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Decision 90-12-119 December 27, 1990

BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA

Application of PACIFIC GAS AND ELECTRIC COMPANY for a Certificate of Public Convenience and Necessity to Construct and Operate an Expansion of its Existing Natural Gas Pipeline System. (U 39 G)	ORIGINAL Application 89-04-033 (Filed April 14, 1989)

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OPINION

I. Summary

A. Commission Approval, As Conditioned

This decision grants a certificate of public convenience and necessity to Pacific Gas and Electric Company (PG&E) to expand its natural gas transportation system from Malin, Oregon, to Kern River Station, California. This expansion would increase PG&E's capacity to transport natural gas on a firm, year-round basis by at least 755 MMcf/d. PG&E's proposal to treat its Expansion Project as a separate operation, analogous to its steam, electric, and gas operations, is approved. Rates for service on the Expansion Project will be established in the project's first general rate case, at which time the reasonableness of construction costs and the allocation of risk will also be addressed.

PG&E is authorized to use incremental cost allocation to establish the cost of the Expansion Project. Its use of full-fixed variable rate design and a non-mileage based rate to a single delivery point are also approved.

Since PG&E has not demonstrated the need for its 100 MMcf/d subscription to firm capacity on the Expansion Project, PG&E must show either the reasonableness of that subscription or the fair allocation of that capacity to other shippers in the Expansion's first general rate case.

The Commission certifies the final environmental impact report (EIR) which it has prepared as the lead agency pursuant to the California Environmental Quality Act. PG&E must comply with the mitigation measures and mitigation monitoring plan recommended by the EIR and adopted as Appendices B and C, respectively, to this decision, as a condition of accepting its certificate of public convenience and necessity.

The Commission is not in a position to find that, in all cases, construction of the Expansion Project is needed to serve the public. PG&E must determine whether the market for natural gas transportation justifies construction of the project and demonstrate the reasonableness of its judgment in its first general rate case. The certificate of public convenience and necessity must be issued, as conditioned, to enable PG&E to respond to market forces.

B. **Procedural History**

On April 14, 1989, PG&E (the Applicant) filed its application for a certificate of public convenience and necessity (CPCN) to expand its existing natural gas pipeline from the California-Oregon border to Kern River Station in San Joaquin County, California (Application). The expanded facilities (Expansion) would accommodate PG&E's receipt at Malin, Oregon of Canadian natural gas to be delivered by Pacific Gas Transmission Company (PGT), PG&E's wholly owned subsidiary, for transportation by PG&E to Kern River Station. A schematic depiction of the Expansion Project is attached as Appendix A to this decision.

The Application consisted of materials required by § 1003.5 of the Public Utilities (PU) Code, Rule 17.1 of the Commission's Rules of Practice and Procedure (Rules). (Special Procedure for Implementation of the California Environmental Quality Act of 1970), and Rule 18 of the Commission's Rules (Applications for CPCN).

PG&E described its "Precedent Agreements" with shippers in its Application. According to the Applicant, the commitments embodied in the Precedent Agreements will provide the Commission with evidence of need for the Expansion Project. Copies of the Precedent Agreements were filed as a supplement to the Application on June 15, 1990.

On October 3, 1989, PG&E filed a "Supplement to Application (A.) 89-04-033 for a Certificate of Public Convenience and Necessity" whereby PG&E increased the capacity of the Expansion from 600 million cubic feet per day (MMcf/d) to 755 MMcf/d.

On November 30, 1989, PG&E filed an "Amendment to the Application" consisting of Precedent Agreements that had been executed since the June 15, 1989 filing and which reflect a total subscription of its amended pipeline capacity, 755 MMcf/d of firm transportation.

On January 12, 1990, PG&E filed its "Second Amendment to the Application" consisting of partial assignments of the Precedent Agreement of the City of Long Beach.

The Application is intended to obtain the approval of this Commission for the certification and construction of the California segment of a larger pipeline expansion project originating in Kingsgate, British Columbia and terminating at Kern River Station, in California. PGT, PG&E's interstate pipeline subsidiary, had filed an application on January 23, 1989 for a certificate of public convenience and necessity at the Federal Energy Regulatory Commission (FERC) to authorize its development of the interstate portion of the pipeline project. (FERC Docket No. CP89-460-000.) That application is still pending before the FERC.

The CPUC determined that one environmental document that would satisfy the requirements of both Federal and California environmental review laws should be prepared pursuant to Section 65951 of the Public Resources Code. Preparation of the joint Environmental Impact Study/Environmental Impact Report (EIS/EIR) under this authority entitled the Commission to postpone action on the application for CPCN beyond one year. The Commission issued Decision (D.) 89-12-049 confirming that it was not required to issue a decision on the application for CPCN within a year of the date PG&E last amended the Application.

Hearings on the non-environmental aspects of the application were conducted between May 21 and June 8, 1990 in San Francisco. Twenty-six witnesses presented direct testimony and PG&E presented four rebuttal witnesses. One hundred five exhibits were introduced and received. Testimony was received from the Applicant, as well as Southern California Edison Company (Edison) and San Diego Gas & Electric Company (SDG&E), which both supported the application. Witnesses for Altamont Gas Transmission Company (Altamont), Kern River Gas Transmission Company (Kern River), Amoco Canada Petroleum Company, Ltd. (Amoco), El Paso Natural Gas Company (El Paso), the State of New Mexico (New Mexico), and Southern California Gas Company (SoCalGas) testified in opposition to the project. A representative of Bonus Gas Producers, Inc. (Bonus) testified that while Bonus supported construction of the project, it objected to the project's allocation of gas transportation capacity. The Commission's Division of Ratepayer Advocates (DRA) testified that it would support the Expansion Project if DRA's proposed conditions were adopted. Concurrent briefs on the non-environmental issues were filed by the above-listed parties, plus the California Gas Users Group (Gas Users).

The Environmental and Resources Advisory Section of the Commission's Advisory and Compliance Division (CACD) analyzed the Proponent's Environmental Assessment, determined the scope of the EIR, and oversaw the preparation of the EIR by an environmental consultant. The draft EIR was circulated on June 29, 1990.

The EIR process and the substantive matters included in the final EIR are discussed in detail under the section, "Environmental Considerations," which follows the discussion of the Application's merits for the issuance of a certificate of public convenience and necessity.

The administrative law judge (ALJ) ruled that comments on the draft EIR would be accepted up to August 21, 1990. On that day, the Commission convened a public participation hearing in Antioch to receive oral comments from the public on the draft EIR. Statements were made by landowners concerned with the pipeline's impact on crop-bearing trees and by Altamont.

Evidentiary hearing on environmental issues was held on August 13 through 17 in San Francisco. The purpose of the hearing was to allow interested parties to offer testimony on the adequacy of the draft EIR and to enable the applicant to cross-examine that testimony under oath. Witnesses for PG&E, Altamont, and Amoco appeared and were cross-examined by Kern River, SoCalGas, PG&E, Altamont, and Amoco. Forty-nine exhibits were received in evidence. Concurrent briefs on environmental issues were filed by PG&E, Altamont, and Kern River.

1. <u>Preliminary Procedural Matters</u>

On August 17, Kern River moved that PG&E be ordered to produce a copy of a settlement that it had entered into with Bonus in the parallel FERC proceeding. On September 12, the ALJ ruled that the request was in the nature of a motion for discovery and ordered PG&E to produce the document. PG&E produced a letter agreement between Bonus and PGT dated July 27, 1990 (Letter Agreement). Bonus is a party to this proceeding whose participation is more fully described under "Positions of the Parties."

On September 24, Kern River and Altamont filed their "Joint Petition of Kern River Gas Transmission Company and Altamont Gas Transmission Company to Set Aside Submission and Reopen Proceeding for the Purpose of Taking Additional Evidence." PG&E opposed this motion in its Response, filed October 1, 1990. Bonus also filed its opposition to the motion on October 1, 1990.

Kern River/Altamont claim that the settlement embodied in the Letter Agreement modifies the description of the Expansion Project and that the Proponent's Environmental Assessment and Draft EIR must be modified to comply with California Environmental Quality Act (CEQA); PGT/PG&E's performance under the settlement requires additional facilities and evidence of those facilities must be taken; the record must be reopened to determine if other shippers seek the delivery terms obtained by Bonus; and these changes will entail a change in rates which must be heard on the record.

We find that the Letter Agreement is between Bonus and PGT. It does not obligate PG&E to transport the volumes that PGT will deliver to the Oregon-California border pursuant to the Letter Agreement. PGT's delivery of gas under the agreement is separate from its proposed deliveries using the Expansion Project, because under the Letter Agreement, PGT is obligated to seek separate authority to transport gas for Bonus regardless of the outcome of the Expansion Project application.

Item 4 of the Letter Agreement states, "Bonus will be responsible for arranging any necessary downstream transportation from Malin." This covenant negates the argument that PG&E must expand its California project by the volumes to be transported by PGT. For example, Bonus may negotiate to use the capacity rights of other shippers for transportation within California. PGT's agreement with Bonus does not affect the volumes of gas to be transported by the California segment in such a way that this Commission must review PG&E's allocation of capacity, revenue recovery, and rates as suggested by Kern River/Altamont.

Kern River/Altamont also argue that PGT's agreement has foreseeable consequences on the California expansion such that the Expansion Project itself has been changed. This triggers the need to recirculate the draft EIR, according to Kern River/Altamont. We disagree. Under Laurel Heights Improvement Association v. Regents of University of California, 47 Cal. 3d 376, (1988), "...an EIR must include an analysis of the environmental effects of future expansion or other action if (1) it is a reasonably foreseeable consequence of the initial project; and (2) the future expansion or action will be significant in that it will likely change the scope or nature of the initial project or its environmental effects. Absent these two circumstances, the future expansion need not be considered in the EIR for the proposed project." (Laurel Heights, supra, at 396.)

The Letter Agreement does not obligate PG&E, the entity whose intrastate proposal is subject to our review, to do anything in California as a result of the parties' agreement. Any future expansion or action required by the Letter Agreement will not foreseeably occur on the California portion of the pipeline. There is no reason to consider the possible expansion of PGT's facilities in the Commission's EIR on the Expansion Project. The statement of one of PGT's corporate officers at the FERC technical conference that accommodation of Bonus' deliveries would entail additional facilities on PG&E's portion assumes that Bonus' deliveries are incremental to capacity that has been allocated on the basis of the Precedent Agreements. Kern River/Altamont have not shown that to be the case; the language in the settlement that requires Bonus to arrange its own intrastate deliveries implies that PG&E will not undertake to provide Bonus incremental capacity on the Expansion Project. Therefore, we find that the settlement embodied in the Letter Agreement does not give rise to a change in the project necessitating either recirculation of the Draft EIR or a reopening of the Commission's proceeding.

2. Motion of Altamont for Official Notice

On November 14, 1990, Altamont filed a motion requesting the ALJ take official notice of the Commission's prepared testimony in a PGT rate proceeding, docket Nos. RP90-109-000, et al. before the FERC.

Altamont asserts that the testimony was submitted to the FERC under date of October 29, 1990, and was therefore not available prior to the conclusion, on June 8, 1990, of the evidentiary hearings on non-environmental issues in this proceeding.

The record on the non-environmental portion of the application was submitted on July 30, 1990 with the filing of concurrent reply briefs. Although the testimony at the FERC may be suitable for official notice, it should not be admitted in evidence at this point in the proceeding, because to do so would require giving the parties additional time to make supplementary arguments relating that evidence to their positions.

The CPUC testimony was offered in a PGT rate case proceeding, one where the rates assessed by PGT as a supplier of natural gas are at issue. Altamont would offer that testimony in this CPCN proceeding, where PGT and its intrastate counterpart, PG&E, propose to provide firm transportation service. The activities under consideration are so different that extensive testimony and briefing would be required to properly introduce the CPUC testimony at the FERC into the record of this CPCN proceeding. Given the limited usefulness of the proffered testimony and the lateness in the case, we find that the Commission's process would not be furthered by granting Altamont's motion. The Motion of Altamont for official notice is accordingly denied.

C. Proposed Decision of the Administrative Law Judge

The proposed decision of the ALJ was filed and served on all parties on November 27, 1990 in accordance with Section 311 of the Public Utilities (PU) Code and Rule 77, et seq., which implements that section of the Code. Comments on the proposed decision were received from PG&E, Kern River, Altamont, Amoco, El Paso, SoCalGas, Edison, SDG&E, Toward Utility Rate Normalization (TURN), Pan-Alberta Gas Company, Ltd. (Pan-Alberta), Southern California Utility Power Pool of the Cities of Burbank, Glendale, and Pasadena; DRA, and the Indicated Expansion Shippers which include Suncor, Inc., BP Resources Canada Limited, American Hunter Exploration Ltd., North Canadian Marketing, Inc., and Salmon Resources, Ltd. Comments of the Department of Fish and Game (DFG) were received one day late. However, for good cause shown, leave will be granted for this late filing.

Reply comments were received from PG&E, Edison, Kern River, Altamont, Amoco, and The Producer/Shipper Group, which included Suncor, Inc., BP Resources Canada Limited, American Hunter Exploration Ltd., North Canadian Marketing Inc., and BP Gas, Inc. for the purpose of the reply comments.

In a ruling that established the dates for filing comments, the ALJ reiterated the Rule 77.3 requirement that comments on the proposed decision "focus on factual, legal, or technical errors in the proposed decision", and warned that comments which merely reargued the positions taken by the parties in briefs were not to be filed. Several of the parties disregarded this ruling and submitted argument against the proposed decision in the guise of comments.

We disapprove of this abuse of the Section 311 process for several reasons. First, such comments misconstrue the effect of the ALJ's proposed decision. The proposed decision is not the brief of a party to be countered with argument but the opinion of an impartial decisionmaker. Secondly, those comments reiterate matters already on the record; the Commission does not have the luxury to review repetitive argument during the limited time available under Rule 77, et seq. Finally, reargument by some of the parties places the other parties at a procedural disadvantage. Accordingly, comments which have reargued the parties' positions have been accorded no weight.

The properly filed comments of the parties have been carefully reviewed. Amendments or clarification which in our judgment should be undertaken to augment the proposed decision are discussed below. The necessary changes have been made to the relevant portions of this decision.

1. Capacity Brokering

PG&E and its prospective shippers object to the requirement that PG&E require as a term of its firm transportation contract that an Expansion shipper may not refuse to broker its subscribed capacity when it has no bona fide need for the capacity and there is demand for that capacity. Our developing policy on capacity brokering is intended to eliminate constraints imposed by pipelines on brokering by shippers. However, pipelines functioned as bottlenecks because they controlled the allocation of capacity on their lines. Under the long term firm transportation contracts proposed by PG&E, the shippers will have purchased the right to pipeline capacity and thus, the right to exclude others from using the Expansion pipeline. Pending the final outcome of this Commission's investigation into capacity brokering (I.88-08-018), this contract term is necessary to avoid the creation of a new bottleneck in natural gas deliveries. Since we have not waived our continuing oversight of special utility contracts as requested by PG&E, the contracts may be amended to incorporate whatever capacity brokering terms are required by the Commission's investigation.

2. SoCalGas

SoCalGas seeks assurance that its recovery of costs incurred to facilitate the downstream delivery of Expansion Project gas would be addressed by the Commission in one of several pending proceedings. DRA also commented on this issue. We find that the "Petition of Southern California Gas Company for Modification of Decision No. 90-02-016" would be the appropriate forum. Consistent with its recommendations in that proceeding, SoCalGas would subsequently file an application for approval of capital expenses to interconnect with the Expansion Project. It has done so with respect to t: WyCal and Kern River pipelines.

3. Risk Allocation

Several parties questioned our failure to assign all risk of underrecovery to PG&E's shareholders at this time. We note that PG&E had proposed that the risk of revenue non-recovery be borne by Expansion sponsors and shippers, and that PG&E would not seek to recover any of the costs of the Expansion Project in any non-Expansion Project rate proceeding. This proposal is consistent with our requirement that the cost of incremental pipeline capacity must be borne by the incremental user (D.90-02-016), and we view it very favorably. The Expansion's incremental service will utilize economies of scale made possible only by the use of existing facilities. Consequently, existing users will be barred from realizing those economies of scale. They should be compensated, in an equitable sense, by freedom from the risk of revenue non-recovery.

Until further Commission action, we find that the project sponsors are PG&E's shareholders, and it is PG&E's shareholders and Expansion shippers, not the existing ratepayers, that bear the risk of the Expansion Project's failure to recover its revenue requirement. The shift of risk to existing ratepayers may occur, if at all, only if the Commission finds that the Expansion Project's contribution to margin would constitute a financial benefit sufficient to overcome the Project's potential burden of revenue underrecovery. However, we conclusively find that none of the costs of the Expansion Project may be recovered in any non-Expansion Project rate proceeding, advice letter or accounting mechanism.

4. Definition of Public Convenience and Necessity

Many of the intervenors commented on the proposed issuance of a CPCN at this time, when the Commission cannot find that the Expansion Project, in all events, is needed to serve the public.

Our finding that the pipeline is not needed in all events is not inconsistent with a finding of public convenience and necessity for the pipeline. In reviewing a grant by this Commission's predecessor of a CPCN to a new entrant, the California Supreme Court stated, "The phrase 'public convenience and necessity' cannot be defined so as to fit all cases. The word 'necessity' must be taken in a relative sense. The Supreme Court of Illinois has well expressed its meaning in Wabash C.& W. Ry. Co. v. Commerce Com., ...where it was said: 'When the statute requires a certificate of public convenience and necessity as a prerequisite to the construction or extension of any public utility, the word 'necessity' is not used in its lexicographical sense of 'indispensably requisite.' If it were, no certificate of public convenience and necessity could ever be granted.'" (San Diego etc. Ferry Co. v. Railroad Com., (1930) 210 Cal. 504, 511, citations omitted.)

The Commission's grant of a CPCN to a new utility has been upheld even though no current demand for the proposed service was shown. The Commission may reasonably rely on estimates of future business to establish need for the service. (San Diego Ferry, at 508.) In this case we have found that the present public convenience and necessity requires the issuance of the CPCN based on a public demand that may arise under the terms of PG&E's Precedent Agreements.

The Applicant has tendered its Precedent Agreements with interested shippers to demonstrate the existence of need for the Expansion Project. Upon review of the contract terms, we conclude that the Precedent Agreements do not impose an irrevocable obligation on the shipper to use the Expansion pipeline; thus, they provide no insurance against underutilization of capacity. However, the Precedent Agreements are evidence of market interest in the Expansion Project. Their terms demonstrate that the shippers are committed to using the Expansion Project, and no other pipeline, to transport the volumes identified in the Agreements. Shippers who have executed Precedent Agreements have also agreed to execute Firm Transportation Agreements for the volumes specified upon approval of the Expansion by the FERC and this Commission.

A definitive need has been shown for 300 MMcf/d of the 755 MMcf/d of the Expansion's firm transportation capacity, as that capacity is subscribed to by Edison and SDG&E which currently have no access to Canadian supplies. An additional 30 MMcf/d of firm capacity is subscribed to by southern California municipalities. Thus, we find that currently some need exists for the Expansion Project.

The court in San Diego Ferry recognized the role of the marketplace in determining the existence of public necessity with its pronouncement, "However, any improvement which is highly important to the public convenience and desirable for the public welfare may be regarded as necessary. If it is of sufficient importance to warrant the expense of making it, it is a public necessity." (Ibid, at 511, citations omitted.)

In this case, PG&E's shareholders would proceed with the construction of the pipeline in response to the demands of the market for new service. Consistent with San Diego Ferry, our issuance of a CPCN may be based on a finding that, if the Expansion Project is of sufficient importance to warrant PG&E's construction of the pipeline at shareholder risk, then a public need for the project will have been established.

Finally, the Commission's own regulatory approach to ensuring that incremental need is met furnishes the necessity for issuance of the certificate. It is within the discretion of the Commission to determine the factors material to public convenience and necessity. (California Motor Transport Co. v. Public Utilities Commission (1963) 59 Cal. 2d 270, 275.) "A strong or urgent reason why a thing should be done creates a necessity for doing it. (San

Diego Ferry, supra, at page 512). We think the following passage is particularly instructive:

> "The Commerce Commission has a right to, and should, look to the future as well as to the present situation. Public utilities are expected to provide for the public necessities not only today, but to anticipate for all future developments reasonably to be foreseen.
>
> The necessity to be provided for is not only the existing urgent need, but the need to be expected in the future, so far as it may be anticipated from the development of the community, the growth of industry, the increase in wealth and population, and all the elements to be expected in the progress of a community."

We have determined that the public's incremental demand for natural gas can best be met by enabling market forces, not this Commission, to select the preferred gas pipeline. In D.90-02-016, the Commission confirmed the criteria that would enable any interstate pipeline to merit the Commission's support before the FERC. Since California's incremental supplies of gas will be supplied by out of state sources, D.90-02-016 effectively established the criteria by which the Commission would evaluate how any new pipeline would serve the public interest. Those criteria have been used to ascertain whether the Expansion Project would serve the public convenience and necessity.

By the same token, we must observe the new market-based method of determining which pipeline should be constructed when considering this application for CPCN. We cannot reverse our policy without revisiting the investigation that gave rise to D.90-02-016. To find in this case that the construction of the Expansion Project is needed in any event would undermine the market forces we have indicated should govern the decision to build any particular pipeline.

We find that a CPCN must be issued today to enable PG&E to meet future demand for firm transportation, as it may arise. We find that there is some need for the Expansion Project, as evidenced by the subscriptions and testimony of Edison and SDG&E. Moreover, today's issuance of the CPCN will allow PG&E to respond to the market's dictates of need for the facility, consistent with the court's definition of "public necessity" and our own market-based approach to the development of incremental interstate transmission capacity. Thus, our issuance of the CPCN to enable PG&E to meet future demand for interstate gas transmission service is well within the Commission's discretion under Section 1001 of the PU Code.

In the application of Pacific Lighting Gas Supply Co., the Commission issued a CPCN for the construction of a gas pipeline based on the applicant's demonstration of a present need, even though there was insufficient evidence that the pipeline would be utilized fully during its useful life. (D.63414). The finding of need is generally required to mitigate the risk of revenue underrecovery. Revenue underrecovery can be minimized if PG&E is required to file its executed Firm Transportation Contracts in this docket no later than 90 days before it begins construction. As in the Pacific Lighting case, the risk of revenue recovery resides with shareholders absent a finding that PG&E's decision to proceed was a reasonable one.

We have reserved the issue of the prudency of PG&E's subscription to 100 MMcf/d of firm transportation to meet "system supply" needs for later review. We do not rely on PG&E's subscription to find that the public convenience and necessity require the issuance of a CPCN today. As with other contracts, we expect that the Firm Transportation Agreement for this 100 MMcf/d of capacity will be filed in this docket.

5. Effect on Competition

The comments of Kern River and Altamont alleged that imposition of the Kern River Station delivery point and non-mileage sensitive rate would severely restrict gas-on-gas competition in Northern California. That is, PG&E will enjoy a competitive advantage by avoiding payment of the G-IND rate for delivery of its system supply gas in Northern California. The need for consideration of this issue is contingent upon whether PG&E executes a Firm Transportation Contract for service on the Expansion Project; no further discussion is necessary here.

Several comments highlighted the need to consider the consistency of the proposed undertaking with antitrust principles. The Commission may approve a project even though it would violate antitrust laws (Northern California Power Agency v. CPUC (1971) 5 Cal.3d 370). At this point, we will review the potential impact of the Expansion Project on competition.

The Expansion Project is intended to provide gas transportation service to the utility and industrial users in Southern California. These users are not in PG&E's service territory, but have traditionally been wholesale, utility electric generation or industrial customers of SoCalGas.

The proposed pipeline will require SoCalGas to incur some expense to interconnect and deliver Expansion Project gas to downstream users. Review of the reasonableness of these expenses for recovery in rates has been provided for. Impacts on the gas procurement activities of SoCalGas cannot be attributed solely to this pipeline, since the Commission has steadily pursued a policy of unbundling traditional local distribution company services to allow for the direct procurement of gas from suppliers by consumers. The Expansion's shippers would facilitate this direct procurement. The resultant impacts on SoCalGas' transportation revenues will be minimal, since no bypass of SoCalGas' distribution facilities is foreseen. Thus, the Expansion Project will not have a negative effect on the business of SoCalGas.

The Kern River pipeline, more fully described under "Positions of the Parties," is intended primarily to serve the incremental demand for natural gas expected to materialize for enhanced oil recovery. While Kern River and the Expansion Project represent alternative means for meeting demand for natural gas in Southern California, they are alternatives only because the gas supplied by one pipeline would displace supplies otherwise directed to certain users. They would each free up gas to be redirected to other load. The physical facilities of the Kern River pipeline terminate in the oil fields, and are designed to provide economic service to the enhanced oil recovery operators. This represents a different market for gas than the one proposed to be served by the Expansion Project.

Altamont, which would deliver natural gas to Kern River for delivery to southern California, has not disclosed who its shippers or intended market are. However, the record shows that Altamont has executed precedent agreements with shippers providing for Altamont's exclusive transportation of 532 MMcf/d over its 719 MMcf/d of capacity. Throughout this proceeding, Altamont has represented that it is a viable alternative to the Expansion Project. Since the volumes of gas indicated in PG&E's Precedent Agreements are, like Altamont's shipments, subject to exclusive transportation agreements, it appears that the Expansion Project has had no deleterious effect on Altamont's viability.

Intervenors have objected that the Expansion Project's use of a non-mileage sensitive transportation rate, a single delivery point in Southern California, and PG&E's subscription to 100 MMcf/d constitute a subsidy of transportation service to southern California. We have found to the contrary. Even if such a subsidy existed, we find that it has not conferred a significant competitive advantage upon the Expansion Project. We find that the competitors of the Expansion Project have suffered no restraint of trade as a result of the Expansion's proposed service or rate design.

6. Biological Opinion

On October 12, 1990, the Commission requested the Department of Fish and Game (DFG) to issue its "Biological Opinion" on the impacts of the Expansion Project pursuant to the California Endangered Species Act. The purpose of the biological opinion is to determine whether the development would jeopardize the continued existence of rare, threatened or endangered species. In formulating its biological opinion, the DFG considered and relied upon the Draft and Final EIRs; the Mitigation and Monitoring Plan for California State-Listed Rare, Threatened and Endangered Species; and the PGT-PG&E Pipeline Expansion Project Species Notes and Proposed Surveys for Special Status Fish and Wildlife, including the Endangered Plant Survey performed by Biosystems Analysis, Inc.

The DFG's biological opinion was transmitted to the Executive Director of the Commission under cover of a letter dated December 21, 1990. Rule 73 states, "Official notice may be taken of such matters as may be judicially noticed by the courts of the State of California." California Evidence Code Section 452 provides for discretionary judicial notice of "...Official acts of the...executive...departments of the United States, of California, and of any other state of the United States." The DFG is an executive agency of this state and is charged with administering the California Endangered Species Act. Since the project EIR identified potential significant negative impacts on special status species, it is reasonable for this Commission to take official notice of the DFG's biological opinion.

In its biological opinion, the DFG concluded that some special status species may receive a "jeopardy opinion." However, the documents on which the DFG based its review contain mitigation measures which, if adopted by the Commission, would reduce the impacts to a "no jeopardy opinion". The DFG stated in its letter transmitting its biological opinion, "The DFG finding of 'no jeopardy' in its State Biological Opinion is based upon the project as proposed in the above-listed documents."

Since the DFG finding of "no jeopardy" is based on the existing final EIR and draws no conclusions that are inconsistent with those of the final EIR, it does not constitute "significant new information." There is no need to recirculate the EIR due to the DFG's Biological Opinion.

The thirty-nine page biological opinion was prepared for all state-listed rare, threatened, or endangered species that could be impacted by the Expansion Project for the entire length of the project in California. It identifies species that could occur in the area of the proposed pipeline and notes that the San Joaquin kit fox inhabits the project area. In the biological opinion, DFG has described the natural history of each species, the effects on the species of project development at specific mileposts, and suggests conditions to avoid jeopardy to the species. Some of the conditions attached in Appendix B of the proposed decision were incorporated in the biological opinion. Others had not been previously imposed on the project. Since the California Endangered Species Act prohibits any development that would jeopardize the continued existence of a rare, threatened, or endangered species, we find that PG&E must comply with the conditions contained in the biological opinion, and the issuance of the CPCN should be conditioned upon such compliance.

The biological opinion incorporates the requirement that PG&E retain a biological monitor, who has been qualified by the Commission, to monitor specific vegetation and wildlife mitigation measures. It also requires PG&E to avoid special status plant species populations by boring under certain bodies of water. PG&E has not specified the means by which the pipeline will cross the bodies of water identified by DFG. No later than 180 days before the planned start of construction on the spread in which the crossing is located, PG&E should provide engineering drawings which indicate the proposed pipeline alignment, construction, and staging areas to enable the biological monitor to ascertain whether special status plant species populations would be harmed or not, and to undertake whatever route changes or other mitigation would be necessary to avoid jeopardizing the species.

The analysis and conclusions of the Final EIR are premised on the assumption that construction would occur during the periods identified in the proponent's environmental assessment (PEA). According to the PEA, construction of compressor facilities would begin in the late spring of 1992 and terminate in November of 1993; construction of pipeline facilities would begin in April of 1993 and conclude in October of 1993.

We have noted that the DFG's biological opinion of "no jeopardy" is based on the Final EIR, among other things. The Expansion Project's "no jeopardy" status can be assured only if construction is restricted to the periods identified in the PEA. We should require, as a condition of the CPCN, that construction occur only during the periods for which the environmental impacts of the development were analyzed in the Final EIR.

7. <u>Mitigation and Monitoring</u>

The comments of PG&E on the environmental conditions of the proposed decision may be grouped into three broad areas, which are: administrative clarification, technical amendments, and a relaxation of survey, mitigation, or monitoring requirements. Because the "no jeopardy" opinion of DFG, which we deem essential to our approval of the Expansion Project, is premised on the Project as modified by the Final EIR, we reject the comments that would weaken the environmental protections called for by the Final EIR. We also decline to make any technical modifications that are inconsistent with the purposes of the surveys, mitigation, and monitoring required by the Final EIR. Only non-substantive changes that provide administrative clarification have been accepted. For example, the permit requirement has been changed so that all permits for development on a particular construction spread shall be obtained prior to construction. The primacy of existing programs to protect a specific resource has been recognized. Appendix B, Mitigation Measures, and Appendix C, Mitigation Monitoring Plan, have been modified to incorporate the accepted changes.

The Commission's environmental consultant has provided a "Draft Mitigation Monitoring, Compliance, and Reporting Plan for the PGT/PG&E Natural Gas Pipeline Project in California" dated December 21, 1990. It is intended to embody the environmental conditions imposed on the Expansion Project. However, due to time constraints, that document has not been conformed with this decision. The Environmental and Resources Advisory Section of the Commission Advisory and Compliance Division shall amend the document to make it consistent with the provisions of this decision. Upon approval of the assigned administrative law judge, it shall become the "Final Mitigation Monitoring, Compliance, and Reporting Plan for the PGT/PG&E Natural Gas Pipeline Project in California."

8. Solano Reroute

The proposed decision would have required PG&E to perform an environmental analysis to select the environmentally preferable route for the section of the pipeline between mileposts 888.6 and 896.2, the "Solano Reroute," and to submit it to the administrative law judge for approval before construction of that segment. This requirement was founded on the August 24, 1990 letter by the DFG expressing concern over the routing of the Expansion through this area. Inclusion of this routing alternative would have required the applicant to undertake further surveys and analysis to determine which route, the one contained in the draft EIR or the

"Solano Reroute," would have been the environmentally preferred route. In its comments on the proposed decision, the DFG concluded that the environmentally preferred route is Alternative B, the route initially selected by the Commission's consultants and subject to public review in the Draft EIR. The DFG adopted this position after review of the Final EIR and discussions with the Commission's staff and consultants responsible for the preparation of the EIR. We will treat the DFG's opinion as a recommendation that the pipeline follow the route known as Alternative B in the Draft EIR. We adopt the DFG's recommendation. Thus, the requirement that PG&E perform further studies to route the pipeline between mileposts 888.6 and 896.2 should be deleted.

9. <u>Cumulative Impacts</u>

The Final EIR and this decision require the restoration and protection of vernal pools and the reduction of air pollutants in order to mitigate the cumulative impacts of development. PG&E and prospective shippers on the Expansion Project asserted that no mitigation is required by the California Environmental Quality Act (CEQA) for facilities that were constructed before the effective date of CEQA. Clearly, the procedural requirements of CEQA do not apply to projects undertaken by a public agency before the effective date of CEQA. However, no authority was cited for the proposition that the environmental impacts of a project which predated CEQA cannot be weighed in evaluating the cumulative impact of a currently proposed development.

CEQA Guidelines section 15355 states:

> "'Cumulative impacts' refer to two or more individual effects which, when considered together, are considerable or which compound or increase other environmental impacts.
>
> "(a) The individual effects may be changes resulting from a single project or a number of separate projects.

> "(b) The cumulative impact from several projects is the change in the environment which results from the incremental impact of the project when added to other closely related past, present, and reasonably foreseeable probable future projects. Cumulative impacts can result from individually minor but collectively significant projects taking place over a period of time."

The CEQA guidelines must be interpreted to afford the fullest possible protection to the environment. (Kings County Farm Bureau v. City of Hanford (1990) 221 Cal.App.3d 692, 720, citing Friends of Mammoth v. Board of Supervisors (1972) 8 Cal.3d 247.) It has been observed that, "One of the most important environmental lessons evident from past experience is that environmental damage often occurs incrementally from a variety of small sources. These sources appear insignificant, assuming threatening dimensions only when considered in light of the other sources with which they interact. Perhaps the best example is air pollution, where thousands of relatively small sources of pollution cause a serious environmental health problem." (Kings County Farm Bureau, supra, at 720.)

In undertaking the analysis of cumulative impacts required by Section 15130 of the Guidelines, we observe that the Expansion Project is a looped pipeline, which means that it consists of a pipeline which runs parallel to the existing pipeline, uses existing compressor facilities where feasible, and is located in the existing pipeline right of way. Its construction and maintenance will adversely impact vernal pools, and it will rely on gas-fired engines for the compression necessary to transport gas through the pipeline. The Final EIR discusses the incremental effects that the Expansion Project is expected to have on existing vernal pools. Based on the observations of experts, the Final EIR describes the likely impact that construction of the existing pipeline had on historic vernal pools. The incremental effects of development on vernal pools and air will occur in addition to those caused by the existing pipeline, and indeed, would not have occurred but for PG&E's choice of a looped pipeline design. As shown in the Final EIR, the Expansion Project is found to have a cumulative impact on historic vernal pools and on air quality.

The failure of the Draft EIR to address the cumulative impact of the Expansion Project was noted by the California Department of Fish and Game in its August 24, 1990 letter to the Commission. Subsequently, the Final EIR required the mitigation of the loss of vernal pool acreage that had been destroyed due to construction of the existing pipeline as well as vernal pool habitat to be lost due to the Expansion Project. Upon review of the Final EIR, the DFG wrote the Commission on December 17, 1990 that it was satisfied with the species and habitat protection afforded by the Final EIR. In its Comments on the proposed decision, the California Department of Fish and Game (DFG) stated, "The DFG strongly believes that certain cumulative impacts should require mitigation. Thus, PGT-PG&E has agreed to develop appropriate cumulative impact mitigation with the DFG in the form of real property acquisition or wildlife easements to compensate for statewide cumulative impact loss of vernal pools and other sensitive habitats found in the vicinity of the proposed project."

The incremental effects on both the impacts on vernal pools and air quality were determined to have significant adverse impacts on the environment that required mitigation. In order to give effect to CEQA, we should require the mitigation of cumulative impacts to vernal pool habitat by including the acreage of previously destroyed vernal pool habitat in the mitigation program.

In order to provide for the efficient operation of the expanded pipeline, upgrades to existing compression facilities will be undertaken. Because these are existing, and not new, facilities, PG&E should use the best available retrofit control technology (BARCT) or reasonably achievable control technology (RACT) as defined by the final guidelines of the California Air Resources Control Board (CARB) and as applicable according to the Local Air Pollution Control District. RACT or BARCT shall be employed even if the Applicant's compressor modifications would not ordinarily trigger the requirement for RACT or BARCT. This will enable PG&E to minimize the emission from existing compressor stations of oxides of nitrogen and for each pollutant emitted in excess of specific prevention of significant deterioration thresholds.

We clarify that Expansion Project shippers should bear the cost of mitigating cumulative impacts because those impacts would not have occurred but for the development of the Expansion Project. Because of the Expansion Project's looped design and our adopted incremental cost allocation, Expansion shippers are benefitting from economies of scale. Those benefits could not be attained without generating the cumulative impacts on the environment. Thus, it is reasonable to include the cost of environmental mitigation identified in the Final EIR, in the cost of the Expansion Project whether for acreage and facilities associated with the Expansion Project or existing facilities due to cumulative impacts of the pipeline.

10. <u>Alternatives Infeasible</u>

The Final EIR concludes that development of the Expansion Project would create significant adverse environmental effects that are not "at least substantially mitigated". Although a statement of overriding considerations to explain the issuance of a CPCN was included, the proposed decision failed to address why the Expansion Project should be approved despite the existence of alternatives. There is no doubt that the Altamont and Kern River pipelines are viable alternatives which, as explained more fully in the body of this decision, may serve the demand for gas which the Expansion seeks to serve.

We reject those alternatives and choose to certificate the Expansion Project because of its economic and operational efficiency. It will utilize capacity on the existing PG&E system which is currently underutilized or idle, including some 130 miles of existing pipe. The construction of the Expansion Project would further the maximum use of existing facilities due to its use of displacement to accomplish delivery to Kern River Station. Certain A&G and O&M expenses which would be incurred by a stand-alone facility will not be incurred specifically for the Expansion Project. The benefits of these economies of scale are reflected in a lower rate to Expansion Project shippers. This is an economic benefit that should be made available to incremental users of PG&E's facilities.

The development of the Expansion would further our regulatory objectives of productive and allocative efficiency. It also is expected to provide existing ratepayers with a fuel savings of roughly $13.7 million, more if the price of gas escalates, due to the increase in compressor efficiency that will result from the looped pipeline design. Existing ratepayers will enjoy increased reliability of deliveries over the entire PG&E system. PG&E's existing ratepayers will also benefit from increased system flexibility and an ability to interchange gas supplies between Lines 300 and 400. Such flexibility should enable PG&E's ratepayers to accept deliveries of whichever is the lower-priced gas from competing regions, i.e., the southwest and Canada.

The Expansion Project is the only proposed interstate pipeline that can deliver these benefits to PG&E's ratepayers. Adoption of one of the other pipeline alternatives would deny these benefits to ratepayers. We cannot, consistent with our role, foreclose ratepayers from enjoying these economic benefits. Therefore, we find that the pipeline alternatives identified in the Final EIR are infeasible for purposes of Section 21002 of the Public Resources Code.

11. AFUDC

PG&E seeks clarification of the rate of return to be used as the basis for accruing its Allowance for Funds Used During Construction. Under the Uniform System of Accounts, 18 Code of Fed. Reg. 201, Gas Plant Instructions, 3(17)(b), AFUDC is normally calculated with the utility's currently effective return. We see no reason to depart from that standard. Although PG&E utilized a nominal 14 percent return on equity and 10 percent cost of debt for the purpose of estimating its cost cap, we find that PG&E should use the return on equity and cost of debt currently authorized during its construction of the Expansion Project to calculate AFUDC.

12. Future Upgrades

We define "future upgrades" as improvements that, in the future, will be necessary or desirable to enable PG&E to maintain or improve its then-existing service. Those upgrades would not be made to accommodate incremental usage. This distinguishes future upgrades of the combined PG&E/Expansion system from the Expansion and justifies the use of allocation based on direct assignment or throughput as opposed to incremental cost allocation. For this reason, the costs of future upgrades will be allocated between ratepayers existing at the time of upgrade, whether those ratepayers are PG&E system ratepayers or Expansion ratepayers.

13. Motion That The Commission Withdraw Testimony

On April 11, 1990, this Commission filed with the FERC its "Amendment to Pleadings and Statement of Support of the Public Utilities Commission of the State of California (Statement) to advise the FERC of the Commission's support of PGT's application for CPCN and offer of settlement concerning the interstate portion of the PGT/PG&E Expansion Project. This support arose from the Commission's conclusion that the PGT application and settlement comply with the criteria adopted by the Commission in D.90-02-016.

On May 18, 1990, Altamont filed in this proceeding its "Motion that the Commission Withdraw Pleading and Statement filed with FERC" (Motion). According to Altamont, the Commission's Statement was a declaration of support for PG&E's intrastate Expansion Project that prejudged the merits of the Expansion Project in violation of the Public Utilities Code and CEQA.

On June 1, 1990, PG&E filed its "Comments on Altamont Gas Transmission Company Motion that the Commission Withdraw Pleading and Statement." PG&E responded that Altamont's Motion is meritless, is in fact a fatally late request for rehearing of D.90-02-016, and should be dismissed.

The ALJ did not rule on Altamont's Motion, finding that resolution of the issue through development of the record was preferable to deliberating the practical effect of the Commission's Statement on this case. Our subsequent discussion reveals that the Expansion as approved differs from PG&E's proposal in several respects. The Commission's support for the PGT expansion cannot be said to have prejudged the result in the intrastate proceeding. The market has not rejected all other pipelines on the basis of the Commission's statement at the FERC; for example, Altamont has steadily maintained that it is a viable alternative to the PG&E Expansion proposal. Moreover, this Commission has clearly observed the procedural and substantive requirements of CEQA prior to certification of the final EIR and the granting of PG&E's certificate. The record demonstrates that the harm envisioned by Altamont has not materialized. The Motion of Altamont is moot and should be dismissed.

II. The Proposed Pipeline Expansion

A. Physical Plant

1. Facilities and Location

The Expansion consists of a pipeline system that is parallel to, and interconnected with, PG&E's existing pipeline facilities from Malin to Kern River Station. PG&E will construct a new pipeline from the Oregon-California border to the Brentwood Compressor Station in Contra Costa County. This pipeline was originally proposed to be 36" in diameter. However, in its October 2, 1989 amendment, PG&E increased the pipeline diameter to 42" for the major portion of the intrastate facility.

As currently proposed, the Expansion Project consists of 295 miles of 42" diameter pipeline from the Oregon-California border to the Brentwood Compressor Station. This segment would run parallel and adjacent to PG&E's existing Line 400. A new 12,400 horsepower gas-fired turbine-driven compressor will be installed at Delevan Compressor Station (Colusa County). Thirteen thousand five hundred horsepower of new compression will be installed at the Brentwood Compressor Station (Contra Costa County). This will create pressure to transport the gas through 120 miles of 36" diameter pipe from Brentwood Compressor Station to Panoche Meter Station. This segment would be located parallel and adjacent to PG&E's existing Line 2. Although the gas is destined for delivery at Kern River Station, PG&E does not propose any construction or modification of its existing facilities for the final 113 miles of the Expansion Project between Panoche Meter Station and Kern River Station.

One hundred thirteen miles of dual 34" pipe that is part of PG&E's existing Lines 300 A and B between Panoche Meter Station and Kern River Station and 17 miles of PG&E's 36" diameter existing Line 400 near Delevan will be used by the Expansion. A portion of the capacity of Line 2 will also be used for Expansion service. As part of the Expansion, PG&E also will modify compressors and/or piping at five existing compressor stations and modify three existing meter stations.

The Expansion terminates at Kern River Station, which is currently designed to exchange 600 MMcf/d between PG&E and SoCalGas. Not all of the gas accepted by PG&E at the Oregon border will actually make the 544.5 mile trip to Kern River Station. Deliveries will be made, in part, by displacement. Expansion gas would displace deliveries of gas currently received by PG&E at the southern portion of its system, so that the gas received from southwest sources will flow to the Expansion shippers. PG&E states that no additional facilities are needed downstream of Kern River Station.

2. Design Capacity

In its original application filed on April 14, 1989, PG&E had proposed an Expansion consisting of a 36" diameter pipe, capable of transporting approximately 600 MMcf/d. This capacity was premised on the capacity design of the interstate portion of the pipeline being proposed by PGT at the FERC. PGT's December 1988 FERC Application contemplated that the project's capacity would be fully subscribed to by southern California utilities. However, in early 1989 it appeared that utility subscriptions would require only 350 MMcf/d of capacity. PG&E/PGT then conducted an "open season" bidding procedure[1] to market the remaining 250 MMcf/d of capacity. Bids were accepted from April 26 through May 2, 1989. In the meantime, Edison, SDG&E, and the City of Long

1 PG&E determined it would allocate firm transportation on the Expansion by an "open season" bid process. Capacity on the Expansion was awarded in relation to the present value of the reservation fee for the term requested, with the maximum bid being a 100% reservation and a 30-year term. The open season procedure also called for the timely execution of a Precedent Agreement.

Beach executed Precedent Agreements[2] for a combined capacity of 350 MMcf/d. Precedent Agreements were executed initially with successful bidders in April of 1989. Each successful bidder was also required to prepay or provide an irrevocable letter of credit equal to the estimated first year's transportation charge. However, in compliance with the terms of a settlement reached at the FERC in Docket No. CP89-460-000, PGT/PG&E has returned the letters of credit to the shippers.

Under the Precedent Agreements, shippers are relieved of their obligations to execute firm transportation agreements if satisfactory regulatory approvals are not obtained, or if they fail to secure a gas supply. Once the two conditions have been satisfied, the parties are obligated to use their best efforts to finalize firm transportation agreements within 120 days.

The Precedent Agreements specified that transportation over the Expansion Project would be on a "firm" basis. PG&E states that its award of firm transportation capacity was based on a winter-based firm capacity of up to 600 MMcf/d. Due to the inefficiency of compressor stations in hot weather, the summer capacity of the Expansion would only be about 80% of the awarded capacity. California shippers desired firm year-round deliveries and found the lower summer volumes inherent in the project to be unsatisfactory. PG&E characterizes this as the "seasonality issue."

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2 The Precedent Agreement between prospective shippers and PG&E required (a) exclusive commitment to the Expansion for the volumes selected; (b) specific support for the Expansion before regulatory agencies; and (c) the procurement of adequate gas supplies and necessary regulatory approvals.

During July and August of 1988, PG&E considered redesigning the pipeline to provide year-round firm transportation of the specified capacity. The Expansion Project was revised by replacing the original 36" pipe with 42" pipe. This produced an additional 155 MMcf/d of capacity, which will accommodate the California shippers' need for firm transportation on a year-round basis, permit transportation by an additional shipper, and enable PG&E to transport an incremental 100 MMcf/d for itself.

Thus, the "design capacity" of the Expansion Project is 755 MMcf/d, but the maximum capacity of the pipeline is 877.5 MMcf/d at Kern River Station during the winter months of October through March. The actual daily capacity on the Expansion depends on a range of operating conditions that occur over the course of the year.

Although 755 MMcf/d of firm capacity has been allocated to shippers that have executed precedent agreements, PG&E proposes to provide transportation in excess of 755 MMcf/d, either firm or interruptible, depending on actual operating conditions at the time.

3. <u>Point of Delivery</u>

The single point of delivery for gas transported over the Expansion is Kern River Station. Shippers or end users would then purchase transportation service by the local distribution company at rates approved by the Commission for delivery to their burner tip. For example, end users located in PG&E's northern California service territory are required to purchase transportation over the PG&E system at the utility's G-IND rate. PG&E does not propose to deliver any Expansion gas directly to northern California.

Since PG&E and SoCalGas facilities are interconnected at Kern River Station, an end user located in southern California would contract with SoCalGas, and then SDG&E, if necessary, for the transportation of Expansion gas to the burner tip.

B. **Estimated Costs**

1. **Construction Costs**

PG&E estimates the fourth quarter 1988 capital cost of the Expansion to be $544.8 million. The capital cost is expected to increase to $696 million by the year 1994, when the Expansion will be completed.

PG&E proposes to price the Expansion Project at "incremental cost." None of the embedded capital costs associated with existing PG&E facilities to be used by the Expansion Project are allocated in Expansion Project rates. Operation and Maintenance (O&M) and administrative and general (A&G) expenses incurred to provide existing PG&E services, which are not specifically increased by the Expansion Project, will not be charged to the Expansion Project. Costs that may be incurred for future additions of compression or other facilities will be assigned exclusively to the Expansion Project or to the existing facilities as far as they are clearly assignable. When costs for future additions are not clearly assignable to one system or the other, the costs will be allocated based on the prorated operating capacity of the Expansion Project relative to that of the existing facilities at the specific locations of the additions.

A detailed breakdown of the Expansion's costs was provided in Exhibit F of the October 1989 Supplement to the Application. PG&E summarizes those costs as follows:

Pipeline (414.6 miles of 42"/36" O.D.)	$357,549,000
Land and Land Rights	13,969,000
Compressor Stations (6 locations)	39,001,000
Meter Stations (3 locations)	7,528,000
Other Project Costs	126,794,000
Total 1988 Cost	$544,841,000

2. **Cost of Financing**

The $544,841,000 estimated completion cost of $544,841,000 includes Allowance for Funds Used During Construction. PG&E proposes to initially finance the Expansion Project through a combination of 70 percent debt ($381,388,700) and 30 percent common equity ($163,452,300). This capital ratio will be changed during the first ten years of operations to a capital ratio of approximately 55 percent debt and 45 percent equity. However, some portion of the debt and common equity may be replaced with preferred stock. For illustrative purposes, PG&E assumes that debt securities will bear interest at the rate of 10 percent and will mature 30 years from the date of issuance, and that PG&E's equity investment will earn a return of 14 percent.

PG&E may revise the rate of return on common equity and capital structure in order to accommodate any substantial change in risk profile of the Expansion Project that may result from cost allocation and rate design that emerge from the negotiations with shippers or as a result of this proceeding.

Using PG&E's consolidated capitalization on December 31, 1988 and a pro forma capitalization based on the foregoing assumptions, the Expansion Project would contribute less than 3.5% of PG&E's resultant total capital structure as a result of financing the Expansion Project. PG&E states that the Expansion should not adversely affect PG&E's cost of capital or ability to raise additional capital.

3. Cost of Operations

PG&E's estimates of operating expenses, taxes, and depreciation appear in Exhibit H, Schedule 1 of its October 1989 Supplement. These figures are stated in 1988 nominal dollars. Based on capital expenditures of $544.8 million, and assuming a 11.2% rate of return, the annual cost of service of the Expansion is $101.1 million in the first year. PG&E shows that the cost of service would decline annually so that in Year 10, it would be $69.2 million; in Year 20 it would be $43.8 million; and in Year 30 it would be $31 million.

The applicant believes that a 30-year useful life should be attributed to the Expansion Project for the purpose of establishing the depreciation rate. A 3.333% per year rate is calculated using the straight-line method. The straight-line method was chosen to approximate the decline in economic value of the property.

4. Cost of Environmental Mitigation

PG&E had not identified the cost of environmental mitigation in its application because those costs were included in PG&E's "contingency" costs.

The Commission has prepared an Environmental Impact Report as part of its duties as a lead agency under the California Environmental Quality Act (Public Resources Code Section 21000, et seq.). The Commission recognizes that the impacts on the environment of the Expansion should be avoided and, where unavoidable, mitigated. This requirement, more fully discussed below, may add up to $40 million to the estimated cost of the Expansion. This $40 million is merely an estimate of the maximum potential cost to comply with the mitigation measures adopted in this decision. We make no finding that $40 million is a reasonable amount, only that environmental costs should be estimated and added to the construction cost cap.

5. Cost Cap

The applicant's estimate of $544.8 million for the cost of the Expansion Project is stated in terms of 1988 dollars. PG&E has applied annual escalation rates of 5.0% for the years 1989 through 1991 and 6.5% for the years 1992 through 1994 to calculate a capital cost of $696 million. This figure is presented solely for the purpose of establishing the cost cap for the project as required by § 1005.5(a) of the PU Code.

C. Rate Design and Rates

PG&E presented a rate design for the revenue requirement for Year 1 based on the $101.1 million first year cost of service noted above. The proposed rate structure parallels the PGT rate design for the interstate portion of the Expansion Project.

For firm transportation service, the rate is a one-part rate in the form of a monthly Reservation Charge. The Reservation Charge is designed to collect 100% of the costs allocated to firm transportation service. Revenue for firm transportation service is thus recovered under "full-fixed-variable" rate design.

The rate for interruptible transportation service is a volumetric Usage Rate which is designed to collect 100% of the costs allocated to interruptible transportation service, that is, on a "100% load factor" basis.

PG&E submitted a pro forma tariff in the form of a FERC tariff and its calculation of illustrative rates for the pro forma rate schedule. Roughly 93% of the annual requirement is expected to be collected in firm transportation rates, with the remaining 7% to be collected in interruptible transportation rates. Under pro forma rate schedule CT-1 Firm Transportation Service, the monthly reservation charge applicable to firm transportation is $10.34 per Mcf; a volumetric CPUC fee charge will be added to shippers' costs. Under pro forma rate schedule CT-2 Interruptible Transportation Service, shippers would pay a volumetric usage charge of $0.35 per Mcf for Interruptible Transportation. Compression and line loss fuel will be paid in kind by the shipper to PG&E. PG&E is currently negotiating with its Expansion Project shippers on the rates and terms associated with the proposed transportation service. PG&E intends to adjust its pro forma tariff based on the outcome of negotiations.

Costs of the Expansion Project will be recovered only from the Expansion's customers. No costs of the Expansion will be allocated to PG&E's existing customers, except to the extent that

PG&E itself is a customer of the Expansion Project. None of the costs of owning or operating the existing PG&E transmission facilities would be allocated to the Expansion.

The costs of Expansion plant and equipment will be recorded in separate Expansion accounts. Costs for future replacement of facilities and operating expenses specifically associated with the Expansion will be segregated. Those costs are to be included in future Expansion rate cases on a forecast basis.

Operational savings of approximately $13.7 million resulting from reduced compressor fuel consumption at compressor stations along the Kingsgate (British Columbia) to Kern River route will reduce PGT/PG&E's existing revenue requirement.

The total average rate for firm transportation on the Expansion Project as originally proposed would have been $0.442664 per Mcf. As a result of the 155 MMcf/d increase in volumes transportable over the amended 755 MMcf/d Expansion Project, PG&E's firm transportation rate is $0.34762 or $0.11 per Mcf less.

D. <u>Project Implementation Plan</u>

PG&E and PGT intend to jointly establish a single project organization to direct the entire Expansion from the Canadian - U.S. boundary to the Panoche Meter Station. A project management contractor will be selected to supervise and coordinate all other contractors. The project management contractor will report to a designated PG&E official who will have ultimate responsibility for the success of the project. The project management contractor will be responsible for the overall schedule, cost, and coordination of project activities.

Costs will be controlled by the project management contractor through a combination of monthly cost monitoring, cost forecasting, and comparison with the estimated cost of each activity and the overall Expansion. The management contractor will analyze significant variances from the budget with the help of PG&E personnel.

A timetable that integrates the major tasks involved in the Expansion into a proposed project schedule was included in the Application.

E. Regulatory Treatment of Expansion Facilities

1. Revenue Recovery

PG&E proposes an Expansion Project rate base separate from PG&E's other regulated utility businesses. According to the Applicant, this will place all risk of cost recovery associated with the Expansion on project sponsors, utility shareholders, and shippers. A general rate case application would be filed in about two years, that is, after construction has been completed and about six months prior to commencement of operation. This rate case would establish the reasonable cost of the Expansion Project and determine actual rates for transportation on the Expansion. PG&E's witness testified that the company subsequently may request authority to operate the Expansion Project as an affiliate of the utility.

2. Waiver of GO 96-A

PG&E requests a waiver under Section XV of General Order 96-A (GO 96-A) of Sections II, IX, and X. Waiver of Section II would enable PG&E to file its Expansion Project tariff in the tariff format used at the FERC. Waiver of Sections IX and X would deprive the CPUC of its authority under GO 96-A to amend the terms and conditions of a contract between PG&E and an Expansion Project customer during the term of the contract when, in the Commission's judgment, the amendment is required to serve the public interest.

PG&E is not requesting the Commission to waive its authority to review the individual firm transportation agreements between PG&E and its Expansion Project shippers upon initial execution of the contracts. PG&E asks that the Commission indicate that it will not require any amendment to the contract after it has granted its initial approval of the contract.

F. <u>Options Granted to Utilities</u>

PGT/PG&E has granted to Edison and SDG&E options to acquire up to 20% and 10%, respectively, of equity ownership in the Kingsgate to Kern River Station project. Those options are exercisable only after PGT/PG&E has received all required regulatory approvals for the project and if, within 120 days of that event, the option holder has executed a long-term gas transportation agreement to secure its firm capacity rights on the project. Upon exercise of those options, Edison and SDG&E would enter into an ownership agreement with PG&E and pay their percentage share of all accumulated equity requirements.

While specific terms remain to be negotiated, the utilities have agreed that partners will be responsible for their respective share of costs until the Expansion Project is completed. After completion, any partner may require expansion of the facility to meet its own capacity requirements, provided that it pays the full transportation cost of service relating to any such expansion. If expansion is undertaken, partners will have the right of first refusal on additional capacity up to their proportionate share. If Edison or SDG&E declines to fund any future expansion and PGT/PG&E has secured alternate funding, ownership interest percentages would be adjusted. If Edison or SDG&E desire to sell their interests in the Expansion Project, PGT/PG&E would have the right of first refusal.

PG&E has not tendered the option agreements for Commission approval, preferring that the Commission review the utilities' exercise of their options, if that should occur.

G. PG&E's Subscription to <u>100 MMcf/d of Capacity</u>

On August 30, 1989, PG&E executed a Precedent Agreement obligating itself to pay for 100 MMcf/d of firm transportation capacity on the Expansion Project. This volume represents roughly two-thirds of the 155 MMcf/d of incremental capacity created by the upgrade from 36" outside diameter pipe to 42" outside diameter pipe.

Based on a volumetric pro rata allocation of the estimated first year's revenue requirement, the cost of this transportation capacity would be roughly $13.4 million per year.

III. Positions of the Parties

A. Pacific Gas and Electric Company

The Applicant's position is that there is a near term need for at least 755 MMcf/d of additional capacity; the Expansion Project meets the Commission's criteria for additional capacity; the proposed incremental cost allocation methodology and rate design proposal are just and reasonable; the Expansion and the method of allocating capacity are non-discriminatory; certain sections of GO 96-A relating to continuing Commission jurisdiction should be waived with respect to the firm transportation agreements for Expansion Project service; and the Expansion should be granted a CPCN consistent with the terms of the application.

PG&E states that the Expansion is an economically efficient transportation-only proposal that is responsive to the market's desire for new transmission capacity, as demonstrated by the Precedent Agreements. The Expansion is distinguished from its interstate competitors, according to PG&E, because the ultimate market for the Expansion will continue to use and contribute to the cost of the intrastate systems of California's local distribution companies to deliver their new Canadian gas supplies to the burner tip. Moreover, the Expansion benefits existing service by providing fuel savings and increased reliability. PG&E claims that its proposed cost allocation and rate design promote economic efficiency and insulates existing service from all new facility and operation costs.

1. PG&E's Subscription to 100 MMcf/d of Capacity

Existing ratepayers would bear only the costs of PG&E's subscription to 100 MMcf/d of Expansion Project capacity, states PG&E. PG&E would recover the cost of Expansion transportation in the same way it recovers the costs for transportation service on any other pipeline.

The subscription was based upon the need for up to 300 MMcf/d of new transmission capacity in northern and central California to meet growing gas demands, to offset declining California gas production, and to enhance use of PG&E's storage cycling capabilities, according to PG&E's witness Thomas.

PG&E demonstrates the need for this capacity with the 1989 California Gas Report, which indicates that PG&E will need 300 MMcf/d of supplemental supplies by 1995. PG&E's internal facilities assessment indicates a need of 200 MMcf/d year-round and an additional 100 MMcf/d during the winter. In July and August of 1989, PG&E's Fuels Policy department and PGT began to discuss the possibility of the Expansion meeting PG&E's incremental needs. During this Commission's OII hearing held in August and September of 1989, PG&E's witness testified that PG&E would need an additional firm 300 MMcf/d by 1995 in its own service area.

PG&E emphasizes that its subscription was not undertaken to revitalize the Expansion Project. At the time PG&E reserved its capacity, the 600 MMcf/d of firm capacity represented by the original project was already fully subscribed, existing shippers were requesting more capacity by seeking elimination of the "seasonality" problem, and the existing queue still represented market interest in the project, according to PG&E.

The installation of 42" pipe instead of 36" pipe for the Stanfield to Brentwood segment was the best engineering solution; no party offered testimony to the contrary, states PG&E.

PG&E maintains that it may reasonably contract to serve its non-core as well as core customers. PG&E quotes our finding in the OII decision, "New interstate and intrastate pipeline capacity will provide appropriate means to enhance the level of service for non-core customers. Core customers will also benefit from additional capacity." PG&E also relies on the Commission's direction to local distribution company's (LDC) to "exercise their own judgment to evaluate the pipeline projects and the timing and amount of additional capacity that best suit each utility situation." (D.90-02-016, p. 89.) PG&E adds that in any event, utility contracts for new capacity will remain subject to Commission approval in subsequent proceedings.

2. <u>Incremental Cost Allocation</u>

Under PG&E's proposed cost allocation methodology, all cost increases above those associated with the existing service are assigned to the Expansion and none of the embedded costs and expenses associated with existing service are allocated to the Expansion. PG&E stresses that there is no offset for benefits to existing service that the Expansion Project will provide, such as the fuel savings made possible by economies of scale. PG&E maintains that its "incremental cost allocation" corresponds directly to economic efficiency and fairness goals by matching the new service with its marginal cost while still providing existing service with substantial benefits.

PG&E believes that the Commission's pronouncement in the Pipeline OII decision (D.90-02-016), that cost responsibility for new capacity must flow to those customers who will benefit from firm service on the proposed pipeline, is a mandate for incremental cost allocation.

PG&E argues that D.90-02-016 did not require that a fee be collected to lower the cost of existing service. Since in the parallel FERC proceeding, PGT has proposed that its portion of the expansion recover only incremental costs, and the Commission has confirmed that the PGT settlement at the FERC meets the OII criteria, only incremental costs of the Expansion should be allocated to Expansion shippers, according to PG&E.

PG&E offers to support its position with the economic theory that incremental pricing is appropriate because it "exploits the available economies of scale, balances the dual regulatory objectives of efficiency and fairness, and does not create a subsidy of new service by existing service." PG&E then explains that its methodology meets the regulatory objectives of "productive and allocative efficiency, and status and distributional fairness." According to PG&E's witness Stalon, "The productive efficiency standard is met because purely incremental cost allocation closely approximates marginal costs and because it adheres to cost-causality principles. The allocative efficiency standard is met because the gas provided to end-users under these efficient transportation rates will be used as one input into the state's other economic processes, notably the generation of electricity. The status fairness criterion is satisfied because there is no increase in the rates for, or diminution in the quality of, existing service, and the distributional fairness standard is met through rates based on embedded costs."

PG&E states that the methodologies proposed by Kern River, Altamont, and DRA to allocate a portion of the "common costs" of PG&E's existing facilities and a portion of PG&E's existing A&G and O&M costs to the Expansion shippers rely on the mistaken assumption that there is an objective, measurable, and "correct" allocation of costs for facilities that produce services in common. According to PG&E's witness, justification for that allocation must come from the objectives underlying the allocation.

The concepts of opportunity costs and value of service should not be used to justify recovery of costs in excess of incremental costs, states PG&E. The economy of scale benefits of using the common facilities for both existing and Expansion service flow precisely from not having to build duplicate facilities, claims PG&E. A usage charge based in part on the cost to replace existing facilities would be based on the cost of facilities that the Expansion specifically does not need. Such rates would be based on dollars not spent in violation of the embedded cost and cost causality principles traditionally used by the Commission.

Existing PG&E customers would not "subsidize" Expansion service due to failure to charge Expansion shippers for the use of common facilities, according to PG&E's witness, Stalon, because "...a subsidy would require in some sense that existing ratepayers suffer in their diminution in the their welfare somewhere or other as a result of the new service, not that they failed to achieve an increase in their welfare." Even so, PG&E maintains that existing ratepayers would experience an increase in their welfare as a result of the Expansion, through fuel savings and other benefits.

PG&E notes that Kern River objects to its proposed full-fixed variable rate design as creating an unfair competitive advantage for PG&E over other pipelines because PG&E's rate design exposes it to less risk and gives it the advantage of lower-cost project financing. In response, PG&E observes that under the FERC Optional Expedited Procedure under which Kern River and other interstate pipeline competitors obtained their FERC certificates, a modified fixed variable rate design is mandated. Under that rate design methodology, about 60% of a project's costs are allocated to a fixed demand charge. PG&E replies that Kern River itself sought the advantage of early certification when it obtained a certificate conditioned on the use of modified fixed variable rate design. Just because Kern River chose a different market strategy than PG&E is no reason to compel the Expansion to adopt the rate design imposed on Kern River, argues PG&E.

PG&E adds that the purpose of modified fixed variable rate design is to encourage economic efficiency by providing recovery of a portion of fixed costs through a volumetric charge.

On the other hand, PG&E believes that full-fixed variable rate design is appropriate here because the Expansion Project is a transportation-only pipeline and shippers will have complete control of the project's capacity. There is no need to include an incentive for shippers to maximize throughput in the rate design. PG&E states that since capacity brokering is available, there is even more reason to adopt a full-fixed variable rate design; it will further the insulation of PG&E's existing service from any risk of Expansion Project underutilization.

PG&E points out that cross-examination of Altamont's project sponsor Amoco, which is also a Canadian producer, revealed that one reason Amoco sought to shift costs from existing service to the Expansion was to enhance Altamont's competitive price position. The other was to reduce the cost of transportation on the existing line, thus increasing the net-back price to Canadian producers such as Amoco.

3. Rate Based on Delivery to Southern California

The tariff proposed for the Expansion provides a rate for delivery to Kern River Station. PG&E explains that this choice of delivery point accommodates the original southern California utility shippers and the bulk of the Project's shippers, who seek delivery to southern California. It also corresponds to the Commission's finding in the OII that the majority of forecasted need for capacity lies in southern California.

The tariff for a single point of delivery, sometimes referred to as a "postage stamp rate," is consistent with this Commission's policies favoring uniform transportation rates, states PG&E. PG&E cites D.87-12-039, the seminal decision concerning the unbundling of utility natural gas service, which rejected geographic discrimination in rates.

PG&E argues that if a delivery point were adopted north of Kern River Station, northern California shippers could employ the Expansion rate to that point, then use the uniform transportation rate of the existing system to deliver the gas. PG&E claims that as a result, the shipper would avoid nearly all the Project costs associated with actually getting the gas to the customers, all at the expense of southern California shippers. PG&E adds that no Expansion Project shipper has opposed the tariff to Kern River Station.

4. PG&E's Use of Precedent Agreements

Since the Commission announced in D.90-02-016 that the market would decide which of several competing interstate pipeline proposals would be constructed, PG&E claims that evidence of market support for the Expansion is directly relevant to showing that the public interest would be served by the Expansion.

PG&E asserts that the full subscription of Expansion Project capacity by shippers who have executed Precedent Agreements, which contain exclusive commitments to the Expansion for the volumes identified in the executed Precedent Agreements, amply demonstrates market support for its proposal. No party has produced any evidence of any firmer form of commitment available prior to certification, argues PG&E. Thus, according to PG&E, the commitments cannot be discounted on the basis that a shipper is holding space on the Expansion Project as an alternative to some other potential source of transportation capacity.

5. Waiver of GO 96-A Authority

The waiver of GO 96-A provisions governing the format of rate schedules would enable PG&E to publish a schedule that could be read in conjunction with the PGT tariff; this would benefit Expansion Project shippers, states PG&E. The proposed waiver of mandatory language giving the Commission authority to modify the contract after initial approval only grants PG&E the same relief as previously granted for long-term transportation contracts between utilities and Enhanced Oil Recovery (EOR) producers, according to PG&E. The applicant further argues that due to the large investment in production facilities and the long term of the transportation contracts, Expansion Project shippers, like EOR customers, require greater regulatory certainty than would be available without the waiver.

6. **The Potential for Demand Side Management**

Pursuant to the ALJ's direction, PG&E included an analysis of the potential for demand side management (DSM) to meet the short-term incremental demand for natural gas identified by the Commission in the OII decision (D.90-02-016). PG&E attempted to show that all of the proposed 755 MMcf/d of capacity should be developed because DSM cannot satisfy more than the difference between the need forecasted to materialize by 1995 (900 MMcf/d) and the capacity of the Expansion project.

PG&E, along with Edison and DRA, evaluated the potential of reducing the demand for gas to fuel electrical generation. PG&E showed a potential savings of 12.1 MMcf/d per program year for PG&E, Edison, and SDG&E combined, and a reduction of 9 MMcf/d for SoCalGas by the year 1995. PG&E points out that even assuming that all of Edison's electric generation at the margin is gas fired such that all reduction in electric demand results in a corresponding decrease in natural gas demand, Edison will still have an incremental need for 351 MMcf/d of gas, an amount in excess of its 200 MMcf/d commitment to the Expansion.

PG&E criticizes DRA's estimate of DSM potential because DRA based its DSM analysis on uncommitted DSM. PG&E states that because the utilities are not committed to measures for attaining these reductions in demand, when cost-effective demand reduction measures are identified, the gas savings potential of uncommitted DSM will be reduced. Even so, PG&E applied the DRA's estimate of gas-fired generation at the margin to the uncommitted DSM figure and concluded that gas savings due to uncommitted DSM potential in 1996 is about 122 MMcf/d.

PG&E points out that none of the parties presenting forecasts of potential statewide DSM savings have indicated that DSM will eliminate the need for additional capacity.

7. <u>Gas-to-Gas Competition</u>

The Applicant asserts that out of 2,500 MMcf/d of existing total pipeline capacity into southern California, only 218 MMcf/d or 8.7% of average daily deliveries consist of Canadian gas. This gas is delivered to SoCalGas, through its affiliate PITCO, and is available only to the core and core-elect customers of SoCalGas.

The existing Alberta-to-California facilities of PGT and PG&E were first constructed in the early 1960's and later expanded to meet PG&E's system needs. A section of the PG&E/PGT route, selected in 1980 as the "Western Leg" of a planned Alaska Natural Gas Transportation System (ANGTS), was built in the early 80's to enable Canadian gas to flow onto Northwest Pipeline Corporation facilities and then to the El Paso Natural Gas Company system for delivery to SoCalGas (PITCO project).

PG&E notes that the Expansion will provide a potential 655 MMcf/d of Canadian capacity to southern California, increasing the share of Canadian gas in the region to nearly 25 percent, as well as provide firm capacity for Canadian supplies to non-core customers in southern California.

PG&E believes that the capacity represented by the Expansion is necessary to allow for suppliers from diverse geographic areas to access consumer markets and will contribute to the level of available capacity that is necessary to provide gas consumers with competitive prices and terms of service as the result of "gas-to-gas" competition. PG&E cites testimony by witnesses for Edison, DRA, Kern River, and Altamont which concur that given new access to Canadian supplies, customers in southern California can benefit from gas-to-gas competition. In particular, Edison's intention to only partially satisfy its needs with Expansion Project capacity will place competitive pressure on southwest suppliers of gas, according to PG&E.

PG&E claims that the incremental nature of the investment in the Expansion facilities, the accounting practices, and implementation of separate rate cases will protect PG&E's existing ratepayers from any risk due to underutilization of the Expansion. In addition, core ratepayers will be protected by the full subscription to firm service and a fixed variable rate structure that fully recovers the intrastate costs of the Expansion from firm capacity holders.

8. Alternative Pipeline Proposals

PG&E compares the cost and pro forma rates of the Expansion with those of the Altamont Project and concludes that the Expansion is less costly. PG&E points out that Altamont cannot be built without the Kern River Project and their combined cost exceeds that of the Expansion Project.

PG&E also touts its experience in operating its existing pipeline over the existing route and its submission to Commission jurisdiction. In contrast, the Altamont/Kern River combination poses a threat of bypass and injury to ratepayers because it would utilize newly constructed distribution facilities to bypass existing LDC service.

As PG&E sees it, the Expansion offers competition that no other pipeline proposal can provide. According to the Applicant, the existing pipeline cannot offer significant competition to either Altamont or Kern River because it has no excess capacity. PG&E argues that if Kern River succeeds, the Expansion will provide the only real Canadian competition because the Altamont/WyCal arrangement prevents Altamont from cutting into Kern River's market.

B. <u>Southern California Edison Company</u>

Edison generates electricity with fossil-fueled plants and is one of the largest natural gas consumers in California. It is unable to obtain firm gas supply service due to the interruptible nature of gas transportation service. As a result, it has experienced significant curtailments of natural gas service. It was curtailed in 11 out of 16 months running from February 1989 to June 1990 at an estimated direct cost to Edison's ratepayers of $42 million.

On April 20, 1989, Edison executed a Precedent Agreement with PGT and PG&E for 200 MMcf/d of Expansion Project capacity. Edison currently obtains its gas from the southwestern production regions via El Paso and Transwestern pipelines. Edison claims that the access to alternative sources of gas from Canada available through the Expansion Project would contribute to supply diversity, reliability of supply, and lead to gas-to-gas competition.

The utility states that it was persuaded by the strong marketing interest shown by Canadian gas suppliers to make an exclusive commitment to 200 MMcf/d on the Expansion. Canadian suppliers have generally indicated a willingness to compete against Edison's weighted average cost of gas, whereas suppliers from other regions have not done so, according to Edison.

Edison states that it can fulfill its commitment to accept 200 MMcf/d from the Expansion Project because its oil and gas average requirements have not fallen below an equivalent of 300 MMcf/d over the past decade. In addition, Edison's average annual gas requirements are forecasted to increase from 435 MMcf/d in 1995 to 616 MMcf/d in 2000.

Edison has an option to participate in the Expansion as an equity owner of up to 20% of the Expansion. Edison reminds the Commission that it encouraged utility equity participation in new pipeline projects in the Pipeline OII decision. If it exercises its equity option, Edison intends to hold its investment as regulated utility-related property, since Edison plans to transport gas over the Expansion solely for the benefit of the its ratepayers. Edison believes that the Commission should endorse such an arrangement.

Since the Expansion is designed primarily to serve southern California, Edison is concerned that SoCalGas' intrastate facilities should be available to provide a matching level of service to Expansion shippers. Edison observes that SoCalGas supports the Western Gas Network instead of the Expansion Project, and fears that SoCalGas may influence the market's selection of new interstate pipelines by imposing discriminatory terms and conditions on Expansion shippers.

Edison states that it has been assured by SoCalGas that SoCalGas' system can deliver Edison's gas from Kern River Station to Edison's delivery points without any significant modifications. Edison intends to seek Commission approval of a long-term contract with SoCalGas for firm intrastate service in conjunction with Expansion deliveries. However, its contract with SoCalGas, like the contracts which SoCalGas will enter into with other Expansion Shippers, are negotiated contracts.

According to Edison, SoCalGas' testimony suggests that it may be able to impact the market's selection of the Expansion by (1) high estimates of the costs for new intrastate facilities associated with the Expansion, and (2) hindering the completion of intrastate transportation arrangements with shippers. These concerns were prompted by SoCalGas' testimony that it might have to install additional facilities if Kern River begins deliveries before the Expansion Project does so.

Edison objects to SoCalGas' request to place conditions on the Expansion and institute a separate proceeding relative to modifications on SoCalGas' system which SoCalGas claims may be necessary. Edison argues that since SoCalGas had not proposed such conditions on the permits for the Western Gas Network and the process could delay construction of the Expansion, these conditions should not be adopted.

C. San Diego Gas & Electric Company

On April 24, 1989, SDG&E, PG&E, and PGT executed a Precedent Agreement which will provide SDG&E with 100 MMcf/d of firm transportation from the Expansion and a limited option for equity participation in the Project. SDG&E claims that the Expansion represents the best way for SDG&E to obtain natural gas to service its customer growth. SDG&E explains that its long-term gas supply strategy relies on diversity of suppliers in new and traditional gas supply regions as well as flexibility to negotiate a mix of short- and long-term contracts. This strategy requires firm transportation. SDG&E has already executed a contract with SoCalGas, which has been approved by the Commission, enabling SDG&E to take firm delivery of gas delivered to SoCalGas at Kern River in quantities sufficient to accommodate SDG&E's participation in the Expansion.

SDG&E seeks additional transmission capacity, such that the transportation costs, plus the commodity cost of gas obtainable thereby, will compete with the volumetric costs of gas delivered from existing production areas supplying SDG&E. SDG&E was led to support the Expansion because when, in March of 1989, SDG&E solicited offers from over 30 U.S. and Canadian suppliers for long-term firm gas supply, responses were received from a number of Canadian suppliers, but only from one U.S. supplier. SDG&E concluded that Canadian suppliers will sell gas to SDG&E long term on conditions competitive on a delivered basis with existing and future southwest U.S. suppliers.

SDG&E reports that it has since obtained contractual commitments for long-term sale of gas from Canadian suppliers which incorporate "net-back" pricing, a pricing arrangement where the costs of transportation are netted out of the export price so the gas may compete on a delivered basis. SDG&E states that total delivered costs of gas via the Project in the future will not exceed today's costs because the price paid to suppliers will net-back the cost of the new pipeline capacity. SDG&E expects to have reached Definitive Agreements with producers during the third quarter of 1990; the agreements are needed to support SDG&E's application with the Canadian National Energy Board for export authorization and Provincial removal permits.

SDG&E also responds to our OII requirement that the availability and reliability of incremental Canadian supplies in the near term and over the 30-year period be shown in this CPCN proceeding. SDG&E's witness testified that the Canadian Western Sedimentary Basin has a resource base of natural gas which is larger than any other gas producing basin serving California. Its proved reserves give it a reserves-life index of 22, more than double the reserves-life index of ten in the United States. Estimates of potential gas resources of Canada have an expected value of 408 trillion cubic feet. This represents 127 years of gas supplies, in addition to the 22 years of proved reserves, according to SDG&E's witness Kenney. About 78% of Canadian's potential gas resources can be recovered at a wellhead price of $3,000/Mcf, based on an average of the estimates from the California Energy Commission and the Canadian Energy Research Institute. Accordingly, SDG&E is confident that there will be ample supplies of natural gas at competitive prices available from Canada in the long term.

SDG&E believes that the issue of supply diversity must be clarified; the state as a whole already is served with natural gas from the southwest and from Canada, but southern California is essentially served only by southwestern gas. Since the Expansion and its competitors are being proposed to serve southern California, SDG&E argues that the fact that Canadian gas is presently delivered to northern California is irrelevant to the issue of supply diversity. According to SDG&E, the Expansion will enhance supply diversity by providing firm transportation for Canadian gas to southern California, states SDG&E.

By contracting for gas priced below the average southwest gas market price, including the cost of delivery from Canada, SDG&E claims that it will directly realize the benefits of gas-on-gas competition for its customers and will lock this benefit in for future years.

D. <u>Kern River Gas Transmission Company</u>

Kern River argues that the Commission should not certificate PG&E's proposed expansion without imposing conditions that are necessary to ensure that market participants in the natural gas are aware of the real cost of PG&E's project. According to Kern River, only then can the market make a fully informed judgment of the Expansion Project's merit relative to other competing proposals.

1. <u>Kern River and the Western Gas Network</u>

In January of 1990, Kern River obtained a FERC certificate to construct and operate a new 36" diameter natural gas pipeline that will extend 676 miles from an interconnection with Northwest Pipeline corporation at Opal, Wyoming to Daggett, California. Kern River's pipeline will have an initial transportation capacity of 700 MMcf/d. It will provide access to Rocky Mountain gas reserves as well as access through interconnected pipelines to Canadian and San Juan gas. Kern River anticipates commencing construction in late 1990, with gas transportation service beginning in early 1992.

Kern River's pipeline will interconnect with the Mojave Pipeline at Dagett, California. From Daggett, Kern River and Mojave will operate a joint pipeline running 225.2 miles west to Kern County.[3] These common facilities will extend from Daggett to various enhanced oil recovery customers in Kern County. Kern River has agreed to transport an additional 500 MMcf/d of Canadian gas for the Altamont project. Kern River would accommodate these additional volumes by adding compression to its system. This interconnected system is called the Western Gas Network by its participants.

2. <u>Increase in Pipeline Capacity and PG&E's Subscription</u>

Kern River claims that PG&E's subscription to expansion capacity is unneeded and was made only to enhance the project's competitiveness. Kern River urges the Commission to review and reject PG&E's participation in the Expansion Project now, because subsequent review would provide no remedy for the anticompetitive effects of that subscription. Kern River argues that since PG&E has proposed the Expansion Project to serve a market beyond the bounds of its service territory, the Expansion Project is an entrepreneurial undertaking. As such, its costs should not be reduced through a subscription for capacity that will not serve the recognized needs of its core market.

Kern River maintains that PG&E has no basis for subscribing to any capacity on the Expansion, other than to reduce its transportation rates so that the Expansion could better compete. Assertions of a need to meet core demand are unsupported.

3 Mojave is a 385-mile pipeline extending from Topock, Arizona to Bakersfield, California. Mojave will receive San Juan and Permian Basin gas from El Paso and Transwestern Pipeline Company and will serve EOR producers and cogenerators. It is a transportation-only, open-access pipeline offering firm and interruptible service. In January, 1990, Mojave received its optional expedited certificate from the FERC, which it has accepted.

by the trends shown in the California Gas Report (CGR), claims Kern River.

Kern River claims that the numbers on the record demonstrate that PG&E's existing system capabilities, either nominal or peak, are sufficient to meet PG&E's forecasted core requirements on a "cold year peak day" from today through the year 2005; while the 1989 CGR forecasts PG&E's core requirements during an abnormal peak day in 2005 at 3,835 MMcf/d, PG&E's existing facilities have a peak capability of 4,360 MMcf/d.

Kern River notes that the total core demands for the second half of the 1990s and beyond under average temperature and cold temperature conditions are lower in the 1989 CGR than in the 1988 CGR, yet PG&E did not propose its 100 MMcf/d allocation until the later, lower forecast of demand was published.

Kern River acknowledges that PG&E's rebuttal witness stated that its 100 MMcf/d of expansion capacity is needed to meet PG&E's total system requirements, and that D.90-02-016 creates uncertainty about the scope of PG&E's utility service obligation. However, Kern River points out, a decision issued in February of 1990 cannot logically be used to justify PG&E's subscription to the Expansion which occurred in September, 1989.

Kern River argues that D.90-02-016 provides no policy support for PG&E's subscription since the Commission there stated that LDC subscriptions to additional capacity must be based on reasonable projections of core needs, and that the "best efforts services" the LDCs may continue to provide non-core customers does not justify subscription to additional firm capacity by the LDCs.

There was no legitimate reason to increase the Expansion Project's capacity from 600 to 755 MMcf/d, either, asserts Kern River; in its April 1989 application, PG&E asserted from an engineering standpoint that its 600 MMcf/d design using 36-inch pipe provides a reasonable basis from which the project volumes can be either incrementally increased or decreased, by adding compression or reducing pipeline looping should the market conditions dictate some other volume.

The "seasonality problem" provides no justification for PG&E's subscription, according to Kern River. PG&E's witness testified that the seasonal swing of the Expansion's original design was a plus or minus 38 MMcf/d from the daily design volume of 600 MMcf. Kern River suggests that PG&E could have remedied its inability to provide year-round firm service by reducing its commitments to shippers by 38 MMcf/d to match the summertime capability of the pipeline of 562 MMcf/d. Kern River points out that five shippers with a total contract capacity of 135 MMcf/d dropped out of the project, providing a simple solution to the seasonality problem. Kern River further suggests that PG&E could have installed additional compression on the system; PG&E's own studies show that the unit cost of service of the 36" design is lower than the cost of service of the 42" design at a daily volume of 600 MMcf/d. In addition, Kern River alleges that excess capacity on PG&E's existing system could have been used to make deliveries to expansion shippers of their full contract volumes on summer days.

Kern River claims that in addition to making the Expansion appear more competitive, PG&E's subscription to 100 MMcf/d of capacity represents a subsidy to the Expansion and to southern California non-core customers. PG&E's core customers would be responsible for nearly the entire cost of the incremental expansion from 600 MMcf/d to 755 MMcf/d. Because the increase in pipeline capacity would enable PG&E to provide 60 MMcf/d of interruptible transportation, and a portion of the revenue requirement has already been allocated to interruptible rates, the proposed rates to southern California non-core customers are reduced by the revenues anticipated to be generated by the amended Expansion's interruptible transportation, asserts Kern River.

Kern River cites evidence to show that the Expansion Project is a business venture for PG&E; just as Kern River, Mojave, and SoCalGas reached a settlement pursuant to which the Kern River and Mojave projects would be built, a memo prepared for the new executive vice president of PG&E and chairman of PGT suggested that a tactical option to improve project viability was for PG&E to contract for up to 300 MMcf/d of firm capacity on the Expansion. Kern River notes that PG&E did not market to the queue of prospective shippers established in the open season the additional capacity that the use of 42" pipe made available. Kern River asserts that all these facts lead to the conclusion that PG&E's subscription was undertaken to subsidize the Expansion's rate to southern California at the expense of PG&E's captive ratepayers to increase the probability that PG&E would defeat its competitors. Kern River argues that PG&E should be ordered to cancel its Precedent Agreement for Expansion service and be directed to use a 36" pipe in its expansion.

3. Other Factors Affecting Cost of Service

Kern River also charges that future ratepayers are being made to subsidize the Expansion because PG&E is proposing the use of an unreasonably long depreciation period. PG&E's rates are based on a useful life of 30 years. The average term of the Precedent Agreements, 23.5 years, should be deemed the economic life of the project and be used to calculate rates, states Kern River.

Kern River objects to PG&E's single delivery point in southern California. Although 182 MMcf/d of Expansion gas is destined for northern California, shippers of this gas must pay for the shipment of gas to Bakersfield. Kern River observes that PG&E's witness testified that PG&E's purpose for tariffing Expansion Project service on a "postage-stamp basis to Kern River Station" is to ensure that delivery to the principal market--southern California--would remain economic. This simply means that

PG&E is seeking to make its project competitive for service to southern California by compelling northern California users of the Expansion Project to subsidize the rate for the favored customers in the south, claims Kern River. PG&E should not be allowed to compete for the southern California market at less than its full cost of serving that market, argues Kern River, because the competitive forces on which the Commission seeks to rely cannot make sound choices if they are not given accurate information.

Kern River's witness stated that because of PG&E's market dominance in northern California and its affiliate relationship with the Expansion's upstream pipelines, Expansion shippers may not have a choice of the most efficient solution to California's capacity needs. Kern River proposes that PG&E be compelled to allow shippers to take delivery at other points on the Expansion and rates should be mileage based, and that PG&E should renegotiate or cancel its Precedent Agreements accordingly.

4. <u>Incremental Cost Allocation</u>

Kern River claims that PG&E would require existing ratepayers to bear costs, assume risks, and provide subsidies in excess of any benefits they might receive from the Expansion. Kern River states that PG&E's proposal to use an incremental method of cost allocation addresses only the Commission's cost allocation criterion for new facilities; it ignores the fact that the Expansion would be fully integrated with PG&E's existing system. Kern River believes that the Expansion should include costs for the use of PG&E's existing gas transportation system for its gas department infrastructure consistent with the preference expressed by PG&E and the CPUC for an "incremental plus pro rata" allocation of existing facilities approach in the FERC certificate proceeding for PGT's PITCO facilities (described above).

Kern River argues that payment for the use of PG&E's existing pipeline facilities and existing gas department infrastructure is reasonable, because the project would greatly benefit from PG&E's existing gas department infrastructure and should be responsible for a share of those costs. Kern River proposed the following methods of cost recovery: a portion of the depreciated cost of the existing facilities that are used by the Expansion shippers should be assigned to the project, based on the levels of throughput by existing customers and expansion shippers; or, existing tariff rates could be charged; for deliveries to SoCalGas, the Schedule G-INT rate of $0.196 per MMBtu would be added to the incremental cost of service of the Expansion. For deliveries to customers within PG&E's service area, the then current schedule G-IND rate would be added to the incremental costs of the Expansion. Since PG&E has tariffed all Expansion Project deliveries to Kern River Station, additional charges would be applicable to deliver the gas from Kern River Station to the end user.

Kern River's witness suggested a third approach, replacement cost less depreciation. Kern River notes that the DRA would calculate the cost of the existing facilities used by the Expansion by adding the depreciated book value of the existing facilities to their replacement value and dividing the total by two. However, DRA should have applied its methodology to more of PG&E's existing facilities than it has, according to Kern River.

Kern River objects to PG&E's proposal to use an incremental method of determining O&M and A&G costs for the Expansion. Kern River contrasts the average annual transmission-related O&M costs of $105 million per year over the period 1985-1989 with PG&E's estimate that the incremental O&M cost of the Expansion Project of $1.2 million. Kern River indicates that PG&E's A&G costs have averaged $172 million, but PG&E's estimate of A&G costs for the Expansion is only $400,000. Kern River argues that it is appropriate to allocate a portion of existing O&M and A&G costs to the Expansion for the reasons given for charging Expansion shippers for the use of existing capital facilities.

Kern River proposes to use the same allocation procedure used in rate cases when costs must be allocated between classes of customers.

The testimony of PG&E's rebuttal witness Stalon giving reasons why the Expansion Project should not pay for the use of the existing system is not convincing, states Kern River, since his testimony is a theoretical discussion of economies of scale, efficiency, and fairness. No effort was made to apply those concepts to the facts, i.e., PG&E's competitive position and the risks and costs assumed by existing ratepayers, according to Kern River.

5. Benefits vs. Burdens

Kern River argues that the claimed fuel cost savings of approximately $13 million per year to existing customers ($9.7 million on PGT and $3.3 million on PG&E) must be considered in perspective of the overall project costs. The reservation charges associated with PG&E's subscription to capacity on the project would more than offset the fuel savings.

The operational benefits of the Expansion Project to existing customers are overstated, according to Kern River. It alleges that while a looped pipeline system may provide some increased reliability, PG&E has diluted the benefit by requiring its existing customers to support deliveries to expansion shippers without imposing any reciprocal obligation on the part of expansion shippers to support existing customers.

Kern River claims that the provisions in the pro forma tariff which provide for pro rata curtailment of Expansion and existing facilities in the event capacity is impaired, require existing customers to provide the equivalent of free stand-by service. The balancing provisions, which automatically carry imbalances forward to the following month, are so liberal that existing customers could be called upon to provide free storage service for Expansion shippers, according to Kern River.

Kern River claims that since deliveries of Canadian gas to southern California would be accomplished by displacement from PG&E's El Paso supplies, if deliveries from either supply area or either pipeline were interrupted, deliveries at Kern River Station could also be interrupted.

Kern River argues that even the equity option agreements between Edison, SDG&E, and PG&E impose costs on existing ratepayers, as they require PG&E to "take whatever actions are necessary to ensure that existing property and facilities, or their functional replacements, are made available to the Expansion Project for the operational life of the Expansion Project and any expansions thereof." Kern River characterizes the agreements as obligating existing ratepayers to bear alone the costs of maintaining and replacing a 40-year old pipeline (PG&E Line 300) even though those facilities also will benefit Expansion Project shippers.

Existing ratepayers are not compensated for opportunity costs they are forced to incur by the project according to Kern River; an opportunity cost is incurred when one provides a service for less than its value. Since PG&E has promised to allow Expansion Project shippers to use the existing facilities at a very high level of reliability for the next 20-30 years at no charge, existing customers would be unable to curb the use of those facilities and existing ratepayers would be faced with an "opportunity cost" for which they are not compensated. Moreover, Kern River asserts that PG&E has surrendered the rights to the economical expansibility of the pipeline by allowing Edison and SDG&E to expand the project to meet their own specific capacity needs.

Kern River's witness observed that one of the impacts of the Expansion Project would be to enhance competition between northern and southern California for Canadian gas supplies. Kern

River speculates that the cost of Canadian gas in PG&E's service territory could increase as a result of the Expansion Project.

Kern River warns that the Expansion would not effectively promote gas-to-gas or pipeline-to-pipeline competition due to its full-fixed variable rate design. Because the shipper must pay the monthly reservation charge regardless of whether any deliveries are taken, the cost of Expansion Project transportation must be added to the price of gas from other sources to calculate the price of non-Expansion gas, and end user might forego the purchase of southwest gas even if it is cheaper than Canadian gas; theorizes Kern River; the full-fixed variable rate design thus impedes gas-to-gas competition. Moreover, because the one-part rate design grants PG&E its full cost of service whether it ships 755 MMcf/d or zero MMcf/d, it has no incentive to cut rates in an effort to keep its pipeline full, argues Kern River.

According to Kern River, the average of 60 MMcf/d of interruptible capacity is unlikely to accrue to the benefit of PG&E's existing customers, as it already has been factored into the pro forma rates for the Expansion Project; as PG&E's witness Blatter testified, any transportation in excess of 60 MMcf/d would benefit PG&E's shareholders and not existing ratepayers.

The Expansion Project would expose PG&E's customers to the risk of rolled in-ratemaking on both the Alberta Natural Gas Company/Foothills Pipelines system and on PGT, according to Kern River; rolled in pricing would reduce the cost of transportation for gas shipped on the expansion project by $0.08 per Mcf and would increase the cost on the existing system. Kern River points out that PGT's settlement at the FERC requires PGT to submit a general rate case to the FERC no later than 14 months after the in-service date and to refrain from opposing the use of rolled in cost allocation principles and from supporting any specific alternative cost allocation principles. This settlement substantially increased the risk to existing customers of higher rates, according to Kern River, in order to further PG&E and PGT's own entrepreneurial interests.

PG&E has refused to guarantee that it would not flow through costs of the expansion to existing customers. This is significant, alleges Kern River, because the Expansion has not been structured in such a fashion that shippers' payments would be made in all events or would be guaranteed by credit-worthy companies. Kern River points out that utility shippers may be constrained by regulatory decisions and cannot execute all events contracts, the non-utility shippers' obligation to provide a corporate guarantee equal to the first year reservation charge arises only at the in-service date of the project, many of the non-utility shippers themselves are special-purpose subsidiaries with limited assets, and any potential protection that the Commission could provide would be waived if PG&E's request to waive GO 96-A is granted.

Kern River states that it does not oppose the issuance of a CPCN if it is appropriately conditioned. Kern River requests that the Commission adopt these conditions if it issues a CPCN to PG&E for its portion of the Expansion:

1. that PG&E cancel its Precedent Agreement for the purchase of 100 MMcf/d of firm transportation on the Expansion;

2. that PG&E construct its segment using 36-inch pipeline looping to deliver 655 MMcf/d to Expansion shippers on a year-round basis unless PG&E reapplies to amend its certificate to show it has contractual commitments from non-affiliated entities for firm transportation in excess of 655 MMcf/d;

3. that PG&E allow Expansion shippers to take delivery of gas at points on the Expansion other than Kern River station, file information regarding the cost of transporting various volumes of gas to those northerly points, and allow any shipper to renegotiate or cancel its

Precedent Agreement in light of this new information;

4. that PG&E recalculate its rate for deliveries to Kern River Station utilizing a 23.5 year depreciation life; that the rate for firm transportation on the Expansion be a two-part rate based on the modified fixed variable rate design used by FERC;

5. that in addition to the charge for new expansion facilities, the revenue requirement for the Expansion shall include an appropriate fee for the use of certain facilities on the existing system plus the O&M and A&G expenses of the existing PG&E system, which shall be allocated between the existing system and Expansion on the same basis as is used by the Commission for the allocation of those costs among classes of PG&E's customers; and

6. that PG&E file a written statement agreeing that it will not seek to impose any of the costs of the Expansion on any of its existing ratepayers at any time during the approved life of the Expansion.

E. Altamont Gas Transmission Company

Altamont Gas Transmission Company (Altamont) opposes the Application. Altamont is a joint venture whose participants include affiliates of Tenneco Gas, Amoco Canada Petroleum Company, Ltd., Petro-Canada, Inc., and Montana Power Company. It proposes to construct a 620-mile pipeline from the U.S.-Canadian border to Opal, Wyoming for the firm transportation of Canadian natural gas. The Altamont pipeline will interconnect with Kern River at Opal, Wyoming.

From Opal, Wyoming, Altamont's shipments will be transported over the facilities of Kern River and the Mojave Pipeline to their ultimate destination, southern California. Kern River plans to expand its capacity to transport an additional 500 MMcf/d of Canadian gas for Altamont. The expansion will involve one compressor station on a then-existing pipeline near Daggett in California.

The Altamont pipeline is designed to have an initial capacity of 719 MMcf/d. It expects to begin service in late 1993. Altamont has filed an application for a CPCN under Section 7(c) of the Natural Gas Act, as well as an application for an Optional Expedited certificate and a Blanket Certificate from the FERC.

Altamont states that if the Kern River, Mojave, and SoCalGas/El Paso projects are all in service, it will be difficult for both Altamont and the Expansion to market all of their combined 1.25 Bcf/d of net additional capacity; if the Expansion is built, it is less likely that the Altamont project will be built; if the Expansion is certificated and constructed and the Altamont pipeline is not, southern and northern California gas markets will be deprived of pipeline-to-pipeline competition. California would lose the benefit of reduction in the cost of transporting Rocky Mountain gas that the combination of the Altamont and Kern River pipelines provide, according to Altamont.

Altamont argues that PG&E's Expansion Project fails to meet two of the fundamental criteria adopted by the Commission for determining whether a proposed transportation project will serve the public interest; first, the Expansion Project is not economically justifiable either as a means to achieve gas cost reductions through gas on gas competition, or on the basis of competitive transmission costs, because the Expansion is structured to unreasonably restrain or prevent other gas supplies from competing with PG&E for sales to customers in PG&E's service territory; second, the Expansion Project does not place cost responsibility for new capacity on those customers who will benefit from firm service on its pipeline, nor does it insulate core customers from the risk that they will bear part of the burden of cost recovery for the Expansion facilities.

Altamont makes many of the arguments that Kern River raises against the Application. Where those issues have been fully discussed above, the discussion will not be repeated here. The following is limited to a further explanation of the issues from Altamont's perspective as a direct competitor of the Expansion Project.

1. <u>The Precedent Agreements</u>

Altamont asserts that if the Expansion Project is built, and Altamont is not, there will be less pipeline-to-pipeline competition to transport California's gas loads. Altamont claims that the terms PG&E offered to potential shippers were aimed at precluding other pipeline projects from competing with the Expansion Project to provide transportation for Canadian gas to southern California, while at the same time precluding shippers on the Expansion Project from competing effectively with PG&E for sales in PG&E's service territory. As an example of this anticompetitive dealing, Altamont cites the allocation of capacity based on how great a percentage of the total transportation rate the shipper was willing to pay as a reservation charge. According to Altamont, a shipper would be compelled to concentrate its efforts on keeping the capacity full, and will have no incentive to use other pipeline facilities that may be priced lower. Other anticompetitive terms include the exclusive dealing terms of the precedent agreement; and the one-point delivery to Kern River station outside of PG&E's service territory.

Altamont asserts, "PG&E's exclusive Precedent Agreements are exclusive dealing arrangements within the purview of the Cartwright Act, Cal. Bus. & Prof. Code Sec. 16727, which prohibits the use of such arrangements by firms with market power, where their effect is to 'substantially lessen competition...' These agreements are likewise contrary to the federal anti-trust laws, particularly Sec. 3 of the Clayton Act, 15 U.S.C. Sec. 14 (1973) and Sections 1 and 2 of the Sherman Act, 15 U.S.C. Secs. 1 and 2."

(Citations omitted). It is clear, says Altamont, that PG&E used its existing market power over the transportation of Canadian gas to cause shippers to execute "exclusive dealing contracts" to "lock up a substantial part of the market for transportation of Canadian gas to southern California, and thereby eliminate competition from other providers of this service, such as Altamont."

Altamont claims that since the Expansion provides no direct transportation capacity to markets inside PG&E's service territory, potential supplier-competitors of PG&E cannot use Expansion Project capacity to sell directly to non-core gas customers in competition with PG&E.

2. PG&E's Subscription to 100 MMcf/d of Capacity

Like Kern River, Altamont objects to PG&E's subscription of 100 MMcf/d on the Expansion Project, but Altamont adds that the subscription is part of PG&E's plan to maintain its northern California transportation monopoly and to protect its sales markets from competition, which will result in PG&E needing amounts greater than it would require in a truly competitive environment.

Altamont points out that PG&E's decision to increase the Expansion Project capacity from 600 MMcf/d to 755 MMcf/d reduced rates on the Expansion Project by $.11 per Mcf. Altamont believes the project's resizing, only four months after PG&E filed its application with the Commission, was a response to competitive pressure from Altamont. Altamont believes that PG&E's subscription was likewise in response to Altamont's pressure, since PG&E did not execute a Precedent Agreement until August 30, 1989, one month after Altamont filed its application with the FERC.

Altamont states that the reservation charge that PG&E will pay for its 100 MMcf/d of Expansion Project capacity will simply be rolled into the other demand charges that PG&E pays and be included in the intrastate transportation rates that PG&E charges for service on its existing system. Competitors who must pay PG&E's intrastate rates would ultimately pay part of PG&E's Expansion reservation charges, thus subsidizing PG&E's competitive position for gas sales, according to Altamont.

3. Cost Allocation and Rate Design

Altamont characterizes as anticompetitive PG&E's cost allocation and rate design because they allegedly result in subsidization of the Expansion Project by existing system customers. Altamont observes that the incremental cost allocation methodology is likewise used for the PGT portion of the Expansion Project. Since PG&E's existing system ratepayers pay all of PGT's cost of service, they will subsidize the rates paid by Expansion Project shippers all the way from Canada to Kern River Station, claims Altamont.

According to Altamont, PG&E has leveraged its utility status and utility-based financial strength to advantage over independently competitive projects, since PG&E's 30-year depreciation schedule will result in lower unit transportation costs than the rates charged by its competitors, such as Altamont, who will be required by lenders and by the FERC to use depreciation schedules shorter than 30 years.

PG&E's pro forma tariff, which provides delivery to Kern River station at a single rate, provides a double anticompetitive benefit to PG&E, claims Altamont; it reduces the Expansion's rates in competition with Altamont and protects PG&E from loss of market share in its service territory.

Altamont claims that PG&E was able to use its dominant market position to require transportation of gas through the Expansion Project in at least one case; the letters of intent between PG&E's gas aggregate affiliate, the Alberta & Southern Company, Ltd. (A&S) and Edison required gas sold by A&S to Edison to be transported over the Expansion.

Altamont states that it is a viable alternative to the Expansion that meets all of the Commission's OII decision criteria that will further, not exclude, pipeline-to-pipeline competition.

Altamont recommends that if a certificate is issued to PG&E for the Expansion Project, the certificate should be conditioned to require PG&E to do the following:

1. to adopt rates, rate design, and terms and conditions of service determined by the Commission prior to issuance of the certificate;

2. to provide reductions in or credits to the cost of service for customers of PG&E's existing system, commensurate with fair and equitable allocation of capital, O&M, and A&G costs between the existing system and the Expansion;

3. to guarantee that existing system customers will bear no costs associated with the Expansion's construction and operation; to release Expansion shippers from the exclusive dealing provisions of their Precedent Agreements with PG&E and PGT;

4. to provide Expansion transportation service to delivery points within PG&E's service territory at mileage-based rates; and

5. to conduct an "open season" to fairly allocate the Expansion's capacity.

F. <u>Amoco Canada Petroleum Company, Ltd.</u>

Amoco Canada Petroleum Company, Ltd. (Amoco) is a producer of natural gas in Canada. It sells some of its production to both A&S and Pan Alberta Gas, Ltd., which are gas aggregators that sell their gas to PG&E and SoCalGas, respectively. Amoco seeks access to the southern California natural gas market, but, as a member of the Altamont joint venture, it supports the Altamont proposal. Amoco opposes the Expansion Project because the Expansion would allegedly exclude the construction of an independent pipeline from Canada to California markets, make

California a less attractive market to suppliers, adversely affect the interests of the customers on PG&E's existing system, and deny southern California gas consumers the benefits of pipeline-to-pipeline competition. Amoco recommends that if a CPCN is issued for the Expansion, it should be subject to the same conditions proposed by Altamont in its brief.

As a participant in the Altamont proposal, many of Amoco's arguments against the Expansion are identical to those of Altamont. Only those arguments which were not raised by Altamont or which materially differ from Altamont's will be summarized here.

1. <u>The Expansion Fails to Promote Competition</u>

Amoco asserts that PG&E and PGT hold market power over the transportation of Canadian gas to California because they operate the only pipeline system that transports gas directly from Western Canada into California. This gas is purchased in Canada by A&S, which sells all of that gas to PG&E. Natural gas supplies purchased by A&S for ultimate sale to PG&E account for 81 percent of all of the Canadian gas consumed in California. PGT also transports the remaining 19 percent of Canadian gas consumed in California from Canada to Stanfield, Oregon, from where it is transported by another pipeline for delivery to SoCalGas.

Amoco notes that the Kern River, Mojave, and SoCalGas Southern System Expansion projects will collectively install 1.3 billion cubic feet per day (Bcf/d) of new gas transmission capacity to California markets before the Expansion Project and Altamont Pipeline are scheduled for operation. While the Expansion has Precedent Agreements with shippers for all of its capacity and Altamont has Precedent Agreements with shippers for 532 MMcf/d of its capacity plus letters evidencing interest in the remaining 168 MMcf/d of its capacity, Amoco believes that these commitments do not necessarily demonstrate that there is a market for the combined capacity of both projects in 1993. While southern California is a strong market, it will not support both the Expansion and the

Altamont pipeline; if the Expansion is built, the southern California market will lose the benefits of pipeline-to-pipeline competition from Canada to California, according to Amoco.

2. **Altamont as an Alternative**

Amoco cites the Commission's duties under § 1001 of the PU Code and proffers the Altamont Pipeline as a viable, competitive alternative to the Expansion Project. According to Amoco, the interconnection of Altamont's pipeline and the Kern River pipeline and the resulting increase in Kern River's capacity, will allegedly benefit California gas markets by lowering the transportation cost of Rocky Mountain gas to southern California by $0.17/Mcf. Amoco adds that because of conditions placed on their FERC certificates, Altamont and Kern River will be unable to reduce their volumetric levels of transportation service upon which their rates are determined, and will have an additional incentive to operate their pipelines at full capacity.

Amoco maintains that gas consumers have benefited from increasing competition among gas suppliers as transportation capacity has become available on existing pipelines and local distribution company systems. According to Amoco, most Canadian gas producers sell their gas on a "net-back" basis, whereupon all else being equal, producers will favor markets where their netback is highest as a result of either relatively higher market value for gas, relatively low transportation costs, or a combination of both. Thus, Amoco argues that if the Altamont pipeline is constructed and lowers Kern River's transportation costs by $0.17, the southern California market would become more attractive to Canadian producers.

If the Expansion's rates are established in the manner proposed by Altamont such that the cost of existing facilities are allocated to the Expansion, using costs escalated to the date of operation, and incorporating the cost of environmental mitigation, Amoco asserts that the cost of transporting Canadian gas to

California through the Altamont/Kern River pipelines will be lower than the cost of transportation on the Expansion. Amoco concludes that the Commission should not issue a CPCN for the Expansion Project until it has determined the just and reasonable rates, terms, and conditions of service which it will approve for implementation by the Expansion.

G. <u>El Paso Natural Gas Co.</u>

El Paso Natural Gas Co. (El Paso) is a pipeline supplier of natural gas produced in the southwestern United States. According to the Fuels Branch of the DRA, El Paso in 1989 supplied approximately 51.4% of the natural gas consumed in the state or about 2,685 MMcf/d average throughput. About 61% of those deliveries are made to SoCalGas. The other 39% is made to PG&E.

1. <u>Unidentified Capacity May Produce Additional Revenues</u>

El Paso questions the design capacity of the Expansion. El Paso notes that to the extent that PG&E can sell firm capacity in excess of the 755 MMcf "daily design," PG&E will realize revenues in excess of costs; PG&E will retain all revenues attributable to interruptible service, including revenues in excess of the $7.4 million in costs which it allocated to interruptible transportation. Thus, argues El Paso, PG&E has an incentive to understate the actual daily capacity which will result from its Expansion. Because the facility design assumes a "summer" ambient temperature of 90 degrees when capacity is limited to 755 MMcf/d, El Paso speculates that the Expansion Project may have capacity in excess of 755 MMcf/d during non-winter months when the temperature is less than 90 degrees.[4]

2. <u>The Expansion's Rates Cannot be Determined</u>

The annual cost of service and proposed rates for service are derived from a capital cost based on 1988 dollars. El Paso argues that the capital cost estimate upon completion of the Expansion in 1994 is the more reasonable basis for proposed rates. While PG&E has proposed to set forth its costs actually incurred in a general rate case application to be filed six months prior to commencement of service, El Paso points out that this filing would be made long after the Precedent Agreement shippers have become bound to PG&E by executed transportation contracts. El Paso argues that the Commission should not approve a CPCN until PG&E proposes rates which are based on a reasonably accurate capital cost estimate.

El Paso criticizes PG&E's proposed transportation tariff and claims that it should not be the basis for a CPCN because PG&E's own witness stated that the entire contents of the tariff are subject to negotiation between PG&E and the shippers, and that the tariff was a "first draft."

El Paso doubts that the 20 Precedent Agreements which have subscribed to the 755 MMcf of the "design day" expansion capacity represent contractual obligations on the part of shippers because even after satisfaction of the precedent conditions set forth in those agreements, all of the terms and conditions of

4 According to the testimony of PG&E's witness cited by El Paso, the Expansion has a maximum capacity of 877.5 MMcf/d at Kern River during the "winter months" of October through March. El Paso notes that PG&E's witnesses also confirmed 815 MMcf/d to be the level of firm capacity, but that the "design day" capacity flow diagram is only a snapshot of system operations that differ over the course of a year.

service are subject to negotiation to the mutual satisfaction of the parties. El Paso claims that a shipper has made no commitment under the Precedent Agreement; as a consequence, PG&E's testimony that the Expansion is fully subscribed can be accorded little weight in evaluating PG&E's proposal.

3. PG&E's Subscription

El Paso cautions that if shippers do not eventually execute gas transportation agreements which provide for capacity that equals the quantity set forth in the Precedent Agreements, the proportionate cost of unsubscribed firm transportation capacity of Project will have to be borne by other shippers. Since PG&E's witness testified in rebuttal that PG&E is seeking capacity of over 300 million MMcf/d by the 1994-95 time frame, El Paso speculates that PG&E may be planning to "subscribe" to capacity which is not contracted for, and to shift the added burden to its existing customers. If the ultimate gas transportation agreements are for relatively short terms, then the longer-term shippers, or PG&E's system customers, will have to bear the reallocation of the remaining unrecovered costs, according to El Paso.

El Paso's witness testified that PG&E's subscriptions to 100 MMcf/d of capacity on the Expansion Project are not needed to meet PG&E's core customer needs through at least the year 2005. El Paso argues that PG&E has more than sufficient existing capacity to meet its core requirements well into the 21st century. Using figures from the 1989 California Gas Report, El Paso testified that even after adjusting PG&E's projected core demand to reflect the "cold year day" (a 1 in 35 year occurrence) and a 20% "slack factor" (excess capacity of 10% was already assumed per the Commission's pipeline OII decision) a surplus of 928 MMcf, 987 MMcf, and 1,067 MMcf of pipeline capacity supply is estimated for the years 1993, 1995, and 2000.

If the subscriptions are required to meet PG&E's non-core demands, then PG&E's non-core customers should pay for the capacity and core customers should not be required to provide a subsidy for PG&E's non-core marketing activities, claims El Paso. El Paso cites the principle, announced in D.90-02-016, that the Commission does not reject the use of curtailments in the context of peak demand planning by gas utilities.

4. <u>New Pipeline Capacity is Unnecessary</u>

El Paso asserts that there are options, other than subscriptions to new pipeline capacity, available to PG&E to meet swings in core demand. These options include storage, demand side management, and the availability of interruptible pipeline capacities. El Paso believes it is not necessary for PG&E to maintain interstate pipeline capacities to meet 100% of its demand 100% of the time. El Paso suggests that PG&E should use its pipeline capacities and storage injection capabilities on days when core demand falls below the average to meet greater than average core demand on other days. El Paso notes that since 1985, PG&E has reduced its firm purchases from El Paso and is currently purchasing little, if any, gas from El Paso; PG&E is instead using El Paso's system on an interruptible basis to transport southwest gas to PG&E's system in California; and PG&E already has tentative plans to increase storage cycling capabilities from 36 Bcf up to 64 Bcf by 1995. El Paso suggests that California production, which in 1995 is estimated to be 226 MMcf/d, could provide PG&E about 40.7 Bcf of storage gas for withdrawal if a 6-month "summer" injection period is used and that PG&E does not need Expansion capacity to support its storage program.

El Paso concludes that PG&E's evidentiary presentation does not support the issuance of the certificate requested. If the Commission nevertheless issues a CPCN, El Paso recommends that the CPCN state that PG&E's shareholders are wholly at risk for any investment in the Expansion until the Commission is able to resolve the questions raised in the record but not adequately addressed by PG&E; this condition should apply to the potential equity participants of other California utilities in the project as well.

H. Southern California Gas Company

SoCalGas is the public utility which provides natural gas service to most of southern California. The Expansion would terminate at the junction of SoCalGas and PG&E facilities. SoCalGas is a customer of PG&E under an interutility agreement which provides additional natural gas supplies to southern California. The Expansion is specifically designed to provide up to 655 MMcf/d of natural gas to SoCalGas' customers and service territory. SoCalGas is concerned about the potential impact of any cost reallocation of existing pipeline demand costs or facility costs to SoCalGas as a result of PG&E's expansion.

Through its witnesses' testimony, SoCalGas detailed the requirements which must be met for SoCalGas to interconnect with any specific interstate project, the potential operating impact and facility costs to SoCalGas' system to accommodate interstate pipelines under various scenarios, and SoCalGas' participation in the Western Gas Network as an alternative to the Expansion.

SoCalGas urges that any CPCN issued to PG&E be conditioned as follows:

1. PG&E must meet all criteria established in the Commission's pipeline OII (I.88-12-027 and reaffirmed in D.89-02-016);

2. PG&E must indemnify SoCalGas for costs SoCalGas incurs in accommodating PG&E during both pre-construction and post-construction including (but not limited to) the situation where PG&E's expansion is not built and SoCalGas has in good faith proceeded with necessary activities to support interconnection to its system;

3. CPUC pre-approves necessary expansion costs by SoCalGas to ensure recovery of those costs regardless of usage;

4. SoCalGas must obtain knowledge of shipper commitments, take-or-pay obligations, and throughput conditions on the PG&E/PGT Expansion, since SoCal will require executed shipper contracts with guaranteed throughput provisions for delivery of interstate gas across SoCalGas' system;

5. CPUC prohibits cross-subsidization by diversion of "transportation only" interstate pipeline gas, which is of particular concern to SoCalGas due to the LDC function of PG&E's existing business;

6. PG&E Expansion supplies must meet SoCalGas' quality specifications;

7. PG&E must execute a new interconnection agreement with SoCalGas.

SoCalGas also urges the Commission to establish a separate proceeding to resolve cost, cost allocation, and rate issues concerning the SoCalGas system arising from the construction of new interstate pipeline systems before SoCalGas is to incur any construction costs.

SoCalGas challenges the Expansion's compliance with OII criteria. According to SoCalGas, the Expansion Project does not offer California the supply or pipeline diversity desired by the Commission because access to Canadian gas would continue to be limited to PG&E/PGT alone as it is today; the Expansion cannot provide gas from the Rocky Mountains or from the southwest. PG&E may not be able to satisfy the economic justification criterion, SoCalGas claims, because the cost increases represented by the escalation of construction costs, environmental mitigation, and allocation of existing system costs combine to increase proposed rates by as much as 50%.

Since neither PG&E nor the Expansion Project shippers know where Expansion gas is going within the SoCalGas system, SoCalGas' task of calculating the requirements to interconnect with the Expansion Project is extremely difficult, asserts SoCalGas. SoCalGas' witness Engel testified that, depending on the total volume delivered by PG&E and the availability of supplies from other interstate projects, interconnection with the Expansion Project could cost nothing or could cost upwards of $120 million. SoCalGas asserts that it would not build facilities without the representation by PG&E that there will be sufficient volumes delivered to SoCalGas to justify the costs of construction. SoCalGas believes that PG&E should indemnify SoCalGas for such costs to protect SoCalGas' ratepayers.

SoCalGas is also concerned that PG&E not unduly mix its transportation function and distribution function, since SoCalGas may be obligated to "backstop" all or a portion of these volumes and have rates based on throughput. SoCalGas is reassured by PG&E's witnesses' testimony that the Expansion would be accounted for and operated as a separate entity, and that the Expansion and existing system will be totally integrated so that in the event of disruption, the consequences must be shared equally among firm sales and firm transportation customers in Northern and southern California. However, SoCalGas urges that DRA's proposed conditions (discussed below) be included in the terms of any Expansion CPCN.

SoCalGas indicates that since the current interutility agreements between SoCalGas and PG&E are not for firm service at Kern River Station, they must be revised and include provisions for the construction of added facilities to accommodate Expansion Project deliveries.

SoCalGas witness Rawlings presented the Commission with a list of issues concerning SoCalGas' costs to accommodate any interstate pipeline project. SoCalGas believes that these issues may need to be resolved in a subsequent hearing. These issues include how to allocate to interstate pipeline customers the cost of incremental system upgrades and fixed costs associated with SoCalGas' existing system; whether the Commission's desire for incremental pricing of interstate pipelines and its desire to avoid bypass can be reconciled; minimizing the risk of non-recovery of costs; allocation of costs of idled capacity; and the allocation to core customers of costs of additional system utilization caused by the new projects. No party opposed SoCalGas' request for a subsequent proceeding on these issues.

Lastly, SoCalGas argues that PG&E must use incremental rates that allocate common costs as the PITCO tariff does. SoCalGas is concerned that PG&E will allow its subsidiary PGT to remain neutral to rolling-in its expansion costs, because such rolling-in would substantially increase rates to existing interstate customers, including PG&E and SoCalGas (which is PITCO's only customer). SoCalGas seeks a Commission mandate to PG&E to have PGT oppose rolling Expansion Project costs into existing rates as a condition of the FERC CPCN.

Although the Commission has encouraged utilities to finalize their agreements with pipeline proponents whose proposals meet the OII's criteria, SoCalGas maintains that the Commission can expedite construction only by approving necessary costs in advance of construction.

I. Division of Ratepayer Advocates

The Commission's Division of Ratepayer Advocates (DRA) acknowledges that the Expansion Project will meet some of the criteria listed by the Commission in D.90-02-016 for improving supply diversity by increasing access to additional Canadian supplies while maintaining close ties with existing suppliers. DRA notes with approval that the accounting for the expenses incurred by the Expansion Project will be maintained outside of PG&E's

normal plant accounts, and that all risk of cost recovery associated with the Expansion will be borne by the Expansion sponsors, utility shareholders, and Expansion customers. However, DRA emphasizes that the risk of stranded investment due to underutilized capacity additions should be imposed squarely on the Expansion sponsor and Expansion shippers.

DRA asserts that the risk of underutilization and stranded investment exists because of the potential for energy savings resulting from demand side management (DSM). In its February 1990 comments to the California Energy Commission, DRA estimated the annual savings in demand for electricity by the year 1995 would decrease natural gas demand by 250 MMcf/d. The DRA believes that a majority of the savings will likely result in displaced natural gas generation. DRA alleges that in addition to DSM, the uncertainty of forecasted demand levels, changes in California and interstate gas supplies, and the potential for bypass of SoCalGas' system all raise the possibility of stranded investment. According to DRA, while PGT's willingness to file for a certificate to allow capacity brokering on the existing and expansion facilities will help alleviate the potential risk of stranded investment for gas ratepayers on the PG&E system, the question of capacity brokering on the El Paso system has not been resolved. Until then, there is the possibility that El Paso's customers will incur demand charges for capacity in excess of core needs.

1. Allocation of Existing Costs

DRA's chief concern with the Expansion proposal is its failure to allocate to the Expansion the cost of existing facilities that would be used by the Expansion. DRA believes that the Expansion Project should benefit from the use of existing facilities, which are less costly than a new stand-alone system, but should pay a fee for the use of existing facilities equal to the average of their book value and replacement value;[5] the Expansion Project should also pay an O&M and A&G charge for the use of shared facilities equal to the lesser of: (a) 90% of the O&M and A&G expenses of a "stand alone" pipeline, or (b) total O&M and A&G of the integrated system times the ratio of Expansion to total throughput. Using PG&E's proposed 11.2% annual rate of return, DRA calculates that the Expansion should pay existing ratepayers approximately $9 million per year for the use of existing facilities and $3.6 million for the first year's O&M/A&G expense. These combined costs would increase the Expansion's rate by roughly 12%, according to DRA.

DRA asserts that if its position is adopted, existing PG&E system customers will benefit from lower compressor fuel charges, revenues from the Expansion's use of existing facilities, increased access to long-term Canadian gas supplies, enhanced transportation reliability, and potential cost reductions through gas-on-gas competition. DRA also notes that any expansion of the project to accommodate deliveries in excess of 755 MMcf/d would be relatively inexpensive. DRA believes that incremental Expansion rates should be based on the cost borne by the original shippers plus the cost of incremental compression facilities.

2. Waiver of GO 96-A

DRA believes that it would be premature to waive certain sections of GO 96-A as requested by PG&E. The Applicant seeks the Commission's waiver of Section II, which establishes the format in

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5 According to DRA, a fee should be charged for the usage of 17 miles of Line 400 and all of Line 300B; no fee would be charged for the use of Line 2 or of existing compression facilities.

which all CPUC jurisdictional utilities must file their tariffs, and Section IX and X, which require each contract between a customer and a utility for service to contain a provision giving notice that the contract shall be subject to any changes required by the CPUC. DRA points out that the long-term transport contracts for which the Commission is being asked to waive its regulatory oversight do not yet exist, and it would be imprudent to relinquish regulatory authority without knowing the terms and conditions of those contracts. DRA emphasizes that 400 MMcf/d of the total capacity of 755 MMcf/d is targeted for PUC-regulated utilities, which may form subsidiaries to own and operate their portions of the Expansion. DRA fears a conflict of interest between the utilities as equity participants in the Expansion Project and their role as providers of utility service; these shippers would be providing utility service to captive ratepayers. DRA recommends the Commission deny PG&E's request for a waiver at this time, but reconsider the request after reviewing the contracts.

3. <u>PG&E's Subscription</u>

DRA next focuses on PG&E's proposed subscription to 100 MMcf/d of capacity for its core ratepayers. DRA asserts that the 1989 California Gas Report forecasts core demand under cold year conditions in the year 2000 to be 1,070 MMcf/d. DRA calculates that this amount is only 45% of the capacity available from existing facilities, not including storage withdrawal.

DRA requests the Commission to take official notice of its pending proceedings concerning utility natural gas procurement, long-run marginal cost, and cost allocation by local distribution companies. DRA claims that under the Commission's proposed rules for utility procurement practices (which were adopted in D.90-09-089), there is no need for PG&E to sign up for capacity on behalf of non-core customers. DRA believes it is the responsibility of those non-core customers to obtain their own capacity. Because PG&E has not shown there is demand for additional capacity for core gas customers and non-core customers can directly subscribe for capacity on the Expansion Project if they choose, PG&E should be precluded from acquiring capacity on behalf of customers other than its utility electric generation (UEG) load, argues DRA.

DRA feels that PG&E has sufficient incentive to minimize the costs of its Expansion Project. Even so, DRA believes that the cost of the Expansion facilities should not be rolled into PG&E's rate base for at least 10 years, and then, only after a hearing. DRA proposes the following conditions to the issuance of a CPCN approving the Expansion:

1. All accounting and expenses of the Expansion Project shall be separately maintained;

2. All risk and cost recovery associated with the Expansion Project shall be borne by the sponsors of the Expansion Project, the utility shareholders, and the Expansion customers;

3. The Expansion Project shall pay a fee for use of existing facilities;

4. Allocation of direct and indirect costs and benefits of operation of an integrated system shall be shared based on relative throughputs of existing and Expansion systems;

5. All capacity, both existing and new, on the PGT system shall be made available for capacity allocation under a Commission-approved brokering proposal; and

6. Applicant's request to serve the core market with its 100 MMcf/d of Expansion Project capacity shall be denied.

J. <u>State of New Mexico</u>

The State of New Mexico, through its Enorgy, Minerals and Natural Resources Department and its Commissioner of Publio Lands (New Mexico) focused its comments on the issue of supply diversity and gas-on-gas competition. New Mexico alleges that PG&E's Expansion does not result in a pipeline network which accesses all major producing areas and therefore does not meet the Commission's definition of "supply diversity" in D.90-02-016.

New Mexico claims that the combination of high fixed transportation charges and high annual minimum take-or-pay obligation imposed by Canadian producers will effectively eliminate gas-on-gas competition from domestic sources. New Mexico observes that Edison, SDG&E, and DRA have recognized that a California consumer that is obligated to pay fixed transportation charges and buy a fixed quantity of Canadian gas has too great an investment in Canadian supplies to buy alternative domestic supplies of gas even if the domestic gas is priced substantially below the fixed unit cost of the Canadian gas. Because PG&E's proposal will decrease gas-on-gas competition and provide no offsetting benefits to gas customers, the Expansion should not be approved, argues New Mexico.

K. <u>Producer Shipper Group</u>

The Producer Shipper Group (PSG) is comprised of a number of shippers[6] that have signed Precedent Agreements with PG&E and PGT in connection with the Expansion. The PSG supports PG&E's "incremental" approach whereby the costs of the incremental facilities are to be borne by the incremental shippers themselves.

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6 The members of the Producer/Shipper Group are: BP Gas, Inc.; BP Resources Canada Ltd; American Hunter Exploration Ltd.; North Canadian Marketing Inc.; Pancontinental Oil, Ltd.; and Suncor, Inc.

According to PSG, the proposed method insulates PG&E's existing ratepayers from the risks and costs of the Expansion Project, is consistent with FERC precedent, maximizes the economic efficiencies associated with an expansion of PG&E's existing pipeline system, and is consistent with the Commission's initial treatment of incremental EOR shippers' rates on the gas utilities' systems in California.

PSG notes that the Commission stated in D.90-02-016 that it generally opposes "rolled-in" ratemaking.[7] The Commission's approval of PG&E's incremental approach to ratemaking is urged as being consistent with this previously announced policy.

PSG observes that the use of existing facilities to provide transportation over the Expansion Project enables the state to gain incremental transport capacity at a lower real cost than would be incurred if equivalent capacity serving the same purpose was built on a stand-alone basis. The avoidance of construction costs over some 130 miles by use of displacement over existing facilities is a "benefit" of the expansion.

The PSG cites PG&E witness Stalon's testimony that the assignment of economy of scale benefits to the Expansion Project shippers makes the best use of the opportunity to achieve economies of scale. According to PSG, PG&E's incremental cost allocation proposal achieves economic efficiency by maximizing the benefits inherent in an incremental expansion project. This is done when costs are imposed upon an incremental user in accordance with the costs that it has imposed upon others. In this case, economic

7 Rolled-in ratemaking refers to the "rolling-in" of expansion facilities costs with existing system costs and charging rates to all ratepayers (existing shippers as well as expansion shippers) based upon an allocation of the entire system costs.

efficiency is achieved by charging Expansion shippers just the costs of those incremental facilities, claims PSG.

PG&E's incremental cost allocation approach also provides tangible benefits for PG&E's existing ratepayers, states PSG. These benefits consist of the increased reliability that would result from the looping of the system, some $13 million of fuel cost savings, and increased flexibility which creates the potential for increased supply options and price competition. Alleged benefits to existing ratepayers also include increased contribution to PG&E's fixed costs due to avoidance of curtailment of service. PSG argues that these benefits can only be realized if the Expansion is built, and this will occur only if the Commission adopts an economically efficient incremental rate design, according to PSG.

The PSG states that the incremental rate approach is consistent with FERC and CPUC policy. As a general rule, FERC applies the incremental rate approach to initial rates when a new group of customers is the primary beneficiary of an expansion project, claims PSG. PSG reminds the Commission that it allowed the utilities to negotiate EOR transportation rates as low as the "marginal" cost of providing service. There, the Commission emphasized that other ratepayers will not subsidize EOR service, and EOR customers will pay at a minimum all incremental costs associated with any new service. PSG claims that in this case, as long as an Expansion shipper is paying the marginal costs associated with providing service to that customer, no subsidization results. Marginal cost based rates are especially appropriate when excess capacity exists, or is created, according to PSG.

PSG refers to the proposals of Kern River, Altamont, and DRA to allocate a portion of common costs of existing facilities to

Expansion shippers as a "super-incremental" approach. The super-incremental approach is allegedly improper because it would shift costs from PG&E's existing ratepayers to Expansion shippers without recognizing the benefits that PG&E's existing customers will receive from construction and operation of the Expansion. Placing Kern River or Altamont in a more favorable position in relation to the Expansion Project does not serve any legitimate policy goal in this proceeding, according to PSG. While PSG acknowledges that the shifting of costs is designed to achieve a level playing field among the competing pipelines, it argues that a level playing field does not necessarily mean a market environment in which no party has a competitive advantage. PSG concludes that PG&E should not be precluded from utilizing its inherent advantage of avoiding the construction of new facilities.

While any super-incremental cost allocation methodology would be improper, according to PSG, witnesses for DRA, Kern River, and Altamont have overstated the common costs that should be allocated to the Expansion shippers. The DRA and Kern River witnesses proposed an allocation of common facilities costs based upon costs that would be incurred if the Expansion were constructed on a stand-alone basis; PSG observes that these costs would exceed the embedded costs of the common facilities borne by PG&E's existing ratepayers.

PSG argues that allowing Expansion shippers to use certain pre-existing pipeline facilities without bearing an allocated portion of the cost of the facilities does not impose an "opportunity cost" upon PG&E's existing ratepayers because there is no evidence that the capacity will be required to serve PG&E's existing ratepayers over the short term to the exclusion of the Expansion Project shippers. Any potential opportunity costs are far outweighed by the benefits of the expansion, claims PSG.

PSG submits that because PG&E's customers will sacrifice nothing in order to enable PG&E to provide service to the Expansion shippers, the Expansion shippers should not pay more for the use of the common facilities than PG&E's existing shippers do. Nor should they pay the G-IND rate, as suggested by Kern River, because only 130 miles of existing facilities would be used by the Expansion, and the G-IND rate includes an allocation of all costs (distribution costs, gas gathering costs, interstate pipeline demand charges, storage costs and customer costs) on the PG&E system.

The proposal of Kern River's witness to allocate PG&E's total transmission-related O&M and A&G costs to Expansion Project shippers based on relative throughput volumes is similarly overbroad, according to PSG, because the total transmission-related O&M and A&G costs include costs for miles greatly in excess of the 130 miles that the Expansion would use. PSG asserts that Kern River's allocation based on gas throughput is unsound because, as DRA's witness acknowledged, A&G costs usually are not related to throughput levels on a pipeline system.

PSG criticizes the attempt by Altamont to calculate O&M and A&G expenses on a cost-per-mile basis overstates costs, because Altamont does not allocate those costs based upon the 130 miles of existing pipeline that the Expansion will use, but on the 544.5 miles of existing pipeline. If some allocation of existing A&G and O&M costs to the Expansion shippers is adopted by the Commission, PSG urges that the allocation be limited to those costs associated with the facilities that will be used by the Expansion.

PSG concludes that Expansion Project shippers should not be burdened with costs that represent a proxy for a stand-alone project because doing so would ignore the economic efficiencies that are intended to be gained by the incremental expansion of PG&E's existing pipeline system.

L. Bonus Gas Producers, Inc.

Bonus is a gas marketing firm headquartered in Calgary, Alberta. Bonus had presented testimony and filed briefs protesting the terms and conditions of the open season capacity auction and the lack of a delivery point anywhere but Kern River Station. On July 27, 1990, Bonus and PGT reached an agreement where, among other things, Bonus withdrew its opposition to PG&E's application for a CPCN. In the "Response of Bonus Energy Inc. in Opposition to the Joint Petition of Kern River and Altamont to Set Aside and Reopen Proceeding" filed October 1, 1990 in this proceeding, counsel for Bonus confirmed Bonus' intent to withdraw its pleadings complaining about Bonus' access to the Expansion. Thus, it is unnecessary to consider Bonus' arguments in this decision.

IV. Discussion

PG&E's application for certification of the Expansion is being made at a time of change in California's natural gas industry. By successive decisions, the Commission has irrevocably altered the manner in which natural gas is purchased and delivered to the consumer. Before the Commission began its restructuring of the natural gas industry in response to consumer demand for transportation services, the provision of natural gas was a vertically integrated service provided by a local distribution company (LDC) such as PG&E. All of the LDCs under the Commission's jurisdiction are, by definition, public utilities. As a public utility, the LDC was a regulated monopoly, with a legal duty to provide service as needed in its service territory. The LDC would bear the responsibility for procuring gas supplies through long-term contracts with pipeline suppliers at a reasonable price and in an amount commensurate with the demand of all its gas consumers. PU Code § 1001, which lists the criteria by which the Commission shall determine whether a proposed pipeline will serve the public convenience and necessity, reflects the Legislature's concern for the development of utility facilities to fulfill utility obligations under the former natural gas industry structure. The existence and degree of need for regulated LDC facilities was easily ascertained because there was no competition, and hence, no alternatives available to serve the public need for gas service.

Our unbundling of gas utility services has created a consumer market that has attracted the interest of gas producers in the southwest, Rocky Mountain region, and western Canada. Following an investigation into the need for additional interstate pipeline capacity (I.89-12-027, "the OII"), we determined that the regulatory response that would provide the most benefit for the California consumer would be to let the market decide which of several competing pipelines would be built. The Commission refrained from endorsing any particular pipeline at the FERC, and instead, listed criteria by which a pipeline could gain CPUC support before the FERC (see, D.90-02-016, "OII decision").

The criteria listed in the OII should be used in our evaluation of the Expansion Project because the Expansion constitutes the in-state portion of an interstate pipeline proposing to import Canadian gas. Under our market-based approach, we would view favorably any pipeline proposal that results in a pipeline network that provides reliability of access to all the major producing areas, is an economically justifiable means to reduce gas costs through gas-on-gas competition, allocates capacity in a non-discriminatory manner, allows for temporary capacity brokering, avoids bypass of the LDC, and allocates cost responsibility to those who will benefit from firm service on the new pipeline.

In the OII decision, we recognized that our jurisdictional utilities may seek incremental interstate pipeline capacity to serve their core loads, but cautioned them that the "best efforts" service of LDCs to noncore customers does not justify their subscription to additional firm capacity. In the competitive marketplace we envisioned, whether or not a pipeline is built will depend on the investment decisions of noncore customers and those intending to provide firm service to that market. We concluded that the incremental users of gas were in a better position than this Commission to determine whether any particular pipeline was needed or not.

Most of the interstate pipeline proposals that are vying to serve the California gas market have intervened in this proceeding. The Applicant notes that although these parties have couched their arguments in terms of ratepayer interests, those arguments are being made in an effort to increase the Expansion Project's costs and thereby lessen the desirability of transportation service by the Expansion. We are not blind to the motives of the competing interstate pipelines, yet, we cannot discount the Expansion's potential impacts on existing ratepayers which its competitors have brought to our attention.

The aspects of the Expansion proposal that are of greatest significance in light of our express criteria are PG&E's subscription to 100 MMcf/d of firm transportation capacity on the Expansion, the failure to include any costs of the existing system in the proposed "incremental rate design," and the Expansion's potential impact on competition due to its single delivery point. We will also focus on PG&E's proposal to allocate revenues from interruptible transportation to its shareholders and its request that the Commission waive its continuing jurisdiction per GO 96-A over PG&E's transportation contracts with Expansion shippers.

A. Need for the Expansion

The Expansion Project would provide a minimum of 755 MMcf/d of pipeline capacity for the firm transportation of natural gas, primarily to serve demand in southern California. The ALJ correctly ruled that our determination in D.90-02-016 concerning California's need for additional natural gas pipeline capacity should control in this proceeding. We reiterate our finding from D.90-02-016 that there is a near-term need for 900 MMcf/d and a long-term need for 1.6 to 2.1 Bcf/d of additional natural gas pipeline capacity. Since the potential of demand side management (DSM) to meet any portion of that forecasted demand was not discussed in D.90-02-016, it is necessary to consider whether DSM could render unnecessary any portion of the Expansion's proposed capacity.

PG&E, DRA, Edison, and SDG&E all introduced evidence of potential reductions in the demand for natural gas to fuel electric generators based on the 1989 California Gas Report (CGR). We will consider the potential of committed DSM resources only, because the realization of uncommitted resources is contingent upon many factors beyond our control.

We find that the effort to expand DSM through the Statewide Collaborative Process will not be sufficient to offset the need for new capacity. The electric conservation proposed in the Collaborative Process would result in a reduction in natural gas consumption of only 27 MMcf/d for each year of the programs. The potential for reduction in the demand for gas used in electrical generation is insufficient to reduce the need for even a portion of the Expansion's capacity, even with the liberal assumption that gas is used at the margin in all cases. Even with the added effort proposed in the Collaborative Report, SoCalGas could reduce gas sales by only 9.0 MMcf/d by 1995.

No other party challenged the assertion that 755 MMcf/d of incremental supplies of natural gas would be needed in the state by the year 1995. Thus, we find that there is a need for the 755 MMcf/d of firm transportation capacity of the Expansion Project.

By concluding that the Expansion Project would provide 755 MMcf/d of needed gas supplies, we are not necessarily finding that the pipeline itself should be constructed in all events. In the following section, we determine that the Expansion Project fulfills the OII criteria. Even so, a pipeline's compliance with the criteria has not resulted in Commission support for that pipeline to the exclusion of any other pipeline.

The Expansion Project is the intrastate portion of the PGT interstate pipeline. The only reason the Applicant has advanced for undertaking the Expansion is to accommodate the delivery of gas transported over the PGT project to southern California. Should the PGT Expansion not receive a CPCN from the FERC, there would be no reason to proceed with the PG&E Expansion.

Because of the pendency of the PGT application and the Altamont application at the FERC, we cannot unconditionally find there is a need for the PG&E Expansion Project. If the FERC certificates the PGT Expansion, there is a greater probability of need. Even so, the ultimate decision whether to build the in-state facilities must be made by PG&E. The Applicant has unequivocally stated that it intends to proceed with construction only if sufficient demand for the pipeline exists.

Clearly, there are alternative pipelines seeking to serve California's incremental demand for interstate gas. The FERC's announced policy is to certificate all interstate pipelines that meet the FERC's requirements. The multitude of potential alternatives to supply California's demand makes it logically impossible for the Commission to find that any one pipeline is needed, since other pipelines appear to be available to serve California's demand.

As we stated in D.90-02-016, we believe that the marketplace should determine which of the several competing pipelines should be built. If the potential shippers and gas consumers favor pipelines other than the PG&E/PGT Expansion, clearly there is no need for the Expansion Project. We are not in a position to predict what the market will do. We have established a near term need for 900 MMcf/d of incremental gas transportation capacity. By this decision, we find that the Expansion Project, as conditioned, would be a reasonable means by which PG&E may serve 755 of that demand. However, we cannot find, in the face of competition from alternatives and the uncertainty of the economy, that the Expansion would be needed under all circumstances.

We need not find that the Expansion Project is indispensibly requisite in order to determine that the public convenience and necessity would be served by PG&E's construction of the Expansion. Issuance of a CPCN at this time is reasonable in light of the current need for 330 MMcf/d of firm capacity demonstrated by Edison, SDG&E, and municipalities. The Precedent Agreements provide evidence that demand for the remaining 425 MMcf/d of capacity may arise in the future. In the meantime, allocating the risk of underutilization of capacity on PG&E's shareholders and Expansion shippers provides PG&E's existing ratepayers with the protection against increased rates that the establishment of current need for the entire capacity of the Expansion would otherwise provide. Finally, we conclude that the public necessity would be served by the authorization to construct the Expansion because such authorization is needed to activate our market-based approach to incremental interstate capacity.

A grant of a CPCN for the Expansion Project would enable PG&E to respond to the need for firm transportation capacity as evidenced by market demand. However, PG&E's decision to build must be a reasonable one. It must appear that sufficient demand for PG&E's proposed service will exist at the time the Expansion is scheduled to commence operations, based on the facts known or reasonably knowable to PG&E at the time of its decision to build.

B. <u>Compliance with the Commission's OII Criteria</u>

1. <u>Supply Diversity and Competition</u>

There is some controversy over what the Commission meant in D.90-02-016 when it required that a proposed interstate pipeline result in a "pipeline network which provides reliability of access to all the major producing areas." New Mexico and Altamont contend that since the Expansion will allow only Canadian producers to gain access to the California market, it fails this test. PG&E, on the other hand, claims that since the Expansion is designed to serve the southern California market, it is that market's supply mix that should be considered.

The pipeline network we promote consists of not only one interstate pipeline in isolation, but an integrated network consisting of LDCs and their suppliers. While PG&E and SoCalGas are interconnected at this time and PG&E receives considerable quantities of Canadian gas, only 8% of the gas consumed in southern California originates from Canada. The Expansion provides a potential 655 MMcf/d of Canadian deliveries to southern California, increasing the share of Canadian gas in the region to nearly 25%. A proposed interstate pipeline need not, on its own, provide access to "all the major producing areas." It is sufficient that its interconnections and downstream operations contribute to diversity of supply for the state as a whole.

While it appears that the delivery of Canadian gas over the Expansion Project would promote gas-to-gas competition, several intervenors object that the Expansion instead would stifle competition. They claim that a competing gas supplier or pipeline would be handicapped by the fixed firm transportation rate because it imposes a fixed cost on the Expansion shipper. That is, the Expansion Project shipper would rationally purchase other supplies only if the shipper's out-of-pocket cost is no more than the delivered cost of Expansion gas. The intervenors contend that the "netback" of southwest producers would have to be reduced by the fixed firm transportation rate paid by Expansion shippers in order to compete with Canadian gas.

This scenario does not convince us that the Expansion Project will stifle competition; instead, it will create competition for other suppliers attempting to serve the southern California market. The encouragement of this competition is consistent with the market-based approach we adopted in D.90-02-016. We foresee that natural gas consumers will benefit from the pressure the Expansion Project will exert on suppliers from other geographic regions. Those suppliers will not be denied access to the market, either. For example, Edison has testified that in addition to its 200 MMcf/d of Expansion capacity, it intends to procure additional volumes of gas from southwest suppliers to be transported by SoCalGas.

Amoco claims that the increased demand for Canadian gas in the California marketplace may ironically raise the price of Canadian gas. Such an increase assumes some limitation on Canadian production, as well as an inability to satisfy that demand with gas from other sources. There is no evidence that either of those two conditions is likely to materialize.

Thus, we conclude that construction of the Expansion will result in access to new supplies of Canadian gas and the resultant mix of supplies to California will promote gas-on-gas competition.

2. Economic Justification

The Expansion Project is economically justified because under PG&E's proposed rate design methodology, it will be paid for by incremental shippers and not existing ratepayers. The Applicant's proposal to segregate Expansion Project costs in separate accounts outside of PG&E's normal plant and expense accounts, to establish a separate general rate case proceeding to determine the reasonable rates for the Expansion Project, and to hold the Expansion Project sponsors and shippers responsible for all costs of the Expansion tend to insulate existing ratepayers from the financial risk of the project.

We note that PG&E has affirmatively stated that it will not seek to recover any Expansion Project costs (other than transportation costs) from its existing ratepayers. Such assurance is also implied from the applicant's intent to collect Expansion costs from only the project sponsors and Expansion shippers. We confirm as a condition of issuance of this CPCN that PG&E's existing ratepayers should not bear any of the costs of the Expansion. This segregation of costs, risk, and benefit is appropriate at this time, particularly since PG&E has not yet executed Firm Transportation Agreements with the Expansion shippers. However, since the Expansion cannot be achieved without the use of PG&E's existing facilities, for which ratepayers have paid the cost of construction, financing, and operation and maintenance, PG&E's existing ratepayers have an equitable interest in the potential margin of the Expansion Project. We will revisit this issue in the Expansion Project's first general rate case, when concrete evidence of shipper participation, the Expansion's costs and rates, and the potential contribution to margin will be available.

We need not dwell extensively on whether the Expansion Project is economically justified. At this time, PG&E has not been assured of revenue recovery and its shareholders, as the project sponsor, have assumed the risk that there will be sufficient demand for Expansion capacity. We will not second-guess the decision of Expansion Project shippers to choose transportation over the Expansion at its rates instead of other alternatives.

3. <u>Non-Discriminatory Allocation of Capacity</u>

The Expansion Project has allocated capacity in a non-discriminatory manner through the open season process. Allocation was objectively based on how great a percentage of the total transportation rate the shipper was willing to pay as a reservation charge. By soliciting bids from prospective shippers, PG&E allocated the Expansion's capacity based on the economic interest expressed by individual firms in the gas marketplace in the Expansion Project.

We find that the Precedent Agreements are reliable indicators of the market's interest in the Expansion Project. No other party introduced the terms of any precedent agreements employed by another pipeline proponent. There is no evidence that PG&E should have required a more definitive commitment from its shippers. The conditions precedent simply recognize the objective conditions that must exist before a shipper can be held to its contractual obligation to pay for transportation service (i.e., regulatory approvals and availability of gas supply). The terms of the agreements provide a reasonable level of commitment by the shipper at this stage of the project's development.

Altamont objects to the "exclusive dealing terms of the Precedent Agreement," presumably represented by this language: "Obligations of Parties: Shipper hereby makes an exclusive commitment to the __ MMcf/day of capacity requested in the incremental expansion." Altamont's reading of the contract terms is slightly askew, however. We agree with PG&E's witness that this term establishes that the shipper has not made arrangements to transport the volumes specified in the Precedent Agreement by alternate means. This commitment has the effect of ensuring that the shipper's commitment is not subject to cancellation due to the shipper's conflicting obligation to another pipeline. The shipper is not prevented from contracting with other parties for firm transportation service. In fact, the witnesses for SDG&E and Edison testified that each of them had contracted with SoCalGas for firm access to producers in the southwest. Moreover, the Precedent Agreements have not "substantially lessened competition," the harm prohibited by the Cartwright Act, because Kern River and Altamont have demonstrated in this proceeding that the competition to provide interstate gas transportation is robust. The record shows that Altamont has executed precedent agreements with shippers allocating 532 MMcf/d of its 719 MMcf/d of capacity.

PG&E has proposed temporary capacity brokering over the PGT portion of the Expansion. We have asserted our approval of this proposal at the FERC, and reiterate it here. It may be assumed that temporary capacity brokering on the PG&E portion of the Expansion Project would follow as a consequence. However, since we cannot foresee how capacity on the Expansion Project may be reassigned by shippers in the future, we will specify as a condition of our approval that PG&E impose temporary capacity brokering as a term of service on the California portion of the pipeline as well. This contract term is necessary to avert the possibility that Expansion shippers who would hold firm transportation capacity rights over periods varying up to 30 years might replace the interstate pipelines as the bottleneck in the natural gas market.

Given our understanding of the Precedent Agreements and the requirement for capacity brokering, we find that the capacity on the Expansion Project has been allocated on a non-discriminatory basis.

4. <u>No Threat of Bypass</u>

In D.90-02-016, we held that to gain our approval, a pipeline should not threaten bypass of local distribution companies (LDC). Since Expansion Project deliveries are to be made at Kern River Station, shippers must use the facilities of either SoCalGas or PG&E to reach their end users, thus avoiding bypass of the LDC. There is some possibility that EOR end users whose load is in the vicinity of Kern River Station may construct their own distribution systems and thus bypass SoCalGas' facilities, but this risk exists today and is not exacerbated by the Expansion proposal.

We conclude that the Expansion Project meets the criteria established in D.90-02-016 for our approval of an interstate pipeline.

C. <u>Facility Design and Cost</u>

The 755 MMcf/d capacity design is reasonable because the state will need that incremental amount of gas transportation capacity by 1995 and shippers have demonstrated demand for the capacity through their execution of Precedent Agreements for 755 MMcf/d.

Several parties have challenged PG&E's upgrade of capacity from 600 MMcf/d in its April 1989 application to 755 MMcf/d in its October 1989 application. PG&E stated that the increase in design capacity was needed to address its shippers' demand for contract volumes on a year round basis (the "seasonality problem") and PG&E's internal analysis of gas need. Altamont suggests that the project was enlarged to provide for a lower volumetric cost in response to competition from Altamont. Kern River produced an internal memorandum to a PG&E/PGT official that suggested that a "tactical option" to "improve project viability" was for PG&E to contract for up to 300 MMcf/d of firm capacity on the Expansion Project.

We are faced with conflicting evidence of PG&E's motives for increasing the size of the Expansion Project. Kern River suggests that PG&E's rejection of the numerous means by which it could have addressed the seasonality problem leads to the conclusion that PG&E's reason for amending its project was to "improve project viability." We are not persuaded that a public utility should renegotiate a lower level of service with its shippers, even though permitted by contract; or increase compression, which would exacerbate the seasonality problem; or utilize the excess capacity on its existing system, thus creating the potential for cost and capacity allocation and accounting problems. A self-imposed limitation of 600 MMcf/d would not have been consistent with our finding in D.90-02-016 that excess pipeline capacity is desirable because it facilitates gas-on-gas competition.

By increasing pipeline diameter PG&E has contradicted its statement in its original application that additional capacity could be handled through compression. We heard testimony from PG&E's witness that operating additional compressors with the original 36" diameter design in the summer would compound the seasonality problem because compressors are less efficient at higher temperatures. The increase in pipeline size and resultant increase in capacity from 600 MMcf/d to 755 MMcf/d was a reasonable response to the seasonality problem. No party introduced testimony to challenge the cost effectiveness of PG&E's 755 MMcf/d proposal. Moreover, there is no reason to limit the size of the Expansion Project to 600 MMcf/d because the Precedent Agreements evidence sufficient market demand for the total 755 MMcf/d of firm transmission capacity. Therefore, we find that the Expansion Project is appropriately sized at 755 MMcf/d.

The cost of the facility in 1988 dollars is $544.8 million. We accept PG&E's use of escalation factors and its proposed development schedule. Under those circumstances, the escalated cost by 1994 is expected to be $696 million. We estimate that the maximum cost of implementing the environmental mitigation required by this decision, fully discussed in "V. Environmental Considerations," will be $40 million. This figure does not represent the reasonable cost of environmental compliance, it is merely an estimate that should be added to PG&E's cost cap. We adopt $736 million as the construction cost cap pursuant to § 1005.5 Subsection (a) of the PU Code.

The first year's revenue requirement under the pro forma tariff is $101.1 million. With the depreciation of plant, the revenue requirement needed to support plant investment should decrease each year, thus allowing PG&E to offer shippers rates that decline over the 30 years. Declining costs will also enable PG&E to offer competitive terms when renegotiating firm transportation agreements, after the initial agreements have expired.

While the maximum contract term is 30 years, the average term of the Precedent Agreements is roughly 23.5 years. Kern River and other competitors maintain that use of a 30-year depreciation period will force PG&E's ratepayers to assume the risk of under-recovery of capital costs. We doubt the risk is as great as portrayed by the intervenors, since at the expiration of the contract, renegotiation of the terms of service is possible and the Expansion Project's cost of service will be lower. Kern River also assumes that PG&E's ratepayers will bear the risk of underrecovery of revenue. This issue of risk allocation is discussed in detail, below. The project sponsor's risk will be substantially lessened by the time the initial transportation agreements expire because of the declining annual revenue requirement.

It is appropriate to use a 30-year depreciation period because this Commission has authorized its regulated utilities to use 30 years as the useful life of natural gas pipelines, and the existing PG&E transmission pipelines, notably Lines 300 and 400, are approximately 30 years old. Altamont claims that the use of a 30-year depreciation period is anticompetitive. We disagree; such a depreciation schedule is entirely appropriate for a public utility such as PG&E, because it enables the utility to provide a monopoly service to the public at a reasonable cost. Despite the existence of competiting pipeline proposals, we note that the Expansion is still an undertaking by a jurisdictional utility subject to the demands we may place on it for service.

PG&E may use its 1988 cost estimate to calculate pro forma rates. We concur with the Applicant's observation that the pro forma tariff is a "rough draft." Except for the rates and charges for service, which we cannot evaluate because the project's final construction costs are not known, and the amount of revenue to be collected from interruptible transportation service, the terms of the pro forma tariff appear to be reasonable. However, the adoption of permanent rates, terms and conditions would be premature at this time because the final cost of the project is not available. Since we have not reviewed PG&E's rates and it is clear that PG&E's shareholders currently bear the risk of revenue underrecovery, no public purpose would be served by establishing rates, terms, and conditions as proposed by Altamont and Amoco.

As El Paso's brief demonstrates, the record is not clear as to the range of firm and interruptible transportation which the Expansion is capable of providing. We are alerted to the fact that there may be substantial firm transportation capacity available during the "shoulder months" when temperatures are below 90 degrees, and that very little information on interruptible capacity is available on the record. PG&E's witness testified that a maximum of 120 MMcf/d of interruptible capacity may be available, depending on variations in the weather. PG&E has chosen 60 MMcf/d as the amount of interruptible capacity for purposes of cost allocation and rate design. However, the actual amount of interruptible transportation capacity and potential revenues from this service were not clearly established. Before the Commission can evaluate any proposal affecting the corporate status or ownership of the Expansion Project, such as converting the Expansion Project to an affiliate, or conveying the Expansion to a utility consortium, we will closely examine the potential for the Expansion to generate revenues in excess of firm transportation rates. This inquiry is especially crucial, given the full-fixed variable rate design proposed by PG&E, and will occur no later than the Expansion's first general rate case.

PG&E's proposal to finance the Expansion Project initially through 70% debt and 30% equity is reasonable. Considering the low risk of project non-performance anticipated as a result of shipper subscriptions and the rate design, the maximum 3.5% of PG&E's total capitalization represented by the Expansion has no potential to adversely affect PG&E's cost of capital or ability to raise capital.

D. <u>Incremental Cost Allocation</u>

The Expansion Project proposes to use some 130 miles of existing gas pipeline, existing metering stations, taps, and other facilities of PG&E. Under PG&E's incremental cost allocation methodology, only the incremental costs of the Expansion in Expansion rates are included; none of the costs of existing facilities needed by the Expansion Project and none of the existing system's A&G and O&M costs would be allocated to the Expansion.

PG&E and PSG have relied heavily on our statement that "cost responsibility for new capacity must flow to those customers who will benefit from firm service on the pipeline." (D.90-02-016, mimeo. p. 100) to support the Expansion's incremental cost allocation methodology. We caution the parties that our decision does not bar an allocation of the cost of existing facilities to the Expansion Project's costs because that statement in D.90-02-016 simply <u>assigns</u> responsibility for the cost of new capacity. It does not <u>delineate</u> the components of the cost of new capacity.

The Applicant's proposal to use incremental cost allocation was heavily criticized by its competitors, who perceived that the Expansion's avoidance of costs gave it an unfair advantage, and by the DRA, which argued that this methodology benefited the Expansion at the expense of existing ratepayers.

Preliminarily, we approve the use of existing facilities identified in the Application. By doing so, PG&E will avoid the cost of constructing of some 130 miles of new pipeline. This savings represents the use of economies of scale and is a prudent use of society's resources.

While agreeing that the avoidance of construction costs is a benefit of the Expansion Project's design, DRA argued that the Expansion should reimburse existing ratepayers for the use of those facilities.

Assessing a charge for the incremental use of PG&E's existing facilities would confer the benefit of economies of scale on PG&E's existing ratepayers, since they would be collecting a fee for the use of facilities by others. On the other hand, making the benefit of economies of scale available to incremental users would tend to encourage the full use of existing facilities. In this case, incremental shippers of gas destined for southern California would be encouraged to use the Expansion Project, which takes advantage of the economies of scale inherent in a looped pipeline system. Those economies of scale result in lower transportation costs than those of an independently engineered and constructed pipeline, and lower transportation costs should confer a benefit on gas consumers. We think that as regulators, the Commission should attempt to allocate efficiencies fairly. The welfare of consumers throughout the state, and not just in PG&E's service territory, may be considered when determining where such benefits should be assigned.

PG&E claims that the Commission should maintain the efficiency achieved by allocating all incremental costs for new capacity to incremental users by requiring <u>only</u> the insulation of existing service from new costs. This implies that existing service is not entitled to any compensation from incremental users.

In support of this position, PG&E's witness characterized the capital cost of existing facilities to be used by the Expansion and the O&M and A&G costs of the existing utility system as "common costs," that is, "(W)hen the same equipment may be used to make products A and B, and when producing A uses capacity that would otherwise be used to make B, then their costs are common rather than joint." No party challenged this assertion. PG&E proposes that the Expansion Project be allocated 0% responsibility for common costs because the Expansion's usage of the existing facility is incremental and there is no basis, short of a policy basis, for allocating common costs.

PG&E's competitors urge that a portion of the cost of the existing system be allocated to the Expansion Project; this would increase the transportation rate charged by the Expansion and to make it less competitive. Kern River asserted that incremental cost pricing would be unfair to PITCO (see below). These are not adequate policy reasons to support the allocation of common costs.

DRA did not suggest any policies that may be furthered by an allocation of common costs to the Expansion Project; it simply stated, "The DRA believes that an appropriate portion of the compressor facilities, existing pipelines, meters, taps and other equipment being used by the expansion facility should be reimbursed to PG&E through a service charge."

Witnesses for Kern River and Altamont suggested that the use of existing facilities by the Expansion Project imposed an "opportunity cost" on existing ratepayers, and that ratepayers should be compensated for this burden. The witness for Kern River admitted that an opportunity cost would arise only if the Expansion Project's operation actually prevented the existing service from gaining further capacity that would otherwise have been available. He added that so long as there is "excess" capacity on the common facilities at the initiation of transportation service there could be no substantial opportunity cost, as defined, in the short run.

We find that existing ratepayers are not faced with an "opportunity cost" associated with the Expansion's use of existing facilities because no party introduced evidence that those facilities are needed, either now or in the future, to serve existing ratepayers. Kern River postulates that since those existing facilities are to be used over a 30-year period, ratepayers will incur an opportunity cost at some future date. We find that theory too speculative to constitute a basis for cost allocation today.

The intervenors cite this Commission's previous approval of an "incremental plus" cost allocation criterion in a negotiated rate agreement between PGT and PITCO. The rate agreement was a negotiated one, reached in 1980 when the gas industry was still rigidly integrated. In that setting, the negotiation of rates in excess of incremental costs clearly benefited PG&E's existing ratepayers, who collected the rates from a non-PG&E ratepayer. Here, the allocation of such rates would have the effect of discouraging the incremental use of existing facilities and negating economies of scale which we are making available to PG&E's prospective Expansion ratepayers. Thus, Kern River's citation to the PITCO settlement does not persuade us to use "incremental plus" ratemaking in this case.

Finally, we consider PG&E's proposed assignment of the costs of future facilities additions. Those costs are to be paid for to the extent responsibility may be assigned to existing and Expansion shippers. The cost of additions that cannot be assigned to one group or the other is to be allocated on the basis of pro rata throughput. We find that this methodology is reasonable and that it should be applied to the capital costs of all future facilities additions, whether incurred on the "existing facilities" identified in this proceeding as being used by the Expansion or the Expansion's new facilities.

E. <u>Rate Design</u>

The full-fixed variable rate design is proposed to collect 100% of the costs of firm transportation from the monthly reservation fee. In common parlance, this means that shippers pay the Expansion Project a fixed demand charge for volumes subject to firm transportation each month. There is no volumetric rate imposed on gas actually delivered. Although the Expansion Project is proposed primarily to provide 755 MMcf/d of firm transportation, it will provide interruptible transportation as well. Those rates are based on a 100% load factor assuming 60 MMcf/d of interruptible transportation capacity and will recover all of the costs allocated to interruptible transportation service. Roughly 93% of the annual requirement is expected to be collected in firm transportation rates, with the remaining 7% to be collected in interruptible transportation rates.

PG&E's proposal to collect 93% of its annual revenue requirement in firm transportation demand charges assures us that there is very little financial risk associated with revenue recovery so long as the Expansion Project is fully subscribed. Assuming that the firm transportation capacity has been fully allocated, the Expansion Project will be self-supporting and not require outside assistance from PG&E's existing ratepayers or its shareholders. The full-fixed variable rate design properly assigns throughput risk to Expansion shippers by placing fixed cost responsibility on them. It thus insulates existing PG&E ratepayers from the risk of underutilization of capacity.

Kern River claims that since PG&E will recover practically all of its revenue requirement through the monthly reservation charge, it will have no incentive to cut costs to maintain throughput. We believe that, in this case, the importance of maximizing the Expansion pipeline's continued throughput is lessened because unlike "traditional" pipelines which aggregated gas and sold it to LDCs, the Expansion is not in control of the supply of gas; its shippers are. In fact, each shipper's fixed costs of service on the Expansion Project provide an incentive to the shipper to maximize throughput in order to recover its fixed costs. In addition to the incentive to maintain throughput, the shipper is required by contract to broker its unused capacity if there is demand for transportation service. Thus, we conclude that the full-fixed variable rate design is appropriate for this transportation-only pipeline. Moreover, we perceive that the marketplace has been quite effective in forcing PG&E to lower its costs and rates and we anticipate that PG&E will continue to offer shippers low rates in response to competition.

PG&E has represented that the costs of the Expansion Project will be recovered only from the Expansion shippers. We expect that this will be so, based on the Expansion's allocation of 93% of project costs to firm transportation in its pro forma tariff.

Kern River claims that the Expansion Project would expose PG&E's customers to the risk of rolled-in ratemaking on upstream portions of the interstate pipeline system that brings Canadian gas to PG&E's customers. We acknowledge the fact that PGT has agreed to a settlement at the FERC where PGT is required to submit a general rate case to the FERC, that PGT may not oppose the use of rolled-in ratemaking, and that as a result, the cost of the Expansion Project may decrease while rates for PG&E's existing customers may increase. However, those are ratemaking issues for the FERC, not this Commission. We believe that the benefits to PG&E's existing customers from the Expansion, the prevention of LDC bypass, and the use of economies of scale outweigh the potential effects of rolled-in ratemaking at the FERC.

PG&E also proposes that the revenues from interruptible transportation service accrue directly to PG&E's shareholders. It is premature to make that assignment at this time for several reasons. First, as discussed above, we have no true idea of the Expansion's interruptible capacity, and thus, no means of estimating the potential revenues from interruptible service. Secondly, we have heard no assurance from PG&E that it would never seek to recover any Expansion Project costs from existing ratepayers. Third, we have not reviewed the commitment of PG&E to 100 MMcf/d of firm capacity on the Expansion; that is, we have not determined whether PG&E's subscription of that capacity on behalf of its utility operations is reasonable, or not. It would be dangerous precedent to grant shareholders the margin represented by interruptible revenues and saddle ratepayers with a contingent liability for the cost of service for capacity they may not need. Finally, since PG&E has not yet executed its firm transportation agreements, we do not know how much of the Expansion Project's revenue requirement will be collected in firm transportation rates. If the amount is insufficient to cover costs, service to shippers may be impaired if interruptible revenues are diverted prematurely to shareholders. Thus, we reserve judgment on PG&E's proposal on interruptible rates for consideration in the Expansion's first general rate case.

F. PG&E's Use of Precedent Agreements

The intervenors complain that PG&E's use of its Precedent Agreements was anticompetitive and discriminatory.

Altamont challenges the restriction of deliveries to Kern River Station as an anticompetitive attempt by PG&E to protect its northern California market from competition. This would be accomplished by charging Expansion Project shippers the cost of transport over PG&E's system, whereas PG&E would be able to deliver gas from Kern River Station at no additional charge.

This argument strays from the primary issues before us. There is no evidence that any shipper on the Expansion Project has complained that it was being denied the opportunity to compete in PG&E's service territory. We believe the reason is simply that roughly 80% of Expansion Project volumes are destined to serve southern California's demand for natural gas. Secondly, no party, even Altamont, has proposed that PG&E should allow shippers to transport Expansion volumes over its existing facilities free of charge. Since PG&E's existing transportation rate is a postage stamp rate, it makes no difference whether the delivery point is at the southern end or northern end of PG&E's system. An Expansion Project shipper seeking to serve a customer in PG&E's service territory would have to pay PG&E's gas transportation rate in either case. Finally, we determine that the restriction of deliveries to Kern River Station was designed to enable the project sponsor to recover the cost of delivery to that point. Given our expressed policy of imposing the cost of new facilities designed to serve incremental users on those users, the Expansion Project's promulgation of rates to recover the cost of service to the full extent of the Expansion's physical plant is reasonable.

The use of a single delivery point and postage stamp tariff are consistent with this Commission's prior determinations. In D.90-02-016, incremental demand for natural gas was identified as being located in southern California, so it is logical for PG&E to propose a project that brings the gas as close to that market over PG&E facilities as possible. Not only does this take advantage of existing economies of scale, it also minimizes the potential for bypass of PG&E's facilities and the resultant harm to PG&E's ratepayers. Moreover, the Commission expressed its policy favoring uniform intrastate transportation rates when it authorized rates to implement the unbundling of gas service. The Commission determined there should be no geographic discrimination in rates when allocating costs to non-core industrial customers in D.87-12-039.

G. <u>PG&E's Subscription to 100 MMcf/d</u>

The competing pipelines and DRA challenge PG&E's subscription to 100 MMcf/d of Expansion Project capacity. The intervenors argue that PG&E's subscription confers a competitive advantage on the Expansion Project. Kern River urges the Commission to examine the reasonableness of the subscription now, rather than to wait until PG&E seeks to recover the cost of capacity in its rates because the alleged competitive harm would have occurred by then.

PG&E's share of the first year's annual revenue requirement based on the proportion of PG&E's subscription to total project volumes would be roughly $13 million; El Paso estimated that the annual revenue requirement was closer to $28 million.

We find it unnecessary to determine the reasonableness of PG&E's subscription at this time. We concede that PG&E's participation as a shipper provides the subscription to firm capacity that allows a greater volume to share the Expansion's costs. Indeed, by subscribing to roughly 64% of the 155 MMcf/d increase over the original project design, PG&E has made possible the $0.11 decrease in firm transportation rates that resulted from the upgrade. This is particularly true because PG&E did not market the additional capacity to the queue of prospective shippers established in the open season. While this gives the Expansion Project a competitive advantage, it does not render it anticompetitive. Any of the other pipeline sponsors, most of whom are natural gas producers and aggregators of gas on existing pipelines, could have subscribed to capacity on their own pipelines in order to maximize the capacity of their projects. The capacity could have been allocated to others later or used to transport pipeline supplies. None of the competitors have suggested why this competitive strategy was not available to it.

While we reserve the question of PG&E's need for 100 MMcf/d of firm transportation capacity for later review, we offer the following observations based on the record before us.

El Paso and Kern River have persuasively shown that PG&E's existing interstate supply, in-state supply, and storage capability are adequate to serve the needs of PG&E's core ratepayers through the year 2000. There is no need for additional capacity to serve the needs of PG&E's core ratepayers in 1994, when the Expansion Project is expected to commence deliveries.

PG&E's responsibility for procuring natural gas supplies to serve non-core ratepayers has been radically diminished by D.90-09-089, the decision on the Commission's rulemaking to change the structure of gas utilities' procurement practices. In that decision, the Commission required utilities to use their capacity rights to purchase gas supplies identified by individual customers on a non-discriminatory "best efforts" basis and to resell the gas to the customer. This level of utility service does not obligate PG&E to acquire firm transportation capacity to serve non-core customers.

Due to our unbundling of the gas procurement from the gas transportation function, D.90-09-089 also addressed the utilities' responsibility to provide transportation services. Specifically, PG&E was directed to make available to noncore transportation customers 250 MMcf/d of its capacity over its PGT line. Like the other utilities, PG&E is required to make available five levels of transportation service. Only two levels of service, core service and firm service for noncore customers, call for firm transportation capacity. The Commission explicitly anticipated curtailment of transportation services by listing curtailments by end use priorities. Clearly, PG&E is not required to provide firm transportation for all of its load in all events.

PG&E has not been encouraged to be a broker of transportation services, either. We did not envision a situation where a shipper or end user seeking firm transportation would seek those services from PG&E's existing system's ratepayers, who hold 100 MMcf/d of firm capacity rights on the Expansion. In other words, we did not unbundle the transportation function in order to relegate the risk of underutilization of capacity to PG&E's ratepayers.

We would prefer that any shipper or end user seeking transportation on the Expansion execute a firm transportation agreement with PG&E or purchase that service from an existing shipper.

PG&E's testimony in the Pipeline OII and in this case, that PG&E projects a need for an additional 300 MMcf/d in its service territory by the year 1995 may be well founded, but it does not justify PG&E's own subscription for firm capacity. That need should be met by others who hold capacity on the Expansion or other pipelines. It would be reasonable for PG&E to offer its 100 MMcf/d of capacity to the potential shippers who were identified in the open season process. In any event, as a part of PG&E's subsequent Expansion rate case proceeding, PG&E must show either that it has awarded that 100 MMcf/d to independent shippers or demonstrate why it needs the 100 MMcf/d or portion thereof of firm transportation capacity. We will not wait until PG&E seeks recovery of the cost of transportation by the Expansion to review the prudency of its subscription.

We find that there is no risk to ratepayers in attributing 100 MMcf/d of Expansion capacity to PG&E at this time. If a decision were to be made on the existing record, PG&E's shareholders would be liable for the disallowance of $13 to $28 million. We will review the reasonableness of PG&E's subscription during its first general rate case proceeding. A decision on the need for the subscription should be made at that time, so that the impacts of PG&E's ratepayer's contribution to revenue recovery can be recognized in the Expansion's rates. If we were to ignore this issue until PG&E sought recovery of Expansion rates, we would hamstring the allocation of risk which we intend to undertake in the first Expansion general rate case. After disposition of the issue of the reasonableness of the subscription, assuming PG&E does use Expansion capacity, the reasonableness of rates paid for Expansion transportation would be reviewed as for rates paid to any other interstate pipeline.

We believe it necessary to resolve the question of need for this subscription no later than the Expansion general rate case to attenuate the risk that ratepayers would pay for firm transportation capacity they don't need. Consideration in the general rate case would provide assurance that the Expansion Project stands a chance of recovering that $13 to $28 million of annual revenue requirement represented by PG&E's subscription.

H. <u>Equity Participation by Edison and SDG&E</u>

Both Edison and SDG&E have demonstrated that their participation in the Expansion Project is intended to serve their forecasted 1995 gas needs. Neither currently has access to a firm gas supply due to the interruptible nature of existing gas transportation service. Neither currently has access to any suppliers other than the southwest. We find that the access to alternative sources of gas from Canada available through the Expansion Project would contribute to supply diversity, reliability of supply, and lead to gas-to-gas competition that will benefit the ratepayers of these two utilities.

Kern River asserts that the equity option agreements between PG&E and each of these two utilities impose costs on existing ratepayers, as PG&E must maintain existing facilities for the use of the Expansion over the operational life of the Expansion Project. Kern River's concern is a permutation of its previously expressed argument that existing ratepayers will subsidize the Expansion Project. We find that PG&E is not ceding control of its existing system to the equity participants under the option agreements. PG&E's commitment of existing system facilities is no greater than if there were no option agreements. While the option agreements obligate the Expansion Project to undertake improvements when demanded by an equity partner, it is clear from the agreement that the requesting partner would bear all the expense of the improvements.

The option agreements require PG&E to maintain existing facilities, but PG&E will collect the cost of capital improvements from its partners. PG&E has proposed to assign the incremental cost of facilities improvements to either system if it can be determined whether the existing system or the Expansion Project occasioned the expense, and if not, the incremental cost will be allocated between existing system and Expansion based on throughput. If one of the utilities declines to contribute its pro rata share to the capital addition, its equity interest in the Expansion Project will be decreased accordingly. We have clarified that the sharing of the cost of additional facilities contemplated in the option agreements shall apply to facilities necessary to maintain the portions of PG&E's existing system used by the Expansion Project as well as to the Expansion's facilities. Taken together, these conditions will ensure that PG&E's ratepayers are not compelled to maintain the existing system for the benefit of the Expansion's equity participants without appropriate compensation.

Next, we review the demand of Edison and SDG&E for the incremental capacity represented by their subscriptions in order to determine whether their participation was undertaken to make the Expansion "viable."

Since the Expansion Project was originally conceived of as a means of bringing Canadian supplies to the southern California utilities, it can be said that without the utilities' subscriptions, there would be no Expansion Project. However, the Commission did encourage utility participation in an appropriate interstate pipeline project in D.90-02-016 because we anticipated that southern California utility electric generation demand for natural gas would increase steadily over the next decade.

We find that Edison's oil and gas average requirements have not fallen below an equivalent of 300 MMcf/d over the past decade. In addition, Edison's average annual gas requirements are forecasted to increase from 435 MMcf/d in 1995 to 616 MMcf/d in 2000. These requirements easily justify Edison's 200 MMcf/d of Expansion capacity.

We find that SDG&E will use its 100 MMcf/d of capacity to foster gas-to-gas competition and thereby obtain gas at the lowest possible price. The Expansion fits into SDG&E's strategy by providing firm transportation for Canadian gas to southern California. SDG&E expects that by contracting for gas priced below the average southwest gas market price, including the cost of delivery from Canada, it will directly realize the benefits of gas-on-gas competition for its customers and will lock this benefit in for future years.

Edison and SDG&E have shown a reasonable need for their capacity and the ability to fulfill their commitments to the Expansion. We give our limited approval to Edison's plan to hold its investment in the Expansion Project as regulated utility-related property, since Edison plans to transport gas over the Expansion solely for the benefit of its ratepayers. Reasonableness review and approval is required before Edison may recover the costs of its equity participation in rates.

We address Edison's concern that SoCalGas' intrastate facilities should be available to provide a matching level of service to Expansion shippers. As a public utility, SoCalGas is enjoined by § 453 Subsection (c) of the PU Code from discrimination in rates, or in any other respect, either as between localities, or as between classes of service. The testimony of SoCalGas' witnesses tends to show that there is existing capacity on SoCalGas' system to accommodate additional interstate deliveries of gas. However, the means used to provide that delivery to end users is highly contingent upon the location of the end users and the timing of the commencement of those deliveries. It is possible that incremental deliveries from one pipeline will not generate new costs, but those from another pipeline would cause SoCalGas to incur additional costs. Edison observes that SoCalGas supports the Western Gas Network instead of the Expansion Project, and fears that SoCalGas may influence the market's selection of new interstate pipelines by imposing discriminatory terms and conditions on Expansion shippers in contracts SoCalGas negotiates with them.

These concerns cannot be addressed in this decision, save for a brief observation. We have not reviewed the terms of SoCalGas' participation in the Western Gas Network or the allocation of margin from the transportation service between SoCalGas' ratepayers and shareholders. Since SoCalGas will face no competition for the distribution function of its existing system, the final delivery of Expansion gas to southern California consumers will be a monopoly function. We expect that the competitive environment for interstate pipelines will not be undermined during the final stages of delivery by any discriminatory practices by either LDC due to their interests in competing interstate pipelines.

Aside from the points already discussed, we will not review the utility option agreements between PG&E and Edison and SDG&E at this time. The terms of the final participation agreements may differ from the terms embodied in the option agreements, rendering unproductive any review of the option agreements at this time. If and when PG&E proposes to convey a portion of its interest in the Expansion Project to Edison or SDG&E, or to any other entity, it will be required to submit its proposal for Commission review because § 851 of the PU Code provides that any conveyance of ownership interest or control of the Expansion Project is subject to our review.

I. Position of SoCalGas

We take it for granted that PG&E's Expansion Project supplies will meet SoCalGas' quality specifications, particularly since much of the Expansion gas supplied to southern California will come from existing sources due to displacement. We also expect that PG&E will provide SoCalGas all non-proprietary information about shippers and deliveries necessary for SoCalGas to accommodate deliveries of Expansion gas on the SoCalGas system as soon as each shipper signs a firm transportation agreement with the Expansion Project.

SoCalGas asks the Commission to require a new interconnection agreement between itself and PG&E. Given the distinctions between PG&E's utility service and the Expansion Project's firm transportation function, we find that the two utilities should negotiate a new interconnection agreement.

SoCalGas seeks a separate proceeding to resolve the cost, cost allocation, and rate issues concerning the SoCalGas system arising from the construction of new interstate pipeline systems. SoCalGas would refrain from incurring any costs for construction unless such proceeding were held. SoCalGas also seeks indemnification of its pre-construction and post-construction costs from PG&E in the event SoCalGas has undertaken construction to support the interconnection of the Expansion Project and the Expansion is not built. In addition, SoCalGas seeks this Commission's pre-approval of necessary expansion costs to ensure recovery of those costs regardless of usage.

SoCalGas maintains that the Commission can expedite its construction of facilities necessary to interconnect with interstate pipelines only by approving necessary costs in advance of construction. We remind SoCalGas that while the interstate pipelines compete against each other, SoCalGas is a monopoly utility that has been granted exclusive rights to deliver natural gas in its service territory. It is required by its franchise to use its facilities and financial resources to provide service as needed.

Since the testimony in this proceeding shows that the basic SoCalGas system can easily accommodate the volumes contemplated on the Expansion Project, even without subtracting open season shipper volumes going to northern California, the Expansion should impose no need for additional SoCalGas intrastate delivery facilities. However, if the timing and operation of the competing pipelines require SoCalGas to deploy additional facilities, then SoCalGas can bring this matter to our attention.

Under normal circumstances, we would find that our established revenue recovery mechanisms would provide SoCalGas adequate assurance that it will recover the reasonable costs of its plant investment. However, SoCalGas must exercise its utility obligation to serve under conditions that we have declared will be shaped by market forces, rather than by regulatory determination. We encourage SoCalGas to accommodate the deliveries of Expansion gas to its service territory by planning for and making system improvements contemporaneous with the development of the Expansion Project. It would be reasonable for SoCalGas to incur pre-construction, construction, and post-construction costs to interconnect Expansion Project facilities regardless of actual usage; however, until the appropriate SoCalGas reasonableness review, we reserve our judgment on whether the specific costs of those undertakings are reasonable and should be recovered in rates.

We will not initiate a separate proceeding to consider the allocation of costs incurred by an LDC to accommodate incremental deliveries of interstate gas. If SoCalGas or any other LDC does in fact realize such costs, the matter may be presented for Commission review in a petition to modify D.90-02-016.

J. General Order 96-A

We will grant PG&E's request to waive Section II of GO 96-A. This will enable PG&E to file its tariff at the Commission in the same format as that used at the FERC. Since the Expansion Project constitutes the intrastate portion of a larger pipeline, and the interstate portion is tariffed at the FERC, we believe that waiver of the format requirements is reasonable because it will lessen the potential for confusion and dispute as to the terms and conditions of Expansion Project service.

On the other hand, we agree with DRA that Sections IX and X of GO 96-A should not be waived at this time because the Commission has not yet reviewed the terms of any of the firm transportation agreements contemplated by the Precedent Agreements.

Our reluctance is heightened by PG&E's admission that its proposed tariff is merely a rough draft. We realize that PG&E will begin to negotiate the terms of its firm transportation agreements with shippers after issuance of this decision, but we cannot anticipate the rates and terms of service of those agreements because this decision adopts only a pro forma tariff for the Expansion Project. Moreover, PG&E has raised the possibility that ownership of the Expansion Project may be shared with Edison and SDG&E pursuant to an equity agreement and that its shareholders may ultimately own the Expansion Project. We believe that the issues of risk allocation, ownership, and margin are so intertwined, yet unresolved at this time, that it would be imprudent to waive our subsequent review of PG&E's firm transportation agreements. PG&E may renew its request after it has filed its firm transportation agreements pursuant to Sections IX and X of GO 96-A.

V. Environmental Considerations

A. Preparation of the EIR

On June 13, 1989, the CPUC and the FERC entered into a Memorandum of Understanding to combine efforts to prepare a joint environmental impact report/environmental impact study (EIR/EIS). Subsequently, the Altamont Gas Transmission Company (Altamont), which has filed an application for CPCN with the FERC, was added to the joint EIR/EIS for environmental review.

The Commission is the lead agency under CEQA, since of all the approvals necessary for development, the Commission's action on the application for CPCN will be the most crucial to the development of the Expansion Project. Other state agencies with permitting authority over the Applicant's project are referred to as responsible agencies. The concerns and comments of responsible agencies were taken into account in the scoping and preparation of the Commission's EIR.

Joint public scoping meetings were held by the CPUC and the FERC in various locations potentially affected by the Expansion Project between September 18 and 20, 1989. Based on the comments received during the scoping meetings, a number of potential environmental impacts from the project were specifically identified for evaluation. These issues, plus the analyses required by CEQA to be included in an EIR, formed the scope of the EIR. Thus, in addition to the environmental impacts of the Expansion Project, the EIR has analyzed the following: possible alternatives to a proposed project that would reduce or eliminate any significant environmental impacts of the proposed project; the energy-use implications of the project; cumulative impacts; and growth-inducing impacts.

Following the preparation of a preliminary administrative Draft EIR/EIS, the Commission determined that various schedule constraints required the Commission to undertake its own environmental review of the PG&E Expansion Project under CEQA. Rather than publish a joint EIR/EIS with the FERC, the Commission would prepare an EIR in compliance with California's environmental statute. The environmental review required under the federal Natural Environmental Policy Act to be certified before the FERC may issue a CPCN for the PGT portion of the Expansion Project and the Altamont Pipeline would be contained in separate document.

On June 29, 1990, the Draft EIR was released for comment. The Draft EIR at that time incorporated analyses to fulfill its role as a joint EIR/EIS for the interstate as well as California impacts of the Expansion Project and the Altamont Project. Since the time the Draft EIR was circulated and the evidentiary hearings on the environmental impacts of the Expansion Project were held, the document has been revised to clearly indicate the California-only impacts of the Expansion Project and its alternatives.

Comments on the Draft EIR were received on August 21, 1990. Over twelve hundred written comments were received from the public, state and federal agencies, the Applicant, and parties to this proceeding. Oral comments on the Draft EIR were solicited at two public meetings in Antioch, California on August 21, 1990. These comments were addressed in the final EIR, issued in November, 1990.

B. Environmental Arguments

Evidentiary hearings on the environmental issues raised by the Application were held on August 13 through 17, 1990, in San Francisco. These hearings were intended to provide parties the opportunity to test through cross-examination any assertions concerning the potential environmental impacts and environmentally related costs of the PG&E Expansion Project.

1. Altamont Motion for Recirculation of Draft EIR

On the first day of hearings, Altamont filed a motion for recirculation of the Draft EIR. Altamont claimed that the document was defective in failing to properly inform the public of the potential impacts of the project because its allegedly confusing presentation of facts. In addition, the motion argued that inclusion of out-of-state environmental impacts in the comparison of alternatives violates CEQA, and that the Draft EIR's association of the in-state environmental impacts of the Kern River or the WyCal projects with Altamont is erroneous.

In its concurrent environmental brief, PG&E responded to Altamont's motion. The Applicant argues that recirculation is required only when "significant new" information is added to an EIR (Public Resources Code Section 21092.1). Altamont has not suggested that the Draft EIR is lacking any significant information, but that its information be edited or organized differently. We find that because no significant new information need be presented to cure any of the defects alleged by Altamont, there is no need to recirculate the Draft EIR.

PG&E also replied that Section 21080(b) of the Public Resources (Pub. Res.) Code merely exempts out-of-state developments from the requirements of CEQA, while Section 1002(4) of the PU Code prohibits the Commission from considering the out-of-state portions of projects when evaluating the merits of a project for a CPCN.

The Draft EIR contained a comparison of the out-of-state portions of the Expansion Project with the out-of-state portions of its alternatives because it was originally intended to embody the federal, as well as state, environmental review. Since the decision to sever the FERC from CPUC review had been made just weeks before the scheduled circulation of the draft document, there was insufficient time to excise the out-of-state discussion.

The standards for the sufficiency of an EIR were summarized recently in Kings County Farm Bureau v. City of Hanford, 221 Cal. App. 3d 692 (1990, cert. den.) at page 712. The court stated:

> "(Under the CEQA guidelines which appear in California Code of Regulations, title 14, section 15000 et seq. (Guidelines)), ... an EIR must be prepared with a sufficient degree of analysis to provide decision makers with information which enables them to make a decision which intelligently takes account of environmental consequences. CEQA requires an EIR to reflect a good faith effort at full disclosure; it does not mandate perfection, nor does it require an analysis to be exhaustive. Although disagreement among experts does not render an EIR inadequate, the report should summarize the main points of disagreement. (Guidelines section 15151). The absence of information in an EIR, or the failure to reflect disagreement among the experts, does not per se constitute a prejudicial abuse of discretion (Pub. Resources Code, Section 21005). A prejudicial abuse of discretion occurs in the failure to include relevant information precludes informed decisionmaking and informed public participation, thereby thwarting the statutory goals of the EIR process (Laurel Heights Improvement Assn. v.

Regents of University of California, (1988) 47 Cal.3d 376, pp. 403-405)."

Under these circumstances the inclusion of the out-of-state impacts of alternatives to the Expansion was not violative of CEQA. In any event, we do not find that inclusion of that analysis could have frustrated or confused any member of the public who was trying to understand the environmental consequences of the Expansion Project. No recirculation of the Draft EIR is required to compensate for the overinclusion of information in the draft when it provides the public with full notice of the impacts of the proposed project.

Altamont's concern that the Draft EIR improperly associated Altamont with other interstate pipelines is no reason for recirculation, either. PG&E analyzes the relation between the interstate pipelines in its response to the motion and suggests that analysis of the combinations is supported by the requirement that the cumulative impacts of several projects must be evaluated. We reach no independent conclusion on the merits of this issue; we stand by the analysis of project alternatives contained in the final EIR. It must be kept in mind that the document Altamont seeks to have recirculated it merely the Draft EIR. The Commission, as the decisionmaking body, is well aware of the distinction between the instate and out-of-state impacts of the proposed development and its alternatives. The fact that the draft was overinclusive does not mean that significant new information, as opposed to editing, is required in the final EIR. We determine that, in fact, the final EIR has rearranged information in a manner that makes it clear to this Commission and the public what project and environmental impacts are being analyzed by the document. The final EIR also considers the arguments of Altamont and Kern River concerning the role of their pipelines as alternatives to the Expansion Project in its analysis of need. We find that there is no need to recirculate the Draft EIR because any deficiency in the analysis was not serious enough to deprive the public of notice of the potential environmental impacts of the project and an opportunity for comment.

Altamont repeated its arguments for the recirculation of the Draft EIR in its August 21, 1990 comments on the Draft EIR. The appropriate responses to those comments have been incorporated in the final EIR which we certify today.

2. <u>Costs of Environmental Mitigation</u>

a. <u>PG&E</u>

At the Commission's request, PG&E assisted the CACD and its environmental consultant in preparing a cost estimate to reflect implementation of mitigation measures contained in the Draft EIR. Although PG&E did not agree with the mitigation measures or the assumptions on which the estimate was based, in the spirit of cooperation the Applicant filed the estimate as part of its witness' testimony. PG&E's witness testified that his estimate represented the Applicant's assessment of environmental mitigation measures that would be required in an "extreme case". Under this scenario, there is "a degree of reasonable likelihood of mitigation measure occurring" in PG&E's judgment. The estimate differs from one that the witness would have made under a "worst case" scenario, that is, one where remotely possible mitigation measures might be necessary.

PG&E interpreted the Commission's objective as the establishment of a "reasonable extreme-case cost" for environmental mitigation to incorporate into the overall cost cap for the project required by Public Utilities Code section 1005.5. In its brief, PG&E claims that the cost cap should exclude elements which have a very low probability of occurring and the costs of rerouting mitigation alternatives. The Applicant states that costs for unestimated realignments or reroutes were either subsumed in the original cost estimate, or they have such a low probability of adding to actual mitigation costs that it is inappropriate to include them in a reasonable extreme-case estimate.

PG&E claims that after deducting from the extreme-case estimate those elements it believes fall beyond the bounds of a reasonable extreme-case mitigation cost estimate, the reasonable extreme-case cost of mitigation is $25.5 million. PG&E's witness claimed that the Draft EIR's mitigation plan included several high-cost mitigation measures that are not necessary to reduce impacts to less than significant. Realignment of the route to avoid special status species would not increase the construction cost estimate because the construction cost estimate builds in a contingency for minor realignment, according to PG&E. PG&E also presented testimony that the actual acreage of vernal pools within the disturbed right of way was less than the consultant's worst-case scenario. Based on PG&E's prior experience with kit fox mitigation in the course of retrofitting the Stanpac 2 line, PG&E revised downward the estimate of compensation for loss of kit fox habitat.

Alternatives to rerouting the pipeline to avoid destruction of vernal pools along the right of way were suggested to show that rerouting is not reasonable and should not be incorporated into the mitigation cost estimate. PG&E stated, "...rerouting will do virtually nothing to protect either the vernal pool habitat on or adjacent to the existing right-of-way because these areas will continue to be affected by necessary pipeline maintenance and use by private landowners....In the end, adoption of rerouting as a mitigation measure would eliminate the environmentally superior opportunities to restore, acquire and protect, or enhance vernal pool habitat in the vicinity of the project." (PG&E Concurrent Phase II Brief, pp. 12 and 13.)

b. Kern River

Kern River's brief on environmental issues argued that the Draft EIR improperly includes a review of impacts occurring outside of California; that the Draft EIR erroneously treats the Kern River project and the joint Kern River/Mojave pipeline systems as alternatives to the Expansion Project; that the Draft EIR incorrectly defines the Altamont/Kern River alternative such that the comparative evaluation is distorted; and because of the magnitude and number of errors contained in the Draft EIR, a corrected EIR must be recirculated so that interested parties may have adequate notice of the issues and comments can be better focused on the environmental impacts of the Expansion Project and the real alternatives to the project.

Our disposition of these claims appears under "Motion of Altamont to Recirculate Draft EIR" and need not be repeated here.

c. Altamont

By its concurrent brief on environmental issues, Altamont argues that a correct comparison of the California environmental impacts of the Expansion Project and the Altamont Project (its only alternative) demonstrates that the Altamont Project is feasible and environmentally superior, and that in the absence of any overriding considerations, CEQA requires the denial of PG&E's application for CPCN. Altamont also alleges that the cost of environmental mitigation will adversely affect the cost of the Expansion Project. Altamont then reiterates, in more detail, the claims it made in its motion to recirculate the Draft EIR with the added claim that after recirculation of the draft, an evidentiary hearing on the final EIR must be held before determining whether or not to grant PG&E a CPCN.

d. Discussion

The Commission has taken the criticisms of the parties on adequacy of the Draft EIR into consideration in the preparation of the final EIR. Since the circulation of the draft document, the CACD and its consultants have identified the necessary resource studies and either obtained them or incorporated them in the adopted mitigation plan. The Commission has consulted with the Department of Fish and Game concerning the Project's potential impact on threatened or endangered species of vegetation or wildlife. Cumulative impacts have been identified and discussed extensively in the final EIR. The final document contains a comprehensive list of mitigation measures required to reduce, as much as possible, the significant negative impacts of the Expansion on the environment. Those mitigation measures are attached as Appendix B to this decision and incorporated by this reference. By adopting the final EIR today, we find that the mitigation measures will minimize the significant negative effects of the Expansion; we also recognize, as discussed below, that certain negative impacts are unavoidable and cannot, by any feasible means, be mitigated. A statement of overriding considerations is adopted in this decision, thus allowing the Commission to authorize the CPCN for the Project consistent with Section 21002.1 of the Pub. Res. Code.

Most of Altamont's arguments were directed toward the CEQA process. That process was intended by the state legislature to inform the public and other governmental agencies of the environmental impact of a proposed project. (No Oil Inc. v. City of Los Angeles (1974) 13 Cal.3d 68,86.) It was not intended to provide opponents of a project with a means of interminably delaying the project. In Long Beach Savings and Loan Association v. Long Beach Redevelopment Agency, the lead agency approved a negative declaration for a project with a number of mitigation measures added in response to public comments. We find PG&E's citation to this case to be on point: "We find nothing in CEQA commanding respondents to circulate for public review additional mitigation measures made in response to comments by those who oppose the project. To allow the public review period to proceed ad nauseam would only serve to arm persons dead set against a project with a paralyzing weapon - hired experts who can always 'discover' flaws in mitigation measures." (Long Beach Sav. and Loan v. Long Beach Redevelopment Agency (1986), 188 Cal.App.3d 249, 283.)

Altamont claims that the analysis in the Draft EIR is inadequate because site-specific studies of resources have not been completed. We repeat that perfection is not required in an EIR; it is sufficient that a good faith effort at full disclosure was made to enable those who did not participate in its preparation to understand and to consider meaningfully the issues raised by the proposed project. The itemization of resources is in sufficient detail to enable us to require pre-construction surveys and studies to analyze the presence of special status species and potentially sensitive soil, water, and air conditions and, on the basis of those studies, require the Applicant to conform to the appropriate mitigation measures.

Altamont candidly asserted that its project was a viable alternative to the Project and that its chances of development would be lessened if the Commission granted PG&E the requested CPCN. This position obviously underlies Altamont's challenges to the Draft EIR process. While we appreciate vigorous advocacy of a party's position, we do not condone arguments which have as their only purpose, the delay of our proceedings. In its brief, Altamont claimed that the Draft EIR should be revised and recirculated, and that hearings on the "resulting Final EIR" should be held to determine whether a CPCN should be issued. There is no statutory authority requiring public hearings before a lead agency adopts a final EIR. Altamont does not indicate what will be gained by holding such hearings. While it had challenged the decision to bifurcate the proceeding into environmental and non-environmental portions, claiming that the interrelationship of the Expansion Project's environmental impacts, mitigation measures, and the costs of the development required an integrated proceeding, Altamont does not explain what, besides the Expansion's cost, is affected by the environmental requirements on the project. We will determine the cost of environmental mitigation and add that to the Expansion's cost cap. It is not necessary to know with certainty the costs of environmental mitigation before those estimates are adopted in a CPCN decision because § 1005.5 subsection (a) of the PU Code requires only the adoption of a maximum project cost. No legitimate regulatory purpose would be served by holding evidentiary hearings after the certification of the EIR.

We do weigh the testimony of Altamont's witness on the potential cost of environmental mitigation against that of PG&E's witness, however. In his testimony prepared in cooperation with the CACD, PG&E's witness estimated that the third quarter 1990 unescalated cost of implementing the environmental mitigation assumed by CACD's consultants would total $28,984,000. Using the escalation figures that PG&E used to arrive at its construction cost cap, that figure would be $36,762,000 by the time of project completion in 1994. Altamont's witness stated that the environmental mitigation costs for large California projects are 5% to 10% of total project costs. Since PG&E's estimated cost cap is $696 million, mitigation costs at 5% would reach $34.8 million; at 10% the costs would total approximately $69 million. These figures bracket the $36,762,000.

We disagree with PG&E's claim that the cost of its own "extreme case scenario" should be reduced by $3 million. For example, the Applicant challenges the assumption that avoidance or mitigation of adverse impacts to endangered plants would require such extensive rerouting of the pipeline that the Applicant would incur additional expense. The standard construction budget allows for "minor adjustments in the center line according to field concerns", according to the witness. However, when asked how great a deviation could be made within the scheduled budget, the witness could not state the "threshold level" at which costs would not be covered by the contingency budget.

PG&E's testimony that actual vernal pool acreage is less than that identified by the consultant is not dispositive of the issue of cost, either. PG&E has, so far, focused on the cost of rerouting to avoid the resource. The final EIR acknowledges that acquisition and restoration of vernal pool habitat may be required to mitigate damage to vernal pools. It is possible that the cost of this mitigation measure will exceed the costs estimated in PG&E's "extreme case" scenario.

Given the uncertainty in the number of resources that will be found when PG&E completes the required field studies as part of the pre-construction mitigation, we find it is reasonable to assume a cost cap of $40 million for the environmental costs of the Expansion Project. This number is well within the range of estimates on the record. By adopting this number as a cost cap we do not find that environmental mitigation will in fact require $40 million. We conclude that it is reasonable to expect that mitigation measures will cost up to $40 million because previous field studies were done under conditions where the existence of special status species could not be ruled out, the values of land impacted by the project have not been conclusively established, fact that many contingencies may occur over the roughly 550 miles of pipeline development.

C. <u>The Commission's Investigation</u>

A CPUC investigation into California's need for incremental interstate gas capacity began on December 19, 1988, and concluded with a decision issued on February 7, 1990 (I.88-12-027, "the OII"). The decision (D.90-02-016) expressed the position that California has a near-term need for 900 MMcf/d of new natural gas capacity, and a longer-term need for somewhere between 1.6 to 2.1 billion cubic feet per day (Bcf/d). "Near-term" and "long-term" correspond roughly to the years 1995 and 2005, respectively, although the CPUC notes that the considerable uncertainty underlying its need projections argues against using a specific year for either the short- or long-term need projections.

These need projections were based on the 1989 California Gas Report (CGR), a document prepared by California's gas and electric utilities, and subsequently modified to account for the perceived need to build gas capacity in excess of the projected demand for gas. Approximately 500 MMcf/d of the near-term need projection is to provide this so-called "slack" capacity, which is expected to be useful in providing enhanced service to non-core customers and in stimulating additional competition among gas suppliers. Similarly, the long-term need of 1.6 to 2.1 Bcf/d includes a slack factor of 500 to 1000 MMcf/d.

Embedded in the CPUC's need projections is an acknowledgement of the need for new gas supply to offset the need for burning oil, for air quality reasons, in California's South Coast Air Basin. It is estimated that 100 to 150 MMcf/d of new gas supply is necessary to accomplish this (Jim Hendry, CPUC, per. comm.). This estimate agrees fairly well with the report prepared for the OII by the DRA, which estimated that 110 MMcf/d would be needed to offset the burning of oil and other fuels. Thus, the environmentally-based need for new gas supply and capacity would appear to be fairly limited, accounting for less than 20% of the capacity represented by the PGT/PG&E project, and less than 10% of the perceived long-term need for additional gas supply.

The need expressed in the OII, perhaps with the exception of the "slack capacity" component, is more properly understood in the context of evaluating alternatives as a need for natural gas services, in that gas is useful not for its own sake but for the services it provides. Thus, underlying the CPUC's gas capacity decision is a perceived need to provide additional energy services, which, in general, could be provided either by increasing the supply of gas, or alternatively, by increasing the efficiencies of the systems either supplying or using the gas. The CPUC is therefore considering not only gas <u>supply</u> projects as possible alternatives to the PGT/PG&E project, but also measures--such as improving energy efficiency and optimizing the existing pipeline system--that would reduce the <u>demand</u> for gas, which in turn frees up existing supply for other uses.

The OII decision appropriately used a statewide resource planning perspective on the issue of need for additional gas supply and capacity. The EIR that has been prepared for the Expansion Project takes a similar approach. That is, it is assumed that the basic objective satisfied by the PGT/PG&E project is that of providing a major increment of the projected need for natural gas services in California. While no two projects considered in this EIR would satisfy precisely the same objectives, in a broader sense, and possibly with some modification to a particular project, they are in fact substitutes for one another. For example, although the Kern River/Mojave project is intended to serve EOR demand, by doing so, the project would free up supplies that had been destined for that market. That "excess" gas could serve southern California electric generation demand. Thus, under certain circumstances, the Kern River/Mojave project could substitute for the Expansion Project. Despite the fact that each of the interstate pipeline project proponents may legitimately claim that it has subscribers for its project, it is not realistic to think that California currently needs all of the projects which are proposed to be built. Those projects, which were evaluated as alternatives, total approximately 2.55 billion cubic feet per day of capacity.

D. **Project Alternatives**

As the lead agency, the Commission must consider alternatives to the Expansion Project if those alternatives would eliminate or reduce any of the significant environmental impacts associated with the Expansion Project. Alternatives are to be considered even if they "would impede to some degree the attainment of the project objectives, or would be more costly." (CEQA Guidelines Section 15126(d)(3)) One of the alternatives which must be considered is the "no project" alternative, wherein the proposed project would simply not be approved. The EIR must identify the environmentally superior alternative among all the alternatives considered.

Consistent with the Commission's statewide resource planning perspective, the EIR considered what alternatives to the Expansion Project could satisfy California's need for additional gas capacity and supply. The basic objective that would be satisfied by the PGT/PG&E project, and that was assumed for the purpose of identifying possible alternatives, is the provision of a major increment of the projected need for natural gas services in California. More specifically, the applicant's project could fulfill one of two objectives identified in the gas capacity decision: Either it could provide a major fraction of the near-term need, that is, need projected to exist by 1995, or a major fraction of the longer-term need, or need expected to materialize by 2005.

In order to identify alternatives to the Expansion Project, we first considered which of these two objectives the PGT/PG&E project would be capable of fulfilling. This, in turn, is influenced by the outcome of the other interstate pipeline projects which are being regarded as project alternatives in the EIR. If one of the other interstate projects such as the Kern River project or the combined Kern River-Mojave project is built first, it would generally satisfy the projected short-term need. The only purpose of the Expansion Project would be to address longer-term projected need. Since sound resource planning dictates that projects not be built significantly in advance of need, and since need increases gradually over time, the need for a second major interstate gas pipeline project would be deferred once the first were built. The length of the deferment would depend largely on the capacity of the pipeline that was built, with the joint Kern River-Mojave alternative effecting the longest deferment. It would also depend on future, presently unanticipated developments in the gas supply and demand situation.

In determining the range of reasonable alternatives to the PGT-PG&E project it was necessary to consider projects in addition to these that could supply comparable amounts of new gas to California. Projects which may be capable of saving or conserving gas, or making more efficient use of existing California pipeline capacity, thereby making existing supplies of gas available for new uses, were considered as well. It was necessary to consider such projects for at least two reasons. The first is that the OII decision, which identified the projected need for new gas capacity and supply, did not address the potential for improving the efficiency of gas use beyond that reflected in the 1989 California Gas Report. The second reason is that the CEQA guidelines explicitly discourage approval of projects which encourage the use of large amounts of energy and, in particular, projects which increase reliance on natural gas, which is recognized to be a high-quality, non-renewable energy resource. Because the Expansion Project would facilitate the depletion of large quantities of natural gas, we considered whether there are alternatives which offer the potential to decrease the incremental demand for natural gas. Chapter 5 and Appendix 5 of the Draft EIR address this question. Together, they suggest that implementation of a combination of energy efficiency measures and improvements to the existing natural gas system in California has the potential to eliminate the need for the PGT/PG&E project.

The EIR considered eight project alternatives in addition to the Expansion Project and the no-project alternative. Six of these are interstate pipeline projects with pending or approved applications before the FERC, all of which are discussed at length in the Commission's Decision 90-02-016. These projects and their respective capacities are: Altamont (715 MMcf/d); Mojave (600 MMcf/d); Kern River (700 MMcf/d); WyCal I (650 MMcf/d); WyCal II 500 MMcf/d); and Joint Kern River-Mojave (1100 MMcf/d).

The other two alternatives are referred to as the Integrated Intrastate and Energy Efficiency/System Optimization alternatives. The Integrated Intrastate Alternative would provide approximately 600 MMcf/d to California using existing capacity and authorized deliveries from the El Paso and Transwestern systems. This alternative would require the construction of a 16.5 mile connector line from Arizona to the city of Needles, California.

The Energy Efficiency/System Optimization alternative entails the broad-scale implementation in the residential, commercial, and industrial sectors of commercially available, technically proven, cost-effective energy efficiency measures. The measures assumed in this alternative go beyond those already factored into the gas demand forecasts reflected in the Commission's gas capacity decision. This alternative also entails the adoption of certain measures, such as optimal use of gas storage and capacity sharing, which would make more efficient use of California's existing gas capacity, thereby decreasing the projected need for new capacity.

E. <u>Comparative Environmental Analysis of Alternative Corridors</u>

The EIR analyzed alternative routes for six segments of the applicant's proposed corridor alignment in an effort to avoid or reduce significant, unmitigable impacts associated with particular sections of the applicant's proposed project. Two of these alternatives--Jepson Prairie Preserve and Brentwood--received a level of analysis comparable to that of the corresponding alignments proposed by the applicant. The remaining four alternative routes were identified after the issuance of the Draft EIR, and were therefore necessarily analyzed in lesser depth than the corresponding alignments proposed by the applicant. CEQA does not require that alternatives be analyzed in the same level of detail as the proposed project. One of these four possible reroutes--the Solano County Vernal Pool Reroute--affects a portion of the Jepson Prairie Preserve alternative route identified in the EIR as the environmentally superior alignment. A second reroute--the Contra Costa Alkali Meadow and Vernal Pool Reroute--affects a section of the Brentwood alternative corridor identified in the EIR as the environmentally superior alignment. In addition to the corridor alternatives, the EIR also analyzed three alternatives to the applicant's proposed site for the Brentwood Compressor Station in Contra Costa County.

1. Jepson Prairie Preserve Alternatives and Mitigation Reroute for Alternative (Mileposts 889-897)

The Jepson Prairie Preserve is a 1600-acre private nature preserve owned and managed by The Nature Conservancy, a private, non-profit environmental conservation organization. The preserve contains a portion of the best remnant of native Central Valley grassland remaining in California, as well as a mosaic of vernal pools, which are increasingly rare and also provide the sole habitat for two vernal pool organisms: the delta green ground beetle and Solano grass. Both of these species are listed as endangered by the Federal Government and as such are protected under the U.S. Endangered Species Act.

The Applicant proposed three different Jepson route alternatives in its PEA. The Draft EIR identified one of these routes, Alternative B, as the environmentally preferable route among the three but still concluded that all three routes would disturb vernal pools. Since there is no proven method of restoring disturbed or degraded vernal pools, and since they are both rare biological formations and provide habitat to two endangered species, it was necessary to attempt to identify alternative routes which would avoid or reduce vernal pool impacts.

With PG&E's assistance, a new route--the Solano County Vernal Pool Reroute (Solano Reroute)--was identified and a preliminary analysis of impacts was performed and summarized in the Final EIR. In its comments on the proposed decision, the Department of Fish and Game (DFG) concluded that Alternative B was still the environmentally preferable route. We will rely on the expertise of the DFG on this issue and adopt Alternative B as the pipeline route between mileposts 889-897.

2. **Brentwood-Antioch Route Alternatives and Contra Costa County Alkali Meadow and Vernal Pool <u>Reroute (Mileposts 903-933)</u>**

Four routes through the Brentwood-Antioch area, including the one originally proposed by the applicant, were studied in the Draft EIR. All four routes would have significant, unavoidable environmental impacts, even assuming that all recommended mitigation measures were implemented. However, Alternative 4 is the superior route of the four, as it would have the least effect on special-status wildlife and plant species, land use, and cultural resources. Alternative 4's significant, unmitigable impacts would be in the areas of geology, vernal pools and alkali meadows, and public safety.

The Contra Costa County Alkali Meadow and Vernal Pool Reroute (Contra Costa Reroute) was studied to determine whether Alternative 4 could be modified to reduce or eliminate its impacts on alkali meadow and vernal pool areas. The Final EIR concludes that modifying Alternative 4 to incorporate the Contra Costa Reroute would eliminate completely these impacts. It would also have fewer significant impacts on land use plans and policies than the unmodified alignment.

Alternative 4, as modified by the incorporation of the Contra Cost Reroute, is adopted as the approved alignment for the applicant's project between Mileposts 903 and 933.

3. <u>Brentwood Compressor Station Site Alternatives</u>

Three alternative sites were analyzed in addition to applicant's proposal to expand the existing station. With the adoption of Brentwood Route Alternative 4, the applicant's proposed expansion of its existing station would no longer be feasible because it is located too far from Alternative 4. Each of the three alternative stations would require the construction of an electric transmission line as a power source for the station, and each site would require approximately 100 acres, of which 80 acres would be buffer area.

All three of the alternative sites would have significant and unavoidable impacts, even if all the recommended mitigation measures were implemented successfully. Overall, however, Site C would have the fewest impacts. As such, it is adopted as the site for the compression facilities necessary in Brentwood for the applicant's project.

4. Shasta County Mitigation Reroute <u>Alternatives (Mileposts 703-704)</u>

Two reroutes were proposed and analyzed in the Final EIR to avoid a special native plant community in Shasta County known as the northern interior cypress forest. One of these would go east of the proposed route, while the other would go west of it; the east and west routes are 0.7 and 0.8 miles long, respectively, which is just 0.1 mile longer than the corresponding sections of the proposed route. The EIR concludes that with appropriate mitigation the west route is environmentally superior to the proposed route because it would avoid the northern interior cypress forest and would have fewer visual impacts.

The Shasta County West Route Alternative, between Mileposts 703 and 704, is adopted for the alignment of the applicant's project to mitigate for the significant, unmitigable impacts that would result from the applicant's proposed alignment through the northern interior cypress forest.

5. **Tehama County Vernal Pool Reroute (Mileposts 731-781)**

This reroute was selected to avoid or reduce impacts to vernal pools in Tehama County. The reroute would be approximately 59 miles long, about 7 miles of which would follow the applicant's proposed route. The Final EIR concludes that the reroute would be environmentally inferior to the proposed route. The former would create greater noise, visual, and public safety impacts because it would be within 50 feet of 45 more residences than the proposed route. The reroute would also have potentially significant and unavoidable land use impacts because most of it would be located outside existing or planned utility rights-of-way, and because it would preclude access to mineral resources throughout most of its right-of-way. These impacts were judged to outweigh the potential for significant, unmitigable impacts to vernal pools that would occur if the vernal pool mitigation measures adopted in this decision, which are experimental in nature, should not be successful.

The applicant's proposed route, which was described in the draft EIR, is adopted in favor of the Tehama County Vernal Pool Reroute.

F. **Environmental Impacts**

The EIR analyzes the environmental impacts that may or would occur as a result of constructing and operating the Expansion Project. Separate comparative analyses are presented for each of the possible reroutes of the pipeline. The EIR also includes analyses of those impacts stemming from the construction and operation of the possible alternatives to the Expansion Project. Except in the case of the Jepson Prairie Preserve (Mileposts 889-897), the final EIR identifies the environmentally superior alignment of the Expansion Project. (We have determined that Alternative B, which was described in the draft EIR, is the environmentally preferred route.) The environmentally superior project among the applicant's project and the project alternatives is identified, and where possible, the respective projects are ranked in order from most to least environmentally desirable.

The environmental impacts of the Expansion Project should be considered under two circumstances: (1) development of the Expansion Project with no mitigation besides that contained in the PEA, and (2) development subject to the full set of mitigation measures identified in the final EIR. Due to the location, nature, and scale of the proposed pipeline project, the Expansion Project as proposed in the applicant's PEA would result in substantial environmental impacts in virtually every relevant category: geology, soils, vegetation, wildlife, fisheries, air quality, noise, public safety, cultural and archaeological resources, visual resources, hydrology and water quality, socioeconomics, depletion of large quantities of non-renewable resources, cumulative impacts, growth inducement, and emissions of greenhouse gases.

Even with the stringent mitigation recommendations that are contained in the final EIR, the applicant's project would have a significant adverse impact on the environment. While the mitigation measures that are being imposed in this decision reduce many of these impacts to a level deemed to be less than significant, they by no means reduce all of them to such a level. The significant, unmitigable impacts of the project include the following:

1. The possibility of pipeline ruptures due to potential seismic and volcanic activity in areas to be traversed by substantial portions of the pipeline and the corresponding threat to health and safety. Because of the risk of extended outages of the proposed pipeline and the existing line to which it would be adjacent, there would also be significant socioeconomic and public health risks associated with the volcanic and seismic risks due to the fact that disruptions in energy services can lead to a variety of adverse social, economic, health, and safety impacts.

2. Depletion of large quantities of natural gas, a high-quality, non-renewable energy resource and the potential for encouraging inefficient and wasteful uses of natural gas.

3. Potential for significant impacts on four endangered, threatened, rare, or other special-status plant species and their habitat.

4. Potential for loss of prime farmland.

5. Significant air quality impacts due to carbon monoxide emissions in the South Coast Air Basin.

6. Potential for significant adverse impacts on lands of cultural importance to Native American communities.

7. Potential for significant growth-inducing impacts.

8. Incremental addition of substantial quantities of greenhouse gases (i.e., carbon dioxide and methane).

The above impacts reflect the level of significant environmental impacts of the Expansion Project only if the environmental mitigation orders in this decision are entirely successful in achieving their objectives. PG&E's faithful and timely implementation of the environmental mitigation orders is necessary to achieving the minimum level of environmental disturbance. Since we cannot guarantee the success of mitigation measures, the possibility exists that the actual significant environmental impacts will be greater than those indicated in the EIR.

G. <u>Comparative Environmental Impacts of Alternatives</u>

The EIR ranked the Expansion Project against the alternative interstate pipeline projects, the integrated intrastate pipeline project, the energy efficiency/capacity optimization project, and the combination of the energy efficiency/capacity optimization alternative with the integrated intrastate pipeline alternative. These rankings were based solely on environmental impacts in California.

Like the Expansion Project, all of the interstate pipeline projects would have substantial significant environmental impacts in California, both before and after the imposition of mitigation measures. Overall, however, these alternative projects would have less serious environmental impacts, both without and with mitigation, than the Applicant's project. The integrated intrastate alternative, in turn, would have far less serious environmental impacts than any of the interstate projects. The energy efficiency/capacity optimization alternative would have virtually no significant adverse environmental impacts, and as such, is the environmentally superior project alternative.

The EIR delineates two different sets of environmental rankings of the applicant's project and the various project alternatives: one for the near-term project objective, and another for the longer-term objective. These conclusions, which are valid whether each project is subject to mitigation measures or not, are as follows:

1. **Near-Term Project Objective**

   a. The energy efficiency/system optimization (EE/SO) alternative is clearly the environmentally superior project alternative, as it avoids essentially all of the impacts associated with the construction and operation of major pipeline systems, and by its nature makes efficient use of energy and avoids substantial depletions of non-renewable resources.

   b. The Integrated Intrastate alternative is second only to the EE/SO option. However, the availability of intrastate supplies is in question beyond 1995, which suggests that another alternative may be needed by then. Coupling the integrated intrastate alternative with the EE/SO alternative would be the optimal solution to near-term need. This option would essentially result in the same level of environmental impacts as the integrated intrastate option by itself, and in terms of satisfying the project objective, would be considerably superior to either alternative by itself. Combining the two would also provide additional time to do a comprehensive study of the EE/SO option.

   c. The Kern River project would result in significantly greater impacts than any of the above options, but would be significantly preferable to the remaining alternatives, including PGT/PG&E.

   d. The PGT/PG&E project would result in the greatest level of significant environmental impacts of any of the alternatives considered in this EIR. Given the clear environmental superiority of the combined EE/SO and Integrated Intrastate options, it would be preferable, from an environmental perspective, to defer a decision on the PGT/PG&E application before the CPUC, and to immediately undertake studies of the EE/SO and Integrated Intrastate alternatives, in order to more carefully evaluate their collective ability to satisfy near-term gas demand.

If for some reason the Integrated Intrastate alternative was found to be infeasible, the CPUC could always reconsider the PGT/PG&E application. This deferral period would also be useful in that the likelihood of any of the other interstate pipeline alternatives being built should become clearer over time. If in fact one or more of them is being built or on the verge of being built, then whether or not the Integrated Intrastate alternative was found to be feasible, the CPUC would be evaluating the PGT/PG&E project in terms of its appropriateness in meeting Project Objective #2, i.e., the long-term rather than the near-term need.

2. Longer Term Project Objective

The conclusions with respect to the environmentally preferred actions the CPUC could take in order to meet the longer-term objective are generally consistent with those above for the short-term objective, except that the Integrated Intrastate alternative is not assumed to be capable of contributing toward meeting the longer-term objective. The conclusions are:

a. The EE/SO alternative is clearly the environmentally superior project alternative, as it avoids essentially all of the impacts associated with the construction and operation of major pipeline systems, and by its nature makes efficient use of energy and avoids substantial depletions of non-renewable resources. Because this alternative should be capable of providing significantly greater energy and capacity savings over the longer-term than over the shorter term, a stronger argument can be made for this alternative for meeting the longer-term objective than for the short-term objective, when one does not consider combining it with the Integrated Intrastate alternative.

b. The Kern River project would result in significantly greater impacts than the EE/SO option, but would be significantly preferable to the remaining alternatives, including PGT/PG&E.

c. The PGT/PG&E project would result in the greatest level of significant environmental impacts of any of the alternatives considered in this EIR. Given the clear environmental superiority of the EE/SO option, it would be preferable, from an environmental perspective, to at least defer the PGT/PG&E application before the CPUC, and to immediately undertake an in-depth study of the EE/SO option, building on the analysis contained in Chapter 5 and Appendix 5 of the Draft EIR, and on ongoing work at the CPUC and elsewhere.

This approach has the added advantage that if at some future point it was determined that the EE/SO option could not provide the requisite energy services and capacity, the CPUC could always reconsider the PGT/PG&E application.

H. Adoption of Mitigation Measures as Condition of Certification

The final EIR contains a tabular summary of significant impacts and mitigation measures for the Expansion Project in California (Table 2-5). This table lists the resource, level of impact assuming that the rec mmended mitigation is successful, and the impacts which are significant and unavoidable, even with mitigation measures.

The identified resources are those which are required to be considered by CEQA. California's Environmental Quality Act requires the lead agency to certify, after completion of the appropriate environmental study, that the proposed development either will or will not have any significant negative impact on the environment. If the project is found to have a significant negative impact, then the lead agency may either deny approval or adopt a statement of overriding considerations and approve the project.

Based on an analysis of the potential impacts of the proposed project and potential reroutes as described in the draft and final EIR, including cultural resource and special-status species surveys of the entire proposed Expansion route, consultation with resource specialists, and research in technical journals, the EIR consultants have concluded that the great majority of the Project's impacts on resources can be reduced to a less-than significant level. However, this result can be achieved only if the consultant's proposed mitigation measures are adopted as a condition of issuance of the CPCN.

The mitigation measures imposed on the Expansion Project are attached as Appendix B to this decision. Since the Expansion Project will involve excavation and other ground disturbance over its entire length of 415 miles, the implementation of the erosion control and restoration plan is necessary to mitigate soil erosion, soil compaction, loss of topsoil, and degradation of water quality. Impacts on hydrology and water quality are mitigated by construction during the dry season, compliance with state and federal agency regulations, and implementation of stream crossing and hydrostatic testing mitigation plans.

The loss of plant communities and habitat for threatened and endangered species is to be mitigated by recontouring, conducting preconstruction surveys, revegetation at either a 3:1 or 4:1 replacement ratio, avoiding the resource, transplanting, and acquisition of the plant community for long-term preservation. Impacts to wildlife will be mitigated by avoidance of habitat during breeding and rearing period and "critical periods," which shall be defined by the State Department of Fish and Game, conducting preconstruction surveys, and avoidance of construction in the habitat. Fisheries are to be protected by implementation of FERC "Stream and Wetland Construction and Mitigation Procedures," boring under the Fall River, and limitation of construction to certain months. Surveys and toxic sediment disposal plans will be developed with named agencies.

Impacts on air quality along the route will be controlled by suppressing dust and proper maintenance of construction equipment and installation of best available control technology for NOx. We note here that PG&E should be required to retrofit all of the compression units on the existing system that will be used directly or indirectly to move Expansion Project gas with reasonable available control technology (RACT) or best available retrofit control technology (BARCT) , as available, as defined by clean air agency guidelines and implemented by the local air pollution control district in which the specific compressor unit is located, for NOx. This shall be done at the expense of the Expansion Project, not existing ratepayers. This upgrade is required because PG&E will be replacing or modifying parts of the compressor units to accommodate the expanded facilities. Since these modifications will facilitate the operation of the new gas-fired Delevan compressor and the new Brentwood compressor, the modifications are contributing to cumulative impacts on air quality. Their effect on air quality should be minimized by the use of BARCT or RACT.

Impacts from construction noise will be mitigated by limiting construction to daytime hours and by notifying people in advance of blasting. Transportation and public safety impacts will be partially mitigated by observing Department of Transportation and CPUC regulations.

Visual resource impacts will be mitigated by implementation of the erosion control plan and minimization of clearing and areas affected by stream crossings. Impacts to prehistoric and historic archeological resources, fossil bearing formations, and historic places would be avoided by relocating the pipeline, partially mitigated through implementation of a data recovery program.

We find that PG&E must carry out the mitigation measures suggested in the final EIR in order to allow the Commission to find that the Expansion's impacts on the environment are less-than-significant for the above-described resources. If PG&E should determine that any of the mitigation measures cannot be successfully implemented, the Commission would have to reevaluate the extent of the Expansion Project's significant environmental impacts. We express this concern especially when the mitigation consists of realigning the pipeline, since this may not always be feasible.

However, the environmental study has identified several resources occurring along the pipeline route which will sustain unavoidable significant impacts, even if all of the proposed mitigation is feasible and successfully implemented. The impacted resources include 30.8 acres of vernal pools which the Expansion would destroy, and one special status plant species potentially affected. As much as 20 acres of prime farmland may be lost and there would be unavoidable conflicts with county land use plans associated with the Brentwood Compressor Station in Contra Costa County. Hazards in the immediate vicinity of the pipeline plus the loss of natural gas to downstream users may result from the potential for ground disturbance where the pipeline is routed over 400 miles of active seismic zones and 85 miles of active volcanic zones. There is no mitigation for the potential disturbance of human burial sites along the route, either.

We are also concerned with the cumulative impacts of this expansion. These impacts are not unique to the Expansion Project, but would be caused by each of the pipeline alternatives. Since 755 MMcf/d of natural gas will be transported and burned, the Expansion directly facilitates the depletion of natural gas reserves. Using simple arithmetic, deliveries of 755 MMcf/d over 30 years would result in the depletion of over eight trillion cubic feet of natural gas reserves. The use of energy, by its very nature, has the potential to induce growth, a significant negative impact under CEQA. Also, although the efforts of regulatory agencies concerned with the permitting of combustion sites are intended to minimize the production of emissions, the greenhouse gases produced as a by-product of burning an additional 755 MMcf of natural gas per day will have a cumulative impact on air quality and the climate. At full capacity, the Expansion Project would result in emissions of 485 million tons of carbon dioxide and almost 590,000 tons of methane over a 30-year period. The EIR identifies 5 tons of CO per day that will be emitted by end users of Expansion Project gas. However, consumption of Expansion gas would enable users such as Edison and SDG&E which burn oil to generate electricity to reduce their CO emissions from burning oil. Moreover, the delivery of this gas will most likely require the development of additional distribution facilities. These activities may not be within the jurisdiction of this Commission, and it is impossible to anticipate what facilities will be needed. Nonetheless, it is foreseeable that the development of those delivery systems will have a cumulative impact on the environment.

In the context of cumulative impacts, it should also be noted that the Expansion Project could, through future enhancements in compression and looping, substantially increase the amount of gas that the system could transport. Such an increase would add appreciably to the potential for growth inducement, depletion of natural gas, requirements for new distribution facilities, and emissions of gases suspected of contributing to the change in climate.

The applicant's project would also have numerous environmental impacts that do not rise to the level of "significant negative impacts" but which constitute a detriment to the environment. Good sense, the professional judgment of the EIR consultant, and our concern that the incremental consumption of energy resources should have minimal impact on the environment compel us to include these measures in a separate section of Appendix B.

These unavoidable negative impacts demonstrate how crucial it is for the Applicant to carry out the required mitigation. A mitigation monitoring program is attached as Appendix C to this decision. The Applicant is expected to comply with the mitigation monitoring program in a timely fashion. The Environmental and Resource Advisory Section of the CACD will be finalizing the "Mitigation Monitoring, Compliance, and Reporting Plan for the PGT/PG&E Natural Gas Pipeline Project in California" (Mitigation Plan). When the Mitigation Plan has been conformed with this decision and forwarded to the Applicant by the Environmental Section, the Applicant will be required to comply with the Mitigation Plan as well. Any questions concerning the interpretation of the program shall be referred to the Environmental and Resources Advisory Section of the CACD.

I. **Statement of Overriding Considerations**

The lead agency may approve the proposed development even though, as mitigated, it poses significant negative impacts if the lead agency adopts a statement of overriding considerations. In this case, the Commission finds that as conditioned, the development of the PGT/PG&E Expansion Project in California should be approved in order to facilitate the development of gas-on-gas competition and to bring the resultant benefits of diversity of supply, reliability of supply, and lower gas prices for California consumers.

Certification of the Expansion Project, as conditioned, places the decision of whether to proceed with the Project on the Applicant. The Commission approves the issuance of a certificate of public convenience and necessity for the construction of the Expansion Project, subject to PG&E's own decision that market conditions have created a demand for the Expansion Project. We believe that the analysis of need in the final EIR is a valuable framework for assessing whether the pipeline will serve demand anticipated to arise in the short term or over the long term. The final EIR also aptly characterizes the alternatives, and hence, the competition the Expansion Project will face when it is developed. If the Applicant determines in the face of competition from DSM and other pipelines that there is in fact a market and demand for its transportation capacity, it will construct the pipeline.

The granting of a certificate of public convenience and necessity at this time is needed to enable the Applicant to react to the market forces that will bring the benefits of gas-on-gas competition to the California consumers. If there is no demand, then the price of gas and other terms of natural gas service must be adjusted to the point where consumers demand it. At that time, the need for the Expansion Project will materialize, and the Applicant must be allowed to take advantage of market timing in order to allow shippers to secure the supply to meet that demand.

We find that the Expansion Project's need for flexibility to respond to market conditions and the desirability of giving consumers the choice of many interstate pipelines constitute overriding considerations justifying the certification of the Expansion Project EIR despite the existence of unavoidable significant negative impacts on the environment.

J. Approval of Expansion Project After Consideration of Alternatives

Chapter 2 of the final EIR identifies the environmentally preferred courses of action available to the Commission with respect to the Expansion Project. This analysis is concerned with the Expansion's role in fulfilling short term (now through 1995) and long term (1996 through 2005) forecasted demand for natural gas.

The Joint Kern River-Mojave, WyCal I, and WyCal II projects have received optional expedited certificates from the FERC.

The Mojave, Kern River, and WyCal I projects have not received right-of-way permits from the California State Lands Commission. A Draft amended EIR is in preparation by the State Lands Commission to evaluate the environmental impacts of the Joint Kern River-Mojave and WyCal II projects in California. The applications of the Kern River and Altamont projects for certificates of public convenience and necessity have not been approved by the FERC.

After comparing the significant and unavoidable impacts that the Expansion Project and each of the identified alternatives would have on the environment in California, we find that only the integrated intrastate project would avoid any substantial significant impacts on the environment. Although this is clearly the environmentally best alternative, the EIR also points out that this alternative could only meet the short term demand for incremental gas supplies.

The pipeline alternatives are listed here in order of their increasing impact on the environment: Kern River, Mojave, and WyCal I, Joint Kern River-Mojave, and PGT/PG&E. Since the Altamont project could not operate until the Kern River project becomes operational, it is not a factor in meeting the first 700 increment of gas demand. It should be viewed as an alternative to the PG&E Expansion Project if the Expansion is deferred and would thus serve the long-term demand for natural gas.

The PGT/PG&E project would result in the greatest level of significant environmental impacts of any of the alternatives considered in the draft and final EIR. It would be preferable, from an environmental perspective, to defer a decision on the PGT/PG&E application and undertake studies to more carefully evaluate the ability to satisfy the project objective through energy efficiency and the integrated intrastate project.

If the integrated intrastate project were found to be infeasible, the Commission could reconsider the PGT/PG&E application. If one of the other pipeline alternatives was soon to be built, then the PGT/PG&E Expansion Project would be evaluated for its appropriateness in meeting longer term need.

Thus, the EIR concludes that in the short run, that is, the period within which PG&E proposes to commence operation of the Expansion Project, a combination of energy efficiency measures and improvements to the existing natural gas system in California has the potential to eliminate the need for the Expansion Project. Improved energy efficiency would constitute the most environmentally desirable alternative in the long run, because the short-term satisfaction of demand by optimizing system efficiency would allow more time to implement demand side management.

However, we do not adopt these measures as alternatives to the Expansion Project because our studies with the California Energy Commission tend to show that improvements of that magnitude could only be achieved by resources that are uncommitted at this time.

Although gas demand may be met by savings in the short run, the record presently before us indicates that additional supplies will be needed to serve California demand in the long run. The California market is best served when consumers can access different supply regions at different transportation rates. The resultant competition should enable gas users to obtain gas at lower prices than if competing transportation pipelines did not exist.

We cannot reject the PG&E Expansion Project today in favor of the more environmentally attractive pipeline proposals. We have concluded that California needs incremental interstate supplies of gas. Selection of one environmentally preferable alternative to the PGT/PG&E Expansion Project would not be consistent with the Commission's declared market-based approach to the provision of incremental gas capacity in California. Competition could not exist if the Commission were to reject the Expansion because it had identified a different pipeline as the least environmentally destructive project. In addition to offering California's incremental users the benefits of competitive prices, security of supply, and diversity of supply that competition between interstate pipelines would provide, the Expansion Project offers operational and economic efficiency that none of the alternatives can provide. The Expansion would make use of 130 miles of existing PG&E pipe and associated facilities that are currently underutilized. The looped design would enable Expansion shippers to use existing facilities without incurring administrative and general and ownership and maintenance costs that are not specifically attributable to the Expansion. The savings would result in lower transportation costs to Expansion shippers than without the looped design. Moreover, the Expansion would confer an estimated $13.7 million annual reduction in transportation costs to existing ratepayers, increased reliability of deliveries, and greater flexibility in interchanging gas supplies. These benefits to existing ratepayers are possible only because of the Expansion's looped design, and could not be realized if an alternative pipeline were selected to serve California's incremental demand. We believe that the benefits to existing ratepayers and the economies of scale available to incremental Expansion shippers are operational and economic consequences unique to the Expansion. No alternative can feasibly provide these benefits. Therefore, we find that the environmentally preferred alternatives are infeasible for purposes of CEQA.

VI. Conclusion

After full consideration of the Application and the positions of all the parties, we conclude that the Expansion Project will serve the public convenience and necessity, if modified to conform with our conditions.

There are several elements of the Application that would be premature to approve in this decision. PG&E has not introduced sufficient evidence on the actual operating, as opposed to the design, capacity of the Expansion Project to enable us to evaluate the potential for recovery of revenues in excess of the revenue requirement. Thus, to approve PG&E's proposal that all revenues from interruptible transportation be retained by shareholders would be irresponsible at this point. The Expansion Project is a utility undertaking, enjoying the right of eminent domain and the economies of scale of the existing utility facilities. The advantage of a 30 year depreciation period also stems from the protection that the Expansion Project enjoys as an undertaking of a jurisdictional public utility. PG&E's own subscription to 100 MMcf/d of firm transportation capacity helps to mitigate the risk of under-participation by shippers, since its subscription has helped to lower the transportation rate by $0.11. Taken together, these attributes confer a benefit on the Expansion Project made possible only by PG&E's obligation to serve ratepayers. The ratepayers accordingly have an equitable claim to the margin that may be represented by revenues from interruptible transportation service. Ratepayer interests deserve our heightened consideration here because PG&E has not stated that it would permanently refrain from seeking to collect any costs of the Expansion Project from its existing ratepayers.

The margin from interruptible transportation service cannot be determined at this time not only due to lack of evidence of operating capacity, which admittedly, will vary from day to day depending on operating conditions, but also because the firm transportation agreements with shippers have not yet been finalized. The 93% allocation of costs to firm transportation rates contained in the pro forma tariff is, like the rates themselves, a "rough draft." PG&E intends to file actual tariffs for transportation in the Expansion's first general rate case. Since the allocation has not been settled, the Commission has no idea how much of the Expansion's cost of service will be recovered in firm transportation rates or how much would remain to be recovered in interruptible rates. If PG&E successfully negotiates rates to recover 100% or more of its cost of service in firm transportation rates, ratepayers should not be precluded from benefiting from the Expansion.

It appears that as proposed, the Expansion Project minimizes risks to its sponsors through its full-fixed variable rate design and the allocation of 93% of its revenue requirement to firm transportation. The minimization of risk makes the Expansion Project a suitable enterprise for ratepayers, and a desirable one for shareholders.

By rejecting PG&E's proposition that all interruptible transportation revenues be assigned to shareholders, we are reserving for future consideration the assignment of margin contribution from the Expansion between shareholders and ratepayers. At this time, we adopt PG&E's proposition that its shareholders and the Expansion shippers should bear the risk of underrecovery of the revenue requirement. The analysis of the financial risk of the project to the project sponsors and allocation of that risk to either shareholders or ratepayers will be undertaken in the Expansion Project's first general rate case.

We note that PG&E has proposed temporary capacity brokering in its application for approval of the out-of-state portion of the Expansion at the FERC. We will explicitly require PG&E to include temporary capacity brokering as a term of its firm transportation contracts for intrastate service.

PG&E's proposal to assign the costs of future facilities additions to either the existing system or the Expansion Project to the extent the costs may be assigned, and if not directly assignable, pro-rata based on throughput, is reasonable. We require this allocation to apply to any upgrades of portions of the existing system that are used by the Expansion to avoid new construction. This will ameliorate any concern that existing ratepayers may be forced to perpetually subsidize the Expansion Project.

As noted above, we doubt that PG&E's subscription to 100 MMcf/d of firm capacity on the Expansion is needed to fulfill any of the utility obligations as redefined by our successive gas industry restructuring orders. Since we have reserved our analysis of the financial risk of the Expansion for the first general rate case, it is necessary for us to determine the reasonableness of PG&E's subscription at the same time. We will require PG&E to demonstrate in the Expansion Project's first general rate case either that it has awarded that 100 MMcf/d increment of capacity to other shippers in a non-discriminatory manner or that it needs the capacity. If PG&E does not demonstrate the reasonableness of its disposition of that 100 MMcf/d of capacity at that time, it will jeopardize any finding that its proposed rates and charges for the Expansion Project are reasonable. The reasonableness of Expansion rates must be established pursuant to § 451 of the PU Code, regardless of the outcome of the risk analysis to be undertaken in the first general rate case.

Finally, today's approval of a CPCN for the Expansion is a qualified one. First of all, we do not determine the reasonable rates and charges for Expansion service. The pro-forma tariff introduced in PG&E's testimony is indeed a rough draft. The actual rates and terms and conditions of service are to be negotiated between PG&E and individual shippers. We expect that these agreements will be in place and available for our review in the Expansion's first general rate case.

Most importantly, by issuing the certificate of public convenience and necessity, we find that PG&E must be afforded the opportunity to exercise its own judgment that the Expansion Project best meets the demands of its market segment. We stated in the OII decision (D.90-02-016) that rather than select the one interstate pipeline that best serves the public's interest we would "let the market decide." Consistent with that finding, we do not find today that the public convenience and necessity require the construction of the Expansion Project in all events. Conversely, we cannot conclude that the Expansion Project is not needed to serve the public because we cannot find that any other interstate pipeline will become operational in time to serve California's identified need for incremental supplies.

This conclusion is also supported by the findings in the final EIR, which we adopt today, that whether the Expansion project should be built turns on what increment of need it is expected to serve, and the alternatives that are competing to meet that need. Whether the Expansion Project should be built to meet demand expected to materialize in 1995 or postponed to address need forecasted by the year 2005 depends on many factors which the Commission is not in a position to assess. Those factors include the effectiveness of committed DSM measures, the efficiency with which existing system capacity is used, the level of shipper commitment to each interstate pipeline, the financial and regulatory viability of each pipeline, and the dates that any of the competing pipelines will begin operation.

As a condition of its acceptance of the CPCN, PG&E is required to evaluate the need for the Expansion Project as it exists on the date it determines to proceed with the development. In order to begin collecting rates on the date of commercial operation, the Expansion Project must be "used and useful." PG&E must demonstrate that sufficient demand for PG&E's proposed service will exist at the time Expansion is scheduled to commence operations, based on the facts known or which reasonably should have been known to PG&E at the time of its decision to build.

A need for some of the Expansion's capacity has been established in this proceeding. We need not find that all of the capacity is currently needed before issuing a CPCN because there is evidence that demand for capacity is likely to arise in the future. PG&E should be allowed to exercise its business judgment that the Precedent Agreements do embody future demand for the Expansion's service. This flexibility is appropriate here because development of the Expansion Project will be at PG&E's shareholders' risk.

We find that issuance of the CPCN is necessary to enable PG&E to respond to consumer demand for transportation over its pipeline. The market structure which we have promoted could not operate unless consumers were given a choice of pipelines service. The Expansion Project, as conditioned, would be an obviously beneficial choice for incremental users because it incorporates economies of scale and offers a tariff structure which encourages gas to gas competition. The public would be permanently denied these benefits unless the Expansion Project were certificated. With our granting of the CPCN, the public can determine whether it wants the service offered by PG&E. Thus, we find that the present and future public convenience and necessity require the issuance of the CPCN for the Expansion Project today.

Findings of Fact

1. On April 14, 1989, PG&E filed its application for a certificate of public convenience and necessity (CPCN) to expand its existing natural gas pipeline from the California-Oregon border to Kern River Station in San Joaquin County, California.

2. The expanded facilities (Expansion) would accommodate PG&E's receipt at Malin, Oregon of Canadian natural gas to be delivered by Pacific Gas Transmission Company (PGT), PG&E's wholly owned subsidiary, for transportation by PG&E to Kern River Station.

3. On October 3, 1989, PG&E filed a "Supplement to Application (A.) 89-04-033 for a Certificate of Public Convenience and Necessity" whereby PG&E increased the capacity of the Expansion from 600 MMcf/d to 755 MMcf/d.

4. On November 30, 1989, PG&E filed an "Amendment to the Application" consisting of Precedent Agreements that had been executed since the June 15, 1989 filing and reflect a total subscription of its amended pipeline capacity, 755 MMcf/d of firm transportation.

5. This Application is intended to obtain the approval of this Commission for the certification and construction of the California segment of a larger pipeline expansion project originating in Kingsgate, British Columbia and terminating at Kern River Station, in California.

6. PGT, PG&E's interstate pipeline subsidiary, had filed an application on January 23, 1989 for a certificate of public convenience and necessity at the Federal Energy Regulatory Commission (FERC) to authorize its development of the interstate portion of the pipeline project, and that application is still pending before the FERC.

7. The CPUC determined that one environmental document that would satisfy the requirements of both Federal and California environmental review laws should be prepared.

8. The Commission issued D.89-12-049 confirming that it was not required to issue a decision on the application for CPCN within a year of the date PG&E last amended the Application.

9. Hearings on the non-environmental aspects of the application were conducted between May 21 and June 8, 1990.

10. The Draft EIR was circulated on June 29, 1990.

11. On August 21, 1990, the Commission convened a public partioipation hearing in Antioch to receive oral comments from the public on the Draft EIR.

12. Evidentiary hearing on environmental issues was held on August 13 through 17 in San Francisco.

13. The record of this proceeding includes a letter agreement between Bonus Gas Producers, Inc. (Bonus) and PGT dated July 27, 1990 (Letter Agreement).

14. The Letter Agreement does not obligate PG&E, the entity whose intrastate proposal is subject to our review, to do anything in California as a result of the parties' agreement, and any future expansion or action required by the Letter Agreement will not foreseeably occur on the California portion of the pipeline.

15. Ruling on Altamont's Motion that the Commission withdraw its statement in support of the PGT application and offer of settlement at the FERC on the basis that the statement was prejudicial to parties in this proceeding was properly deferred while the record was being compiled in this case.

16. The Expansion consists of a pipeline system that is parallel to, and interconnected with, PG&E's existing pipeline facilities from Malin to Kern River Station.

17. As currently proposed, the Expansion Project consists of 295 miles of 42" diameter pipeline from the Oregon-California border to the Brentwood Compressor Station in Contra Costa County. This segment would run parallel and adjacent to PG&E's existing Line 400. A new 12,400 horsepower gas-fired turbine-driven compressor will be installed at Delevan Compressor Station. Thirteen thousand five hundred horsepower of new compression will be installed at Brentwood Compressor Station. This will create pressure to transport the gas through 120 miles of 36" diameter pipe from Brentwood Compressor Station to Panoche Meter Station. This segment would be located parallel and adjacent to PG&E's existing Line 2. PG&E does not propose any construction or modification of its existing facilities for the final 113 miles of the Expansion Project between Panoche Meter Station and Kern River Station. One hundred thirteen miles of dual 34" pipe that is part of PG&E's existing Lines 300 A and B between Panoche Meter Station and Kern River Station and 17 miles of PG&E's 36" diameter existing Line 400 near Delevan will be used by the Expansion. A portion of the capacity of Line 2 will also be used for Expansion service. As part of the Expansion, PG&E also will modify compressors and/or piping at five existing compressor stations and modify three existing meter stations.

18. Expansion gas would displace deliveries of gas currently received by PG&E at the southern portion of its system, so that the gas received from southwest sources will flow to the Expansion

shippers. PG&E states that no additional facilities are needed downstream of Kern River Station.

19. In early 1989 it appeared that utility subscriptions would require only 350 MMcf/d of capacity. PG&E/PGT then conducted an "open season" bidding procedure to market the remaining capacity, from April 26 through May 2, 1989.

20. PG&E determined it would allocate firm transportation on the Expansion by an "open season" bid process. Capacity on the Expansion was awarded in relation to the present value of the reservation fee for the term requested, with the maximum bid being a 100% reservation and a 30-year term. The open season procedure also called for the timely execution of a Precedent Agreement.

21. Edison, SDG&E, and the Cities of Long Beach, Burbank, Glendale, and Pasadena executed Precedent Agreements for a combined capacity of 330 MMcf/d.

22. The Precedent Agreement between prospective shipper and PG&E required (a) exclusive commitment to the Expansion for the volumes selected; (b) specific support for the Expansion before regulatory agencies; and (c) the procurement of adequate gas supplies and necessary regulatory approvals.

23. Precedent Agreements were executed initially with successful bidders in April of 1989.

24. Under the Precedent Agreements, shippers are relieved of their obligations to execute firm transportation agreements if satisfactory regulatory approvals are not obtained, or if they fail to secure a gas supply. Once the two conditions have been satisfied, the parties are obligated to use their best efforts to finalize firm transportation agreements within 120 days.

25. The Precedent Agreements specified that transportation over the Expansion Project would be on a "firm" basis.

26. During the months of July and August in 1988, the Expansion Project was revised by replacing the original 36" pipe with 42" pipe. This produced an additional 155 MMcf/d of capacity,

which will accommodate the California shippers' need for firm transportation on a year-round basis, permit transportation by an additional shipper, plus enable PG&E to transport an incremental 100 MMcf/d for itself.

27. The "design capacity" of the Expansion Project is 755 MMcf/d, but the maximum capacity of the pipeline is 877.5 MMcf/d at Kern River Station during peak day conditions which may occur during the winter months of October through March. The actual daily capacity on the Expansion depends on a range of operating conditions that occur over the course of the year.

28. Although 755 MMcf/d of firm capacity has been allocated to shippers that have executed precedent agreements, PG&E proposes to provide transportation in excess of 755 MMcf/d, either firm or interruptible, up to a maximum throughput of 877 MMcf/d, depending on actual operating conditions at the time.

29. The single point of delivery for gas transported over the Expansion is Kern River Station. Shippers or end users would then purchase transportation service by the local distribution company at rates tariffed by the Commission for delivery to their burner tip.

30. PG&E estimates the fourth quarter 1988 capital cost of the Expansion to be $544.8 million, which is expected to increase to $696 million by the year 1994, when the Expansion will be completed.

31. The Commission has prepared an Environmental Impact Report as part of its duties as a lead agency under the California Environmental Quality Act (Public Resources Code Section 21000, et seq. "CEQA"). The Commission recognizes that the impacts on the environment of the Expansion should be avoided and, where unavoidable, mitigated, and this requirement will add $40 million to the estimated cost of the Expansion.

32. PG&E proposes to initially finance the Expansion Project through a combination of 70 percent debt ($381,388,700) and 30 percent common equity ($163,452,300). This capital ratio will be changed during the first ten years of operations to a capital ratio of approximately 55 percent debt and 45 percent equity, but some portion of the debt and common equity may be replaced with preferred stock.

33. PG&E may revise the rate of return on common equity and capital structure in order to accommodate any substantial change in risk profile of the Expansion Project that may result from the cost allocation and rate design that emerge from the negotiations with shippers or as a result of this proceeding.

34. PG&E's estimated cost of the Expansion Project is based on a 14% return on equity and a 10% cost of debt. These figures are used for the purpose of establishing a cost cap but not for the purpose of computing the allowance for funds used during construction.

35. The Expansion will not adversely affect PG&E's cost of capital or ability to raise additional capital.

36. Based on capital expenditures of $544.8 million, and assuming a 11.2% rate of return, the annual cost of service of the Expansion is $101.1 million in the first year, and PG&E shows that the cost of service would decline annually.

37. The Applicant believes that 30-year straight-line depreciation should be used because this depreciation method approximates the decline in economic value of the property.

38. PG&E presented a rate design for the revenue requirement for Year 1 based on the $101.1 million first year cost of service. The proposed rate structure parallels the PGT rate design for the interstate portion of the Expansion Project.

39. PG&E submitted a pro forma tariff in the form of a FERC tariff and its calculation of illustrative rates for the pro forma rate schedule. PG&E is currently negotiating with its Expansion

Project shippers as to the rates and terms of service for the proposed transportation service. PG&E intends to adjust its pro forma tariff based on the outcome of negotiations.

40. PG&E proposes an Expansion Project rate base separate from PG&E's other regulated utility businesses. A general rate case application would be filed in about two years from this date, after construction has been completed, and about six months prior to commencement of operation. This rate case would establish the reasonable cost of the Expansion Project and determine actual rates for transportation on the Expansion.

41. Under PG&E's proposal, costs of the Expansion Project will be recovered only from the Expansion's customers and Expansion Sponsors. None of the costs of the Expansion will be allocated to PG&E's existing customers, except to the extent that PG&E itself is a customer of the Expansion Project. None of the costs of owning or operating the existing PG&E transmission facilities would be allocated to the Expansion under PG&E's "incremental cost" methodology.

42. PG&E proposes that all revenues from interruptible transportation shall accrue to its shareholders.

43. The costs of Expansion plant and equipment will be recorded in separate Expansion accounts.

44. Costs for future replacement of facilities and operating expenses specifically associated with the Expansion will be segregated. Those costs are to be included in future Expansion rate cases on a forecast basis.

45. Operational savings of approximately $13.7 million resulting from reduced compressor fuel consumption at compressor stations along the Kingsgate to Kern River route will reduce PGT/PG&E's existing revenue requirement.

46. The Expansion Project will provide increased system reliability and flexibility in supply procurement for PG&E's existing ratepayers due to its looped design.

47. PG&E and PGT intend to jointly establish a single project organization to direct the entire Expansion from the Canadian - U.S. boundary to the Panoche Meter Station.

48. PG&E requests a waiver pursuant to Section XV of General Order 96-A (GO 96-A) of Sections II, IX, and X, which would enable PG&E to file its Expansion Project tariff in the tariff format used at the FERC, and would deprive the CPUC of its authority under GO 96-A to amend the terms and conditions of a contract between PG&E and an Expansion Project customer during the term of the contract when, in the Commission's judgment, the amendment is required to serve the public interest.

49. PGT/PG&E has granted to Edison and SDG&E options to acquire up to 20% and 10%, respectively, equity ownership in the Kingsgate to Kern River Station project.

50. PG&E has not tendered the option agreements for Commission approval, preferring that the Commission review the utilities' exercise of their options, if that should occur.

51. On August 30, 1989, PG&E executed a Precedent Agreement obligating itself to subscribe to 100 MMcf/d of firm transportation capacity on the Expansion Project.

52. PG&E's application for certification of the Expansion is being made at a time of change in California's natural gas industry.

53. PU Code § 1001, which lists the criteria by which the Commission shall determine whether a proposed pipeline will serve the public convenience and necessity, reflects the role of the utility under the former natural gas industry structure.

54. Following an investigation into the interstate natural gas pipeline supply and capacity available to California (I.88-12-027), we determined that the regulatory response that would provide the most benefit for the California consumer would be to let the market decide which of several competing pipelines would be built (D.90-02-016).

55. Under our market-based approach in I.88-12-027, we would view favorably any pipeline proposal that results in a pipeline network which provides reliability of access to all the major producing areas, is an economically justifiable means to reduce gas costs through gas-on-gas competition, allocates capacity in a non-discriminatory manner, allows for temporary capacity brokering, avoids bypass of the LDC, and allocates cost responsibility to those who will benefit from firm service on the new pipeline.

56. In the competitive marketplace we envisioned in I.88-12-027, whether a pipeline is built will depend on the investment decisions of non-core customers and those intending to provide firm service to that market.

57. The various interstate pipeline proposals that are vying to serve the California gas market have intervened in this proceeding.

58. The primary aspects of the Expansion proposal that demand examination in light of our express criteria are PG&E's subscription to 100 MMcf/d of firm transportation capacity on the Expansion, the failure to include any costs of the existing system in the proposed "incremental rate design," PG&E's proposal to allocate revenues from interruptible transportation to its shareholders, and the Expansion's potential impact on competition due to its single delivery point.

59. In D.90-02-016 we found that there is a near-term need for 900 MMcf/d and a long-term need for 1.6 to 2.1 Bcf/d of additional natural gas pipeline capacity in California.

60. PG&E, DRA, Edison, and SDG&E all introduced unchallenged evidence based on the 1989 California Gas Report (CGR) that shows that the potential of committed DSM resources to reduce demand by the year 1995 is limited to a reduction in gas consumption of only 27 MMcf/d by UEG usage and a reduction in gas sales by only 9.0 MMcf/d by SoCalGas.

61. We find that a need exists for an incremental 755 MMcf/d of firm natural gas transportation capacity which the Expansion Project is proposed to provide.

62. Edison's annual requirements for electric generation have not fallen below the natural gas equivalent of 300 MMcf/d. Edison's subscription to 200 MMcf/d of Expansion capacity will alleviate Edison's dependence on interruptible pipeline capacity. The interruptible nature of Edison's supply has resulted in the curtailment of gas service in 11 out of the 16 months ending with April 1990 at the direct cost of $42 million to Edison's ratepayers. SDG&E's long-term gas strategy relies on firm transportation, since in SDG&E's experience, the lack of access to firm transportation limits access to the broadest range of gas supplies and imposes unnecessary costs on ratepayers.

63. There is need for some of the capacity represented by the Expansion Project, as evidenced by the testimony of Edison and SDG&E and the subscription of these two utilities to 300 MMcf/d of firm transportation service on the Expansion.

64. The Precedent Agreements evidence the good faith commitment of shippers and PG&E to enter into a long-term firm gas transportation agreement provided that PG&E obtains regulatory approval and the shippers acquire long-term gas supplies.

65. The Precedent Agreements are reliable indicators of the market's interest in the Expansion Project, and the terms of the agreements provide a reasonable level of commitment by the shipper at this stage of the project's development.

66. There is evidence that the Expansion Project may be needed in the future to meet the demand demonstrated by shippers that have executed Precedent Agreements.

67. PG&E would rely on the Precedent Agreements to show that, in its business judgment, demand for the remainder of Expansion Project capacity will arise in the future.

68. At this time, PG&E has not been assured of revenue recovery and its shareholders, as the project sponsor, have assumed the risk that there will be sufficient demand for its capacity.

69. The pipeline network we seek to promote is not a single interstate pipeline supplier, but an integrated network consisting of LDCs and their suppliers.

70. A proposed interstate pipeline need not, on its own, access "all the major producing areas." It is sufficient that its interconnections and downstream operations contribute to diversity of supply for the state as a whole.

71. Construction of the Expansion will result in access to new supplies of Canadian gas and the resultant mix of supplies to California will promote gas-on-gas competition.

72. The Expansion is economically justified because under PG&E's proposed rate design methodology, it will be paid for by incremental shippers and not existing ratepayers.

73. The Applicant's proposal to segregate Expansion Project costs in separate accounts outside of PG&E's normal plant accounts and expense accounts, to establish a separate general rate case proceeding to determine the reasonable rates for the Expansion Project, and to hold the Expansion Project sponsors and shippers responsible for all costs of the Expansion tends to insulate existing ratepayers from the financial risk of the project.

74. The Expansion has allocated capacity in a non-discriminatory manner through the open season process.

75. PG&E has proposed temporary capacity brokering over both the PGT and PG&E portions of the Expansion.

76. Since holding the right to firm transportation capacity over several years would enable Expansion shippers to replace pipelines as the bottlenecks in the interstate transportation of natural gas, we will specify as a condition of our approval that PG&E include temporary capacity brokering as a term of its firm

transportation contracts for service on the California portion of the pipeline. This will assure the fullest use of capacity to bring competing interstate supplies to the consumer.

77. The Expansion Project meets the criterion that a pipeline should not threaten bypass of local distribution companies established in D.90-02-016 for our approval of an interstate pipeline.

78. The 755 MMcf/d capacity design is reasonable because the state will need that incremental amount of gas transportation capacity by 1995 and shippers have demonstrated demand for the capacity through their execution of Precedent Agreements for 755 MMcf/d.

79. The increase in pipeline size and resultant increase in capacity from 600 MMcf/d to 755 MMcf/d was a reasonable response to the seasonality problem.

80. The estimated maximum cost of implementing the environmental mitigation required by this decision will be $40 million, which is an estimate that should be added to the cost cap for the Expansion Project required under PU Code § 1005.5 subsection (a).

81. It is appropriate to use a 30-year depreciation period because that is used by the CPUC and the FERC to estimate the useful lives of gas transmission pipelines, existing PG&E pipelines, notably Lines 300 and 400, are approximately 30 years old, and because it enables the utility to provide a monopoly service to the public at a reasonable cost.

82. The system's "design day" capacity, deliverable the entire year, is 755 MMcf/d; this is the amount of firm capacity available for contract. Between the 755 MMcf/d of firm capacity and 877.5 MMcf/d of peak capacity lies the potential range of interruptible capacity of 0 MMcf/d to 122.5 MMcf/d. There may be substantial transportation capacity during the "shoulder months"

when temperatures are below 90 degrees; and very little information on interruptible capacity was available.

83. PG&E's proposal to finance the Expansion Project initially through 70% debt and 30% equity is reasonable.

84. The Expansion proposes to use some 130 miles of existing PG&E gas pipeline, existing metering stations, taps, and other facilities which will avoid the cost of constructing of some 130 miles of new pipeline. This savings represents the use of economies of scale and is a prudent use of society's resources.

85. PG&E proposes that the Expansion be allocated 0% responsibility for common costs because the Expansion's usage of the existing facility is incremental and there is no basis, short of a policy basis, for allocating common costs.

86. PG&E's competitors urge that a portion of the cost of the existing system be allocated to the Expansion, which would increase the transportation rate charged by the Expansion and make it less competitive, but did not provide adequate policy reasons to support the allocation of common costs.

87. No party proposed any basis for the allocation of common costs between the existing system and the Expansion Project.

88. The proposal to exclude the costs of existing PG&E system facilities that will be used by the Expansion Project from the Expansion Project revenue requirement is reasonable because assigning the benefits of existing economies of scale to the incremental user is an efficient allocation of resources.

89. Existing ratepayers are not faced with an "opportunity cost" associated with the Expansion's use of existing facilities because there is no evidence that those facilities are needed to serve existing ratepayers, and Kern River's theory that ratepayers would incur an opportunity cost at some future date is too speculative to constitute a basis for cost allocation today.

90. The allocation of "incremental plus" rates for the Expansion would have the effect of discouraging incremental use of existing facilities and negating economies of scale.

91. PG&E proposes that the costs of future facilities additions should be paid for to the extent responsibility may be assigned to existing and Expansion shippers, and the cost of additions that cannot be assigned to one group or the other should be allocated on basis of pro rata throughput.

92. The full-fixed variable rate design is proposed to collect 100% of the costs of firm transportation from the monthly reservation fee.

93. Although the Expansion is proposed primarily to provide 755 MMcf/d of firm transportation, it will provide at least 60 MMcf/d of interruptible transportation as well. The rates for firm and interruptible transportation are based on 100% load factor and will recover all of the costs allocated to firm and interruptible transportation service, respectively.

94. PG&E's proposal to collect 93% of its annual revenue requirement in firm transportation demand charges assures us that there is little financial risk associated with revenue recovery so long as the Expansion is fully subscribed.

95. The shipper's fixed costs of service on the Expansion Project provide an incentive to the shipper to maximize throughput in order to recover its fixed costs.

96. The benefits to PG&E's existing customers from the Expansion, the prevention of LDC bypass, and the use of economies of scale outweigh the potential effects of rolled-in ratemaking at the FERC.

97. It is necessary for us to determine the reasonableness of PG&E's subscription at the earliest time.

98. The subscription has the potential to affect the cost of service to other shippers on the Expansion Project if PG&E's subscription cannot be recovered in rates because of the $13 to $28 million in annual revenues represented by that subscription.

99. We should require PG&E to demonstrate either that it has awarded its 100 MMcf/d increment of capacity to other shippers in a non-discriminatory manner or that it needs the capacity in the Expansion Project's first general rate case. If PG&E does not demonstrate reasonableness at that time, it jeopardizes our approval of the rates and charges for the Expansion Project.

100. In order to grant a certificate for a proposed development, we must determine, among other things, the portion of the project cost which will be borne by ratepayers.

101. None of the costs of the Expansion Project will be borne by ratepayers of the existing PG&E system.

102. PG&E proposes that the revenues from interruptible transportation service accrue directly to PG&E's shareholders. PG&E's shareholders would be at risk fo recovering 7% of the revenue requirement of the Expansion. This proposal would assign interruptible revenues in excess of the revenue requirement to shareholders as well. It is premature to make that assignment at this time.

103. The lack of evidence as to shipper liability for the payment of firm transportation rates intended to recover the project's revenue requirement, coupled by the lack of reliable evidence of the Project's interruptible capacity, frustrate our ability to assign the risk of revenue recovery between shareholder and ratepayers in this decision; however, we confirm that the risk that subscriptions to firm capacity may not equal or exceed 755 MMcf/d will be borne by PG&E as the Project's sponsor and the risk of revenue recovery will be borne by PG&E's shareholders and Expansion shippers.

104. No portion of the Expansion Project's costs shall be borne by ratepayers until the reasonableness of those costs has been determined in the Expansion Project's first general rate case, and a final allocation of risk between shareholder and ratepayer has been made.

105. Today's approval of a CPCN for the Expansion is a qualified one. There is sufficient need for issuance of the certificate; however, we do not determine that construction of the Expansion would in all cases be reasonable.

106. By issuing the certificate of public convenience and necessity, we find that PG&E must be afforded the opportunity to exercise its own judgment that the Expansion Project best meets the demands of its market segment.

107. No shipper on the Expansion Project has complained that it was being denied the opportunity to compete in PG&E's service territory.

108. Since PG&E's existing transportation rate is a postage stamp rate, it makes no difference whether the delivery point is at the southern or northern end of PG&E's system. A shipper seeking to serve a customer in PG&E's service territory would have to pay PG&E's gas transportation rate in either case.

109. The restriction of deliveries to Kern River Station was designed to enable the project sponsor to recover the cost of delivery to that point, and given our expressed policy of imposing the cost of new facilities designed to serve incremental users on those users, the Expansion Project properly promulgates rates to recover the cost of service of the full extent of the Expansion's physical plant.

110. PG&E's participation as a shipper constitutes a subscription to firm capacity that allows a greater volume to share the Expansion's costs, thus lowering the firm transportation rate and giving the Expansion a competitive advantage. PG&E's participation as a shipper is anticompetitive, since any of the

other pipeline sponsors, whose members include gas producers, gas aggregators, or interstate pipelines, could have executed a contract as a shipper on their proposed pipeline to maximize the capacity of their own projects.

111. There is no need for additional capacity to serve the needs of PG&E's core ratepayers in 1994, when the Expansion is expected to commence deliveries.

112. PG&E's responsibility for procuring natural gas supplies to serve non-core ratepayers has been radically diminished by D.90-09-089, the decision on the Commission's rulemaking to change the structure of gas utilities' procurement practices.

113. The new level of utility service described by D.90-09-089 does not obligate PG&E to acquire firm transportation capacity to serve non-core customers.

114. We did not unbundle the transportation function in order to impose the risk of underutilization of capacity back on PG&E's ratepayers.

115. PG&E's share of the first year's annual revenue requirement based on the proportion of PG&E's subscription to total project volumes would be roughly $13 million; El Paso testified that the cost of that subscription is $28 million a year.

116. PG&E's testimony in the Pipeline OII and in this case that PG&E projects a need for an additional 300 MMcf/d in its service territory by the year 1995 may be well founded, but it does not necessarily justify PG&E's own subscription for firm capacity. That need should be met by others who hold capacity on the Expansion or other pipelines.

117. It is likely that the queue of shippers who responded to PG&E's open season bidding process represent demand for firm transportation rights on the Expansion Project sufficient to subscribe to the 100 MMcf/d currently held by PG&E.

118. There is insufficient evidence to show that PG&E's subscription to 100 MMcf/d of firm transportation capacity on the Expansion Project is reasonable.

119. It is necessary to resolve the question of PG&E's need for this subscription no later than the Expansion general rate case because, due to $13 to $28 million in annual revenues represented, the subscription has the potential to affect the cost of service to other shippers on the Expansion Project if PG&E is not authorized to hold that capacity.

120. Access by Edison and SDG&E to alternative sources of gas from Canada available through the Expansion Project would contribute to supply diversity, reliability of supply, and lead to gas-to-gas competition that will benefit the ratepayers of these two utilities.

121. PG&E has raised the possibility that ownership of the Expansion Project may be shared with Edison and SDG&E pursuant to an equity agreement and that its shareholders may ultimately own the Expansion Project.

122. PG&E would not cede control of existing system to the equity participants, Edison and SDG&E, under the option agreements.

123. Edison and SDG&E have shown a need for 300 MMcf/d of firm transportation service on the Expansion and demonstrated the ability to fulfill their commitments to the Expansion.

124. Given the distinctions between PG&E's utility service and the Expansion's firm transportation function, we find that a new interconnection agreement is necessary and that PG&E and SoCalGas should negotiate a new interconnection agreement.

125. SoCalGas must exercise its utility obligation to serve under conditions that we have declared will be shaped by market forces, rather than by regulatory determination.

126. SoCalGas' incurrence of pre-construction, construction, and post-construction costs to interconnect Expansion Project facilities would be reasonable regardless of actual usage, but the

reasonableness of such costs must be reviewed in a subsequent proceeding. The allocation of these costs should be made as quickly as possible.

127. Waiver of the GO 96-A Section II tariff format requirements will lessen the potential for shipper confusion as to the terms and conditions of Expansion Project service.

128. PG&E will begin to negotiate the terms of its firm transportation agreements with shippers after issuance of this decision, but we cannot anticipate the rates and terms of service of those agreements because this decision adopts only a pro forma tariff for the Expansion Project.

129. Except for the rates and charges for Firm and Interruptible Transportation Service, which cannot be determined until actual costs of construction, interruptible capacity, and revenue allocation have been determined in the first general rate case, the terms and conditions of service proposed in the pro forma tariff appear to be reasonable.

130. The issues of risk allocation, ownership, and margin are so intertwined, yet unresolved, at this time that it would be imprudent to waive our subsequent review of PG&E's firm transportation agreements which is provided in Sections IX and X of GO 96-A.

131. On June 13, 1989, the CPUC and FERC entered into a Memorandum of Understanding to combine efforts to prepare a joint EIR/EIS.

132. Subsequently, the Altamont Gas Transmission Company (Altamont), which has filed an application for CPCN with the FERC, was added to the joint EIR/EIS for environmental review.

133. The EIR has analyzed the following: possible alternatives to a proposed project that would reduce or eliminate any significant environmental impacts of the proposed project; the energy-use implications of the project; cumulative impacts; and growth-inducing impacts.

134. On June 29, 1990, the Draft EIR was released for comment. The Draft EIR at that time incorporated analyses to fulfill its role as a a joint EIR/EIS for the interstate as well as California impacts of the Expansion Project and the Altamont Project.

135. On August 13, 1990, Altamont filed a motion for recirculation of the Draft EIR, claiming that the document was defective because it failed to properly inform the public of the potential impacts of the project in that it was confusing, improperly compared the out-of-state impacts of the Expansion Project and its alternatives, and erroneously associated the in-state environmental impacts of the Kern River or WyCal projects with those of the Altamont project.

136. The inclusion of the analysis of the out-of-state impacts of alternatives and the association of in-state impacts of alternatives with each other could not have frustrated or confused any member of the public who was trying to understand the environmental consequences of the Expansion Project.

137. The clarification of the in-state impacts of the Expansion Project and revisions to the discussion of alternatives contained in the final EIR do not constitute "significant new information" as that term is employed under CEQA.

138. The EIR ranked the Expansion Project against the alternative interstate pipeline projects, the integrated intrastate pipeline project, the energy efficiency/capacity optimization project, and the combination of the energy efficiency/capacity optimization alternative with the integrated intrastate pipeline alternative, based solely on environmental impacts in California.

139. Since the circulation of the Draft EIR and the evidentiary hearings on the environmental impacts of the Expansion Project, the document has been revised to clearly indicate the California-only impacts of the Expansion Project and its alternatives.

140. The execution of a letter agreement by PGT and Bonus Gas Producers, Inc. did not alter the "project definition" of the proposed expansion, and therefore, recirculation of the EIR is not required by CEQA.

141. The Commission need not reconvene evidentiary hearings to reconsider the rates and terms of service proposed for the Expansion Project as the result of the PGT/Bonus letter agreement because PG&E is not required to do anything on the in-state portion of the PGT/PG&E Expansion Project in response to the letter agreement.

142. Comments on the Draft EIR were addressed in the final EIR, issued on November 19, 1990.

143. Consistent with the Commission's statewide resource planning perspective, the EIR considered what alternatives to the Expansion Project could satisfy California's need for additional gas capacity and supply.

144. The basic objective that would be satisfied by the PGT/PG&E project, and that was assumed for the purpose of identifying possible alternatives, is the provision of a major increment of the projected need for natural gas services in California.

145. While no two of the projects considered in this EIR would satisfy precisely the same objectives, in a broader sense, possibly with some modification to a particular project, they are substitutes for one another.

146. Since sound resource planning dictates that projects not be built significantly in advance of need, and since need increases gradually over time, the need for a second major interstate gas pipeline project would be deferred once either a pipeline with sufficient capacity to meet the projected long-term need of up to 2.1 Bcf/day has been constructed or the project sponsor concludes a sufficient market for the capacity does not exist at the time construction is scheduled to commence.

147. In determining the range of reasonable alternatives to the PGT-PG&E project it was necessary to consider not only projects that could supply comparable amounts of new gas to California, but also those which may be capable of conserving gas or making more efficient use of existing California pipeline capacity, thereby making existing supplies of gas available for new uses.

148. All of the interstate pipeline projects would have substantial significant environmental impacts in California, both before and after the imposition of mitigation measures. However, the alternative pipeline projects would have less serious environmental impacts, both without and with mitigation, than the Applicant's project.

149. The integrated intrastate alternative, in turn, would have far less serious environmental impacts than any of the interstate projects.

150. The energy efficiency/capacity optimization alternative would have virtually no significant adverse environmental impacts, and as such, is the environmentally superior project alternative.

151. Chapter 5 and Appendix 5 of the Draft EIR suggest that implementation of a combination of energy efficiency measures and improvements to the existing natural gas system in California has the potential to eliminate the need for the PGT/PG&E project.

152. The EIR considered eight project alternatives in addition to the Expansion Project and the no-project alternative.

153. The EIR analyzed alternative routes for six segments of the Applicant's proposed corridor alignment in an effort to avoid or reduce significant, unmitigable impacts associated with particular sections of the Applicant's proposed project. Two of these alternatives--Jepson Prairie Preserve and Brentwood--received a level of analysis comparable to that of the corresponding alignments proposed by the Applicant.

154. The final EIR contains a tabular summary of significant impacts and mitigation measures for the Expansion Project, including alternative routes, in California (Table 2-5).

155. Alternative 4, as modified by the incorporation of the Contra Costa Reroute, is adopted as the approved alignment for the Applicant's project through the Brentwood-Antioch area between Mileposts 903 and 933 because it would eliminate completely the project's impact on alkali meadow and vernal pool areas.

156. Site C is adopted as the site for the compression facilities necessary in Brentwood for the Applicant's project because it would have the fewest significant and unavoidable impacts on resources.

157. The Shasta County West Route Alternative, between Mileposts 703 and 704, is adopted for the alignment of the Applicant's project to avoid the northern interior cypress forest.

158. The Applicant's proposed route between Mileposts 731-781 is adopted in favor of the Tehama County Vernal Pool Reroute.

159. The mitigation measures imposed on the Expansion Project are attached as Appendix B to this decision.

160. PG&E must construct the Expansion Project as modified by this decision and carry out the mitigation measures suggested in the final EIR in order to allow the Commission to find that the Expansion's impacts resources are less-than-significant for the identified resources.

161. A mitigation monitoring program is attached as Appendix C to this decision. The Applicant shall comply with the mitigation monitoring program in a timely fashion. Any questions concerning the interpretation of the program shall be referred to the Environmental and Resources Advisory Section of the CACD.

162. The EIR analyzes the environmental impacts that may or would occur as a result of constructing and operating the Expansion Project. The final EIR is incorporated herein by this reference.

163. The final EIR identifies the environmentally superior alignment of the Expansion Project. We conclude on the basis of the opinion of the Department of Fish and Game that Alternative B, and not the Solano Reroute, should be used in the Jepson Prairie area.

164. Due to the location, nature, and scale of the proposed pipeline project, the Expansion Project as proposed in the Applicant's PEA would result in substantial environmental impacts in virtually every relevant category: geology, soils, vegetation, wildlife, fisheries, air quality, noise, public safety, cultural and archaeological resources, visual resources, hydrology and water quality, socioeconomics, depletion of large quantities of non-renewable resources, cumulative impacts, growth inducement, and emissions of greenhouse gases.

165. After receiving field survey data of the proposed Expansion route, including survey data to determine the presence of threatened, rare, or endangered species, consultation with resource specialists, and research in technical journals, the EIR consultants have concluded that the great majority of the Project's impacts on resources can be reduced to a less-than significant level; however, this result can be achieved only if the consultant's proposed mitigation measures are adopted as a condition of issuance of the CPCN.

166. Changes or alterations have been required in, or incorporated into, the Expansion Project that mitigate or avoid most of the significant environmental effects identified in the Final EIR.

167. Even with the stringent mitigation recommendations that are contained in the final EIR, the Applicant's project would have a significant adverse impact on the environment.

168. The significant, unmitigable impacts of the project include the following:

a. The possibility of pipeline ruptures,

b. Depletion of large quantities of natural gas, a high-quality, non-renewable energy resource and the potential for encouraging inefficient and wasteful uses of natural gas.

c. Potential for significant impacts on four endangered, threatened, rare, or other special-status plant species and their habitat.

d. Potential for loss of prime farmland.

e. Significant air quality impacts due to carbon monoxide emissions in the South Coast Air Basin.

f. Potential for significant adverse impacts on lands of cultural importance to Native American communities.

g. Potential for significant growth-inducing impacts.

h. Incremental addition of substantial quantities of greenhouse gases (i.e., carbon dioxide and methane).

169. The cumulative impacts of the Expansion Project are not unique to the Expansion, but would be caused by each of the pipeline alternatives identified in the EIR.

170. Since we cannot guarantee that the environmental mitigation ordered by this decision will be entirely successful in achieving their objectives, the possibility exists that the actual significant environmental impacts will be greater than those indicated in the EIR.

171. Cumulative impacts include the destruction of vernal pools, the degradation of air quality due to combustion of natural gas, the inducement of growth, and environmental impacts caused by the development of downstream facilities necessary to deliver Expansion gas. Due to the Commission's lack of jurisdiction over the end use of natural gas, the Commission cannot mitigate some of

the impacts of the Expansion Project. However, the Commission notes that if a "project" as defined by CEQA is undertaken to deliver or use Expansion gas, the project proponent must pass environmental review at that time.

172. PG&E should mitigate the cumulative impact of its pipeline operations on air quality by retrofitting the compression units at the five compressor stations on the existing system that will be used directly or indirectly to move Expansion Project gas with reasonably achievable control technology (RACT) or best available retrofit control technology (BARCT), as defined by California Air Resources Board's final guidelines and implemented by the local air pollution control district, to reduce emissions. This cost should be allocated entirely to the Expansion Project, since the existing facilities are to be modified to facilitate the use of additional gas-fired compression at Delevan and new compression at Brentwood which is required to serve the Expansion.

173. Although the efforts of regulatory agencies concerned with the permitting of combustion sites are intended to minimize the production of emissions, the greenhouse gases produced as a by-product of burning an additional 755 MMcf of natural gas a day will have a cumulative impact on air quality and the climate.

174. These unavoidable negative impacts demonstrate how crucial it is for the Applicant to carry out the required mitigation.

175. The Biological Opinion of the California Department of Fish and Game, transmitted to the Commission on December 21, 1990, is incorporated herein by this reference. The "Project Effects on Listed Species" and "Conditions to Avoid Jeopardy" stated in the Biological Opinion should be observed by the project applicant and all of its contractors, employees, and other agents, as a condition of acceptance of the CPCN to construct the Expansion Project in order to conform with the California Endangered Species Act.

176. The DFG finding of "no jeopardy" is premised upon the Expansion Project as modified by mitigation measures set forth in the Draft and Final EIRs, the Mitigation and Monitoring Plan for California State-listed Rare, Threatened, and Endangered Species, and the PGT-PG&E Pipeline Expansion Project Species Notes and Proposed Surveys for Special Status Fish and Wildlife.

177. The final EIR concludes that the Expansion Project is not the most environmentally preferred alternative, and that whether it fulfills the need for natural gas depends on the availability of demand side management, efficient use of existing system capacity, and the competition presented by other interstate pipelines.

178. Improved energy efficiency and the integrated intrastate project cannot be adopted as alternatives to the Expansion Project because the record shows that the hypothetical improvements in supply from energy efficiency cannot occur through the use of committed resources, and the supply potentially available through the integrated intrastate project would not meet long term needs.

179. None of the competing alternative pipelines have received all of the necessary regulatory approvals to begin construction.

180. Incremental interstate gas transmission to California should be developed on the basis of competition, and competition cannot exist if the Commission were to certificate the one pipeline it believed to be the least environmentally harmful project.

181. The granting of a certificate of public convenience and necessity at this time is needed to enable the Applicant to react to market forces in the manner this Commission has encouraged in D.90-02-016 that will bring the benefits of gas-on-gas competition to the California consumers.

182. The Expansion Project's need for flexibility to respond to market conditions on behalf of incremental ratepayers, such as the Producer/Shipper Group, the desirability of giving consumers the choice of many interstate pipelines so that in the long run, California's ratepayers will enjoy the lower prices and security of

supply that can only result from competition between competing producers and suppliers of gas, and the cost and operational advantages of a looped pipeline system constitute overriding considerations justifying the issuance of the CPCN for the Expansion Project despite the existence of unavoidable significant negative impacts on the environment.

183. The looping of the existing system that would be accomplished by the Expansion offers the existing ratepayers approximately $13.7 million per year in fuel savings, increased system reliability in the event of supply shortages or mechanical failure on a portion of the combined system, and greater flexibility in accepting deliveries from either Canada or the Southwest, leading to potentially lower costs of gas.

184. None of the project alternatives enable PG&E's incremental Expansion ratepayers to avoid A&G and O&M costs or the construction of 130 miles of pipeline and associated compressor facilities. None of the project alternatives would utilize existing excess pipeline capacity or provide consumers with the operational reliability of a looped pipeline system.

185. Although the other interstate pipelines identified in the final EIR are environmentally superior because they would impose less adverse effects on special status plant and animal species, prime agricultural land, and Native American communities, the pipelines would impose the following significant unmitigable impacts on the environment as would the Expansion Project:

(1) The possibility of pipeline rupture.

(2) Significant air quality impacts on the South Coast Air Basin.

(3) Potential growth-inducing impacts.

(4) Depletion of natural gas reserves.

(5) Addition of greenhouse gases.

186. The Expansion Project is a utility undertaking, enjoying the right of eminent domain and the economies of scale of the existing utility facilities.

187. The advantage of a 30-year depreciation period stems from the protection that the Expansion Project enjoys as an undertaking of a jurisdictional public utility.

188. PG&E's own subscription to 100 MMcf/d of firm transportation capacity helps to mitigate the risk of under-participation by shippers, since its subscription has helped to lower the transportation rate by $0.11.

189. The Expansion Project receives certain benefits made possible only by PG&E's obligation to serve ratepayers.

190. $736 million, consisting of $696 million for construction and $40 million for environmental mitigation, is the reasonable construction cost cap for the Expansion Project, as that term is defined by § 1005.5 subsection (a) of the PU Code.

191. PG&E should be permitted to use its 1988 cost estimate to calculate pro forma rates. The adoption of permanent rates, terms and conditions would be premature at this point because the final cost of the project is not available.

192. PG&E should use the return on equity and cost of debt currently authorized during construction to calculate its AFUDC.

193. PG&E's four-fold strategy to protect existing ratepayers from the risk of non-recovery of revenues in case the Expansion Project is underutilized consists of the following:

a. Full subscription of the Expansion's firm capacity.

b. Incremental cost-of-service treatment for the Expansion Project.

c. Full-fixed variable rate design.

d. Capacity brokering for firm capacity holders.

194. If PG&E successfully negotiates rates to recover 93% or more of its cost of service in firm transportation rates, ratepayers should not be precluded from benefitting from the Expansion.

195. It appears that as proposed, the Expansion Project minimizes risks to its sponsors through its full-fixed variable rate design and the allocation of 93% of its revenue requirement to firm transportation, and this minimization of risk makes the Expansion Project a suitable enterprise for ratepayers, and a desirable one for shareholders.

196. PG&E has not stated that it will refrain from seeking to recover any of the Expansion Project's revenue requirements from existing ratepayers.

197. PG&E's assignment of the risk of revenue recovery to Project sponsors and shippers should be approved until the Commission has examined the potential for the Expansion to generate revenues in excess of its revenue requirement. This exanination and risk allocation should occur no later than the Expansion's first general rate case.

<u>Conclusions of Law</u>

1. Recirculation of the Draft EIR is not necessitated by the fact that the draft discussed the out of state effects of alternative pipelines and associated the environmental impacts of alternative pipelines with each other because the information that was added to the final EIR to rectify those matters did not constitute "new information" as that term is employed under CEQA.

2. Recirculation of the Draft EIR is not required under CEQA and the Commission need not reopen the record to review PG&E's allocation of capacity, revenue recovery, and rates as a result of PGT's agreement with Bonus because the project definition of the Expansion Project has not been changed by the agreement.

3. Withdrawal of the Commission's statement at the FERC in support of the certificate application and offer of settlement by PGT for the interstate portion of the Expansion Project was not required because the statement had resulted in no prejudice to any party in the instant proceeding.

4. The criteria adopted in D.90-02-016 should be applied to the Expansion, which constitutes the in-state portion of one of the competing interstate pipelines we reviewed in I.88-12-027.

5. Our determination in D.90-02-016 concerning California's need for additional natural gas pipeline capacity should control in this proceeding.

6. Since the potential of demand side management (DSM) to meet any portion of that forecasted demand was not discussed in D.90-02-016, it was necessary to consider whether DSM could render unnecessary a portion of the Expansion's proposed capacity.

7. The sponsors of the Expansion Project, that is, PG&E's shareholders, and the Expansion shippers should bear the risk of revenue underrecovery. PG&E's existing ratepayers shall not bear any of the project's risk unless the Commission finds that the financial benefit to ratepayers through margin contribution substantially outweighs the risk of revenue underrecovery.

8. The issue of whether PG&E may seek to recover any Expansion costs (other than transportation charges) from its existing ratepayers should be revisited in the Expansion Project's first general rate case, when concrete evidence of shipper participation, the operating capacity of the pipeline, and the Expansion's costs and rates will be available.

9. The Precedent Agreements have not "substantially lessened competition," the harm prohibited by the Cartwright Act, because Kern River and Altamont have demonstrated that the competition to provide interstate gas transportation is robust.

10. The Expansion Project has no impermissible impact upon competition for the purpose of review under Northern California Power Agency v CPUC.

11. D.90-02-016 does not bar an allocation of the cost of existing facilities to the Expansion Project's costs because it simply assigns responsibility for the cost of new capacity. It does not delineate the components of the cost of new capacity.

12. It is reasonable for the Expansion Project to use PG&E's existing facilities identified in the Application to provide incremental service to Expansion shippers.

13. The welfare of consumers throughout the state, and not just in PG&E's service territory, may be considered when allocating the benefits of economies of scale from the use of existing facilities.

14. It would not be reasonable to allocate common costs between the existing system and the Expansion Project because no compelling policy reason for doing so has been shown.

15. PG&E's proposal to assign the costs of future facilities additions to the Expansion Project by direct assignment, and if not directly assignable, then on a pro-rata basis depending on throughput, is reasonable. It is reasonable to apply this allocation method to any upgrades of portions of the existing system that are used by the Expansion to avoid new construction so as to ameliorate any concern that existing ratepayers are forced to perpetually subsidize the Expansion Project.

16. The full-fixed variable rate design is appropriate for this transportation-only pipeline.

17. The use of a single delivery point and postage stamp tariff are consistent with this Commission's prior determinations.

18. There is insufficient evidence to demonstrate that PG&E's subscription to 100 MMcf/d of firm transportation capacity on the Expansion Project is reasonable.

19. It would be reasonable for PG&E to offer its 100 MMcf/d of capacity to the potential shippers who were identified in the open season process.

20. It would not be prudent to authorize permanent rates as proposed for the Expansion Project if the Expansion Project may not be able to recover the approximately 13.2% of its cost of service represented by PG&E's subscription to 100 MMcf/d of firm transportation capacity due to a finding that PG&E's subscription was not needed.

21. A reasonableness review of PG&E's subscription should be conducted no later than the Expansion Project's first general rate case.

22. As a part of PG&E's subsequent Expansion rate case proceeding, PG&E should be required to show either that it has awarded that 100 MMcf/d to independent shippers or demonstrate why it needs the 100 MMcf/d or portion thereof of firm transportation capacity.

23. The sharing of the cost of incremental facilities contemplated in the equity participation option agreements should apply to facilities necessary to maintain the portions of PG&E's existing system used by the Expansion as well as to the Expansion's facilities.

24. Edison's plan to hold its investment in the Expansion Project as regulated utility-related property is reasonable, since Edison plans to transport gas over the Expansion solely for the benefit of the its ratepayers. Reasonableness review of the cost is required before Edison may recover the costs of its equity participation in rates.

25. If and when PG&E proposes to convey a portion of its interest in the Expansion Project to Edison or SDG&E, or to any other entity, PG&E should be required to submit its proposal for Commission review because any conveyance of ownership interest or control of the Expansion Project is subject to our review pursuant to § 851 of the PU Code.

26. SoCalGas' incurrence of pre-construction, construction, and post-construction costs to interconnect Expansion facilities would be reasonable regardless of actual usage; however, we should reserve our judgment on whether the costs of those undertakings is reasonable and should be recovered in rates until we have reviewed a formal application for approval of capital expenses to interconnect with the Expansion Project.

27. PG&E has not introduced sufficient evidence on the actual, as opposed to the design, capacity of the Expansion Project to enable us to evaluate the potential for recovery of revenues in excess of the revenue requirement.

28. There is insufficient information concerning the actual operating capacity of the Expansion Project and the actual subscriptions to firm capacity by Expansion shippers to support a finding that PG&E's proposal to allocate the revenues from interruptible transportation to its shareholders is reasonable.

29. The ratepayers have an equitable claim to the margin that may be represented by revenues from interruptible transportation service.

30. PG&E's proposition that all interruptible transportation revenues be assigned to shareholders must be rejected at this time.

31. The risk of recovery of Expansion costs shall reside with PG&E's shareholders until subsequent decision by this Commission.

32. PG&E's proposal that the costs of the Expansion Project shall be recovered in rates as established by separate Expansion Project ratemaking proceedings, and not in any other rates established in other PG&E rate proceedings, is reasonable.

33. PG&E's requested waiver of Section II of GO 96-A should be granted to enable PG&E to file its tariff at the Commission in the same format as that used at the FERC.

34. Sections IX and X of GO 96-A should not be waived at this time because the Commission has not yet reviewed the terms of any of the firm transportation agreements contemplated by the Precedent Agreements and the issue of risk allocation has not yet been resolved.

35. It would be unreasonable to authorize PG&E to change the corporate status or ownership of the Expansion Project unless the Commission had first completed its review of the potential for the Expansion to generate revenues in excess of its cost of service.

36. The assignment of the risk of underutilization and underrecovery of revenue requirement to the utility's shareholders mitigates the burden on ratepayers that is generally addressed by a finding of need for the project.

37. It is reasonable to certificate the Expansion Project because there is need for some of the capacity to be provided by the Expansion Project, there is evidence of future demand in addition to the current need for the services to be provided by the Expansion, and development pursuant to the CPCN will only occur after Expansion investors have determined that the project is of sufficient importance to warrant its risk and expense.

38. We find today that the public convenience and necessity require the issuance of a certificate to PG&E for the construction of the Expansion Project; however, we do not find that construction would be reasonable in all events.

39. It is consistent with the market-based principles adopted in D.90-02-016 to refrain from finding at this time that construction of the Expansion Project is needed to in all events serve the public convenience and necessity.

40. PG&E, as instructed by this Commission in the decision, should determine whether, based on market conditions existing at the time it commences construction, the Expansion Project should be developed.

41. Approval of a certificate of public convenience and necessity is reasonable at this time because if PG&E determines that there is demand for 755 MMcf/d of incremental interstate pipeline capacity at the price set by the Expansion Project, it should be able to accommodate market interest in the Expansion Project without any regulatory delay. The execution of Firm Transportation Contracts with shippers for 755 MMcf/d of capacity will establish the existence of market interest and no further regulatory review of the market will be needed before the Expansion Project can commence construction.

42. PG&E should be required to evaluate the reasonableness of its decision to build the Expansion Project as of the date it determines to proceed with the development. This evaluation will necessarily consider the competition to serve the demand for natural gas represented by Demand Side Management, alternative gas delivery systems, interstate pipelines, the analysis of need contained in the final EIR, and the Firm Transportation Contracts then in place.

43. PG&E must show that the Expansion is "used and useful," that is, that sufficient demand for firm transportation will exist to ensure revenue recovery on the date of operation, before it may recover rates for Expansion service.

44. The Public Utilities Commission is the lead agency under the California Environmental Quality Act (CEQA) for the purposes of certifying the final environmental impact report (EIR) for the proposed Expansion Project.

45. The Commission lacks the jurisdiction necessary to mitigate several of the cumulative impacts of the Expansion Project resulting from the end-use of Expansion gas.

46. All of the mitigation measures listed in Appendix B to this decision and more fully described in the final EIR should be adopted.

47. All of the mitigation measures listed by the DFG in its biological opinion should be adopted. Where the requirements of the Final EIR and the biological opinion conflict, the provision which provides the greater environmental protection or mitigation should be observed.

48. It is reasonable to require the use of reasonable available control technology (RACT), and best available retrofit control technology (BARCT), when modifications to existing gas-driven compressors are proposed in order to mitigate cumulative impacts even if those modifications would not trigger the use of RACT and BARCT under local air pollution control district guidelines.

49. A mitigation monitoring program, as described in the final EIR, shall be adopted as required by § 21081.6 of the California Public Resources Code.

50. PG&E should meet a high standard of care in undertaking the mitigation measures prescribed in this order.

51. As part of the mitigation monitoring program to be discussed below, PG&E must demonstrate both that (1) all of the detailed studies adequately address the specific locations where the pipeline and its appurtenant facilities will be placed and that (b) impacts to the specific resources discovered as a result of those detailed studies are adequately mitigated.

52. The Commission may rely on the conclusion of the California Department of Fish and Game that a route alternative contained in the Draft EIR is environmentally preferable to a route described in the Final EIR to require the applicant to use the former route.

53. The finding of "no jeopardy" by DFG under the California Endangered Species Act could not be sustained if there were any diminution or weakening of the mitigation measures contained in the documents on which the DFG relied to form its biological opinion.

54. The Commission as the lead agency under CEQA may approve the proposed development even though, as mitigated, it poses significant negative impacts if the Commission adopts a statement of overriding considerations.

55. Even though the final EIR identifies several significant negative impacts on the environment which cannot be successfully mitigated by the Expansion Project, it is reasonable and prudent to certify the final EIR for the Expansion Project and to issue a certificate of public convenience and necessity because of the following overriding economic considerations:

> The benefits of diversity of supply and competitive gas prices for California's end users cannot be assured unless PG&E, as the sponsor of a proposed interstate pipeline is authorized to respond to market demand for new capacity.
>
> The cost of fuel used to transport gas over PG&E's existing system will be reduced by approximately $13.7 million a year.
>
> The increased reliability of operations and operational flexibility will enable PG&E to procure supplies for its existing ratepayers from different producing regions at lower cost.

> Existing facilities and capacity will be used to avoid the unnecessary expenditure of capital and economies of scale will be used to provide PG&E's Expansion ratepayers with lower rates than if a stand-alone system were constructed.

56. The alternatives to the project which have been identified in the Final EIR are infeasible for the purpose of accomplishing the goals of this Commission because none of them will provide PG&E's incremental Expansion ratepayers with the lower rates possible through the use of economies of scale and the reliability of service available through looped pipeline design, and none of the alternatives will provide PG&E's existing ratepayers with the approximately $13.7 million annual fuel savings, increased reliability, and flexibility of supply inherent in the looped pipeline design.

57. The Commission finds that as conditioned, the EIR for the PGT/PG&E Expansion Project in California should be certified in order to facilitate the development of gas-on-gas competition and to realize the resultant benefits of diversity of supply, reliability of supply, and lower gas prices for California consumers.

58. Certification of the Expansion Project, as conditioned, will serve the public convenience and necessity because only then can PG&E respond to market demand for transportation over the Expansion Project and provide the diversity of supply, capacity, and competition that will result in lower prices and security of gas supply.

59. The Commission should approve the issuance of a certificate of public convenience and necessity for the construction of the Expansion Project, but require PG&E to execute firm transportation service agreements with its shippers, and to risk the reasonableness of its decision to build the pipeline.

O R D E R

IT IS ORDERED that:

1. A certificate of public convenience and necessity (CPCN) is granted, subject to the conditions set forth in this order, to Pacific Gas and Electric Company (PG&E) to construct and operate a natural gas pipeline from Malin, Oregon, to Kern River Station, California, having a firm transportation capacity of 755 MMcf/d, to construct a new compression station at Brentwood, California, and to make related improvements to other compression stations, meters, and taps.

2. The maximum reasonable cost of the proposed project pursuant to Public Utilities Code § 1005.5 shall be $736 million.

3. The risk of non-recovery of Expansion Project costs and expenses shall be borne by PG&E's shareholders and Expansion shippers unless otherwise ordered by this Commission.

4. The measures necessary to mitigate the negative environmental impacts of the Expansion Project are listed in Appendix B, "Summary of Mitigation Measures for the PGT/PG&E Natural Gas Pipeline Project in California". PG&E's acceptance of this certificate of public convenience and necessity is conditioned upon the compliance of PG&E with all of the terms and conditions of Appendix B.

5. The measures necessary to avoid jeopardy to state-listed rare, threatened, or endangered species are listed in the Biological Opinion of the California Department of Fish and Game, transmitted to the Executive Director on December 21, 1990. PG&E's acceptance of this certificate of public convenience and necessity is conditioned upon the compliance of PG&E with all of the terms and conditions of the Biological Opinion, which by this reference is incorporated and made a part of this decision. In the event of differences between the Final EIR and the Biological Opinion, the

provision which provides stricter environmental protection shall be observed.

6. The monitoring program required by Public Resources Code section 21081 appears as Appendix C, "Mitigation Monitoring Program". PG&E's acceptance of this certificate of public convenience and necessity is conditioned upon the compliance of PG&E with all of the terms and conditions of Appendix C and the Final Mitigation Monitoring, Compliance, and Reporting Plan for the PGT/PG&E Natural Gas Pipeline Project in California, described herein.

7. Construction of the Expansion Project shall be undertaken by PG&E consistent with the provisions of the final EIR, the adopted Mitigation Monitoring Plan, and the adopted Mitigation Monitoring Program. PG&E shall be responsible for the compliance with this Commission order by all of its contractors, subcontractors, employees, or other agents in furtherance of the Expansion Project; the action or inaction of those agents undertaken in the furtherance of the Expansion Project shall be attributed to PG&E for the purposes of enforcing the terms of the Mitigation Monitoring Plan and the Mitigation Monitoring Program.

8. Upon the submittal of PG&E's letter of intent to accept this certificate of public convenience and necessity, PG&E shall file a revised schedule of project activities, similar to the schedule filed as Exhibit K to the original application, but showing the revised date of operation.

9. PG&E shall use the return on equity and cost of debt currently authorized during construction for purposes of computing its allowance for funds used during construction.

10. Construction shall occur only during the periods for which the environmental impacts of the development were analyzed in the Final EIR. No later than 180 days before the planned start of construction on the spread in which is planned the crossing of a body of water which DFG has identified in its Biological Opinion,

PG&E shall provide engineering drawings which indicate the proposed pipeline alignment, construction, and staging areas to enable the biological monitor to ascertain whether special status plant species populations would be harmed or not, and to undertake whatever route changes would be necessary to avoid jeopardizing the species.

11. Existing PG&E system facilities that will be used by the Expansion Project shall be modified with reasonably achievable control technology (RACT) and best available retrofit control technology (BARCT), as defined by guidelines of the California Air Resources Board, and as determined by the local air pollution control district at the time of construction to reduce the emission of oxides of nitrogen, and the cost of such compliance shall be borne by the Expansion Project.

12. At least 90 days prior to construction, PG&E shall file its finalized Firm Transportation Contracts with Expansion Project shippers with the Commission in this docket.

13. During construction, PG&E shall file quarterly reports for the project with the Central Files office of the CPUC. PG&E shall simultaneously provide one copy of each quarterly report to the Energy Branch of CACD to review for compliance with this order. The quarterly reports shall include the following:

a. A period cost report reflecting:

(1) Monthly budgeted expenses.

(2) Actual monthly expenses.

(3) Budgeted total cost to date.

(4) Actual total cost to date.

(5) Total committed costs to date.

(6) Total budgeted costs for the project at completion.

(7) Forecasted total costs for the project at completion.

b. S-curve graphs showing budgeted and actual project costs by month, and year-to-date.

c. An exhibit showing the major milestones of scheduling for each major phase of the project.

d. A narrative explanation of the major accomplishments and problems occurring since the last report with special emphasis on any variance from budgeted expenses or construction schedules, and a description of PG&E's progress toward the major milestone including an estimate of whether those milestone will be achieved within budgeted costs and on schedule.

14. No later than two years after PG&E has indicated its acceptance of this certificate of public convenience and necessity and no less than six months before the scheduled date of operation, PG&E shall file the Expansion Project general rate case application with the Commission. PG&E shall recover its cost of the Expansion Project through rate proceedings established for this purpose; none of the costs of the Expansion Project may be recovered in any other PG&E rate proceeding, advice letter, or accounting mechanism. The general rate case shall address all of the matters identified in this decision to be resolved at that general rate case, including, but not limited to the following. A finding of reasonableness shall be made before PG&E may recover any of its Expansion Project costs from any ratepayers.

a. The reasonableness of the Applicant's decision to construct the Expansion Project. PG&E must demonstrate that sufficient demand for PG&E's proposed service will exist at the time the Expansion is scheduled to commence operations, based on the facts known or reasonably discernable by PG&E at the time of its decision to proceed, to avoid underrecovery of the Expansion's revenue requirement.

b. The reasonableness of the cost of construction, including the cost of environmental mitigation.

c. The reasonableness of PG&E's subscription to 100 MMcf/d of firm capacity, unless PG&E has allocated the capacity to other shippers, in which case PG&E must show that the allocation was non-discriminatory. If PG&E proposes to retain its 100 MMcf/d subscription, the application shall include PG&E's plan to mitigate CO_2 and CH_4 emissions from the use of this increment of gas.

d. The actual firm and interruptible operating capacity of the Expansion Project.

e. The amount of firm and interruptible capacity subscribed to by Expansion shippers in transportation agreements.

f. The allocation of the cost of service between firm transportation and interruptible transportation revenues.

g. The establishment of firm and interruptible rates and the terms and conditions of service over the Expansion Project.

h. The allocation of the risk of revenue recovery by the Expansion Project between ratepayers and shareholders.

15. The cost of future capital additions to portions of the existing PG&E system which are to be used by the Expansion Project shall be allocated between existing ratepayers and Expansion shippers based on which group the improvement will serve, but if this cannot be determined, the cost of the improvement will be allocated on a pro-rata throughput basis.

16. PG&E shall require as a condition of its contracts with Expansion Project shippers that a shipper may not refuse to broker capacity subscribed to under contract when the shipper has no bona fide need for the capacity and demand for that capacity exists.

Capacity on the Expansion Project shall be subject to any capacity brokering program subsequently ordered by this Commission.

17. The motion of Altamont Gas Transmission Company dated May 18, 1990 that the Commission withdraw its statement before the FERC is denied.

18. The motion of Altamont Gas Transmission Company dated August 13, 1990 for recirculation of the Draft EIR is denied.

19. The "Joint Petition of Kern River Gas Transmission Company and Altamont Gas Transmission Company to Set Aside Submission and Reopen Proceeding for the Purpose of Taking Additional Evidence" filed on September 24, 1990, is denied.

This order is effective today.

Dated December 27, 1990, at San Francisco, California.

G. MITCHELL WILK
President
FREDERICK R. DUDA
STANLEY W. HULETT
JOHN B. OHANIAN
Commissioners

I will file a written concurring opinion.

/s/ G. MITCHELL WILK
Commissioner

I will file a written dissent.

/s/ PATRICIA M. ECKERT
Commissioner

I CERTIFY THAT THIS DECISION WAS APPROVED BY THE ABOVE COMMISSIONERS TODAY

NEAL J. SHULMAN, Executive Director

G. MITCHELL WILK, Commissioner, concurring:

I support the granting of the certificate of public convenience and necessity to Pacific Gas and Electric Company (PG&E) to expand its natural gas transportation system. I believe the decision effectively strikes the difficult balance between our PU Code Section 1001 responsibilities and our February pipeline capacity decision (D.90-02-016) to let market-forces work to bring California ratepayers reliable natural gas supplies at the lowest possible cost.

I believe it important that we act now to enable PG&E to respond to the market forces. It is appropriate that PG&E shareholders and Expansion shippers remain at risk for recovery of Expansion Project costs at this time.

While I support the decision, I am concerned that we may have inconsistencies in our position taken here and at the FERC with respect to allocation of facilities' costs and rate design. I anticipate these issues will be raised by parties in petitions for modification or rehearing, and I look forward to revisiting them at that time.

G. MITCHELL WILK, Commissioner

December 27, 1990
San Francisco, California

A.89-04-003
D.90-12-119

PATRICIA M. ECKERT, Commissioner, Dissenting

Government should be consistent, especially when in the business of regulating businesses.

Two glaring policy inconsistencies exist in the majority opinion granting Pacific Gas and Electric Company a certificate of public convenience and necessity. These inconsistencies are in the rate design and the cost allocation adopted for the expansion pipeline.

With respect to rate design, the majority opinion adopts a full-fixed-variable method for firm gas transportation. This method assigns a fixed rate to a shippers's entire contracted volume. The adopted fixed charge guarantees the pipeline its entire revenue requirement regardless of the volume of gas transported.

The Commission has argued <u>against</u> this rate design scheme before the FERC on the grounds that it is anticompetitive and shifts far too much business risk from pipelines to their customers. Once locked into a fixed charge, the ability of the shippers to seek the most competitive, least cost gas is severly limited. A fixed charge rate design inhibits both gas-on-gas competition and pipeline-on-pipeline competition. To remedy this problem, we have argued, before the FERC, for the allocation of a reasonable percentage of pipeline costs to a volumetric charge. This is the type of allocation which should be implemented in this case.

The majority opinion also adopts a purely incremental method of cost allocation. None of the existing facility costs is allocated to the expansion project even though existing facilities are essential for expansion project operation. A reasonable cost allocation for a looped pipeline expansion should allocate a portion of these costs to the expansion customers. The Commission has, likewise, advocated this position before the FERC. The majority opinion is inconsistent with the Commission's previously articulated position on this issue.

This Commission has consistently maintained that the market forces of competition should drive California's natural gas market. This policy is fundamental to both our recent gas procurement decision and our pipeline decision. I fully support this policy, and believe the Commission should stay the course. This is essential if we are to maintain the competitive landscape we have so painstakingly painted over the past few years. The pipeline market must be granted the freedom to determine how best to meet California's capacity needs. Unfortunately, the majority opinion departs from this policy and limits the ability of the market to operate dynamically.

For the above reasons, I must respectfully dissent from today's decision.

/s/ Patricia Eckert

Patricia M. Eckert, Commissioner

December 27, 1990

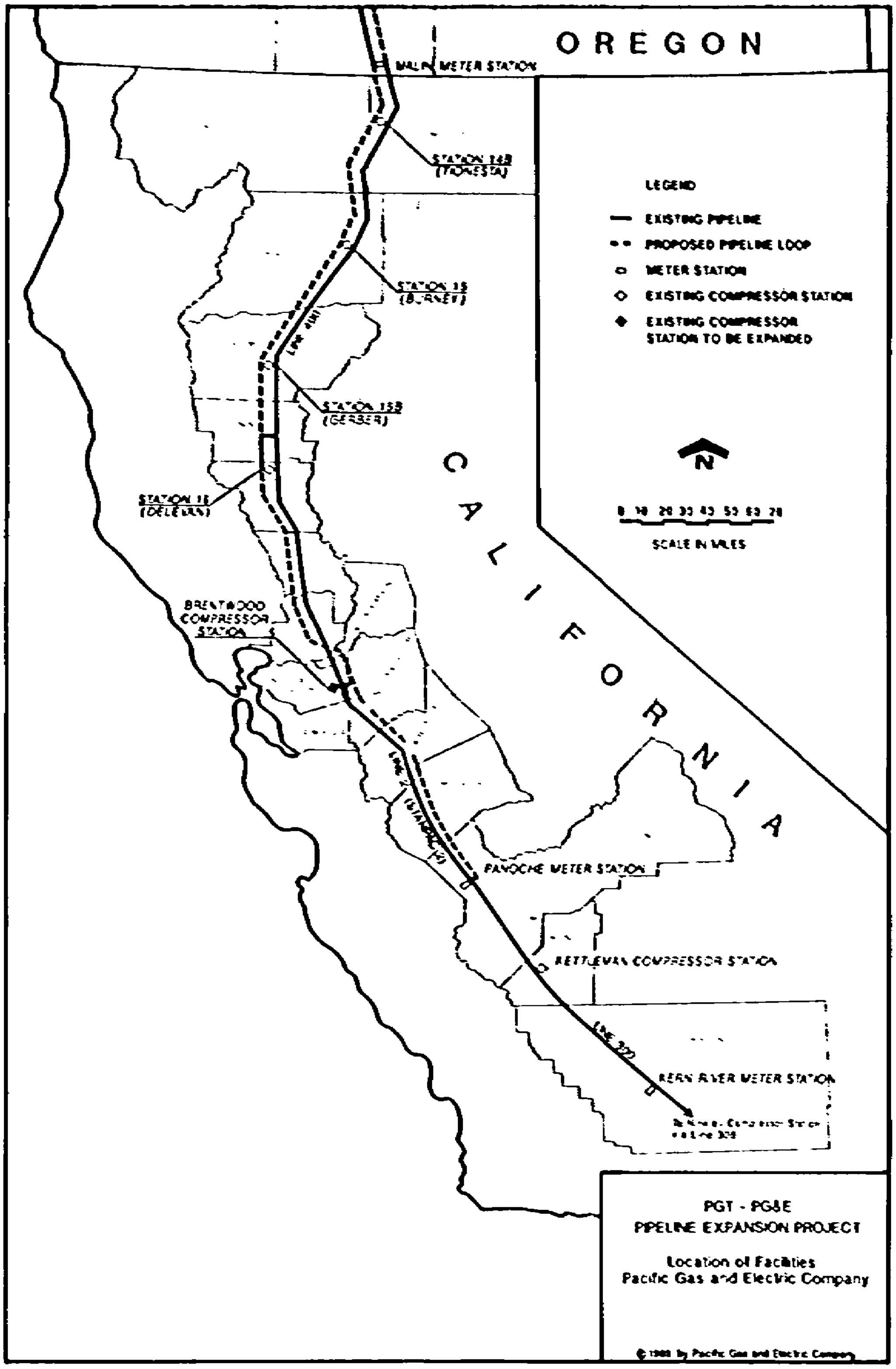
San Francisco, California

APPENDIX A

Pacific Gas and Electric Company
San Francisco, California

Cancelling

Cal. P.U.C. Sheet No. 4-P
Cal. P.U.C. Sheet No.



Advice Letter No.
Decision No.

Issued by
Gordon R. Smith
Vice President
Finance and Rates

Date Filed ______
Effective ______
Resolution No. ______

(END OF APPENDIX A)

Appendix B. Summary of Mitigation Measures for the PGT/PG&E Natural Gas Pipeline Project in California

MITIGATION MEASURES FOR SIGNIFICANT IMPACTS

General

1. Retain Environmental Monitors. The CPUC or its designee shall determine the qualifications of the environmental monitors necessary to monitor each mitigation measure. The CPUC or its designee shall retain appropriately qualified environmental monitors that will be funded by the applicant but will be independent of PGT/PG&E. The environmental monitor for each construction spread, consistent with the mitigation monitoring program has authority to and responsibility for determining which mitigation measures will be applied and the manner in which they will be applied. The environmental monitor will document all monitoring required for mitigation and submit written reports to the CPUC or its designee as specified in measures below. Documentation necessary for reporting will be determined by the environmental monitor with the approval of the CPUC if not specified in the mitigation measure. All reports shall be double-sided and printed on recycled paper.

One environmental monitor for each construction spread shall be retained to supervise mitigation. This individual is responsible for monitoring and documenting the implementation of all mitigation during construction, including necessary agency coordination and review and onsite monitoring. The environmental monitor may delegate monitoring and reporting tasks to qualified individuals with the CPUC's approval. When mitigation below requires a special resource monitor, the environmental monitor is ultimately responsible for ensuring that the monitoring and reporting specified in each mitigation measure are accomplished.

An environmental monitor must be at the site during that portion of construction that has the potential to create a significant environmental impact or an impact otherwise required to be mitigated. When the environmental monitor is not required on site due to the nature of the construction activities, the construction supervisor will be required on site at any time construction or delivery of materials occurs. During these periods, the environmental monitor shall be responsible for maintaining the field markings and for instructing each successive construction supervisor as to the restrictions in force at the site.

The environmental monitor assigned to each construction spread is responsible for establishing checklists, logs, and journals to document the implementation of mitigation. When mitigation for construction activities does not specify a monitoring program, the environmental monitor must conduct routine inspections of construction practices to ensure ongoing conformance with approved mitigation. All documents must be accessible by the CPUC upon request or must be submitted as specified in the mitigation monitoring plan.

2. Secure a Performance Bond. PGT/PG&E shall obtain a performance bond or other type of financial guarantee acceptable to the CPUC from an agent approved by the CPUC to ensure that approved mitigation measures will be completed. The CPUC shall stipulate the amount of the bond or other financial security after mitigation costs have been determined and before construction activities begin.

3. Conduct Preconstruction Surveys and Mark Resources. Conduct a preconstruction survey to identify environmental resources for each construction spread over the entire length of the pipeline. The survey shall be conducted based on final design, marking, and staking in the areas of the right-of-way and access roads. The requirement for accuracy in the preconstruction survey necessitates that the entire pipeline alignment for that construction spread and all associated access roads be tentatively identified on maps which will allow location in the field. Engineering and survey crews shall mark the pipeline route and right-of-way boundaries as well as certain resources as specified in the mitigation measures. The environmental monitor shall sign all maps.

The survey shall be performed by appropriately qualified persons representing those disciplines where specific sensitivities have been identified in the EIR. Thus, for example: an area generally characterized as habitat for special-status plants must be surveyed by a qualified botanist at the proper times of year to precisely identify and locate the potential resources of a given area; local cultural resource features must be identified by a professional archaeologist; and soils or geologic features which dictate localized design modifications or construction practices must be identified and marked by a professional engineering geologist.

The form of the survey can vary according to the scientific requirements of the resource under investigation or specifications elsewhere in the EIR or mitigation monitoring plan, but the results of the survey shall be reported in written form and at a minimum shall include:

1. A location map showing the portion of the project surveyed.
2. Maps showing the location of each tower and access road surveyed.
3. A list of the resources subject to survey.
4. Names, qualifications, and employment of persons conducting the survey.
5. Dates of survey, particularly as in relation to environmental constraints such as the bloom times of identified plants, etc.

6. Level of effort in person hours spent in the field.

7. A list of site-specific resources found, and for each:

   a. Detailed site map showing the resource and the nearby project features. This map should be accurate enough to identify the resource boundary in the field and shall be signed by the environmental monitor.

   b. Description of the resource stating its susceptibility to damage from construction.

   c. Measures to be undertaken to mitigate potential damage.

Whenever engineering changes are made by PG&E/PGT, and the environmental monitors shall be notified no later than 30 days before construction is to commence. The new location shall be indicated on a map of suitable accuracy. The spread shall be resurveyed, if necessary, as determined by the environmental monitor. Thus, the preconstruction survey must be kept up to date continually throughout line engineering. The resurvey can be conducted by the same or different personnel, but the environmental monitor must be supplied with a precise map showing the changes and be informed of personnel changes.

All sensitive resources which are to receive special protection shall be suitably marked during the survey. Also, the locations where fencing will be installed shall also be clearly marked during the survey. The marking must be done under the supervision of the environmental monitor and must be of sufficient visibility and durability that it will be obvious to all personnel throughout construction in the area.

4. Develop and Implement an Operations and Maintenance Plan. During the detailed design phase, determine the locations, frequency, and techniques of inspections to be conducted during the operation of the pipeline and the reporting requirements for monitoring. Incorporate these specifications into the operations and maintenance plan for the pipeline. The operations and maintenance plan must be consistent with the inspection procedures outlined in the EIR and the mitigation monitoring plan. Include in this plan all operations and maintenance aspects of any resource-specific mitigation plans developed and implemented as part of this mitigation monitoring and reporting plan.

The resource-specific mitigation plans included in this mitigation monitoring and reporting plan follow in the order of their appearance: emergency preparedness plan, worker education program (referred to in the findings as the Environmental Education Plan (EEP)), ECR plans (the last item of which is a termination and rehabilitation plan), spill prevention and control (SPC) plan, stream crossing mitigation plan, hydrostatic testing mitigation plan, protection plan for the Mayfield Ice Cave area, native plant nursery mitigation plan, wetland mitigation plans, riparian mitigation plans, transplanting mitigation plan, reseeding mitigation plan, weed control plan, special native plant community revegetation plan, vernal pool revegetation plan, mitigation plan for impacts on spawning gravels near the proposed Fall River crossing (unless the crossing is bored), toxic sediment work plan for crossings in the Sacramento-San Joaquin River Delta, formal housing plan for construction workers, fire control plan (FCP), dust control plan, road crossing mitigation plan, cultural resources mitigation plan, and paleontologic resources mitigation plan.

Submit the final plan to the CPUC or its designee for approval as specified in each applicable mitigation measure. Submit quarterly reports during the detailed design, construction, and restoration phases of the project; biannual reports for the next 5 years; and annual reports thereafter to the CPUC or its designee for the lifetime of the pipeline, or as specified in the approved mitigation plan.

5. Develop and Implement an Emergency Preparedness Plan. During the detailed design phase, prepare an emergency preparedness plan in coordination with local and state jurisdictions that includes procedures for preventing and responding to emergencies related to the project. Include in this plan detailed, site-specific measures for impacts from seismic events, volcanic eruptions, pipeline ruptures, blasting, or other project-related activities. Incorporate in this plan all measures developed as part of the mitigation and monitoring plan relating to emergency preparedness (e.g., emergency measures contained in the SPC plan and FCP). Ensure that the plan addresses protection of construction workers as well as the public in the vicinity of the pipeline.

Submit the final plan to the CPUC or its designee for review. Submit quarterly reports during the detailed design, construction, and restoration phases of the project; biannual reports for the next 5 years; and annual reports thereafter to the CPUC or its designee for the lifetime of the pipeline, or as specified in the approved mitigation plan.

6. Develop and Implement a Worker Education Program. Develop and implement a worker education program including a handbook. The program should educate construction workers on general and specific mitigation measures for soils, hydrology and water quality, special-status plants and wildlife, wetlands, air quality, and cultural resources. The handbook shall document potential sensitive resources, proper construction techniques, and general on-site procedures shall be compiled and kept on site at all times during construction.

Outline in the plan which resources and mitigation measures should be addressed in preconstruction briefings, and where along each construction spread these briefings should be held. The text must be keyed to the maps. Additional detailed topics to be included in the education program are discussed under mitigation measures for specific resources. Provide instructional aids to ensure workers are aware of mitigation measures that require their participation.

The worker education program shall include a presentation to the construction crew by the environmental monitor within 5 days of commencement of construction for each construction spread. All workers for that spread must be present and sign an attendance roster that will be kept by the environmental monitor. The presentation shall review sensitive resources and construction techniques relevant to the spread as well as general site restrictions such as use of private vehicles, no pets on site, etc., as identified in the EIR.

The handbook shall contain the following information:

1. Photographs and descriptions of the sensitive resources. This will not only assist the field personnel in recognizing these features where they have been marked, but may prevent damage to the same resources should they be discovered at nearby sites that may have been overlooked;

2. Photographs and descriptions of the field markings the crew should heed as they are operating and storing equipment and material along the line;

3. A list of general measures to be followed for construction in all areas and a list of measures that pertain to each specific locality or resource needing special protection;

4. The names, addresses, and telephone numbers of those persons responsible for monitoring and enforcement of the mitigation plan. These includes (a) the environmental monitor, (b) the construction supervisor, (c) the CPUC project manager, (d) the applicant's project manager, and (e) the person with authority to issue a stop-work order;

5. A list of the sanctions to be imposed in the event violations are discovered.

Submit the final plan to the CPUC or its designee for approval. Submit monthly reports during the construction phase of the project to the CPUC or its designee.

7. **Obtain All Permits for Each Construction Spread before Beginning Construction Activities in That Spread.** PGT/PG&E shall submit a permit acquisition schedule to the CPUC showing anticipated application filing dates, durations of permit activities, and dependencies on other activities, including the name of a contact person at each agency issuing a permit. No construction activity shall begin on the "A" spreads until all permits are obtained for these areas unless otherwise specified in writing by the permitting agency. No construction activity shall begin on the "B" spreads until all permits are obtained for these areas unless otherwise specified in writing by the permitting agency. Any exceptions to this requirements must be approved by the CPUC or its designee.

Geology

8. Implement Engineering Solutions. Implement several general measures to reduce significant geologic impacts:

- o select the pipeline route to avoid geologic hazards, such as landslides;
- o retain a geotechnical specialist to evaluate minor rerouting options and select construction procedures during onsite study in the detailed design phase of the project;
- o further refine the proposed alignments to avoid difficult terrain (e.g., rock outcrops, active slides); and
- o conduct geologic, geotechnic, and engineering studies at the sites during the detailed design phase of the project to plan relocation.

The following are more detailed measures for specific significant impacts. All mitigation measures described above and below must be approved by CPUC or its designee and the land management agency with jurisdiction and must be monitored as designated by that agency.

9. Recontour Topographic Changes Caused by Grading. Recontour topographic changes caused by grading to the approximate original slopes during the restoration phase of the project and revegetate. Submit ECR plans to CPUC or its designee or the land management agency with jurisdiction. See the model ECR plan in Exhibit 1.

10. Reestablish Land Contours and Drainage Channels. Reestablish land contours and drainage channels to approximate their original conditions. Assess and document drainage conditions before and after construction to ensure that original conditions have been restored. Submit a report documenting preconstruction and postconstruction conditions to CPUC or its designee and the land management agency with jurisdiction.

11. Restore Areas to Approximate Original Contours. On steep terrain or in wet areas where the right-of-way must be graded at two elevations (two-toning), or where diversion dams must be built to facilitate construction, restore and revegetate the areas upon completion of construction to approximate original contours. Submit site-specific ECR plans to CPUC or its designee or the land management agency with jurisdiction. See the model ECR plan in Exhibit 1.

12. Limit the Creation of Access Roads. To minimize disturbance caused by the project, limit the creation of access roads. During the detailed design phase, consult with local land management agencies concerning placement of new access roads. Submit for approval to CPUC or its designee and DFG or the land management agency with jurisdiction detailed, site-specific plans that show the design and location of new access roads prior to construction and an environmental analysis of the impacts of the construction of the access road.

13. Design Access Roads to Conform with the Surrounding Topography and Minimize Alteration of Natural Features. Design access roads to conform with the surrounding topography and minimize alteration of natural features. Avoid cutting trees and removing boulders where possible. Submit final design plans to CPUC or its designee and the land management agency with jurisdiction.

14. Restore Abandoned Roads to Their Original Contours. Restore roads abandoned following construction to their original contours, including replacing rocks and vegetation, and close them to the public. Implement mitigation measures 104, 105, and 107 under "Visual Resources."

15. Develop Recommendations and Implement Measures to Prevent Significant Slope Stability Problems. The preferred mitigation for unstable terrain is to avoid the area. Conduct selective preconstruction field screening of sensitive and potentially unstable terrain. Develop site-specific recommendations to prevent slope stability problems. (See the model ECR plan in Exhibit 1.) Decide on measures to be implemented during the detailed design phase of the project; the measures shall be approved by CPUC or its designee and the land management agency with jurisdiction and incorporated into construction specifications so that they are legally binding on contractors.

When slope stability problems cannot be avoided (e.g., in areas that contain abundant landslide terrain), retain a geotechnical specialist to determine what measures should be implemented. The measures may include but are not limited to:

- o Conduct preconstruction and postconstruction geotechnical studies to determine ground movement of the area.
- o Consult with the federal, state, or local agencies with jurisdiction to select a route if the route would cross areas of active landslides or areas of high landslide potential.
- o Consult with these agencies again before construction to review the selected route.
- o Grade and excavate using the cut-and-fill method to minimize effects on natural drainage and slope stability.
- o Excavate and grade to increase the stability and decrease the gradient of unstable slopes.

- o Mitigate small-scale slope stability problems by limiting the size of cuts and fills in sensitive terrain.

- o Shore or backfill trenches quickly in areas of soft ground to avoid soil creep.

- o Survey, flag, and monitor areas of sensitive or potentially unstable terrain. Conduct ground-movement monitoring surveys for active landslide areas that would be crossed by the pipeline. See the operations and maintenance plan described in mitigation measure 4.
- o Reduce grading on excessively steep slopes that would otherwise require extensive cuts by using detour access roads around the slope for rubber-tired traffic.
- o Where sidehills are unavoidable, use two-toning. (Two-toning involves making two small cuts rather than one large cut so that the working side is higher than the spoil side.)

- o Avoid reactivating stabilized slides and initiating new ones.

- o Divert seeps and concentrated surface runoff with berms, ditches, and slope shaping.

- o Install ditch plugs at slope crests and at significant breaks in slope.

- o Install subsurface drains and avoid undercutting landslide toes.

- o Use additional stabilization measures, such as dewatering and buttressing, to stabilize active landslide areas that would be crossed by the pipeline. Dewatering by trenching to intercept subsurface water is probably the method of choice for shallow landslides and will require long-term maintenance.

16. Implement Engineering Solutions to Reduce Seismic Impacts. Implement the following mitigation measures to reduce seismic impacts on the proposed project:

- o conduct detailed geological/geotechnical and aerial photograph investigations to identify any areas of Holocene surface displacement during the detailed design phase;

- o implement V-shaped trenching and other engineering design measures to be determined by a qualified engineer if evidence of Holocene surface displacement is found; and

- o retain a qualified engineer to design the project to the standards of the American National Standards Institute (ANSI) for the corresponding seismic risk zones to prevent damage from ground shaking, liquefaction, and differential settling, and identify and implement any other design standards deemed necessary.

Submit the engineering evaluations and recommendations to CPUC or its designee for review for conformance with the CPUC's regulations, including General Order No. 112-D. Obtain approval as required by any land management agency with jurisdiction.

17. Reduce the Severity of Impacts from Volcanic Activity. Include monitoring requirements for indicators of renewed volcanic activity, such as ground swelling, tremors, earthquakes, and minor eruptions (gas venting) that occur well in advance of an eruption in the operations and maintenance plan and the emergency preparedness plan. Include the frequency and techniques for monitoring, measures to be taken in response to various indicator levels, and emergency measures in the event of an eruption.

Soils

18. Develop and Implement a Comprehensive Erosion Control and Restoration Plan. To prevent and mitigate significant adverse impacts on soil resources, prepare a comprehensive erosion control, restoration, and revegetation plan. Develop the plan in cooperation with CPUC or its designee, FERC, the California Department of Forestry and Fire Protection (CDF) and other land management and state agencies with jurisdiction, and landowners. Incorporate the FERC Procedures outlined in Exhibit 2 and the specific measures discussed in the model ECR plan (Exhibit 1).

PGT/PG&E submitted preliminary ECR plans with its applications to CPUC and FERC. During the design phase of the project, when the pipeline route and design have been finalized, the applicant should:

- o modify preliminary ECR plans to include detailed, site-specific measures and preconstruction negotiations with involved parties; percent revegetation cover to be achieved; and locations, frequency, and techniques of monitoring;
- o submit the revised plans to CPUC or its designee for approval; and
- o incorporate approved measures into construction contracts, specifications, and drawings so that contractors are legally bound to implement them.

During the construction phase of the project, the applicant should:

- o conduct a worker education program on the ECR plan within 5 days before construction begins (see mitigation measure 6) and
- o ensure long-term and short-term mitigation objectives are met (see specific measures in the model ECR plan [Exhibit 1]).

The pipeline would cross private, U. S. Bureau of Land Management (BLM), U. S. Forest Service (USFS), and state lands. The BLM, USFS, and state ECR plans or requirements applicable to pipeline construction address erosion control, restoration, floodplains, wetland construction, streambed alteration, streambank disturbance, contaminated sediments, and clearing of the pipeline right-of-way. Identify in the ECR plan which agencies must be notified (e.g., U. S. Army Corps of Engineers [COE] and California Department of Fish and Game [DFG]) of these activities.

These agencies may specify additional reporting requirements. Submit quarterly reports during the detailed design, construction, and restoration phases of the project; biannual reports for the next 5 years; and annual reports thereafter to CPUC or its designee, or as specified in site-specific ECR plans.

19. Develop and Implement a Spill Prevention and Control Plan. To reduce potentially significant impacts on soil productivity caused by a chemical spill during construction or operation or from a pipeline rupture during hydrostatic testing, the project applicant should develop and implement an SPC plan in accordance with federal and state permitting requirements. Require in this plan the safe collection and disposal of hazardous substances generated during normal construction and operation activities, identification of pipeline low points designed to trap and store liquids, emergency response measures for quick and safe cleanup of accidental construction spills or pipeline ruptures, and notification procedures to the landowner or authority with jurisdiction of any spills. Include proper storage of chemicals, fuel, and lubricating oils and installation of spill containments around all chemical, fuel, and oil storage areas. Specify the frequency, locations, and techniques of monitoring and reporting requirements. In addition, the applicant should:

- submit a detailed, site-specific SPC plan to CPUC or its designee for approval;
- incorporate approved measures into construction contracts so that contractors are legally bound to implement them;
- conduct a worker education program on the SPC plan within 5 days before construction begins for each new construction crew; and
- monitor the construction and operation phases as specified in the plan.

Hydrology and Water Quality

20. Develop and Implement a Stream Crossing Mitigation Plan. To minimize and control channel erosion after pipeline construction, develop a stream crossing mitigation plan in consultation with COE, FERC, the U. S. Bureau of Reclamation, DFG, the California Department of Water Resources (DWR), and the regional water quality control board (RWQCB). Specify in this mitigation plan the site-specific constructions procedures;

locations, frequency, and techniques of inspections of all affected stream crossings, and the reporting requirements for each of the following measures.

When the design phase of the project is completed, obtain authorization from the land management agencies with jurisdiction and provide copies of the approved stream crossing mitigation plan to CPUC or its designee, FERC, COE, the land management and state agencies with jurisdiction, and landowners.

20a. Comply with State and Federal Agency Regulations. Contact the U. S. Environmental Protection Agency (EPA), COE, and DFG to obtain the required permits to proceed with construction activities associated with pipeline placement at stream crossings. Mitigate construction-related impacts on a case-by-case basis by requirements set forth by these permitting agencies. COE permits under Section 404 of the Clean Water Act may be required for these construction activities. Minor crossings may qualify for authorization under a nationwide permit, such as nationwide permit 14. DWR must review and approve the plans and specifications of any proposed pipeline installations across or adjacent to SWP facilities.

Include steps for obtaining all required permits and mitigation measures for affected crossings in the stream crossing mitigation plan. Obtain all required permits prior to beginning any construction activities in an area and submit copies to the CPUC.

20b. Schedule Construction within the Banks of Intermittent and Ephemeral Streams during the Dry Season. Schedule construction within the banks of intermittent and ephemeral streams during the dry season unless directed otherwise by state, local, or federal agencies with jurisdiction, when these channels contain little or no flow. Obtain approval from COE or RWQCB if stream crossing construction would occur at any time other than during the dry season.

Include the construction schedule for all stream crossings in the stream crossing mitigation plan.

20c. Implement the Erosion Control and Restoration Plan. Implement mitigation measure 18 to mitigate for the increased risk of surface runoff and soil erosion from streambanks and uplands. Runoff from the cleared right-of-way could increase stream turbidity and sedimentation. Include site-specific measures, such as regrading and installing erosion-control structures, reseeding, replanting, fertilizing, and applying mulches, in the ECR plan for affected stream crossings.

Include these site-specific ECR measures in the stream crossing mitigation plan.

20d. Reduce Streambed Alteration. Implement site-specific mitigation measures developed in consultation with the permitting agencies and land management agencies with jurisdiction, especially COE, to reduce streambed alteration. Include these measures in the stream crossing mitigation plan.

20e. Reduce Impacts from Contaminated Sediments. To reduce effects on downstream beneficial uses from construction at stream crossings with sediment contamination, conduct surficial and deep sediment testing at sites known to have, or suspected of having, contaminated sediments. Submit the test results for identified stream crossings to FERC, COE, and RWQCB. Obtain the required permits from agencies with jurisdiction (described in Table 1-4 of the draft EIR) to proceed with construction.

Develop mitigation in consultation with the permitting and land management agencies and include these measures in the stream crossing mitigation plan.

21. Construct and Design Drainage Control Structures in Accordance with Engineering Standards. Construction of new access roads could alter existing drainage patterns and lead to an increased risk of erosion. Construct and design drainage control structures, such as culverts, in accordance with city, county, and state engineering standards and other land management agency requirements. Maintain drainage control structures for existing access roads. (See mitigation measures 10 and 15.)

22. Implement Hydrostatic Testing Mitigation Measures

22a. Obtain Necessary Permits from Agencies for Withdrawal and Discharge of Streamflows for Hydrostatic Testing. Obtain all necessary permits from agencies with jurisdiction, and withdraw or discharge water in accordance with permit requirements. Obtain a National Pollutant Discharge Elimination System (NPDES) permit and other state-issued withdrawal and discharge permits as required in the FERC Procedures. If surface waters are not available or permits are not granted for withdrawal, use recycled water from previously tested loops or water trucked-in from approved sites. Notify agencies with jurisdiction, including RWQCB, DFG, and local irrigation districts (for canals), of intent to use specific water resources before testing activities. COE permits will be required where outfall structures or fills for containment/controlled release, energy dissipation, or erosion control are placed in waters under COE jurisdiction.

Submit copies of permits or site-specific alternate plans for each hydrostatic testing operation to CPUC or its designee.

22b. Use Energy-Dissipating Structures at Hydrostatic Test Water Discharge Points. Discharge hydrostatic test waters into an energy-dissipating structure using a velocity-dispersion device or structure, hay bale, or silt fence containment structure. Energy-dissipating structures must meet minimum criteria set forth in the FERC Procedures. COE permits will be required where outfall energy-dissipating structures are needed.

22c. Implement the Spill Prevention and Control Plan. Implement mitigation measure 17.

22d. Maintain Aquifer Water at Acceptable Levels for Existing Beneficial Uses. Develop and implement a site-specific plan acceptable to permitting agencies for aquifers affected by hydrostatic testing. The plan must be submitted to the CPUC or its designee for approval.

23. Mitigate for Potential Impacts on Groundwater Resources. Mitigate for potential impacts on groundwater resources; avoid contaminating groundwater, overdrafting aquifers for hydrostatic testing, and alternating subsurface flow patterns. Implement the SPC plan outlined in mitigation measure 19, mitigation measure 22d to maintain aquifer levels for beneficial downstream uses, and the ECR plan described in mitigation measure 18 to reduce altered subsurface flow in shallow aquifers and soil horizon mixing.

24. Avoid Impacts on Wells from Blasting. Perform a site-specific geotechnical study to determine which wells could be affected by blasting activities. Submit a copy of this study to CPUC. Use sequential blasting within those areas identified by the study. Sequential blasting consists of using several small charges in succession instead of one large charge. Any well that is damaged must be replaced. If the water source is disrupted such that the well water is unusable for more than 2 weeks, the well shall be replaced using another water source or municipal water shall be brought to the well users.

25. Determine the 100-Year Floodplain along the Pipeline Route and Design the Pipeline to Withstand Flooding and Erosional Damage. Review the Federal Emergency Management Agency (FEMA) maps of the areas that would be traversed by the proposed pipeline routes and review previous floodplain studies to determine the portions of the pipelines that would cross 100-year floodplains. Determine the flood hazards of stream crossings that lie within national forest boundaries with associated 100-year floodplains on a case-by-case basis, including visual interpretation of topographic maps, stereo aerial photographs, and field inspections.

Design those portions of the pipeline that would cross a 100-year floodplain to withstand pipeline buoyancy forces and potential floodflow scour at the stream crossing. Weight and bury the pipeline a minimum of 6 feet below the anticipated scour depth at stream crossings. Locate all aboveground facilities outside 100-year floodplains.

Submit final plans of pipeline and aboveground facility placement on FEMA maps to CPUC or its designee for approval. Include detailed site-specific measures for pipeline or facility placement in the 100-year floodplain.

Land Use

Mineral Resources

26. **Resolve Mineral Resource Conflicts by Mutual Agreement.** Contact owners of mineral resources that would be crossed by the pipeline right-of-way, where new right-of-way is required, to resolve any conflicts through mutual agreement.

Urban Resources

27. **Resolve Development Plan Conflicts by Mutual Agreement.** Where the proposed project would be located in new right-of-way in an area planned for development and would be incompatible with the plans of the development project, the applicant and landowner should resolve any conflicts through mutual agreement. Submit a copy of the agreement signed by all involved parties to CPUC or its designee. Develop a form letter to inform property owners of their rights.

28. **Reduce Residential Impacts**

28a. **Notify Local Residents of Construction Activity.** Two weeks in advance and by direct contact, notify all permitted users, landowners, and land managers along the right-of-way and residents within 50 feet of the right-of-way whose safety, property, business, or operations might be affected by any construction activity. Notify all local residents of construction activity through the local media. Activities such as temporary road closures, removal or cutting of fences, or disturbances involving range improvements or other range-related structures could affect property, business, or land use operations. Send copies of the notice to CPUC or its designee.

28b. **Use Construction Dust-Control Techniques.** Implement mitigation measure 88.

28c. **Maintain Construction Equipment Properly.** Implement mitigation measure 89.

29. **Store Chemicals Properly and Install Spill Containments.** Implement the SPC plan described in mitigation measure 19.

Mitigation Measures for Urban Resources Specific to Brentwood Pipeline Route Alternative 4

30. **Locate Pipeline Selectively in Utility Corridor of Brentwood Pipeline Route Alternative 4.** Locate the pipeline on the east side of the utility corridor until the pipeline reaches the Discovery Bay storage facility, and on the west side of the utility corridor from before the utility corridor crosses the canal surrounding Discovery Bay until after it crosses Route 4.

Recreational Resources

31. **Provide a Geologic Survey and Prepare and Implement a Protection Plan for the Mayfield Ice Cave Area.** Provide CPUC or its designee and the Shasta National Forest, administered as part of the Lassen National Forest, a geologic survey of the entire impact area in the vicinity of the Mayfield Ice Cave and a protection plan that addresses methods to avoid damage to the cave caused by construction of the proposed project. Submit the geologic survey and protection plan for approval to the Shasta National Forest, administered as part of the Lassen National Forest, before beginning construction activities in the area.

Plans and Policies

32. **Comply with Relevant Plans and Policies.** To ensure that all relevant plans and policies are complied with during construction and operation of the pipeline project and that all permits are obtained from local jurisdictions, consult with all local jurisdictions and administrative agencies; review plans, policies, and regulations; and negotiate with land managers, landowners, and easement holders to identify all potential land use conflicts.

Obtain from each local jurisdiction and administrative agency a list of all permits required and relevant plans and policies to be complied with during construction and operation of the pipeline project. Submit a copy of these lists to CPUC or its designee. All permits shall be obtained prior to construction in accordance with mitigation measure 7.

33. **Obtain a Permit of Mutual Agreement from Solano County.** To mitigate for the otherwise significant and unavoidable impact of inconsistency with an existing land use designation, obtain a permit of mutual agreement from Solano County to incorporate the portion of the pipeline route that is outside an existing utility corridor or area designated for this type of use. The CPUC will provide an arbitrator at the request of either party.

34. **Obtain Appropriate Authorization from Contra Costa County.** To mitigate for the otherwise significant and unavoidable impact of inconsistency with an existing land use designation, obtain appropriate authorization from Contra Costa County to incorporate the portion of the pipeline route that is outside an existing utility corridor or area designated for this type of use and to incorporate the use of a compressor station. Provide a copy of this authorization to the CPUC. Obtain this authorization if the proposed route or Brentwood Pipeline Route Alternative 2 or 4 is selected or if Alternative Compressor Station Site A or B is selected. The CPUC will provide an arbitrator at the request of either party.

Vegetation and Wildlife - General

35. **Retain Qualified Biological Monitors.** During construction activities, biological monitors are required to minimize potential impacts on vegetation and wildlife and determine the success of mitigation measures. Minimum qualifications for biological monitors are:

- o a bachelor's degree in biological sciences, zoology, botany, ecology, wildlife biology, or a closely related field and 1 year experience; *or* 3 years of demonstrated field experience;
- o demonstrated experience with or knowledge of the species or process to be monitored;
- o knowledge of the federal or state ESA where this applies; and
- o demonstrated experience in implementing mitigation measures.

CPUC or its designee will determine which of the above qualifications are necessary to monitor specific vegetation and wildlife mitigation measures. PGT shall retain biological monitors during the detailed design phase of the project, concurrent with development of vegetation and wildlife mitigation plans.

36. **Establish Compensation Ratios.** If preconstruction surveys identify additional occurrences of special-status species (as defined in Exhibit 1 of this Appendix B) or special native plant communities, PGT/PG&E should compensate for the disturbance or loss of habitat at a ratio set by DFG and the U. S. Fish and Wildlife Service (USFWS).

37. **Establish Deed Restrictions for Offsite Compensation.** If compensation involves the acquisition and permanent protection of offsite habitat, the applicant shall acquire the land specified for the project and donate the property to a land conservancy organization or land management agency, subject to a restriction on the use of the property for preservation of the habitat values existing on the date of the applicant's acquisition. In the alternative, the applicant may fund the acquisition of the property by the conservancy organization with the approval of that organization.

38. **Commit to an Agreement with DFG to Implement Mitigation Measures That Reduce Impacts on Vegetation and Wildlife to Less-than-Significant Levels.** Before construction begins, commit to an agreement with DFG to implement measures stipulated in the Findings that would compensate for or reduce project-related impacts to less-than-significant levels.

39. **Support or Develop Restoration Pilot Projects.** Support existing restoration research projects or develop restoration pilot projects to verify the efficacy of mitigation plans and

to discover new techniques for creating herbaceous wetlands, riparian forest, riparian scrub, volcanic mudflow vernal pools, hardpan vernal pools, claypan vernal pools, alkali meadow, valley needlegrass grassland, and northern interior cypress forest. Pilot restoration projects should be in place at least 1 year before pipeline construction in California to allow for analysis of establishment success. In cases where recent local restorations have been proven successful, these can be substituted for a pilot restoration project and the techniques employed can be incorporated into the mitigation plans, with the concurrence of the land management agency and DFG.

Provide CPUC or its designee with locations of these pilot restoration projects and research programs, including site-specific data to be monitored and monitoring techniques.

The applicant shall also submit a proposal for funding a program to enhance the habitat of wildlife species potentially affected by the Expansion Project. Funding shall be commensurate with the project's impacts to wildlife as determined by DFG.

40. Establish Native Plant Nurseries or Utilize Existing Native Plant Nurseries. Locally collected native plant seed and rooted stock will be needed for mitigation restorations along the pipeline route. Develop and implement a site-specific native plant nursery mitigation plan that includes the number and location of nurseries, techniques for identification and collection of plant seed and stock, operation and management procedures, timing of implementation, and amount of plants necessary for successful restoration efforts, including native ground cover requirements of site-specific ECR plans. Include in the plan locations, frequencies, and techniques for monitoring and reporting requirements. Submit a copy of the plan to CPUC or its designee for approval during the detailed design phase.

41. Specify Mitigation That Is Necessary in the Acquired Right-of-Way in Permits Issued by Land-Administering Agencies or in Agreements with Individual Landowners. Specify mitigation that is necessary in the acquired right-of-way in the permits issued by land-administering agencies or in agreements with individual landowners. For example, when negotiating or renegotiating right-of-way agreements with landowners in areas of concern for San Joaquin kit fox, include in the agreements the revegetation prescription that is appropriate for restoration of kit fox habitat. The applicant must supply mitigation even if the landowner does not specify measures to compensate for the loss of or damage to resources. Submit copies of these negotiation agreements to CPUC or its designee and incorporate them into the operations and maintenance plan described in mitigation measure 4.

42. Comply with State and Federal Regulations for Prevention of Wildland Fires. Ensure that project-related activities comply with state and federal regulations to prevent wildland fires and minimize habitat loss.

42a. Shield All Welding Activity from Surrounding Vegetation. Shield all welding and other mechanical activities that might generate sparks or heated debris from surrounding vegetation to minimize the need to clear surrounding habitat for wildfire prevention.

42b. Provide a Setback Inside the Fence Line for Fenced Facilities. For any project facility, such as a metering or compressor station, that is fenced for security reasons, provide a setback inside the fence line to prevent the potential spread of fire to the wildland. This measure would minimize the necessity to create firebreaks around the outside of the fence line and would result in less habitat loss.

43. Prohibit Possession of Firearms at the Construction Site. Prohibit all construction workers from bringing firearms to the construction site.

Wetlands and Riparian Habitat

44. Comply with DFG Streambed Alteration Agreement Guidelines for Wetlands and Riparian Habitat. Design and implement revegetation plans for wetlands at stream and lake crossings in California according to guidelines established under streambed alteration agreements made with DFG (Sections 1600-1606 of the California Fish and Game Code).

45. Reestablish Herbaceous Wetland Hydrology and Vegetation and Monitor Their Success

45a. Develop and Implement Detailed Wetland Mitigation Plans. Develop and implement detailed mitigation plans to comply with Section 404 of the Clean Water Act to ensure no loss of wetland value or acreage occurs. Wetland mitigation plans must be site specific and incorporate the concept that, subject to agency approvals, natural regeneration may be the most appropriate and effective method of revegetation for minor herbaceous wetland areas of minimal value (of small size and neither critical nor of particular ecological interest). Many of the herbaceous wetlands that would be crossed are intermittent stream swales supporting vegetation that will rapidly reestablish if preconstruction hydrologic, topographic, and soil conditions are restored. Consult with USFWS, DFG, COE, and the land management agency with jurisdiction regarding mitigation plans. Methods and objectives would vary according to site-specific conditions, but typically include the following measures in mitigation plans:

- o determine the preconstruction acreage of wetlands to be removed at each site;
- o specify that a qualified botanist measure the species diversity and percent vegetative cover of dominant wetland plant species and total vegetative cover of existing wetlands before construction;
- o specify that a qualified wildlife biologist assign numerical values and score wildlife habitat conditions before construction for parameters such as structural diversity, cover for wildlife nest sites, and food base;

- o recontour the ground surface to restore preconstruction contours and wetland hydrology;
- o reestablish subsurface soil conditions to maintain preconstruction wetland hydrology;
- o stockpile and cover the wetland topsoil from the excavated site containing intact roots, rhizomes, and seed banks;
- o replace the topsoil after construction;
- o revegetate disturbed wetlands with plant material taken from a local source; and
- o follow FERC Procedures.

During the design phase of the project when pipeline routes and designs have been finalized, submit the final site-specific wetland mitigation plans that include techniques and frequency of monitoring required to COE and land management agencies with jurisdiction for approval. Submit a copy of the approved plans to CPUC or its designee.

45b. Monitor Establishment Success of Wetland Vegetation. Provide CPUC or its designee with detailed, site-specific monitoring plans to monitor establishment success of wetland vegetation. Each monitoring plan shall include monitoring techniques and frequencies for all locations, as well as dates on which monitoring should occur. At a minimum, the plan should contain the following measures:

- o A qualified biological monitor shall monitor the establishment success of wetland vegetation annually for 5 years. In the first year, monitor the site quarterly. Submit an annual (quarterly in the first year) written report to CPUC or its designee within 30 days of site visits. Indicate in the report the presence of serious hydrologic or vegetative problems determined after each evaluation and what remedial actions should be implemented. Submit a followup report of site-specific remedial actions and their results within 60 days of each report.
- o A qualified biological monitor shall be present onsite to monitor the implementation of mitigation plans.
- o Include the following criteria in the monitoring plans. At the end of 3 years, consider mitigation successful if at least 50 percent of the number of wetland species present before construction is reestablished (including 100 percent of the number of dominant native wetland species) and 100 percent of the preconstruction vegetative cover is established, the site meets COE criteria

for jurisdictional wetlands, the wetland acreage equals or exceeds preconstruction extent, and wildlife habitat value scores are equal to or greater than preconstruction scores. Three years following construction, individuals of the dominant wetland plant species should have reproductive rates equivalent to those of individuals in adjacent undisturbed portions of the same wetland system. These criteria are meant to ensure that in-kind replacement of functioning wetlands will be established.

- Evaluate recovery efforts at the end of the third year. Implement postmitigation measures and additional recovery efforts or replantings in areas where initial restoration was not successful. Submit a written report to CPUC or its designee of the third-year evaluation and additional recovery efforts implemented within 60 days of the evaluation.

- Evaluate recovery efforts 5 years after construction. If success criteria are not met within 5 years, take remedial action and reinitiate monitoring for an additional 5 years. Submit a written report to CPUC or its designee within 60 days of the fifth-year evaluation and obtain concurrence from CPUC or its designee of additional remedial actions and monitoring to be taken.

46. Reestablish Riparian Scrub and Forest Vegetation and Monitor Their Success

46a. Develop and Implement Detailed Riparian Mitigation Plans. Develop detailed, site-specific riparian revegetation plans with the assistance of federal and state agencies and private organizations (e.g., USFWS, DFG, USFS, BLM, and The Nature Conservancy). Methods and objectives would vary according to site-specific conditions, but typically include the following measures in revegetation plans:

- determine the preconstruction acreage of riparian vegetation to be removed at each site;

- specify that a qualified botanist measure species diversity, densities of woody species, and percent cover of existing riparian vegetation to be removed;

- specify that a wildlife biologist assign numerical values and score wildlife habitat conditions before construction for parameters such as structural diversity, cover for wildlife nest sites and cavities, and food base;

- take cuttings from plants that are to be removed before construction and store properly to maintain viability;

- use a tree spade to remove and replant entire trees and shrubs;

- o revegetate all areas that are in the construction right-of-way but outside the operational right-of-way with native cottonwoods, willows, and other native species from the local area;

- o plant appropriately sized trees as determined by a restoration horticulturalist at a 3:1 replacement of original numbers of stems using local genetic stock (see mitigation measure 40);

- o collect additional cuttings from the local area; and

- o protect the plantings from browsing damage.

During the design phase of the project when pipeline routes and designs have been finalized, submit the final site-specific riparian scrub and forest mitigation plans that include techniques and frequency of monitoring required to CPUC or its designee for approval.

46b. **Monitor Establishment Success of Riparian Scrub and Forest Vegetation.** Provide CPUC or its designee with a detailed, site-specific plan to monitor establishment success of riparian vegetation. Include in each monitoring plan monitoring techniques and frequencies for all locations, as well as dates on which monitoring should occur and reporting requirements. At a minimum, include the following measures in each plan:

- o Revegetate 3 acres of riparian scrub for every acre removed; revegetate 3 acres of riparian forest for every acre removed. To meet this requirement and maintain an operational right-of-way, it may be necessary to establish riparian scrub or forest on contiguous or nearby sites, along unvegetated streambanks, or at the landward edge of existing riparian vegetation. Establishment on a contiguous site is optimal. Where contiguous establishment is not possible, noncontiguous establishment may be approved on a case-by-case basis by CPUC or its designee.

- o Monitor annually (quarterly in the first year) the establishment success of riparian forest and scrub vegetation by a qualified biological monitor for 5 years after construction.

- o Consider establishment successful after 5 years if the following criteria are met:

  - the establishment of 80 percent of the original site's total cover in riparian scrub and 50 percent of the original total cover in riparian forest,

  - the establishment of a higher tree density than the original site in riparian forest habitat, the establishment of 50 percent of the original site's native plant species and 100 percent of the original native dominant species, and

wildlife habitat scores equal to or greater than preconstruction scores.

- Submit an annual written report (quarterly in the first year) to CPUC or its designee, with a final report in the fifth year. If success criteria are not met within 5 years, include in the fifth-year report site-specific remedial actions and monitoring to be initiated.

Special-Status Plants

Implement the mitigation measures presented below as necessary for the special-status (Exhibit 1) plant species affected as presented in Table C-1, in combination with earlier applicable measures, as determined by the biological monitor.

47. Conduct Preconstruction Special-Status Plant Surveys along Access Roads. Conduct field surveys for special-status plant species along any new access road corridors or expansion areas of existing access roads before construction begins. Submit the results to CPUC or its designee and the land management agency with jurisdiction and DFG. Consult with land management agencies with jurisdiction concerning additional mitigation required. Modify road alignments to avoid impacts on any special-status plant species found.

48. Conduct Preconstruction Special-Status Plant Surveys in All High-Density Vernal Pool Areas. Resurvey all high-density vernal pool areas listed in Appendix E-4 of the draft EIR for special-status plant species to locate any annual plant species that may not have appeared during the 1990 drought year. Conduct the surveys in the spring and summer before construction begins or during any normal to wet hydrologic year as defined by DWR before construction begins. If new populations of special-status plant species are found, implement the mitigation measures below applicable to those species, as determined by the biological monitor.

49. Avoid Special-Status Plant Species Populations and Habitat by Rerouting the Pipeline

49a. Select Jepson Prairie Preserve Alternative Route B. Select Jepson Prairie Preserve Alternative Route B to reduce impacts on dwarf downingia (population 3), Colusa grass, and Crampton's tuctoria.

50. Avoid Special-Status Plant Species Populations by Boring under Water Bodies. Bore under the Sacramento River, San Joaquin River and Gallagher Slough, and Dutch Slough crossings to reduce impacts on Mason's lilaeopsis and Suisun Marsh aster. Restrict all construction activities to the land side of the levees around these water bodies. If boring

Table C-1. Mitigation Measures Required to Reduce Impacts on Special-Status Plant Species and Special Native Plant Communities to Less-Than-Significant Levels

Resource	Required Mitigation Measures	
	Preferred Action	Alternative Action
Special-Status Plant Species[a]		
Suisun Marsh aster		
Direct impacts	Bore under water body	Transplant; acquire existing population
Habitat loss	Restore bank topography	
Fremont's calycadenia		
Population 1		
Direct impacts	Fence; reseed; acquire existing population	
Habitat loss	None	
Population 2		
Direct impacts	Fence	
Habitat loss	None	
Silky cryptantha		
Direct impacts	Fence	
Habitat loss	None	
Dwarf downingia		
Populations 1 and 2		
Direct impacts	Fence	
Habitat loss	None	
Population 3		
Direct impacts	Fence; reseed; acquire existing population; restore vernal pool	
Habitat loss	None	

Table C-1. Continued

Resource	Required Mitigation Measures	
	Preferred Action	Alternative Action
Bogg's Lake hedge-hyssop		
Direct impacts	Fence	
Habitat loss	Reroute - Tehama County	Implement all vernal pool mitigations; acquire existing vernal pools
Red Bluff rush		
Direct impacts	Fence; reseed; acquire existing population; restore vernal pool	
Habitat loss	None	
Mason's lilaeopsis		
Direct impacts	Bore under water bodies	Transplant; acquire existing populations
Habitat loss	Restore bank topography	
Colusa grass		
Direct impacts	None	
Habitat loss	Reroute - Jepson Alternative B or Solano County	Fence playa pools
Pilose Orcutt grass		
Direct impacts	None	
Habitat loss	Reroute - Tehama County	Implement all vernal pool mitigations; acquire existing vernal pools
Slender Orcutt grass		
Direct impacts	Fence	
Habitat loss	Reroute - Tehama County	Implement all vernal pool mitigations; acquire existing vernal pools
Abart's paronychia		
Direct impacts	Fence	
Habitat loss	None	

Table C-1. Continued

Resource	Required Mitigation Measures	
	Preferred Action	Alternative Action
Greene's Orcutt grass		
Direct impacts	None	
Habitat loss	Reroute - Tehama County	Implement all vernal pool mitigations; acquire existing vernal pools
Crampton's tuctoria		
Direct impacts	None	
Habitat loss	Reroute - Jepson Alternative B or Solano County	Fence playa pools
Palmate-bracted bird's-beak		
Direct impacts	None	
Habitat loss	Reroute - Brentwood Alternative 4 with Contra Costa County reroute; implement all herbaceous wetland mitigations	Implement all alkali meadow and herbaceous wetland mitigations; acquire existing alkali meadow
Special Native Plant Communities		
Vernal pools	Reroute - Tehama, Solano, and Contra Costa Counties	Implement all vernal pool mitigations; acquire existing vernal pools
Valley needlegrass grassland	Fence; restore community; acquire existing valley needlegrass grassland	
Alkali meadows	Reroute - Contra Costa County	Fence; restore community; acquire existing alkali meadows
Northern interior cypress forest	Reroute - Shasta County	Fence; restore community; acquire existing northern interior cypress forest

[a] For all special-status plant species, direct impacts are significant and require mitigation; habitat loss is a significant impact and requires mitigation only for federally listed and state-listed rare, threatened, and endangered plant species (see "Significance Criteria" in Chapter 3 of the final EIR).

is not possible, mitigation measure 53 requires that appropriate mitigation be conducted for special-status plants at these crossings.

51. Avoid Colusa Grass and Crampton's Tuctoria Habitat by Narrowing and Fencing the Construction Right-of-Way between Large Playa Pools. If construction activities would occur in areas that would provide suitable habitat for Colusa grass and Crampton's tuctoria, in consultation with DFG, USFWS, and the land management agencies with jurisdiction, the applicant shall implement the following measures:

- o schedule construction in late summer or fall, after the large playa pools have dried and before the first fall rains;
- o restrict the construction right-of-way to a 50-foot width in the area between the playa pools;
- o fence the construction right-of-way temporarily for at least 500 feet beyond the playa pools;
- o restrict construction vehicles and private vehicles from fenced areas;
- o immediately reseed the construction site following construction with locally collected (see mitigation measure 40) purple needlegrass (*Stipa pulchra*) before the first fall rains;
- o retain a qualified biological monitor onsite during construction between the playa pools with the authority to stop any activity that may threaten the plant habitat; and
- o retain a qualified biological monitor to supervise the removal of temporary fences after construction.

Consider mitigation successful for Colusa grass and Crampton's tuctoria habitat after the actions listed above are completed without disturbing the special-status plants.

52. Avoid Special-Status Plant Species Populations Outside and Straddling the Right-of-Way by Fencing the Construction Right-of-Way or Population. In consultation with DFG and the land management agencies with jurisdiction, implement the following measures:

- o retain a qualified biological monitor to identify and flag the boundaries of the special-status plant populations before construction;
- o fence the construction right-of-way temporarily at least 500 feet beyond the edges of the plant population, or fence the entire population if it is small;

- o post "keep out" signs that note the presence of rare plants;
- o prohibit pedestrian traffic or vehicular traffic past the fenceline;
- o for species that occur in vernal pools, place the fence above the upper edge of the watershed of the vernal pool;
- o provide at least a 25-foot-wide space between the fence and the nearest plant for upland species;
- o retain a qualified biological monitor onsite during construction near special-status plant species populations with the authority to stop any activity that may threaten the plant population; and
- o retain a qualified biological monitor to supervise the removal of temporary fences after construction.

Consider mitigation successful for silky cryptantha, Frémont's calycadenia (population 2), dwarf downingia (populations 1 and 2), and Ahart's paronychia after the actions listed above are completed without disturbing the special-status plants.

Use these same procedures to fence and protect portions of special-status plant populations that straddle the construction right-of-way boundary and for which reseeding procedures would be conducted to mitigate for plants removed.

53. Transplant Populations of Perennial Special-Status Plant Species from the Construction Right-of-Way

53a. Prepare Specific Transplanting Mitigation Plans. Prepare specific transplanting plans for Mason's lilaeopsis populations 2 and 3 and Suisun Marsh aster population 1. The transplanting mitigation plan should follow the outline and guidelines presented in Howald and Wickenheiser (1989). Develop the transplanting plans in consultation with DFG, USFWS, and the land management agencies with jurisdiction. Consult private organizations (e.g., The Nature Conservancy and the California Native Plant Society [CNPS]) for their expertise in developing transplanting plans. Include the following measures in transplanting plans:

- o Retain a qualified botanist to census the plants to be removed and estimate reproduction rates before construction.
- o Locate a mitigation site in unoccupied suitable habitat equal to or greater than the construction site in extent and quality. Establishment on a contiguous site is optimal. Where contiguous establishment is not possible,

noncontiguous establishment may be approved on a case-by-case basis by CPUC or its designee.

- o Transplant individual plants from the construction site to the mitigation site.

- o Salvage topsoil with the potential of containing seeds of these species to an appropriate depth and rake into the soils of the mitigation site.

- o Retain a qualified biological monitor onsite during construction at the Sacramento River, San Joaquin River and Gallagher Slough, and Dutch Slough crossings with the authority to stop any activity that may threaten additional portions of the plant populations.

- o Guarantee by land acquisition or land use restrictions (e.g., deeding the site to a conservation organization such as The Nature Conservancy) that the population at the mitigation site will be protected in perpetuity.

- o Establish a long-term endowment or contribute to an existing endowment to manage the mitigation site in perpetuity.

During the design phase of the project when pipeline routes and designs have been finalized, submit the final site-specific transplanting plans that include techniques and frequency of monitoring required to CPUC or its designee and the land management agency with jurisdiction for approval.

53b. Monitor the Survival and Reproductive Success of Transplants. Provide CPUC or its designee with a detailed, site-specific plan to monitor the survival and reproductive success of transplants. Include in the plan monitoring techniques and frequencies for all locations, as well as dates on which monitoring should occur and reporting requirements. At a minimum, include the following measures:

- o Retain a qualified biological monitor to monitor the survival and reproductive success of the transplants annually for 5 years after construction. Submit a written report to CPUC or its designee within 30 days of annual monitoring (quarterly in the first year).

- o Consider mitigation successful if, at the end of 5 years, the mitigation site supports a population equal to or greater than the number of individuals that were removed and if reproductive rates are equal to or greater than reproductive rates measured before construction.

- o Implement interim remedial actions if annual monitoring results indicate low establishment or reproductive rates. Submit a written report to CPUC or its designee within 60 days of implementing remedial actions.

53c. **Acquire and Protect Existing Special-Status Plant Populations.** Because all transplanting procedures carry a risk of failure, conduct the transplanting measures in conjunction with implementation of mitigation measure 53 to ensure that potential long-term losses to Mason's lilaeopsis and Suisun Marsh aster are minimized.

54. Collect Seed and Reseed Populations of Annual Special-Status Plant Species in the Construction Right-of-Way

54a. **Prepare a Specific Reseeding Mitigation Plan.** Prepare a specific reseeding mitigation plan for Fremont's calycadenia population 1, dwarf downingia population 3, and Red Bluff rush population 1. Follow the outline and guidelines presented in Howald and Wickenheiser (1989) and develop the reseeding plan in consultation with DFG, USFWS, and land management agencies with jurisdiction. Consult private organizations (e.g., The Nature Conservancy and CNPS) for assistance. Include the following measures in reseeding plans:

- retain a qualified botanist to census the plants to be removed and estimate reproductive rates before construction;
- collect seed from mature plants that are to be removed and store them during construction;
- salvage topsoil with the potential of containing seeds of these species to a 2- to 3-inch depth and store it during construction;
- salvage all additional soil to a 1-foot depth and store it during construction;
- restore habitat to original surface contours and replace soil following construction (for Red Bluff rush and dwarf downingia vernal pool habitat, implement the restoration specified in mitigation measure 62);
- rake topsoil potentially containing seeds onto the surface;
- spread salvaged seed over the site; and
- retain a qualified biological monitor onsite during construction with the authority to stop any activity that may threaten additional portions of the plant populations.

During the design phase of the project when pipeline routes and designs have been finalized, submit the final site-specific reseeding plans that include techniques and frequency of monitoring required to CPUC or its designee for approval.

54b. Monitor the Establishment and Reproductive Success of Reseeding Sites. Provide CPUC or its designee with a detailed, site-specific plan to monitor survival and reproductive success of transplants. Include monitoring techniques and frequencies for all locations, as well as dates on which monitoring should occur and reporting requirements in the plan. At a minimum, include the following measures:

- o Retain a qualified biological monitor to monitor the establishment and reproductive success of the reseeding sites annually for 5 years after construction. Submit a written report to CPUC or its designee within 60 days of the annual monitoring that includes remedial actions taken.

- o Consider mitigation successful if, at the end of 5 years, the mitigation site supports a population equal to or greater than the number of individuals that were removed and if reproductive rates are equal to or greater than reproductive rates measured before construction.

- o Implement interim remedial actions if annual monitoring results indicate low establishment or reproductive rates.

54c. Acquire and Protect Existing Populations of Special-Status Plant Species. Because all reseeding procedures carry a risk of failure, conduct the reseeding measures in conjunction with mitigation measure 53 to ensure that potential long-term losses to Fremont's calycadenia, dwarf downingia, and Red Bluff rush are minimized.

55. Acquire and Protect Existing Populations of Special-Status Plant Species. For all special-status plant populations for which transplanting or reseeding efforts are conducted, acquire sites supporting unprotected existing populations of these species. The existing population should be a viable, reproducing population supporting more individuals over a larger area than the population to be removed. Protect the acquired site from impacts in perpetuity. In choosing a population for protection, give preference to those populations most immediately threatened. Consult DFG, USFWS, and CNPS during the site-selection process. Establish an endowment or contribute to an existing endowment to ensure long-term management of the acquired population.

The sites supporting the protected populations of Mason's lilaeopsis and Suisun Marsh aster should preferably be contiguous with the sites used to introduce transplants of these species. If contiguous sites are not possible, noncontiguous sites may be approved by CPUC or its designee on a case-by-case basis.

Noxious Weeds

56. Develop and Implement a Weed Control Mitigation Plan. Follow all federal, state, and local weed control requirements and guidelines. Prepare a weed control plan and submit it to CPUC or its designee for approval. At a minimum, include the following measures in the plan:

- o Conduct a preconstruction census to determine species and amounts of noxious weeds present; information available through each county may be used.

- o Determine the significance threshold for an increase in population for each weed species existing in the construction right-of-way in coordination with county agricultural commissioners.

- o Reseed construction areas as rapidly as possible in the appropriate season as determined by the biological monitor.

- o Make all seed available for inspection by the county agriculture department before planting in the event that the site is reseeded or replanted.

- o Retain a soil specialist to approve soil that may be needed for fill to avoid possible transfer of soil-borne contaminants (i.e., nematodes, noxious weed seeds).

- o Clean plant material and mud from construction equipment regularly to avoid the spread of noxious weeds in sensitive areas (prime agricultural land, special native plant communities, and rare plant habitats).

- o Steam clean construction equipment before it crosses any state or county border.

- o Make equipment available for inspection by state or county agricultural officials if requested.

- o Notify the California Department of Food and Agriculture, Control and Eradication Division, before equipment crosses into the state, and notify county agricultural commissioners before equipment enters their counties.

- o Allow county agriculture department personnel access to construction sites and grant permission for them to spray or remove any noxious weeds that germinate after construction is completed. Reimburse the county for the actual cost of noxious weed eradication.

- o Use only USFS-certified seed on USFS land.

- o Retain a qualified biological monitor to monitor population expansion or colonization by weedy species annually for 5 years after construction. Monitor quarterly in the first year. If new weeds become established or existing weed populations expand, implement remedial actions and reinitiate monitoring. Submit an annual (quarterly in the first year) written report to CPUC or its designee that includes remedial measures implemented within 60 days of monitoring.

- o Consider weed control successful if no weed species new to the area are observed and if existing weed populations do not increase significantly (as defined locally for each weed species) at the construction site after 5 years.

Special Native Plant Communities

57. Avoid Northern Interior Cypress Forest and Alkali Meadows

57a. Select the Shasta County Cypress Forest Reroute - West. Select the Shasta County Northern Interior Cypress Forest Reroute - West to avoid impacts on northern interior cypress forest. If this reroute is not selected, implement mitigation measure 58 below.

57b. Select the Contra Costa County Alkali Meadow and Vernal Pool Reroute. Select the Contra Costa County Alkali Meadow and Vernal Pool Reroute to avoid impacts on alkali meadow and vernal pools in Contra Costa County. If this reroute is not selected, implement mitigation measure 58 below.

58. Reestablish Special Native Plant Communities and Monitor Their Success. If realignment of the pipeline is infeasible for alkali communities and northern interior cypress forest, implement this reestablishment mitigation. Reestablish valley needlegrass grassland, alkali communities, and northern interior cypress forest at the construction site and at suitable offsite mitigation sites. Restrict the construction right-of-way to the existing disturbed right-of-way through areas supporting special native plant communities. Provide for acquisition and protection of the remaining northern interior cypress forest that is currently privately owned. Develop and implement a revegetation plan with input from federal and state agencies and private organizations (e.g., DFG, USFS, USFWS, BLM, and The Nature Conservancy) and submit the plan to CPUC or its designee for approval. Methods and objectives would vary according to site-specific conditions, but typically vegetation plans should include the following measures:

- o Determine the preconstruction acreage of the community to be removed.
- o Fence the construction right-of-way and post "keep out" signs that note the presence of special native plant communities to minimize potential impacts adjacent to the construction area during construction.

- o Stockpile and cover the topsoil from special native plant communities' habitats before construction and replace it after construction.

- o Reestablish special native plant species by replanting salvaged material or establishing new individuals as determined by the requirements of the species.

- o Propagate and plant native species supplied by local native plant nurseries (see mitigation measure 40).

- o Control weeds with methods acceptable for the type of plant community involved and the site on which it occurs; these methods may include mechanical clearing, hand clearing, or use of herbicides and should continue for 5 years or until native vegetation becomes well established.

- o Acquire suitable offsite mitigation sites to establish additional special native plant communities. Establishment on a contiguous site is optimal. Where contiguous establishment is not possible, noncontiguous establishment may be approved on a case-by-case basis by CPUC or its designee.

- o Replace 3 acres created for each acre removed.

- o Develop success criteria based on the community affected and including planting survivorship (i.e., communities should be self-sustaining) and final species composition and percent cover being comparable to preconstruction levels. If success criteria are not met after 5 years, take remedial action and reinitiate monitoring.

- o Retain a qualified biological monitor to monitor revegetation success annually for 5 years after construction. Monitor quarterly in the first year. Submit an annual (quarterly in the first year) written report to CPUC or its designee within 60 days of monitoring that includes any remedial action initiated.

59. **Replant New and Salvaged Material in Valley Needlegrass Grassland.** In valley needlegrass grassland, implement the following additional measures:

- o determine the location and extent of valley needlegrass grassland along the construction right-of-way;

- o transplant native bunchgrasses from the construction area to pots or tubes before construction;

- o collect local seed from native bunchgrasses and germinate in pots, tubes, or flats; and o plant bunchgrasses in the construction area after construction.

60. Acquire and Protect Existing Stands of Special Native Plant Communities. For all special native plant communities for which restoration efforts are conducted, acquire sites supporting unprotected existing stands of these communities. Ensure that the existing community is a viable system supported over a larger area than the removed community. Protect the acquired site from impacts in perpetuity. In choosing a site for protection, give preference to those sites most immediately threatened. Consult DFG, BLM (for northern interior cypress forest), and The Nature Conservancy during the site-selection process. Establish an endowment or contribute to an existing endowment to ensure long-term management of the acquired plant community. Implement this measure before impacts occur on the community to be removed.

61. Avoid Vernal Pools

61a. Deleted.

61b. Select the Contra Costa County Alkali Meadow and Vernal Pool Reroute. Select the Contra Costa County Alkali Meadow and Vernal Pool Reroute to avoid impacts on vernal pools between MP 929 and MP 932.

61c. Select Jepson Prairie Preserve Alternative B. Select Jepson Prairie Preserve Alternative B to avoid impacts on large playa pools.

62. Create and Restore Vernal Pools

Avoid high-density vernal pool areas by rerouting the pipeline. If rerouting is not feasible, CPUC or its designee may approve vernal pool restoration on a case-by-case basis as mitigation for impacts on vernal pools.

62a. Develop and Implement a Site-Specific Vernal Pool Revegetation Plan. Develop and implement a site-specific vernal pool revegetation plan following the requirements and guidelines of COE, EPA, USFS, BLM, USFWS, and DFG. Include the following measures in the plan:

- o Specify that a qualified botanist measure species diversity and percent cover of dominant vernal pool plant species and total vegetative cover of existing vernal pools before construction.
- o Specify that a qualified wildlife biologist measure and score wildlife habitat values of vernal pools.
- o Limit construction to the existing disturbed right-of-way in high-density vernal pool areas.

- Fence the construction right-of-way and post "keep out" signs during construction.

- Determine the acreage of vernal pools to be removed.

- Acquire a suitable mitigation site off the right-of-way to establish additional vernal pool acreage, preferably contiguous with the vernal pool acquisition site discussed in mitigation measure 63. If a contiguous site is not possible, a noncontiguous site may be approved by CPUC or its designee on a case-by-case basis.

- Collect seeds, salvage topsoil with seed bank, and store the topsoil during the dry season.

- Reestablish subsoil conditions in the vernal pool restoration and creation sites to maintain vernal pool hydrology, which may involve sealing the pipeline trench with a local clay soil, bentonite clay, or other suitable long-lasting material to restore the impermeable subsurface layer.

- Recontour the surface to preconstruction microrelief of mound-intermound, reticulate patterned swale-pool, linear swale-pool, or isolated pool topography.

- Reapply salvaged topsoil into restored vernal pools during the same dry season when the soil was removed.

- Rake collected seeds into salvaged topsoil before fall rains begin (if seeds are to be stored, they should be stored in a cold storage unit).

- Seed newly created vernal pools with local seed and seed propagated in local native plant nurseries (see mitigation measure 40).

- Guarantee by land acquisition or land use restrictions that the mitigation site will be protected in perpetuity.

- Establish a long-term endowment or contribute to an existing endowment to manage the mitigation site in perpetuity.

- Replace affected vernal pool acreage at a ratio of 4 acres created for 1 acre removed. This replacement ratio allows for the uncertainty of establishment success with this experimental procedure.

- Create additional vernal pools on the nearest suitable sites to the pipeline route.

Because vernal pool creation is an experimental procedure and establishment success is uncertain, implement the above measures in conjunction with mitigation measure 63 below.

62b. **Monitor the Success of Recreated Vernal Pools.** Retain a qualified biological monitor to monitor the success of recreated vernal pools 6 months after construction and then annually for 5 years after construction. Submit annual (biannual in the first year) written reports to CPUC or its designee that include interim remedial actions taken. Consider mitigation successful if at least 100 percent of the native species present before construction are reestablished over the vernal pool restoration sites in numbers or percent cover similar to preconstruction numbers or percent cover, and wildlife habitat value scores are greater than or equal to preconstruction scores. These criteria are meant to ensure that in-kind replacement of functional vernal pool communities will be established. If success criteria are not met within 5 years, take remedial actions to achieve success levels and reinitiate monitoring for an additional 5 years.

62c. **Incorporate Contra Costa County's Mitigation Vernal Pools into Vernal Pool Revegetation Plans.** Incorporate into the proposed project's vernal pool revegetation plans all portions of Contra Costa County's mitigation vernal pools that would be affected by the PGT/PG&E project. PGT/PG&E and Contra Costa County should jointly determine which mitigation vernal pools would be affected. CPUC will provide an arbitrator to ensure a reasonable settlement in the event that the parties cannot otherwise resolve any conflict.

63. **Acquire and Protect Existing Vernal Pools.** Acquire sites supporting unprotected existing examples of claypan, hardpan, and volcanic substrate vernal pools for which restoration efforts are being conducted. Ensure that the existing vernal pools are viable systems of equal or higher quality and equal or greater area than the removed vernal pools. Protect the acquired vernal pools and their watersheds from impacts in perpetuity. In choosing a site for protection, give preference to those sites most immediately threatened. Provide for enhancement of existing, protected vernal pools where exotic species have invaded the vernal pool and threaten the viability of native species. Consult with DFG, COE, USFWS, and The Nature Conservancy during the site-selection process. Establish an endowment or contribute to an existing endowment to ensure long-term management of the acquired vernal pool sites.

The sites supporting the protected existing or enhanced vernal pools should preferably be contiguous and comanaged with the sites used to create new vernal pools (see mitigation measure 62). If a contiguous site is not possible, a noncontiguous site may be approved on a case-by-case basis by CPUC or its designee.

Provide for enhancement of existing, protected vernal pools where exotic species have invaded the vernal pools and threaten the viability of native species.

Special-Status Wildlife Species

64. Conduct Preconstruction Wildlife Surveys. Conduct preconstruction surveys for selected federally listed or state-listed threatened or endangered wildlife species within 60 days prior to construction of the pipeline. These surveys would identify potential impacts that may occur because of changes in the distribution of these species prior to pipeline construction. Report the results of the surveys to USFWS, DFG, and CPUC or its designee. Comply with the requirements of the consultation procedures identified in Section 7 of the federal ESA or the California ESA.

Conduct surveys in known and potential habitats identified in Table 3E-2 of the draft EIR and Chapter 3 in the final EIR. Confine surveys for small mammals, herpetofauna, and ground-nesting birds to the right-of-way and new access roads. Survey an additional 500 feet of potential habitat along each side of the right-of-way for dens used by carnivores. Include surveys for active bald eagle nests within 1.5 miles of the right-of-way and for other active raptor nests within 1.0 mile of the right-of-way.

Species listed under the federal ESA or protected by other laws for which surveys should be conducted include the bald eagle, golden eagle, American peregrine falcon, northern spotted owl, blunt-nosed leopard lizard, giant kangaroo rat, and valley elderberry longhorn beetle (VELB). If California condors are released from captivity before or during construction of the pipeline, CPUC or its designee, FERC, and the applicant must consult with USFWS and DFG to ensure that impacts on this species do not occur.

Species listed by California as threatened or endangered include the bank swallow, Swainson's hawk, California black rail, greater sandhill crane, and giant garter snake.

65. Implement a Worker Education Program for Special-Status Wildlife Species. Incorporate in the worker education program described in mitigation measure 6 an education plan for construction workers that provides species identification, habitat requirements, behavioral attributes, and federal and state regulations and policies governing the legal protection of the bald eagle, San Joaquin kit fox, VELB, Delta green ground beetle (DGGB), and Swainson's hawk.

The worker education program should be conducted by a biological monitor within 5 days before construction activities begin within the range of the five identified species. The foremen and supervisors should conduct periodic tailgate briefings to inform construction workers on the requirements specified in the mitigation measures.

66. Avoid Direct Mortality or Destruction of Important Habitat for Special-Status Wildlife Species during Construction. Important habitats for special-status species include dens, nests, roosts, burrows, and caves. Avoid the destruction or removal of important habitat. Implement the following measures for special-status species that occur along the PGT/PG&E proposed route.

67. Avoid Construction during Critical Biological Periods. To minimize disturbance during critical biological periods to special-status wildlife species and important game species along the right-of-way from construction activities, prepare and implement a critical biological period avoidance plan. Identify in the plan the agencies with jurisdiction (including DFG), the location of critical habitat, recommended construction scheduling, and location and frequency of monitoring. Avoid construction during the periods shown in Table C-2. Submit a copy of this plan to the CPUC or its designee for approval after agency review.

68. Avoid Direct Mortality or Destruction of Important Habitat for the Bald Eagle during Construction. Undertake the following mitigation measures for DFG-identified essential bald eagle habitat at Lake Britton (MP 685-687):

- o Identify and mark clearly all trees used by bald eagles.
- o Mark all trees used by bald eagles on USFS lands in consultation with a USFS biologist.
- o Confine the construction right-of-way to the smallest possible area and fence it.
- o Fence areas on USFS lands with marked trees to exclude construction.
- o Do not remove any known roost trees, perch trees, snags, spike-topped conifers, or nest trees.
- o If timber is to be removed, follow the timber harvest guidelines developed by the interagency task force (U. S. Forest Service 1986).
- o Retain mature trees and snags at large stream and river crossings to provide potential bald eagle feeding and wintering habitat.

Follow similar guidelines for construction along Spring Creek (MP 678), Fall River (MP 679), South Fork Cow Creek (MP 719), South Fork Bear Creek (MP 725.5), Paynes Creek (MP 744), Salt Creek (MP 752), and Thomes Creek (MP 767):

- o Do not remove or destroy known roost trees or active nests during construction. If a perch tree must be removed during construction, create a new perch tree from a suitable tree nearby. Removal of known perch trees shall require approval by USFWS and DFG.
- o Retain mature trees and snags at large stream and river crossings to provide potential bald eagle feeding and wintering habitat.

Table C-2. Critical Biological Periods Where Construction Activities Would Disturb Wildlife Species and Lead to Higher Mortality Rates in California

Special-Status Wildlife Species	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Milepost
San Joaquin kit fox natal dens													924-1,021.6
Sierra Nevada red fox natal dens													
Bald eagle nesting season													685-688
Golden eagle and prairie falcon nesting season													620, 629, 700, 924-927
Swainson's hawk nesting season													623.5-625.5, 791, 879, 896
Bank swallow nesting season													688.5, 755
Osprey													686, 688.5
Northern goshawk													632-692
Burrowing owl nesting season													930, 937.3, 941.2, 1,007.8
Black-tailed deer migration													719-723, 728-733.5
Waterfowl nesting season													676, 686

69. Avoid Direct Mortality or Destruction of Important Habitat for the Golden Eagle, Northern Goshawk, Swainson's Hawk, and Osprey during Construction. Implement the following mitigation measures:

- o Do not remove trees with active nests during construction. Avoid active nest trees by reducing the right-of-way width or rerouting the pipeline.

- o If trees with active nests must be removed during construction, retain a qualified wildlife biologist to retrieve young birds in the nest and take them to a wildlife rehabilitation center. Use nest relocation, fostering, and cross-fostering of young raptors to reduce mortality. Use of these measures must be approved in advance of construction by DFG.

70. Avoid Direct Mortality or Destruction of Important Habitat for San Joaquin Kit Fox during Construction. Employ the mitigation measures below adapted from the Stanpac No. 2 Pipeline project and approved by DFG to reduce impacts on San Joaquin kit fox.

70a. **Conduct Preconstruction Surveys for San Joaquin Kit Fox Dens.** Within 60 days before construction activities begin, retain a biological monitor to survey the construction right-of-way and a buffer zone within 200 feet of the project impact area for San Joaquin kit fox dens. Conduct surveys using the methods described by Hall (1983) and DFG (1983). Survey related sites, such as access roads, laydown areas, and other work locations. Notify the land management agencies with jurisdiction if any potential, active, or natal dens are identified during the survey. Document encounters with any other sensitive species or their sign and, in consultation with USFWS (Sacramento Endangered Species Office), DFG (Region IV), and CPUC or its designee, minimize impacts on these animals or plants.

Retain a biological monitor to conduct ground surveys for kit fox dens as follows (DFG 1983) and supervise these surveys.

Conduct ground surveys by at least two investigators walking the staked pipeline and road rights-of-way and carefully surveying an area approximately 200 feet wide (100 feet on either side of the centerline). Conduct surveys in valley grassland habitat types. Adequate ground searches for dens along the pipeline and unpaved access road rights-of-way will require approximately 8 hours per investigator to search a strip 100 feet wide and 2 miles long. More time may be required in areas where grasses are over 6-12 inches high. Survey designated laydown and work areas, as well as a 200-foot-wide buffer strip around the perimeter of these areas, for kit fox dens.

During the survey, collect the following data: date, time, temperature, weather, topography, habitat type, and den site. Collect the following data in association with each observed den site:

- type (kit fox, coyote, ground squirrel, badger, unidentified);
- activity (active, natal, potential);
- number and dimensions of entrances;
- position on slope;
- aspect;
- elevation;
- presence or absence of fox tracks, scats, prey remains, matted vegetation, dirt berms, owls, and other mammals;
- species composition and relative cover of surrounding vegetation; and
- presence of unusual or uncommon species. (O'Farrell and McCue 1981.)

Issue den locations an identification number, flag them (using steel rod with blue survey ribbon), and plot them on 7.5-minute topographical maps. Erect flagging (steel rods with blue survey ribbon) around a buffer strip 50 feet in diameter around den locations. This flagging will be arranged to prevent inadvertent trespass but not discourage kit fox use. Remove flagging within 30 days after construction activity.

Conduct a scent station survey along the pipeline right-of-way to support the den survey. The scent station survey should consist of stations located a minimum of 0.5 mile apart in suitable habitat (valley grassland) in the right-of-way. Stations should consist of a 3-foot-radius plot cleared of vegetation, an 18-inch-by-36-inch smoked aluminum panel (Barrett 1983), and a suitable bait (Roughton and Sweeney 1982). Check stations daily for 3 days.

Do not consider tracks or lack of tracks definitive information as to the presence or absence of kit fox. Kit fox tracks are difficult to differentiate from those of other canids, particularly gray fox, and vary in size because of variations in the consistency of the material in which they occur. Use tracks of appropriate size (Murie 1974) as an indicator of fox occurrence.

Notify USFWS (Sacramento Endangered Species Office), DFG (Region IV), and CPUC or its designee of the results of the survey within 30 days before construction begins.

70b. Determine Activity Status of Potential San Joaquin Kit Fox Dens. Should any potential dens (burrows with entrances 6 inches to 12 inches in diameter that show signs of recent use) be located within the project impact area or buffer zone, the biological monitor shall determine the activity status by searches for tracks, scat, and prey remains and night spotlight surveys (O'Farrell and McCue 1981). An alternate technique for determining occupancy of a potential den employs a fiber-optic endoscope that can be inserted into a burrow to inspect visually its contents and suitability for use by kit fox. Survey areas around active or natal dens for an additional 500 feet for other dens or San Joaquin kit fox activity.

The biological monitor shall conduct surveys for kit fox activity as follows (DFG 1983, O'Farrell and McCue 1981) and supervise these surveys.

Night spotlight surveys provide a good opportunity to confirm the presence of kit foxes visually. Kit foxes are active at night up to 1 mile from denning locations. Kit foxes have been observed at night in almost all weather conditions, but are most active on warm nights. Night surveys should be performed by two persons in one vehicle, each with a 300,000-candle power (or greater) hand-held spotlight. Vehicle speed should not exceed 5 mph. Perform night surveys under optimum viewing conditions on accessible roadways within 0.5 mile of the pipeline right-of-way. To prevent habitat destruction, do not conduct off-road vehicle surveys. Perform night surveys during the period from dusk to dawn and repeat them for 3 consecutive nights.

70c. Protect Confirmed Active and Natal San Joaquin Kit Fox Dens. Fully protect confirmed active and natal dens by pipeline realignment (a minimum of 200 feet from the den site). Prohibit construction activity within 500 feet of any identified natal dens from February through August, when pups may be in the den or confined to the den site.

If active or natal dens are identified during the ground surveys, mark and record them as described above (mitigation measure 70a). Confirm their status (active or natal) through night spotlight surveys (see mitigation measure 70b). Notify USFWS (Sacramento Endangered Species Office), DFG (Region IV), and CPUC or its designee of the location and activity within 48 hours of identification. In consultation with USFWS (Sacramento Endangered Species Office), DFG (Region IV), and CPUC or its designee, identify routing alternatives to relocate the pipeline. If relocation is prohibited by legal or construction constraints, implement the protocol described in mitigation measure 68d for potential den destruction.

70d. Use Approved Procedures for Den Destruction. If destruction of a potential den is considered unavoidable, in consultation with USFWS (Sacramento Endangered Species Office), DFG (Region IV), and CPUC or its designee, block the den entrances by loose dirt for 3 consecutive nights to discourage use but allow animals to escape. Completely destroy the den. Proceed with construction activity after the den site has been destroyed. Notify USFWS (Sacramento Endangered Species Office), DFG (Region IV), and CPUC or its designee at least 48 hours before potential dens are destroyed. Destroy dens by excavating the den site by hand to ensure that animals that may be trapped inside can be removed and relocated safely. The biological monitor shall monitor and document den excavation onsite. Diagram the structure of any den or den system that is destroyed. Replace active or natal dens with artificial dens.

70e. Develop and Implement an Education Program for Construction Workers. Develop an education program for construction workers that requires them to:

- o avoid intentional or accidental disturbance of all San Joaquin kit fox individuals or dens, as well as other sensitive species that may be encountered;
- o restrict vehicle traffic to designated access roads or corridors in the immediate vicinity of construction sites and to speeds of 25 mph or less;
- o refrain from bringing pets or firearms to construction sites to prevent harassment or accidental killing of San Joaquin kit foxes;
- o cover or fill construction excavations deeper than 3 feet at the end of each working day or shift, or provide escape ramps to prevent entrapment of San Joaquin kit foxes; and
- o deposit all food-related trash in closed containers or remove it daily from work sites.

To support information presented in the periodic tailgate sessions, supply an informational brochure to all personnel working on the project. To prevent entrapment of kit fox or other species in open trenches, cover excavations with material suitable to prevent entrapment of kit fox, fill them with soil, and construct escape ramps. Construct ramps where open trenches deeper than 3 feet would be left unattended, uncovered, or unfilled for more than 8 hours. Locate escape ramps constructed by trenching or backfilling every 200 yards in open, unattended trenches.

70f. Mark the Boundary of Storage and Work Facilities and the Construction Right-of-Way. Fence the boundary of all laydown and other storage and work facilities with a 6-foot-high chain-link fence. Bury the fence 6 inches deep to deter entry by burrowing. Flag the pipeline construction right-of-way periodically (every 100 feet) by using metal t-posts or other suitable markers in valley grassland habitats. Confine construction activity and access to these areas and rights-of-way.

70g. Locate Construction Yards and Pipe Storage Areas at Previously Disturbed Sites. Locate construction yards and pipe storage areas at previously disturbed sites. Do not situate temporary structures, equipment, and other material in the construction yard less than 10 feet from the final designated perimeter to prevent fires.

70h. Restore the Pipeline Right-of-Way to Compensate for San Joaquin Kit Fox Habitat Loss or Degradation. Mitigate for temporary loss or degradation of San Joaquin kit fox habitat by restoring the pipeline right-of-way. Approximately 403.5 acres of San Joaquin kit fox habitat (valley grassland) would be affected by construction. Restore all affected habitat immediately following pipe installation. Implement erosion control features to limit steepness and length of slope (e.g., water bars, collection ditches, terraces, and riprap) and mulching with hay, straw, or wood fibers to protect soil surface.

Acquire in perpetuity a parcel of land (no less than 44.3 acres in size) associated with or contiguous with the pipeline right-of-way, a designated open-space or wildlife habitat mitigation area, or as otherwise agreeable to USFWS (Sacramento Endangered Species Office), DFG (Region IV), and CPUC or its designee, to compensate for long-term habitat loss and degradation. Restrict uses of the parcel to ensure long-term habitat protection by recording an instrument encumbering the parcel with language agreed on by DFG and CPUC or its designee. The affected area (403.5 acres) multiplied by a compensation factor of 1.11 yields 447.8 acres. Approximately 403.5 acres of affected habitat should be restored. Therefore, acquire an additional 44.3 acres (447.8 - 403.5 = 44.3) to offset the construction impacts and habitat degradation of the project on San Joaquin kit fox habitat.

70i. Submit Results of Surveys to USFWS, DFG, and CPUC. Submit a written report of the results of the San Joaquin kit fox surveys to USFWS (Sacramento Endangered Species Office), DFG (Region IV), and CPUC or its designee before construction activity begins. Notify these agencies of active or natal dens or populations of rare plants within 48 hours of identification.

70j. Submit Final Mitigation Report to USFWS, DFG, and CPUC. Submit a final written report on the implementation of all mitigation measures described above for the San Joaquin kit fox to USFWS (Sacramento Endangered Species Office), DFG (Region IV), and CPUC or its designee within 90 days after construction in known or potential kit fox range. In addition to detailed descriptions of the results of all mitigation measures implemented before and during construction, specify in the report any recommended supplemental measures.

71. Avoid Direct Mortality or Destruction of Important Habitat for Valley Elderberry Longhorn Beetle during Construction.

71a. Reduce Construction Impacts on Valley Elderberry Longhorn Beetle. Implement the following mitigation measures during construction of the pipeline to reduce impacts on the VELB:

- o Reroute all new access roads and mainline valves outside VELB habitat.
- o A qualified biological monitor should be present if elderberry shrubs must be disturbed in occupied VELB habitat.

- o Reduce the width of the right-of-way and fence it to minimize impacts on elderberry shrubs. Confine all vehicle and foot traffic to the right-of-way in these areas.

- o Survey and document existing clumps and clusters of elderberry shrubs within the right-of-way. Fence and flag them. Trim shrubs, rather than removing them. Fell trees directionally and hand-cut felled trees before removal.

- o If elderberry shrubs cannot be avoided and no VELB exit holes are present in the shrubs to be removed or shrubs within 0.1 mile, the plants may be removed. Use cuttings from removed elderberry shrubs to establish new shrubs after construction.

- o If elderberry shrubs must be removed and exit holes are evident on the shrubs to be removed or on other shrubs within 0.1 mile of the construction area, mitigation may include transplanting shrubs. (See mitigation measure 71b.) Remove these shrubs using an acceptable technique and establish them in an area as close as possible to the right-of-way.

- o Transplant elderberry shrubs with stems greater than 1.5 inches in diameter when the plants are dormant (approximately November through the first two weeks in February). Transplanting during the nongrowing season will reduce the shock to the plants and increase the chances of success. Follow elderberry shrub planting procedures outlined in *General Compensation Guidelines for the Valley Elderberry Longhorn Beetle* (USFWS 1988).

- o If evidence of VELBs is present, place cut branches and stems in a pile next to where the elderberry shrubs will be transplanted or near elderberry shrubs not to be cut or moved. If no emergence holes or adults are observed during the survey, it is not necessary to move the cut stems. If during the course of trimming the trees back, however, galleries (i.e., tunnels excavated by beetle larvae inside the stems and trunks) are detected, place the pruned material next to the transplanted elderberry shrubs. Depending on the larval stage, some larvae may continue to develop and eventually emerge from the pruned material.

- o Do not maintain the right-of-way in VELB habitat.

- o Do not use insecticides, herbicides, and other substances that could affect the VELB or elderberry shrubs within the right-of-way.

71b. Compensate for the Loss of VELB Habitat by Replacing Elderberry Stems with a Diameter Equal to or Greater than 1.5 Inches. In the area selected as a compensation site, replace each stem 1.5 inches or greater in diameter that would be moved or destroyed.

Use a ratio from 2:1 to 5:1, as specified below. Apply this replacement requirement even if the trunk and associated stems are transplanted. Replacement stock may be obtained from a variety of sources, such as nursery stock or material transplanted or pruned from the elderberry shrubs onsite. The ratio is dependent on the habitat quality and quantity; determine the ratio as follows:

- o No replacement

  Example:

Total number of elderberry clumps or clusters	10
Number of clumps or clusters with evidence of the VELB	0
Number of stem diameters equal to or greater than 1.5 inches	0

  Compensation required: None

- o Ratio of 2:1. Apply this ratio in situations involving elderberry clusters (i.e., a group of stems, the majority of which are less than 1.5 inches in diameter, with no main trunk). Clusters represent young trees that do not have as high a potential for current beetle use as do stems with larger diameters. Usually, no evidence of beetle use is present on these young stems; however, clusters can mature rapidly to a size where beetle use would be expected.

  Example:

Total number of elderberry clusters	15
Number of clusters with evidence of the VELB	0
Number of stem diameters equal to or greater than 1.5 inches	0

  Compensation required: Plant 30 stems (ratio 2:1)

- o Ratio of 3:1. Apply this ratio to medium-sized trees with stem diameters of 1.5 inches or greater. Presence of beetles is evidenced by emergence holes, but beetles occur in less than 50 percent of the elderberry clusters or clumps (i.e., a plant with one main trunk, often with a diameter more than 3 inches, with smaller or equal-sized stems surrounding it).

  Example:

Total number of elderberry clumps or clusters	25
Number of clumps or clusters with evidence of the VELB	7
Number of stem diameters equal to or greater than 1.5 inches	150

Compensation required: Plant 450 stems (ratio 3:1) and transplant elderberry shrubs 7

- Ratio of 5:1. Apply this ratio to good-quality habitat with beetle emergence holes present in more than 50 percent of the clumps. Prime trees may be characterized as tall (30 feet or more) with old stumps (more than 3 inches in diameter) and with about 30-50 percent dead limbs.

  Example:

Total number of elderberry clumps or clusters	20
Number of clumps or clusters with evidence of the VELB	12
Number of stem diameters equal to or greater than 1.5 inches	100

  Compensation required: Plant 500 stems (ratio 5:1) and transplant elderberry shrubs 12

In situations where the ratio based on the size of the stem diameter differs from the ratio based on the percentage of clumps with evidence of the VELB, evidence of the VELB will determine the replacement ratio.

71c. Compensate for the Loss of VELB Habitat by Monitoring Transplanted Stems. Monitor all plantings annually and at the end of the growing season (September) to ascertain survival and growth rates for 3 years from the date of transplant. Submit a written report to USFWS and CPUC or its designee annually, including dates of watering, growth rates, and mortality figures, along with a map of each site with an overlay of the transplanted stems and their status.

71d. Compensate for the Loss of VELB Habitat by Replacing Dead or Nonvigorous Plants Annually. Replace dead, stunted, or otherwise nonvigorous plants on a yearly basis so that the following minimum survival rates are achieved for the original plants: first year, 95 percent; second year, 90 percent; third and fourth years, 85 percent; and fifth year, 80 percent. Maintain all viable plantings even if survival is greater than the minimum rates. USFWS and CPUC or its designee shall determine replacement responsibilities for plants that are lost because of uncontrollable circumstances (e.g., flooding or vandalism) on a case-by-case basis.

71e. Select Compensation Sites for Transplanting and Revegetation in Consultation with USFWS. Select compensation sites for transplanting and revegetation of elderberry shrubs in consultation with USFWS to ensure future protection of the plants. Transplant and revegetate elderberry shrubs as close as possible to the impact zone to reduce habitat fragmentation and subpopulation isolation. It may be necessary to purchase or acquire an easement for an offsite property to ensure long-term protection of the compensation site.

Determine the size and location of any offsite compensation area that may need to be acquired in consultation with USFWS and CPUC or its designee.

An area greater than that affected by the project would probably need to be acquired, enhanced, and protected to fully compensate for VELB habitat losses. Compensation sites should be as close to the affected area as possible to reduce habitat fragmentation and subpopulation isolation. USFWS should approve the location and size of compensation sites before the revegetation effort is begun.

Monitor all plantings on the compensation sites and in the right-of-way during the growing season (March-September) to ascertain survival and growth rates for 5 years from the date of transplant or planting. Submit a yearly report to USFWS and CPUC or its designee including dates of watering, growth rates, and mortality figures. Plants that die or appear stunted or otherwise nonvigorous should be replaced yearly so that after 5 years the overall survival rate will be 80 percent.

72. Avoid Direct Mortality or Destruction of Important Habitat for Molestan Blister Beetles. Implement the following mitigation measures for molestan blister beetle habitat during construction of the pipeline:

- Reduce and fence the right-of-way to minimize impacts on vernal pools occupied by molestan blister beetles. Confine all vehicle and foot traffic to the construction right-of-way.
- Implement vernal pool mitigation measures 59 and 60 if vernal pools occupied by molestan blister beetles are disturbed.
- Prohibit use in the right-of-way of insecticides, herbicides, and other substances that could affect the molestan blister beetle, its prey species, or its habitat.

73. Avoid Construction within 1.5 Miles of an Active Prairie Falcon Nest or 1.0 Mile of an Active Bald Eagle, Golden Eagle, or Swainson's Hawk Nest. Prohibit construction within 1.0 mile of an active bald eagle nest between January 15 and August 15 (Stone pers. comm.). This distance is required because disturbance to bald eagles could be considered a "take," which is prohibited under the federal and California ESAs.

Prohibit construction within 1.5 miles of an active prairie falcon nest or within 1.0 mile of an active Swainson's hawk or golden eagle nest during the critical biological periods shown in Table C-2. These species are not protected under the federal ESA. If construction must occur during critical biological periods within the distances identified above, a biological monitor must monitor the nests. If construction activities result in abandonment of young birds, retrieve birds and bring them to a qualified rehabilitation center, or relocate the nest or foster or cross-foster young raptors to reduce mortality.

Obtain approval from DFG, USFWS, and CPUC or its designee before implementing either of the above measures.

74. Avoid Construction during Deer Migration or Cover and Fence the Construction Trench. Construction activities could disrupt black-tailed deer migratory patterns, and open trenches could cause serious injury and increased mortality rates. To reduce disrupted black-tailed deer migratory patterns and potential injury or mortality, avoid construction during migration (Table 1) or cover the trench with an earthen plug at least 200 feet wide and at intervals of approximately 400 yards and fence the trench to guide the game to the crossings if construction must occur during migration.

Mitigation Measures Specific to Jepson Prairie Preserve Alternative A

75. Avoid Direct Mortality or Destruction of Important Habitat for Delta Green Ground Beetles. Employ the following mitigation measures during construction of the pipeline for Jepson Prairie Preserve Alternative A to reduce impacts on the DGGB:

- Retain a qualified biological monitor onsite when construction occurs near DGGB habitat.
- Confine construction between playa pools L1 and L2 (Figure C-1) to a 50-foot-wide construction lane. Apply similar excavation, backfilling, and compaction techniques as those used to cross L2 during construction of the existing pipeline.
- Stockpile excavated soil and bury the pipeline in it near the excavation site.
- Fence sensitive habitat areas near the construction zone and erect "keep out" signs. Confine vehicle and foot traffic to access roads and the construction right-of-way.
- Revegetate all disturbed sensitive habitat areas using native species endemic to the vernal pool/lake-grassland matrix. (See mitigation measure 40.)
- Prohibit use of insecticides, herbicides, and other substances that could affect the DGGB, its prey species, or the vegetation or water quality of vernal pools and playa pools.

Fisheries

76. Coordinate Surveys with DFG and Develop a Mitigation Plan for Impacts on Spawning Gravels - Fall River Crossing. To determine whether the temporary increases in suspended sediments and deposition of fine sediment downstream of the proposed crossing would have a significant impact on trout spawning gravels near the proposed Fall River crossing

(MP 679.1), coordinate site-specific surveys with DFG prior to construction and develop a mitigation plan in accordance with Sections 1600-1606 et seq. of the California Fish and Game Code (Streambed Alteration Permit). Potential mitigation measures may include cleaning gravel, restricting the timing and duration of construction, and boring beneath the stream. Coordinate specific measures relating to water quality with the RWQCB. (See mitigation measure 77.) Submit the final plan to DFG, RWQCB, and CPUC or its designee for approval.

77. **Bore under the Fall River Crossing.** To avoid impacts on the federally listed and state-listed endangered Shasta crayfish, bore under the Fall River crossing. Implementation of this mitigation measure would preclude the necessity for implementation of mitigation measure 76 above.

78. **Implement FERC Procedures and Restrict the Construction Period for Crossings of Sacramento River Tributaries.** To prevent potentially significant temporary increases in turbidity and suspended sediment on spawning habitat of eggs of anadromous fish, implement FERC Procedures (Exhibit 3) and restrict in-channel construction to July 15-September 15, at proposed crossings of Sacramento River tributaries that support anadromous salmonids between MP 718.6 and MP 743.7. Notify DFG before construction of all crossings according to Sections 1600-1606 et seq. of the California Fish and Game Code.

or to a period agreed to by CDFG,

79. **Implement FERC Procedures and Restrict the Construction Period for the First Sacramento River Crossing.** To prevent potentially significant impacts from temporary increases in turbidity and suspended sediment on anadromous fish from avoidance of spawning and rearing habitat, implement FERC Procedures (Exhibit 3) and restrict in-channel construction activity to July 15-September 15, at the first Sacramento River crossing (MP 755.3). Before construction, notify DFG according to Sections 1600-1606 et seq. of the California Fish and Game Code, and submit site-specific construction procedures to CPUC or its designee and FERC for review and approval.

or to a period agreed to by CDFG,

80. **Restrict Construction Period for Crossings in the Sacramento-San Joaquin River Delta.** Because the prolonged period of increased turbidity expected at these crossings could lower light levels sufficiently and for a long enough time to significantly reduce feeding, growth, and survival of sight-feeding fish that use the Delta as a rearing area, restrict in-channel construction activity at the second Sacramento River crossing (MP 906.1), the San Joaquin River crossing (MP 910.2), and the Dutch Slough crossing (MP 913.6) to October 15-January 15. If this construction period is not feasible, develop a revised construction plan in coordination with DFG and CPUC or its designee, and submit site-specific construction procedures to CPUC or its designee for review and approval before construction.

81. **Prepare a Toxic Sediment Work Plan for Crossings in the Sacramento-San Joaquin River Delta.** To prevent significant impacts on Delta fish populations from increases in the concentration of contaminants released from bottom sediments during in-channel construction, prepare a toxic sediment work plan describing the procedures for testing sediment and containing site-specific control and disposal plans. Submit these plans to the San Francisco Bay and Central Valley RWQCBs for review in accordance with Section 401 of the Clean Water Act. Submit copies of the approved plans to CPUC or its designee before construction begins.

Mitigation Measures Specific to Brentwood Pipeline Route Alternatives 2, 3, and 4

82. **Restrict Construction Period for the Sacramento-San Joaquin River Delta Crossings.** To prevent impacts from increased turbidity and suspended sediment on sight-feeding fish that use the Delta as a rearing area and impacts from increased contaminants released from bottom sediments during in-channel construction on Delta fish populations, restrict in-channel construction activity at the Sacramento River crossing (MP 3.1 BV), the Mayberry Slough crossing (MP 5.8 BV), and the San Joaquin River crossing (MP 6.6 BV) to October 15-January 15. In-channel construction activity at the Dutch Slough crossing (MP 0.4 BV) and the Rock Slough crossing (MP 3.5 BV) should be restricted to October 15-January 15.

Socioeconomics

83. **Develop and Implement a Formal Housing Plan for Construction Workers.** The temporary increases in population associated with the construction of the PGT/PG&E project would cause a shortage of available temporary housing supplies in most counties that would be crossed by the project.

To ensure that temporary housing is available for construction workers, develop and implement a formal housing plan that incorporates the following measures:

- identify temporary housing outside each construction spread that could be utilized by construction workers;
- provide written information to construction employees concerning the location of temporary housing within adjacent pipeline construction spreads and counties that are within commuting distance of the project; and
- distribute the plan to each county government in which it is estimated that temporary housing vacancy rates would fall below 3 percent during construction and request that the county circulate the plan to other departments within the county that may be affected by the expected temporary increases in population.

Submit a copy of the formal housing plan to CPUC or its designee for approval.

84. **Maintain Police Protection at Preconstruction Levels of Service.** The temporary increases in population of counties along the proposed pipeline may cause public service capacity to be exceeded for law enforcement agencies and health services. Implement the following measures:

- o contact all local law enforcement agencies whose jurisdiction would be crossed by the pipeline or whose jurisdiction includes areas that would be utilized by construction crews for housing;

- o assess the possibility of law enforcement problems associated with construction, focusing particularly on areas that would be used for housing by construction crews; and

- o provide funding to local law enforcement agencies to maintain service at preconstruction levels, if it is determined that the ability to serve residents would drop substantially below preconstruction levels.

These funding levels must be agreed on by both the applicant and the law enforcement agency that would be affected. If an agreement on the level of funding cannot be reached, CPUC or its designee shall appoint a mediator whose decisions will be binding on both the applicant and the law enforcement agency.

85. **Maintain Emergency Transportation at Preconstruction Levels of Service.** Emergency transportation may be adversely affected by the increase in population associated with pipeline construction. Contact local private ambulance operators or service districts to determine response time from the construction site to available hospitals. To maintain ambulance service at preconstruction levels of service, implement one of the following measures:

- o provide funding to public ambulance services to maintain service at preconstruction levels;

- o in cases where transportation is provided by private operators, contract with those operators to provide ambulance service to the pipeline while maintaining service at preconstruction levels; or

- o purchase and operate ambulances to be used only for emergencies associated with pipeline construction.

86. **Develop and Implement a Fire Control Plan.** Meet with CDF, USFS, or the agency responsible for fire protection on lands that would be crossed by the proposed pipeline to develop an FCP. The FCP should ensure that the project applicant is following all local,

state, and federal fire regulations. The plan should be approved by all affected fire agencies before project approval by CPUC or its designee. During the design phase, meet with CDF, USFS, and other land management agencies with jurisdiction to develop site-specific fire plans. Submit copies of these approved plans to CPUC or its designee.

In addition to state laws contained in Cal. Pub. Res. Code Sections 4442, 4427, and 4425, include the following precautions in the FCP for lands under CDF jurisdiction:

- In addition to the backpack pump and shovel required at the immediate welding site, a fire tanker will be centrally located on active areas of the project and available for use. The tanker will have at least a 300-gallon capacity, with a live hose reel or live hose basket with 250 feet of at least 3/4 inch I.D. heavy-duty rubber hose; a portable or power takeoff pump will be required with discharge capacity of at least 20 gpm at 150 PSI pressure. Gear-type pumps will be provided with a bypass or pressure relief valve so that the hose nozzle can be shut while the pump is operating. The tanker unit will have a shutoff hose nozzle that is adjustable for straight stream, spray, or fog; at least 12 feet of 1-inch suction hose with an intake screen; and an additional 250 feet of 3/4-inch heavy-duty rubber hose or 1-inch cotton jacket rubber-lined or linen hose. Tools, adapters, accessories, and fuel necessary to operate the pump and truck will be provided. Fuel sufficient to run the pumping unit for at least 2 hours will be maintained with the unit at all times.

- Tool caches sealed with a hasp will be provided and maintained by PGT/PG&E or its contractors for emergency firefighting use at each operating landing and other locations, or moved in conjunction with equipment being used by the contractors as specified by the agency representative, and in a quantity designated by the agency representative. The tool boxes will be red, labeled "for firefighting only," and proportionate for the operation, as specified in Cal. Pub. Res. Code Section 4428(a). The chain saw requirements of Cal. Pub. Res. Code Section 4428(b) will also be followed.

- PGT/PG&E or its contractors will provide a fire guard for each construction schedule who will be physically able, vigilant, and suitably trained to detect fires and use available required firefighting equipment to take prompt and efficient suppression action on any fire that starts within the project area. The fire guard will perform duties as outlined in the duty roster (Exhibit 3 of this appendix). Additional fire watchmen with radio communication to the fire guards may be required if construction activities are spread too far apart for one fire guard to manage the task effectively.

- All welding activities will be curtailed during "red flag conditions." Red flag conditions are a prediction made during the daily fire weather forecast for extreme fire behavior conditions, such as high winds, low humidity, high incidence of lightning activity, or movement of a frontal system through the area. These conditions generally exist for short periods (less than 24 hours). When red flag conditions are forecast, the fire guard will contact the agency representative for a determination as to when all welding activity will cease.

- All burning will require a permit regardless of the time of year. The applicant will obtain the permit through the agency representative.

- All lunch and warming fires will require a permit to be obtained by the applicant through the agency representative. All fires will be completely extinguished at the end of each work day.

- Equipment parking areas, storage areas, and small stationary engine sites, where permitted, will be cleared of all flammable material and equipped as required by law. Glass jugs or bottles will not be used as containers for gasoline or other flammable materials.

- Each fuel truck will have a large extinguisher with a minimum rating of 40 B:C or higher, charged with the chemicals necessary to control an electrical or gas fire.

- All motorized equipment will be equipped with federally approved or state-approved spark arresters.

- PGT/PG&E will teach basic firefighting techniques to crew members expected to operate in areas of extreme fire danger.

- PGT/PG&E will designate in writing who on the job will be responsible for the above activities.

Other agencies responsible for fire protection should use the FCP above as a model for lands under their jurisdiction.

Air Quality

87. Submit a Dust Control Plan to Affected Air Pollution Control Districts in the San Joaquin Valley. Submit a dust control plan to each air pollution control district (APCD) within the San Joaquin Valley through which the PGT/PG&E pipeline route would pass. The dust control plan must be approved by the relevant APCD before construction begins. Address in the plan all construction-related prohibitions and requirements contained in the fugitive dust regulation, as adopted the fugitive dust regulation before project construction begins, implement the dust control measures included in the draft version of the plan.

88. Control Fugitive Dust at All Times. Apply water or a dust suppressant to exposed earth during clearing, grading, earth moving, and other site preparation work. Construction spread contractors should control fugitive dust by applying dust suppressants twice per day or as deemed necessary to limit concentrations to safe levels. Use a dust suppressant that has minimal impact on biological resources (such as lignin sulfonate or water). Ensure that an adequate supply of water or dust-suppressant compounds is available to contractors at all times. The relevant APCD should monitor the dust suppression activities of the individual construction spread contractors.

89. Properly Maintain Construction Equipment. Properly maintain construction equipment to minimize emissions from internal combustion engines, ensure efficient fuel combustion, and reduce combustion byproducts. The local APCD should monitor construction equipment maintenance procedures.

90a. Obtain a PSD Permit for the Delevan Compressor Station from the Colusa County Air Pollution Control District. In California, the only natural-gas-fired compressor station would be the Delevan Compressor Station (MP 810) in Colusa County. Because oxides of nitrogen (NOx) emissions for this compressor station are estimated to be 492 tpy (an increase of 156 tpy), a PSD permit is required. Identify best available control technology (BACT) for each pollutant emitted in excess of specific prevention of significant deterioration (PSD) thresholds, perform air quality modeling, and obtain a PSD permit from the Colusa County APCD. As required by PSD regulations, install BACT for NOx control and estimate the air quality impacts of this compressor station to ensure that neither the Class I or II NOx increments nor the national or state ambient standards are exceeded.

90b. Install RACT or BARCT for Existing Gas Turbine Compressor Drivers. Install reasonable available control technology (RACT) or best available retrofit control technology (BARCT), as applicable, as defined by final California Air Resources Board guidelines and implemented by local APCDs under the California Clean Air Act. Such retrofit shall be completed no later than 3 years after construction and startup of the proposed project.

Noise

91. Limit Construction Activity to Daytime Hours. Limit the use of construction equipment powered by internal combustion engines, the use of impact equipment, or other construction activity that would result in disturbance of nearby sensitive noise receptors to between 7:00 a.m. and 7:00 p.m and 9:00 a.m. and 5:00 p.m. where there are sensitive receptors within 1,000 feet. This would restrict disturbance of sensitive receptors to less sensitive periods of the day.

92. Erect Temporary Noise Barriers. Identify locations where sensitive noise receptors (residences within 660 feet) would be exposed to construction noise greater than a daytime hourly equivalent noise level (Leq) of 70 A-weighted decibels (dBA) for more than 10 days and construct a temporary noise barrier at those locations. The barrier should shield the receptors sufficiently to lower the hourly Leq noise level to less than 70 dBA. If a temporary noise barrier is determined to be infeasible at some locations, reduce the duration of construction noise at those locations to less than 10 days.

93. Reduce Residential Impacts from Blasting Activity

93a. Limit Blasting Activity to Daytime Hours. Limit blasting activity to between 9:00 a.m. and 5:00 p.m. to restrict the disturbance to less sensitive periods of the day.

93b. Notify Residents of Expected Blasting Activity. Notify residents within 1,000 feet of blasting sites of the expected blasting activities at least 48 hours before blasting. Submit copies of the notice to CPUC or its designee.

93c. Temporarily Relocate Residents from within 250 Feet of Blasting Locations. Relocate residents and domestic animals from within 250 feet of blasting locations for safety and noise reasons, provided that they agree to relocation. Notify these residents directly at least 3 weeks in advance of the actual move of plans to relocate them temporarily for approximately one-half day. Submit a list of affected parties to CPUC or its designee.

94. Use Noise-Reducing Equipment. Construct compressor stations with noise-reducing equipment, such as intake and exhaust silencers, blowdown silencers, low-speed cooling fans, buried piping, special ventilation systems, and masonry walls around noise-generating equipment.

Prevent noise standards from being exceeded and prevent an increase of ambient noise levels of more than 3 dBA at all times. Provide detailed construction plans and specifications to CPUC or its designee for approval.

Transportation

95. Develop and Implement a Road Crossing Mitigation Plan. Develop a detailed, site-specific road crossing mitigation plan that identifies each road crossing, method of crossing, necessary permits, and permitting agency on land not administered by USFS. (See Chapter 2 of this final EIR for a discussion of the transportation mitigation plan required on land administered by USFS.) Submit the plan to CPUC or its designee and federal, state, or local agencies with jurisdiction for approval. Include the following mitigation measures in the plan:

95a. Bore High-Traffic-Volume Roads. Bore all road crossings where traffic volume is greater than 15,000 average daily traffic per lane and an onsite detour cannot be provided.

95b. Work with Local Authorities to Determine the Best Method of Crossing Low-Traffic-Volume Roads and Driveways. Work with local authorities to determine the best method of crossing low-traffic-volume roadways and driveways that are the sole access to an area or are important in some other way.

95c. Bore Roads Where Nearest Detour Is 5 Miles or More. Bore all road crossings where the nearest detour is at a distance of 5 miles or more.

96. Select Truck Haul Routes That Do Not Exceed Roadway Weight Capacities. The trucking operations may overload the weight capacity of some portions of the chosen haul route, causing roadway surface damage. Select truck haul routes that do not exceed weight capacities of roadways. Consult with each locality's department of public works or other agencies with jurisdiction to ensure selected haul routes do not exceed roadway weight capacities.

97. Use a Bus or Carpool System to Transport Construction Crews. Use a bus or carpool system to reduce the number of vehicles during peak hour to below 100, eliminating single-passenger and low-passenger vehicles. Eight to 10 50-passenger-capacity buses would be needed to transport the workers. Park these buses in designated areas.

98. Prevent Disruption of Transportation on Road between MP 660 and MP 678. The road between MP 660 and MP 678 is a one-lane road that is the only access to a large area of land. This road is important for fire access and timber access. Pipeline construction would occur on the existing roadway for several miles. To prevent disruption of transportation on this road, work with the USFS liaison officer for the Modoc National Forest to determine the best method of constructing the pipeline between MP 660 and MP 678. Mitigation measures may include, but are not limited to:

- o building a new road,
- o shifting the proposed pipeline alignment to maintain a travel lane at all times, and
- o timing the pipeline construction to avoid the logging and fire seasons.

99. Prevent Disruptions to Shipping Channels. To reduce the potential disruption of shipping from crossing the Sacramento deepwater ship channel and other waterways, bore the crossing. A COE permit is required for crossings whether they are trenched or bored under Section 10 of the Rivers and Harbors Act. If COE determines that the crossings can be trenched, comply with all stipulations of the Port of Sacramento, COE, the U. S. Coast Guard, and other shipping interests.

Public Safety

100. Comply with U. S. Department of Transportation and CPUC Regulations. Construct, operate, and maintain the pipeline in accordance with U. S. Department of Transportation regulations (49 CFR 190, 191, and 192; 18 CFR 2.69; and 29 CFR 1926), CPUC General Order No. 112-D, and ANSI specifications. In addition, implement the operations and maintenance plan and emergency preparedness plan described in mitigation measures 3 and 4, respectively.

Visual Resources

101. Blend Aboveground Structures with Natural Surroundings. Paint all semipermanent and permanent facilities to blend with the natural surroundings. Paint the facilities a uniform, noncontrasting color. Semipermanent and permanent structures are those facilities that are onsite more than 90 days after completion of the project. Choose the color at each site from the BLM 10 Standard Environment Color System. Follow BLM selection criteria for colors.

Locate power lines at the base of slopes to provide a background of topography or natural cover. Materials used to construct towers or poles should harmonize with the natural surroundings. Where natural wood poles are appropriate, the color range should be limited to present a unified series of poles. Choose conductor material to avoid a strong silhouette and to provide blending of the conductors into their setting. When lines are adjacent to roads, avoid guyed towers to limit the visual impact.

Prepare photographic simulations of areas in which facilities are proposed within foreground-middleground areas of high scenic value or sensitivity. Using the simulation as a guide, design and locate the pipeline route and ancillary structures to blend into the existing environment. On federal land, obtain BLM and USFS approval of the design before beginning construction. Obtain approval from CPUC or its designee for structure design on nonfederal land.

102. Minimize Clearing. Monitor clearing by an onsite inspector. Minimize clearing as much as possible at stream and road crossings. Leave trees as close to the downhill side of the pipeline as possible. Do not locate landings and turnouts on exposed slopes or on crests of ridges.

Do not leave abrupt, straight lines from clearing in forested lands. Create curvilinear boundaries instead of straight lines when clearing, and minimize scarring of the landscape. Minimize erosion by grading, and conform to the natural topography. Clear the alignment by cutting stubble, rather than scraping as determined by the environmental monitor. Implement the ECR plan described in Exhibit 1.

103. Minimize the Area Affected by Road Crossings. Locate staging areas and additional rights-of-way, requiring clearing of vegetation at least 50 feet from the roadside on nonforested land and at least 100 feet from the roadside in forested lands. At road crossings in nonforested areas, where landowner or applicant vehicle access to the pipeline right-of-way is not required, berm the road crossing to prevent access to the right-of-way by off-road vehicle users. At road crossings in forested areas, where landowner or applicant vehicle access to the pipeline right-of-way is not required, leave in place or plant a screen of trees across the right-of-way in a manner to screen views while not affecting the buried pipeline.

104. Minimize the Area Affected by Stream Crossings. Locate staging areas and additional rights-of-way at least 100 feet from the streambank or beyond the riparian vegetation zone. Implement the ECR plan described in Exhibit 1 to revegetate and restore stream, river, and other water shorelines to a natural-appearing condition.

105. Implement the Erosion Control and Rehabilitation Plan. Implement mitigation measure 16.

106. Reduce Surface Contrast. Replace surface soil material with the same color material where existing soil surface and backfill colors contrast. Stockpile and spread the original surface material.

107. Restore Earthforms. Restore all disturbed land to the original contours. Inspect all disturbed land 1 year after construction is complete and document all areas where settling and other defects have occurred. Restore the contours within 1 year of inspection. Round cut-and-blasted slopes at the top to blend the cut and provide a transition. Redistribute boulders that have been displaced and stored to one side of the right-of-way over the area in a random manner. Do not leave rows or boundaries of newly placed boulders.

108. Restore Rock Faces. Cut or blast rock faces unevenly. They should vary 4-6 feet from the plane of the cut. Smooth-cut or blasted rock faces are not visually acceptable. Treat rock outcroppings and blasted rock faces occurring in visually sensitive areas with an aging agent.

109. Retain Rock Outcroppings. To avoid disturbance to unique or visually sensitive rock outcroppings, the applicant shall conduct a preconstruction survey to identify such locations and shall reroute the pipeline route around rock outcroppings. If a rock outcropping cannot be avoided, obtain approval from CPUC or its designee to document and replace the outcropping. Documenting shall include photographing outcroppings from at least three angles before demolition or modification. Replacement shall include reconstructing rock outcroppings as close to their original condition as possible, and setting the rocks to their original soil line.

110. Reroute the Pipeline to Avoid the Jepson Prairie Preserve. Do not construct the pipeline route across the Jepson Prairie Preserve property (MP 892.5). Select Alternative B.

111. Restrict Clearing to the Existing Right-of-Way. Confine clearing to PGT/PG&E's existing right-of-way in California at MP 673.5-687.0, MP 688.0, and MP 692.7-734.6 to avoid producing a wider scar across the natural landscape. Confine the construction area to the existing right-of-way.

Cultural Resources and Paleontology

112. Develop and Implement a Cultural Resources Mitigation Plan. The mitigation measures presented below are general in nature and are pending completion of the inventory and evaluation of the National Register of Historic Places (NRHP) eligibility of resources along the pipeline routes. Specific measures to avoid or mitigate adverse impacts on historic properties will be developed in the context of the National Historic Preservation Act (NHPA) Section 106 process before the issuance of a FERC license. Before construction and in accordance with Section 106, develop and implement a detailed, site-specific cultural resources mitigation plan that incorporates the following mitigation measures.

113. Relocate the Pipeline to Avoid the Cultural Resource. Relocate the pipeline to avoid prehistoric and historic resources and specific areas of concern to the Native American community. Any resources formally determined ineligible for inclusion in the NRHP are not covered by the provisions of Section 106 of the NHPA. However, such resources located on federal, state, county, or Native American lands may be considered significant by these agencies and avoidance may be required (e.g., state historic landmarks). Resolve these concerns during the permitting process.

Avoidance of cultural resources is based on the values that make them eligible for inclusion in the NRHP. For example, for a prehistoric archeological site that is eligible based solely on the scientific data contained within the site boundaries, avoidance can be achieved by restricting any ground-disturbing activities within the site. However, if the NRHP eligibility of a site is based partially on the setting of the resource (e.g., a segment of historic trail in a rustic setting), avoidance must take into consideration such factors as the introduction of visual and audible elements that are out of character with the resource. Boring under intact segments of linear features (e.g., roads, trails) and restoration of vegetation may be needed to avoid resources of this nature. Develop this mitigation measure in consultation with the Office of Historic Preservation, FERC, Advisory Council on Historic Preservation (ACHP), and any interested parties, and implement it. CPUC or its designee may provide an arbitrator, if requested by any involved party.

114. Implement a Data Recovery Plan in Consultation with the Office of Historic Preservation, FERC, and ACHP to Recover Significant Values. Prehistoric and historic resources with significant values (those values resulting in NRHP eligibility) that lie solely in the scientific data contained in the archeological deposit may be excavated under a data recovery plan developed in consultation with the Office of Historic Preservation, FERC, and the ACHP. Develop and implement an approved data recovery plan to avoid an adverse effect determination under Section 106 of the NHPA (36 CFR 800.9).

In the case of a standing historic structure (e.g., bridge, cabin) that is eligible for inclusion in the NRHP based on its potential contribution to architectural research, data recovery would depend on recording the structure according to the standards of the Historic American Building Survey and the Historic American Engineering Record. The completion of research would be designed to preserve the significant architectural values and avoid an adverse effect determination under Section 106 of the NHPA (36 CFR 800.9).

115. Monitor Trenching of the Pipeline during Construction. Subsurface excavations related to the trenching of the pipeline have the potential to reveal previously unidentified archeological resources that may be eligible for listing in the NRHP. An archeologist should be present during construction activities with the potential to uncover such resources. Include detailed measures for the evaluation and treatment of any cultural resources discovered during such construction activities in the cultural resources mitigation plan (refer to 36 CFR 800.11).

116. Monitor Identified Cultural Resources after Construction of the Pipeline. A professional archeologist should monitor the pipeline corridor right-of-way and conduct an annual field check of all archeological resources that have not been officially determined ineligible for listing in the NRHP. Include in the field check an assessment of any observed disturbance to or alteration of the resource, as well as proposed measures to rectify resource degradation (e.g., stabilization of unstable slopes affecting archeological resources). Submit an annual status report documenting the monitoring effort, resource status, and any proposed action to the Office of Historic Preservation for consultation.

117. Solicit the Concerns of Native American Groups. Areas of traditional religious or cultural values and practices identified by Native American groups are specifically protected under the American Indian Freedom of Religion Act. The NHPA (36 CFR 800) also emphasizes the consideration of the concerns of Native American groups in the evaluation of cultural resources. Consider the expressed concerns of Native American groups when developing mitigation for impacts on areas of Native American interest (e.g., traditional plant-gathering areas), and include relocating the pipeline as a possible mitigation measure to avoid the area of concern.

118. Develop and Implement a Paleontologic Resources Mitigation Plan. Develop and implement a detailed, site-specific paleontologic resources mitigation plan in consultation with scientific researchers and any other interested parties (e.g., USFS and BLM resource personnel). Submit the plan to CPUC or its designee and the land management agency with jurisdiction for approval.

119. Relocate the Pipeline to Avoid the Paleontologic Resource. Relocate the pipeline to avoid known paleontologic resources where these resources have been determined by detailed scientific investigation to be unique within a particular geologic rock unit or formation (e.g., a vertebrate faunal or paleobotanical floral quarry site).

120. Conduct Paleontologic Collections to Recover Important Resources. Paleontologic resources with significant values that lie solely in the scientific data contained in the deposit may be excavated under a data recovery plan developed in consultation with qualified paleontologists and agency officials (e.g., CPUC or its designee, FERC, USFS, BLM). Develop and implement a data recovery plan as part of the paleontologic resources mitigation plan described in mitigation measure 118.

MITIGATION MEASURES FOR LESS-THAN-SIGNIFICANT IMPACTS

Vegetation

121. Transplant the Delta Tule Pea Plant. Transplant the single Delta tule pea plant in the construction right-of-way at Gallagher Slough to the nearest suitable habitat upstream from the construction site.

Wildlife

122. Reseed Preferred Browse Species on Deer Winter Ranges. To minimize the loss of preferred browse species on migratory mule and black-tailed deer winter ranges, reseed bitterbrush between MP 619 and MP 642, MP 649.0 and MP 653.5, and MP 661 and MP 669. Reseed buck brush between MP 681 and MP 686, MP 715 and MP 728, and MP 739 and MP 749.

123. Avoid Acorn-Producing Oaks along the Construction Right-of-Way. Avoid acorn-producing oaks along the construction right-of-way in the range of the wild turkey because it is an important component of the wild turkey diet.

Land Use

All Resources

124. Notify Affected Parties of Construction Activities. To minimize all land use impacts associated with the pipeline project, notify 2 weeks in advance and by direct contact, all local residents, permitted users, landowners, and land managers whose safety, property, business, or operations might be affected by any construction activity. Activities such as temporary road closures, removal or cutting of fences, or disturbances involving range improvements or other range-related structures, could affect property, business, or land use operations.

125. Clear Minimum Right-of-Way Width and Minimize Right-of-Way Damage. To minimize construction impacts on sensitive areas, clear the minimum required right-of-way width and minimize right-of-way damage. do not strip vegetation less than 4 inches in height, leave trees standing, and mow rather than clear taller vegetation. Adjust the pipeline locally to avoid areas with sensitive communities, species, or activities.

Wherever feasible,

126. Restore Structures to Preconstruction Conditions. To minimize impacts on structures damaged during construction, restore all structures, such as terraces, levees, underground drainage systems, irrigation pipelines, and canals, to preconstruction conditions. Remove all unnecessary roads and block all unnecessary access clearings created for construction.

127. Compensate for Losses of Resource Production. Compensate at fair market value all landowners who experience a loss in resource production.

Agricultural Resources

128. Use Construction Techniques Sensitive to Crop Production. Wherever feasible, schedule construction activities after growing seasons; consult with local growers on preventing conflicts with planting, irrigation, and harvesting.

129. Use Construction Techniques Sensitive to Orchards and Vineyards. Protect the vegetation that would not be cleared from construction activities.

130. Design and Implement Revegetation Plans. To minimize impacts on agricultural resources, design and implement site-specific revegetation plans according to the requirements or guidelines of the land management agency, state agency, or landowner. Include in these plans provision for necessary topsoil replacement, seedbed preparation, mulching, and fertilization; advocate use of seed mixtures containing native species; and provide for control of noxious weeds and erosion.

131. Monitor Revegetation and Erosion Control. In cooperation with USFS or BLM, monitor the success and maintenance of erosion control and revegetation programs on federal lands for at least two growing seasons.

132. Salvage and Replace Topsoil for Cultivated Land. To minimize impacts on crop production, selectively salvage and replace topsoil as directed by the landowner for all cultivated lands that would be affected by the pipeline project and on all other lands as requested by the land management agency or landowner. Notify all landowners of cultivated land of their option to have topsoil salvaged and replaced. Do not use topsoil for filling sack breakers or for padding in the trench.

133. Aid Vegetation Regrowth with Soil Amendments and Seeding Methods. To minimize impacts on crop production, add soil amendments, including fertilizer, and use seeding methods to aid in the development of a positive growth medium for regrowth of vegetation.

134. Retain a Reclamation Specialist. To minimize impacts on agricultural resources during construction for each construction spread, employ an onsite reclamation specialist certified by the U. S. Soil Conservation Service. The specialist should direct restoration procedures when special conditions are encountered and act as a liaison with USFS and BLM.

135. Replace Water Lines. Replace any water lines that are damaged by pipeline construction.

136. Fence the Right-of-Way to Aid Revegetation. To minimize impacts on rangeland and pasture, fence the right-of-way for the 3- to 5-year period in sensitive areas where reestablishment of vegetation would be particularly difficult to achieve. Construct, maintain, and remove these fences. Locate crossovers at least every 500 yards, or elsewhere at the request of the local land manager or permittee.

137. Develop and Implement Protective Grazing Procedures for Vegetation Reestablishment. To minimize impacts on rangeland and pasture, delay grazing on rangeland to allow vegetation to become established. Develop procedures for excluding grazing within the right-of-way with participation of the land manager or landowner on a site-specific basis. Include protective procedures, such as fencing, removing range animals from affected allotments, compensating the range permittee, and adjusting grazing schedules within allotments.

Urban Resources

138. Coordinate with Byron Airport Management during Construction. Coordinate with Byron Airport management during construction to ensure that no conflicts occur.

Forest Resources

139. Clear Merchantable Timber. To minimize impacts on timber production, clear all areas containing merchantable timber before clearing the right-of-way.

140. Protect Remaining Vegetation from Construction Activities. To minimize impacts on timber yield, protect the remaining vegetation from construction activities by fencing or flagging.

Recreational Resources

141. Avoid Construction during the Peak Tourist Season. To minimize impacts on recreational activities, avoid construction during the peak tourist season. Where recreational activities cannot be avoided, minimize disturbances to those activities by limiting construction to the minimum right-of-way.

Plans and Policies

142. Consult with City and County Planning Departments before Construction in Their Jurisdictions. To minimize impacts on the local plans and policies for existing and future land uses, consult with all city and county planning departments before construction in their jurisdictions.

Public Safety

143. Notify Operators of Intended Excavation and Implement One-Call Systems. Contractors shall notify pipeline operators of intended excavation and provide one-call systems as a mechanism for coordinating notification and pipeline location. Design one-call centers to provide the full range of services needed by pipeline operators to satisfy federal regulations for prevention of damage to the pipeline by outside forces.

144. Regulate Land Use to Prevent Conflicts near Pipelines. Implement the following measures to prevent land use conflicts near the pipelines. At a minimum, land use control could focus on the pipeline right-of-way by requiring pipeline operators to:

- o review easement agreements to ensure that they contain adequate protection against encroachments that may adversely affect the safe operation of pipelines;
- o conduct right-of-way surveillance programs at intervals adequate to identify new encroachments; and
- o initiate semi-annual liaison with all local planning and development departments through whose jurisdiction the pipeline runs to discuss development plans and preventive measures that ensure pipeline safety.

The applicant shall fund local planning departments to:

- o modernize land records systems to ensure that the types, boundaries, and holders of easements are identified by parcel and that easement holders can be contacted readily by local governments; and
- o prepare planning guidelines in consultation with pipeline operators and developers to safely integrate pipelines into development projects and protect the lines during construction.

145. Prevent Damage from Seismic Forces. Because there is flexibility in determining their location, valves, compressor stations, and other support facilities shall be located so that the only seismic hazard to which they may be subjected is ground shaking. Locating the facilities away from potential seismic hazards is preferred to designing the system to compensate for such hazards. When designing the pipeline and determining alignment, identify sources of relative displacement, such as faulting and liquefaction, and ensure that the necessary flexibility exists to accommodate these displacements.

146. Select a Route to Minimize Seismic Hazards. Cross active fault breakage zones only once and in as short a distance as possible to minimize the amount of pipeline subject to distortion from ground displacements, thereby minimizing the possibility of rupture.

147. Use Construction Techniques to Avoid Pipeline Damage. Use shallow burial construction techniques in a moderately low-shear-strength backfill to limit the longitudinal friction, lateral passive pressure, and uplift resistance when crossing a fault. Deep burial shall be used when the pipeline is either encased in a larger diameter culvert or surrounded by a crushable packing such as gravel. Contingency plans shall be developed to ensure orderly shutdown, rapid repair, and timely startup of the pipeline in the vicinity of major fault crossings. Incorporate contingency measures into the emergency preparedness plan described in mitigation measure 5.

148. Implement Federal and State Emergency Preparedness Programs. To minimize public safety impacts, emergency preparedness programs shall be implemented near pipelines. The severity of pipeline accidents shall be reduced by the timely and informed response of local public safety officials working in cooperation with pipeline operators.

- PG&E/PGT shall develop a centralized or regional emergency communications systems through which local fire departments and other safety officials and the pipeline operators can report and receive information about pipeline accidents and appropriate response measures. Work with emergency services in each county along the pipeline route to develop an emergency communication network that links emergency services to each other and to the pipeline operators.

- PG&E/PGT shall contact organizations and federal and state offices that provide training programs for emergency response to hazardous materials accidents and shall provide instructional materials on emergency planning and response procedures for pipeline failures.

Visual Resources

Mitigation Measures Specific to Brentwood Alternative Compressor Station Sites

149. Minimize Visual Impacts from Aboveground Structures at Alternative Compressor Station Site C. To minimize visual impacts from aboveground structures at Alternative Compressor Station Site C, implement mitigation measure 101.

MITIGATION MEASURES FOR SIGNIFICANT IMPACTS ASSOCIATED WITH MITIGATION REROUTES

Mitigation measures are listed below for reroute alternatives only when the impacts for the reroute would differ from those described for the proposed route.

Shasta County Cypress Forest Reroute West

Land Use - Plans and Policies

150. Obtain a Use Permit from Shasta County. Obtain a use permit from Shasta County to mitigate for the otherwise significant and unavoidable impact of inconsistency with an existing land use designation. (The reroute right-of-way is not incorporated as a utility corridor into the plans and policies of Shasta County.)

Vegetation

151. Minimize Impacts on Special-Status Plants. To minimize impacts on special-status plants, implement mitigation measures 47 through 55.

Air Quality

152. Reduce Construction Emissions. To reduce the incremental increase in construction emissions associated with the reroute in Shasta County to less-than-significant levels, implement mitigation measures 88 and 89.

Visual Resources

153. Minimize Clearing and Implement the ECR Plan. To reduce long-term vegetation impacts on montane chapparal and mixed conifer forest and the highly visible linear corridor created by right-of-way clearing, minimize right-of-way clearing and implement mitigation measure 18.

Cultural and Paleontologic Resources

154. Reduce Direct and Indirect Impacts on Cultural and Paleontologic Resources from Pipeline Construction, Operation, and Increased Public Access. To reduce direct and indirect impacts on cultural and paleontologic resources from pipeline construction, operation, and increased public access, implement mitigation measures 112 through 120.

Transportation

155. **Prevent Disruption of Transportation on Road between MP 703.5 and MP 704.1.** Provide a temporary detour for the road crossing between MP 703.5 and MP 704.1 to prevent the disruption of transportation for the sole access to an area.

156 - 168. Deleted

Contra Costa County Alkali Meadow and Vernal Pool Reroute

Hydrology and Water Quality

169. **Minimize Stream Crossing Impacts.** To reduce impacts on stream crossings with the potential for moderate to high bank erosion, implement mitigation measure 20.

Land Use - Plans and Policies

170. **Obtain Appropriate Authorization from Contra Costa County.** Obtain appropriate authorization from Contra Costa County to mitigate for the otherwise significant and unavoidable impact of inconsistency with an existing land use designation. (The reroute right-of-way is not incorporated as a utility corridor into the plans and policies of Contra Costa County.) Provide a copy of that authorization to the CPUC.

Vegetation

171. **Minimize Impacts on Special-Status Plants.** To reduce impacts on special-status plants, implement mitigation measures 47 through 55.

172. **Minimize Impacts on Wetlands and Riparian Habitat.** To reduce impacts on wetlands and riparian habitat, implement mitigation measures 44 through 46.

Wildlife

173. **Reduce Impacts on San Joaquin Kit Fox.** To reduce impacts on San Joaquin kit fox, implement mitigation measure 69.

174. **Reduce Impacts on Burrowing Owls during Construction.** To avoid destruction of active burrowing owl nests during construction, implement mitigation measure 67.

Air Quality

175. **Reduce Construction Emissions.** To reduce the incremental increase in construction emissions associated with the reroute in Contra Costa County to less-than-significant levels, implement mitigation measures 87 and 88.

Transportation

176. **Prevent Traffic Disruptions and Cutting Off Sole Access Roads.** To reduce impacts from disrupted traffic on sole access roads, implement mitigation measure 95.

Cultural and Paleontologic Resources

177. **Reduce Direct and Indirect Impacts on Cultural and Paleontologic Resources from Pipeline Construction, Operation, and Increased Public Access.** To reduce direct and indirect impacts on cultural and paleontologic resources from pipeline construction, operation, and increased public access, implement mitigation measures 112 through 120.

MITIGATION MEASURES FOR SIGNIFICANT CUMULATIVE IMPACTS

The following mitigation measures for significant cumulative impacts were specified by resource in Chapter 6 of the draft EIR.

Soils

178. **Mitigate for the Cumulative Increases in Soil Erosion Rates.** Implement mitigation measure 18.

Hydrology and Water Quality

179. **Mitigate for the Cumulative Impacts of Alteration of Streamflow and Topography.** Implement mitigation measures 20 through 24.

Land Use

180. **Mitigate for the Cumulative Permanent Reduction in Agricultural Resources.** Implement mitigation measures 128 through 137.

181. **Mitigate for the Cumulative Loss of Mineral Resources.** Implement mitigation measure 26.

Vegetation and Wildlife

182. Mitigate for the Cumulative Losses of Wetlands and Riparian Vegetation. Implement mitigation measures 44 through 46.

In addition, CPUC or its designee, in cooperation with appropriate state agencies and public and private utilities, should implement a program of utility corridor mapping throughout the state, including corridor resource inventories, and promote use of specific corridors to minimize impacts on vegetation and wildlife, and, in particular, sensitive, rare, threatened, and endangered species and habitats.

183. Mitigate for the Cumulative Loss of Special-Status Plant and Wildlife Species. Implement mitigation measures 47 through 55 and 64 through 75.

Socioeconomics

184. Mitigate for Cumulative Increases in Population and Demand for Housing, Public Services and Utilities, and Other Private Services. Implement mitigation measures 83 through 86.

Air Quality

185. Mitigate for Cumulative Short-Term Increases in Dust Emissions. Implement mitigation measure 88.

186. Limit Cumulative Increases in Source Emissions. Implement mitigation measure 87.

187. Mitigate for Greenhouse Gas (Carbon Dioxide and Methane) Emissions. The applicant shall develop, submit for approval to the CPUC, and implement a proposed mitigation plan addressing the significant environmental impact, as identified in the EIR, due to emissions of greenhouse gases (GHG) associated with the Expansion Project. These emissions include: carbon dioxide releases associated with the end-use combustion of natural gas transported on the Project and the generation of compression necessary to support the transport of gas on the Project; and the intentional or inadvertent releases of methane associated with the transport of gas on the Project. This plan shall be submitted to the CPUC within four months following the certification of the Project.

The plan shall include realistic proposals that the applicant intends to pursue to address the greenhouse-gas/climate-change issue, and more specifically, to mitigate for the fact that the Expansion Project would effect the emissions to the atmosphere of substantial quantities of additional GHGs. The plan should reflect a thorough understanding of the relevant literature pertaining to policies for and methods and costs of reducing net GHG emissions. The plan should include, but not necessarily be limited to, the applicant's proposals for research, policy development (including how better to integrate electric and gas resource planning to optimize efficient use of all energy resources), and for directly or indirectly abating GHG emissions associated with the Expansion Project.

The applicant's proposals for GHG abatement should be presented in the form of a "supply curve" (analogous to energy conservation supply curves), where the entity being supplied is net reductions in GHG emissions to the atmosphere. Such a supply curve would indicate the quantity of net GHG emissions reductions that could be achieved with each measure, beginning with the least expensive measure and ending with the most expensive measure necessary to completely mitigate for the Expansion Project's GHG emissions. This curve shall be constructed in a "least cost" fashion, i.e., it should indicate the economically optimal path of investment to completely abate the GHG emissions associated with the gas that will be transported on the Expansion Project.

on the Environmental Project. This quantity of GHG abatement shall be in addition to any reductions (The applicant has

The applicant shall indicate in its plan measures it proposes to implement to abate a quantity of GHG emissions at least equal to that associated with the 100-MMcf/d subscription the applicant has pursued or will pursue in connection with any of its other activities, including those stemming from its participation in California Energy Commission or CPUC proceedings, or in the California Energy Efficiency Collaborative Process. Following review and approval by the CPUC, the applicant shall begin implementing the measures identified in its plan to accomplish this quantity of GHG abatement.

Noise

188. Mitigate for Cumulative Increases in Construction Noise. Implement mitigation measures 91 through 93.

189. Mitigate for Cumulative Compressor Station Noise Impacts. Implement mitigation measure 94.

Transportation

190. Mitigate for Cumulative Increases in Peak-Hour Traffic. Implement mitigation measure 97.

Public Safety

191. Mitigate for Cumulative Risks to Public Safety. Implement mitigation measure 5.

Visual Resources

192. Mitigate for Cumulative Visual Impacts. Implement mitigation measures 101 through 111.

Cultural Resources and Paleontology

193. Mitigate for the Cumulative Degradation of Cultural Resource Sites. Implement mitigation measures 112 through 120.

MITIGATION MEASURES FOR SIGNIFICANT CUMULATIVE IMPACTS OF DOWNSTREAM FACILITIES AND THE PROPOSED PGT/PG&E PROJECT

194. Follow CEQA or CEQA-Equivalent Procedures for Permitting New or Expanded downstream Facilities. New facilities may be required in order to deliver gas transported on the Expansion Project to the points of end use. Under CEQA, any significant environmental impacts associated with such "downstream" facilities, which include new or expanded distribution systems, need to be accounted for in assessing and mitigating the Expansion Project's impacts. Therefore, any and all facilities that may be required in order to accommodate natural gas from the PGT/PG&E expansion project, and over which CPUC has jurisdiction, shall receive full environmental review as per CEQA requirements. This requirement shall apply even if a particular project would not require CEQA review under normal CPUC certification procedures.

Where the environmental review addresses protected plant or animal species or their habitats, the project sponsor shall consult with and reach agreement with the U.S. Fish & Wildlife Service and the California Department of Fish & Game on appropriate mitigation; this mitigation shall be incorporated into the design of the project in question.

If mitigation decided on by F&W or DFG includes providing funds to acquire habitat or enhance existing habitat to compensate for a project's impacts, these funds shall be levied on the project sponsor and administered by a trustee approved by the CPUC or its designee.

The applicant shall include the above stipulations in its contracts with the sponsors of facilities as referred to above. The applicant shall also require that each of its subscribers provide plans for all proposed new or expanded facilities to the appropriate permitting agencies.

197. Apply Mitigation Measures Described in the Draft EIR for Source Emissions. Implement mitigation measure 90 for source emissions for downstream facilities. In addition, PGT/PG&E shall include these stipulations in its contracts with downstream end users of gas from the proposed project.

198. Apply Mitigation Measures Described in the Draft EIR for Cultural and Paleontologic Resources to Downstream Facilities. Implement mitigation measures 112 through 120 for impacts on cultural and paleontologic resources from downstream facilities. In addition, PGT/PG&E shall include these stipulations in its contracts with downstream end users of gas from the proposed project.

MITIGATION MEASURES FOR SIGNIFICANT CUMULATIVE EFFECTS OF PGT/PG&E'S EXISTING PIPELINE AND THE PROPOSED PIPELINE PROJECT

199. Compensate for Cumulative Impacts on Vernal Pools along the Existing PGT/PG&E Pipeline. To mitigate for the cumulative impact on vernal pools along the existing right-of-way in California resulting from the siting and construction of theproposedpipeline adjacent to the applicant's existing pipeline, PGT/PG&E shall determine the number and acres of vernal pools that existed in the right-of-way before construction of the existing pipeline and shall compensate for those impacts by, at the option of DFG, either recreating and permanently managing and protecting vernal pools at a 4:1 replacement ratio or, acquiring property with habitat qualities acceptable to DFG and conveying that property, subject to restrictions on use intended to protect those habitat qualities, to DFG at a replacement ratio acceptable to DFG. Submit methodology and results to DFG and CPUC (or its designee) for review and concurrence.

For all areas established as mitigation for direct or cumulative impacts of the proposed PGT/PG&E project, PGT/PG&E shall include funding for long-term permanent management and protection of the areas in accordance with guidelines established in coordination with DFG. This funding shall also support associated research and development efforts as needed to ensure the success of the vernal pool recreation efforts.

200. Mitigate for the Cumulative Losses of Forest, Woodland, and Sagebrush-Steppe Habitats along the Existing Right-of-Way. To mitigate for the cumulative loss of forest, woodland, and sagebrush-steppe habitats along the existing right-of-way in California, PGT/PG&E shall, in consultation with and with the approval of DFG, determine the number and acres of each of these habitats that existed in the right-of-way before construction of the existing pipeline. PGT/PG&E shall compensate for the loss of those habitats either by recreating the habitats in protected areas at a 1:1 ratio or by contributing to a fund to be administered by a trustee to acquire habitat and enhance existing habitat.

For all areas established as mitigation, PGT/PG&E shall include funding for long-term permanent management and protection of the areas in accordance with guidelines established in coordination with DFG.

201. Mitigate for the Cumulative Loss of Cultural and Paleontologic Resources along the Existing Right-of-Way. To mitigate for the cumulative loss of cultural and paleontologic resources along the existing right-of-way in California, PGT/PG&E shall contribute to the funding of cultural and paleontologic record searches and field surveys of the project area so that the prehistoric and historic use of the area can be better understood, sites can be identified, and unique resource areas can be protected. The amount of cost sharing shall be determined by the Office of Historic Preservation, in coordination with CPUC or its designee and the project applicant.

Exhibit 1. Special-Status Vegetation and Wildlife Resources

SPECIAL-STATUS PLANT SPECIES

Special-status plant species include:

- species that are currently listed, proposed for listing, or candidates under review for listing as threatened or endangered under the federal Endangered Species Act (ESA) (50 CFR 17.12; 55 FR 6184-6229, February 21, 1990);
- species that are currently listed, proposed for listing, or candidates under review for listing as rare, threatened, or endangered under the California Native Plant Protection Act and ESA (DFG 1989);
- species that are considered "rare, threatened, and endangered in California and elsewhere" by the California Native Plant Society (CNPS) (Smith and Berg 1988);
- species listed as sensitive by the U.S. Forest Service (USFS) (Forest Service Manual 2670) in Region 5 (California); and
- species listed as sensitive by the U.S. Bureau of Land Management (BLM).

SPECIAL-STATUS WILDLIFE SPECIES

Special-status wildlife species include:

- animals that are listed, proposed for listing, or candidates under review for listing as threatened or endangered by the federal government (50 CFR 17.11, January 1, 1989; 54 FR 554, January 6, 1989);
- animals that are state listed, proposed for state listing, or candidates under review for state listing (California Administrative Code, Title 14, Section 670.5);
- California's species of concern identified by DFG (Remsen 1978, Williams 1986, DFG 1988a); and
- animals listed as sensitive by USFS (Forest Service Manual 2670) in Region 5 (California).

APPENDIX C
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MITIGATION MONITORING PROGRAM
A.89-04-033 - PG&E Pipeline Expansion Project

A. Introduction

The California Public Utilities Commission has certified the final Environmental Impact Report (EIR) for the application of Pacific Gas and Electric Company (PG&E) for a certificate of public convenience and authority to expand its existing natural gas pipeline from Malin, Oregon, to Kern River Station, California (A.890940933).

The EIR identifies several significant negative impacts to the environment that are likely to occur as the result of the proposed expansion. It recommends certain mitigation measures be undertaken to avoid or lessen the potential harm to the environment. The CPUC has adopted those mitigation measures as a condition of its issuance of the certificate of public convenience and necessity.

The required mitigation measures are attached as Appendix B to the CPUC decision granting the certificate. They have been more fully described in the certified EIR.

The CPUC is required by Public Resources Code section 21081.6 to adopt a monitoring program for the changes to the project which it has adopted or made a condition of project approval in order to mitigate or avoid significant effects on the environment. The monitoring program is to be designed to ensure compliance during project implementation.

The construction of the expansion project shall be undertaken consistent with the Mitigation Monitoring Program. The goal of this program is to ensure that the mitigation measures outlined in the EIR and subsequently identified by further studies to be conducted after finalization of construction plans are fully implemented.

B. <u>Mitigation Monitoring Program</u>

The Mitigation Monitoring Program shall consist of a preconstruction survey and the marking of sensitive resources, an environmental education plan for the construction crew, a restoration plan, enforcement and reporting requirements, sanctions for violating environmental plans, and a mitigation monitoring plan containing resource-specific mitigation measures. The Mitigation Monitoring Plan is attached as a separate document. The general provisions of the Mitigation Monitoring Program are summarized below.

1. <u>Preconstruction Survey</u>

Upon certification of the project by the CPUC, the utility shall conduct a preconstruction survey of environmental resources. The preconstruction survey shall be conducted for the final design and route of the pipeline. The survey must be performed with sufficient accuracy to precisely identify the nature of the resources, the resource locations, and its susceptibility to impact from the pipeline construction and any other mitigation measures. The survey must be conducted for the entire pipeline route and the route shall be clearly marked by the survey team.

The survey shall be performed by a qualified environmental monitor (EM) representing those disciplines where specific sensitivities have been identified in the EIR. The EM shall identify and mark sensitive resources for protection and follow survey procedures outlined in the EIR. All changes made by PGT in route alignment shall be resurveyed following the procedures listed above. Hence, the preconstruction survey must be kept up-to-date through completion of the project. Resurveying can be conducted by the same or different personnel, but CPUC must be notified of changes and supplied with maps.

Prior to any construction, there shall be a preconstruction meeting at the field site. The meeting shall have a minimum attendance of the EM and Construction Supervisor for that site. The Construction Supervisor shall certify that the current construction plan is accurately shown on the resource maps, and s/he shall state the construction schedule for the site. The EM shall explain the environmental sensitivities, list the applicable construction restrictions, and show the location of the markings on both the ground and on the resource map.

2. Environmental Education Plan

The utility shall prepare and have approved in final form by the CPUC staff an Environmental Education Plan (EEP). The EEP is intended to serve as a practical guide for use by field personnel as to the prior construction procedures that must be followed at every stage of construction. Thus, the EEP will contain general and specific provisions. The general provisons shall be the good environmental practices adopted for the project as a whole (e.g. no pets, fire avoidance, etc.). The specific provisions apply to identified portions of the project.

The EEP must be based on a series of maps showing the project and resource protection areas at a suitable scale and accuracy to allow both the construction supervisor and the EM in the field to unambiguously determine whether the environmental protection provisions of the plan are being followed. The maps in the EEP should be the final version of the map presented in the preconstruction survey, and it must be up-to-date. The first map will be an index map to the entire route. The map will show schematically the set of more detailed maps of those area of the route where sensitive resources are located. The detailed maps will be at the scale necessary to delineate the resources that must be given special protection.

3. Monitoring and Supervision

Upon approval of the EEP by the CPUC, the utility may commence construction providing that the monitoring and supervision procedures are followed. These procedures include that the construction supervisor must have a copy of the EEP on site, the EM must be on site during portions of construction most likely to damage a sensitive resource and if the markings of a sensitive resource change, the change must be approved by the EM and the change marked on the relevant maps. After all construction is complete, the EM and construction supervisor shall inspect the site and asses the level of damage to the resources, if any.

4. Enforcement

The EM is the primary means of inspecting and documenting the utility's compliance with the Commission's environmental protection requirements. In addition, the CPUC must establish the appropriate chain of authority to enforce sanctions in the event of violations of the monitoring program.

5. Restoration Plan

If the EM believes that there is a deficiency in the utility construction process or in the success of a mitigation measure, s/he will notify the utility and the Commission of the deficiency and convene a meeting to determine the nature and extent of the deficiency and the remedial action to be taken.

C. Sanctions

The utility constructs and operates the pipeline under the authority of the CPUC. That authority is granted by a CPC&N which carries with it certain conditions to be fulfilled by the utility. In the proper administration of its statutory authority, the CPUC will take every step available to ensure that the conditions are carried out exactly. In the event that the CPUC finds sanctions for inadequate administration of environmental protection are necessary, it may either issue a stop-work order and or establish that portions of the project cost are ineligible for inclusion in the utility rate base.

D. Periodic and Final Reports on the Mitigation Monitoring Program

As specified in the EIR and Mitigation Monitoring Plan, the EM and construction teams will be required to submit reports to the CPUC to document ongoing success of the program and the degree to which the utility has demonstrated good faith in meeting the objectives of the program and fulfilling its individual measures. The CPUC should keep a permanent record of the mitigation program including the reports, meeting notes and any complaints made relating to the construction phase of the project.

E. Mitigation Monitoring Plan

The mitigation monitoring plan is detailed and project specific. It includes the following: specific mitigation measures; the approvals required by the CPUC or its designee for certain measures; the timing for implementation of measures in relation to the construction schedule; the designation of specific staff who are responsible for monitoring and documenting the successful implementation of each measure, and as necessary, for developing and imposing remedial actions when a measure is not successful; the reporting requirements the utility or monitor must follow for each measure; and the standard of success against which the performance of the mitigation can be evaluated.

(END OF APPENDIX C)

List of Appearances

Applicant: Jo Shaffer, Attorney at Law, for Pacific Gas and Electric Company.

Protestants: Messrs. Skadden, Arps, Slate, Meagher & Flom, by Stephen F. McGregor, Douglas Nordlinger, and John S. L. Katz, Attorneys at Law, for Mojave Pipeline Company; and Messrs. Skaff & Anderson, by Andrew J. Skaff and Dwight C. Donovan, Attorneys at Law, for State of New Mexico, Energy Minerals & Natural Resources Department, and Mojave Pipeline Company.

Interested Parties: Messrs. Lindsay, Hart, Neil & Weigler, by Michael P. Alcantar, Attorney at Law, for Cogenerators of Southern California; C. Hayden Ames, Attorney at Law, for Chickering & Gregory; Beth Bowman, Barton M. Myerson, and Judy Anderson, Attorneys at Law, for San Diego Gas & Electric Company; Darrell Bolognesi, for S. H. Cowell Foundation; Del Borggard and Patrick J. Power, Attorney at Law, for Bonus Gas Processors; W. E. Cameron, for City of Glendale; Steven M. Cohn and Patrick J. Bittner, Attorneys at Law, for California Energy Commission; Mark Cook, Attorney at Law, for WyCal; Karen Edson, for KKE & Associates; Michel P. Florio and Joel R. Singer, Attorneys at Law, for Toward Utility Rate Normalization; Steven Harris, for Transwestern Pipeline Company; Messrs. Graham & James, by Martin A. Mattes, Peter W. Hanschen, and Richard L. Goldberg, and Messrs. Wright & Talisman, by Michael J. Thompson and Harold L. Talisman, Attorneys at Law, for Kern River Gas Transmission Company; Leamon W. Murphy, for Imperial Irrigation District; Messrs. Jones, Day, Reavis & Pogue, by Norman A. Pedersen, Attorney at Law, for Southern California Utility Power Pool; Robert L. Pettinato, for Los Angeles Department of Water & Power; David Plumb, for City of Pasadena; Patrick J. Power and Richard Alesso, Attorneys at Law, for City of Long Beach and City of Palo Alto; John B. Price, Attorney at Law, for Mobil Natural Gas, Inc.; David Schultz, for Pacific Gas Transmission Company; Ronald V. Stassi, for City of Burbank; Nancy Thompson, for Barakat, Howard & Chamberlin; Messrs. Morrison & Foerster, by Dhruv Khanna and James M. Tobin, Attorneys at Law, for Altamont Gas Transportation Project; Messrs. Arent, Fox, Kintner, Plotkin & Kahn, by Michael R. Waller and Anne W. Yates, Attorneys at Law, for Altamont Gas Transmission Project and Amoco Canada Petroleum Company, Limited; Greg H. Giesbrecht, for Natgas U.S., Inc.; Robert K. Weatherwax, for Sierra Energy and Risk Assessment, Inc.; Robert B. Weisenmiller, for Morse, Richard, Weisenmiller & Associates; Kevin Woodruff, for Henwood

APPENDIX D
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List of Appearances

Energy Services, Inc.; Phillip D. Endom, R. O. Baish, M. D. Ferguson, and Randolph L. Wu, Attorneys at Law, for El Paso Natural Gas; Rand Carroll, Attorney at Law, for State of New Mexico; BP Resources Canada Limited, by Frank C. Basham, for BP Resources Canada Limited; Tom Beach, for Alberta Petroleum Marketing Commission; Messrs. Brady & Berliner, by John W. Jimison, Attorney at Law, for Canadian Producer Group; Adrian J. Hudson, for California Gas Producers Association; Brian Sway, for Capitol Oil Company; Recon Research Corporation, by Andrew Safir, for City of Palo Alto; Recon Research Corporation, by Ron Oeschler, for Westcoast Energy Company; Sheldon Reid, for North Canadian Oils Limited; Christopher Ellison, and Messrs. Greve, Clifford, Diepenbrock & Paras, by Matthew V. Brady, for Department of General Services; Nancy I. Day, David L. Huard, and Michael A. Cartelli, Attorneys at Law, for Southern California Gas Company; John M. Dunn, for Salmon Resources, Limited; Richard K. Durant, Frank J. Cooley, and Florence J. Pinigis, Attorneys at Law, for Southern California Edison Company; Tony O. Hemming, Attorney at Law, for Texaco Inc. and Texaco Producing Inc.; Luce, Forward, Hamilton & Scripps, by John W. Leslie, Attorney at Law, for Producer/Shipper Group (Suncor Inc., Pan Continental Oil, Ltd., North Canadian Marketing Inc., Canadian Hunter Exploration Ltd., BP Resources Canada Limited); Maurice Randall, for Pan Continental Oil, Ltd.; Randy Schultz, for Pacific Northwest Shipper Group; Ed M. Small, for Suncor, Inc.; Michael St. Clair, for American Hunter Exploration, Limited; c/o Senior Vice President Administration, University of California Office of the President, by Thomas A. Tribble, for Regents of the University of California; Timothy T. West, Attorney at Law, for BP Gas, Inc.; and Messrs. Armour, St. John, Wilcox, Goodin & Shlotz, by James D. Squeri and Barbara Snider, Attorneys at Law, for self.

Commission Advisory and Compliance Division: Anne W. Premo and Clyde Murley.

Division of Ratepayer Advocates: James S. Rood and Lionel B. Wilson, Attorneys at Law, and Grayson Grove.

(END OF APPENDIX D)