Stage 1 will be sufficiently different than the project design favored by the ultimate developer that additional time will be required in Stage 2 for Energy Commission and air quality district approvals.

Table 1: Summary of Elapsed Times for Each Option (Months)

Option	Stage 1	Stage 2	Total
1. IOU Chooses Developer	46-51	35-51	81-102
2. IOU Initiates Project	42-49	41-54	83-103
3. Prepermitted Projects	0	32-54	32-54

Source: Energy Commission staff.

Costs

Option 1 is a greater departure from the usual speculative process in which a power plant developer fronts the costs of permitting and expects to recover these costs once a project is constructed and becomes operational. In the setting of a contingent generator option, with only a limited prospect that the plant is ever constructed, these upfront costs may be so large that some special subsidy is needed to make Option 1 viable. Option 2 shifts the Stage 1 effort to the IOU rather than a developer and the IOUs may be better positioned financially to negotiate site purchase and control, advanced equipment ordering, and so forth. As a result, it is possible that Option 2 costs might be slightly lower than those for Option 1. The costs of Option 3 are less clearly understood since there is no clear distinction between Stage 1 costs and Stage 2 costs. The developer essentially fronts Stage 1 costs on a speculative basis, but presumably these will be recovered in a final project PPA.

Maximizing Upfront Permitting

Option 3 essentially eliminates the permitting step by limiting the pool of projects to those already having an approved permit. Option 1 would appear to have an edge over Option 2 as a result of greater project specificity in Stage 1. If ever triggered, the potential change in project design that a developer might insist upon would seem to require a more in depth review by the Energy Commission and air permitting agency than would Option 1.

Flexibility of Project Design and Location

Options 1 and 2 have very similar characteristics. The design and location of projects are much wider than would be the case for Option 3, which depends upon a small set of projects already permitted—thus fixed by location and difficult to revise generating technologies.

Problem to Be Mitigated

The results of the California ISO power flow studies identify different system problems in each of the California ISO's annual studies of local capacity issues. Sometimes the California ISO determines that the limiting contingency involves a broad area and that the specific location of a mitigating power plant is not critical. In other instances, the California ISO has found specific transmission lines that are overloaded. Option 1 works best when the possible range of sites is relatively wide and a premium is placed on developer creativity in finding a site, subject to satisfying locational effectiveness factor assessments through local capacity studies. Option 2 works best if there are precise sites that are needed for additional generation to alleviate specific transmission line overloads. To the extent such sites can be accommodated within the footprint of existing utility substations, or by purchase of adjacent properties, Option 2 may be able to use these superior sites not normally available to a generation developer. Option 3 depends upon a match between projects selected by a developer and the reliability needs of Southern California. Since most of the likely sites are former OTC power generation facilities, there is likely to be some match, but it might not be optimal for any specific reliability problem.

These concerns have been voiced in the assessments of the problems resulting from retirement of San Onofre or the more general issue of fossil-fueled OTC power plant retirement, so it is possible that all options have features that are desirable and fit different contingencies. Greater clarity about the nature of the potential reliability problem that distinguishes between regional voltage problems versus specific transmission line overloads would be helpful in selecting among the three options.

Sequential or Parallel Energy Commission and CPUC Review in Stage 2

All three options require that both Energy Commission/air district and CPUC finalize reviews of some aspects of the project in Stage 2. Table 2, Table 3, and Table 4 show these as sequential steps, but they could be at least partially parallel. The advantage of parallel steps is that the total elapsed time for Stage 2 could be shortened. Since the CPUC may never have seen a project brought forward in Stage 2 of Option 3, it is possible that sequential or at least less degree of parallel processing would be appropriate. If so, then Option 3 Stage 2 might be several months longer than shown in Table 1, Table 2, Table 3, and Table 4.

Next Steps

This revised paper develops three options for creating a generator mitigation measure that could be used to satisfy potential shortfalls in satisfying local capacity requirements in Southern California resulting from the retirement of San Onofre and the staged retirement of fossil-fueled OTC facilities. This paper incorporates the thinking of agency staff about possible modifications to Energy Commission permitting and CPUC procurement oversight and PPA review processes to implement these options. Some refinement of the initial options through discussions with SCE and SDG&E and the air districts in which these facilities would be located—SCAQMD and SDAPCD—have already been included, but another round of discussions would be beneficial. Once this second round of discussion is complete, then agency staff will make a specific proposal to agency leaders.

Table 2: Option 1—IOU Chooses Developer Who Initiates Process With a Specific Project

Step	CEC or CPUC Activity	Developer or IOU	Time Required
Stage 1: Project Selection and Preliminary Approval			
Regulatory Design[13]	Approve concept and direct SCE and SDG&E to select developers		3 months
Design and Announce RFO		IOUs prepare and release RFO	2 months
Prepare Bids		Developers proposals and initiate site selection/control	3 months
RFO to Solicit and Select Developers		IOU reviews bids and selects developer(s)	6 months
Site Surveys and Other Preparation		Environmental consultant examines site, begins surveys as suggested in Appendix, and applies for ISO interconnection	6 months
Preliminary Project Design and Key Equipment Selection		Developer gets into equipment queue	2 months
AFC and ATC Preparation		Prepare and submit AFC to CEC, and ATC to air district	6 Months[14]
PPA Prepared		Developer and IOU negotiate PPA and submit to CPUC	2-3 months
AFC Data Adequacy,	CEC and air district conduct		8 Months[15]

13 CPUC staff has indicated that the best avenue maybe a modification to the procurement plan to allow for contingency contracts and that this process could take up to three months.

14 Energy Commission: Based on input from past applicants. Assumes developer has prepared, has site control, is aware of issues, and has firm project description with equipment identified.

Step	CEC or CPUC Activity	Developer or IOU	Time Required
Review and Decision	review processes and issue permit or partial approval documents		
Reconsideration and Judicial appeal	CEC reconsiders its decision and/defends appeal to State Supreme Court		2 Months
Two-Stage PPA Approved[16]	CPUC approves with modifications and/or conditions		6 – 10 months
Stage 1 Total			46-51 months
Stage 2: Actual Project Development (If Triggered)			
Trigger Contingency Measure	Interagency decision to proceed and initiation of implementation processes in affected agencies		4 months
Developer Submits Supplements to AFC and ATC		Developer prepares and submits supplement to AFC and supplement to air district[17]	3 months
CEC completes AFC Review and Air District Completes ATC Review	CEC reviews and approves AFC with conditions (and air district approves project with its conditions)		3-6 months[18]
Assess Implications of CEC/Air District Permit Conditions		Developer and IOU determine if PPA changes needed as a result of revised CEC or air district permit conditions	2 months
Review/Revise Second Stage of PPA (as needed)	CPUC reviews any proposed changes to the *project construction and operation* stage of the PPA resulting from CEC or air district permit changes		2 months

15 Energy Commission: Assumes no major issues with site or surrounding community, site surveys for biological and cultural resources are done, equipment has been identified, Air District permitting process is well underway, emission reduction credits (ERCs) are identified, and Phase I and Phase II cluster studies of downstream transmission impacts are done.

16 CPUC staff has indicated that the “design PPA” and the “actual PPA” may need to come in together, as the CPUC may want to consider how much it would cost to have the site preparation and permitting, but also how much it would cost to trigger full development.

17 Energy Commission: Air district will require 30 days for completeness review of application and take another 90-120 days to complete the preliminary determination of compliance.

18 The length of time is likely to increase with the passage of time since the initial review of the project, because air quality requirements may have changed or best available control technology determinations may have been updated.

Step	CEC or CPUC Activity	Developer or IOU	Time Required
Reconsideration and Judicial Appeal	CEC reconsiders its decision and defends appeal to State Supreme Court		2 Months
Project Development Launched	CEC CPM signs off start of construction letter[19] and CPUC approves go ahead for project	Developer completes equipment ordering, construction plans and receives preconstruction approvals	3 months
Construction		Project developer and construction team create a power plant	12-24 months[20]
Final Testing and Acceptance	CEC CBO issues temporary certificate of occupancy	Project testing results in commercial project	1-2 months
Construction Concludes	CEC CBO issues certificate of occupancy	Developer team completes project	3 months
Stage 2 Total			35-51 months

Source: Energy Commission staff.

Table 3: Option 2—IOU Initiates Project Development

Step	CEC or CPUC Activity	Developer or IOU	Time Required
Stage 1: Project Selection and Preliminary Approval			
Regulatory Design[21]	CPUC approves concept and direct SCE and SDG&E to implement stage 1		3 months
Site Selection		IOU reviews potential sites and selects one	3 months
Site Surveys and Other Preparation		Environmental consultant examines site, begins surveys as suggested in Appendix, and applies for ISO interconnection	6 months
Preliminary Project Design		IOU develops preliminary project design	2 months
Preliminary Plan for Air Quality Approach		IOU decides how to satisfy likely air permit requirements[22]	2 months

19 Energy Commission: Permission to start construction. The Energy Commission process allows for submittal of preconstruction submittals required by conditions of certification if developer submits them after the Presiding Member's Proposed Decision is released, at developer's own risk, concurrent with final months of licensing process, thus allowing construction to begin shortly after issuance of permit.

20 This range reflects the difference between a peaker (12 months) and a combined cycle (24 months).

21 CPUC staff has indicated that the best venue maybe a modification to the procurement plan to allow for contingency contracts and that this process could take up to three months.

Step	CEC or CPUC Activity	Developer or IOU	Time Required
Preliminary Equipment Selection		IOU gets into equipment queue	2 months
AFC and ATC Preparation		IOU prepares and submits AFC to CEC, and ATC to air district	6 Months[23]
Pro Forma PPA Prepared		IOU submits "pro forma" PPA to CPUC	2-3 months
AFC Data Adequacy, Review and Decision	CEC conducts AFC process for "pro forma" project		8 Months[24]
Reconsideration and Judicial appeal	CEC reconsiders its decision and/defends appeal to State Supreme Court		2 Months
Pro Forma PPA Reviewed and Approved[25]	CPUC approves with modifications and/or conditions		6 – 12 months
Stage 1 Total			42-49 months
Stage 2: Actual Project Development (if Triggered)			
Trigger Contingency Measure	Interagency decision to proceed and initiate processes in affected agencies		4 months
Solicit and Select Developers		IOU reviews bids and selects developer(s)	3 months
Developer Submits Supplements to AFC and ATC		Developer prepares and submits supplements to the AFC and ATC processes[26]	3 months[27]
CEC Completes AFC	CEC reviews and approves		6 months[28]

22 If SCAQMD implements proposed Rule 1304.2 as informally discussed, an IOU will be allowed to reserve air quality credits sufficient to cover this facility. If triggered and final air permit is provided, then air credits will be surrendered from the Rule 1315 internal bank.

23 Energy Commission: Based on input from past applicants. Assumes developer has prepared, has site control, is aware of issues, and has firm project description with equipment identified.

24 Energy Commission: Assumes no major issues with site or surrounding community, site surveys for biological and cultural resources are done, equipment has been identified, Air District permitting process is well underway, emission reduction credits (ERCs) are identified, and Phase 1 and Phase 2 cluster studies of downstream transmission impacts are done.

25 CPUC staff has indicated that the preliminary PPA encompassing the entire project may need to be considered, as the Commission may want to consider not how much it would cost to have the site preparation and permitting, but how much the total project would cost if triggered.

26 Energy Commission: Air district will require 30 days for completeness review of application and take another 90-120 days to complete the preliminary determination of compliance.

27 See footnote 12.

Step	CEC or CPUC Activity	Developer or IOU	Time Required
Review and Air District Completes ATC Review	AFC with conditions (and air district approves project with its conditions)		
Project Development Launched	CEC CPM signs off start of construction letter[29] and CPUC approves go ahead for project	Developer completes equipment ordering, construction plans and receives preconstruction approvals	3 months
PPA Revisions Prepared and Submitted[30]		Developer and IOU negotiate/submit final PPA	3 months
Revised PPA Approved	CPUC reviews and approves PPA with modifications and/or conditions		3 months
Construction		Project developer and construction team create a power plant	12-24 months[31]
Final Testing and Acceptance	CEC CBO issues temporary certificate of occupancy	Project testing results in commercial project	1-2 months
Construction Concludes	CEC CBO issues certificate of occupancy	Developer team completes project	3 months
Stage 2 Total			**41-54 months**

Source: Energy Commission staff.

28 The length of time is likely to increase with the passage of time since the initial review of the project, because air quality requirements may have changed or best available control technology determinations may have been updated.

29 Energy Commission: Permission to start construction. The Energy Commission process allows for submittal of preconstruction submittals required by conditions of certification if developer submits them after the Presiding Member's Proposed Decision is released, at developer's own risk, concurrent with final months of licensing process, thus allowing construction to begin shortly after issuance of permit.

30 CPUC staff believes that both stages of the PPA may need to be reviewed at the outset of the project.

31 This range reflects the difference between a peaker (12 months) and a combined cycle (24 months).

Table 4: Option 3—Use Projects With Approved Siting Permits

Step	CEC or CPUC Activity	Developer or IOU	Time Required
Stage 1: Monitor Pool of Projects with Permits			
Periodically Monitor Status of	CEC would periodically review all projects in permitting processes, and those with final permits, to determine pool of projects by local capacity area and technology		0 months
Stage 1 Total			0 months
Stage 2: Actual Project Development (if Triggered)			
Trigger Contingency Measure	Inter-agency decision to proceed and initiate processes in affected agencies		4 months
Solicit and Select Developers		IOU reviews bids and selects developer(s)	3 months
Modifications to Existing Permits		Developer submits Permit to Amend (PTA) and modifications to ATC[32]	0-3 months[33]
CEC Completes PTA Review and Air District Completes ATC Review	CEC reviews and approves PTA with conditions (and air district approves project with its conditions)		0-6 months[34]
Project Development Launched	CEC CPM signs off start of construction letter, and CPUC approves go ahead for project	Developer completes equipment ordering, construction plans and receives preconstruction approvals	3 months
PPA Revisions Prepared and Submitted[35]		Developer and IOU negotiate/submit final PPA	3 months
Revised PPA Approved	CPUC reviews and approves PPA with modifications and/or conditions		3 months
Construction		Project developer and	12-24 months[36]

32 Energy Commission: Air district will require 30 days for completeness review of application and take another 90-120 days to complete the Preliminary Determination of Compliance.

33 See footnote 12.

34 The length of time depends on whether any change in permit is required, and if so, the extent of the change.

35 CPUC staff believes that both stages of the PPA may need to be reviewed at the outset of the project.

Step	CEC or CPUC Activity	Developer or IOU	Time Required
		construction team create a power plant	
Final Testing and Acceptance		Project testing results in commercial project	1-2 months
Construction Concludes	CEC CBO issues certificate of occupancy	Developer team completes project	3 months
Stage 2 Total			32-54 months

Source: Energy Commission staff.

36 This range reflects the difference between a peaker (12 months) and a combined cycle (24 months).

ACRONYMS

ACRONYM	DEFINITION
AFC	Application for Certification
ARB	California Air Resources Board
California ISO	California Independent System Operator
CAM	Cost allocation mechanism
CEC	California Energy Commission
CPUC	California Public Utility Commission
IEPR	*Integrated Energy Policy Report*
IOU	Investor-owned utility
OTC	Once-through-cooling
PPA	Power purchase agreement
PSD	Prevention of significant deterioration
RFO	Request for offer
SCAQMD	South Coast Air Quality Management District
SCE	Southern California Edison Company
SDAPCD	San Diego Air Pollution Control District
SDG&E	San Diego Gas & Electric Company
San Onofre	San Onofre Nuclear Generation Station
U.S. EPA	United States Environmental Protection Agency

APPENDIX:
Energy Commission Staff Guidelines for Expediting Application for Certification Processing

The following description stems from the six-month emergency permitting regulations the Energy Commission had as a result of the legislation during the 2000 – 2001 electricity crisis. Although those regulations are no longer in effect, the Energy Commission staff believes that many of the same screening criteria could help to expedite the Energy Commission's existing AFC process compared to the typical application.

Background

The Energy Commission's AFC process for thermal power plants 50 megawatts and larger is designed to be a 12-month one-stop permitting process that is open and transparent and includes multiple opportunities for public, agency, tribal and intervener participation. However, there are opportunities for applicants to complete the permitting process in less than 12 months if they select and propose good sites and provide exceptional applications. Applicants are strongly encouraged to request prefiling meetings with the staff to discuss their project development plans and get valuable feedback on the sites being considered. Applicants are also advised to meet early with tribes that may have an interest in the project area and the air quality management district and the transmission interconnection authority that may have long lead times for their review of the project.

To be able to receive a decision in less than 12 months after acceptance of an application, the application needs to contain all of the information that is relevant to the project and required in Appendix B of the Siting Regulations.[37] If an information requirement in Appendix B is not relevant to a proposed project because of its design, location, or other particular circumstance, the application need not provide the information and, instead, shall provide an explanation with specific facts as to why the requirement is not relevant to the project as proposed. Applicants are encouraged to request a prefiling review pursuant to section 1709.5 to determine the extent to which documentation relevant to a proposed application is sufficient to meet the information requirements in Appendix B and to determine which information requirements, if not all, are relevant to the proposed application.

Site Selection Criteria

Selecting the project site is the most important part of project development that can allow for an expedited project review. The following list of site selection criteria should be used to select a site with the fewest number of issues that would need to be addressed during the certification process.

37 http://www.energy.ca.gov/title20/index.html

- Does the site have appropriate zoning?
- Can the project developer obtain site control?
- Is there community interest in community development of the site?
- Is the site large enough for project?
- Will the site require cancelation of a Williamson Act contract?
- Have the appropriate Native American tribes been consulted about the proposed site?
- Will the parcel accommodate minimum setbacks?
- Is the site a single parcel?
- Does the parcel have a clean title?
- Is the site a brownfield site?
- Will the site require demolition or remediation?
- Are there any fatal flaws associated with the site?
- Distance to natural gas?
- Distance to transmission?
- Distance to recycled water?
- Distance to wastewater disposal?
- Distance to nearest sensitive receptor?
- Any endangered species on site or important cultural resources impacted?

Specific Guidelines

In addition to all the filing requirements for an AFC, the application should also contain:

(1) Substantial evidence that the project as proposed in the application will comply with all standards, ordinances, and laws applicable at the time of certification, including:

- (A) A list of all such standards, ordinances, and laws.
- (B) Information demonstrating that the project as proposed in the application will comply with all such standards, ordinances, and laws.
- (C) Where a standard, ordinance, or law is expected to change between the time of filing an application and certification, information from the responsible jurisdiction documenting the impending change, the schedule for enactment of the change, and whether the proposed project will comply with the changed standard, ordinance, or law.
- (D) A list of the requirements for permitting by each federal, state, regional, and local agency that has jurisdiction over the proposed project or that would have jurisdiction, but for the exclusive jurisdiction of the Commission, and the information necessary to meet those requirements.

(2) Substantial evidence that the project as proposed in the application will not cause a significant adverse impact on the environment, including all the following:

- (A) A detailed modeling analysis assessing whether the cumulative impacts of all inert criteria pollutants (nitrogen oxides, sulfur oxide, carbon monoxide, and PM10/PM2.5[38]) from the typical operating mode of the project in combination with all stationary emissions sources within a six-mile radius of the proposed site that have received construction permits, but are not yet operational, and all stationary emissions sources that are undergoing air district permit application review, will cause or contribute to a violation of any ambient air quality standard.
- (B) A description of the initial commissioning phase of the project planned, which is the phase between the first firing of emissions sources and the consistent production of electricity for sale to the market, including the types and durations of equipment tests, criteria pollutant emissions, and monitoring techniques to be used during such tests, and air dispersion modeling analyses of the impacts of those emissions on state and federal ambient air quality standards for nitrogen oxide, sulfur oxide, carbon monoxide, and PM10/PM2.5.
- (C) A detailed description of the mitigation, which an applicant shall propose, for all project impacts from criteria pollutants that exceed state or federal ambient air quality standards, but are not subject to offset requirements under the district's new source review rule.
- (D) A modeling analysis that identifies the extent of potential public exposure to toxic substances, as identified in Subsection (g)(9)(A) of Appendix B, resulting from normal facility operation.
- (E) If the project will result in a discharge of waste that could affect the water quality of the state, a complete report of proposed waste discharge as required by Section 13260 of the Water Code. This should allow for issuance of waste discharge requirements by the appropriate regional water quality control board within 100 days after filing of the application.
- (F) A demonstration, based on appropriate data including, but not limited to, scientific surveys taken at the appropriate time of year, that the project will have no significant impact on wetlands, plant or animal species that are endangered, threatened, or of concern under state or federal law, or the areas listed in Public Resources Code Section 25527.
- (G) With respect to the handling of hazardous materials, a demonstration that (i) the project will not use or store any regulated substance defined in Section 25532(g) of the

38 Particulate matter is (PM) one of the criteria pollutants emanating from a power plant due to the combustion of fuel and from other sources, such as the friction of rubber tires mounted on cars and trucks on roads. PM is commonly measured in two size ranges, PM10 refers to particles 10 microns and smaller, while PM2.5 refers to particles 2.5 microns and smaller.

California Health and Safety Code or (ii) the project is eligible for Program 1 status pursuant to Section 68.10 of Part 68 of Title 40 of the Code of Federal Regulations or can demonstrate that no worst case accidental release would result in a plausibility (risk greater than 1 in 1,000,000) of an impact at the nearest public receptor above the maximum airborne concentration below which it is believed nearly all individuals could be exposed for up to one hour without experiencing or developing irreversible or other serious health effects or symptoms that could impair an individual's ability to take protective action. The Emergency Response Planning Guidelines, Level 2 (ERPG 2), reflect this maximum airborne concentration standard.

- (H) If the project will store or use a regulated substance defined in Section 25532(g) of the Health and Safety Code, a demonstration either that the boundary of the power plant site will not be within 1,000 feet of any residential area, school, general acute care hospital, long-term health care facility, or child day care facility as such terms are defined in section 25534.1 of the Health and Safety Code or that the project will pose no plausible potential for exposure at such facilities from an accidental release of the regulated substance.
- (I) A demonstration that the proposed facility will not require storage of gaseous flammable or explosive materials in quantities greater than 25,000 standard cubic feet.

(3) Substantial evidence that the project will not cause a significant adverse impact on the electrical system, including all of the following:

- (A) An interconnection study identifying the electrical system impacts and a discussion of the mitigation measures considered and those proposed to maintain conformance with National Electricity Reliability Council, Western States Coordinating Council, California ISO, or other applicable reliability or planning criteria based on load flow, post transient, transient, and fault current studies performed by or for the transmission owner in accordance with all applicable California ISO or other interconnection authority's tariffs, operating agreements, and scheduling protocols.
- (B) A full description of the facilities, if any, that are required for interconnection, including all such facilities beyond the point where the outlet line joins with the interconnected system and a full description of the environmental setting, environmental impacts, and any recommended mitigation measures proposed by the applicant for any required facilities beyond the point where the outlet line joins with the interconnected system.

(4) A discussion of the potential for disproportionate impacts from the project on minority or low-income people. Such discussion shall include, but not be limited to, all of the following:

- (A) demographic information by census tract, based on the most recent census data available, showing the number and percentage of minority populations and people living below the poverty level within six miles of the proposed site.

- (B) one or more maps at a scale of 1:24,000 showing the distribution of minority populations and low-income populations and significant pollution sources within six miles of the proposed site, such as those permitted by the U.S. EPA (toxic release inventory sites), the local air quality management district, or the California Department of Toxic Substances Control.
- (C) Identification of available health studies concerning the potentially affected population(s) within a six-mile radius of the proposed power plant site.

(5) The following information to demonstrate that the project, if certified, is likely to be constructed and operated.

- (A) Information demonstrating the applicant's control, by ownership, lease, option, or other legally binding agreement that the Energy Commission finds acceptable, of the proposed site.
- (B) A will-serve letter[39] or similar document from each provider of water to the project, indicating each provider's willingness to provide water to the project and describing all conditions under which the water will be provided, and a discussion of all other contractual agreements with the applicant pertaining to the provision of water to the project.
- (C) A will-serve letter from a gas distribution company if a greenfield site or a repower expected to use significantly more natural gas than existing distribution pipeline capacity allows.

39 A "will serve letter" is a letter from a service provider to a prospective customer indicating that the service can be provided. It is commonly used to demonstrate to a permitting agency that the developer of a project can obtained a necessary service if the project is developed.