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Decision **88 12 030** DEC 9 1988

BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA

ORIGINAL

In the Matter of the Application of SOUTHERN CALIFORNIA EDISON COMPANY (U-338-E) for a certificate that the present and future public convenience and necessity require or will require the construction and operation by Applicant of a 500 kV transmission line between Palo Verde Switchyard and Devers Substation.

Application 85-12-012
(Filed February 26, 1986;
amended August 15, 1988)

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<u>James Scarff</u>, Attorney at Law, <u>Michael Burke</u>, <u>Burt Mattson</u>, and <u>Stuart Chaitkin</u>, for the Division of Ratepayer Advocates.

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APPENDIX E: Edison/DRA Agreement Re Certain Conditions on Agreement

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INTERIM OPINION

I. Decision Summary

This proceeding has been bifurcated into two phases. This order addresses the issues pertaining to Phase I of the proceeding.

By this order, we approve the application of Southern California Edison Company (SCE) for a certificate of public convenience and necessity (CPC&N) to construct Devers Palo Verde No. 2 (DPV2), a second 500 kilovolt (kV) transmission line between Palo Verde Switchyard and Devers Substation. The DPV2 project is certified for no earlier than a June 1, 1993 in-service date, subject to several conditions stipulated to by SCE and the Division of Ratepayer Advocates (DRA).

First, SCE is required to enhance near-term project benefits so that the impact on ratepayers during the 1993-1997 period will not be substantially different than under DRA's 1997 in-service date case. Second, the construction of DPV2 will be suspended if an SCE/SDG&E merger is still an active possibility as of January 1, 1990. Third, SCE is required to file by November 1, 1989 all transmission service contracts associated with this project. Finally, SCE is required to file detailed studies on wind-loading and the likelihood of simultaneous outages of Devers Palo Verde No. 1 (DPV1) and DPV2.

Our approval is subject to implementation of all mitigation measures described in the environmental documents, where applicable. Our decision also provides for a mitigation monitoring program and adopts a cost cap of $172,400,000 for SCE's share of project costs. This cap may be adjusted to reflect the actual costs of mitigation measures, SCE's final ownership share, and the actual line rating of DPV2.

II. Procedural History

In December 1985, SCE filed its original Application (A.) 85-12-012 requesting a CPC&N to construct DPV2. As originally proposed, DPV2 was scheduled for a June 1990 in-service date. The application was accepted for filing on February 26, 1986.[1]

Shortly thereafter, a protest was filed by San Diego Gas & Electric Company (SDG&E). SDG&E had responded to a solicitation for participation in the project. SDG&E had requested a share of the project's capacity, but did not receive one from SCE. Through this protest, SDG&E alleged anticompetitive behavior and sought an allocation by this Commission of 400 megawatts (MW) of capacity on the project. This protest was settled in July 1986 under an agreement whereby (1) SCE granted SDG&E an option for 100 MW of transmission service on the Devers-Palo Verde No. 1 line and (2) SCE and SDG&E agreed to an exchange of 200 MW of transmission capacity between SCE's Devers-Palo Verde system and SDG&E's Southwest Powerlink (SWPL). This agreement was made contingent upon construction of DPV2.[2]

In August 1986, SCE submitted a revised economic analysis of the DPV2 project. On October 9, 1986, the Public Staff Division (subsequently renamed Division of Ratepayer Advocates (DRA)) filed

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1 On January 2, 1986, the Executive Director notified SCE that the December, 1985 application tendered for filing was incomplete and would not be accepted for filing. SCE subsequently submitted additional information on January 27, 1986. The supplemented application then was accepted for filing on Febuary 26, 1986.

2 The settlement agreement between SCE and SDG&E occurred after Administrative Law Judge Wu denied an SCE motion to dismiss SDG&E's protest and ordered both utilities to submit showings on comparative need for capacity.

a motion to "suspend the clock."[3] DRA alleged that SCE's revisions amounted to a second base case requiring substantial new analysis by DRA. DRA also requested direct access to SCE's computer models.

In December 1986, SCE and DRA settled this dispute. A new procedural schedule was arranged, and an alternative way of validating SCE's computer models was adopted.

The Draft Environmental Impact Report (DEIR) was completed in March 1987. Public participation hearings were held to receive comments on the DEIR from March 24-26, 1987, in Riverside, Desert Hot Springs, and Blythe.

Evidentiary hearings began on May 11, 1987 and continued until May 14 when it was discovered that SCE's computer models had been run with inconsistent data inputs. This inconsistency resulted in an exaggeration of the calculated project benefit of economy power purchases in the Southwest. DRA then moved for dismissal of the application. SCE opposed this motion and suggested that a two-month delay in the proceeding schedule would enable both SCE and DRA to correct the errors that had been discovered.

On June 5, 1986, an assigned commissioner ruling denied DRA's motion but ruled that SCE could not rely upon the alleged benefit of economy power from the Southwest as a justification for the project unless it filed a new application. SCE was given the option of proceeding with the current application using transmission service revenues and other benefits as justification for the project.

3 Under the Permit Streamlining Act an agency must issue a decision within certain time limits. Unless the "clock" was "suspended," the applicable time period could have run before DRA completed its analysis.

SCE elected to proceed with the original application without any reliance upon the alleged benefit of economy power purchases from the Southwest. SCE submitted additional testimony which for the first time quantified the value of benefits other than transmission service revenues and the now excluded benefit of economy power purchases.

The Final Environmental Impact Report (FEIR) was issued in August, 1987. Evidentiary hearings were held from September 14-17, 1987. Opening and closing briefs were submitted by October 15, 1987 for decision by the Commission at its December 9, 1987 meeting.

After submittal of the case, DRA discovered a letter of agreement between SCE and Los Angeles Department of Water and Power (LADWP) which confirmed the willingness of SCE and LADWP to exchange transmission capacity rights on the Pacific Intertie and the DPV2 transmission systems. In DRA's view, this agreement affected the cost effectiveness of the proposed DPV2 transmission line. DRA then filed a second petition to either dismiss SCE's application or, in the alternative, to set aside submission and reopen the proceeding.

DRA also filed in SCE's general rate case proceeding, A.86-12-047, a motion to set aside submission with respect to the high voltage DC terminal expansion project (DC Expansion). DRA also believed that the recently discovered SCE-LADWP letter agreement affected the cost effectiveness of the DC Expansion.

In response to these two motions, action on the Administrative Law Judge's (ALJ) proposed decision for A.85-12-012 was withheld pending resolution of the relevance of the SCE-LADWP agreement to the proposed DPV2. And in Decision (D.) 87-12-066 on SCE's general rate case, the Commission denied DRA's motion to set aside that proceeding, but ordered that further consideration of the cost effectiveness of the DC Expansion be given in SCE's application for DPV2.

On January 4, 1988, the ALJ for the DPV2 proceeding issued a ruling ordering SCE to submit any contemporaneous documentation supporting its claim of confidentiality for the SCE-LADWP letter agreement. The ruling also required SCE to file an accounting of all expenses incurred for DPV2, stating that "the Commission may consider a disallowance of regulatory expense incurred for work which was performed but is now useless due to the concealment of the 1985 letter agreement." SCE made this filing on February 3, 1988.

On February 23, 1988 a prehearing conference was held to address the consolidated DPV2 and the DC Expansion projects. SCE and DRA proposed to jointly conduct a preliminary study to determine if DPV2 could be cost effective, assuming an operating date later than June 1, 1990. Based on the results of this study, SCE would decide whether or not to supplement the application and move forward with DPV2, or not to proceed with DPV2 at all.

On March 4, 1988, LADWP forwarded to SCE an executed copy of the Exchange Agreement and Supplemental Letter Agreement for the Dismissal of the Suppliers' Litigation (Exchange Agreement). The Exchange Agreement was executed on December 18, 1987, and made effective as of July 29, 1988. An overview of the terms of the Exchange Agreement is presented in Figure 2 (see Section VI.A).

On May 24, 1988, a second prehearing conference was held. At that time SCE announced that, based on the preliminary results of the SCE/DRA joint study, it planned to file an amended application for DPV2 on August 8, 1988. In addition, DRA and SCE presented a joint proposal for a two-phase approach to the proceeding. Phase I would address the amended DPV2 application, including consideration of certain aspects of the Exchange Agreement. Phase II would address the cost-effectiveness of the DC Expansion Project, including applicable aspects of the Exchange Agreement. The prudence of the Exchange Agreement would be addressed partially in Phase I and in Phase II. This two phase approach was adopted by the ALJ.

SCE's Amended Application and Amended Proponent's Environmental Impact Assessment (PEA) were filed on August 15, 1988. DRA filed its prepared testimony on September 12, 1988. Evidentiary hearings on Phase 1 issues were held on September 22 and 23, 1988. The Addendum to the FEIR (FEIR Addendum) was filed on September 23, 1988 and entered into the record as Exhibit 30.

ALJ Gottstein presided at the September 1988 hearings. James Kahle and Gary Schoonyan appeared as witnesses on behalf of SCE. DRA stipulated to introducing into evidence the testimony of the remaining SCE witnesses. Michael Burke, Robert Weatherwax, and Karen Shea appeared as witnesses for DRA. No other parties participated in either direct or cross examination during the September 1988 hearings. DRA and SCE filed concurrent briefs on October 12, 1988. Comments on the ALJ proposed decision were filed by DRA and SCE. We have considered them carefully, and have made changes where appropriate.

III. Project Description

There are already a number of high-voltage transmission lines running from southern California to the Southwest (see Figure 1). These include the following lines:

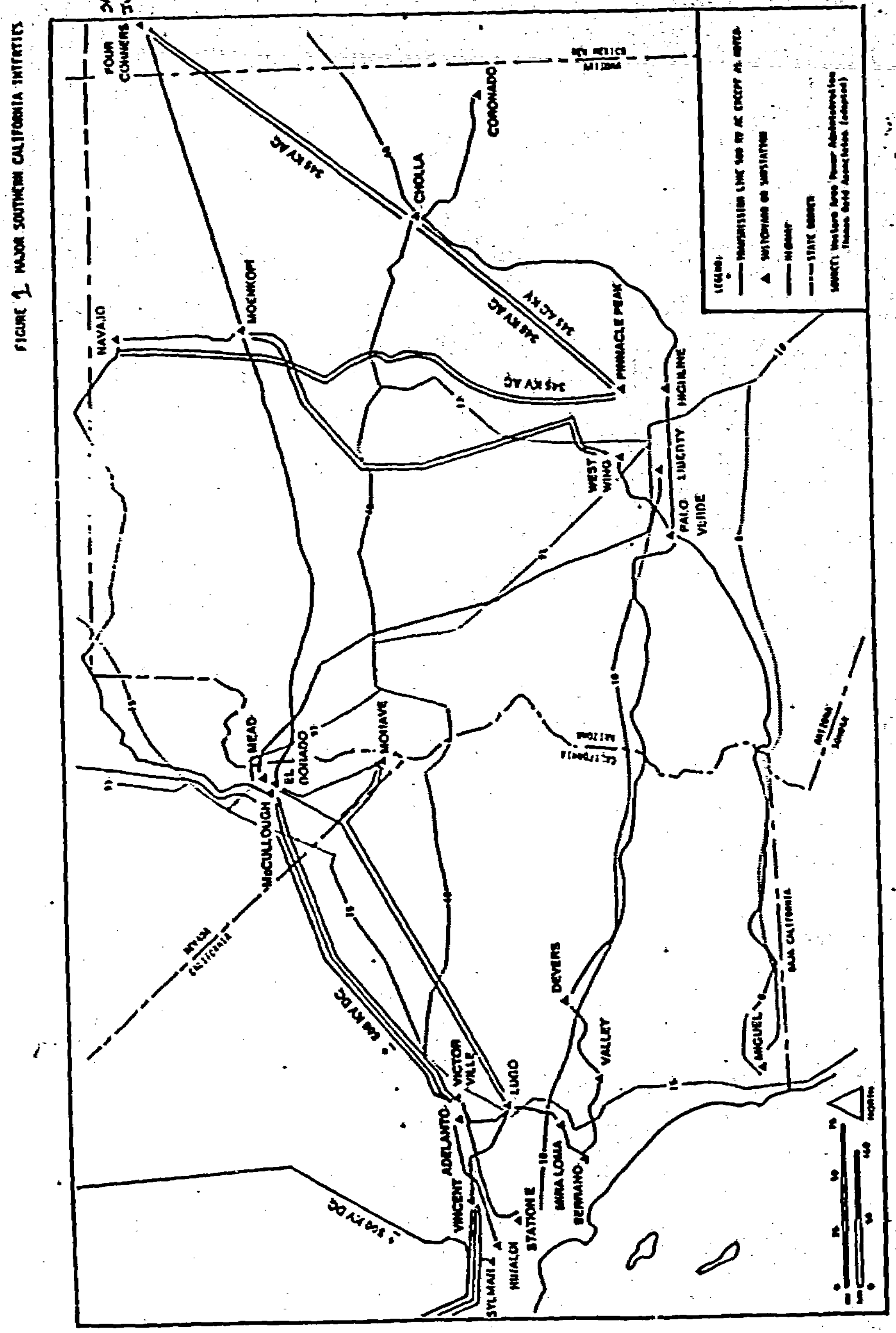
TABLE 1

Existing Transmission Lines from the Southwest
(from Exh. 15, Table III-6, p. III-28);
SCE DR #267; Tr. at 438.

	Size (kV)	Entitlements (MW) All Users*	Entitlements (MW) SCE
Devers - Palo Verde #1 (DPV1)	500	1309	1309
Moenkopi - El Dorado	500	1330	1330
Southwest PowerLink (SWPL) (Palo Verde - Miguel)	500	1181	0
Liberty - Mead	345	450	0
Navajo - El Dorado	500	1330	0
Total		5600	2639

* Maximum ratings of the lines.

Figure 1. Existing California High Voltage Transmission lines from the Southwest. (from Exh. 6-B at 10)



In 1979, SCE was granted a CPC&N to construct DPV1, a 500 kV AC transmission line from the Palo Verde Nuclear Generating Stations in Arizona (approximately 50 miles west of Phoenix) to SCE's Devers substation approximately 10 miles northwest of Palm Springs, California.[4] The main purpose of DPV1 was to bring SCE's share of its 579 MW firm capacity of the Palo Verde plant and its 350 MW entitlement in the Cholla #4 generating plant to SCE's service area. The extra capacity on the line has been used to bring in economy energy from the Southwest.

SCE proposes to build DPV2, a second 500 kV line parallel to DPV1 on a common transmission corridor. In its amended application, SCE requests authorization for an in-service date of June 1, 1993. DPV2 is expected to provide 1200 MW of transmission capacity from the Palo Verde switchyard to the Devers substation. A detailed description of project location is presented in Appendix A. To accommodate the full capacity of the new line, even in case of an outage, SCE further proposes to make certain improvements to the Palo Verde Switchyard and Devers substation.[5] The primary project objective is to provide additional transmission capacity to SCE and other project participants. Secondary objectives include increased access to economy energy from either

4 D.90552 (issued July 17, 1979), as modified by D.91421 (issued March 18, 1980) and D.92302 (issued October 8, 1980). The Moenkopi-El Dorado line was built in 1969, and did not require certification by this Commission. SCE and Arizona Public Service (APS) share ownership of the line. SCE has 100% entitlement to the line under financial arrangements with APS.

5 The improvements include adding 500 kV circuit breakers, disconnect switches, shunt reactors, and series compensation banks at or between the Palo Verde Switchyard and Devers Substation. In addition, a new 1000 MVA 500/200 kV transformer bank will be installed at the Devers Substation.

the Pacific Northwest (PNW) or the Southwest, and displacement of more costly oil and gas generation.[6]

Table 2 lists the participating utilities and their respective shares. Of the 1200 MW, SCE will own 758 MW, or approximately 63%. From SCE's ownership share, 100 MW of firm transmission service (T/S) will be provided to LADWP and 150 MW will be provided to Modesto-Santa Clara-Redding Public Power Agency (MSR).

LADWP and nine other members of the Southern California Public Power Authority (SCPPA) will own the remaining 442 MW of project capacity (See Table 2). The SCPPA participants have 442 MW of firm entitlements in the Palo Verde Generation Station in Arizona, and MSR has a firm entitlement of 150 MW in Unit 4 of the San Juan Generating Station located in New Mexico. Both SCPPA and MSR will use DPV2 to deliver power from those generating sources to their systems in California. Each project participant would require firm power transmission services West of Devers (WOD) in order to gain access to their share of DPV2.

IV. Project Costs

Total project capital costs are estimated at $260 million in dollars escalated to the date of expenditure. This figure reflects the additional costs of improvements to the Palo Verde Switchyard and Devers Substation. SCE's share of the capital costs, subject to ratebasing, would be approximately $172 million

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6 Exhibit 6B, DEIR Vol. 2, page 1, as modified by Exhibit 30, Addendum to the FEIR, page 5.

TABLE 2

Devers-Palo Verde No. 2
Project Participants

	Utility	Participation Shares MW Own	MW T/S	% Own	% T/S
1.	SCE	758.00*		63.2*	
2.	LADWP	367.75	100.00	30.7	8.3
3.	M-S-R		150.00	0.0	12.5
4.	IMPERIAL IRRIG. DIST.	14.62		1.2	
5.	RIVERSIDE	12.15		1.0	
6.	VERNON	11.03		0.9	
7.	BURBANK	9.90		0.8	
8.	GLENDALE	9.90		0.8	
9.	PASADENA	9.90		0.8	
10.	AZUSA	2.25		0.2	
11.	BANNING	2.25		0.2	
12.	COLTON	2.25		0.2	
	Subtotal (Non-Edison)	442.00	250.00	36.8	20.8
	TOTAL	1,200.00		100.0%	

* Firm transmission service will be provided to LADWP (100 MW for 22 years) and M-S-R (150 MW) from Edison's ownership share. In addition, San Diego Gas & Electric has an option to receive 100 MW of firm transmission service on DPV#1 if the Project is built and certain other conditions are met.

Source: Exhibit 30, Addendum to the FEIR for the DPV2 Project, Table 1, page 6.

in 1993 dollars.[7] During the September 1988 hearings, DRA and SCE stipulated to this figure for SCE's estimated share of project costs (see Table 3). The net present value (NPV) of SCE's total cost of DPV2, including capital and operation and maintenance, is $175 million in 1990 dollars.

V. Changes Reflected in the Amended Application

As described in Section II above, SCE's original application was accepted for filing on February 26, 1986. An amended application was filed on August 15, 1988. A number of significant changes were reflected in the amended application, and are summarized below:

- Deferral of In-Service Date for Three Years. In its initial application, SCE proposed an in-service date of June 1990. In its amended application, SCE adopted DRA's recommendation that the in-service date be deferred until June 1, 1993.

- Incorporation of the Exchange Agreement. Unlike SCE's previous filings, the amended application incorporates the effects of the Exchange Agreement on the ownership structure and economics of DPV2 (see Section VI.A.).

- Restructuring of Ownership. The original application stated that SCE would own "up to" 85% of the project. SCE now projects an ownership share of 758 MW (63.2%). LADWP's ownership share increases from 151 MW to 368 MW, and the other SCPPA cities with interest in DPV2 acquire ownership interest.

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7 The $172 million figure assumes SCE's ownership share of 63.17% (or 758 MW) of DPV2, including substation facilities. SCE will assume 100% of the project's right-of-way expenses, and 100% of the costs of the additional transformer bank required at Devers substation.

TABLE 3

Summary of Estimated Construction Costs
(in 1993 dollars)

✓

Elements	Total Element Costs ($000)
Transmission Line Element Costs	
500 kV Transmission Line Element in CA	$102,908
500 kV Transmission Line Element in AZ	88,888
Subtotal	191,796
Adjustment	9,450 *
Adjusted Subtotal	201,246
Substation Element Costs	
Devers Substation - 500 kV	10,776
Palo Verde Switchyard - 500 kV	12,468
Devers Substation - 220 kV	17,653
Subtotal	40,897
Series Capacitor Element Costs	
East Series Capacitor	8,415
West Series Capacitor	10,139
Subtotal	18,554
Total Project Costs	251,247
Adjustment	9,450 *
Adjusted Total Project Costs	260,697
SCE's share (stipulated)	$172 million *

* The "adjustments" to total costs reflect DRA's conclusions that SCE's estimated costs were understated by about $9.5 million. This difference was due to a substantial understatement of aluminum costs which were partly compensated for by an overstatement of steel costs. As noted on page D-1 of their Amended Application (August 1988), SCE has agreed with these revised project cost estimates.

Source: Exhibit 30, Addendum to the FEIR, page 4.

- <u>Reduction in West of Devers Construction Costs</u>. As originally proposed, the cost of building DPV2 included $31.1 million for system upgrades west of Devers (WOD) substation. As a result of a detailed re-evaluation of the thermal capability of the transmission system WOD substation, SCE determined that it would not be necessary to bundle the transmission lines west of the Devers Substation. This reduced project costs by $13.5 million.

- <u>"Bridging" LADWP on DPV1 Until 1993</u>. The original plan to build DPV2 would have provided LADWP with 368 MW of transmission capacity as of June 1, 1990. In SCE's amended application, DPV1 is used to provide LADWP with this capacity from June 1, 1990 until the now proposed in-service date.

- <u>Changes in Quantification of Benefits</u>. In SCE's amended application, new or refined methodologies were used to analyze project benefits. These were based primarily on the joint study efforts undertaken by DRA and SCE in preparation for Phase 1 evidentiary hearings.[8]

VI. <u>Economic Analysis of Project Alternatives</u>

As described in SCE's amended application, DPV2 is not proposed to meet the needs of SCE for any firm capacity it has, or will acquire in the future in the Southwest. Rather, primary project benefits will be from transmission service revenues and

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8 See <u>Concurrent Brief of DRA</u>, page 9a, Table 2, for a comparison of the benefits claimed in SCE's 1987 testimony and in its Amended Application.

increased access to economy energy.[9] In addition, SCE claims that DPV2 will significantly reduce transmission losses, improve utility interconnection support (UIS), enhance transmission stability, and improve air quality.

A. The SCE/LADWP Exchange Agreement

The SCE/LADWP Exchange Agreement, which was discovered after submittal of this case in late 1987, changed several of the factors originally considered in the economic analysis of DPV2. The Exchange Agreement provides for a swap of AC and DC Pacific Intertie capacity to the PNW, which provides SCE with a net increase of 180 MW of Intertie capacity. SCE also obtains the use of 200 MW of LADWP's Castaic Pumped Storage plant (Castaic) for operations. LADWP obtains the use of SCE's transmission facilities, with certain service charges waived. In addition, The Exchange Agreement settles a lawsuit between SCE and LADWP (the "Suppliers Contract" litigation).[10] A summary of the Exchange

9 "Economy energy" refers to power imported on a non-firm basis from outside the region. As described in greater detail in Appendix B, SCE's access to attractively priced economy energy from the Southwest actually decreases (until 2005) with the construction of DPV2. All the benefits attributable to increased economy energy are derived from the access to additional PNW purchases, made possible by the Exchange Agreement "swap" of Intertie access capacity.

10 The Suppliers' Contract was an agreement between SCE, LADWP, PG&E, SDG&E, and the California Department of Water Resources (CDWR), dated November 18, 1966, for the sale, exchange, and transmission of electricity to operate State Water Project Pumping Plants.

Agreement is presented in Figure 2. An overview of the provisions considered in the Phase I analysis is presented in Figure 3.[11]

B. SCE/DRA Joint Study Arrangements

SCE and DRA initially performed independent economic analyses of project alternatives.[12] Starting in February of 1988, SCE and DRA began a joint study process to develop common assumptions and methodologies for evaluating DPV2 that would be acceptable to both parties. As part of this process, SCE and DRA jointly developed new methodologies or refined existing ones to analyze the project benefits associated with the DPV2 alternatives, including the effects of applicable provisions of the Exchange Agreement. As explained in DRA's prepared testimony, SCE took the lead in the assessment of stability and loss reduction benefits and estimation of transmission revenues. DRA, and its consultant Sierra Energy and Risk Assessment, Inc. (SERA), took the lead in production cost modeling, air quality assessment, and in refining the alternative cases and sensitivity analyses. For UIS, both parties discussed methodological issues, but ultimately both employed different methodologies.

During the joint study process, SCE and DRA agreed upon the use of common assumptions and methodologies for the base case analysis of DPV2 and alternatives.

11 The provisions that will be considered in Phase II analysis of the DC Expansion are: Use of 200 MW of Castaic as pumped storage; 220 MW of firm PNW transmission access (in lieu of non-firm access) and the value of the Suppliers' Contract litigation settlement. For a discussion of the rationale for allocating 180 MW of PNW non-firm transmission capacity to the DPV2 project, see Tr. at 843-846.

12 Since the earlier testimony and analysis presented by DRA and SCE were essentially "superceded" by the joint study analysis, we do not describe them in this order. DRA's Concurrent Brief provides a useful overview of the changes made in methodologies since the outset of this proceeding.

EDISON/LADWP EXCHANGE AGREEMENT OVERVIEW

Edison Obtains

Pacific Intertie
- 500 mW DC

Castaic Pumped Storage
- 200 mW use
- LADWP's best efforts for additional

Suppliers' Contract
- Settlement

LADWP Obtains

Pacific Intertie
- 320 mW AC

DPV#2 Project
- 217 mW T/S converted to ownership
- 100 mW T/S
- Right to Build

Devers-Sylmar
- 468 mW T/S

FIGURE 2

EDISON/LADWP EXCHANGE AGREEMENT PROVISIONS APPLICABLE TO THE DEVERS-PALO VERDE NO. 2 T/L PROJECT ANALYSIS

Use of 200 mW of LADWP's Castaic Pumped Storage capacity towards meeting Edison's spinning reserve

An additional 180 mW of non-firm Northwest transmission access,

LADWP's receiving a 217 mW ownership allocation in DPV#2 in lieu of firm transmission service from Edison,

LADWP's receiving 368 mW of "bridging" transmission service on DPV#1 from June 1, 1990 until DPV#2 goes into operation,

Waiver of transmission service charges for LADWP's 368 mW of firm service from Devers to Sylmar/Victorville for 22 years,

Waiver of transmission service charges for LADWP's 100 mW of firm service from Palo Verde to Sylmar/Victorville for 22 years.

FIGURE 3

3/6/88

Summaries of these assumptions and methodologies are presented in Appendix B. The overall results and conclusions presented by SCE and DRA during the Phase I hearings were very similar. Both conclude that DPV2, coming on-line in 1993, will yield over $300 million in net benefits (in net present value, 1990 dollars) to SCE's ratepayers.[13] However, the absolute magnitude of net benefits differed between the two analyses, primarily due to the different assessments of UIS benefits and modeling corrections that were made by SERA subsequent to SCE's submittal.[14] In addition, DRA evaluated the project's overall cost-effectiveness relative to the alternatives of deferring the project until 1995 or 1997. DRA also performed several sensitivity analyses to test the robustness of its base case results.

During the September 1988 hearings, SCE stipulated to the economic analysis performed by DRA. Hence we will focus our discussion on those results.

C. Project Alternatives

During the course of this proceeding, DRA and SCE evaluated the economic, environmental, and technical impacts of a wide range of project alternatives. The full range of alternatives

13 At the outset of this proceeding, DRA's position was that the proposed project was not cost-effective. In its September 1988 filing, DRA identifies the following factors which caused the change in its position: (1) the existence of the SCE/LADWP Exchange Agreement; (2) the delay of construction from 1990 until at least 1993 coupled with the reduced construction costs WOD and use of existing surplus transmission capacity as a "bridge"; (3) refinement and updating of the production cost benefits; and (4) developing and applying new methodologies to quantify previously unquantified strategic benefits. See Exhibit 32, Table 2-1, page 2-4 for a summary of the estimated impact of these changes on DRA's analysis.

14 See Appendix B, Table B-1 for a comparison of DRA's and SCE's base case results.

is described in Appendix C. DRA and SCE chose to focus their updated economic analysis on a limited series of alternatives, almost all of which featured providing LADWP with transmission service on DPV1 for some amount of time. These altenatives were:

1. "No Project"--Reference Case A, which consists only of a swap between SCE and LADWP of 320 MW of Pacific Intertie access.[15] LADWP and other SCCPA participants continue using current transmission arrangements for getting Palo Verde power. MSR has no ability to secure its firm entitlement to San Juan 4.

2. "Infinite Bridge"--Case B: Never building the line, while permitting LADWP to start operating on DPV1 in 1990.[16] The full 500/320 MW swap with LADWP is included. It has no associated revenue requirement.

3. "Expanded Infinite Bridge"--Case C: Never building the line, expanding the capacity of DPV1 and SWPL by 100 MW each in 1993, and from then on providing transmission service on DPV1 not only to LADWP but to MSR and other SCCPA also. The full 500/320 MW swap with LADWP is included. It has a revenue requirement based on SCE's

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15 As summarized in Figure 1, the full SCE/LADWP Exchange Agreement provides SCE with 500 MW of DC Intertie access (320 MW firm and 180 MW of assumed non-firm). SCE in return provides LADWP with 320 MW of AC Intertie access (100 firm and 220 non-firm). For the Reference Case A, DRA assumes that SCE effectively converts 220 MW of Intertie capacity from non-firm to firm.

16 SCE has contracts for the purchase of 350 MW from Cholla plant in Eastern Arizona and 250 MW from the Navaho plant in northern Arizona. (See Figure 1 for locations.) The power from these facilities is carried over SCE's existing systems (DPV1 and Moenkopi-El Dorado, respectively). Between 1986 and the in-service date of DPV2 both contracts terminate. Because of SCE's near-term excess capacity, the utility has not renewed these contracts. The Infinite Bridge scenario assumed that SCE uses the capacity freed up by the termination of these two contracts to wheel LADWP's power.

share of the required series compensation.[17]

4. "Build DPV2"—Cases W(93, 95, 97): In the W(93) Case, DPV2 comes on-line in June, 1993. In the W(95) and W(97) Cases, DPV2 is deferred until 1995 and 1997, respectively. LADWP is on DPV1 starting in 1990. Upon completion of DPV2, LADWP, other SCPPA and MSR all use it.[18] SDG&E gets 100 MW on DPV1 starting January 1995 (or 1997 depending on the DPV2 on-line date). The full 500/320 MW swap is included.

Figure 4 summarizes the major assumptions for each of these cases with regard to the intertie swap, T/S provisions, and use of Castaic for spinning reserves.

D. Summary of Base Case Results

The base case results of DRA's economic analysis are summarized in Table 4 and depicted in Figure 5.[19] As shown in Table 4, all the W Cases ("build DPV2") yield net savings to SCE ratepayers of over $360 million in NPV when compared to the Reference Case A. Building DPV2 with a 1993 in-service date has a

17 In lay terms, increasing series compensation allows a utility to "pack" more energy into a transmission line, similar to increasing the pressure of a water pipe. However, as you add series compensation to high-voltage transmission lines, a phenomenon known as subsynchronous resonance (SSR) occurs where the harmonic frequencies of the transmission system "beat" against the mechanical frequencies of the turbine shafts. This can cause serious mechanical failures at generating stations, unless corrective measures are taken. SSR mitigation devices are included in the cost of the Expanded Infinite alternative.

18 Instead of paying SCE for transmission service on DPV2 (as in Cases B and C), most of the project participants gain access to Southwest power via their ownership interest.

19 We use the term "base case" to distinguish these results from the various sensitivity cases conducted by DRA.

FIGURE 4

Summary of Alternative Cases

Cases	PNW Intertie Access Swap*	Additional T/S Provided on DPV1/DPV2	Castaic Avail. for Spinning
"Reference" A	320/320	0	No
"Infinite Bridge" B	500/320	• Only LADWP on DPV1: • 368 MW paid T/S; • 100 MW free T/S (22 yrs.) • All WOD T/S free	Yes
"Expanded Infinite Bridge" C	500/320	• Same as Case B for LADWP; • MSR and other SCPPA added to expanded DPV1 in 1993. • 72 MW paid T/S (SCPPA) • 150 MW paid T/S (MSR) • WOD T/S paid (SCPPA/MSR)	Yes

* Under the 500/320 swap, it is assumed that the Exhange Agreement results in 180 MW of additional transmission capacity (for non-firm purchases) to the Pacific Northwest (PNW).

(Continued)

FIGURE 4

Summary of Alternative Cases
(Continued)

Cases	PNW Intertie Access Swap	Additional T/S Provided on DPV1/DPV2	Castaic Avail. for Spinning
"Build DPV2" W(93)	500/320	• Case B until line is built (LADWP on DPV1) • All participants on DPV2 after 1993** • 150 MW paid T/S Palo Verde to Midway (MSR) • 100 MW paid T/S after June 1995 Palo Verde to SONGS (SDG&E) • WOD T/S paid (SCPPA)	Yes
W(95)	500/320	Case W(93) postponed until 1995	Yes
W(97)	500/320	Case W(93) postponed until 1997	Yes

** LADWP's 368 MW of paid T/S, MSR's 150 MW of paid T/S, and the other SCPPA participants 72 MW of paid T/S became "ownership shares" under the W Cases.

TABLE 4

DRA's Base Case Analysis of DPV2 Alternatives

(NPV in Millions 1990$)

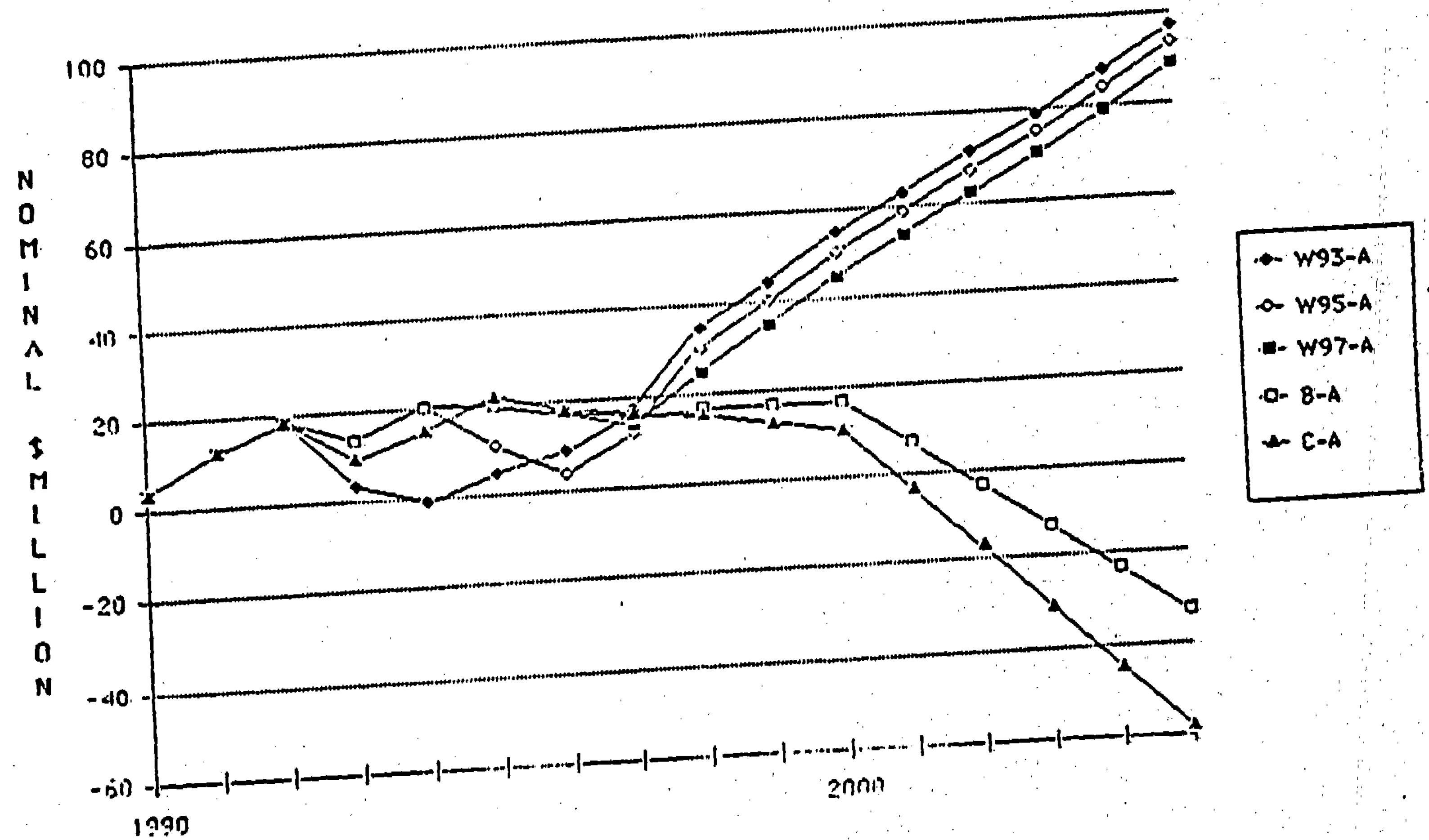
	Case W(93)-A	Case W(95)-A	Case W(97)-A	Case B-A	Case C-A
Costs	175	154	135	0	15
Benefits					
Production Cost Benefits*	239	227	216	<100>	<255>
Transmission Service Revenues	121	123	117	84	160
Reduced Transmission Line Losses	101	98	95	38	56
Stability Benefits	16	15	13	0	0
Utility Interconnection Support	62	61	60	0	7
TOTAL BENEFIT	540	524	501	122	<32>
NET SAVINGS	364	370	366	22	<47>
B/C Ratios	2.08	2.40	2.71	-	-

* Production cost benefits reflect the changes associated with (1) PNW economy energy, (2) 200 MW of Castaic available as spinning reserve, (3) QF payments, (4) NOx emissions, and (5) SW economy energy.

Source: Exhibit 36

Figure 5

NET BENEFITS



slightly lower NPV than building later. The Infinite Bridge alternative (Case B) yields net savings of $22 million. The Expanded Bridge alternative (Case C) leaves the ratepayer actually worse off (by $47 million) than the "do nothing" Reference Case.[20]

Figure 5 displays the annual benefit stream for all cases. The options diverge significantly in the late 1990's as the combination of capacity value and increased gas costs tend to make the DPV2 build cases substantially more attractive, in spite of their required capital costs.[21]

As illustrated in Figure 6, deferring DPV2 until 1997 (the W(97) Case) yields the optimal level of net benefits among the build DPV2 alternatives in the mid-1990's. DRA estimates a difference in net benefits between the W(97) and W(93) Cases of approximately $34 million in NPV (or $55 million in current year dollars) during the 1993-1997 period. This is illustrated by the shaded portion of Figure 6. This comparison is the basis for DRA's "benefit enhancement" condition to granting SCE's request for a 1993 in-service date (see Section VIII below).

E. Sensitivity Analyses

DRA performed several sensitivity cases to evaluate the effect of select assumptions on the benefits of the line, including:

1. Highest Block Pricing Of Economy Energy

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20 Production costs benefits for Cases B and C are actually negative (in NPV) in DRA's analysis, as shown in Table 4. The use of existing line space results in "foregone" Southwest economy energy benefits, relative to the Reference Case. These negative net benefits more than offset the benefits of increased PNW economy energy purchases resulting from the Exchange Agreement. Case C is more negative because it is the case in which the most surplus SCE line space is used to provide T/S to others.

21 See Appendix B for a description of how the production cost benefits, loss reduction benefits and UIS depend upon these factors.

TABLE 5

Comparison of DPV2 Sensitivity Analyses

(NPV in Millions 1990$)

	Base Case	Sensitivity Cases (1)	(2)	(3)	(4)
W(93)	364	306*	126	302	306
W(95)	370	N/R	143	305	N/R
W(97)	366	N/R	150	306	N/R
B	22	N/R	122	22	158
C	-47	N/R	208	-54	136

Legend:

(1) No Castaic

(2) No Production Cost Benefits

(3) No UIS

(4) Highest Block Pricing of Economy Energy

N/R: Not run.

NOTE: DRA also ran the W(93) Case with a 10 percent discount factor (instead of 12), but the resulting change in NPV was not presented in testimony. However, as stated on Page 8-15 of Exhibit 36, the general effect of a lower discount rate would be to substantially increase the benefits of the alternatives that include the line. DRA also evaluated the effect of a lower fuel escalation rate after 2005 (4.1% instead of 7%) and concluded that the change would have only a minor effect on the results (page 8-14, Exhibit 32).

* Estimated based on savings for "A" case with and without Castaic.

2. No Production Cost Benefits

3. No UIS Benefits

4. No Castaic After 1992

As summarized in Table 5, the relative magnitude of net benefits among "build" and "no build" cases is most dramatically affected under alternative economy energy pricing assumptions and, as a limiting case, under a scenario where no production cost benefits are assumed.[22]

In DRA's base case analysis, economy energy prices were based on the production costs of the PNW and Southwest resources generating the energy surplus. Each block of economy energy was priced successively higher to reflect the increasing production costs of the region. In contrast, under Sensitivity Case (1), economy energy is priced at the most expensive energy taken for a particular hour.[23] This translates into average prices of about 75% to 93% of SCE's marginal cost based on the tier 2 gas price, depending on the system heat rate.[24]

Under Sensitivity Case (1), the net benefits of Cases B and C increase by $135 million and $180 million, respectively,

22 DRA/SERA also assessed the impact of the following changes on production cost benefits for the W(93) Case: (1) no gas curtailment; (2) absence of Rancho Seco; (3) alternative out-of-state coal cost assumptions; and (4) individual PNW hydro case evaluation. The base case analysis of W(93) Case was relatively insensitive to changes (1) and (4). The line became slightly more attractive under change (2). It became less attractive under change (3) but within the range of sensitivities illustrated in Table 5.

23 For example, if during the duration of one hour, the base case runs show SCE taking energy priced at blocks 1, 2 and 3, the sensitivity analysis would calculate production costs based on SCE economy energy takes priced at block 3.

24 See Exhibit 36, page 5.

relative to DRA's base case analysis. While this significantly reduces the differences among alternatives, the build cases still yield the highest net benefits (over $300 million).

Sensitivity Case (2), No Production Savings, excludes all benefits from having Castaic available and assumes that there are no increased economy energy purchases to offset production costs, to reduce avoided cost payments to qualifying facilities, or to reduce NO_x emissions. As illustrated in Table 5, under this scenario all the build cases still yield net benefits of over $125 million. However, Case C becomes more attractive than any of the build alternatives with net benefits of $208 million.

In DRA's view, the results of its sensitivity analyses demonstrate the robustness of the joint study conclusions since, under all sensitivity cases, building DPV2 remains cost-effective. The relative ranking of the "no project" and "build" alternatives change only under one sensitivity case, which witness Weatherwax characterizes as a "stylized extreme case."[25] DRA concludes that, "even if economy issues were so severe as to eliminate all production cost benefits, building the line would still be a viable option in the context now proposed by the Applicant."[26]

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25 At the evidentiary hearings, Witness Weatherwax characterized Sensitivity Case (2) in this manner, pointing out that the analysis did not take account of improvements in stability or decreases in line losses that would occur as economy energy transfers are reduced or eliminated (Tr. Vol 10., p. 830).

26 Exhibit 32, p. 2-8.

F. Methodological Issues that <u>Merit Further Attention</u>

During the Phase I evidentiary hearings, SCE and DRA identified the following analytical issues that merit further attention in future proceedings:[27]

1. <u>Integration of Methodologies for Calculating the Individual Benefit Components</u>. Greater consistency is needed in accounting for the relationship between "line loading" assumptions for production cost benefits, reduced line losses and stability benefits (DRA/SCE Brief).

2. <u>Quantification of UIS Benefits</u>

    a. The appropriate base amount of UIS needs to be reevaluated (DRA Brief; Tr. at 754-756, Tr. at 865).

    b. Quantification of operational and planning benefits need to be refined, including:

        (1) Review and update the resource assumptions used in SERA's "shadow pricing" methodology. (SCE Brief, Tr. at 860-864.)

        (2) Examine further the "operating" value of UIS relative to combustion turbines (Tr. at 858-860).

        (3) Evaluate SERA's approach using an Expected Unserved Energy measure of value (SCE Brief).

        (4) Consider whether or not the planning benefits for one utility

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27 To identify the source: "DRA, Brief" refers to pages 63-66 of the <u>Concurrent Brief of DRA</u>. "SCE, Brief" refers to pages 49-54 of <u>Applicant's Concurrent Brief</u>. Transcript and Exhibit references are also given where appropriate.

are at all appropriate for another utility (Tr. at 865).

c. The effect of changing use of the transmission system over time (and what is available for UIS) should be incorporated into the analysis (SCE/DRA Brief).

d. If UIS is claimed as a benefit of new transmission lines, this additional UIS should be reflected back in the calculation of a utility's ERI for valuing new capacity purchases. (DRA Brief, pp. 27-28.)

3. Economy Energy Benefits

a. Refinement of SCE's Pacific Northwest Model is needed to replace "block pricing" with a continuous supply curve of available economy energy (DRA/SCE Brief, Tr. at 868-871).

b. Pricing at the highest cost block of economy energy needs to be enhanced in situations where that cost is significantly lower than the California utility's marginal costs (SCE Brief).

4. Air Quality Benefits

a. The assumption that NO_x reduction savings are constant (unescalated) needs to be reexamined (DRA Brief, Tr. at 866).

b. An alternate approach that assigns a dispatch penalty for gas-fired units should be considered (SCE Brief).

5. Value of Reduced Losses

a. The method of measuring average line losses (i.e., by extrapolating peak line losses) needs to be revisited; (DRA Brief; Tr. at 809-810, 866).

b. The dynamic relationship between line losses and production cost benefits needs to be incorporated into the analysis (DRA, SCE, Brief).

6. Value of Stability

a. Changes in N-2 risks need to be accounted for (DRA/SCE Brief, Tr. at 851-853).

b. The inverse relationship between line usage level and stability benefits needs to be incorporated/coordinated among scenarios (DRA/SCE Brief; Tr. at 813-814, 864, 865).

c. The issue of how to credit stability benefits to an individual utility (and its ratepayers) needs to be examined (Exhibit 32, p. 2-22).

7. Appropriate Discount Rate. The assumption that the cost of capital (rather than a net after-tax) discount rate should be reconsidered (DRA, Tr. at 867).

VII. Environmental Considerations

The environmental impacts of the proposed project and alternatives were evaluated in the Draft and Final Environmental Impact Report (EIR), submitted prior to SCE's filing of its amended application.[28] DRA reviewed SCE's amended application and PEA, and concluded that these documents contain only minor changes in the environmental effects of the project and its environmetal context. Specifically, the amended application and PEA reflect no

28 The Draft and Final EIR for this project was prepared by two consulting firms under the direction of DRA: Western Ecological Services Company, Inc. (WESCO, Volume 1) and Sierra Energy and Risk Assessment (SERA) with R.W. Beck and Associates and Thomas Reid Associates (Volume 2). (See Exhibits 6A, 6B, 6C). The Addendum to the Final EIR was prepared by DRA staff (Exhibit 30). The environmental review addressed the impacts of the California portion of the line.

significant changes from the initial application and PEA in the following areas:

- The expected environmental impacts of construction and operation of DPV2;
- The environmental context of DPV2;
- The list of alternatives to DPV2, or
- The expected environmental impacts associated with those alternatives.

Accordingly, DRA issued an Addendum to the FEIR (Exhibit 30) which describes changes in the Project's Purpose and Need and Alternatives sections from those that appear in the DEIR, as amended in the Final EIR.

A. Impacts of the Proposed Project

The environmental impacts associated with the project result from the proposed construction and operation of a new high-voltage transmission line. The EIR analysis concludes that the proposed project will have potentially significant effects in the areas of geology, soils and hydrology, biological resources, land use and planning, visual, acoustic and Native American cultural resources.[29] Numerous mitigation measures were identified during the environmental review.[30]

In its brief, SCE argues that the measures recommended in the EIR mitigate most of the environmental impacts, and that the remaining impact in the Blythe area is reduced to a minimal level. SCE recommends that the Commission find that the unmitigated environmental impacts of the project are insignificant.

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29 Exhibit 6C (FEIR), Appendix, pages 9-10.

30 Appendix D provides a list of references for the specific mitigation measures presented in the EIR documents.

DRA, on the other hand, concludes that there remain significant environmental impacts after mitigation. DRA identifies the following impacts as those that cannot be mitigated to the point where they are insignificant:

1. Crop-Dusters in the Blythe Area. The proposed line will cross about 10 miles of irrigated farmland near Blythe. This new line will disrupt agricultural activities in and near the right-of-way in several ways. Most importantly, it will significantly increase the danger to pilots of crop dusters.[31] DRA and consultants set forth proposed mitigation measures in this area to reduce the risk of pilots flying into the line or towers. However, even if these mitigation measures are taken, DRA believes that the remaining risk to crop dusters still constitutes a significant impact.

2. Threatened & Endangered Plants and Wildlife. The proposed line would cross the habitat of several rare, threatened or endangered species. In cooperation with the Department of Fish and Game, DRA has proposed mitigation measures which would greatly reduce the impacts on these species. Nevertheless, DRA believes that there is a residual risk from human error in implementing those measures in the field. In accordance with California Environmental Quality Act (CEQA) Guidelines § 15091(a)(3), DRA recommends that the Commission find that further mitigation measures are infeasible.

B. Comparison Among Project Alternatives

DRA and SCE examined alternative transmission line corridors, alternative transmission lines, increasing the capacity of existing transmission lines, and alternatives that did not involve transmission lines. Each alternative was evaluated in

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31 The probable impacts are described in Exhibit 6A (pages 167-174) and Exhibit 6B (pages 37-39).

terms of its relative level of environmental impacts, cost-effectiveness, and technical/institutional factors. A description and comparison of each alternative is presented in Appendix C. Each of the alternatives with less environmental impacts than the proposed project is discussed below.

1. The "No-Project" Alternative

DRA considers the no-project alternative, because it involves no construction of additional transmission lines, to be clearly one of the environmentally preferred alternatives. As described in Section VI, the no-project alternative was reevaluated as "Reference Case A" during Phase I hearings, due to the major changes in economic context since the EIR was prepared. Under the no-project alternative, SCE would not provide transmission service to MSR, LADWP, or the other SCPPA coparticipants.[32] SCE would forego over $360 million worth of benefits to its ratepayers. DRA now believes that under most circumstances the no-project alternative cannot meet the project objectives.[33]

SCE argues that there is a significant negative regional impact associated with the no-project alternative. In SCE's view, the SCPPA participants and MSR would build either DPV2 or the proposed Phoenix-Mead-Adelanto DC project themselves, in order to have a long-term transmission path for their Palo Verde and San Juan entitlements. The latter would be three times as expensive,

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32 DRA states that the conclusions reached in the Draft EIR that the no-project alternative can meet all the project objectives are now anachronistic since the project objectives have changed both in substance and timing.

33 One important qualification to DRA's rejection of the no-project alternative is SCE's proposed merger with SDG&E. DRA argues that, if the merger occurs, then SCE's access to SWPL would allow the no-project alternative to meet all of SCE's objectives with essentially no environmental impact. This issue is discussed in Section VIII of this order.

twice as long, and have a significantly greater environmental impact than DPV2.

2. <u>The "Infinite Bridge" Alternative</u>

The Infinite Bridge scenario is similar to the no-project alternative except that SCE uses its existing system to wheel LADWP's power. This alternative was reevaluated as "Case B" during Phase I hearings.

Both DRA and SCE consider this project substantially less cost-effective than the proposed project (see Section VI above). DRA and SCE conclude that choosing this alternative would force SCE to forego over $340 million (NPV) in ratepayer benefits. SCE also argues (as it did for the no-project alternative) that SCPPA and MSR would probably build their own line if the Infinite Bridge alternative was adopted.

3. <u>The Series Compensation Alternatives</u>

SCE and DRA examined two alternatives for raising SCE's transfer capacity from the Southwest by increasing the series compensation on one or more existing transmission lines. Because no new towers would need to be built or new conductors strung, these alternatives would cause none of the environmental impacts associated with any of the DPV2 scenarios.

a. <u>The "Expanded Infinite Bridge"</u>

The Expanded Infinite Bridge alternative would increase series compensation from 50% to 70% on DPV1 and the Miguel-Palo Verde line (SWPL) thereby increasing the overall California-Arizona transfer capacity on DPV1 and SWPL by about 200 MW. SCE would then wheel MSR's, LADWP's, and the SCPPA cities' power over the expanded DPV1. This alternative was evaluated as "Case C" in DRA's and SCE's updated economic analysis. This alternative is estimated to cost $16 million.

Because this alternative would not involve the construction of new transmission lines, it is also one of the environmentally preferred alternatives.

SCE opposes this alternative, arguing that the technology is too risky, perhaps very expensive, and this alternative would require much cooperation with other utilities, particularly Arizona Public Service.

DRA does not recommend this alternative because it is substantially less cost-effective than the proposed project. It has a projected NPV of negative 47 million. DRA also notes the uncertainty about gaining the cooperation of other owners of Palo Verde to install the SSR suppression equipment that would be required.

4. <u>All Lines 70% Compensation Alternatives</u>

Another alternative studied involved increasing the series compensation on all the existing Arizona-California interties from various levels ranging from 26-70% to a uniform 70%. This would increase transfer capacity on the interties by 400 MW at a cost of approximately $118-136 million. Some of this 400 MW would be allocated to other utilities using the intertie.

Although SERA's initial analysis showed this alternative to be probably technically feasible, SERA did not do a detailed economic analysis because the SWPL-DPV1 series compensation alternative could achieve the same project objectives at much less expense, with less technical complexity, and without having to obtain cooperation from so many other utilities who may have little incentive in accepting increased risk of SSR.

5. <u>Conversion of DPV1 to DC</u>

This alternative would involve converting DPV1 to 500 kV DC line with a transfer capacity of approximately 2500 MW. Since new towers would not have to be installed, this alternative would have fewer environmental impacts than the proposed project. Although the increase in transfer capacity of 1300 MW would be slightly greater than DPV2, the expense would be much greater--$750 million.[34] On a per-kW basis, the cost would be approximately three times greater than DPV2.

Both SCE and DRA expressed concerns regarding the stability and reliability effects of this alternative. DRA witness Weatherwax characterized the effect of a single 2500 MW DC line on SCE's system stability as being, if not "unacceptable," at least "extremely discouraging." (Tr. at 800-801.) SCE states that it is uncertain whether the Palo Verde plant could effectively coordinate its complex control system with that of the DC line. Loop flow benefits previously associated with this alternative in the Draft EIR are no longer material due to the installation of phase shifters elsewhere.

6. Non-Transmission Line Alternatives

DRA's consultants examined QF's, conservation and load management, and additional loop flow control measures as alternatives to DPV2. DRA notes that important loop flow control measures have been taken independent of DPV2, and the exchange agreement with LADWP allows SCE through DPV2 to capture significant benefits from the PNW. DRA concludes that none of these alternatives would meet project objectives.

Both SCE and DRA conclude that alternatives with fewer environmental impacts either do not meet project objectives or are economically infeasible. Both argue that the substantial positive economic benefits to ratepayers from the proposed project outweigh the residual environmental impacts. SCE and DRA recommend that the Commission issue a Statement of Overriding Considerations.

34 The net increase in transfer capacity is only 1300 MW because converting the 500 kV AC DPV1 line to 500 kV DC operation results in the loss of about 1200 MW of existing AC transmission capacity.

VIII. DRA Recommendations and Joint Agreement on Conditions

Although DRA and SCE concur that DPV2 with a June 1, 1993 operating date is clearly cost-effective, DRA raised several concerns about the project. First, consistent with the results of DRA's economic analysis (see Section VI.D), DRA believes that even greater benefits could be achieved by delaying the project until 1997. Second, DRA is concerned that if an SCE/SDG&E merger occurs, the cost-effectiveness of the proposed project could change dramatically. Third, DRA is concerned about the uncertainty surrounding transmission service/project ownership arrangements. Finally, DRA expressed concerns over wind loading problems at DPV1, and the possibility of a simultaneous failure of two major transmission lines (an "N-2" event) because DPV2 is in close proximity to DPV1.

As a result of these and other concerns, DRA made several recommendations in its September 1988 testimony (Exhibit 28). During the September 1988 hearings in Phase I, SCE and DRA reached agreement on certain conditions to the CPC&N. The mutually agreed conditions are set forth in an SCE/DRA Agreement Re Certain Conditions on Certificate (Joint Agreement on Conditions), signed September 29, 1988 and attached as Appendix E to this order. DRA's recommendations are summarized below:

A. Require SCE to Demonstrate Benefit Enhancements for a 1993 In-Service Date

As described in Section VI.D above, DRA's economic analysis of alternatives indicate that deferring DPV2 until 1997 yields the optimal level of net benefits in the mid-1990's. DRA also concludes from its analysis that the 1997 build scenario has the least dependence on assumptions regarding economy energy pricing.[35] DRA argues that SCE should not be satisfied with simply creating a cost-effective project; it should seek to maximize ratepayer benefits.

DRA recommends that SCE pursue benefit enhancement measures to render ratepayers "indifferent" between a 1993 and 1997 on-line date. This approach is recommended (as opposed to deferral) because of the generally uncertain nature of the forecasts, assumptions and projections that underly an analysis of this magnitude, and the possibility that LADWP could successfully exercise their option to build DPV2 or an alternative line. In addition, DRA argues that SCE is in the position to enhance benefits during the 1993-1997 period through layoffs (i.e., leasing transmission capacity to other utilities on a short-term basis) and/or adjustments to transmission service rates.

SCE has agreed to DRA's proposal for purposes of this proceeding, as reflected in the Joint Agreement on Conditions (Appendix E). Under this agreement, SCE is required to demonstrate that it will be able to augment the benefits attributable to DPV2 by an amount approximately equal to the difference between a 1993 scenario and a 1997 scenario in the early years of the Project. SCE and DRA have agreed that on an NPV basis the appropriate figure is $33.7 million. Under the agreement SCE is free to choose any method it wishes for benefit enhancements so long as it can establish by November 1, 1989 that it has executed contractual or other agreements which will provide for a $33.7 million level of benefit enhancement (in NPV).

35 This is illustrated in Table 5, under the "No Production Cost Benefits" Sensitivity Case. See also Exhibit 32, page 2-24 and page 8-12.

B. Suspend Construction if an SCE/SDG&E Merger is Still Active

Towards the end of the Phase I study process, SCE made an offer to merge with SDG&E, as an alternative to the proposed merger between SDG&E and Tucson Electric Power (TEP).[36] On October 28, 1988 SCE filed A.88-10-055 requesting Commission approval of the merger. In DRA's view, a SCE/SDG&E merger would clearly affect the viability of DPV2, and possibly make Case B or C the more attractive alternative. This is due to the largely empty status of SDG&E's Southwest Power Link (SWPL) and the potential for using both SWPL and DPV1 transmission paths to bring in Southwest energy for an integrated SCE/SDG&E system. In DRA's view, SCE's access to SWPL would allow the "no project" alternative to meet all of SCE's objectives from the project with essentially no environmental impact.

In order to get a rough estimate of the effects of the merger, DRA's consultant SERA evaluated DPV2 relative to a Reference Case that assumed a SCE/SDG&E merger. The results showed a minimum reduction of 50 percent in economy energy transfers on DPV2 to SCE.

The DRA/SERA report delineates three questions that should be investigated further before the Commission reaches a final determination on the effect of such a merger. SERA notes that the probable effect of two of the three adjustments would be to <u>reduce</u> SCE's need for DPV2.[37] SCE has agreed to file a report by January 15, 1990, describing the status of the merger offer.

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36 Earlier in Phase I, SDG&E announced its desire to merge with TEP. DRA states that it does not expect the proposed SDG&E/TEP merger to have a major impact on the viability of DPV2.

37 See Exhibit 32, pages 3-56 to 3-61.

Language acceptable to both parties has been worked out in the Joint Agreement on Conditions. If the merger is still being actively considered as of January 15, 1990, or consummated prior to that date, SCE has agreed to suspend construction of DPV2 pending Commission review of the situation.

C. Order a Detailed Study of a DPV1 and DPV2 "N-2" Event

DRA independently investigated the increase in risk of a major blackout that would be associated with construction and operation of DPV2. DRA's analysis shows that if DPV2 were built, there would be approximately a 1 in 15 years probability of a simultaneous outage of DPV1 and DPV2 under conditions which would cause major system outage absent some remedial protective scheme.[38]

In its amended application, SCE proposed a load shedding scheme to shed 1000 MW of load within 1/4 second of detection of a disruption on DPV1/DPV2. DRA recommends that SCE be ordered to file a report with the Commission by July 1, 1989 describing the likelihood and impact of such an outage and the feasibility of possible mitigation measures. SCE has no objection to this recommendation, as reflected in the Joint SCE/DRA Agreement on Conditions. DRA further recommends that this report provide

38 DRA argues that a simultaneous or near-simultaneous outage of DPV1 and DPV2 is hardly a remote scenario. DPV2 and DPV1 use the same terminating switchyards, occupy the same right-of-way for most of their length, and even share the same towers in 13 instances. Between March 1982 and December 1986, there were ten unscheduled outages of DPV1. According to DRA, since July of 1986, there have been three events which probably would have brought down both DPV1 and DPV2--the damage at the Devers substation resulting from the July 1986 earthquake on the Banning fault, and blowdown of the DPV1 towers on August 21, 1986, and again on October 29, 1987 due to excessive wind loading.

responses to several topics related to the vulnerability of the Devers substation to seismic events.[39]

D. Order SCE to File Final T/S Contracts Associated with DPV2

SCE has not signed transmission service agreements with any of the municipal utility coparticipants. There is some uncertainty regarding the amount of transmission service revenues that SCE would receive if DPV2 were built. Accordingly, DRA recommends that SCE be required to file by November 1, 1989, copies of all transmission service contracts for transmission service over DPV2 and west of the Devers Substation associated with DPV2. As reflected in the Joint Agreement on Conditions, SCE has agreed to this condition.

E. Require SCE to Report on Current Status of Exchange Agreement

The SCE/LADWP Exchange Agreement currently assumes a DPV2 in-service date of June 1990. SCE proposes to provide the promised 468 MW of transmission service to LADWP on that date, but over DPV1 until DPV2 comes into service. In theory, DRA argues that LADWP should be indifferent to this alternative, and might even prefer it since it would defer LADWP's capital contribution to the project. For this reason, both SCE and DRA assumed that LADWP would accept this arrangement in their analyses and assumed that the other key aspects of the exchange agreement would come into effect on June 1990 (e.g., PNW intertie/DC Upgrade capacity swap, 200 MW of Castaic).

However, DRA notes that LADWP may not be entirely indifferent to this proposal. One of the provisions LADWP negotiated into the exchange agreement was an option to build DPV2

39 Exhibit 6C (FEIR), G-1 at p. 19. DRA recommends that a copy of these responses be sent to the City of Palm Springs.

itself if SCE did not start construction on the line by July 1989. Even under SCE's proposed 1993 in-service date, construction would not begin by this deadline.

SCE is currently negotiating an amendment to this Exchange Agreement conforming it to a deferred start date. DRA is concerned that other terms of the Exchange Agreement might change, which could have a substantial effect on the cost-effectiveness of DPV2 and of the DC Expansion Project.

Accordingly, DRA recommends that SCE be required to provide to the Commission an executed copy of all amendments to the Exchange Agreement on or before November 1, 1989. SCE has agreed to this condition (Joint Agreement on Conditions, paras. 4 and 6).

F. Order a Detailed Study on Wind-loading and the DPV1 Failures

DPV2 is proposed for the same transmission corridor and will be subject to the same wind forces as DPV1. On August 21, 1986, eight towers of DPV1 were blown down by wind causing the line to go out of service. Towers of DPV1 were blown down again on October 29, 1987. DRA recommends that SCE be required to prepare a report analyzing the direct and indirect costs of the DVP1 outage relative to the costs of building towers to withstand greater wind forces. SCE has agreed to submit a report by November 1, 1989 analyzing the failures of the DPV1 line due to wind loading (Joint Agreement on Conditions, para. 5).

G. Impose a Sliding Cost Cap

DRA recommends that the Commission establish a cost cap for SCE's share of DPV2 not to exceed $172.4 million, assuming the firm summer rating of SCE's share of the line meets of exceeds 758 MW plus or minus five percent (Joint Agreement on Conditions at paras. 9-10). Should SCE's final ownership interest be less than the proposed 63.2 percent, DRA recommends that the cost cap for the line portion of the costs be reduced accordingly.

H. Investigate the Joint Study Process

DRA describes the most recent phase of DPV2 as "unique" in several ways. First, both the applicant and DRA staff were dependent on the other party for doing some of the analysis. At the same time, each party maintained control over the assumptions that went into the scenarios for "its" case(s). Second, frequent meetings between DRA, its consultant, and the applicant were held prior to the applicant preparing its amended application. Third, both parties came to understand each other's case much more clearly, and avoided much of the need for burdensome data requests and the frequent miscommunication that results from such data requests.

While DRA firmly believes the net benefits of such a process are strongly positive, witness Burke cautioned that the Commission must (1) make sure that this joint study process is closely coordinated with any CEQA review, particularly with regard to evaluation of alternatives, and (2) provides means where intervenors can be meaningfully involved in the joint study process without forcing applicants to disclose proprietary information. DRA anticipates that such involvement will become more complex if the number of intervenors is larger. DRA recommends the Commission consider incorporating a pre-application joint study into the requirements for CPC&N applications through an amendment to General Order (GO) 131-C.

IX. Discussion

The Commission is required to evaluate this application in conformance with the requirements of the CEQA and the State EIR

Guidelines.[40] The significance of that requirement goes far beyond the mere preparation of an EIR as part of the regulatory steps in processing the application. It is the purpose of the EIR to identify the significant environmental effects of the proposed project, identify project alternatives and indicate how the significant effects can be mitigated or avoided.[41]

Under CEQA, the Commission is required to give preference to environmentally preferred alternatives.[42] However, CEQA does not require the mandatory choice of the environmentally best feasible project. Other considerations, such as economic, legal, social, and technological factors may make the environmentally superior alternatives unacceptable. The applicant's proposal can be approved once its significant adverse environmental effects have been reduced to an acceptable level by mitigation measures. If any significant effects are still unavoidable, the Commission must balance the benefits of the project against those unavoidable environmental risks.[43]

The Draft and Final EIR contain an extensive list of measures designed to mitigate the adverse environmental impacts of

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40 Cal. Pub. Res. Code §§ 21000 et seq.; Cal. Code Reg. Code §§ 15000 et seq.

41 Cal. Pub. Res. Code §§ 21002.1(a), 21061.

42 Cal. Pub. Res. Code § 21002.

43 Specifically, CEQA requires that a Lead Agency issue a Statement of Overriding Consideration for projects that pose a risk for significant environmental impacts. Such a statement must certify that the Lead Agency is aware of these risks, has employed all feasible mitigation measures, and has weighed any residual risk of impact against the overall benefits offered by the proposed project. State CEQA Guidelines, 15092(2) and 15093. See also a discussion of CEQA issues in D.84-10-034, pages 44-50, mimeo, the Applicant's Concurrent Brief (pages 42-44) and the Concurrent Brief of DRA (pages 56-58).

the proposed project. All of the mitigation measures should be adopted as more fully described in the EIR documents.[44] In addition, to ensure that all effective mitigation steps are taken by SCE, we will adopt a mitigation monitoring program, along the lines of that adopted for SDG&E's Eastern Interconnection System and SCE's DPV1 project.[45] The goal of the program will be to assure that the mitigation programs outlined in the EIR are fully implemented and that additional mitigation takes place consistent with the results of further studies undertaken after engineering plans and construction methods are finalized. All costs of the mitigation monitoring program will be borne by SCE as part of the project costs.

We conclude, based on the environmental analysis presented in this proceeding, that the recommended mitigation measures reduce most of the environmental impacts of DPV2 to an insignificant level.[46] However, even after all feasible mitigation measures are employed, the project poses a risk of significant impacts in two areas. As described in Section VII.A., these impacts involve the disruption of activities in the Blythe agricultural area and disruption of the habitat of several rare or endangered species. We note that even these remaining impacts are partially mitigated with the implementation of recommended mitigation measures.[47]

44 Appendix D provides a reference of specific environmental mitigation measures.

45 D.93785, issued December 1, 1981, in A.59755; D.84-10-034 issued on October 3, 1984 in A.59982.

46 Exhibit 6C, Appendix at 9.

47 See Exhibit 6A at 159-161, 169, 170, 172; Exhibit 6C at 7-8, 12-13, Tr. at 760-761.

A. Overriding Considerations

The EIR analysis concludes that DPV2 is the environmentally preferred alternative when compared to routing and new construction alternatives. However, there are several alternatives identified as being environmentally preferable to DPV2. The record in this case persuades us that alternatives with fewer environmental impacts than DPV2 either do not meet project objectives and/or are economically infeasible. Under the "No-Project" (Case A) and "Infinite Bridge" (Case B) alternatives, SCE would forego over $340 million worth of net benefits to its ratepayers. Furthermore, under most circumstances, these alternatives cannot meet project objectives.[48] There is also a significant possibility that other project participants would build an alternative line with greater regional impacts, should SCE's application for certification be denied.

Under the "Expanded Infinite Bridge" (Case C) alternative, SCE ratepayers would experience negative net benefits of approximately $47 million. With the exception of a single "worst case" sensitivity run, this alternative is consistently less cost-effective than the proposed project. There is also uncertainty about gaining the cooperation of other owners of Palo Verde to install the SSR suppression equipment that would be needed.[49] The EIR indicates that other series compensation alternatives would be over three times as expensive as DPV2 on a per kW basis, and have potential negative impacts on system stability. Finally, none of the non-transmission line alternatives evaluated in the EIR would meet project alternatives. In view of

48 As pointed out by DRA, one possible exception would be the integration of SCE and SDG&E's systems via a merger.

49 Exhibit 32, pages 8-9, Tr. at 750-52, 802-3.

these economic and technical considerations, we conclude that the most environmentally superior alternatives are unacceptable.

DPV2, on the other hand, meets all project objectives, and provides SCE ratepayers with substantial benefits. The economic benefits of DPV2 and alternatives were evaluated and discussed at great length during the course of this proceeding. Both DRA and SCE conclude that DPV2, with an in-service date of 1993, would provide SCE ratepayers with approximately $360 million in net benefits (in NPV, 1990$). DRA presented a wide range of sensitivity cases which demonstrated that, even under the most adverse set of assumptions (e.g., no production cost benefits), DPV2 would provide net economic benefits of over $125 million (in NPV). We conclude that these substantial benefits outweigh the residual environmental impacts of the proposed project.

In sum, our overriding considerations for approving the construction of DPV2 are the substantial economic benefits of the project, coupled with the economic infeasibility of alternatives and the inability of most environmentally preferred alternatives to meet project objectives.

B. Conditions to Project Certification

We agree with DRA that certain conditions to our approval of DPV2 are appropriate. While DPV2 is clearly cost-effective with a June 1, 1993 operating date, we share DRA's conviction that, where feasible, resource planning decisions should be designed to maximize ratepayer benefits. The benefit enhancement measures agreed upon by DRA and SCE provide an optimal alternative to project deferral. From 1993 to 1997, ratepayer benefits will be increased to match the higher benefits associated with a 1997 in-service date. At the same time, ratepayers will reap the superior benefits of the 1993 scenario commencing in 1997 and continuing through the life of the project. We therefore adopt the benefit enhancement condition, as agreed upon by DRA and SCE, in their Joint Agreement on Conditions.

We also share DRA's concerns about the potential effects on DPV2 of a SCE/SDG&E merger, the stability impacts of the project, the remaining uncertainty surrounding transmission service/project ownership arrangements and the status of amendments to the LADWP Exchange Agreement. We therefore adopt DRA's recommendations for addressing these concerns, as reflected in the Joint Agreement on Conditions. In addition, we direct SCE to respond to the questions on seismic preparedness raised in comments to the DEIR.

C. Adopted Cost Cap

Pursuant to Public Utilities Code 1005.5, we will adopt a cost cap of $172,400,000 for SCE's share of project costs, subject to ratebasing. This figure represents DRA's estimate of total project costs, as stipulated to by SCE, not including mitigation (or mitigation monitoring) costs.

For SCE's Balsam Meadow hydroelectric and DPV1 projects, we limited rate base treatment of the new plant facilities to an adopted cost estimate adjusted for inflation and for environmental impact mitigation costs. SCE was permitted to seek adjustments required by unforeseen circumstances with a showing of need and cost-effectiveness.[50] We also adopted a cost-monitoring program in order to protect SCE ratepayers from avoidable cost overruns. We will adopt similar procedures here.

As agreed upon in the Joint Agreement on Conditions, SCE will file by November 1, 1989, a summary of any changes in cost estimates. This filing shall indicate the following, as appropriate:

1. Adjustments in adopted project costs because of any anticipated delays in starting the project or inflation;

50 D.83-10-031; D.84-10-034, page 58.

2. Adjustments in project costs as a result of final design criteria; and

3. Additional project costs resulting from the adopted mitigation measures (and mitigation monitoring program).

An order approving or rejecting the amended cost data will be issued following assessment by our staff. Should SCE's final ownership interest be less than the proposed 63.2 percent, the cost cap for the line portion of the costs will be reduced accordingly. In addition, the Commission may make further adjustments to the cost cap, if the final firm summer rating is determined to fall below 1140 MW.

D. Joint Study Process and Remaining Analytical Issues

We now turn to the joint study process and analytical issues that merit further consideration.

In our view, a joint study process, similar to the one initiated during the most recent phase of DPV2, can be an efficient and effective means for evaluating the merits of a project, and for identifying the most relevant issues for litigation. In this proceeding, the joint study process developed new or refined analytical methods for evaluating the strategic benefits of transmission line projects. We especially commend DRA and its consultant SERA for the extensive analytical work presented in this proceeding. Per DRA's recommendation, we will consider commencing a rulemaking to incorporate a pre-application joint-study phase into the requirement for CPC&N applications.

Our support for joint studies, however, is not without some concerns. As pointed out by DRA, to be effective, this process (1) must be closely coordinated with any CEQA review, particularly with regard to evaluation of alternatives, and (2) must provide for the effective involvement of intervenors. We add our concern that joint studies have the potential for making it difficult to identify and explore key assumptions or methodological issues on the record. This is evidenced by the fact that the presiding ALJ, rather than the parties, conducted most of the questioning during the September, 1988 hearings, in order to illuminate any remaining technical or policy issues for further consideration by the Commission.

At the request of the presiding ALJ, DRA and SCE summarized the issues that merit further attention in their concurrent briefs submitted on October 12, 1988. These issues do not appear to have a significant effect on the overall conclusions of the joint study. However, both SCE and DRA acknowledge that they could have a major impact on the cost-effectiveness of other projects, and should be explored further.

We note, in particular, the issue of economy energy pricing assumptions. For the DPV2 analysis, DRA and SCE assumed that prices for Pacific Northwest (and Southwest) economy energy are cost-based, reflecting the production costs of the exporting utility. At the request of the ALJ, DRA provided the results of an earlier sensitivity case performed across all project alternatives to explore the relative effects of "highest block" pricing assumptions. Under this scenario, DPV2 remained the most cost-effective alternative, with over $300 million in net benefits (in NPV).

For future proceedings, SCE suggests further refinements to the "highest block" approach in situations where that cost is significantly lower than the California utility's marginal costs. SCE's suggestion is consistent with the Commission's recent discussion of the Bonneville Power Administration's (BPA's) policies and PNW economy energy pricing assumptions for resource planning:

> "The Pacific Northwest will typically have largesurpluses for some years to come, but those surpluses mean little without assurance on price. Until and unless BPA (or the Federal Energy Regulatory Commission or the courts in their review of BPA's decisions) provides

> appropriate assurance as to some other price assumption, we arguably should assume that all purchases of 'economy' energy from BPA will be slightly below short-run marginal cost."[51] (D.88-09-026, pages 9-10.)

For CPC&N proceedings, we expect DRA and other parties to use pricing assumptions for PNW economy energy that reflect BPA policies and are consistent with our approach in other proceedings, such as OIR-2, where long-term resource alternatives are evaluated. SCE's suggestion is well taken, and should be given immediate consideration for the Phase II "base case" analysis in this proceeding. Similarly, other issues identified in Section VI.E should be explored and addressed in Phase II, to the extent that they are applicable to the DC Expansion Project. We strongly encourage all interested parties to become familiar with the analysis presented in Phase I of this proceeding, and with the issues identified for further refinement/reconsideration.

A final issue that was raised during the course of this proceeding involves the joint study assumption that surplus line space of another utility (e.g., LADWP, SDG&E) would not be made available to SCE to carry additional economy energy purchases.[52] Without that assumption, witness Weatherwax estimates that 60 to 70 percent of the production cost benefits of DPV2 could disappear, although he would still expect the "build cases" to have a benefit-cost ratio of over 2-to-1.[53] In its brief, SCE argues that the

51 D.88-09-026 also states: "Given BPA's Intertie Access Policy, we would expect similar upward pressure on the prices of other energy sellers in the Pacific Northwest." (footnote 5, page 9).

52 DRA assumed that, unlike for economy energy, other utilities could be called upon to wheel for next day UIS support (See Appendix B).

53 Tr. at 819.

likelihood of SCE being able to import significant amounts of economy energy on other systems is relatively small:

> "If Edison desired to import significant amounts of economy energy on some other system, except for a relatively insignificant amount of capacity on Western Area Power Administration's system, it would be limited to using SDG&E and LADWP entitlements. Historically, other utilities, particularly LADWP, have been reluctant to provide transmission service to Edison, except in emergency situations. In addition, LADWP's willingness to part with line space to the Northwest in exchange for line space to the Southwest (per the Exchange Agreement) and SDG&E's intervention in this proceeding in an attempt to obtain more transmission capacity to the Southwest indicate that it is highly unlikely that either of these utilities would be willing to part with any of their own Southwest capacity." (Applicant's Concurrent Brief, page 34.)

We do not have an adequate record in this case to evaluate SCE's power-pooling opportunities for either economy energy or emergency interconnection support. We are satisfied that, for this particular project, adequate sensitivity analyses were conducted to assure the robustness of the joint study conclusions in face of uncertain assumptions. However, assumptions concerning wheeling opportunities could "make or break" a future project, particularly one in which transmission service revenues are not a large component of project benefits. We therefore need to develop a better understanding of current utility practices in providing emergency support, access to economy energy and other power-pooling arrangements.

As a policy issue, we also need to examine whether or not the current practices of California utilities are optimal from the standpoint of system efficiency. If increased coordination or power-pooling among California utilities is feasible, there is the potential for reducing the need to construct additional transmission lines. In order to gain a better understanding of these issues, we direct DRA to conduct a study on power pooling/coordination arrangements among California utilities. To the extent possible, this effort should be coordinated with any ongoing studies in this area at the California Energy Commission.

As part of this effort, DRA should conduct a case study on the current and historical practices of SCE in receiving and providing emergency support, wheeling services for economy energy, and other coordination/power pooling arrangements. We direct SCE to cooperate with staff in providing data on the frequency and cost of these power transfers.

The DRA study should also compile information on power-pooling/coordination arrangements in other regions of the country, with particular focus on UIS and wheeling of economy energy. DRA should include specific recommendations regarding the technical and economic feasibility of alternative arrangements, as they might apply to California utilities.

This order completes our Phase I examination of SCE's amended DPV2 application. As described in Section II above, our review of this transmission project has been long and arduous. Earlier phases of this proceeding were plagued with discovery disputes between DRA and SCE and data input inconsistencies in SCE's filed testimony, which contributed to significant delays. Discovery of the SCE/LADWP Exchange Agreement in late 1987 dramatically changed the economic context of both DPV2 and the DC Expansion such that each needed to be "revisited" in further evidentiary hearings.

We acknowledge the more recent "cooperative spirit" exhibited by DRA and SCE during Phase I, and encourage similar joint study efforts for future proceedings, where practicable. We also commend the joint study participants for their efforts to quantify, and integrate, the cumulative impacts of DPV2 and the SCE/LADWP Exchange Agreement. This is consistent with our directives to SCE regarding the necessity for discussing the interrelationships of projects:[54]

> "the Commission seeks sufficient information to understand not only the purpose of this specific proposal, but also how it would fit as part of your current integrated plans for purchasing power and upgrading transmission capability." (Letter from Joseph Bodovitz, March 1, 1985 re: first rejection of SCE's application for the Gould-Mesa transmission line.)
>
> "...our major concern is the determination of need for the proposed project in a systemwide context. Piecemeal consideration of transmission lines makes little sense from both a public policy perspective and when the requirements of CEQA are concerned..." (Letter from Joseph Bodovitz, August 22, 1985 re: second rejection of SCE's application for the Gould-Mesa transmission line.)
>
> "Of particular concern has been the PUC's obligation to review proposed transmission projects in the context of SCE's existing and planned system, thus allowing a fully informed consideration of the alternatives to a given project." (Letter from Joseph Bodovitz to John Bury, January 2, 1986, re: rejection of SCE's application for DPV2.)"

We remind SCE and other parties to our proceedings of these concerns. It is our expectation that future CPC&N applications for transmission lines will contain the information needed to effectively, and efficiently, evaluate specific projects within a systemwide context. With this perspective, we will

54 See also the Commission's discussion in the Devers-Valley-Serrano decision (D.84-10-034), mimeo. at 51-51a.

embark on Phase II of this proceeding to examine the cost-effectiveness of the DC Expansion project, in full consideration of the SCE/LADWP Exchange Agreement.

Findings of Fact

1. SCE requests a certificate of public convenience and necessity to construct a Devers Palo Verde No. 2 (DPV2), a 500 kV transmission line between Devers substation and the Palo Verde Nuclear Generating Stations in Arizona.

2. SCE's original application and PEA were accepted for filing on February 26, 1986.

3. SCE's amended application and amended PEA were filed on August 15, 1988.

4. SCE's amended application and PEA reflect the following changes: (1) deferral of the in-service date of DPV2 until mid-1993; (2) incorporation of the SCE/LADWP Exchange Agreement; (3) reduction in West of Devers construction costs; (4) restructuring of ownership among project participants; (5) "bridging" transmission service to LADWP on DPV1 from 1990 until the in-service date; and (6) updated assumptions and new or refined methodologies for quantifying project benefits.

5. SCE's amended application and PEA did not significantly change the environmental effects of the project or its environmental context from those originally filed by SCE in 1986.

6. The firm summer rating of DPV2 will be 1200 MW (with all Palo Verde units on line), plus or minus five percent.

7. SCE's project objectives are to provide itself, LADWP, MSR, and other SCPPA participants with transmission capacity, to purchase additional economy energy from either the Northwest or the Southwest, and to displace more costly oil and gas generation.

8. SCE's preferred route for DPV2 would parallel SCE's existing 238 mile 500 kV transmission line (DPV1).

9. DPV2 is expected to provide 1200 MW of transmission capacity, of which SCE will own approximately 758 MW (or 63%).

10. LADWP and other SCPPA participants will own the remaining 442 MW of project capacity. From SCE's ownership share, 250 MW of firm transmission service (T/S) will be provided to MSR and LADWP.

11. Total project costs, subject to ratebasing, are estimated at $260 million (in dollars escalated to the date of expenditure). This figure includes the costs of West of Devers (WOD) improvements.

12. SCE's share of total costs is approximately $172 million in 1993 dollars, assuming an ownership share of 63.17%, including substation facilities. This figure is based on SCE assuming 100% of the right-of-way expenses, and 100% of the additional transformer bank required at Devers substation.

13. The net present value (NPV) of SCE's total cost, including capital and O&M, is estimated to be $175 million in 1990 dollars.

14. These estimated costs do not include any mitigation measures or mitigation monitoring program costs.

15. DRA and SCE conducted a joint study to evaluate the cost-effectiveness of the proposed project and several project alternatives.

16. DPV2 will provide SCE with the following benefits: increased transmission service revenues, reduced production costs, reduced transmission losses, improved utility interconnection support (UIS), improved air quality, and enhanced transmission stability.

17. Under DRA/SCE's base case assumptions, building DPV2 yields net savings to SCE ratepayers of approximately $360 million (in NPV, 1990 dollars).

18. DRA conducted several sensitivity analyses to assure the robustness of the joint study conclusions in face of uncertain assumptions (e.g., UIS benefits, economy energy pricing, gas curtailment).

19. While the magnitude of net benefits associated with DPV2 is highly sensitive to economy energy pricing assumptions, the project remains cost-effective under even "worst case" assumptions.

20. Even under the most adverse set of assumptions, e.g., no production cost benefits, DPV2 would provide net economic benefits of over $125 million in NPV, 1990 dollars.

21. Building DPV2 yields the highest net benefits when compared with no project alternatives.

22. The difference in net benefits between the 1993 and 1997 in-service cases is approximately $34 million in NPV during 1993-1997.

23. The 1997 in-service case is the least sensitive to economy energy prices, relative to earlier in-service dates.

24. During Phase I hearings, SCE and DRA identified several analytical issues that merit further attention in future Commission proceedings.

25. A comprehensive record on environmental matters was developed in this proceeding through issuance of a Draft EIR, consultation with public agencies and others, and public hearings. All are elements in the environmental process which culminated in the issuance of the Final EIR and its Addendum.

26. Statement of Overriding Considerations:

(a) The proposed project (DPV2) will result in significant environmental effects on geology, soils and hydrology, biological resources, land use and planning, visual, acoustic and Native American cultural resources.

(b) The mitigation measures proposed in the Draft and Final EIR and adopted in this decision reduce most of the environmental impacts of DPV2 to an insignificant level.

(c) After all feasible mitigation measures are employed, the proposed project still poses a risk of significant impacts on Native American resources, agricultural activities in the Blythe area and on the habitat of several rare or endangered species.

(d) None of these residual impacts can be mitigated to insignificant levels by feasible modifications of design, construction, or operating characteristics of the proposed project.

(e) Several project alternatives were considered, including alternative transmission lines, increasing the capacity of existing transmission lines and "no-project" alternatives.

(f) DPV2 is the environmentally preferred alternative when compared to routing and new construction alternatives.

(g) Under the "no-project" alternatives (Reference Case A and "Infinite Bridge" Case B), SCE would forego over $340 million worth of net benefits to its ratepayers.

(h) None of the "no-project" alternatives, conservation or loop-flow measures would meet project objectives.

(i) Under alternatives to increase the capacity of existing transmission lines (e.g., the "Expanded Infinite Bridge, Case C), SCE ratepayers would experience negative net benefits estimated at $47 million.

(j) Alternatives for increasing the capacity of existing lines would require the installation of subsynchronous resonance (SSR) suppression equipment.

(k) There is significant uncertainty about gaining the cooperation of other owners of Palo Verde to install SSR suppression equipment on Palo Verde plant generators.

(l) The residual impacts of the proposed project cannot be mitigated by selecting an acceptable alternative.

(m) Any remaining environmental impacts are outweighed by the beneficial effects of the proposed project.

(n) Our overriding considerations for approving the construction of DPV2 are the substantial economic benefits of the project, coupled with the economic infeasibility of alternatives, and the inability of most environmentally preferred alternatives to meet project objectives.

27. An SCE/SDG&E merger could dramatically effect the economic benefits of DPV2 and possibly make "no project" alternatives preferable.

28. DRA estimates based on historical experience that if DPV2 were built, there would be approximately a 1 in 15 years probability of a simultaneous outage (N-2 event) on DPV1 and DPV2 the effects of which could be mitigated by some remedial protective scheme.

29. DPV2 and DPV1 use the same terminating switchyards, occupy the same right-of-way for most of their length and share the same towers in 13 instances.

30. Between March 1982 and December 1986, there were ten unscheduled outages of DPV1, including one incident of earthquake damage at Devers substation and the blowdown of DPV1 towers on August 21, 1986 due to excessive wind loading.

31. Transmission service revenues are estimated to cover approximately 70% of SCE's share of total costs.

32. SCE has not signed transmission service agreements with any of the municipal utility coparticipants on DPV2.

33. The SCE/LADWP Exchange Agreement currently assumes a DPV2 in-service date of June 1990.

34. SCE is currently negotiating an amendment to this Exchange Agreement conforming it to a deferred start date.

35. SCE and DRA reached agreement on several conditions to the CPC&N, as set forth in the Joint Agreement on Conditions, signed September 29, 1988.

36. The joint study process can be an effective and efficient means for evaluating the merits of a project and for identifying the most relevant issues for litigation.

37. For the joint study analysis of DPV2, DRA and SCE assumed that prices for Pacific Northwest (and Southwest) economy energy are cost-based, reflecting the production costs of the exporting utility.

38. In D.88-09-026, we stated that, for long-run resource planning assumptions, we should assume "that all purchases of economy energy from BPA will be slightly below short-run marginal cost."

39. For the joint study analysis, it was assumed that surplus line space of other utilities would not be made available to SCE to carry additional economy energy. Approximately 60-70 percent of the production cost benefits of DPV2 could disappear without this assumption.

40. DRA assumed that surplus line space of other utilities would be made available to SCE to obtain emergency utility interconnection support.

41. We do not have an adequate record in this case to evaluate SCE's power-pooling opportunities for either economy energy or energy interconnection support.

42. Increased coordination or power-pooling among California utilities could reduce the need to construct additional transmission lines.

Conclusions of Law

1. Present and future convenience and necessity require the construction and operation of DPV2.

2. The Final EIR and its Addendum have been completed in compliance with the CEQA guidelines and we have reviewed and

considered the information contained in the Final EIR and its Addendum in reaching this decision.

3. Where feasible, resource planning decisions should be designed to maximize ratepayer benefits.

4. Deferring DPV2 until 1997 yields the optimal level of net benefits in the mid-1990's.

5. SCE should be required to either defer DPV2 until 1997, or enhance project benefits during the 1993-1997 period by approximately $34 million (in NPV).

6. The mitigation measures set forth in the Draft and Final EIR should be conditions of authorization.

7. A mitigation monitoring program, as identified in the preceding opinion, should be established.

8. Construction of DPV2 should be suspended pending further Commission review if the SCE/SDG&E merger is still being actively considered as of January 15, 1990.

9. SCE should be required to file detailed reports describing the likelihood and impact of a simultaneous outage of DPV1 and DPV2, the wind loading problems that have occurred at DPV1, and possible mitigation measures.

10. SCE should be required to file by November 1, 1989 copies of all transmission service contracts related to the proposed project including final amendments to the SCE/LADWP Exchange Agreement.

11. It is reasonable to adopt a cost monitoring program, similar to the one adopted for SCE's DPV1 project, in order to protect SCE's ratepayers from avoidable cost overrruns.

12. It is reasonable to adopt a "sliding" cost cap to reflect SCE's final ownership share of the project and the actual firm summer rating of the line.

13. Because assumptions concerning wheeling opportunities could "make or break" a future project, current utility practices

in providing emergency support, access to economy energy and other power-pooling arrangements should be investigated.

14. The issue of whether or not the current power-pooling or coordination practices of California utilities are optimal in terms of regional system efficiency should be examined.

15. A draft Order Instituting Rulemaking (OIR) should be prepared for the Commission to consider modifying GO 131 to incorporate a joint study pre-application phase in CPC&N proceedings.

16. SCE and other parties to our proceedings should provide the information needed to effectively, and efficiently, evaluate specific projects within a systemwide context.

17. Because SCE and other project participants are in need of the transmission facilities that will be provided by the authorized system, this decision should be effective on the date signed.

INTERIM ORDER

IT IS ORDERED that:

1. A certificate of public convenience and necessity (CPC&N) is granted, subject to the conditions set forth in this order, to Southern California Edison Company (SCE) to construct and operate a second 500 kilovolt (kV) transmission line between its Devers substation and the Palo Verde Nuclear Generating Stations in Arizona (DPV2).

2. This certificate is granted for an operating date of no sooner than June 1, 1993.

3. By January 15, 1990 SCE shall submit a report to the Commission describing the status of the efforts of SCEcorp (SCE's parent company) to merge with San Diego Gas & Electric Company (SDG&E). This report will indicate, as of January 1, 1990, whether (a) a merger agreement has been entered into by SCEcorp or SCE and SDG&E, (b) SCEcorp or SCE has commenced and is continuing a

solicitation of SDG&E shareholders for the purpose of a merger, and (c) SCEcorp or SCE has a public merger offer with SDG&E outstanding. If one or more of these conditions exist as of January 1, 1990, or if a merger is consummated prior to this date, SCE (1) shall not commence construction of DPV2, and (2) shall petition the Commission for reevaluation of DPV2 in the context of the then status of the merger activity. To protect DPV2 project dates, SCE may solicit bids from material suppliers prior to January 1, 1990, but may not award any contracts for the purchase of material.

4. By July 1, 1989 SCE shall submit to the Commission a statement of its plans to enhance the net benefits attributable to DPV2 in the early years by measures such as increased transmission service revenues, transmission capacity layoffs, or other measures. This report shall include an analysis, including a production costing analysis, of the net benefits that would be derived from implementation of such plan, and showing that the enhanced benefits could not be realized without having DPV2 in service prior to 1997. The goal in implementing these benefit enhancements will be to generate additional net benefits to enhance the near-term benefits so that the impact on the ratepayers during the 1993-97 time period will not be substantially different than under DRA's 1997 in-service date case (Case W(97) in Exh. 32).

5. By July 1, 1989 SCE shall submit to the Commission a study on the likelihood and potential impact of a simultaneous outage of both the DPV1 and DPV2 lines. This study shall assess alternative measures for mitigating the impacts of such a simultaneous outage, and the effectiveness, cost, reliability, and feasibility of these measures.

6. By November 1, 1989, SCE shall submit copies of the applicable signed agreements implementing the benefit enhancement measures referenced above, and copies of signed contracts for transmission service over DPV1 from 1990-93, over DPV2, and over

SCE's existing system west of the Devers Substation, including all final amendments to the SCE/LADWP Exchange Agreement.

7. By November 1, 1989, SCE shall submit to the Commission a report analyzing the failures of the DPV1 line which occurred on August 21, 1986 and October 29, 1987 due to wind loading. This report will include responses to the following questions related to the vulnerability of the Devers substation to seismic events:

1. What level seismic shaking ("G" forces) is incorporated in design of foundations and in specifications for equipment.

2. What provisions for equipment movement from dislocation or ground displacement have been made.

3. What is the estimated availability and mean time to repair damaged equipment.

4. How much damage could be sustained and what level of service maintained at Devers.

5. What capacity exists to serve Palm Springs and the SCE system in general if Devers is out of service due to temporary repairs. (Final EIR at p. 19.)

SCE shall provide a copy of its responses to these questions to the City of Palm Springs.

8. As soon as SCE can do so with a reasonable degree of certainty, it shall describe in writing what it believes will be the final provisions of the amendment to the "Los Angeles-Edison Exchange Agreement Between the Department of Water and Power of the City of Los Angeles and Southern California Edison Company," which is presently being negotiated to provide, among other things, for the Department of Water and Power to receive transmission service over DPV1 from June 1, 1990 until the earlier of (1) the date when DPV2 commences commercial operation, or (2) June 1, 1993.

9. SCE shall implement the mitigation measures contained in the Draft and the Final Environmental Impact Reports and Addendum (EIR).

10. All reasonable costs related to the mitigation monitoring program shall be considered as construction expenses related to this project.

11. Within 90 days, the Executive Director shall prepare and present to the Commission a recommended mitigation monitoring program consistent with the discussion in this decision. The recommendation shall include an estimated cost for the program.

12. By November 1, 1989, SCE shall file an amended cost estimate for the project, reflecting:

(a) Any adjustments in adopted project costs due to anticipated delays in starting the project or inflation;

(b) Any adjustments in project costs as a result of final design criteria; and

(c) Additional project costs resulting from the adopted mitigation measures (and mitigation monitoring program).

This filing will be in the form of an advice letter, requesting Commission action on approving or rejecting the amended cost data.

13. No later than six months prior to the project in-service date, SCE shall report the firm summer rating of DPV2. If this rating is finally determined to be below 1140 MW, SCE shall include in an advice letter filing the per-megawatt costs of the project and a recommendation for Commission action on adjusting the final cost cap.

14. Except as otherwise provided for in this order, SCE's share of total project costs subject to ratebasing shall not exceed the lesser of (1) $172,400,000 or (2) SCE's final ownership interest times the total cost of jointly owned facilities, plus 100% of the 220 kV Devers substation costs and 100% of right-of-way acquisition costs. After considering the information filed on the

actual firm summer rating, per ordering paragraph 13 above, the Commission may make further adjustments to the cost cap.

15. During construction SCE shall file quarterly reports for the project which contain:

(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 SCE's progress toward the major milestone including an estimate of whether those milestone will be achieved within budgeted costs and on schedule.

16. SCE shall not apply for cost recovery of any amount above the amended cost estimate, pursuant to Ordering Paragraphs 12 and 13, except that SCE may apply for reasonable costs caused by delay in initial construction in an amount equal to the adopted cost of the project times the increase in the Producer Price Index for Industrial Commodities, subgroup 10 "Metals and Metal Products," as

published by the U.S. Bureau of Labor Statistics for each month the initial construction is delayed past June 1, 1993. SCE may apply for added adjustments only with a showing of unforeseen circumstances as approved by the Commission after advice letter filing.

17. Unless otherwise indicated, SCE shall make all filings ordered above as compliance filings with an original and 12 conformed copies, and serve all parties of record with either the filing or notice that the filing has been made and when a copy can be obtained from SCE. The filings shall comply with the applicable rules in Article 2 of the Rules of Practice and Procedure and shall have attached a certificate showing service by mail on all parties. The compliance filings shall be part of the public record for this proceeding. In addition, two copies of each filing shall be sent to the Commission Advisory and Compliance Division with a transmittal letter stating the proceeding and decision numbers.

18. Consistent with the discussion in this decision, DRA shall conduct a study on power-pooling/coordination arrangements among California utilities, including a compilation of information on power-pooling/coordination arrangements in other regions of the county. This study shall include a case analysis of SCE's power transfers with other utilities. DRA shall submit a proposal and schedules to the Executive Director for completing this study by June 1, 1989. A final report shall be filed no later than twenty-four (24) months from the effective date of this order.

19. Consistent with the discussion in this decision, a draft OIR for modifying GO 131-C to incorporate a joint study pre-application phase for CPC&N proceedings shall be prepared for Commission consideration.

20. The Executive Director of the Commission shall file a Notice of Determination for the project, as set forth in Appendix F to this decision, with the Secretary of Resources.

This order is effective today.

Dated DEC 9 1988, at San Francisco, California.

STANLEY W. HULETT
President
DONALD VIAL
FREDERICK R. DUDA
G. MITCHELL WILK
JOHN B. OHANIAN
Commissioners

I CERTIFY THAT THIS DECISION WAS APPROVED BY THE ABOVE COMMISSIONERS TODAY.

Victor Weisser, Executive Director

SO

DPV2 Project Location

The proposed project consists of constructing a 500 kV transmission line from the high voltage switchyard adjacent to the Palo Verde Nuclear Generating Station (PVNGS) in Arizona to Devers Substation near Palm Springs, California. The preferred route would parallel Edison's existing 238 mile 500 kV transmission line (Devers-Palo Verde #1), of which 112 miles is located in Arizona and 126 miles is located in California.[1]

A. Termination Points

The Arizona segment of the proposed transmission line terminates at the switchyard rack positions of PVNGS. PVNGS is located in the Palo Verde Hills approximately 1 mile south of Wintersburg, Arizona in northwestern Maricopa County, about 36 miles west of the nearest boundary of the City of Phoenix. The California segment of the line terminates at Edison's Devers Substation approximately 10 miles northwest of Palm Springs, California.

B. Existing Facilities

Existing facilities related to the proposed project include the Devers Substation, located about 2 miles northwest of the community of North Palm Springs and 10 miles north of Palm Springs, California; the Devers-Palo Verde #1 500 kV line and right-of-way; and the Palo Verde Nuclear Generating Station and switchyard located in the Palo Verde Hills approximately 1 mile south of Wintersburg, Arizona in northwestern Maricopa County, about 36 miles west of the nearest boundary of the City of Phoenix.

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1 This appendix provides an overall description of the project location. Additional detail on the proposed facilities, construction and operating and maintenance costs is provided in Chapter 3 of Exhibit 25, Amended Proponents' Environmental Assessment.

C. Preferred (Proposed) Route

1. Arizona Route Segment

The preferred route parallels Edison's existing single circuit 500 kV line (Devers-Palo Verde #1). The line departs the PVNGS switchyard and proceeds in a westerly direction for approximately 3 miles to a point south of the Palo Verde Hills. The route then turns northwesterly and proceeds approximately 20 miles northwest of Burnt Mountain. The route then turns westerly and generally follows Interstate 10 and the Central Arizona Project (CAP) for approximately 20 miles through the Big Horn Mountains and across the Harquahala Plain to a point 0.5 mile north of Interstate 10 where it turns southwest, crosses Interstate 10, and proceeds approximately 5 miles where it meets the El Paso Natural Gas Company's existing pipeline just north of its Wendon Pump Station north of the Eagletail Mountains.

At this point, the route parallels the El Paso Natural Gas pipeline for approximately 56 miles, crossing the Ranegras Plain, Kofa National Wildlife Refuge, La Posa Plain, Arizona State Highway 95, through the Dome Rock Mountains to the summit of Copper Bottom Pass. The route then turns southwesterly away from the pipeline, descends the western slope of the Dome Rock Mountains, and proceeds approximately 9 miles to a crossing at the Colorado River. One of the two series compensation banks (described in Section 2.4.4) would be located on the proposed right-of-way adjacent to the Devers-Palo Verde #1 series compensation bank about 1 mile east of the Kofa National Wildlife Refuge.

2. California Route Segment

Upon crossing the Colorado river, the route leaves Arizona and passes into the Palo Verde Valley, 5 miles south of Blythe, California. The route proceeds westerly across farmlands for approximately 10 miles to the top of the Palo Verde Mesa, then proceeds northwesterly approximately 4 miles to a point 2 miles south of Interstate 10 and 5 miles southwest of the Blythe Airport.

At this point the route proceeds westerly, generally parallel to Interstate 10 approximately 63 miles to a point in Shavers Valley where it turns northerly and crosses Interstate 10 approximately 2 miles east of the Cactus City rest stop. After crossing Interstate 10 the route then parallels Edison's existing Devers-Julian Hinds 220 kV transmission line the remaining 46 miles to the Devers Substation. The total length of the line is approximately 238 miles. The second series compensation site would be located on the right-of-way adjacent to the Devers-Palo Verde #1 line series capacitor site about 60 miles west of Blythe.

D. Proposed Transmission Line Facilities

The proposed transmission line is similar to other 500 kV transmission lines in the United States. The transmisison line consists of overhead wires (conductors) which form three electrical phases. These conductors would be supported by lattice steel structures and would be electrically isolated from the structures by insulators. In addition to the conductors, structures, and insulators, the proposed transmission line would contain hardware and overhead groundwires.

(END OF APPENDIX A)

SUMMARY OF ASSUMPTIONS, METHODOLOGIES, AND RESULTS FOR DPV2 BASE CASE ANALYSIS

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Tables and Figures

Attachment 1: Summary of Base Case Assumptions

I. Introduction

This appendix summarizes the assumptions and methodologies used by DRA and SCE to analyze the economic benefits of DPV2 and project alternatives in Phase I of this proceeding. It was developed by the presiding Administrative Law Judge to provide a concise consolidation of the technical information presented during Phase I evidentiary hearings.[1] It is also designed to provide additional background and insight for the various methodological issues raised in this proceeding.[2]

The following types of economic benefits are discussed:

- Transmission Service Revenues
- Production Cost Benefits
- Air Quality Benefits
- QF Payment Benefits
- Stability
- Transmission Loss Reduction and Reimbursement Benefits
- Utility Interconnection Support

For each type of benefit, the results of DRA's and SCE's base case analyses are presented.[3] Table B-1 summarizes the results of DRA and SCE's base case analysis for a June 1, 1993 in-service date. For reference Figure B-1 (Exchange Agreement Provisions) and Figure B-2 (Summary of Alternative Cases) are reproduced from the body of this order. Attachment 1 summarizes the common policy and technical assumptions used for the base case analyses.

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1 Most of the material was developed from Appendix A of DRA's Exhibit 28, augmented by the results presented in Exhibit 32, 35, and 36, DRA/SCE concurrent briefs and the oral testimony presented during the hearings.

2 These issues are identified, and referenced, in Section VI.F of this order.

3 "Base Case" refers to the SCE/DRA analysis using the joint study assumptions described in Exhibit 32 (Section 1.C), and summarized in Section VI.B of this order. In addition, DRA performed several sensitivity analyses, the results of which are presented in Exhibits 32 and 36, and summarized in Section VI.E of this order.

II. Transmission Service Revenues

Concept

DPV2 will provide California utilities with transmission access to bulk power markets in the Southwest. SCE will derive revenues from the sale of transmission services (e.g. wheeling) to the other participants on DPV2 and on SCE's transmission network west of Devers, which connects to the participants' various delivery points, and to LADWP on DPV1 until DPV2 comes on-line.

Background

SCE's current application is different from its original January 1986 application in two key ways that affect transmission service (T/S) revenues. First, several participants in the project will now own their entitlements rather than purchase T/S from SCE. (SCE's project ownership share is 256 MW less than in its original application.) Second, the additional transmission capacity provided by DPV2 has enabled SCE to enter into other T/S arrangements involving DPV1 that might not otherwise have been considered cost-beneficial for SCE.

SCE currently supplies little firm T/S on DPV1.[4] The parties to whom SCE would supply T/S either on DPV1, DPV2, or SCE's transmission system west of Devers are:

- Modesto-Santa Clara-Redding Public Power Agency (MSR), for its 150 MW entitlement in DPV2 for the life of the San Juan Unit 4 plant;

- LADWP, for 368 MW of "bridging" T/S on DPV1 from June 1, 1990 until DPV2 goes into service;

- LADWP, for 368 MW of firm service from Devers to Sylmar/Victorville and for 100 MW of additional firm service from Palo Verde to Sylmar/Victorville for 22 years, waived per the Exchange Agreement;

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4 Little wheeling is currently offered on DPV1 because of SCE's layoff of its 350 MW share of the Cholla coal plant; that layoff is scheduled to end in 1990.

- All utilities[5] scheduling power over SCE's network transmission system from the Devers Substation to their respective service delivery points;

- SDG&E, for its option of 100 MW of firm T/S on DPV1 beginning in 1995.

The "updated" economic analysis prepared by SCE in August 1986 indicated that T/S revenues would have a levelized annual value of $33.8 million. The DRA/SCE stipulated level of T/S revenue on DPV2 as estimated in September 1987 was $28.79 million per year levelized. In the DRA/SERA alternative of routing the power on DPV1 starting in 1990, the revenues were estimated to be $30.7 million annually.[6]

Study Agreement Methodology

SCE's T/S rates were set using the FERC-approved embedded-cost (cost-of-facility) methodology.[7] For west of Devers service, estimated T/S rates were calculated along contract paths to the designated delivery point of each participating utility.[8]

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5 These utilities are part of the Southern California Public Power Authority (SCPPA). The specific utilities owning shares of DPV2 capacity but expected to purchase transmission service from SCE are Riverside, Vernon, Burbank, Glendale, Pasadena, Azusa, Banning, Colton, and the Imperial Irrigation District.

6 SERA prepared testimony, September 1987.

7 SCE is presently investigating several alternative transmission service rate structures patterned after proposed rates being considered by the FERC. Under these alternatives, T/S revenues would be greater than under cost-of-facility based rates.

8 The rate shown in the table for SCPPA reflects a weighted average of the participants' delivered rates.

The table below shows, for each party to whom SCE is supplying T/S, the appropriate transmission line, the amount of T/S, and the applicable T/S rate.

Party	Transmission Line	Amount	Rate[9]
MSR	DPV2	150 MW	$37.24/kW-yr.
MSR	Devers to Midway	150 MW	$40.41/kW-yr.
LADWP	DPV1[10]	367.75 MW	$25.66/kW-yr.
LADWP	West to Sylmar[11]	367.75 MW	Free for 22 yrs., Then $37.09/kW-yr.
SCPPA	Devers to varying delivery points	74.25 MW	$26.16/kW-yr.
SDG&E	DPV1	100 MW	$25.66/kW-yr.
	Devers to SONGS	100 MW	$15.50/kW-yr.

The total T/S revenues are calculated by multiplying the amount of T/S for each party by the rate and summing all of those subtotals.

T/S revenues attributable to the Project begin in June 1990 when the Exchange Agreement with LADWP becomes effective. Between 1990 and 1993, T/S charges for LADWP's 368 MW of firm "bridging" service on DPV1 will yield revenues as shown below.

When the Project goes into operation in 1993, revenues from MSR's 150 MW of firm T/S from Palo Verde to Midway and SCPPA's 74 MW of firm service to various delivery points west of Devers begin accruing and will be paid for the life of the Project. Once the 22-year waiver of charges for LADWP's 368 MW of west-of-Devers T/S expires in 2012, T/S revenues will be received from LADWP for the remaining Project life. Together these services will yield revenues as shown below.

SDG&E is assumed to exercise its option to purchase 100 MW of firm T/S from Palo Verde to San Onofre on DPV1 in 1995. If SDG&E does not exercise this option, the foregone T/S revenues would be partially offset by SCE's increased economy energy purchase opportunities, system stability improvements, increased interconnection support, and air emission reduction benefits.

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9 The transmission service rates are levelized (1990 $) nonescalating amounts.

10 LADWP receives "transitional" transmission service on DPV1 until DPV2 is on-line.

11 Includes the effects of the Exchange Agreement between SCE and LADWP.

Value of T/S Benefits

The value of the T/S revenues attributable to various cases, under DRA's base case assumptions, are shown in the following table:[12]

T/S Revenues (NPV in 1990 million $)

Category	W(93)-A	W(95)-A	W(97)-A	B-A	C-A
East of Devers*	$ 64	$ 71	$ 74	$75	$110
West of Devers	57	52	43	9**	50
Total	121	123	117	84	160
Annual (Levelized)	14.8	na	na	na	na

NOTE: "na" means "not available"

* Includes LADWP "bridging" T/S, DPV2 or DPV1 (depending on the case) T/S, and SDG&E T/S (for the W Cases only).

** This represents T/S paid by LADWP after the 22-year "waiver" for 100 MW, per the Exchange Agreement.

The annual value of the T/S revenues for each case is shown in Figure B-3. The greatest T/S revenues occur under Case C, as clearly shown in the table above and in Figure B-3. This is because all the project participants (including LADWP) are paying for transmission services on DPV1 both east and west of Devers in this scenario. In contrast, under the W Cases, LADWP, MSR, and other SCPPA participants receive access to DPV2 via "ownership shares", and do not pay SCE for T/S. The lowest revenues occur under Case B, where only LADWP is provided with T/S, with most of West of Devers charges to LADWP waived per the Exchange Agreement. The W(97) Case is the highest of the W Cases on an annual basis (see Figure B-3), reflecting the escalating cost of DPV2, which is reflected in cost-of-facility based rates.

12 DRA's estimate of net benefits is approximately $3 million lower than SCE's for the W(93) Case (see Table B-1). This is due to DRA's assumption that MSR will not have to pay for wheeling WOD for 100 MW of San Juan 4 from June 1993 until that capacity is again available to MSR in January 1995.

III. Production Cost Benefits

Concept

Production cost benefits from DPV2 and applicable provisions of the Exchange Agreement result primarily from the increased availability of relatively cheap economy energy.[13] To the extent that power from the Southwest is available and priced below SCE's own generation resources, such power can displace more expensive local generation, and thus provide reductions in SCE's operating costs.

Similarly, increased access to economy energy from the Pacific Northwest (PNW), made available per the Exchange Agreement, can also reduce SCE's operating costs.

To the extent that increased economy energy purchases displace oil/gas-fired generation, SCE and its ratepayers also benefit from improved air quality. In addition, increased access to economy energy should also lower avoided energy costs, as SCE reduces its use of the most inefficient generation resources. As a result, payments to certain qualifying facilities (QFs) would decline, providing ancilliary benefits to SCE ratepayers.[14]

In order to analyze the cost-effectiveness of a proposed change in the resources (including transmission capacity) available to a utility, complex computer models, known as production cost models, are used to simulate the decisions that the utility makes in operating its system. Subject to certain operational characteristics, the models "dispatch" the resources available to SCE to meet system loads (customer demands) at the lowest possible price to those customers.

Background

In SCE's January 1986 application for DPV2, the projected Southwest economy energy savings were a levelized $22.8 million per year (1990 $). DRA found levelized savings of less than $1 million per year. In May 1987, because of computer modeling discrepancies,

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13 Economy energy refers to the import of surplus energy from out of the region on a non-firm basis.

14 Air quality benefits (in the form of reduced NOx emissions) and reductions in payments to QFs are included in DRA's calculations of total production cost savings. The methodologies used to value these benefits are described separately in Sections IV and V of this appendix.

assigned commissioner ruling eliminated SCE's claim of these economy energy benefits due to the DPV2 line from the evaluation of the project's cost-effectiveness.

Particularly because of the expected effects of the SCE/LADWP Exchange Agreement and because of Southwest economy energy availability modeling improvements made more recently, SCE and DRA agreed to look at the production cost benefits again during the Study Agreement phase in the Spring 1988.

Study Agreement Methodology

DRA and SCE agreed to calculate fuel and purchased power expenses using SERASYM, a production cost model developed by DRA's consultants, Sierra Energy Risk Associates (SERA). SERASYM simulates the commitment and dispatch of SCE's resources to meet forecast load requirements and to provide adequate reserve margins. The load and resource projections represented in SERASYM were based on SCE's 1987 Resource Plan, with certain modifications agreed to by SCE and DRA for a common base case.[15] In simulating the effects of DPV2 it was assumed that surplus line space held by other utilities (e.g., SDG&E, LADWP) could not be called upon or utilized by SCE for deliveries of economy energy.[16]

DRA estimated the price and availability of economy energy using SERA's Southwest Energy Resource Assessment Model (SERAM) and SCE's Pacific Northwest Energy Model.[17] In brief, these models match the resources available in those regions to forecasts of expected loads, to determine the quantity of surplus energy available for export to California. Each model incorporates SCE's available transmission capacity as a constraint on the transfer of economy energy to the SCE system.

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15 See SCE's Amended PEA, (Exhibit 25), pages 2-47, 2-48, and Appendix A for a summary of the resource plan assumptions.

16 This assumption was also made by SCE in its original assessment of Utility Interconnection Support (UIS) benefits. However, as described in Section VI.B, DRA argued that, unlike for economy energy, SCE could depend on other utilities to wheel power, as needed, for UIS.

17 SERAM is a public domain model developed by SERA under contract to the CPUC. It is a substantial modification of SCE's own Southwest Energy Model. Within SERAM, the Southwest is considered to contain Arizona, New Mexico, Colorado, Utah, and Mexico subregions. For more detail on this model, see Exhibit 28, Appendix B and Exhibit 4B, Appendix A.

For the base case analysis, DRA assumes that SCE is able to price discriminate in the economy energy market. This is reflected in DRA's "cost-based" approach to economy energy pricing, which bases those prices on the production costs of the resources generating the regional surplus. Using this approach, DRA develops regional "supply curves" of economy energy comprised of four price blocks. Each block is priced successively higher to reflect the increasing production costs of the region. These supply curves are then used as inputs into the SERASYM production cost model.[18]

The DPV2 project, in conjunction with various provisions of the Exchange Agreement with LADWP, affects SCE's energy production costs through the interaction of the following factors related to economy energy:

1. Increased Northwest economy energy purchases on SCE's additional 180 MW of PNW transmission access beginning in 1990, per the Exchange Agreement.

2. Increased SW economy energy purchases on SCE's DPV2 entitlement beginning in 1993.

3. Foregone SW economy energy purchases due to LADWP's receiving 368 MW of "bridging" transmission service on DPV1 between 1990 and 1993.

4. Foregone SW economy energy purchases due to LADWP's receiving 100 MW of firm transmission service for 22 years beginning in 1990.

5. Foregone SW economy energy purchases due to SDG&E's (option of) receiving 100 MW of firm transmission service on DPV1 beginning in 1995.

6. Decreased availability of SW economy energy due to MSR's taking delivery of power from its 150 MW of San Juan Unit 4 entitlement.

7. Increased access to available SW economy energy by other utilities on DPV2.

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18 Because of the current limitations of SCE's PNW Energy Model, the supply curve from SERAM was "blocked", rather than extended in a continuous fashion. (See TR at 870.)

8. Improvements in system efficiency that lower avoided costs and thus lower the payments made to QFs.

9. Increased opportunity for off-peak economy energy purchases due to having 200 MW of Castaic Pumped Storage capacity for spinning reserve.[19]

Value of Production Cost Benefits

Figure B-4 presents, for each case, the annual value of total production cost benefits under DRA's base case assumptions. The NPV of total production cost benefits are summarized in the following table:[20]

Production Cost Benefits (NPV in millions of 1990 $)

Category	W(93)-A	W(95)-A	W(97)-A	B-A	C-A
Increased PNW Purchases	$108	na	na	na	na
200 MW of Castaic	58	na	na	na	na
QF Payments Reduced	38	na	na	na	na
Increased SW Purchases	0	na	na	na	na
Subtotal	204	197	191	(61)	(186)
Air Quality (NOx Reduct.)	35	30	25	(39)	(69)
Total Benefits	239	227	216	(100)	(255)

19 Spinning reserve represents power that is available from generating units connected to the system and able to deliver power promptly. California utilities are required by the California Power Pooling Agreement to have spinning reserves equal to 7% of load, plus 100% of non-firm imports. This means that for every MW of non-firm energy imported, a utility must have 1 MW of capacity "spinning". By having 200 MW of Castaic pumped storage hydro available, SCE can import additional economy energy, and save the additional start-up/running costs of thermal units.

20 DRA's base case results are approximately $25 million higher than the net benefits presented in SCE's Amended Application (see Table B-1). The major factor contributing to this difference is certain model corrections that SERA made after the deadline passed for SCE's filing (but in time for DRA's submittal). These corrections served to increase the amount of economy energy in the Southwest.

CORRECTION

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LEGIBILITY

8. Improvements in system efficiency that lower avoided costs and thus lower the payments made to QFs.

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Value of Production Cost Benefits

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Increased SW Purchases	0	na	na	na	na
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19 Spinning reserve represents power that is available from generating units connected to the system and able to deliver power promptly. California utilities are required by the California Power Pooling Agreement to have spinning reserves equal to 7% of load, plus 100% of non-firm imports. This means that for every MW of non-firm energy imported, a utility must have 1 MW of capacity "spinning". By having 200 MW of Castaic pumped storage hydro available, SCE can import additional economy energy, and save the additional start-up/running costs of thermal units.

20 DRA's base case results are approximately $25 million higher than the net benefits presented in SCE's Amended Application (see Table B-1). The major factor contributing to this difference is certain model corrections that SERA made after the deadline passed for SCE's filing (but in time for DRA's submittal). These corrections served to increase the amount of economy energy in the Southwest.

As indicated in the above table, access to cheaper PNW economy energy is the driving force behind nearly all of the production cost benefits attributable to DPV2.[21] What is particularly striking is the fact that, compared to a no-DPV2 scenario (Reference Case A), **with DPV2 there is less economy energy taken at higher per kWh cost from the Southwest resulting in net reductions in savings for every year from 1990 until 2005.** The reduction in Southwest purchases occurs in part because more PNW economy is substituted with the advent of the Exchange Agreement.[22] Another factor affecting SCE's Southwest economy energy purchases is the increased competition by other participants for lowest price energy in the Southwest. This results in there being less of the cheapest economy energy available to SCE with the line than without it (even though the total amount of available energy has done up). Overall, there are no net benefits to SCE from increased Southwest purchases under the "build DPV2" cases.

Production cost benefits for Cases B and C are actually negative (in NPV) in DRA's base case analysis. Use of SCE's existing line space under Case B results in "foregone" Southwest economy energy benefits, relative to the Reference Case A. These negative net benefits more than offset the positive benefits of increased purchases from the PNW. Case C is still more negative because it is the case in which the most surplus SCE line space is used to provide transmission service to others.

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21 The availability of Castaic for spinning reserves avoids not only the higher operating cost of thermal units, but also some start-up costs. Hence, part of its value is independent from the spread between economy energy prices and the operating costs of "spinning" thermal units.

22 Because of operational considerations, PNW economy energy, when priced the same, will always be taken prior to Southwest economy.

IV. Air Quality Benefits*

Concept

The South Coast Air Basin and Ventura County are in violation of Federal Clean Air Act ambient air quality standards for ozone and nitrogen oxides (NOx). Most of SCE's oil/gas-fired generation plants are located in these "non-attainment" areas. SCE's plants already employ the most cost-effective NOx emission controls and are very clean by industry standards. Consequently, additional emission reductions are very expensive to achieve.

To the extent that purchases of energy from the PNW or Southwest displace oil/gas-fired generation located in the environmentally sensitive South Coast Air Basin and Ventura County, SCE will save the costs of cleaning up emissions that would result without DPV2 (and the Exchange Agreement).

Background

Neither of the economic analyses presented earlier by SCE (the Proponents Environmental Analysis (PEA) and the "updated" analysis, dated August 1986), attempted to quantify these air quality benefits. (They were considered a "strategic" benefit of the project.) In its prepared direct testimony (April 1987, p.40), SCE estimated that a 900 million KWh/year reduction in Los Angeles area oil/gas-fired generation would reduce these aggregate emissions by 600 to 2,600 tons per year, depending on the fuel displaced.

Study Agreement Methodology

In the Study Agreement, SCE and DRA/SERA agreed to assign a value to the air quality benefits of DPV2 based on the avoided cost of retrofitting emission control equipment. SCE reports that implementing additional controls on their plants would presently cost from $19,000 per ton for methanol overfiring to $35,000 per ton or more for selective catalytic reduction (SCR) equipment. In addition, these cost estimates do not include probable reductions in plant efficiency due to increased auxiliary power requirements, and increased maintenance and forced outages due to emission control equipment failures.

* Included in DRA's calculation of total production cost savings (see Section III).

The production cost model (SERASYM) provided data relating the NOx emissions to the hourly power output of each of SCE's oil or gas-fired power plants. SERASYM was run for each case (and Reference Case A) to calculate the reduction of oil/gas-fired generation (displaced by out-of-region purchases) and resulting reduction in NOx emissions. SCE and DRA agreed to use a $19,000 (unescalated) per ton retrofit cost to value the NOx reductions.

The maximum number of tons/year of NOx emissions saved by DPV2 in the study agreement analysis was 415 tons.

Limitations of This Methodology

This methodology does not reflect differences in plant-specific performance; all tons of NOx are considered equally costly to cleanup. Air pollution control costs are not internalized into the dispatch sequence of the production costing model. In addition, no attempt was made to quantify the health-related air quality benefits of reduced emissions in the South Coast Air Basin.

Total Value of Air Quality Benefit

The NPV of air quality benefits for DRA's analysis of the W(93) Case is $35 million. This amount is included in DRA's estimate of total production cost benefits (see Section III). Figure B-5 presents the annual net benefits of NOx reductions for all cases. As expected, these benefits are negative for Cases B and C due to the net reduction in total economy energy purchases under those scenarios (see Section III).

V. QF Payment Benefits*

Concept

California's utility companies pay QFs for the energy and capacity that they produce according to rules adopted by the CPUC. QF energy payments depend on the type of contract negotiated for the specific resource (i.e., fixed price, avoided cost-dependent, or heat rate-dependent). For Standard Offer #1 and Standard Offer #2, the energy payments made to QFs are based on the utility's avoided energy (marginal) costs.

Inclusion of the DPV2 line in SCE's system and the associated changes in SCE's access to the northwest due to the Exchange Agreement with LADWP, should enable SCE to make less use of its own most inefficient generation resources, thus lowering avoided energy costs. Consequently, the payments made to QFs with avoided cost-based rates will decline, providing an ancilliary benefit attributable to the new transmission line.

Background

Neither SCE nor DRA attempted to quantify the QF payments benefits attributable to DPV2 prior to the Study Agreement.

Study Agreement Methodology

The production costing model (SERASYM) determines the appropriate payment for avoided cost-dependent QF purchases based on the marginal costs it calculates. In order to make that calculation, SERA staff coded the contract types in the resource data base for the appropriate QFs, along with the vintage of the appropriate QF contracts. Vintage data for QFs were needed because, under certain standard offers, payment mechanisms change after the initial ten years that the QF is on-line.

Value of Benefit

To the extent that DPV2 improves the overall efficiency of the SCE system by lowering avoided energy costs, QF energy payments are adjusted (lowered) accordingly. As shown in Section III of this appendix, the NPV of reduced QF payments comprises approximately 15% of total production cost benefits for the W(93) Case.

* Included in DRA's calculation of total production cost savings. (See Section III)

VI. Reliability Benefits

An electric system's "reliability" is a relatively easy measurement for an end-user: how frequently and for how long does the power go off? However, from the utility's perspective it is more complicated. The utility is concerned not only with the frequency and duration of outages, but also with their extent, and these factors do not necessarily change in the same direction. Common sense (and economics) suggest that a utility will tend to design its system to avoid more widespread outages, even if these are less frequent and of shorter duration.

High-voltage transmission lines are big resources. DPV2 has a rated capacity of 1,200 MW, about the same as each of the units at Diablo Canyon. Furthermore, DPV2 occurs adjacent to, and utilizes the same substations and occasionally even the same towers as DPV1. Together these lines carry approximately 2,400 MW, more than SCE's allocation from SONGS 1, 2, and 3 put together. If these lines are both operating, they provide support to the system in case other resources have sudden failures. Conversely, if both these lines are heavily loaded and they simultaneously fail, then they pose quite a threat to the rest of the SCE system (and the entire WSCC) system. A new line cannot be characterized in simple terms as either increasing or reducing system reliability.

Of importance in the analysis of reliability is the time frame of events. These can be divided roughly into events which take place over periods of hours or days, and events which take place in a very few seconds. In one case human intervention is possible; in the other the control functions must be automatic. To use an end-user analogy, the user can run out and borrow flashlight batteries from one of his neighbors when he sees his batteries running down, but a hospital operating room must have an emergency generator to maintain continuous power even during outages.

To distinguish these two types of support, utility planners label one "System Stability" and the other "Utility Interconnection Support" (UIS). One can think of system stability as the hospital's planning to have an emergency backup system that will kick in almost instantly. The homeowner going to his neighbor to borrow batteries is more analogous to utility interconnection support.

With the above analogy in mind, it is possible to consider an electric utility's system. There should be redundancy and flexibility to absorb inevitable sudden disruptions of major units--either generating plants or transmission lines. This is the "stability" of the system. At a less immediate response level, a utility should be able to "borrow" resources from its neighboring utilities for short periods of time, so long as both utilities have a few hours advance warning. A utility's ability to call on its neighbors is its level of UIS.

Both system stability and UIS can be measured. The way in which they are measured and other contrasting features of these two aspects of reliability is shown in Table B-2.

A. System Stability

As noted above, system stability refers to what happens to the utility system when there is an instantaneous outage of one or or more major components of that utility's system or even a neighboring utility's system. Examples of such outages include failures of major transmission lines or substations, as well as generating stations. Such failures can literally threaten one or more utilities' entire systems. In less than a second, there is an imbalance between loads and resources. The system acts to restore the balance faster than human interaction can occur. Energy, moving in the direction of least impedence, automatically and instantly flows from other utilities toward the utility with the loss of plant or line regardless of contractual relationships until and unless circuit breakers or other protective devices act to isolate parts of the system or even one entire utility from others "islanding").

These events occur in a time span so short that human intervention is not possible. What will occur in terms of power flows is a function of the overall instantaneous load and resource mix at the time of the emergency. The concern of utility planners is to prevent the entire system from failing and to control and minimize the damage to each utility's system. Within milliseconds, automatic load shedding systems engage. Within less than a minute, human operators can intervene to shed load or begin to increase resources, for example, by ramping up spinning reserve, starting combustion turbines, or turning on hydroelectric resources. After the system has stabilized, utility dispatchers may begin to consider whether or not to acquire UIS for the next day.

Utility planners distinguish between "N-1" and "N-2" events. The former represents a situation where single transmission lines or generating plants are lost. Under an N-2 event, there is a simultaneous outage of two transmission lines, that could result in a major blackout.

System stability for N-1 events is enhanced by increasing the margin in transmission capacity. The construction of DPV2 adds to margin by reducing the loadings of other parallel lines in the Arizona-California transmission system. However, construction of DPV2 increases the risk of a simultaneous loss of DPV1 and DPV2 ("N-2" event). At the same time, DPV2 will increase SCE's ability to withstand N-2 events on other than the DPV1/DPV2 corridor.

Background

The value of stability has not been quantified in any of the previous analyses submitted for the DPV2 proceeding by either SCE or DRA.

Study Agreement Methodology

In order to establish a value for the stability component of increased reliability, SCE tested its system for substitute methods of achieving the same level of stability without the line as that exhibited with the addition of the line. Specifically, SCE measured stability benefits by simulating the performance of the Arizona-California transmission system, with and without DPV2, during a severe disturbance. A three-phase fault was simulated near the Palo Verde 500 kV switchyard, resulting in the loss of DPV1 (the single most critical outage in the system).[23] Voltage fluctuations were then recorded. Simulations were repeated where the system without DPV2 was augmented with Static VAR Compensators (SVCs)[24] until the system performed comparably to the case with DPV2. The costs of the substitute methods were then assigned to the value of increased stability.

The value of the stability benefits defined in this manner is calculated by the following formula:

Stability Benefits =
(Substation Rev.Req.Factor) * (MVAR of SVC) * ($/MVAR) ✓

"Substation Revenue Requirement Factor" is the yearly factor used to indicate the share of the SVC capital costs that are assignable to individual years through the life of the project.

"MVAR of SVC" is the amount of Static VAR Compensators devices in millions of VARs.

"$/MVAR" is the cost per millions of VARs of the SVC devices. ✓

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23 Voltages at the Miguel 500 kV Substation were monitored since stability at Miguel is affected most by this disturbance.

24 "VAR" stands for Volt-Ampere-Reactive. It is a measure of reactive power. SVCs are a class of devices which quickly switch shunt capacitors and reactors on- and off-line in response to system reactive power needs. In this way, they can stabilize voltage fluctuations during the critical seconds immediately following a disturbance.

SCE's simulations of their system with DPV2 indicate that 350 MVAR of SVCs would be required to attain the same level of stability as their system without DPV2 assuming that DPV2 was loaded with 700 MW (i.e., 7/12 loaded). SCE's current installed cost estimate for SVCs is approximately $60 per kVAR. For the DPV2 analysis, SVCs were conservatively assumed to cost $50/kVAR and no escalation factor was applied.

Value of Benefit

The results of SCE's studies show that DPV2 will enhance system stability under N-1 events. The levelized value of the stability benefits for the W(93) Case is approximately $2 million per year, with a net present value of $16 million (1990 $). No stability benefits are found in Cases B and C.

Neither DRA or SCE quantified the reliability impacts of DPV2 in terms of an N-2 event. However, DRA independently investigated this issue, and recommends further studies on the likelihood of an N-2 event and possible mitigation measures. (See Section VIII.C of this order.)

B. Utility Interconnection Support

Concept

Utility interconnection support (UIS) refers to the ability of one utility to draw on capacity and energy from neighboring utilities in times of unexpected supply outages or greatly increased demands. Occasionally, a utility has unscheduled outages on facilities (generating plant or transmission lines) which cause the utility to be short of capacity or energy for one or more days. In such cases, the utility usually makes it through the remainder of that day relying on its own resources. In the meantime, the utility's dispatchers contact dispatchers from neighboring utilities and acquire capacity or firm energy from those neighbors for the next day or two until the first utility's plant is back on line or back to full operation. The goal of this support is to avoid having to shed load or commit excessively expensive generating or transmitting resources the following day.

The presence of this capacity to meet short-term capacity shortages allows the utility to defer construction of new generating plants and aids in day-to-day operations. To the extent that a new transmission line such as DPV2 increases a utility's ability to rely on UIS it has measurable economic value.

UIS has two aspects: planning value and operating value. UIS has planning value because it (1) reduces the utility's probability of incurring outages (i.e. it reduces the Loss of Load Probability (LOLP)), or (2) allows the utility to defer construction of some other project, typically a generating plant(s), while maintaining the same LOLP. UIS also has some operating value in that it may allow for VARs support and other operating benefits in common with combustion turbines.

Background

This is the first transmission line CPCN proceeding in which specific methodologies for quantifying UIS planning benefits have been proposed. DRA first presented a methodology, based on a SERA study, during the September 1987 hearings. The approach outlined in the SERA study formed the basis of both SCE's and DRA's revised testimony during the September 1988 hearings. This approach is described briefly below.

SERA's 1987 Study

To quantify UIS planning benefits, SERA determined the value of improved reliability (reduced outages) on SCE system by deriving a LOLP "shadow price".[25] The starting point for valuing LOLP reductions is the avoided cost of adding peaking capacity, represented by the avoided cost of a combustion turbine (CT). In its 1987 study, SERA assumed that the annual planning value of a CT is 90% of avoided costs.[26]

SERA argued that UIS planning benefits cannot be valued at 90% of avoided costs, the full planning value of a CT. CTs have numerous operational characteristics--lacking in transmission lines--which reduce system operating costs. The value of these cost savings must be netted out of the CT planning value, to yield an appropriate planning value for LOLP. SERA ran SERASYM with and without 200 MW of CTs to calculate the reduction in variable operating costs and LOLP associated with CT additions. The model results were used to derive the LOLP "shadow price" for valuing UIS planning benefits (see below). Specifically, the total value of LOLP was calculated as the difference between the planning value of a CT (90% of avoided costs) and the variable cost reductions associated with the CT additions. The "shadow price" of LOLP is the ratio between total LOLP value and the reduction in LOLP associated with adding CTs.

25 Incremental changes in LOLP do not have a direct market price, so a "shadow price" needed to be developed.

26 90% of the full cost of a CT was discounted by the appropriate Energy Reliability Index (ERI) to yield the planning value of a CT. The remaining 10% of the cost of a CT was assumed to represent the operating benefits of a CT (undiscounted).

Next, SERASYM was used to calculate the change in variable operating costs and LOLP, resulting from the addition of 200 MW of UIS (instead of CTs). The change in LOLP was multiplied by the LOLP shadow price. Increases in variable operating costs were subtracted from this total to yield the net planning benefits of UIS. Based on this analysis, SERA concluded that the value of increasing UIS by 200 MW is approximately one-half the value of adding an equivalent amount of CTs to the system.

Study Agreement Methodology

For the Study Agreement phase, DRA and SCE stipulated that the operating value of UIS is equal to 5% of the avoided capacity costs, or about half that estimated for a SCE owned and operated CT.[27] Both agreed to use SCE's planning assumption of 1,200 MW for the amount of existing UIS on SCE's system.

To estimate the amount of additional UIS attributable to DPV2, SCE uses an approach that bases the increase in UIS on the additional line share made available by DPV2.[28] SCE's calculations can be summarized as follows:

Planning assumption: 1,200 MW of existing UIS on SCE's system

Additional UIS capability: DPV2 1,200 MW capacity less firm schedules yields 400 MW

Existing transmission transfer capability (surplus, after firm schedules) coming into SCE's control area from neighbors: 6,651 MW

For every MW of surplus transmission capacity into SCE's system, there is approximately 1/6 MW of UIS: 1,200/6,651 = .18

DPV2 adds 400 MW, so additional UIS is .18 x 400 = 72 MW

72 MW x .50 x (CT discounted by ERI) = Value of planning benefits

72 MW x .05 x CT value = Value of operational benefits

In its updated testimony, DRA/SERA used a very different approach for estimating the increase in UIS attributable to DPV2. The key difference between the two approaches is DRA's assumption

27 In SERA's 1987 study, the operating benefits of UIS were assumed to be zero.

28 This is similar to the approach taken by SERA in the 1987 study.

that it is appropriate to (1) consider generating capacity in regions other than neighboring utilities, and (2) assume that for UIS purposes SCE would have access to other utilities' transmission capacity. In other words, DRA bases UIS benefits on the increase in surplus capability of the whole Southwest, including wheeling to SCE.[29]

The explicit calculations used in DRA's analysis are described in Chapter 6 of Exhibit 32 and in Exhibit 34. The bottom line is that DRA's approach attributes 157 MW of additional UIS to DPV2, twice the level calculated by SCE.

Value of UIS Benefits

As a result of its revised methodology, DRA's estimated value of UIS for the W(93) Case is $63 million, more than twice SCE's estimate (see Table B-1).[30]

The table below presents the results of DRA's analysis for all cases:

	UIS Benefits (NPV in 1990 million $)				
	W(93)-A	W(95)-A	W(97)-A	B-A	C-A
UIS Benefits	62	61	60	0	7

Figure B-6 presents the annual value of UIS benefits for all cases. UIS benefits sharply increase in all instances starting in 1997 when the ERI for SCE becomes non-zero and rises to one by 1998.

29 During the September 1988 evidentiary hearings, SCE stipulated to DRA's methodology for the purpose of this proceeding.

30 Under DRA's approach, there are no UIS benefits attributable to Case B, and only a very slight (17 MW) increase in Case C. (See Exhibit 34.) Using SCE's approach, on the other hand, yields large negative UIS benefits for Case B and (even more negative) for Case C. This is because SCE's "surplus" capacity on its own lines are reduced under those scenarios (and it is assumed that UIS cannot be "wheeled" to SCE).

VII. Transmission Loss Reduction And Reimbursement Benefits

Concept

Transmission lines cannot transmit power without losses, at least until superconductivity becomes a reality. Transmission line losses are a function of the square of the amount of electrical current carried on a transmission line. Losses are reduced when a given quantity of power is transported over a greater number of transmission lines. Adding DPV2 to the existing transmission system will cause power flows to shift onto the new line, reducing power flows on the lines which parallel it. This will serve to reduce average line losses on SCE's total system from Arizona. Later, as additional power transfers are made on DPV2, system losses will increase. However, increased losses from the anticipated additional transfers are less than the loss reductions which will result from adding the line.

Normally, to compensate for transmission losses on its system, SCE must provide additional resources and generate additional power. The net reduction in losses resulting from DPV2 means that SCE will not have to purchase or install as much generating capacity or burn as much fuel, thus reducing its cost of service.

Another aspect of loss-related benefits resulting from DPV2 is the reimbursement for losses SCE receives from utilities purchasing transmission service. When utilities enter into transmission service contracts, estimates of the expected transmission line losses from applicable transmission lines are made. Agreements are signed that specify how to account for (or reimburse the appropriate party for) these expected losses. If actual losses are less than the estimated losses, the party providing the transmission service reaps the benefits. If actual losses exceed the estimates (due to inadvertent power flow or loop flow, for instance), the wheeling utility is not reimbursed for the additional loss.[31]

DPV2 will reduce SCE's loss-related expenses in this manner as well, because of the SCE/SCPPA capacity exchange arrangement involving the Salt River Project (SRP). This exchange

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31 Reimbursements for energy losses are based on an accounting of the power scheduled over a given contract transmission path in a specified period of time. Reimbursements for capacity losses are handled by reducing scheduled capacity deliveries in the amount of contract losses.

was instituted in order for the SCPPA participants in DPV2 to receive their Palo Verde power deliveries. The transmission service arrangements with the SCPPA participants will provide for SCE to be reimbursed for the loop flow-caused additional line losses that that arrangement has been imposing on SCE's system.

Background

SCE's original January 1986 application did not quantify the benefit of reduced transmission line losses at all, and assessed the elimination of the SCPPA/SRP exchange arrangement only for its loop flow mitigation benefit.

Study Agreement Methodology

SCE performed comparative flow studies with and without DPV2, and its associated 300 MW of additional schedules.[32] The loss reduction effects of the DPV2 line on both the 500 kV (Extra High Voltage) and the 230 kV (bulk power) systems were analyzed. (Most of the loss reduction occurs on the EHV system.) Results indicate that DPV2 reduces SCE's transmission losses by 13 MW in the peak summer case. This megawatt reduction was assumed to remain constant throughout the study period. The peak summer case data was extrapolated to yield an annual energy loss reduction of 43 gWh.

Loss savings attributable to the DPV2 line are calculated by adding together the values of both the real and non-reimbursed contract-related losses.

The real losses are derived from the:

- Difference in capacity losses with and without DPV2;

- Difference in energy losses with and without DPV2.

The contract-related losses are derived from the:

- Reimbursed transmission service energy losses;

- Reimbursed transmission service capacity losses.

The derivation of the value of these components follows.

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32 SCE assumed an additional 300 MW of transfers scheduled over DPV2 for purposes of analyzing losses. This assumption is based on additional firm schedules anticipated over DPV2 together with SCE's SERASYM results regarding additional economy energy transfers expected on the line.

Capacity Losses. The value of the difference in capacity losses due to the DPV2 line is calculated by determining how much an equivalent amount of capacity would cost to make up for the losses. The capacity loss reduction from the power flow analysis is multiplied by the proxy value of capacity, discounted by the appropriate energy reliability index (ERI). The proxy value of capacity is determined by the CPUC in the OIR-2 process. The ERI was set by the CEC in ER 6. This forecast of capacity does not show any capacity value until 1997.

Value of capacity loss = Capacity loss reduction
* Proxy * ERI

Energy Losses. Annual energy losses can be correlated to the megawatt (capacity) losses which occur under peak load conditions through the use of "loss factors", which are analagous to capacity factors in that they relate capacity and energy.[33]

The reduction in annual energy losses resulting from the DPV2 line was calculated as follows:

Annual gWh Losses = MW Loss
* Loss Factor * (8.76 kWh/year)

(The 13 MW peak loss reduction represented a 43 gWh annual energy loss reduction.)

The value of the difference in energy losses due to the DPV2 line is calculated by determining how much an equivalent amount of fuel would cost to make up for the losses. More specifically, energy losses were valued using the cost of gas-fired generation and SCE's incremental energy rates (IER's), as calculated by SERASYM. The steps are:

Value of energy loss = (Fuel Cost) * (Net Btu Loss)
Net Btu Loss = (Btu Loss w/o DPV2) - (Btu Loss w/DPV2)

For both the without DPV2 and the with DPV2 cases:

Btu Loss = (Total gWh Losses) * (IER)
Total gWh Loss = (EHV Energy Loss) +
(Bulk Power Energy Loss)

Capacity and Energy Reimbursements. In the economic analysis, capacity and energy reimbursements are valued in the same manner as the loss reduction benefits just outlined. Specifically:

33 The loss factors associated with the EHV and bulk power systems were calculated to be 0.366 and 0.432, respectively.

The value of the reimbursed transmission service energy losses due to contractual arrangements is calculated as follows:

Value of contractual reimbursed T/S energy losses = (Fuel Cost) * (Reimbursed gWh Loss) * (IER)

The value of the reimbursed transmission service capacity losses due to contractual arrangements is calculated as follows:

Value of reimbursed capacity loss = (Capacity loss reimbursed) * (Proxy) * (ERI)

Value of Loss Reduction Benefit

Figure B-7 displays DRA's base case results for the annual net loss reduction benefits. In terms of NPV, the results are summarized below:

Loss Reduction/Reimbursement Benefits
(in NPV, million 1990 $)

	W(93)-A	W(95)-A	W(97)-A	B-A	C-A
Total Benefits	101	98	95	38	56

As indicated in the above table, the W Cases all yield substantially more loss reduction/reimbursement benefits than Case B or C. The results tend to follow a trajectory similar to a combination of capacity values and marginal generation costs. This is because the value of energy loss reductions (including reimbursements) is tied to production costs. The value of capacity loss reductions (and reimbursements) is tied to the proxy value of capacity, which increases dramatically (when the ERI goes to unity) in 1997.

These results differ slightly from those presented in SCE's Amended Application.[34] One difference is in the reimbursed losses due to DRA's assumption that MSR would only have 50 MW until 1995. The other difference is due to updated marginal costs employed in DRA's analyses, upon which less savings are based.

34 For the W(93) Case, SCE's analysis produced loss reduction benefits of approximately $112 million (in NPV, 1990 $), see Table B-1.

Table B-1

Application No. 85-12-012
Devers-Palo Verde T/L No. 2

Comparison Exhibit
1993 Start-Up
($ millions)

	Net Present Value		Levelized Value	
	Edison	DRA	Edison	DRA
BENEFITS				
DPV2 T/S Revenues	63.04	64.20	7.60	7.74
WOD T/S Revenues	60.79	57.00	7.33	6.87
Total T/S Revenues	123.83	121.20	14.92	14.61
Prod. Cost Savings	188.27	203.69	22.69	24.55
Loss Reduction	111.78	100.95	13.47	12.17
Air Quality	24.76	35.12	2.98	4.23
Stability	16.40	16.40	1.98	1.98
UIS	31.04	61.91	3.74	7.46
Total Benefits	496.08	539.27	59.78	64.99
COSTS				
Capital Costs	165.77	171.85	19.98	20.71
O & M	3.01	3.05	.36	.37
Total Costs	168.78	174.90	20.34	21.08
NET BENEFITS	327.30	364.37	39.44	43.91

Sources

1. Edison estimates: Exhibit 25, Table 2-6, pages 2-74 to 2-83
2. DRA estimates: Exhibit 32, Table 8-1, pages 8-2 to 8-7; and page 8-9

Table B-2

Different Measurements of Reliability:
Utility Interconnection Support and System Stability

	UIS	System Stability
Time frame	Next day	Less than 1 second to several seconds
Analytic tools	Load flows	Stability models
Arranged by dispatchers	Yes	No, automatic
Scheduled flows	Yes	No
Operational limits	Transmission capacity; Nomograms	Protective equipment*
Measurement	MW	Probabilities**

* *See* Amended PEA at p. 2-118.

** TR at 692.

EDISON/LADWP EXCHANGE AGREEMENT PROVISIONS APPLICABLE TO THE DEVERS-PALO VERDE NO. 2 T/L PROJECT ANALYSIS

Use of 200 mW of LADWP's Castaic Pumped Storage capacity towards meeting Edison's spinning reserve

An additional 180 mW of non-firm Northwest transmission access,

LADWP's receiving a 217 mW ownership allocation in DPV#2 in lieu of firm transmission service from Edison,

LADWP's receiving 368 mW of "bridging" transmission service on DPV#1 from June 1, 1990 until DPV#2 goes into operation,

Walver of transmission service charges for LADWP's 368 mW of firm service from Devers to Sylmar/Victorville for 22 years,

Walver of transmission service charges for LADWP's 100 mW of firm service from Palo Verde to Sylmar/Victorville for 22 years.

FIGURE B-1

FIGURE B-2

Summary of Alternative Cases

Cases	PNW Intertie Access Swap*	Additional T/S Provided on DPV1/DPV2	Castaic Avail. for Spinning
"Reference" A	320/320	0	No
"Infinite Bridge" B	500/320	• Only LADWP on DPV1: • 368 MW paid T/S; • 100 MW free T/S (22 yrs) • All WOD T/S free	Yes
"Expanded Infinite Bridge" C	500/320	• Same as Case B for LADWP; • MSR and other SCPPA added to expanded DPV1 in 1993. • 72 MW paid T/S (SCPPA) • 150 MW paid T/S (MSR) • WOD T/S paid (SCPPA)	Yes

* Under the 500/320 swap, it is assumed that the Exchange Agreement results in 180 MW of additional transmission capacity (for non-firm purchases) to the Pacific Northwest (PNW).

(Continued)

FIGURE B-2

Summary of Alternative Cases
(Continued)

Cases	PNW Intertie Access Swap	Additional T/S Provided on DPV1/DPV2	Castaic Avail. for Spinning
"Build DPV2" W(93)	500/320	• Case B until line is built (LADWP on DPV1) • All participants on DPV2 after 1993** • 150 MW paid T/S (MSR) • 100 MW paid T/S after June 1995 (SDG&E) • WOD T/S paid (SCPPA, SDG&E)	Yes
W(95)	500/320	Case W(93) postponed until 1995	Yes
W(97)	500/320	Case W(93) postponed until 1997	Yes

** LADWP's 368 MW of paid T/S, MSR's 150 MW of paid T/S, and the other SCPPA participants 72 MW of paid T/S became "ownership shares" under the W Cases.

FIGURE B-3

TRANSMISSION SERVICE REVENUES

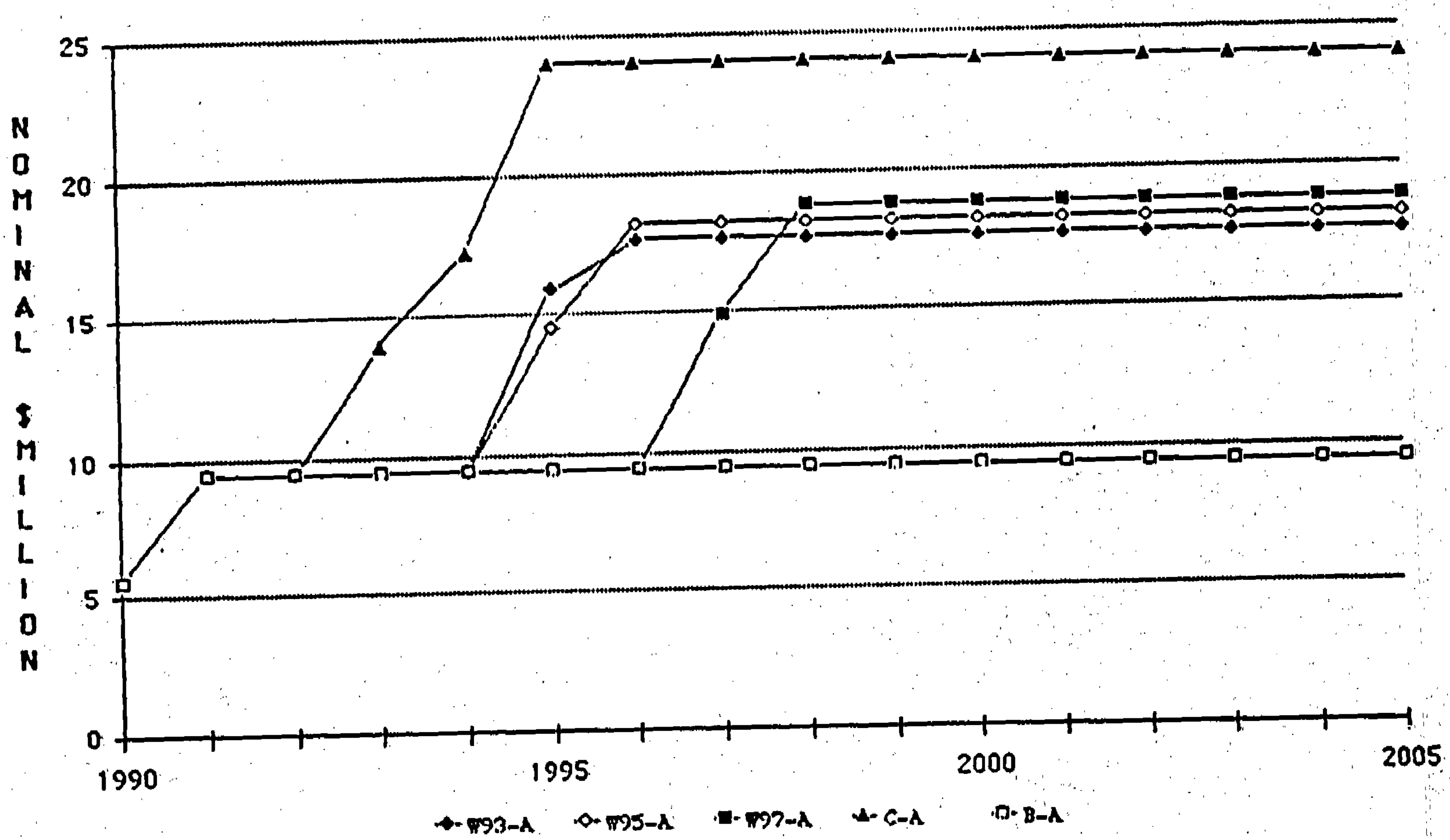


FIGURE B-4

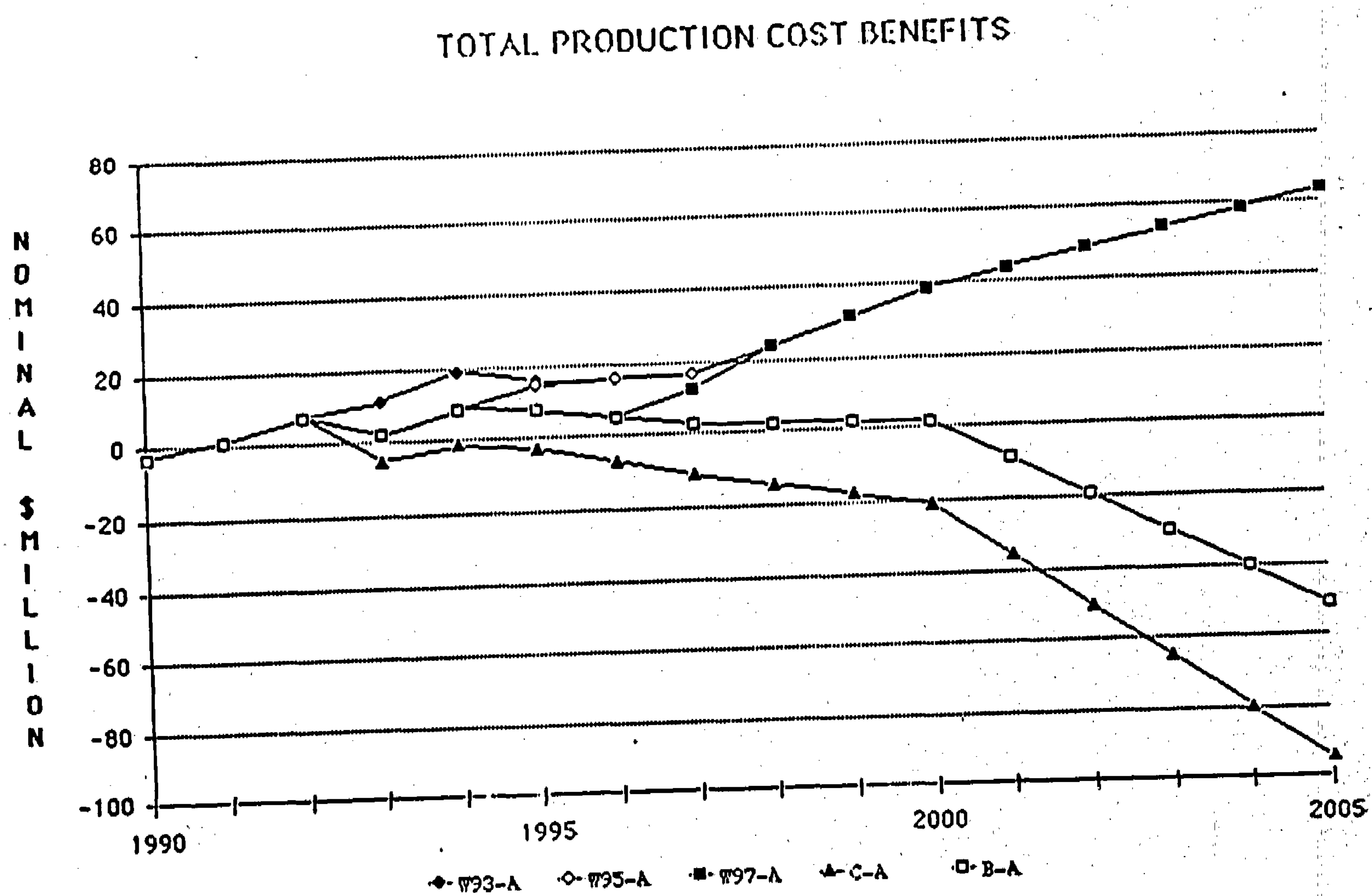

TOTAL PRODUCTION COST BENEFITS
NOMINAL $MILLION
80
60
40
20
0
-20
-40
-60
-80
-100
1990
1995
2000
2005
W93-A
W95-A
W97-A
C-A
B-A

FIGURE B-5

REDUCED NOx EMISSIONS

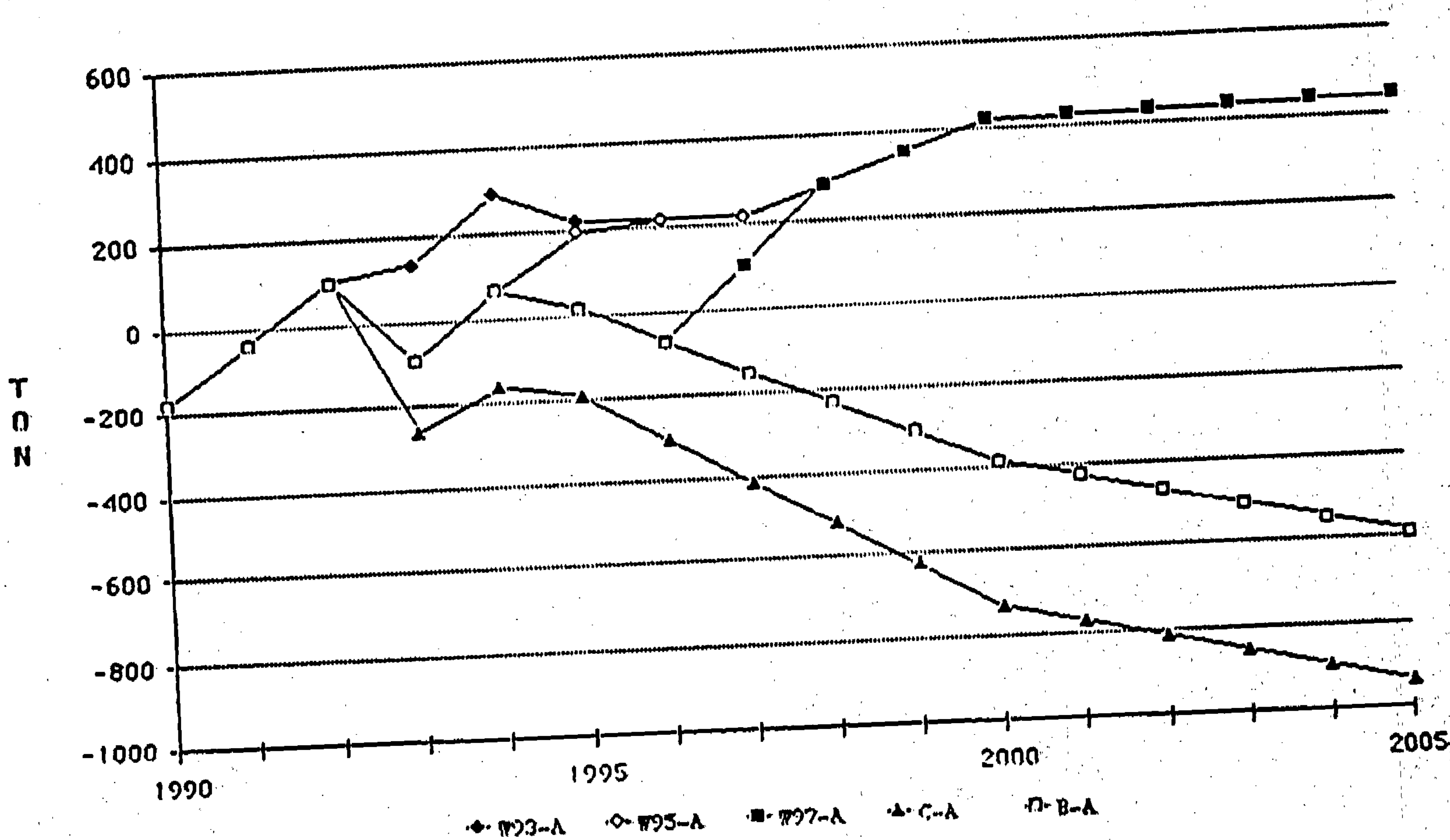
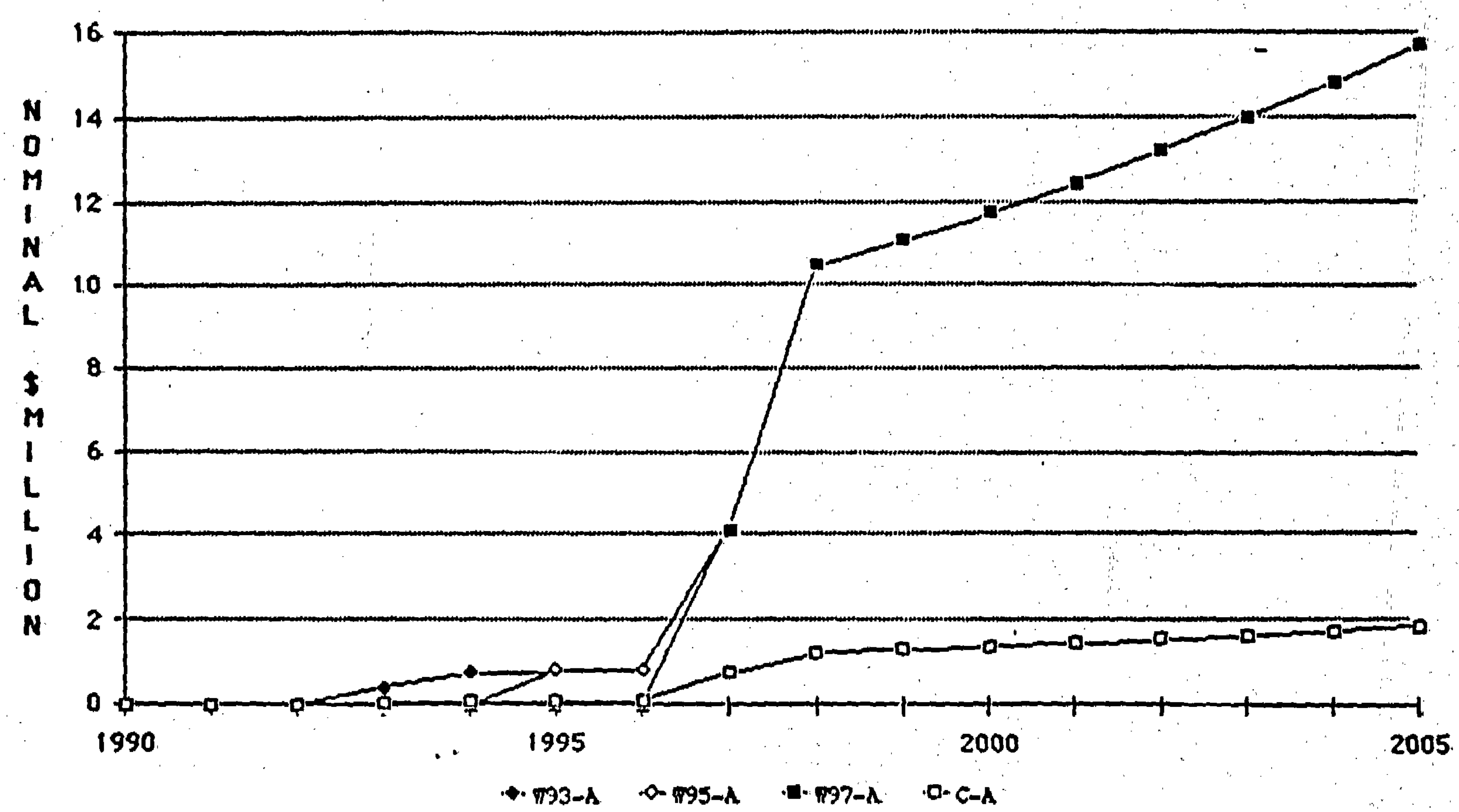


FIGURE B-6

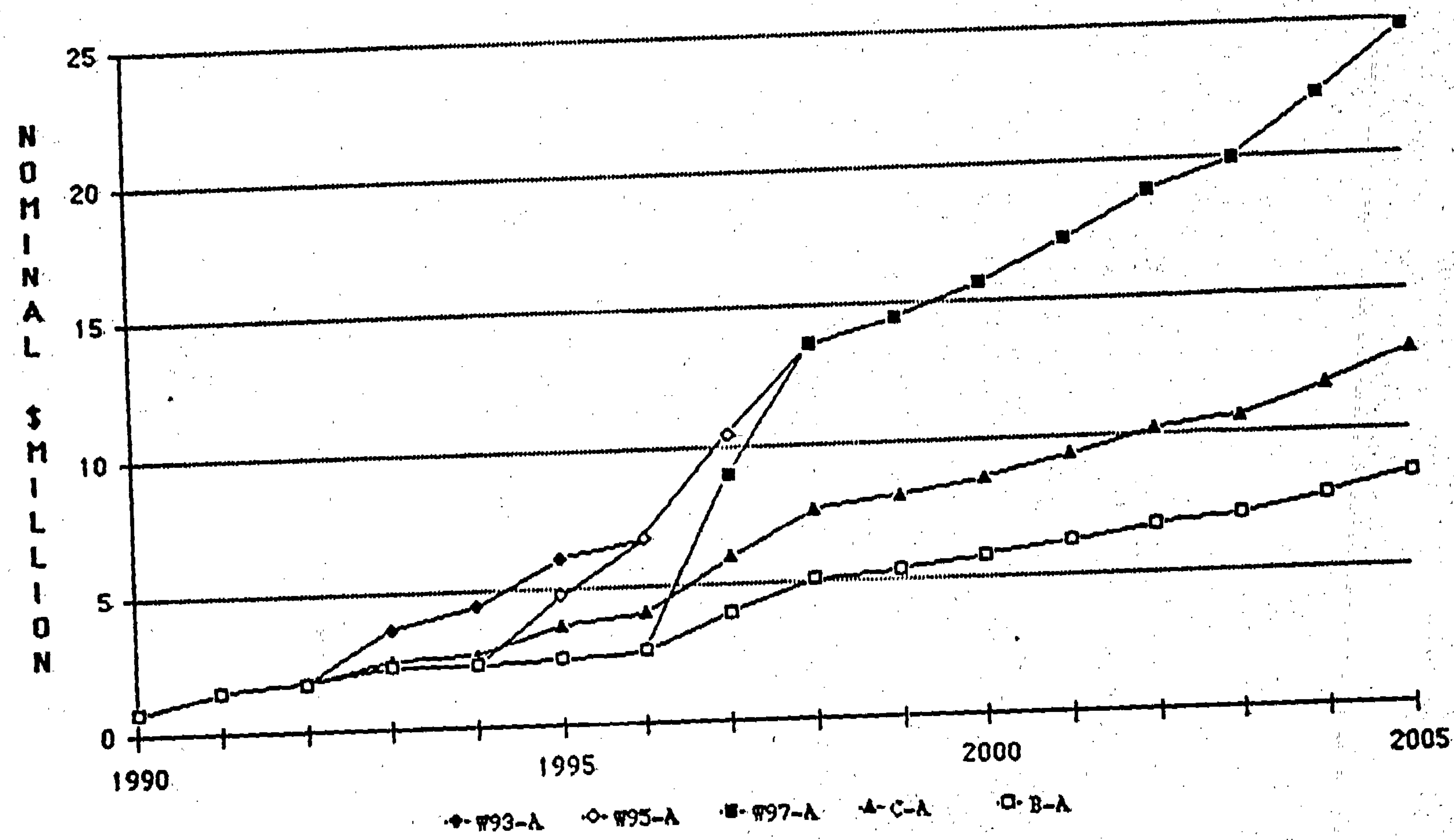
UIS BENEFITS



Note: Case B's UIS benefits are zero.

FIGURE B-7

LOSS REDUCTION/REIMBURSEMENT BENEFITS



Attachment 1

Summary of Base Case Assumptions

During the joint study process, SCE and DRA agreed upon the use of common assumptions for the base case analysis of DPV2 and alternatives.[1] These include:

- Economy Pricing: Pricing by PNW and Southwest utilities would be based on their production cost plus 15 percent for all but the cheapest sources of energy. The cheapest sources are priced at production cost of the most expensive of the resources found in the lowest priced block of power.

- Use of Empty Transmission Capacity for Economy: Surplus line space of another utility (e.g., LADWP) would not be made available to carry additional SCE economy purchases during times that the SCE system is fully loaded.

- Use of SERASYM: DRA and SCE agreed to use SERA's proprietary production cost model SERASYM, for modeling the SCE service territory.

- Resource Plan/Load Forecast: The SCE Fall 1987 Resource Plan and compatible load forecast were used.[2]

- SCE Capacity Value: The capacity valuation produced using CEC Electricity Report VI assumptions was used.

- Gas/Oil Price Forecast: The 1988 California Gas Report price forecast for the second tier gas price and for residual oil pricing were used.

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1 See Exhibit 32, p. 1-11 to p. 1-15.

2 See SCE's Amended PEA (Exhibit 25) pp. 2-47 and 2-48 and Appendix A for a summary of resource plan assumptions.

- <u>Gas Curtailments:</u> Gas curtailments were modeled in the last two weeks of December for each year. In addition, the first week of January was assumed curtailed in 1997 and the first two weeks of January in 2000 and thereafter.

- <u>Value of Stability</u>: The value of stability improvements in the PSW transmission system due to DPV2 were assumed to be credited only to SCE ratepayers.

- <u>Cost of Capital</u>: SCE's 12.01 percent cost of capital was employed.

- <u>SDG&E Line Usage</u>: SDG&E was assumed to exercise its option for 100 MW of transmission service for 30 years on DPV1 on the later of June 1995 or the DPV2 on-line date.

- <u>Line Reinforcements West of Devers (WOD)</u>: The line reinforcements formerly planned for WOD are not included in the project cost effectiveness assessment and their absence will not result in a line overload.

(END OF APPENDIX B)

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APPENDIX C
Page 1

Comparison of Project Alternatives

During this proceeding SCE and DRA evaluated a broad range of project alternatives to constructing DPV2, including:

1. Location Alternatives: Alternative routes to avoid the Blythe agricultural area.

2. Electrical System and Technical Alternatives: Alternative means of achieving the objective of the project through use of other existing and new transmission systems, upgrades or modifications to existing equipment. These include:

   a. Phoenix-Mead-Adelanto. Under this alternative, SCPPA and MSR participants would build a 500 kV DC line from Adelanto, California to Mead, Nevada and from Mead to Phoenix, Arizona. Neither SCE (or the CPUC) would be involved.

   b. Valley-Miguel Interconnect. Under this alternative, a 500 kV line would be built between Miguel (SDG&E) and Valley (SCE) to increase net east-to-west transfer capability.

   c. SWPL#2 Plus Interconnect. The Southwest Powerlink (SWPL) is a 500 kV AC transmission line connecting the Palo Verde switchyard with San Diego, California. Under this alternative, a second 500 kV line would be built along the same corridor, and the Valley-Miguel line would be built to interconnect SDG&E and SCE.

   d. All Intertie--70% Compensation. The power transfer capacity of existing equipment would be increased by increasing the series compensation on the existing AZ-CA Interties to 70 percent of each line's inductive reactance.

   e. DPV1, SWPL--70% Compensation. The overall AZ-CA transfer capability would be increased by increasing series compensation on DPV1 and segments of SWPL ("Expanded Infinite Bridge Case C").

f. DPV1 Convert to 500 kV DC. DPV1 would be converted from AC to DC operation. All of the insulators would be changed and converter stations would be added at each line terminal.

g. DPV1 Convert to 765 kV AC. DPV1 would be converted to 765 kV AC operation. Existing towers would need to be replaced and power transformers would be required at each line terminal. The line would be removed from service for the construction period.

h. Loop Flow Control Equipment. Loop flow control alternatives would be implemented to increase the allowable firm power transfer on existing lines.

3. No Project: Effects of not implementing the project, and using the existing SCE system:

   a. without providing any wheeling ("Reference Case A"); or

   b. providing wheeling service to LADWP ("Infinite Bridge Case B")

4. System Timing Alternatives: Delaying the project on-line date from 1993 to 1995 or 1997. (Cases W(95) and W(97))

As described below, each alternative was evaluated in terms of its relative environmental impacts, cost-effectiveness and technical/institutional considerations. Figure C-1 presents a matrix summarizing SCE's evaluation of the alternatives with less environmental impacts than DPV2.

A. Alternatives with Greater Environmental Impacts

1. Location Alternatives

SCE and DRA studied two alternative routes to avoid the Blythe agricultural area by skirting around Blythe to the north and south. These studies concluded that the proposed route minimized

Figure C-1

ALTERNATIVE EVALUATION MATRIX

ALTERNATIVE DESCRIPTION	SYSTEM CHARACTERISTICS	ECONOMIC FACTORS: TOTAL PROJECT (1) CAPITAL COST	$/kW	SCE SHARE: NET BENEFIT	BENEFIT/COST RATIO	ENVIRONMENTAL FACTORS	TECHNICAL/INSTITUTIONAL FACTORS	KEY DECISION POINTS
[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
No-Project A. [illegible]	[illegible]		(2)	0	N.A.	(2)	(2)	[illegible]
B. [illegible]	[illegible]	0	[illegible]	[illegible]	N.A.	(2)	(2)	[illegible]
[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
[illegible]	[illegible]	[illegible]	[illegible]	-	-	[illegible]	[illegible]	[illegible]
[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
[illegible]	[illegible]	[illegible]	[illegible]	-	-	[illegible]	[illegible]	[illegible]

NOTES:

(1) [illegible]

(2) [illegible]

(3) [illegible]

(4) [illegible]

(5) [illegible]

(6) [illegible]

Source: Applicant's Concurrent Brief, page 36.

environmental impacts compared with alternative routes.[1] Table C-1 presents the EIR team's comparative evaluation of route alternatives.

2. Other Transmission Line Alternatives

a. Phoenix-Mead-Adelanto 500 kV DC

DRA reviewed both LADWP's Mead-Adelanto 500 kV DC line[2] and the Phoenix-Mead-Sylmar line studied by the Western Area Power Administration. The cost of these alternatives is estimated at $850 million (1990 $), about three times the cost of DPV2. These alternatives also have a significantly greater environmental impact than the proposed project. DRA concludes that the proposed project is preferable to these alternatives on both economic and environmental grounds.

b. Valley-Miguel/SDG&E Interconnect

This alternative would consist of a 500 kV line between SDG&E's Miguel Substation and SCE's Valley Substation. The strengthening of the SDG&E-SCE transfer capabilities would increase the transfer capacity of the existing SWPL line by approximately 200 MW. The cost of the Valley-Miguel line would be approximately $240 million. The line would involve the construction of 91 miles of new transmission line, only 9 of which are parallel to an existing line. The environmental impacts of this alternative are higher than for the proposed project. DRA concludes that, for a cost close to DPV2, this alternative would only increase the transfer capacity from Arizona by one-sixth as much.

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1 Exhibit 25, Amended PEA, pp. 10-24 through 10-93; Exhibit 6A, DEIR, Vol. 1, pp. 239-45.

2 Without an additional transmission line from Phoenix to Mead, the proposed Mead-Adelanto line does not increase transfer capability from the Palo Verde/Phoenix area to southern California. For the comparison of alternatives, Mead-Adelanto is coupled with the Westwing-Mead 500 kV DC project that would bring power out of the Phoenix area.

Table C-1

Comparative Evaluation of Devers-Palo Verde
500 kV Transmission Line Route Alternatives[1]

Environmental Consideration	Transmission Line Routes: Proposed	Northern Blythe Alt.	Southern Blythe Alt.
Total Length	126 mi.	132 mi.(L)	125.5 mi.
New ROW Required	0 mi.(P)	17 mi.	16.0 mi.
Geology	Low	Mod	Mod
Soils	Mod	Mod	Mod
Hydrology	Low	Low	Low
Biological Resources	Low(P)	Low	Mod(L)
Land Use	High	High	High
Socioeconomic	Low	Low	Low
Visual	Mod	High	High
Acoustic	Low	Low	Low
Archaeol. and Historical Resources	Low(P)	Mod	Mod
Nat. Amer. Resources	High	High(L)	High
TOTALS			
No. High & Mod.	4	6	7
No. Pref. (P)	3	0	0
No. Least Pref. (L)	0	2	1

NOTES: Impact Ratings are High, Moderate, or Low
(P) = Clearly the preferred choice
(L) = Clearly the least preferred choice
If no (P) or (L) is indicated among the range of alternatives, no clear advantage or disadvantage could be identified.
All ratings are based on projected impacts and represent professional judgments of the EIR team.

[1]This analysis considers impacts in California only - comparative values for some resource areas would change when considering implications in Arizona.

Source: Exhibit 6A, page 244.

c. Second SWPL + Valley-Miguel

This alternative would consist of building a second SWPL 500 KV AC line and the Valley-Miguel line. DRA concludes that it would have all the adverse impacts of the Valley-Miguel line plus impacts associated with building a second SWPL.

B. Alternatives with less Environmental Impacts

1. The "No-Project" Alternative

DRA considers the no-project alternative, because it involves no construction of additional transmission lines, to be clearly one of the environmentally preferred alternatives. As described in the body of this order, the no-project alternative was reevaluated as "Reference Case A" during Phase I hearings, due to the major changes in economic context since the EIR was prepared. Under the no-project alternative, SCE would not provide transmission service to MSR, LADWP, or the other SCPPA coparticipants.[3] SCE would forego over $360 million worth of benefits to its ratepayers. DRA now believes that under most circumstances the no-project alternative cannot meet the project objectives.[4]

SCE argues that there is a significant negative regional impact associated with the no-project alternative. In SCE's view, the SCPPA participants and MSR would build either DPV2 or the proposed Phoenix-Mead-Adelanto DC project themselves, in order to have a long-term transmission path for their Palo Verde and San Juan entitlements. The latter would be three times as expensive, twice as long, and have a significantly greater environmental impact than DPV2.

3 DRA states that the conclusions reached in the Draft EIR that the no-project alternative can meet all the project objectives are now anachronistic since the project objectives have changed both in substance and timing.

4 One important qualification to DRA's rejection of the no-project alternative is SCE's proposed merger with SDG&E. DRA argues that, if the merger occurs, then SCE's access to SPWL would allow the no-project alternative to meet all of SCE's objectives from the project with essentially no environmental impact. This issue is discussed in Section VIII of this order.

2. The "Infinite Bridge" Alternative

The Infinite Bridge scenario is similar to the no-project alternative except that SCE uses its existing system to wheel LADWP's power. As described in the body of this order, this alternative was reevaluated as "Case B" during Phase I hearings.

Both DRA and SCE consider this project substantially less cost-effective than the proposed project. Although this alternative is preferable during the initial years, it turns negative after 2002 due to opportunity costs. The total project life benefits of this alternative are $22 million (NPV). DRA and SCE conclude that choosing this alternative would force SCE to forego over $340 million (NPV) in ratepayer benefits. SCE also argues (as it did for the no-project alternative) that SCPPA and MSR would probably build their own line if the Infinite Bridge alternative was adopted.

3. The Series Compensation Alternatives

SCE and DRA examined two alternatives for raising SCE's transfer capacity from the Southwest by increasing the series compensation on one or more existing transmission lines. In layman's terms, increasing series compensation allows a utility to "pack" more power into a transmission line. Because no new towers would need to be built or new conductors strung, these alternatives would cause none of the environmental impacts associated with any of the DPV2 scenarios.

Increasing the series compensation on transmission lines increases the likelihood a utility will encounter problems with subsynchronous resonance (SSR) at a generating plant.[5] A variety of SSR mitigation devices are available at a range of prices. Until a detailed engineering study is done of the particular transmission line(s), it is not possible to tell which of these devices would be effective in correcting the problem. DRA's analysis made conservative assumptions that relatively expensive SSR mitigation devices would be required.

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5 SSR can be described as a phenomenon where the harmonic frequencies of the transmission system "beat" against the mechanical frequencies of turbine shafts. This can cause serious mechanical failures at generating stations, unless corrective measures are taken.

a. The "Expanded Infinite Bridge"

The Expanded Infinite Bridge alternative would increase series compensation from 50% to 70% on DPV1 and the Miguel-Palo Verde line (SWPL) thereby increasing the overall California-Arizona transfer capacity on DPV1 and SWPL by about 200 MW. SCE would then wheel MSR's, LADWP's, and the SCPPA cities' power over the expanded DPV1. This alternative was evaluated as "Case C" in DRA's and SCE's updated economic analysis. This alternative is estimated to cost $16 million.

Because this alternative would not involve the construction of new transmission lines, it is also one of the environmentally preferred alternatives.

SCE opposes this alternative, arguing that the technology is too risky, perhaps very expensive, and this alternative would require much cooperation with other utilities, particularly Arizona Public Service.

DRA does not recommend this alternative because it is substantially less cost-effective than the proposed project. It has a projected NPV of negative 47 million. DRA also notes the uncertainty about gaining the cooperation of other owners of Palo Verde to install the SSR suppression equipment that would be required.

4. All Lines 70% Compensation Alternatives

Another alternative studied involved increasing the series compensation on all the existing Arizona-California interties from various levels ranging from 26-70% to a uniform 70%. This would increase transfer capacity on the interties by 400 MW at a cost of approximately $118-136 million. Some of this 400 MW would be allocated to other utilities using the intertie.

Although SERA's initial analysis showed this alternative to be probably technically feasible, SERA did not do a detailed economic analysis because the SWPL-DPV1 series compensation alternative could achieve the same project objectives at much less expense, with less technical complexity, and without having to obtain cooperation from so many other utilities who may have little incentive in accepting increased risk of SSR.

5. Conversion of DPV1 to DC

This alternative would involve converting DPV1 to 500 kV DC line with a transfer capacity of approximately 2500 MW. Since new towers would not have to be installed, this alternative would have less environmental impacts than the proposed project. Although the increase in transfer capacity of 1300 MW would be slightly greater[6] than DPV2, the expense would be much greater--$750 million. On a per-kW basis, the cost would be approximately three times greater than DPV2.

Both SCE and DRA expressed concerns regarding the stability and reliability effects of this alternative. DRA witness Weatherwax characterized the effect of a single 2500 MW DC line on SCE's system stability as[7] being, if not "unacceptable", at least "extremely discouraging." SCE states that it is uncertain whether the Palo Verde plant could effectively coordinate its complex control system with that of the DC line. Loop flow benefits previously associated with this alternative in the Draft EIR are no longer material due to the installation of phase shifters elsewhere.[8]

6. <u>Non-Transmission Line Alternatives</u>

DRA's consultants examined QF's, conservation and load management, and additional loop flow control measures as alternatives to DPV2. DRA notes that important loop flow control measures have been taken independent of DPV2, and the exchange agreement with LADWP allows SCE through DPV2 to capture significant benefits from the PNW. DRA concludes that none of these alternatives would meet project objectives.

C. <u>Alternatives with the Same Environmental Impacts</u>

1. <u>Upgrading DPV1 to 765 kV AC</u>

This alternative would involve the reconstruction of the existing DPV1 line to a four-conductor configuration. All the towers would have to be replaced and DPV1 would be out of service during the construction period. During that period, SCE would be isolated from its Palo Verde generation entitlement. The net increase in transfer capacity would be approximately 400 MW at a cost of about $335 million, or $840 million per kW.

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6 The net increase in transfer capacity is only 1300 MW because converting the 500 kV AC DPV1 line to 500 kV DC operation results in the loss of about 1200 MW of existing AC transmission capacity.

7 Tr. at 800-801.

8 Tr. at 801.

The reason for this expense is that the existing towers and footings are not strong enough and do not provide adequate clearances for 765 kV operation. The existing towers and footings would therefore have to be removed and replaced with stronger and taller structures. In addition, new 765 kV transformers would be required at each end of the line to connect it to the existing transmission network. Environmental impacts of this alternative are extensive ground disturbance resulting from the removal of existing towers and constructing new towers and greater visual impact due to the higher towers. The EIR analysis concluded that this alternative "would entail virtually the same construction impacts as would the proposed new line."[9]

2. 1995 or 1997 In-Service Dates

Under these alternatives, the physical impacts of line would be the same as described for the proposed project. The only difference is in the timing of the impacts--they would occur either two or four years later. DRA's evaluation of the relative net benefits of these alternatives is presented in the body of this order.

9 Exhibit 6B at 83.

(END OF APPENDIX C)

DPV2

List of References of Specific
Environmental Mitigation Requirements
(Source: Exhibit 37)

References to Mitigation in the FEIR (Aug.'87)

(Letters (B,C,etc.) refer to those letters received in response to the DEIR.)

References where Vol. 1 of the DEIR is referred to:

p.7 (C-1)	DFG proposed 7 mitigation measures: -DEIR author generally agreed, but suggested modifications to #3. (Needs "stipulation" from Applicant.) (Reference to #3 in 1st bullet is wrong; should have been #4.) -CPUC "acknowledges" position expressed in DFG's #7; it will be "considered".
p.8 (C-2)	DFG: Notification to DFG will be required: comment "noted". (as called for in the Fish & Game Code)
p. 14 (D-21)	Accept SCE's revision to mitigation measure (last paragraph, line 7) on p. 210 of DEIR.
p. 14 (D-22)	Revise mitigation statements (1st paragraph) on p.211 of DEIR. (SCE's comments)
p. 14 (D-23)	Revise mitigation statements (2nd paragraph) on p.211 of DEIR. (SCE's comments)

References where Vol. 2 of the DEIR is referred to:

FEIR-p.19 (G-1)	Staff recommends condition of approval requiring SCE to document the Seismic Preparedness of Devers, providing responses to 5 topics. (City of Palm Springs' comments)

References to Mitigation in the DEIR, Vol. 1 (March 1987)

pp.135-238 Section 5.0 Environmental Impacts & Mitigation Measures

p.137 Geology. 5.1.4 Mitigation Measures
7 measures on pp.138-139.

p.144 Soils. 5.2.4 Mitigation Measures: 2 measures.

p.147 Hydrology. 5.3.4 Mitigation Measures: 4 measures.

p.159 Biological Resources. 5.4.4 Mitigation Measures
p.159-Vegetation: Details of proposed transplant efforts need to be identified. Additional mitigation guidelines, as given by E. Linwood Smith & Associates (1985: Appendix N) and presented in Appendix B of this DEIR Vol. 1, should be followed to the extent feasible.

pp.159-160-Summary of 8 primarily recommended mitigation measures.

p.160-Wildlife: Adhere to mitigation measures presented by the Applicant in Section 7.6 of the PEA, as well as adopting the Vegetation Mitigation Measures and 6 others listed on pp.160-161.

Land Use & Planning
p.172-Tower Siting & Design: The proposed transmission line meets all CAAA & ASAE recommended criteria with one exception. The proposed project should include measures to increase the visibility of the line:
1) use of specular conductors.
2) use of white reflective devices on towers.
3) expand system of lights.

p.182 5.5.3 Mitigation Measures

p.182 Consistency w/Relevant Plans & Policies - 1 measure.

p.183 Residential, Commercial & Industrial Land Use Mitigation - 1 measure.

p.183 Agricultural Land Use Mitigation
- To minimize reductions in crop productivity - 3 measures.

pp.183-184 - To minimize agricultural aircraft safety hazards - 2 measures.

p.184 Transportation & Utilities Mitigation - 4 measures.

p.184 Park, Recreation & Preservation Area Mitigation - 3 measures.

p.185	General Mitigation: at end of projects useful life - dismantling & removal. 1 paragraph.
p.189	Socioeconomic Impacts. 5.6.4 Mitigation Measures (1st paragraph) No mitigation is proposed. Recommended, however, to coordinate work crews to avoid significant impacts to temporary housing supply.
	Visual Resources 5.7.3 Mitigation Measures
p.210	General Consideration - 3 measures.
p.211	Site-Specific Mitigation Measures for High Impact Areas - Proponent's Preferred Route: Mitigation measures for 3 route segments
p.218	Acoustic Considerations 5.8.4 Mitigation Measures Transmission Line Noise: No measures required. Construction Noise: 6 measures.
p.226	Archaeological & Historical Resources 5.9.3 Mitigation Measures: 2 measures.
p.227	Also, SCE will comply w/BLM policy...: 2 measures.
p.229	Native American Resources 5.10.3 Mitigation Measures One paragraph.

References to Mitigation in Appendix A of the DEIR, Vol. 1 - Summary of Public Scoping Meetings & Workshop

Summary of Public Workshop: Blythe, 6/16/86.
Points Raised by Public Participants(no page #s):

Hazards to Aerial Applicators: 3 mitigation measures noted.
Production Losses: 2 mitigation measures noted.
Hazards to Field Workers: 1 mitigation "measure" noted.
Increased Pesticide Usage: 1 mitigation measure noted.
Electric Field Effects: Mitigation: Unknown.
Visual: 1 mitigation measure noted (Place lines underground.)

References to Mitigation in Appendix B of the DEIR, Vol. 1 - Biological Impact & Mitigation Planning Chart

Source: E. Linwood Smith & Associates, 1985. Biological Inventory & Impact Assessment. DPV2. Prepared for Edison. See pages 3 of 5 thru 5 of 5 & the Planning Chart. This Appendix was referred to on p.159 of the DEIR, Vol. 1 in the Vegetation section (as noted above).

References to Mitigation in the DEIR, Vol. 2, (March '87)

pp.99-105		Section 4.0 of DEIR, Vol.2 = Mitigation Programs for High-Voltage Transmission Lines
		Generic mitigation for high-voltage transmission lines throughout CA.
		Project-specific mitigation for DPV2 is described in Vol.1 of the DEIR.
p.99	4.1	Pre-construction surveys based on final design, marking and staking in the fields of tower locations and access roads.
p.100	4.2	All sensitive resources discovered in the survey to be suitably marked for later protection or avoidance.
p.101	4.3	Environmental Protection Plan (EPP) & Handbook
p.102	4.4	Monitoring & Supervision
p.103	4.5	Enforcement
p.103	4.6	Restoration Plan
p.104	4.7	Sanction
p.104	4.8	Periodic & final reports on the mitigation/ monitoring program.

References to Mitigation in the Original PEA (December 1985)

Section 7.0 Mitigation of Significant and Potentially Significant Impacts of the Proposed Project

Land Use Mitigation. Section 7.1
In Arizona, no mitigation was needed nor identified.
pp.7-2,3,4 In CA, mitigation measures were identified for sections of 3 "links".

Cultural Resource Mitigation Section 7.2
p.7-4 Precise mitigation measures: developed on a case-by-case basis.

Geologic & Pedologic Mitigation Section 7.3
p.7-4,5 One paragraph discussion of mitigation measures.

Meteorologic, Climatologic, Air Quality Mitigation Section 7.4
p.7-5 No significant impacts. No mitigation required.

Hydrologic Mitigation Section 7.5
p.7-5 No significant impacts.

<u>Biological Mitigation</u> Section 7.6
p.7-6,7,8 Mitigation recommendations listed for 6 project "links".

<u>Sonic Mitigation</u> Section 7.7
p.7-9 No significant impacts. No mitigation required.

<u>Visual Mitigation</u> Section 7.8
p.7-9 Link 1: 2 measures.
Link 2: 3 measures.
p.7-11 Links 6, 8, 10: 3 measures.
Link 12: 2 measures.
p.7-13 Links 13 and 14: 3 measures.
Link 16: 2 measures.

<u>Socioeconomic Mitigation</u> Section 7.9
p.7-16 No significant impacts. No mitigation.

<u>Traffic & Transportation Mitigation</u> Section 7.10
p.7-16 No significant impacts. No mitigation.

<u>Public Health & Safety Mitigation</u> Section 7.11
p.7-16 No significant impacts.
Line is designed to minimize exposures. Public concerns addressed as they arise.

<u>References to Mitigation in the Amended PEA (August 1988)</u>

General Comment: No new mitigation measures are necessary.

Section 7.0 Mitigation...
(Almost exactly the same as Section 7.0 of Original PEA)
See list of mitigation measures for Original PEA.

Added: <u>General Mitigation</u> Section 7.12
"Site specific areas that require mitigation measures will be coordinated with the agency specifically involved with those areas, such as governmental agencies listed in Exhibit F of the application."

CERTIFICATE OF SERVICE

I hereby certify that I have this day served the foregoing document upon all known parties of record in this proceeding by mailing by first-class or sending by overnight delivery a copy thereof properly addressed to each party.

Dated at San Francisco, California, this 12th day of October 1988.

/s/ RENITA Y. STONE
Renita Y. Stone

(END OF APPENDIX D)

BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA

In the Matter of the Application of SOUTHERN CALIFORNIA EDISON COMPANY (U 338-E) for a certificate that the present and future public convenience and necessity require or will require the construction and operation by Applicant of a 500 kV transmission line between Palo Verde Switchyard and Devers Substation.	Application No. 85-12-012

EDISON/DRA AGREEMENT RE CERTAIN CONDITIONS ON CERTIFICATE

As part of the continuing effort to narrow the issues and to expedite the proceedings in this case, Southern California Edison Company ("Edison"), the Applicant herein, and the Division of Ratepayer Advocates ("DRA") of the California Public Utilities Commission ("Commission") jointly recommend to the Commission that if a Certificate of Public Convenience and Necessity is issued for Edison's proposed Devers-Palo Verde No. 2 500 kV Transmission Line ("DPV2"), such certificate should include the following conditions:[1]

1. By January 15, 1990 Edison shall submit a report to the Commission describing the status of the efforts of SCEcorp (Edison's parent company) to merge with San Diego Gas & Electric Company ("SDG&E"). This report will indicate, as of January 1, 1990, whether (a) a merger agreement has been entered into by SCEcorp or Edison and SDG&E, (b) SCEcorp or Edison has commenced and is continuing a solicitation of SDG&E shareholders for the purpose of a merger, and

1. The dates for submission of the various reports and studies described herein have been chosen with the understanding that if Edison builds DPV2 for a June 1, 1993 operating date it will not be necessary to begin making commitments for purchasing material until February, 1990.

(c) SCEcorp or Edison has a public merger offer with SDG&E outstanding. If one or more of these conditions exist as of January 1, 1990, Edison (1) shall not commence construction of DPV2, and (2) shall petition the Commission for reevaluation of DPV2 in the context of the then status of the merger activity. To protect DPV2 project dates, Edison may solicit bids from material suppliers prior to January 1, 1990, but may not award any contracts for the purchase of material.

2. By July 1, 1989 Edison shall submit to the Commission a statement of its plans to enhance the net benefits attributable to DPV2 in the early years by measures such as increased transmission service revenues, transmission capacity layoffs, or other measures. This report shall include an analysis, including a production costing analysis, of the net benefits that would be derived from implementation of such plan, and showing that the enhanced benefits could not be realized without having DPV2 in service prior to 1997.

3. By July 1, 1989 Edison shall submit to the Commission a study on the likelihood and potential impact of a simultaneous outage of both the DPV1 and DPV2 lines. This study shall assess alternative measures for mitigating the impacts of such a simultaneous outage, and the effectiveness, cost, reliability, and feasibility of these measures. DRA recognizes that the final evaluation of strengthening the towers as a means of improving the reliability of these two lines will be made in the later report described in paragraph 5.

4. By November 1, 1989, Edison shall submit copies of the applicable signed agreements implementing the benefit enhancement measures referenced in Paragraph 2 above, and copies of signed contracts for transmission service over DPV1 from 1990-93, over DPV2, and over Edison's existing system west of the Devers Substation.

5. By November 1, 1989, Edison shall submit to the Commission a report analyzing the failures of the DPV1 line which occurred on August 21, 1986 and October 29, 1987 due to wind loading.

6. As soon as Edison can do so with a reasonable degree of certainty, it shall describe to the Commission what it believes will be the final provisions of the amendment to the "Los Angeles-Edison Exchange Agreement Between The Department of Water And Power Of The City Of Los Angeles And Southern California Edison Company", which is presently being negotiated to provide, inter alia, for the Department of Water and Power to receive transmission service over DPV1 from June 1, 1990 until the earlier of (1) the date when DPV2 commences commercial operation, or (2) June 1, 1993.

7. The reports described in Paragraphs 1 through 6 above shall be in the form of advice filings.

8. The project is cost-effective with a June 1, 1993 in-service date. However, if the in-service date is delayed to June, 1997, the Net Present Value ("NPV") of DPV2 for the initial period beginning on June 1, 1993 and ending on December 31, 1996 is $33.7 million greater, and the NPV attributable to DPV2 from 1997 on is reduced by almost $32 million (both in 1990 $). The goal in implementing the benefit enhancements referred to in Paragraphs 2 and 4 above will be to generate additional net benefits to enhance the near-term benefits so that the impact on the ratepayers during the 1993-97 time period will not be substantially different than under DRA's 1997 in-service date case (Case W(97) in Exh. 32).

9. Initially, the cost cap for Edison's share of DPV2, adopted pursuant to Public Utilities Code §1005.5, will be $172,400,000. By November 1, 1989, Edison will file with the Commission a summary of any changes in cost estimates to provide more current information with respect to the components of project costs, such as cost of materials and

cost of mitigation measures. At that time the cost cap will be adjusted, if appropriate.

10. Edison agrees that the firm summer rating of DPV2 will be 1200 MW (with all Palo Verde units on line), plus or minus five percent. Due to the coordination required between utilities in the Pacific Southwest to determine the actual rating of DPV2, the final determination will not occur until approximately six months prior to the project in-service date. If this rating is finally determined to be below 1140 MW, then the Commission may make further adjustments to the cost cap.

If a Certificate of Public Convenience and Necessity is issued by the Commission for DPV2, Edison and DRA respectfully request that the conditions described herein be included.

Respectfully submitted,

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Attorney for
DIVISION OF RATEPAYER ADVOCATES

Dated: September 29, 1988

(END OF APPENDIX E)

APPENDIX F

NOTICE OF DETERMINATION

TO: x Office of Planning and Research
1400 Tenth Street, Room 121
Sacramento, CA 95814

___ County Clerk
County of ______

FROM: (Public Agency) CPUC
505 Van Ness Avenue
San Francisco, CA 94102

SUBJECT: Filing of Notice of Determination in compliance with Section 21108 or 21152 of the Public Resources Code.

Devers-Palo Verde No.2 500 kV Transmission Line
Project Title

86072810	Mike Burke	(916) 322-7316
State Clearinghouse Number (If Submitted to Clearinghouse)	Contact Person	Area Code/Number/Extension

Western Arizona and Riverside County in California
Project Location

Construct a second 500 kV transmission line in an existing right-of-way
Project Description

between Edison's Devers Substation near Palms Springs and the Palo Verde Nuclear Plant in Arizona.

This is to advise that the California Public Utilities Commission (Lead Agency or Responsible Agency) has approved the above described project on ______ (Date) and has made the following determinations regarding the above described project:

1. The project x will, ___ will not have a significant effect on the environment.
2. x An Environmental Impact Report was prepared for this project pursuant to the provisions of CEQA.
   ___ A Negative Declaration was prepared for this project pursuant to the provisions of CEQA.
3. Mitigation measures X were, ___ were not made a condition of the approval of the project.
4. A statement of Overriding Considerations X was, ___ was not adopted for this project.

This is to certify that the final EIR with comments and responses and record of project approval is available to the General Public at:

CPUC, 505 Van Ness Avenue, San Francisco, CA 94102

Date Received for Filing and Posting at OPR ______

______
Signature (Public Agency) Title

(END OF APPENDIX F)

ALJ/MEG/tcg

Decision __________

BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA

In the Matter of the Application of SOUTHERN CALIFORNIA EDISON COMPANY (U-338-E) for a certificate that the present and future public convenience and necessity require or will require the construction and operation by Applicant of a 500 kV transmission line between Palo Verde Switchyard and Devers Substation.	Application 85-12-012 (Filed February 26, 1986; amended August 15, 1988)

Philip Walsh, Carol A. Schmid-Frazee, Arthur L. Sherwood, Attorneys at Law, for Southern California Edison Company, applicant.

James F. Walsh, E. Gregory Barnes, William L. Reed, and Manning W. Puette, Attorneys at Law, for San Diego Gas & Electric Company and Emanuel H. Blum, for Sky Valley Chamber of Commerce and S. V. Homeowners, protestants.

Howard V. Golub, Andrew L. Niven, and John W. Busterud, Attorneys at Law, for Pacific Gas and Electric Company; William S. Shaffran, Deputy City Attorney, for the City of San Diego; Morse, Richard, Weisenmuller and Associates by Robert Weisenmuller; Jeffrey E. Jackson, Attorney at Law, for Southern California Gas Company; Michael Peter Florio, Attorney at Law, for T.U.R.N.; Nancy J. Albers, for Unocal Corporation; and Edward J. Terhaar, for MSR Public Power Agency; interested parties.

James Scarff, Attorney at Law, Michael Burke, Burt Mattson, and Stuart Chaitkin, for the Division of Ratepayer Advocates.

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APPENDIX A: DPV2 Project Location

APPENDIX B: Summary of Assumptions, Methodologies and Results for DPV2 Base Case Analysis

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APPENDIX E: Edison/DRA Agreement Re Certain Conditions on Agreement

APPENDIX F: Notice of Determination

INTERIM OPINION

I. Decision Summary

This proceeding has been bifurcated into two phases. This order addresses the issues pertaining to Phase I of the proceeding.

By this order, we approve the application of Southern California Edison Company (SCE) for a certificate of public convenience and necessity (CPC&N) to construct Devers Palo Verde No. 2 (DPV2), a second 500 kilovolt (kV) transmission line between Palo Verde Switchyard and Devers Substation. The DPV2 project is certified for no earlier than a June 1, 1993 in-service date, subject to several conditions stipulated to by SCE and the Division of Ratepayer Advocates (DRA).

First, SCE is required to enhance near-term project benefits so that the impact on ratepayers during the 1993-1997 period will not be substantially different than under DRA's 1997 in-service date case. Second, the construction of DPV2 will be suspended if an SCE/SDG&E merger is still an active possibility as of January 1, 1990. Third, SCE is required to file by November 1, 1989 all transmission service contracts associated with this project. Finally, SCE is required to file detailed studies on wind-loading and the likelihood of simultaneous outages of Devers Palo Verde No. 1 (DPV1) and DPV2.

Our approval is subject to implementation of all mitigation measures described in the environmental documents, where applicable. Our decision also provides for a mitigation monitoring program and adopts a cost cap of $172,400,000 for SCE's share of project costs. This cap may be adjusted to reflect the actual costs of mitigation measures, SCE's final ownership share, and the actual line rating of DPV2.

II. Procedural History

In December 1985, SCE filed its original Application (A.) 85-12-012 requesting a CPC&N to construct DPV2. As originally proposed, DPV2 was scheduled for a June 1990 in-service date. The application was accepted for filing on February 26, 1986.[1]

Shortly thereafter, a protest was filed by San Diego Gas & Electric Company (SDG&E). SDG&E had responded to a solicitation for participation in the project. SDG&E had requested a share of the project's capacity, but did not receive one from SCE. Through this protest, SDG&E alleged anticompetitive behavior and sought an allocation by this Commission of 400 megawatts (MW) of capacity on the project. This protest was settled in July 1986 under an agreement whereby (1) SCE granted SDG&E an option for 100 MW of transmission service on the Devers-Palo Verde No. 1 line and (2) SCE and SDG&E agreed to an exchange of transmission capacity between SCE's Devers-Palo Verde system and SDG&E's Southwest Powerlink (SWPL). This agreement was made contingent upon construction of DPV2.[2]

In August 1986, SCE submitted a revised economic analysis of the DPV2 project. On October 9, 1986, the Public Staff Division (subsequently renamed Division of Ratepayer Advocates (DRA)) filed

1 On January 2, 1986, the Executive Director notified SCE that the December, 1985 application tendered for filing was incomplete and would not be accepted for filing. SCE subsequently submitted additional information on January 27, 1986. The supplemented application then was accepted for filing on Febuary 26, 1986.

2 The settlement agreement between SCE and SDG&E occurred after Administrative Law Judge Wu denied an SCE motion to dismiss SDG&E's protest and ordered both utilities to submit showings on comparative need for capacity.

a motion to "suspend the clock."[3] DRA alleged that SCE's revisions amounted to a second base case requiring substantial new analysis by DRA. DRA also requested direct access to SCE's computer models.

In December 1986, SCE and DRA settled this dispute. A new procedural schedule was arranged, and an alternative way of validating SCE's computer models was adopted.

The Draft Environmental Impact Report (DEIR) was completed in March 1987. Public participation hearings were held to receive comments on the DEIR from March 24-26, 1987, in Riverside, Desert Hot Springs, and Blythe.

Evidentiary hearings began on May 11, 1987 and continued until May 14 when it was discovered that SCE's computer models had been run with inconsistent data inputs. This inconsistency resulted in an exaggeration of the calculated project benefit of economy power purchases in the Southwest. DRA then moved for dismissal of the application. SCE opposed this motion and suggested that a two-month delay in the proceeding schedule would enable both SCE and DRA to correct the errors that had been discovered.

On June 5, 1986, an assigned commissioner ruling denied DRA's motion but ruled that SCE could not rely upon the alleged benefit of economy power from the Southwest as a justification for the project unless it filed a new application. SCE was given the option of proceeding with the current application using transmission service revenues and other benefits as justification for the project.

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3 Under the Permit Streamlining Act an agency must issue a decision within certain time limits. Unless the "clock" was "suspended," the applicable time period could have run before DRA completed its analysis.

SCE elected to proceed with the original application without any reliance upon the alleged benefit of economy power purchases from the Southwest. SCE submitted additional testimony which for the first time quantified the value of benefits other than transmission service revenues and the now excluded benefit of economy power purchases.

The Final Environmental Impact Report (FEIR) was issued in August, 1987. Evidentiary hearings were held from September 14-17, 1987. Opening and closing briefs were submitted by October 15, 1987 for decision by the Commission at its December 9, 1987 meeting.

After submittal of the case, DRA discovered a letter of agreement between SCE and Los Angeles Department of Water and Power (LADWP) which confirmed the willingness of SCE and LADWP to exchange transmission capacity rights on the Pacific Intertie and the DPV2 transmission systems. In DRA's view, this agreement affected the cost effectiveness of the proposed DPV2 transmission line. DRA then filed a second petition to either dismiss SCE's application or, in the alternative, to set aside submission and reopen the proceeding.

DRA also filed in SCE's general rate case proceeding, A.86-12-047, a motion to set aside submission with respect to the high voltage DC terminal expansion project (DC Expansion). DRA also believed that the recently discovered SCE-LADWP letter agreement affected the cost effectiveness of the DC Expansion.

In response to these two motions, action on the Administrative Law Judge's (ALJ) proposed decision for A.85-12-012 was withheld pending resolution of the relevance of the SCE-LADWP agreement to the proposed DPV2. And in Decision (D.) 87-12-066 on SCE's general rate case, the Commission denied DRA's motion to set aside that proceeding, but ordered that further consideration of the cost effectiveness of the DC Expansion be given in SCE's application for DPV2.

On January 4, 1988, the ALJ for the DPV2 proceeding issued a ruling ordering SCE to submit any contemporaneous documentation supporting its claim of confidentiality for the SCE-LADWP letter agreement. The ruling also required SCE to file an accounting of all expenses incurred for DPV2, stating that "the Commission may consider a disallowance of regulatory expense incurred for work which was performed but is now useless due to the concealment of the 1985 letter agreement." SCE made this filing on February 3, 1988.

On February 23, 1988 a prehearing conference was held to address the consolidated DPV2 and the DC Expansion projects. SCE and DRA proposed to jointly conduct a preliminary study to determine if DPV2 could be cost effective, assuming an operating date later than June 1, 1990. Based on the results of this study, SCE would decide whether or not to supplement the application and move forward with DPV2, or not to proceed with DPV2 at all.

On March 4, 1988, LADWP forwarded to SCE an executed copy of the Exchange Agreement and Supplemental Letter Agreement for the Dismissal of the Suppliers' Litigation (Exchange Agreement). The Exchange Agreement was executed on December 18, 1987, and made effective as of July 29, 1988. An overview of the terms of the Exchange Agreement is presented in Figure 2 (see Section VI.A).

On May 24, 1988, a second prehearing conference was held. At that time SCE announced that, based on the preliminary results of the SCE/DRA joint study, it planned to file an amended application for DPV2 on August 8, 1988. In addition, DRA and SCE presented a joint proposal for a two-phase approach to the proceeding. Phase I would address the amended DPV2 application, including consideration of certain aspects of the Exchange Agreement. Phase II would address the cost-effectiveness of the DC Expansion Project, including applicable aspects of the Exchange Agreement. The prudence of the Exchange Agreement would be addressed partially in Phase I and in Phase II. This two phase approach was adopted by the ALJ.

SCE's Amended Application and Amended Proponent's Environmental Impact Assessment (PEA) were filed on August 15, 1988. DRA filed its prepared testimony on September 12, 1988. Evidentiary hearings on Phase 1 issues were held on September 22 and 23, 1988. The Addendum to the FEIR (FEIR Addendum) was filed on September 23, 1988 and entered into the record as Exhibit 30.

ALJ Gottstein presided at the September 1988 hearings. Mr. James Kahle and Mr. Gary Schoonyan appeared as witnesses on behalf of SCE. DRA stipulated to introducing into evidence the testimony of the remaining SCE witnesses. Mr. Michael Burke, Robert Weatherwax, and Karen Shea appeared as witnesses for DRA. No other parties participated in either direct or cross examination during the September 1988 hearings. DRA and SCE filed concurrent briefs on October 12, 1988.

III. Project Description

There are already a number of high-voltage transmission lines running from southern California to the Southwest (see Figure 1). These include the following lines:

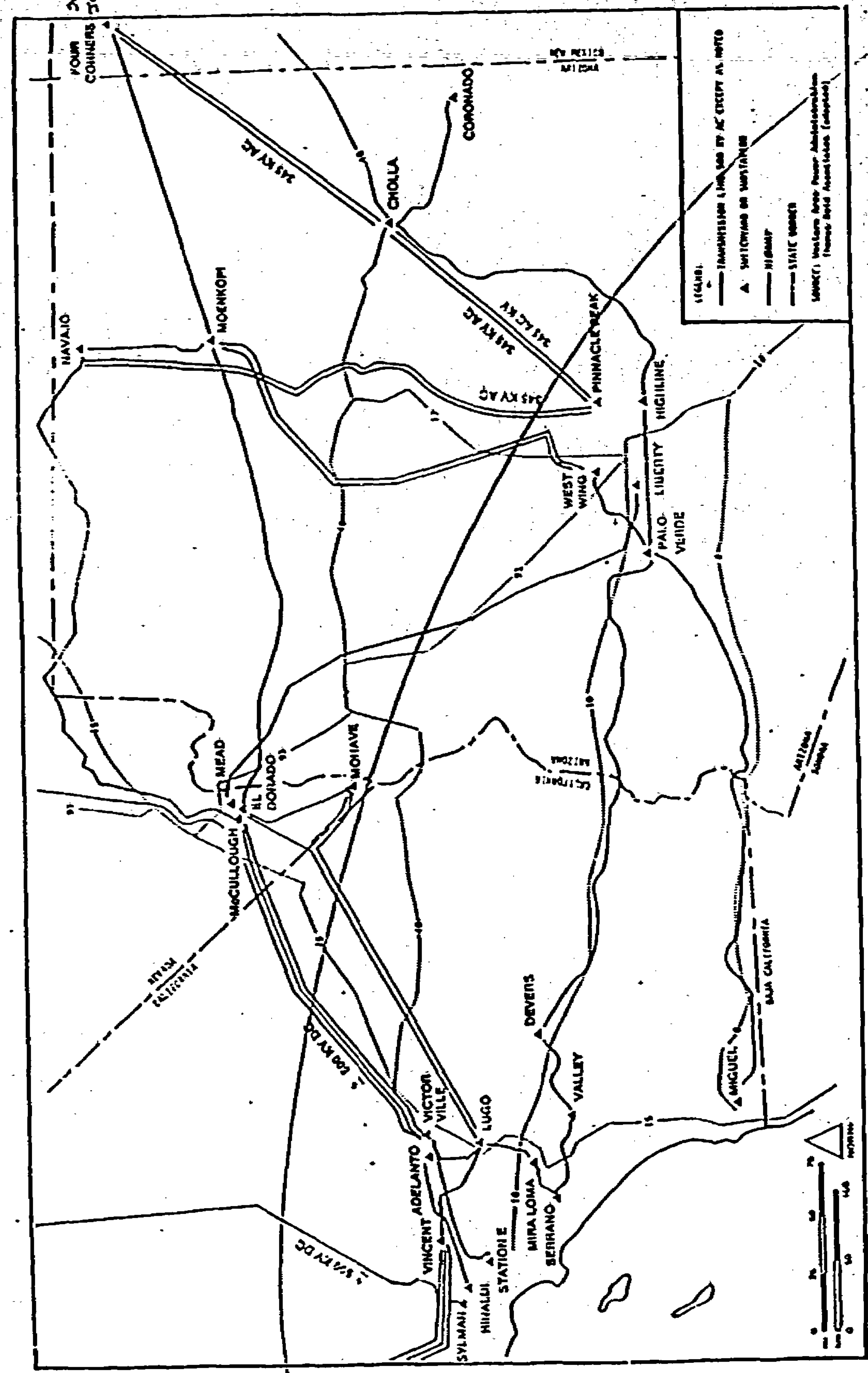
TABLE 1

Existing Transmission Lines from the Southwest
(from Exh. 15, Table III-6, p. III-28);
SCE DR #267; Tr. at 438.

	Size (kV)	Entitlements (MW) All Users	SCE
Devers - Palo Verde #1 (DPV1)	500	1309	1309
Moenkopi - El Dorado	500	1330	1330
Southwest PowerLink (SWPL) (Palo Verde - Miguel)	500	1181	0
Liberty - Mead	345	450	0
Navajo - El Dorado	500	1330	0
Total		5600	2639

Figure 1. Existing California High Voltage Transmission lines from the Southwest. (from Exh. 6-B at 10)

FIGURE 1 MAJOR SOUTHERN CALIFORNIA INTERTIES



In 1979, SCE was granted a CPC&N to construct DPV1, a 500 kV AC transmission line from the Palo Verde Nuclear Generating Stations in Arizona (approximately 50 miles west of Phoenix) to SCE's Devers substation approximately 10 miles northwest of Palm Springs, California.[4] The main purpose of DPV1 was to bring SCE's share of its 579 MW firm capacity of the Palo Verde plant and its 350 MW entitlement in the Cholla #4 generating plant to SCE's service area. The extra capacity on the line has been used to bring in economy energy from the Southwest.

SCE proposes to build DPV2, a second 500 kV line parallel to DPV1 on a common transmission corridor. In its amended application, SCE requests authorization for an in-service date of June 1, 1993. DPV2 is expected to provide 1200 MW of transmission capacity from the Palo Verde switchyard to the Devers substation. A detailed description of project location is presented in Appendix A. To accommodate the full capacity of the new line, even in case of an outage, SCE further proposes to make certain improvements to the Palo Verde Switchyard and Devers substation.[5] These improvements, excluding DPV2 itself, will be referred to as West of Devers (WOD) improvements. The primary project objective is to provide additional transmission capacity to SCE and other project participants. Secondary objectives include increased

---

4 D.90552 (issued July 17, 1979), as modified by D.91421 (issued March 18, 1980) and D.92302 (issued October 8, 1980). The Moenkopi-El Dorado line was built in 1969, and did not require certification by this Commission. SCE and Arizona Public Service (APS) share ownership of the line. SCE has 100% entitlement to the line under financial arrangements with APS.

5 The improvements include adding 500 kV circuit breakers, disconnect switches, shunt reactors, and series compensation banks at the Palo Verde Switchyard and Devers Substation. In addition, a new 1000 MVA 500/200 kV transformer bank will be installed at the Devers Substation.

access to economy energy from either the Pacific Northwest (PNW) or the Southwest, and displacement of more costly oil and gas generation.[6]

Table 2 lists the participating utilities and their respective shares. Of the 1200 MW, SCE will own 758 MW, or approximately 63%. From SCE's ownership share, 100 MW of firm transmission service (T/S) will be provided to LADWP and 150 MW will be provided to Modesto-Santa Clara-Redding Public Power Agency (MSR).

LADWP and nine other members of the Southern California Public Power Authority (SCPPA) will own the remaining 442 MW of project capacity (See Table 2). The SCPPA participants have 442 MW of firm entitlements in the Palo Verde Generation Station in Arizona, and MSR has a firm entitlement of 150 MW in Unit 4 of the San Juan Generating Station located in New Mexico. Both SCPPA and MSR will use DPV2 to deliver power from those generating sources to their systems in California. Each project participant would require firm power transmission services WOD in order to gain access to their share of DPV2.

IV. Project Costs

Total project capital costs are estimated at $260 million in dollars escalated to the date of expenditure. This figure reflects the additional costs of WOD improvements. SCE's share of the capital costs, subject to ratebasing, would be approximately

6 Exhibit 6B, DEIR Vol. 2, page 1, as modified by Exhibit 30, Addendum to the FEIR, page 5.

TABLE 2

Devers-Palo Verde No. 2
Project Participants

	Utility	Participation Shares MW Own	MW T/S	% Own	% T/S
1.	SCE	758.00*		63.2*	
2.	LADWP	367.75	100.00	30.7	8.3
3.	M-S-R		150.00	0.0	12.5
4.	IMPERIAL IRRIG. DIST.	14.62		1.2	
5.	RIVERSIDE	12.15		1.0	
6.	VERNON	11.03		0.9	
7.	BURBANK	9.90		0.8	
8.	GLENDALE	9.90		0.8	
9.	PASADENA	9.90		0.8	
10.	AZUSA	2.25		0.2	
11.	BANNING	2.25		0.2	
12.	COLTON	2.25		0.2	
	Subtotal (Non-Edison)	442.00	250.00	36.8	20.8
	TOTAL	1,200.00		100.0%	

* Firm transmission service will be provided to LADWP (100 MW for 22 years) and M-S-R (150 MW) from Edison's ownership share. In addition, San Diego Gas & Electric has an option to receive 100 MW of firm transmission service on DPV#1 if the Project is built and the transfer capability between Edison and SDG&E is increased.

$172 million in 1993 dollars.[7] During the September 1988 hearings, DRA and SCE stipulated to this figure for SCE's estimated share of project costs (see Table 3). The net present value (NPV) of SCE's total cost of DPV2, including capital and operation and maintenance, is $175 million in 1990 dollars.

V. Changes Reflected in the Amended Application

As described in Section II above, SCE's original application was accepted for filing on February 26, 1986. An amended application was filed on August 15, 1988. A number of significant changes were reflected in the amended application, and are summarized below:

- Deferral of In-Service Date for Three Years. In its initial application, SCE proposed an in-service date of June 1990. In its amended application, SCE adopted DRA's recommendation that the in-service date be deferred until June 1, 1993.

- Incorporation of the Exchange Agreement. Unlike SCE's previous filings, the amended application incorporates the effects of the Exchange Agreement on the ownership structure and economics of DPV2 (see Section VI.A.).

- Restructuring of Ownership. The original application stated that SCE would own "up to" 85% of the project. SCE now projects an ownership share of 758 MW (63.2%). LADWP's ownership share increases from 151 MW to 368 MW, and the other SCPPA cities with interest in DPV2 acquire ownership interest.

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7 The $172 million figure assumes SCE's ownership share of 63.17% (or 758 MW) of DPV2, including substation facilities. SCE will assume 100% of the project's right-of-way expenses, and 100% of the costs of the additional transformer bank required at Devers substation.

TABLE 3

Summary of Estimated Construction Costs

Elements	Total Element Costs ($000)
Transmission Line Element Costs	
500 kV Transmission Line Element in CA	$102,908
500 kV Transmission Line Element in AZ	88,888
Subtotal	191,796
Adjustment	9,450 *
Adjusted Subtotal	201,246
Substation Element Costs	
Devers Substation - 500 kV	10,776
Palo Verde Switchyard - 500 kV	12,468
Devers Substation - 220 kV	17,653
Subtotal	40,897
Series Capacitor Element Costs	
East Series Capacitor	8,415
West Series Capacitor	10,139
Subtotal	18,554
Total Project Costs	251,247
Adjustment	9,450 *
Adjusted Total Project Costs	260,697
SCE's share (stipulated)	$172 million *

* The "adjustments" to total costs reflect DRA's conclusions that SCE's estimated costs were understated by about $9.5 million. This difference was due to a substantial understatement of aluminum costs which were partly compensated for by an overstatement of steel costs. As noted on page D-1 of their Amended Application (August 1988), SCE has agreed with these revised project cost estimates.

Source: Exhibit 30, Addendum to the FEIR, page 4.

- Reduction in West of Devers Construction Costs. As originally proposed, the cost of building DPV2 included $31.1 million for system upgrades west of Devers (WOD) substation. As a result of a detailed re-evaluation of the thermal capability of the transmission system WOD substation, SCE determined that it would not be necessary to install these upgrades. This reduced project costs by $13.5 million.

- "Bridging" LADWP on DPV1 Until 1993. The original plan to build DPV2 would have provided LADWP with 468 MW of transmission capacity as of June 1, 1990. In SCE's amended application, DPV1 is used to provide LADWP with this capacity from June 1, 1990 until the now proposed in-service date.

- Changes in Quantification of Benefits. In SCE's amended application, new or refined methodologies were used to analyze project benefits. These were based primarily on the joint study efforts undertaken by DRA and SCE in preparation for Phase 1 evidentiary hearings.[8]

VI. Economic Analysis of Project Alternatives

As described in SCE's amended application, DPV2 is not proposed to meet the needs of SCE for any firm capacity it has, or will acquire in the future in the Southwest. Rather, primary project benefits will be from transmission service revenues and

8 See Concurrent Brief of DRA, page 9a, Table 2, for a comparison of the benefits claimed in SCE's 1987 testimony and in its Amended Application.

increased access to economy energy.[9] In addition, SCE claims that DPV2 will significantly reduce transmission losses, improve utility interconnection support (UIS), enhance transmission stability, and improve air quality.

A. <u>The SCE/LADWP Exchange Agreement</u>

The SCE/LADWP Exchange Agreement, which was discovered after submittal of this case in late 1987, changed several of the factors originally considered in the economic analysis of DPV2. The Exchange Agreement provides for a swap of AC and DC Pacific Intertie capacity to the PNW, which provides SCE with a net increase of 180 MW of Intertie capacity. SCE also obtains the use of LADWP's Castaic Pumped Storage plant (Castaic). LADWP obtains the use of SCE's transmission facilities, with certain service charges waived. In addition, The Exchange Agreement settles a lawsuit between SCE and LADWP (the "Suppliers Contract" litigation).[10] A summary of the Exchange Agreement is

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9 "Economy energy" refers to power imported on a non-firm basis from outside the region. As described in greater detail in Appendix B, SCE's access to economy energy from the Southwest actually decreases (until 2005) with the construction of DPV2. All the benefits attributable to increased economy energy are derived from the access to additional PNW purchases, made possible by the Exchange Agreement "swap" of Intertie access capacity.

10 The Suppliers' Contract was an agreement between SCE, LADWP, PG&E, SDG&E, and the California Department of Water Resources (CDWR), dated November 18, 1966, for the sale, exchange, and transmission of electricity to operate State Water Project Pumping Plants.

presented in Figure 2. An overview of the provisions considered in the Phase I analysis is presented in Figure 3.[11]

B. SCE/DRA Joint Study Arrangements

SCE and DRA initially performed independent economic analyses of project alternatives.[12] Starting in February of 1988, SCE and DRA began a joint study process to develop common assumptions and methodologies for evaluating DPV2 that would be acceptable to both parties. As part of this process, SCE and DRA jointly developed new methodologies or refined existing ones to analyze the project benefits associated with the DPV2 alternatives, including the effects of applicable provisions of the Exchange Agreement. As explained in DRA's prepared testimony, SCE took the lead in the assessment of stability and loss reduction benefits and estimation of transmission revenues. DRA, and its consultant Sierra Energy and Risk Assessment, Inc. (SERA), took the lead in production cost modeling, air quality assessment, and in refining the alternative cases and sensitivity analyses. For UIS, both parties discussed methodological issues, but ultimately both employed different methodologies.

During the joint study process, SCE and DRA agreed upon the use of common assumptions and methodologies for the base case analysis of DPV2 and alternatives.

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11 The provisions that will be considered in Phase II analysis of the DC Expansion are: Use of 200 MW of Castaic as pumped storage; 220 MW of firm PNW transmission access (in lieu of non-firm access) and the value of the Suppliers' Contract litigation settlement. For a discussion of the rationale for allocating 180 MW of PNW non-firm transmission capacity to the DPV2 project, see Tr. at 843-846.

12 Since the earlier testimony and analysis presented by DRA and SCE were essentially "superceded" by the joint study analysis, we do not describe them in this order. DRA's Concurrent Brief provides a useful overview of the changes made in methodologies since the outset of this proceeding.

EDISON/LADWP EXCHANGE AGREEMENT OVERVIEW

Edison Obtains

Pacific Intertie
- 500 mW DC

Castaic Pumped Storage
- 200 mW use
- LADWP's best efforts for additional

Suppliers' Contract
- Settlement

LADWP Obtains

Pacific Intertie
- 320 mW AC

DPV#2 Project
- 217 mW T/S converted to ownership
- 100 mW T/S
- Right to Build

Devers-Sylmar
- 468 mW T/S

FIGURE 2

EDISON/LADWP EXCHANGE AGREEMENT PROVISIONS APPLICABLE TO THE DEVERS-PALO VERDE NO. 2 T/L PROJECT ANALYSIS

Use of 200 mW of LADWP's Castaic Pumped Storage capacity towards meeting Edison's spinning reserve

An additional 180 mW of non-firm Northwest transmission access,

LADWP's receiving a 217 mW ownership allocation in DPV#2 in lieu of firm transmission service from Edison,

LADWP's receiving 368 mW of "bridging" transmission service on DPV#1 from June 1, 1990 until DPV#2 goes into operation,

Waiver of transmission service charges for LADWP's 368 mW of firm service from Devers to Sylmar/Victorville for 22 years,

Waiver of transmission service charges for LADWP's 100 mW of firm service from Palo Verde to Sylmar/Victorville for 22 years.

FIGURE 3

8/6/88

Summaries of these assumptions and methodologies are presented in Appendix B. The overall results and conclusions presented by SCE and DRA during the Phase I hearings were very similar. Both conclude that DPV2, coming on-line in 1993, will yield over $300 million in net benefits (in net present value, 1990 dollars) to SCE's ratepayers.[13] However, the absolute magnitude of net benefits differed between the two analyses, primarily due to the different assessments of UIS benefits and modeling corrections that were made by SERA subsequent to SCE's submittal.[14] In addition, DRA evaluated the project's overall cost-effectiveness relative to the alternatives of deferring the project until 1995 or 1997. DRA also performed several sensitivity analyses to test the robustness of its base case results.

During the September 1988 hearings, SCE stipulated to the economic analysis performed by DRA. Hence we will focus our discussion on those results.

C. Project Alternatives

During the course of this proceeding, DRA and SCE evaluated the economic, environmental, and technical impacts of a wide range of project alternatives. The full range of alternatives

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13 At the outset of this proceeding, DRA's position was that the proposed project was not cost-effective. In its September 1988 filing, DRA identifies the following factors which caused the change in its position: (1) the existence of the SCE/LADWP Exchange Agreement; (2) the delay of construction from 1990 until at least 1993 coupled with the reduced construction costs WOD and use of existing surplus transmission capacity as a "bridge"; (3) refinement and updating of the production cost benefits; and (4) developing and applying new methodologies to quantify previously unquantified strategic benefits. See Exhibit 32, Table 2-1, page 2-4 for a summary of the estimated impact of these changes on DRA's analysis.

14 See Appendix B, Table B-1 for a comparison of DRA's and SCE's base case results.

are described in Appendix C. DRA and SCE chose to focus their updated economic analysis on a limited series of alternatives, almost all of which featured providing LADWP with transmission service on DPV1 for some amount of time. These altenatives were:

1. "No Project"--Reference Case A, which consists only of a swap between SCE and LADWP of 320 MW of Pacific Intertie access.[15] LADWP and other SCCPA participants continue using current transmission arrangements for getting Palo Verde power. MSR has no ability to secure its firm entitlement to San Juan 4.

2. "Infinite Bridge"--Case B: Never building the line, while permitting LADWP to start operating on DPV1 in 1990.[16] The full 500/320 MW swap with LADWP is included. It has no associated revenue requirement.

3. "Expanded Infinite Bridge"--Case C: Never building the line, expanding the capacity of DPV1 and SWPL by 100 MW each in 1993, and from then on providing transmission service on DPV1 not only to LADWP but to MSR and other SCCPA also. The full 500/320 MW swap with LADWP is included. It has a revenue requirement based on SCE's

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15 As summarized in Figure 1, the full SCE/LADWP Exchange Agreement provides SCE with 500 MW of DC Intertie access (320 MW firm and 180 MW of assumed non-firm). SCE in return provides LADWP with 320 MW of AC Intertie access (100 firm and 220 non-firm). For the Reference Case A, DRA assumes that SCE effectively converts 220 MW of Intertie capacity from non-firm to firm.

16 SCE has contracts for the purchase of 350 MW from Cholla plant in Eastern Arizona and 250 MW from the Navaho plant in northern Arizona. (See Figure 1 for locations.) The power from these facilities is carried over SCE's existing systems (DPV1 and Moenkopi-El Dorado, respectively). Between 1986 and the in-service date of DPV2 both contracts terminate. Because of SCE's near-term excess capacity, the utility has not renewed these contracts. The Infinite Bridge scenario assumed that SCE uses the capacity freed up by the termination of these two contracts to wheel LADWP's power.

share of the required series compensation.[17]

4. *"Build DPV2"--Cases W(93, 95, 97)*: In the W(93) Case, DPV2 comes on-line in June, 1993. In the W(95) and W(97) Cases, DPV2 is deferred until 1995 and 1997, respectively. LADWP is on DPV1 starting in 1990. Upon completion of DPV2, LADWP, other SCPPA and MSR all use it.[18] SDG&E gets 100 MW on DPV1 starting January 1995. The full 500/320 MW swap is included.

Figure 4 summarizes the major assumptions for each of these cases with regard to the intertie swap, T/S provisions, and use of Castaic for spinning reserves.

D. Summary of Base Case Results

The base case results of DRA's economic analysis are summarized in Table 4 and depicted in Figure 5.[19] As shown in Table 4, all the W Cases ("build DPV2") yield net savings to SCE ratepayers of over $360 million in NPV when compared to the Reference Case A. Building DPV2 with a 1993 in-service date has a slightly lower NPV than building later. The Infinite Bridge

17 In lay terms, increasing series compensation allows a utility to "pack" more energy into a transmission line, similar to increasing the pressure of a water pipe. However, as you add series compensation to high-voltage transmission lines, a phenomenon known as subsynchronous resonance (SSR) occurs where the harmonic frequencies of the transmission system "beat" against the mechanical frequencies of the turbine shafts. This can cause serious mechanical failures at generating stations, unless corrective measures are taken. SSR mitigation devices are included in the cost of the Expanded Infinite alternative.

18 Instead of paying SCE for transmission service on DPV2 (as in Cases B and C), most of the project participants gain access to Southwest power via their ownership interest.

19 We use the term "base case" to distinguish these results from the various sensitivity cases conducted by DRA.

FIGURE 4

Summary of Alternative Cases

Cases	PNW Intertie Access Swap*	Additional T/S Provided on DPV1/DPV2	Castaic Avail. for Spinning
"Reference" A	320/320	0	No
"Infinite Bridge" B	500/320	o Only LADWP on DPV1: o 368 MW paid T/S; o 100 MW free T/S (22 yrs) o All WOD T/S free	Yes
"Expanded Infinite Bridge" C	500/320	o Same as Case B for LADWP; o MSR and other SCPPA added to expanded DPV1 in 1993. o 72 MW paid T/S (SCPPA) o 150 MW paid T/S (MSR) o WOD T/S paid (SCPPA)	Yes

* Under the 500/320 swap, it is assumed that the Exchange Agreement results in 180 MW of additional transmission capacity (for non-firm purchases) to the Pacific Northwest (PNW).

(Continued)

FIGURE 4

Summary of Alternative Cases
(Continued)

Cases	PNW Intertie Access Swap	Additional T/S Provided on DPV1/DPV2	Castaic Avail. for Spinning
"Build DPV2" W(93)	500/320	o Case B until line is built (LADWP on DPV1) o All participants on DPV2 after 1993** o 150 MW paid T/S (MSR) o 100 MW paid T/S after June 1995 (SDG&E) o WOD T/S paid (SCPPA, SDG&E)	Yes
W(95)	500/320	Case W(93) postponed until 1995	Yes
W(97)	500/320	Case W(93) postponed until 1997	Yes

** LADWP's 368 MW of paid T/S, MSR's 150 MW of paid T/S, and the other SCPPA participants 72 MW of paid T/S became "ownership shares" under the W Cases.

TABLE 4

Comparison of DPV2 Sensitivity Analyses

(NPV in Millions 1990$)

	Base Case	Sensitivity Cases (1)	(2)	(3)	(4)
W(93)	364	306*	126	302	306
W(95)	370	N/R	143	305	N/R
W(97)	366	N/R	150	306	N/R
B	22	N/R	122	22	158
C	-47	N/R	208	-54	136

Legend:

(1) No Castaic

(2) No Production Cost Benefits

(3) No UIS

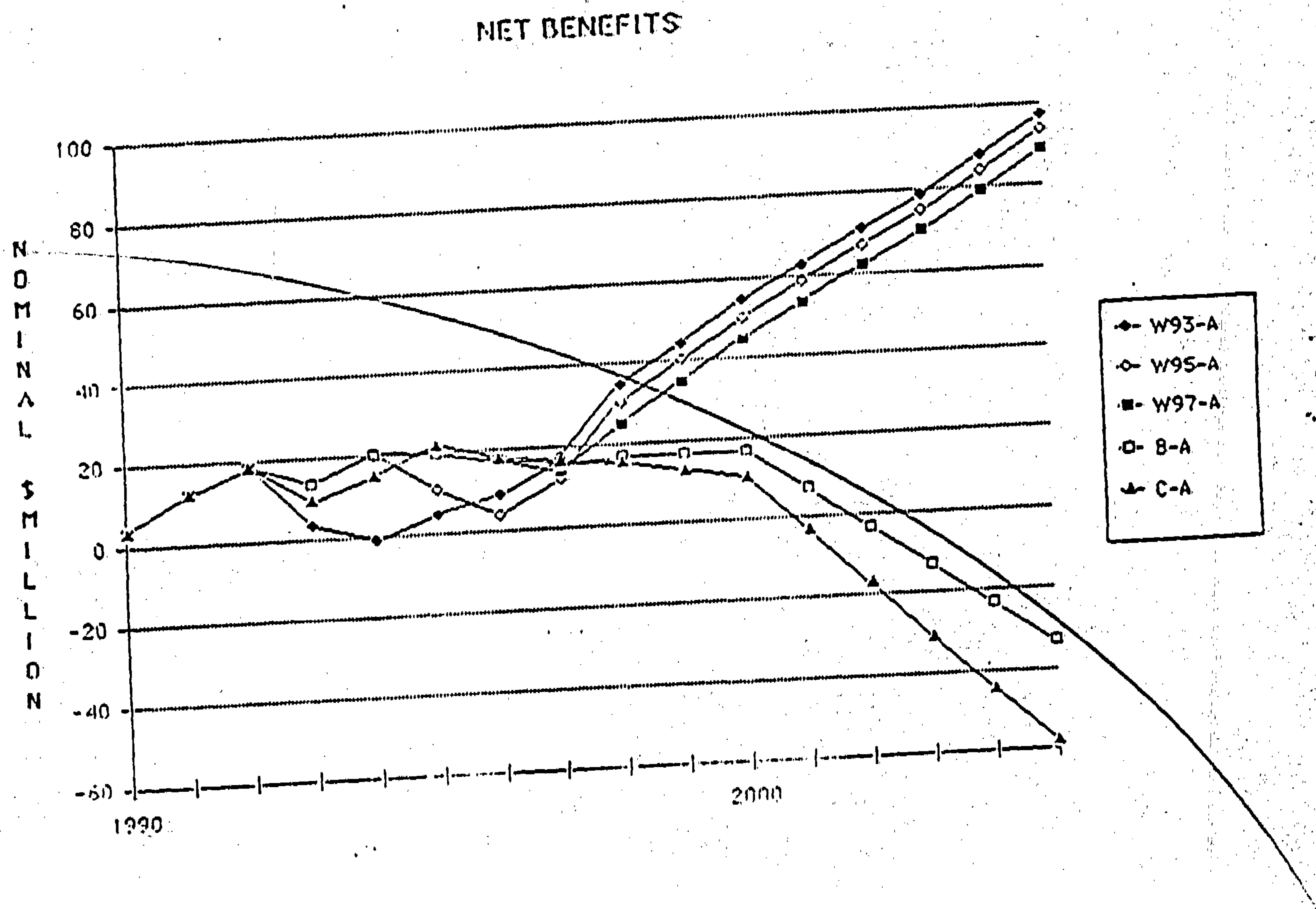
(4) Highest Block Pricing of Economy Energy

N/R: Not run.

NOTE: DRA also ran the W(93) Case with a 10 percent discount factor (instead of 12), but the resulting change in NPV was not presented in testimony. However, as stated on Page 8-15 of Exhibit 36, the general effect of a lower discount rate would be to substantially increase the benefits of the alternatives that include the line. DRA also evaluated the effect of a lower fuel escalation rate after 2005 (4.1% instead of 7%) and concluded that the change would have only a minor effect on the results (page 8-14, Exhibit 36).

* Estimated based on savings for "A" case with and without Castaic.

Figure 5


NET BENEFITS
100
80
60
40
20
0
-20
-40
-60
NOMINAL $ MILLION
1990
2000
W93-A
W95-A
W97-A
B-A
C-A

alternative (Case B) yields net savings of $22 million. The Expanded Bridge alternative (Case C) leaves the ratepayer actually worse off (by $47 million) than the "do nothing" Reference Case.[20]

Figure 5 displays the annual benefit stream for all cases. The options diverge significantly in the late 1990's as the combination of capacity value and increased gas costs tend to make the DPV2 build cases substantially more attractive, in spite of their required capital costs.[21]

As illustrated in Figure 6, deferring DPV2 until 1997 (the W(97) Case) yields the optimal level of net benefits among the build DPV2 alternatives in the mid-1990's. DRA estimates a difference in net benefits between the W(97) and W(93) Cases of approximately $34 million in NPV (or $55 million in current year dollars) during the 1993-1997 period. This is illustrated by the shaded portion of Figure 6. This comparison is the basis for DRA's "benefit enhancement" condition to granting SCE's request for a 1993 in-service date (see Section VIII below).

E. Sensitivity Analyses

DRA performed several sensitivity cases to evaluate the effect of select assumptions on the benefits of the line, including:

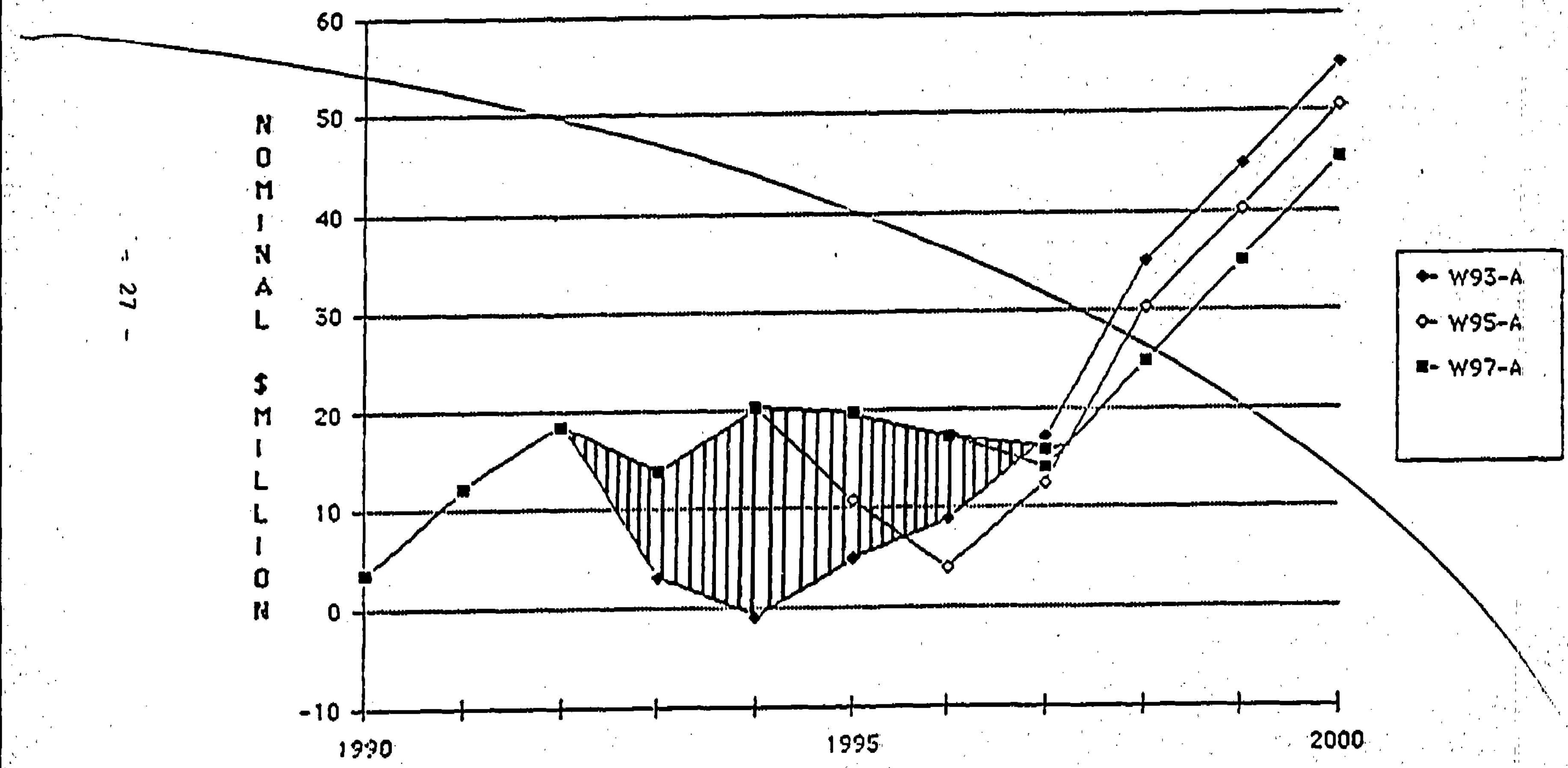
1. Highest Block Pricing Of Economy Energy

20 Production costs benefits for Cases B and C are actually negative (in NPV) in DRA's analysis, as shown in Table 4. The use of existing line space results in "foregone" Southwest economy energy benefits, relative to the Reference Case. These negative net benefits more than offset the benefits of increased PNW economy energy purchases resulting from the Exchange Agreement. Case C is more negative because it is the case in which the most surplus SCE line space is used to provide T/S to others.

21 See Appendix B for a description of how the production cost benefits, loss reduction benefits and UIS depend upon these factors.

Figure 6 Comparsion of the Net In-Service Benefit Streams Assuming In-Service Dates of 1993, 1995, and 1997 (From Exh.32, Fig. 2-4, p. 2-7.)

Shaded area = Benefits Edison agrees to make up "to fill the gap" to build for a 1993 in-service date



2. No Production Cost Benefits

3. No UIS Benefits

4. No Castaic After 1992

As summarized in Table 5, the relative magnitude of net benefits among "build" and "no build" cases is most dramatically affected under alternative economy energy pricing assumptions and, as a limiting case, under a scenario where no production cost benefits are assumed.[22]

In DRA's base case analysis, economy energy prices were based on the production costs of the PNW and Southwest resources generating the energy surplus. Each block of economy energy was priced successively higher to reflect the increasing production costs of the region. In contrast, under Sensitivity Case (1), economy energy is priced at the most expensive energy taken for a particular hour.[23] This translates into average prices of about 75% to 93% of SCE's tier 2 gas price, depending on the system heat rate.[24]

Under Sensitivity Case (1), the net benefits of Cases B and C increase by $135 million and $180 million, respectively,

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22 DRA/SERA also assessed the impact of the following changes on production cost benefits for the W(93) Case: (1) no gas curtailment; (2) absence of Rancho Seco; (3) alternative coal cost assumptions; and (4) individual hydro case evaluation. The base case analysis of W(93) Case was relatively insensitive to changes (1) and (4). The line became slightly more attractive under change (2). It became less attractive under change (3) but within the range of sensitivities illustrated in Table 5.

23 For example, if during the duration of one hour, the base case runs show SCE taking energy priced at blocks 1, 2 and 3, the sensitivity analysis would calculate production costs based on SCE economy energy takes priced at block 3.

24 See Exhibit 36, page 5.

TABLE 5

DRA's Base Case Analysis of DPV2 Alternatives

(NPV in Millions 1990$)

	Case W(93)-A	Case W(95)-A	Case W(97)-A	Case B-A	Case C-A
Costs	175	154	135	0	15
Benefits					
Production Cost Benefits*	239	227	216	<100>	<255>
Transmission Service Revenues	121	123	117	84	160
Reduced Transmission Line Losses	101	98	95	38	56
Stability Benefits	16	15	13	0	0
Utility Interconnection Support	62	61	60	0	7
TOTAL BENEFIT	540	524	501	122	<32>
NET SAVINGS	364	370	366	22	<47>
B/C Ratios	2.08	2.40	2.71	-	-

* Production cost benefits reflect the changes associated with (1) PNW economy energy, (2) 200 MW of Castaic available as spinning reserve, (3) QF payments, (4) NOx emissions, and (5) SW economy energy.

Source: Exhibit 36

relative to DRA's base case analysis. While this significantly reduces the differences among alternatives, the build cases still yield the highest net benefits (over $300 million).

Sensitivity Case (2), No Production Savings, excludes all benefits from having Castaic available and assumes that there are no increased economy energy purchases to offset production costs, to reduce avoided cost payments to qualifying facilities, or to reduce NO_x emissions. As illustrated in Table 5, under this scenario all the build cases still yield net benefits of over $125 million. However, Case C becomes more attractive than any of the build alternatives with net benefits of $208 million.

In DRA's view, the results of its sensitivity analyses demonstrate the robustness of the joint study conclusions since, under all sensitivity cases, building DPV2 remains cost-effective. The relative ranking of the "no project" and "build" alternatives change only under one sensitivity case, which witness Weatherwax characterizes as a "stylized extreme case."[25] DRA concludes that, "even if economy issues were so severe as to eliminate all production cost benefits, building the line would still be a viable option in the context now proposed by the Applicant."[26]

25 At the evidentiary hearings, Witness Weatherwax characterized Sensitivity Case (2) in this manner, pointing out that the analysis did not take account of improvements in stability or decreases in line losses that would occur as economy energy transfers are reduced or eliminated (Tr. Vol 10., p. 830).

26 Exhibit 32, p. 2-8.

F. Methodological Issues that Merit Further Attention

During the Phase I evidentiary hearings, SCE and DRA identified the following analytical issues that merit further attention in future proceedings:[27]

1. Integration of Methodologies for Calculating the Individual Benefit Components. Greater consistency is needed in accounting for the relationship between "line loading" assumptions for production cost benefits, reduced line losses and stability benefits (DRA/SCE Brief).

2. Quantification of UIS Benefits

   a. The appropriate base amount of UIS needs to be reevaluated (DRA Brief; Tr. at 754-756, Tr. at 865).

   b. Quantification of operational and planning benefits need to be refined, including:

      (1) Review and update the resource assumptions used in SERA's "shadow pricing" methodology. (SCE Brief, Tr. at 860-864.)

      (2) Examine further the "operating" value of UIS relative to combustion turbines (Tr. at 858-860).

      (3) Evaluate SERA's approach using an Expected Unserved Energy measure of value (SCE Brief).

      (4) Consider whether or not the planning benefits for one utility

27 To identify the source: "DRA, Brief" refers to pages 63-66 of the Concurrent Brief of DRA. "SCE, Brief" refers to pages 49-54 of Applicant's Concurrent Brief. Transcript and Exhibit references are also given where appropriate.

are at all appropriate for another utility (Tr. at 865).

c. The effect of changing use of the transmission system over time (and what is available for UIS) should be incorporated into the analysis (SCE/DRA Brief).

d. If UIS is claimed as a benefit of new transmission lines, this additional UIS should be reflected back in the calculation of a utility's ERI for valuing new capacity purchases.

3. <u>Economy Energy Benefits</u>

a. Refinement of SCE's Pacific Northwest Model is needed to replace "block pricing" with a continuous supply curve of available economy energy (DRA/SCE Brief, Tr. at 868-871).

b. Pricing at the highest cost block of economy energy needs to be enhanced in situations where that cost is significantly lower than the California utility's marginal costs (SCE Brief).

4. <u>Air Quality Benefits</u>

a. The assumption that NO_x reduction savings are constant (unescalated) needs to be reexamined (DRA Brief, Tr. at 866).

b. An alternate approach that assigns a dispatch penalty for gas-fired units should be considered (SCE Brief).

5. <u>Value of Reduced Losses</u>

a. The method of measuring <u>average</u> line losses (i.e., by extrapolating peak line losses) needs to be revisited; (DRA Brief; Tr. at 809-810, 866).

b. The dynamic relationship between line losses and production cost benefits needs to be incorporated into the analysis (DRA, SCE, Brief).

6. Value of Stability

   a. Changes in N-2 risks need to be accounted for (DRA/SCE Brief, Tr. at 851-853).

   b. The inverse relationship between line usage level and stability benefits needs to be incorporated/coordinated among scenarios (DRA/SCE Brief; Tr. at 813-814, 864, 865).

   c. The issue of how to credit stability benefits to an individual utility (and its ratepayers) needs to be examined (Exhibit 32, p. 2-22).

7. Appropriate Discount Rate. The assumption that the cost of capital (rather than a net after-tax) discount rate should be reconsidered (DRA, Tr. at 867).

VII. Environmental Considerations

The environmental impacts of the proposed project and alternatives were evaluated in the Draft and Final Environmental Impact Report (EIR), submitted prior to SCE's filing of its amended application.[28] DRA reviewed SCE's amended application and PEA, and concluded that these documents contain only minor changes in the environmental effects of the project and its environmetal context. Specifically, the amended application and PEA reflect no

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28 The Draft and Final EIR for this project was prepared by two consulting firms under the direction of DRA (Exhibits 6A, 6B, 6C). The Addendum to the Final EIR was prepared by DRA staff (Exhibit 30). The environmental review addressed the impacts of the California portion of the line.

significant changes from the initial application and PEA in the following areas:

- The expected environmental impacts of construction and operation of DPV2;
- The environmental context of DPV2;
- The list of alternatives to DPV2, or
- The expected environmental impacts associated with those alternatives.

Accordingly, DRA issued an Addendum to the FEIR (Exhibit 30) which describes changes in the Project's Purpose and Need and Alternatives sections from those that appear in the DEIR, as amended in the Final EIR.

A. Impacts of the Proposed Project

The environmental impacts associated with the project result from the proposed construction and operation of a new high-voltage transmission line. The EIR analysis concludes that the proposed project will have potentially significant effects in the areas of geology, soils and hydrology, biological resources, land use and planning, visual, acoustic and Native American cultural resources.[29] Numerous mitigation measures were identified during the environmental review.[30]

In its brief, SCE argues that the measures recommended in the EIR mitigate most of the environmental impacts, and that the remaining impact in the Blythe area is reduced to a minimal level. SCE recommends that the Commission find that the unmitigated environmental impacts of the project are insignificant.

29 Exhibit 6C (FEIR), Appendix, pages 9-10.

30 Appendix D provides a list of references for the specific mitigation measures presented in the EIR documents.

DRA, on the other hand, concludes that there remain significant environmental impacts after mitigation. DRA identifies the following impacts as those that cannot be mitigated to the point where they are insignificant:

1. Crop-Dusters in the Blythe Area. The proposed line will cross about 10 miles of irrigated farmland near Blythe. This new line will disrupt agricultural activities in and near the right-of-way in several ways. Most importantly, it will significantly increase the danger to pilots of crop dusters.[31] DRA and consultants set forth proposed mitigation measures in this area to reduce the risk of pilots flying into the line or towers. However, even if these mitigation measures are taken, DRA believes that the remaining risk to crop dusters still constitutes a significant impact.

2. Threatened & Endangered Plants and Wildlife. The proposed line would cross the habitat of several rare, threatened or endangered species. In cooperation with the Department of Fish and Game, DRA has proposed mitigation measures which would greatly reduce the impacts on these species. Nevertheless, DRA believes that there is a residual risk from human error in implementing those measures in the field. In accordance with California Environmental Quality Act (CEQA) Guidelines § 15091(a)(3), DRA recommends that the Commission find that further mitigation measures are infeasible.

B. Comparison Among Project Alternatives

DRA and SCE examined alternative transmission line corridors, alternative transmission lines, increasing the capacity of existing transmission lines, and alternatives that did not involve transmission lines. Each alternative was evaluated in

31 The probable impacts are described in Exhibit 6A (pages 167-174) and Exhibit 6B (pages 37-39).

terms of its relative level of environmental impacts, cost-effectiveness, and technical/institutional factors. A description and comparison of each alternative is presented in Appendix C. Each of the alternatives with less environmental impacts than the proposed project is discussed below.

1. The "No-Project" Alternative

DRA considers the no-project alternative, because it involves no construction of additional transmission lines, to be clearly one of the environmentally preferred alternatives. As described in Section VI, the no-project alternative was reevaluated as "Reference Case A" during Phase I hearings, due to the major changes in economic context since the EIR was prepared. Under the no-project alternative, SCE would not provide transmission service to MSR, LADWP, or the other SCPPA coparticipants.[32] SCE would forego over $360 million worth of benefits to its ratepayers. DRA now believes that under most circumstances the no-project alternative cannot meet the project objectives.[33]

SCE argues that there is a significant negative regional impact associated with the no-project alternative. In SCE's view, the SCPPA participants and MSR would build either DPV2 or the proposed Phoenix-Mead-Adelanto DC project themselves, in order to have a long-term transmission path for their Palo Verde and San Juan entitlements. The latter would be three times as expensive,

32 DRA states that the conclusions reached in the Draft EIR that the no-project alternative can meet all the project objectives are now anachronistic since the project objectives have changed both in substance and timing.

33 One important qualification to DRA's rejection of the no-project alternative is SCE's proposed merger with SDG&E. DRA argues that, if the merger occurs, then SCE's access to SWPL would allow the no-project alternative to meet all of SCE's objectives with essentially no environmental impact. This issue is discussed in Section VIII of this order.

twice as long, and have a significantly greater environmental impact than DPV2.

2. The "Infinite Bridge" Alternative

The Infinite Bridge scenario is similar to the no-project alternative except that SCE uses its existing system to wheel LADWP's power. This alternative was reevaluated as "Case B" during Phase I hearings.

Both DRA and SCE consider this project substantially less cost-effective than the proposed project (see Section VI above). DRA and SCE conclude that choosing this alternative would force SCE to forego over $340 million (NPV) in ratepayer benefits. SCE also argues (as it did for the no-project alternative) that SCPPA and MSR would probably build their own line if the Infinite Bridge alternative was adopted.

3. The Series Compensation Alternatives

SCE and DRA examined two alternatives for raising SCE's transfer capacity from the Southwest by increasing the series compensation on one or more existing transmission lines. Because no new towers would need to be built or new conductors strung, these alternatives would cause none of the environmental impacts associated with any of the DPV2 scenarios.

a. The "Expanded Infinite Bridge"

The Expanded Infinite Bridge alternative would increase series compensation from 50% to 70% on DPV1 and the Miguel-Palo Verde line (SWPL) thereby increasing the overall California-Arizona transfer capacity on DPV1 and SWPL by about 200 MW. SCE would then wheel MSR's, LADWP's, and the SCPPA cities' power over the expanded DPV1. This alternative was evaluated as "Case C" in DRA's and SCE's updated economic analysis. This alternative is estimated to cost $16 million.

Because this alternative would not involve the construction of new transmission lines, it is also one of the environmentally preferred alternatives.

SCE opposes this alternative, arguing that the technology is too risky, perhaps very expensive, and this alternative would require much cooperation with other utilities, particularly Arizona Public Service.

DRA does not recommend this alternative because it is substantially less cost-effective than the proposed project. It has a projected NPV of negative 47 million. DRA also notes the uncertainty about gaining the cooperation of other owners of Palo Verde to install the SSR suppression equipment that would be required.

4. All Lines 70% Compensation Alternatives

Another alternative studied involved increasing the series compensation on all the existing Arizona-California interties from various levels ranging from 26-70% to a uniform 70%. This would increase transfer capacity on the interties by 400 MW at a cost of approximately $118-136 million. Some of this 400 MW would be allocated to other utilities using the intertie.

Although SERA's initial analysis showed this alternative to be probably technically feasible, SERA did not do a detailed economic analysis because the SWPL-DPV1 series compensation alternative could achieve the same project objectives at much less expense, with less technical complexity, and without having to obtain cooperation from so many other utilities who may have little incentive in accepting increased risk of SSR.

5. Conversion of DPV1 to DC

This alternative would involve converting DPV1 to 500 kV DC line with a transfer capacity of approximately 2500 MW. Since new towers would not have to be installed, this alternative would have fewer environmental impacts than the proposed project. Although the increase in transfer capacity of 1300 MW would be slightly greater than DPV2, the expense would be much greater--$750 million.[34] On a per-kW basis, the cost would be approximately three times greater than DPV2.

Both SCE and DRA expressed concerns regarding the stability and reliability effects of this alternative. DRA witness Weatherwax characterized the effect of a single 2500 MW DC line on SCE's system stability as being, if not "unacceptable," at least "extremely discouraging." (Tr. at 800-801.) SCE states that it is uncertain whether the Palo Verde plant could effectively coordinate its complex control system with that of the DC line. Loop flow benefits previously associated with this alternative in the Draft EIR are no longer material due to the installation of phase shifters elsewhere.

6. Non-Transmission Line Alternatives

DRA's consultants examined QF's, conservation and load management, and additional loop flow control measures as alternatives to DPV2. DRA notes that important loop flow control measures have been taken independent of DPV2, and the exchange agreement with LADWP allows SCE through DPV2 to capture significant benefits from the PNW. DRA concludes that none of these alternatives would meet project objectives.

Both SCE and DRA conclude that alternatives with fewer environmental impacts either do not meet project objectives or are economically infeasible. Both argue that the substantial positive economic benefits to ratepayers from the proposed project outweigh the residual environmental impacts. SCE and DRA recommend that the Commission issue a Statement of Overriding Considerations.

34 The net increase in transfer capacity is only 1300 MW because converting the 500 kV AC DPV1 line to 500 kV DC operation results in the loss of about 1200 MW of existing AC transmission capacity.

VIII. DRA Recommendations and Joint Agreement on Conditions

Although DRA and SCE concur that DPV2 with a June 1, 1993 operating date is clearly cost-effective, DRA raised several concerns about the project. First, consistent with the results of DRA's economic analysis (see Section VI.D), DRA believes that even greater benefits could be achieved by delaying the project until 1997. Second, DRA is concerned that if an SCE/SDG&E merger occurs, the cost-effectiveness of the proposed project could change dramatically. Third, DRA is concerned about the uncertainty surrounding transmission service/project ownership arrangements. Finally, DRA expressed concerns over wind loading problems at DPV1, and the possibility of a simultaneous failure of two major transmission lines (an "N-2" event) because DPV2 is in close proximity to DPV1.

As a result of these and other concerns, DRA made several recommendations in its September 1988 testimony (Exhibit 28). During the September 1988 hearings in Phase I, SCE and DRA reached agreement on certain conditions to the CPC&N. The mutually agreed conditions are set forth in an SCE/DRA Agreement Re Certain Conditions on Certificate (Joint Agreement on Conditions), signed September 29, 1988 and attached as Appendix E to this order. DRA's recommendations are summarized below:

A. Require SCE to Demonstrate Revenue Enhancements for a 1993 In-Service Date

As described in Section VI.D above, DRA's economic analysis of alternatives indicate that deferring DPV2 until 1997 yields the optimal level of net benefits in the mid-1990's. DRA also concludes from its analysis that the 1997 build scenario has the least dependence on assumptions regarding economy energy pricing.[35] DRA argues that SCE should not be satisfied with simply creating a cost-effective project; it should seek to maximize ratepayer benefits.

DRA recommends that SCE pursue revenue enhancement measures to render ratepayers "indifferent" between a 1993 and 1997 on-line date. This approach is recommended (as opposed to deferral) because of the generally uncertain nature of the forecasts, assumptions and projections that underly an analysis of this magnitude, and the possibility that LADWP could successfully exercise their option to build DPV2 or an alternative line. In addition, DRA argues that SCE is in the position to enhance revenues during the 1993-1997 period through layoffs (i.e., leasing transmission capacity to other utilities on a short-term basis) and/or adjustments to transmission service rates.

SCE has agreed to DRA's proposal for purposes of this proceeding, as reflected in the Joint Agreement on Conditions (Appendix E). Under this agreement, SCE is required to demonstrate that it will be able to augment the benefits attributable to DPV2 by an amount approximately equal to the difference between a 1993 scenario and a 1997 scenario in the early years of the Project. SCE and DRA have agreed that on an NPV basis the appropriate figure is \$33.7 million. Under the agreement SCE is free to choose any method it wishes for revenue enhancements so long as it can establish by November 1, 1989 that it has executed contractual or other agreements which will provide for a \$33.7 million level of benefit enhancement (in NPV).

35 This is illustrated in Table 5, under the "No Production Cost Benefits" Sensitivity Case. See also Exhibit 32, page 2-24 and page 8-12.

B. Suspend Construction if an SCE/SDG&E Merger is Still Active

Towards the end of the Phase I study process, SCE made an offer to merge with SDG&E, as an alternative to the proposed merger between SDG&E and Tucson Electric Power (TEP).[36] On October 28, 1988 SCE filed A.88-10-055 requesting Commission approval of the merger. In DRA's view, a SCE/SDG&E merger would clearly affect the viability of DPV2, and possibly make Case B or C the more attractive alternative. This is due to the largely empty status of SDG&E's Southwest Power Link (SWPL) and the potential for using both SWPL and DPV1 transmission paths to bring in Southwest energy for an integrated SCE/SDG&E system. In DRA's view, SCE's access to SWPL would allow the "no project" alternative meet all of SCE's objectives from the project with essentially no environmental impact.

In order to get a rough estimate of the effects of the merger, DRA's consultant SERA evaluated DPV2 relative to a Reference Case that assumed a SCE/SDG&E merger. The results showed a minimum reduction of 50 percent in economy energy transfers on DPV2 to SCE.

The DRA/SERA report delineates three questions that should be investigated further before the Commission reaches a final determination on the effect of such a merger. SERA notes that the probable effect of two of the three adjustments would be to reduce SCE's need for DPV2.[37] SCE has agreed to file a report by January 15, 1990, describing the status of the merger offer.

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36 Earlier in Phase I, SDG&E announced its desire to merge with TEP. DRA states that it does not expect the proposed SDG&E/TEP merger to have a major impact on the viability of DPV2.

37 See Exhibit 32, pages 3-56 to 3-61.

Language acceptable to both parties has been worked out in the Joint Agreement on Conditions. If the merger is still being actively considered as of January 15, 1990, or consummated prior to that date, SCE has agreed to suspend construction of DPV2 pending Commission review of the situation.

C. Order a Detailed Study of a DPV1 and DPV2 "N-2" Event

DRA independently investigated the increase in risk of a major blackout that would be associated with construction and operation of DPV2. DRA's analysis shows that if DPV2 were built, there would be approximately a 1 in 15 years probability of a simultaneous outage of DPV1 and DPV2 under conditions which would cause major system outage absent some remedial protective scheme.[38]

In its amended application, SCE proposed a load shedding scheme to shed 1000 MW of load within 1/4 second of detection of a disruption on DPV1/DPV2. DRA recommends that SCE be ordered to file a report with the Commission by July 1, 1989 describing the likelihood and impact of such an outage and the feasibility of possible mitigation measures. SCE has no objection to this recommendation, as reflected in the Joint SCE/DRA Agreement on Conditions. DRA further recommends that this report provide

38 DRA argues that a simultaneous or near-simultaneous outage of DPV1 and DPV2 is hardly a remote scenario. DPV2 and DPV1 use the same terminating switchyards, occupy the same right-of-way for most of their length, and even share the same towers in 13 instances. Between March 1982 and December 1986, there were ten unscheduled outages of DPV1. Since July of 1986, there have been three events which probably would have brought down both DPV1 and DPV2--the damage at the Devers substation resulting from the July 1986 earthquake on the Banning fault, and blowdown of the DPV1 towers on August 21, 1986, and again on October 29, 1987 due to excessive wind loading.

responses to several topics related to the vulnerability of the Devers substation to seismic events.[39]

D. Order SCE to File Final T/S
Contracts Associated with DPV2

SCE has not signed transmission service agreements with any of the municipal utility coparticipants. There is some uncertainty regarding the amount of transmission service revenues that SCE would receive if DPV2 were built. Accordingly, DRA recommends that SCE be required to file by November 1, 1989, copies of all transmission service contracts for transmission service over DPV2 and west of the Devers Substation associated with DPV2. As reflected in the Joint Agreement on Conditions, SCE has agreed to this condition.

E. Require SCE to Report on Current
Status of Exchange Agreement

The SCE/LADWP Exchange Agreement currently assumes a DPV2 in-service date of June 1990. SCE proposes to provide the promised 468 MW of transmission service to LADWP on that date, but over DPV1 until DPV2 comes into service. In theory, DRA argues that LADWP should be indifferent to this alternative, and might even prefer it since it would defer LADWP's capital contribution to the project. For this reason, both SCE and DRA assumed that LADWP would accept this arrangement in their analyses and assumed that the other key aspects of the exchange agreement would come into effect on June 1990 (e.g., PNW intertie/DC Upgrade capacity swap, 200 MW of Castaic).

However, DRA notes that LADWP may not be entirely indifferent to this proposal. One of the provisions LADWP negotiated into the exchange agreement was an option to build DPV2

39 Exhibit 6C (FEIR), G-1 at p. 19. DRA recommends that a copy of these responses be sent to the City of Palm Springs.

itself if SCE did not start construction on the line by July 1989. Even under SCE's proposed 1993 in-service date, construction would not begin by this deadline.

SCE is currently negotiating an amendment to this Exchange Agreement conforming it to a deferred start date. DRA is concerned that other terms of the Exchange Agreement might change, which could have a substantial effect on the cost-effectiveness of DPV2 and of the DC Expansion Project.

Accordingly, DRA recommends that SCE be required to provide to the Commission an executed copy of all amendments to the Exchange Agreement on or before November 1, 1989. SCE has agreed to this condition (Joint Agreement on Conditions, paras. 4 and 6).

F. Order a Detailed Study on Wind-loading and the DPV1 Failures

DPV2 is proposed for the same transmission corridor and will be subject to the same wind forces as DPV1. On August 21, 1986, eight towers of DPV1 were blown down by wind causing the line to go out of service. Towers of DPV1 were blown down again on October 29, 1987. DRA recommends that SCE be required to prepare a report analyzing the direct and indirect costs of the DVP1 outage relative to the costs of building towers to withstand greater wind forces. SCE has agreed to submit a report by November 1, 1989 analyzing the failures of the DPV1 line due to wind loading (Joint Agreement on Conditions, para. 5).

G. Impose a Sliding Cost Cap

DRA recommends that the Commission establish a cost cap for SCE's share of DPV2 not to exceed $172.4 million, assuming the firm summer rating of SCE's share of the line meets of exceeds 758 MW plus or minus five percent (Joint Agreement on Conditions at paras. 9-10). Should SCE's final ownership interest be less than the proposed 63.2 percent, DRA recommends that the cost cap for the line portion of the costs be reduced accordingly.

H. Investigate the Joint Study Process

DRA describes the most recent phase of DPV2 as "unique" in several ways. First, both the applicant and the staff were dependent on the other party for doing some of the analysis. At the same time, each party maintained control over the assumptions that went into the scenarios for "its" case(s). Second, frequent meetings between DRA, its consultant, and the applicant were held prior to the applicant preparing its amended application. Third, both parties came to understand each other's case much more clearly, and avoided much of the need for burdensome data requests and the frequent miscommunication that results from such data requests.

While DRA firmly believes the net benefits of such a process are strongly positive, witness Burke cautioned that the Commission must (1) make sure that this joint study process is closely coordinated with any CEQA review, particularly with regard to evaluation of alternatives, and (2) provides means where intervenors can be meaningfully involved in the joint study process without forcing applicants to disclose proprietary information. DRA anticipates that such involvement will become more complex if the number of intervenors is larger. DRA recommends the Commission consider incorporating a pre-application joint study into the requirements for CPC&N applications through an amendment to General Order (GO) 131-C.

IX. Discussion

The Commission is required to evaluate this application in conformance with the requirements of the CEQA and the State EIR

Guidelines.[40] The significance of that requirement goes far beyond the mere preparation of an EIR as part of the regulatory steps in processing the application. It is the purpose of the EIR to identify the significant environmental effects of the proposed project, identify project alternatives and indicate how the significant effects can be mitigated or avoided.[41]

Under CEQA, the Commission is required to give preference to environmentally preferred alternatives.[42] However, CEQA does not require the mandatory choice of the environmentally best feasible project. Other considerations, such as economic, legal, social, and technological factors may make the environmentally superior alternatives unacceptable. The applicant's proposal can be approved once its significant adverse environmental effects have been reduced to an acceptable level by mitigation measures. If any significant effects are still unavoidable, the Commission must balance the benefits of the project against those unavoidable environmental risks.[43]

The Draft and Final EIR contain an extensive list of measures designed to mitigate the adverse environmental impacts of the proposed project. All of the mitigation measures should be

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40 Cal. Pub. Res. C.21000 et seq.; Cal. Admin. C.15000 et seq.

41 Cal. Pub. Res. C.21002.1(a), 21061.

42 Cal. Pub. Res. C.21002.

43 Specifically, CEQA requires that a Lead Agency issue a Statement of Overriding Consideration for projects that pose a risk for significant environmental impacts. Such a statement must certify that the Lead Agency is aware of these risks, has employed all feasible mitigation measures, and has weighed any residual risk of impact against the overall benefits offered by the proposed project. State CEQA Guidelines, 15092(2) and 15093. See also a discussion of CEQA issues in D.84-10-034, pages 44-50, mimeo, the Applicant's Concurrent Brief (pages 42-44) and the Concurrent Brief of DRA (pages 56-58).

adopted as more fully described in the EIR documents.[44] In addition, to ensure that all effective mitigation steps are taken by SCE, we will adopt a mitigation monitoring program, along the lines of that adopted for SDG&E's Eastern Interconnection System and SCE's DPV1 project.[45] The goal of the program will be to assure that the mitigation programs outlined in the EIR are fully implemented and that additional mitigation takes place consistent with the results of further studies undertaken after engineering plans and construction methods are finalized. All costs of the mitigation monitoring program will be borne by SCE as part of the project costs.

We conclude, based on the environmental analysis presented in this proceeding, that the recommended mitigation measures reduce most of the environmental impacts of DPV2 to an insignificant level.[46] However, even after all feasible mitigation measures are employed, the project poses a risk of significant impacts in two areas. As described in Section VII.A., these impacts involve the disruption of activities in the Blythe agricultural area and disruption of the habitat of several rare or endangered species. We note that even these remaining impacts are partially mitigated with the implementation of recommended mitigation measures.[47]

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44 Appendix D provides a reference of specific environmental mitigation measures.

45 D.93785, issued December 1, 1981, in A.59755; D.84-10-034 issued on October 3, 1984 in A.59982.

46 Exhibit 6C, Appendix at 9.

47 See Exhibit 6A at 159-161, 169, 170, 172; Exhibit 6C at 7-8, 12-13, Tr. at 760-761.

A. <u>Overriding Considerations</u>

The EIR analysis concludes that DPV2 is the environmentally preferred alternative when compared to routing and new construction alternatives. However, there are several alternatives identified as being environmentally preferable to DPV2. The record in this case persuades us that alternatives with fewer environmental impacts than DPV2 either do not meet project objectives and/or are economically infeasible. Under the "No-Project" (Case A) and "Infinite Bridge" (Case B) alternatives, SCE would forego over $340 million worth of net benefits to its ratepayers. Furthermore, under most circumstances, these alternatives cannot meet project objectives.[48] There is also a significant possibility that other project participants would build an alternative line with greater regional impacts, should SCE's application for certification be denied.

Under the "Expanded Infinite Bridge" (Case C) alternative, SCE ratepayers would experience <u>negative</u> net benefits of approximately $47 million. With the exception of a single "worst case" sensitivity run, this alternative is consistently less cost-effective than the proposed project. There is also uncertainty about gaining the cooperation of other owners of Palo Verde to install the SSR suppression equipment that would be needed.[49] The EIR indicates that other series compensation alternatives would be over three times as expensive as DPV2 on a per kW basis, and have potential negative impacts on system stability. Finally, none of the non-transmission line alternatives evaluated in the EIR would meet project alternatives. In view of

48 As pointed out by DRA, one possible exception would be the integration of SCE and SDG&E's systems via a merger.

49 Exhibit 32, pages 8-9, Tr. at 750-52, 802-3.

these economic and technical considerations, we conclude that the most environmentally superior alternatives are unacceptable.

DPV2, on the other hand, meets all project objectives, and provides SCE ratepayers with substantial benefits. The economic benefits of DPV2 and alternatives were evaluated and discussed at great length during the course of this proceeding. Both DRA and SCE conclude that DPV2, with an in-service date of 1993, would provide SCE ratepayers with approximately $360 million in net benefits (in NPV, 1990$). DRA presented a wide range of sensitivity cases which demonstrated that, even under the most adverse set of assumptions (e.g., no production cost benefits), DPV2 would provide net economic benefits of over $125 million (in NPV). We conclude that these substantial benefits outweigh the residual environmental impacts of the proposed project.

In sum, our overriding considerations for approving the construction of DPV2 are the substantial economic benefits of the project, coupled with the economic infeasibility of alternatives and the inability of most environmentally preferred alternatives to meet project objectives.

B. Conditions to Project Certification

We agree with DRA that certain conditions to our approval of DPV2 are appropriate. While DPV2 is clearly cost-effective with a June 1, 1993 operating date, we share DRA's conviction that, where feasible, resource planning decisions should be designed to maximize ratepayer benefits. The revenue enhancement measures agreed upon by DRA and SCE provide an optimal alternative to project deferral. From 1993 to 1997, ratepayer benefits will be increased to match the higher benefits associated with a 1997 in-service date. At the same time, ratepayers will reap the superior benefits of the 1993 scenario commencing in 1997 and continuing through the life of the project. We therefore adopt the revenue enhancement condition, as agreed upon by DRA and SCE, in their Joint Agreement on Conditions.

We also share DRA's concerns about the potential effects on DPV2 of a SCE/SDG&E merger, the stability impacts of the project, the remaining uncertainty surrounding transmission service/project ownership arrangements and the status of amendments to the LADWP Exchange Agreement. We therefore adopt DRA's recommendations for addressing these concerns, as reflected in the Joint Agreement on Conditions. In addition, we direct SCE to respond to the questions on seismic preparedness raised in comments to the DEIR.

C. Adopted Cost Cap

Pursuant to Public Utilities Code 1005.5, we will adopt a cost cap of $172,400,000 for SCE's share of project costs, subject to ratebasing. This figure represents DRA's estimate of total project costs, as stipulated to by SCE, not including mitigation (or mitigation monitoring) costs.

For SCE's Balsam Meadow hydroelectric and DPV1 projects, we limited rate base treatment of the new plant facilities to an adopted cost estimate adjusted for inflation and for environmental impact mitigation costs. SCE was permitted to seek adjustments required by unforeseen circumstances with a showing of need and cost-effectiveness.[50] We also adopted a cost-monitoring program in order to protect SCE ratepayers from avoidable cost overruns. We will adopt similar procedures here.

As agreed upon in the Joint Agreement on Conditions, SCE will file by November 1, 1989, a summary of any changes in cost estimates. This filing shall indicate the following, as appropriate:

1. Adjustments in adopted project costs because of any anticipated delays in starting the project or inflation;

50 D.83-10-031; D.84-10-034, page 58.

2. Adjustments in project costs as a result of final design criteria; and

3. Additional project costs resulting from the adopted mitigation measures (and mitigation monitoring program).

An order approving or rejecting the amended cost data will be issued following assessment by our staff. Should SCE's final ownership interest be less than the proposed 63.2 percent, the cost cap for the line portion of the costs will be reduced accordingly. In addition, the Commission may make further adjustments to the cost cap, if the final firm summer rating is determined to fall below 1140 MW.

D. Joint Study Process and <u>Remaining Analytical Issues</u>

We now turn to the joint study process and analytical issues that merit further consideration.

In our view, a joint study process, similar to the one initiated during the most recent phase of DPV2, can be an efficient and effective means for evaluating the merits of a project, and for identifying the most relevant issues for litigation. In this proceeding, the joint study process developed new or refined analytical methods for evaluating the strategic benefits of transmission line projects. We especially commend DRA and its consultant SERA for the extensive analytical work presented in this proceeding. Per DRA's recommendation, we will consider commencing a rulemaking to incorporate a pre-application joint-study phase into the requirement for CPC&N applications.

Our support for joint studies, however, is not without some concerns. As pointed out by DRA, to be effective, this process (1) must be closely coordinated with any CEQA review, particularly with regard to evaluation of alternatives, and (2) must provide for the effective involvement of intervenors. We add our concern that joint studies have the potential for making it difficult to identify and explore key assumptions or methodological issues on the record. This is evidenced by the fact that the presiding ALJ, rather than the parties, conducted most of the questioning during the September, 1988 hearings, in order to illuminate any remaining technical or policy issues for further consideration by the Commission.

At the request of the presiding ALJ, DRA, and SCE summarized the issues that merit further attention in their concurrent briefs submitted on October 12, 1988. These issues do not appear to have a significant effect on the overall conclusions of the joint study. However, both SCE and DRA acknowledge that they could have a major impact on the cost-effectiveness of other projects, and should be explored further.

We note, in particular, the issue of economy energy pricing assumptions. For the DPV2 analysis, DRA and SCE assumed that prices for Pacific Northwest (and Southwest) economy energy are cost-based, reflecting the production costs of the exporting utility. At the request of the ALJ, a sensitivity case was performed across all project alternatives to explore the relative effects of "highest block" pricing assumptions. Under this scenario, DPV2 remained the most cost-effective alternative, with over $300 million in net benefits (in NPV).

For future proceedings, SCE suggests further refinements to the "highest block" approach in situations where that cost is significantly lower than the California utility's marginal costs. SCE's suggestion is consistent with the Commission's recent discussion of the Bonneville Power Administration's (BPA's) policies and PNW economy energy pricing assumptions for resource planning:

> "The Pacific Northwest will typically have large surpluses for some years to come, but those surpluses mean little without assurance on price. Until and unless BPA (or the Federal Energy Regulatory Commission or the courts in their review of BPA's decisions) provides

> appropriate assurance as to some other price assumption, we arguably should assume that all purchases of 'economy' energy from BPA will be slightly below short-run marginal cost." (D.88-09-026, pages 9-10.)[51]

For CPC&N proceedings, we expect DRA and other parties to use pricing assumptions for PNW economy energy that reflect BPA policies and are consistent with our approach in other proceedings, such as OIR-2, where long-term resource alternatives are evaluated. SCE's suggestion is well taken, and should be given immediate consideration for the Phase II "base case" analysis in this proceeding. Similarly, other issues identified in Section VI.E should be explored and addressed in Phase II, to the extent that they are applicable to the DC Expansion Project. We strongly encourage all interested parties to become familiar with the analysis presented in Phase I of this proceeding, and with the issues identified for further refinement/reconsideration.

A final issue that was raised during the course of this proceeding involves the joint study assumption that surplus line space of another utility (e.g., LADWP, SDG&E) would not be made available to SCE to carry additional economy energy purchases.[52] Without that assumption, witness Weatherwax estimates that 60 to 70 percent of the production cost benefits of DPV2 could disappear, although he would still expect the "build cases" to have a benefit-cost ratio of over 2-to-1.[53] In its brief, SCE argues that the

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51 D.88-09-026 also states: "Given BPA's Intertie Access Policy, we would expect similar upward pressure on the prices of other energy sellers in the Pacific Northwest." (footnote 5, page 9).

52 DRA assumed that, unlike for economy energy, other utilities could be called upon to wheel for next day UIS support (See Appendix B).

53 Tr. at 819.

likelihood of SCE being able to import significant amounts of economy energy on other systems is relatively small:

> "If Edison desired to import significant amounts of economy energy on some other system, except for a relatively insignificant amount of capacity on Western Area Power Administration's system, it would be limited to using SDG&E and LADWP entitlements. Historically, other utilities, particularly LADWP, have been reluctant to provide transmission service to Edison, except in emergency situations. In addition, LADWP's willingness to part with line space to the Northwest in exchange for line space to the Southwest (per the Exchange Agreement) and SDG&E's intervention in this proceeding in an attempt to obtain more transmission capacity to the Southwest indicate that it is highly unlikely that either of these utilities would be willing to part with any of their own Southwest capacity." (Applicant's Concurrent Brief, page 34.)

We do not have an adequate record in this case to evaluate SCE's power-pooling opportunities for either economy energy or emergency interconnection support. We are satisfied that, for this particular project, adequate sensitivity analyses were conducted to assure the robustness of the joint study conclusions in face of uncertain assumptions. However, assumptions concerning wheeling opportunities could "make or break" a future project, particularly one in which transmission service revenues are not a large component of project benefits. We therefore need to develop a better understanding of current utility practices in providing emergency support, access to economy energy and other power-pooling arrangements.

As a policy issue, we also need to examine whether or not the current practices of California utilities are optimal from the standpoint of system efficiency. If increased coordination or power-pooling among California utilities is feasible, there is the potential for reducing the need to construct additional transmission lines. In order to gain a better understanding of these issues, we direct DRA to conduct a study on power pooling/coordination arrangements among California utilities. To the extent possible, this effort should be coordinated with any ongoing studies in this area at the California Energy Commission.

As part of this effort, DRA should conduct a case study on the current and historical practices of SCE in receiving and providing emergency support, wheeling services for economy energy, and other coordination/power pooling arrangements. We direct SCE to cooperate with staff in providing data on the frequency and cost of these power transfers. This report is to be filed no later than eight months from the effective date of this order.

The DRA study should also compile information on power-pooling/coordination arrangements in other regions of the country, with particular focus on UIS and wheeling of economy energy. DRA should include specific recommendations regarding the technical and economic feasibility of alternative arrangements, as they might apply to California utilities. A final report on the results of the study is to be filed no later than eighteen months from the effective date of this order.

This order completes our Phase I examination of SCE's amended DPV2 application. As described in Section II above, our review of this transmission project has been long and arduous. Earlier phases of this proceeding were plagued with discovery disputes between DRA and SCE and data input inconsistencies in SCE's filed testimony, which contributed to significant delays. Discovery of the SCE/LADWP Exchange Agreement in late 1987 dramatically changed the economic context of both DPV2 and the DC Expansion such that each needed to be "revisited" in further evidentiary hearings.

We acknowledge the more recent "cooperative spirit" exhibited by DRA and SCE during Phase I, and encourage similar joint study efforts for future proceedings, where practicable. We also commend the joint study participants for their efforts to quantify, and integrate, the cumulative impacts of DPV2 and the SCE/LADWP Exchange Agreement. This is consistent with our directives to SCE regarding the necessity for discussing the interrelationships of projects:[54]

> "the Commission seeks sufficient information to understand not only the purpose of this specific proposal, but also how it would fit as part of your current integrated plans for purchasing power and upgrading transmission capability." (Letter from Joseph Bodovitz, March 1, 1985 re: first rejection of SCE's application for the Gould-Mesa transmission line.)

> "...our major concern is the determination of need for the proposed project in a systemwide context. Piecemeal consideration of transmission lines makes little sense from both a public policy perspective and when the requirements of CEQA are concerned..." (Letter from Joseph Bodovitz, August 22, 1985 re: second rejection of SCE's application for the Gould-Mesa transmission line.)

> "Of particular concern has been the PUC's obligation to review proposed transmission projects in the context of SCE's existing and planned system, thus allowing a fully informed consideration of the alternatives to a given project." (Letter from Joseph Bodovitz to John Bury, January 2, 1986, re: rejection of SCE's application for DPV2.)"

We remind SCE and other parties to our proceedings of these concerns. It is our expectation that future CPC&N applications for transmission lines will contain the information needed to effectively, and efficiently, evaluate specific projects within a systemwide context. With this perspective, we will

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54 See also the Commission's discussion in the Devers-Valley-Serrano decision (D.84-10-034), mimeo. at 51-51a.

embark on Phase II of this proceeding to examine the cost-effectiveness of the DC Expansion project, in full consideration of the SCE/LADWP Exchange Agreement.

Findings of Fact

1. SCE requests a certificate of public convenience and necessity to construct a Devers Palo Verde No. 2 (DPV2), a 500 kV transmission line between Devers substation and the Palo Verde Nuclear Generating Stations in Arizona.

2. SCE's original application and PEA were accepted for filing on February 26, 1986.

3. SCE's amended application and amended PEA were filed on August 15, 1988.

4. SCE's amended application and PEA reflect the following changes: (1) deferral of the in-service date of DPV2 until mid-1993; (2) incorporation of the SCE/LADWP Exchange Agreement; (3) reduction in West of Devers construction costs; (4) restructuring of ownership among project participants; (5) "bridging" transmission service to LADWP on DPV1 from 1990 until the in-service date; and (6) updated assumptions and new or refined methodologies for quantifying project benefits.

5. SCE's amended application and PEA did not significantly change the environmental effects of the project or its environmental context from those originally filed by SCE in 1986.

6. The firm summer rating of DPV2 will be 1200 MW (with all Palo Verde units on line), plus or minus five percent.

7. SCE's project objectives are to provide itself, LADWP, MSR, and other SCPPA participants with transmission capacity, to purchase additional economy energy from either the Northwest or the Southwest, and to displace more costly oil and gas generation.

8. SCE's preferred route for DPV2 would parallel SCE's existing 238 mile 500 kV transmission line (DPV1).

9. DPV2 is expected to provide 1200 MW of transmission capacity, of which SCE will own approximately 758 MW (or 63%).

10. LADWP, other SCPPA participants will own the remaining 442 MW of project capacity. From SCE's ownership share, 250 MW of firm transmission service (T/S) will be provided to MSR and LADWP.

11. Total project costs, subject to ratebasing, are estimated at $260 million (in dollars escalated to the date of expenditure). This figure includes the costs of West of Devers (WOD) improvements.

12. SCE's share of total costs is approximately $172 million in 1993 dollars, assuming an ownership share of 63.17%, including substation facilities. This figure is based on SCE assuming 100% of the right-of-way expenses, and 100% of the additional transformer bank required at Devers substation.

13. The net present value (NPV) of SCE's total cost, including capital and O&M, is estimated to be $175 million in 1990 dollars.

14. These estimated costs do not include any mitigation measures or mitigation monitoring program costs.

15. DRA and SCE conducted a joint study to evaluate the cost-effectiveness of the proposed project and several project alternatives.

16. DPV2 will provide SCE with the following benefits: increased transmission service revenues, reduced production costs, reduced transmission losses, improved utility interconnection support (UIS), improved air quality, and enhanced transmission stability.

17. Under DRA/SCE's base case assumptions, building DPV2 yields net savings to SCE ratepayers of approximately $360 million (in NPV, 1990 dollars).

18. DRA conducted several sensitivity analyses to assure the robustness of the joint study conclusions in face of uncertain assumptions (e.g., UIS benefits, economy energy pricing, gas curtailment).

19. While the magnitude of net benefits associated with DPV2 is highly sensitive to economy energy pricing assumptions, the project remains cost-effective under even "worst case" assumptions.

20. Even under the most adverse set of assumptions (e.g., no production cost benefits), DPV2 would provide net economic benefits of over $125 million (in NPV, 1990 dollars).

21. Building DPV2 yields the highest net benefits when compared with no project alternatives.

22. The difference in net benefits between the 1993 and 1997 in-service cases is approximately $34 million (in NPV) during 1993-1997.

23. The 1997 in-service case is the least sensitive to economy energy prices, relative to earlier in-service dates.

24. During Phase I hearings, SCE and DRA identified several analytical issues that merit further attention in future Commission proceedings.

25. A comprehensive record on environmental matters was developed in this proceeding through issuance of a Draft EIR, consultation with public agencies and others, and public hearings. All are elements in the environmental process which culminated in the issuance of the Final EIR and its Addendum.

26. <u>Statement of Overriding Considerations</u>:

(a) The proposed project (DPV2) will result in significant environmental effects on geology, soils and hydrology, biological resources, land use and planning, visual, acoustic and Native American cultural resources.

(b) The mitigation measures proposed in the Draft and Final EIR and adopted in this decision reduce most of the environmental impacts of DPV2 to an insignificant level.

(c) After all feasible mitigation measures are employed, the proposed project still poses a risk of significant impacts on Native American resources, agricultural activities in the Blythe area and on the habitat of several rare or endangered species.

(d) None of these residual impacts can be mitigated to insignificant levels by feasible modifications of design, construction, or operating characteristics of the proposed project.

(e) Several project alternatives were considered, including alternative transmission lines, increasing the capacity of existing transmission lines and "no-project" alternatives.

(f) DPV2 is the environmentally preferred alternative when compared to routing and new construction alternatives.

(g) Under the "no-project" alternatives (Reference Case A and "Infinite Bridge" Case B), SCE would forego over $340 million worth of net benefits to its ratepayers.

(h) None of the "no-project" alternatives, conservation or loop-flow measures would meet project objectives.

(i) Under alternatives to increase the capacity of existing transmission lines (e.g., the "Expanded Infinite Bridge, Case C), SCE ratepayers would experience negative net benefits estimated at $47 million.

(j) Alternatives for increasing the capacity of existing lines would require the installation of subsynchronous resonance (SSR) suppression equipment.

(k) There is significant uncertainty about gaining the cooperation of other owners of Palo Verde to install SSR suppression equipment on DPV1 or SWPL.

(l) The residual impacts of the proposed project cannot be mitigated by selecting an acceptable alternative.

(m) Any remaining environmental impacts are outweighed by the beneficial effects of the proposed project.

(n) Our overriding considerations for approving the construction of DPV2 are the substantial economic benefits of the project, coupled with the economic infeasibility of alternatives, and the inability of most environmentally preferred alternatives to meet project objectives.

27. An SCE/SDG&E merger could dramatically effect the economic benefits of DPV2 and possibly make "no project" alternatives preferable.

28. DRA estimates that if DPV2 were built, there would be approximately a 1 in 15 years probability of a simultaneous outage (N-2 event) of DPV1 and DPV2 absent some remedial protective scheme.

29. DPV2 and DPV1 use the same terminating switchyards, occupy the same right-of-way for most of their length and share the same towers in 13 instances.

30. Between March 1982 and December 1986, there were ten unscheduled outages of DPV1.

31. Since July of 1986, there have been three events which probably would have brought down both DPV1 and DPV2. Two of these events were due to excessive wind loading. The third was due to earthquake damage at Devers substation.

32. Transmission service revenues are estimated to cover approximately 70% of SCE's share of total costs.

33. SCE has not signed transmission service agreements with any of the municipal utility coparticipants on DPV2.

34. The SCE/LADWP Exchange Agreement currently assumes a DPV2 in-service date of June 1990.

35. SCE is currently negotiating an amendment to this Exchange Agreement conforming it to a deferred start date.

36. SCE and DRA reached agreement on several conditions to the CPC&N, as set forth in the Joint Agreement on Conditions, signed September 29, 1988.

37. The joint study process can be an effective and efficient means for evaluating the merits of a project and for identifying the most relevant issues for litigation.

38. For the joint study analysis of DPV2, DRA and SCE assumed that prices for Pacific Northwest (and Southwest) economy energy are cost-based, reflecting the production costs of the exporting utility.

39. In D.88-09-026, we stated that, for long-run resource planning assumptions, we should assume "that all purchases of economy energy from BPA will be slightly below short-run marginal cost."

40. For the joint study analysis, it was assumed that surplus line space of other utilities would not be made available to SCE to carry additional economy energy.

41. Approximately 60-70 percent of the production cost benefits of DPV2 could disappear without this assumption.

42. For utility interconnection support (UIS), DRA assumed that surplus line space of other utilities would be made available to SCE to obtain emergency UIS support.

43. We do not have an adequate record in this case to evaluate SCE's power-pooling opportunities for either economy energy or energy interconnection support.

44. Increased coordination or power-pooling among California utilities could reduce the need to construct additional transmission lines.

Conclusions of Law

1. Present and future convenience and necessity require the construction and operation of DPV2.

2. The Final EIR and its Addendum have been completed in compliance with the CEQA guidelines and we have reviewed and

considered the information contained in the Final EIR and its Addendum in reaching this decision.

3. Where feasible, resource planning decisions should be designed to maximize ratepayer benefits.

4. Deferring DPV2 until 1997 yields the optimal level of net benefits in the mid-1990's.

5. SCE should be required to either defer DPV2 until 1997, or enhance project revenues during the 1993-1997 period by approximately $34 million (in NPV).

6. The mitigation measures set forth in the Draft and Final EIR should be conditions of authorization.

7. A mitigation monitoring program, as identified in the preceding opinion, should be established.

8. Construction of DPV2 should be suspended pending further Commission review if the SCE/SDG&E merger is still being actively considered as of January 15, 1990.

9. SCE should be required to file detailed reports describing the likelihood and impact of a simultaneous outage of DPV1 and DPV2, the wind loading problems that have occurred at DPV1, and possible mitigation measures.

10. SCE should be required to file by November 1, 1989 copies of all transmission service contracts related to the proposed project including final amendments to the SCE/LADWP Exchange Agreement.

11. It is reasonable to adopt a cost monitoring program, similar to the one adopted for SCE's DPV1 project, in order to protect SCE's ratepayers from avoidable cost overrruns.

12. It is reasonable to adopt a "sliding" cost cap to reflect SCE's final ownership share of the project and the actual firm summer rating of the line.

13. Because assumptions concerning wheeling opportunities could "make or break" a future project, current utility practices

in providing emergency support, access to economy energy and other power-pooling arrangements should be investigated.

14. The issue whether or not the current power-pooling or coordination practices of California utilities are optimal in terms of regional system efficiency should be examined.

15. A draft Order Instituting Rulemaking (OIR) should be prepared for the Commission to consider modifying GO 131 to incorporate a joint study pre-application phase in CPC&N proceedings.

16. SCE and other parties to our proceedings should provide the information needed to effectively, and efficiently, evaluate specific projects within a systemwide context.

17. Because SCE and other project participants are in need of the transmission facilities that will be provided by the authorized system, this decision should be effective on the date signed.

INTERIM ORDER

IT IS ORDERED that:

1. A certificate of public convenience and necessity (CPC&N) is granted, subject to the conditions set forth in this order, to Southern California Edison Company (SCE) to construct and operate a second 500 kilovolt (kV) transmission line between its Devers substation and the Palo Verde Nuclear Generating Stations in Arizona (DPV2).

2. This certificate is granted for an operating date of no sooner than June 1, 1993.

3. By January 15, 1990 SCE shall submit a report to the Commission describing the status of the efforts of SCEcorp (SCE's parent company) to merge with San Diego Gas & Electric Company (SDG&E). This report will indicate, as of January 1, 1990, whether (a) a merger agreement has been entered into by SCEcorp or SCE and SDG&E, (b) SCEcorp or SCE has commenced and is continuing a

solicitation of SDG&E shareholders for the purpose of a merger, and (c) SCEcorp or SCE has a public merger offer with SDG&E outstanding. If one or more of these conditions exist as of January 1, 1990, or if a merger is consummated prior to this date, SCE (1) shall not commence construction of DPV2, and (2) shall petition the Commission for reevaluation of DPV2 in the context of the then status of the merger activity. To protect DPV2 project dates, SCE may solicit bids from material suppliers prior to January 1, 1990, but may not award any contracts for the purchase of material.

4. By July 1, 1989 SCE shall submit to the Commission a statement of its plans to enhance the net benefits attributable to DPV2 in the early years by measures such as increased transmission service revenues, transmission capacity layoffs, or other measures. This report shall include an analysis, including a production costing analysis, of the net benefits that would be derived from implementation of such plan, and showing that the enhanced benefits could not be realized without having DPV2 in service prior to 1997. The goal in implementing these benefit enhancements will be to generate additional net benefits to enhance the near-term benefits so that the impact on the ratepayers during the 1993-97 time period will not be substantially different than under DRA's 1997 in-service date case (Case W(97) in Exh. 32).

5. By July 1, 1989 SCE shall submit to the Commission a study on the likelihood and potential impact of a simultaneous outage of both the DPV1 and DPV2 lines. This study shall assess alternative measures for mitigating the impacts of such a simultaneous outage, and the effectiveness, cost, reliability, and feasibility of these measures.

6. By November 1, 1989, SCE shall submit copies of the applicable signed agreements implementing the benefit enhancement measures referenced above, and copies of signed contracts for transmission service over DPV1 from 1990-93, over DPV2, and over

SCE's existing system west of the Devers Substation, including all final amendments to the SCE/LADWP Exchange Agreement.

7. By November 1, 1989, SCE shall submit to the Commission a report analyzing the failures of the DPV1 line which occurred on August 21, 1986 and October 29, 1987 due to wind loading. This report will include responses to the following questions related to the vulnerability of the Devers substation to seismic events:

1. What level seismic shaking ("G" forces) is incorporated in design of foundations and in specifications for equipment.

2. What provisions for equipment movement from dislocation or ground displacement have been made.

3. What is the estimated availability and mean time to repair damaged equipment.

4. How much damage could be sustained and what level of service maintained at Devers.

5. What capacity exists to serve Palm Springs and the SCE system in general if Devers is out of service due to temporary repairs. (Final EIR at p. 19.)

SCE shall provide a copy of its responses to these questions to the City of Palm Springs.

8. As soon as SCE can do so with a reasonable degree of certainty, it shall describe in writing what it believes will be the final provisions of the amendment to the "Los Angeles-Edison Exchange Agreement Between the Department of Water and Power of the City of Los Angeles and Southern California Edison Company," which is presently being negotiated to provide, <u>inter alia</u>, for the Department of Water and Power to receive transmission service over DPV1 from June 1, 1990 until the earlier of (1) the date when DPV2 commences commercial operation, or (2) June 1, 1993.

9. SCE shall implement the mitigation measures contained in the Draft and the Final Environmental Impact Reports and Addendum (EIR).

10. All reasonable costs related to the mitigation monitoring program shall be considered as construction expenses related to this project.

11. Within 90 days, the Executive Director shall prepare and present to the Commission a recommended mitigation monitoring program consistent with the discussion in this decision. The recommendation shall include an estimated cost for the program.

12. By November 1, 1989, SCE shall file an amended cost estimate for the project, reflecting:

(a) Any adjustments in adopted project costs due to anticipated delays in starting the project or inflation;

(b) Any adjustments in project costs as a result of final design criteria; and

(c) Additional project costs resulting from the adopted mitigation measures (and mitigation monitoring program).

This filing will be in the form of an advice letter, requesting Commission action on approving or rejecting the amended cost data.

13. No later than six months prior to the project in-service date, SCE shall report the firm summer rating of DPV2. If this rating is finally determined to be below 1140 MW, SCE shall include in an advice letter filing the per-megawatt costs of the project and a recommendation for Commission action on adjusting the final cost cap.

14. Except as otherwise provided for in this order, SCE's share of total project costs subject to ratebasing shall not exceed the lesser of (1) $172,400,000 or (2) SCE's final ownership interest times the total cost of jointly owned facilities, plus 100% of the 220 kV Devers substation costs and 100% of right-of-way acquisition costs. After considering the information filed on the

actual firm summer rating, per ordering paragraph 13 above, the Commission may make further adjustments to the cost cap.

15. During construction SCE shall file quarterly reports for the project which contains:

(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 SCE's progress toward the major milestone including an estimate of whether those milestone will be achieved within budgeted costs and on schedule.

16. SCE shall not apply for cost recovery of any amount above the amended cost estimate, except that SCE may apply for reasonable costs caused by delay in initial construction in an amount equal to the adopted cost of the project times the increase in the Producer Price Index for Industrial Commodities, subgroup 10 "Metals and Metal Products," as published by the U.S. Bureau of Labor

Statistics for each month the initial construction is delayed past June 1, 1993. SCE may apply for added adjustments only with a showing of unforeseen circumstances as approved by the Commission after advice letter filing.

17. Unless otherwise indicated, SCE shall make all filings ordered above as compliance filings with an original and 12 conformed copies, and serve all parties of record with either the filing or notice that the filing has been made and when a copy can be obtained from SCE. The filings shall comply with the applicable rules in Article 2 of the Rules of Practice and Procedure and shall have attached a certificate showing service by mail on all parties. The compliance filings shall be part of the public record for this proceeding. In addition, two copies of each filing shall be sent to the Commission Advisory and Compliance Division with a transmittal letter stating the proceeding and decision numbers.

18. Consistent with the discussion in this decision, DRA shall conduct a study on power-pooling/ coordination arrangements among California utilities, including a compilation of information on power-pooling/coordination arrangements in other regions of the county. This study shall include a case analysis of SCE's power transfers with other utilities, the results of which are to be filed with the Executive Director no later than eight months from the effective date of this order. A final report shall be filed no later than eighteen months from the effective date of this order.

19. Consistent with the discussion in this decision, a draft OIR for modifying GO 131-C to incorporate a joint study pre-application phase for CPC&N proceedings shall be prepared for Commission consideration.

20. The Executive Director of the Commission shall file a Notice of Determination for the project, as set forth in Appendix F to this decision, with the Secretary of Resources.

This order is effective today.

Dated ____________________, at San Francisco, California.

DPV2 Project Location

The proposed project consists of constructing a 500 kV transmission line from the high voltage switchyard adjacent to the Palo Verde Nuclear Generating Station (PVNGS) in Arizona to Devers Substation near Palm Springs, California. The preferred route would parallel Edison's existing 238 mile 500 kV transmission line (Devers-Palo Verde #1), of which 112 miles is located in Arizona and 126 miles is located in California.[1]

A. Termination Points

The Arizona segment of the proposed transmission line terminates at the switchyard rack positions of PVNGS. PVNGS is located in the Palo Verde Hills approximately 1 mile south of Wintersburg, Arizona in northwestern Maricopa County, about 36 miles west of the nearest boundary of the City of Phoenix. The California segment of the line terminates at Edison's Devers Substation approximately 10 miles northwest of Palm Springs, California.

B. Existing Facilities

Existing facilities related to the proposed project include the Devers Substation, located about 2 miles northwest of the community of North Palm Springs and 10 miles north of Palm Springs, California; the Devers-Palo Verde #1 500 kV line and right-of-way; and the Palo Verde Nuclear Generating Station and switchyard located in the Palo Verde Hills approximately 1 mile south of Wintersburg, Arizona in northwestern Maricopa County, about 36 miles west of the nearest boundary of the City of Phoenix.

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1 This appendix provides an overall description of the project location. Additional detail on the proposed facilities, construction and operating and maintenance costs is provided in Chapter 3 of Exhibit 25, Amended Proponents' Environmental Assessment.

C. Preferred (Proposed) Route

1. Arizona Route Segment

The preferred route parallels Edison's existing single circuit 500 kV line (Devers-Palo Verde #1). The line departs the PVNGS switchyard and proceeds in a westerly direction for approximately 3 miles to a point south of the Palo Verde Hills. The route then turns northwesterly and proceeds approximately 20 miles northwest of Burnt Mountain. The route then turns westerly and generally follows Interstate 10 and the Central Arizona Project (CAP) for approximately 20 miles through the Big Horn Mountains and across the Harquahala Plain to a point 0.5 mile north of Interstate 10 where it turns southwest, crosses Interstate 10, and proceeds approximately 5 miles where it meets the El Paso Natural Gas Company's existing pipeline just north of its Wendon Pump Station north of the Eagletail Mountains.

At this point, the route parallels the El Paso Natural Gas pipeline for approximately 56 miles, crossing the Ranegras Plain, Kofa National Wildlife Refuge, La Posa Plain, Arizona State Highway 95, through the Dome Rock Mountains to the summit of Copper Bottom Pass. The route then turns southwesterly away from the pipeline, descends the western slope of the Dome Rock Mountains, and proceeds approximately 9 miles to a crossing at the Colorado River. One of the two series compensation banks (described in Section 2.4.4) would be located on the proposed right-of-way adjacent to the Devers-Palo Verde #1 series compensation bank about 1 mile east of the Kofa National Wildlife Refuge.

2. California Route Segment

Upon crossing the Colorado river, the route leaves Arizona and passes into the Palo Verde Valley, 5 miles south of Blythe, California. The route proceeds westerly across farmlands for approximately 10 miles to the top of the Palo Verde Mesa, then proceeds northwesterly approximately 4 miles to a point 2 miles south of Interstate 10 and 5 miles southwest of the Blythe Airport.

At this point the route proceeds westerly, generally parallel to Interstate 10 approximately 63 miles to a point in Shavers Valley where it turns northerly and crosses Interstate 10 approximately 2 miles east of the Cactus City rest stop. After crossing Interstate 10 the route then parallels Edison's existing Devers-Julian Hinds 220 kV transmission line the remaining 46 miles to the Devers Substation. The total length of the line is approximately 238 miles. The second series compensation site would be located on the right-of-way adjacent to the Devers-Palo Verde #1 line series capacitor site about 60 miles west of Blythe.

D. Proposed Transmission Line Facilities

The proposed transmission line is similar to other 500 kV transmission lines in the United States. The transmisison line consists of overhead wires (conductors) which form three electrical phases. These conductors would be supported by lattice steel structures and would be electrically isolated from the structures by insulators. In addition to the conductors, structures, and insulators, the proposed transmission line would contain hardware and overhead groundwires.

(END OF APPENDIX A)

SUMMARY OF ASSUMPTIONS, METHODOLOGIES, AND RESULTS FOR DPV2 BASE CASE ANALYSIS

APPENDIX B
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Tables and Figures

Attachment 1: Summary of Base Case Assumptions

I. Introduction

This appendix summarizes the assumptions and methodologies used by DRA and SCE to analyze the economic benefits of DPV2 and project alternatives in Phase I of this proceeding. It was developed by the presiding Administrative Law Judge to provide a concise consolidation of the technical information presented during Phase I evidentiary hearings.[1] It is also designed to provide additional background and insight for the various methodological issues raised in this proceeding.[2]

The following types of economic benefits are discussed:

- Transmission Service Revenues
- Production Cost Benefits
- Air Quality Benefits
- QF Payment Benefits
- Stability
- Transmission Loss Reduction and Reimbursement Benefits
- Utility Interconnection Support

For each type of benefit, the results of DRA's and SCE's base case analyses are presented.[3] Table B-1 summarizes the results of DRA and SCE's base case analysis for a June 1, 1993 in-service date. For reference Figure B-1 (Exchange Agreement Provisions) and Figure B-2 (Summary of Alternative Cases) are reproduced from the body of this order. Attachment 1 summarizes the common policy and technical assumptions used for the base case analyses.

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1 Most of the material was developed from Appendix A of DRA's Exhibit 28, augmented by the results presented in Exhibit 32, 35, and 36, DRA/SCE concurrent briefs and the oral testimony presented during the hearings.

2 These issues are identified, and referenced, in Section VI.F of this order.

3 "Base Case" refers to the SCE/DRA analysis using the joint study assumptions described in Exhibit 32 (Section 1.C), and summarized in Section VI.B of this order. In addition, DRA performed several sensitivity analyses, the results of which are presented in Exhibits 32 and 36, and summarized in Section VI.E of this order.

II. Transmission Service Revenues

Concept

DPV2 will provide California utilities with transmission access to bulk power markets in the Southwest. SCE will derive revenues from the sale of transmission services (e.g. wheeling) to the other participants on DPV2 and on SCE's transmission network west of Devers, which connects to the participants' various delivery points, and to LADWP on DPV1 until DPV2 comes on-line.

Background

SCE's current application is different from its original January 1986 application in two key ways that affect transmission service (T/S) revenues. First, several participants in the project will now own their entitlements rather than purchase T/S from SCE. (SCE's project ownership share is 256 MW less than in its original application.) Second, the additional transmission capacity provided by DPV2 has enabled SCE to enter into other T/S arrangements involving DPV1 that might not otherwise have been considered cost-beneficial for SCE.

SCE currently supplies little firm T/S on DPV1.[4] The parties to whom SCE would supply T/S either on DPV1, DPV2, or SCE's transmission system west of Devers are:

- Modesto-Santa Clara-Redding Public Power Agency (MSR), for its 150 MW entitlement in DPV2 for the life of the San Juan Unit 4 plant;
- LADWP, for 368 MW of "bridging" T/S on DPV1 from June 1, 1990 until DPV2 goes into service;
- LADWP, for 368 MW of firm service from Devers to Sylmar/Victorville and for 100 MW of additional firm service from Palo Verde to Sylmar/Victorville for 22 years, waived per the Exchange Agreement;

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4 Little wheeling is currently offered on DPV1 because of SCE's layoff of its 350 MW share of the Cholla coal plant; that layoff is scheduled to end in 1990.

- All utilities[5] scheduling power over SCE's network transmission system from the Devers Substation to their respective service delivery points;

- SDG&E, for its option of 100 MW of firm T/S on DPV1 beginning in 1995.

The "updated" economic analysis prepared by SCE in August 1986 indicated that T/S revenues would have a levelized annual value of $33.8 million. The DRA/SCE stipulated level of T/S revenue on DPV2 as estimated in September 1987 was $28.79 million per year levelized. In the DRA/SERA alternative of routing the power on DPV1 starting in 1990, the revenues were estimated to be $30.7 million annually.[6]

Study Agreement Methodology

SCE's T/S rates were set using the FERC-approved embedded-cost (cost-of-facility) methodology.[7] For west of Devers service, estimated T/S rates were calculated along contract paths to the designated delivery point of each participating utility.[8]

5 These utilities are part of the Southern California Public Power Authority (SCPPA). The specific utilities owning shares of DPV2 capacity but expected to purchase transmission service from SCE are Riverside, Vernon, Burbank, Glendale, Pasadena, Azusa, Banning, Colton, and the Imperial Irrigation District.

6 SERA prepared testimony, September 1987.

7 SCE is presently investigating several alternative transmission service rate structures patterned after proposed rates being considered by the FERC. Under these alternatives, T/S revenues would be greater than under cost-of-facility based rates.

8 The rate shown in the table for SCPPA reflects a weighted average of the participants' delivered rates.

The table below shows, for each party to whom SCE is supplying T/S, the appropriate transmission line, the amount of T/S, and the applicable T/S rate.

Party	Transmission Line	Amount	Rate[9]
MSR	DPV2	150 MW	$37.24/kW-yr.
MSR	Devers to Midway	150 MW	$40.41/kW-yr.
LADWP	DPV1[10]	367.75 MW	$25.66/kW-yr.
LADWP	West to Sylmar[11]	367.75 MW	Free for 22 yrs., Then $37.09/kW-yr.
SCPPA	Devers to varying delivery points	74.25 MW	$26.16/kW-yr.
SDG&E	DPV2	100 MW	$15.50/kW-yr.

The total T/S revenues are calculated by multiplying the amount of T/S for each party by the rate and summing all of those subtotals.

T/S revenues attributable to the Project begin in June 1990 when the Exchange Agreement with LADWP becomes effective. Between 1990 and 1993, T/S charges for LADWP's 368 MW of firm "bridging" service on DPV1 will yield revenues as shown below.

When the Project goes into operation in 1993, revenues from MSR's 150 MW of firm T/S from Palo Verde to Midway and SCPPA's 74 MW of firm service to various delivery points west of Devers begin accruing and will be paid for the life of the Project. Once the 22-year waiver of charges for LADWP's 368 MW of west-of-Devers T/S expires in 2012, T/S revenues will be received from LADWP for the remaining Project life. Together these services will yield revenues as shown below.

SDG&E is assumed to exercise its option to purchase 100 MW of firm T/S from Palo Verde to San Onofre on DPV1 in 1995. If SDG&E does not exercise this option, the foregone T/S revenues would be partially offset by SCE's increased economy energy purchase opportunities, system stability improvements, increased interconnection support, and air emission reduction benefits.

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9 The transmission service rates are levelized (1990 $) nonescalating amounts.

10 LADWP receives "transitional" transmission service on DPV1 until DPV2 is on-line.

11 Includes the effects of the Exchange Agreement between SCE and LADWP.

Value of T/S Benefits

The value of the T/S revenues attributable to various cases, under DRA's base case assumptions, are shown in the following table:[12]

T/S Revenues (NPV in 1990 million $)

Category	W(93)-A	W(95)-A	W(97)-A	B-A	C-A
East of Devers*	$ 64	$ 71	$ 74	$75	$110
West of Devers	57	52	43	9**	50
Total	121	123	117	84	160
Annual (Levelized)	14.8	na	na	na	na

NOTE: "na" means "not available"

* Includes LADWP "bridging" T/S, DPV2 or DPV1 (depending on the case) T/S, and SDG&E T/S (for the W Cases only).

** This represents T/S paid by LADWP after the 22-year "waiver" for 100 MW, per the Exchange Agreement.

The annual value of the T/S revenues for each case is shown in Figure B-3. The greatest T/S revenues occur under Case C, as clearly shown in the table above and in Figure B-3. This is because all the project participants (including LADWP) are paying for transmission services on DPV1 both east and west of Devers in this scenario. In contrast, under the W Cases, LADWP, MSR, and other SCPPA participants receive access to DPV2 via "ownership shares", and do not pay SCE for T/S. The lowest revenues occur under Case B, where only LADWP is provided with T/S, with most of West of Devers charges to LADWP waived per the Exchange Agreement. The W(97) Case is the highest of the W Cases on an annual basis (see Figure B-3), reflecting the escalating cost of DPV2, which is reflected in cost-of-facility based rates.

12 DRA's estimate of net benefits is approximately $3 million lower than SCE's for the W(93) Case (see Table B-1). This is due to DRA's assumption that MSR will not have to pay for wheeling WOD for 100 MW of San Juan 4 from June 1993 until that capacity is again available in January 1995.

III. Production Cost Benefits

Concept

Production cost benefits from DPV2 and applicable provisions of the Exchange Agreement result primarily from the increased availability of relatively cheap economy energy.[13] To the extent that power from the Southwest is available and priced below SCE's own generation resources, such power can displace more expensive local generation, and thus provide reductions in SCE's operating costs.

Similarly, increased access to economy energy from the Pacific Northwest (PNW), made available per the Exchange Agreement, can also reduce SCE's operating costs.

To the extent that increased economy energy purchases displace oil/gas-fired generation, SCE and its ratepayers also benefit from improved air quality. In addition, increased access to economy energy should also lower avoided energy costs, as SCE reduces its use of the most inefficient generation resources. As a result, payments to certain qualifying facilities (QFs) would decline, providing ancilliary benefits to SCE ratepayers.[14]

In order to analyze the cost-effectiveness of a proposed change in the resources (including transmission capacity) available to a utility, complex computer models, known as production cost models, are used to simulate the decisions that the utility makes in operating its system. Subject to certain operational characteristics, the models "dispatch" the resources available to SCE to meet system loads (customer demands) at the lowest possible price to those customers.

Background

In SCE's January 1986 application for DPV2, the projected Southwest economy energy savings were a levelized $22.8 million per year (1990 $). In May 1987, because of computer modeling discrepancies, assigned commissioner ruling eliminated SCE's claim

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13 Economy energy refers to the import of surplus energy from out of the region on a non-firm basis.

14 Air quality benefits (in the form of reduced NOx emissions) and reductions in payments to QFs are included in DRA's calculations of total production cost savings. The methodologies used to value these benefits are described separately in Sections IV and V of this appendix.

of these economy energy benefits due to the DPV2 line from the evaluation of the project's cost-effectiveness.

Particularly because of the expected effects of the SCE/LADWP Exchange Agreement and because of production cost modeling improvements made more recently, SCE and DRA agreed to look at the production cost benefits again during the Study Agreement phase in the Spring 1988.

Study Agreement Methodology

DRA and SCE agreed to calculate fuel and purchased power expenses using SERASYM, a production cost model developed by DRA's consultants, Sierra Energy Risk Associates (SERA). SERASYM simulates the commitment and dispatch of SCE's resources to meet forecast load requirements and to provide adequate reserve margins. The load and resource projections represented in SERASYM were based on SCE's 1987 Resource Plan, with certain modifications agreed to by SCE and DRA for a common base case.[15] In simulating the effects of DPV2 it was assumed that surplus line space held by other utilities (e.g., SDG&E, LADWP) could not be called upon or utilized by SCE for deliveries of economy energy.[16]

DRA estimated the price and availability of economy energy using SERA's Southwest Energy Resource Assessment Model (SERAM) and SCE's Pacific Northwest Energy Model.[17] In brief, these models match the resources available in those regions to forecasts of expected loads, to determine the quantity of surplus energy available for export to California. Each model incorporates SCE's available transmission capacity as a constraint on the transfer of economy energy to the SCE system.

15 See SCE's Amended PEA, (Exhibit 25), pages 2-47, 2-48, and Appendix A for a summary of the resource plan assumptions.

16 This assumption was also made by SCE in its original assessment of Utility Interconnection Support (UIS) benefits. However, as described in Section VI.B, DRA argued that, unlike for economy energy, SCE could depend on other utilities to wheel power, as needed, for UIS.

17 SERAM is a public domain model developed by SERA under contract to the CPUC. It is a substantial modification of SCE's own Southwest Energy Model. Within SERAM, the Southwest is considered to contain Arizona, New Mexico, Colorado, Utah, and Mexico subregions. For more detail on this model, see Exhibit 28, Appendix B and Exhibit 4B, Appendix A.

For the base case analysis, DRA assumes that SCE is able to price discriminate in the economy energy market. This is reflected in DRA's "cost-based" approach to economy energy pricing, which bases those prices on the production costs of the resources generating the regional surplus. Using this approach, DRA develops regional "supply curves" of economy energy comprised of four price blocks. Each block is priced successively higher to reflect the increasing production costs of the region. These supply curves are then used as inputs into the SERASYM production cost model.[18]

The DPV2 project, in conjunction with various provisions of the Exchange Agreement with LADWP, affects SCE's energy production costs through the interaction of the following factors related to economy energy:

1. Increased Northwest economy energy purchases on SCE's additional 180 MW of PNW transmission access beginning in 1990, per the Exchange Agreement.

2. Increased SW economy energy purchases on SCE's DPV2 entitlement beginning in 1993.

3. Foregone SW economy energy purchases due to LADWP's receiving 368 MW of "bridging" transmission service on DPV1 between 1990 and 1993.

4. Foregone SW economy energy purchases due to LADWP's receiving 100 MW of firm transmission service for 22 years beginning in 1990.

5. Foregone SW economy energy purchases due to SDG&E's (option of) receiving 100 MW of firm transmission service on DPV1 beginning in 1995.

6. Decreased availability of SW economy energy due to MSR's taking delivery of power from its 150 MW of San Juan Unit 4 entitlement.

7. Increased access to available SW economy energy by other utilities on DPV2.

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18 Because of the current limitations of SCE's PNW Energy Model, the supply curve from SERAM was "blocked", rather than extended in a continuous fashion. (See TR at 870.)

8. Improvements in system efficiency that lower avoided costs and thus lower the payments made to QFs.

9. Increased opportunity for off-peak economy energy purchases due to having 200 MW of Castaic Pumped Storage capacity for spinning reserve.[19]

Value of Production Cost Benefits

Figure B-4 presents, for each case, the annual value of total production cost benefits under DRA's base case assumptions. The NPV of total production cost benefits are summarized in the following table:[20]

Production Cost Benefits (NPV in millions of 1990 $)

Category	W(93)-A	W(95)-A	W(97)-A	B-A	C-A
Increased PNW Purchases	$108	na	na	na	na
200 MW of Castaic	58	na	na	na	na
QF Payments Reduced	38	na	na	na	na
Increased SW Purchases	0	na	na	na	na
Subtotal	204	197	191	(61)	(186)
Air Quality (NOx Reduct.)	35	30	25	(39)	(69)
Total Benefits	239	227	216	(100)	(255)

19 Spinning reserve represents power that is available from generating units connected to the system and able to deliver power promptly. California utilities are required by the Western System Coordinating Council to have spinning reserves equal to 7% of load, plus 100% of non-firm imports. This means that for every MW of non-firm energy imported, a utility must have 1 MW of capacity "spinning". By having 200 MW of Castaic pumped storage hydro available, SCE can import additional economy energy, and save the additional start-up/running costs of thermal units.

20 DRA's base case results are approximately $25 million higher than the net benefits presented in SCE's Amended Application (see Table B-1). The major factor contributing to this difference is certain model corrections that SERA made after the deadline passed for SCE's filing (but in time for DRA's submittal). These corrections served to increase the amount of economy energy in the Southwest.

As indicated in the above table, access to cheaper PNW economy energy is the driving force behind nearly all of the production cost benefits attributable to DPV2.[21] What is particularly striking is the fact that, compared to a no-DPV2 scenario (Reference Case A), **with DPV2 there is <u>less</u> economy energy taken at <u>higher</u> per kWh cost from the Southwest resulting in <u>net reductions in savings</u> for every year from 1990 until 2005.** The reduction in Southwest purchases occurs in part because more PNW economy is substituted with the advent of the Exchange Agreement.[22] Another factor affecting SCE's Southwest economy energy purchases is the increased competition by other participants for lowest price energy in the Southwest. This results in there being less of the cheapest economy energy available to SCE with the line than without it (even though the total amount of available energy has done up). Overall, there are no net benefits to SCE from increased Southwest purchases under the "build DPV2" cases.

Production cost benefits for Cases B and C are actually negative (in NPV) in DRA's base case analysis. Use of SCE's existing line space under Case B results in "foregone" Southwest economy energy benefits, relative to the Reference Case A. These negative net benefits more than offset the positive benefits of increased purchases from the PNW. Case C is still more negative because it is the case in which the most surplus SCE line space is used to provide transmission service to others.

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21 The availability of Castaic for spinning reserves avoids not only the higher operating cost of thermal units, but also some start-up costs. Hence, part of its value is independent from the spread between economy energy prices and the operating costs of "spinning" thermal units.

22 Because of operational considerations, PNW economy energy, when priced the same, will always be taken prior to Southwest economy.

IV. Air Quality Benefits*

Concept

The South Coast Air Basin and Ventura County are in violation of Federal Clean Air Act ambient air quality standards for ozone and nitrogen oxides (NOx). Most of SCE's oil/gas-fired generation plants are located in these "non-attainment" areas. SCE's plants already employ the most cost-effective NOx emission controls and are very clean by industry standards. Consequently, additional emission reductions are very expensive to achieve.

To the extent that purchases of energy from the PNW or Southwest displace oil/gas-fired generation located in the environmentally sensitive South Coast Air Basin and Ventura County, SCE will save the costs of cleaning up emissions that would result without DPV2 (and the Exchange Agreement).

Background

Neither of the economic analyses presented earlier by SCE (the Proponents Environmental Analysis (PEA) and the "updated" analysis, dated August 1986), attempted to quantify these air quality benefits. (They were considered a "strategic" benefit of the project.) In its prepared direct testimony (April 1987, p.40), SCE estimated that a 900 million KWh/year reduction in Los Angeles area oil/gas-fired generation would reduce these aggregate emissions by 600 to 2,600 tons per year, depending on the fuel displaced.

Study Agreement Methodology

In the Study Agreement, SCE and DRA/SERA agreed to assign a value to the air quality benefits of DPV2 based on the avoided cost of retrofitting emission control equipment. SCE reports that implementing additional controls on their plants would presently cost from $19,000 per ton for methanol overfiring to $35,000 per ton or more for selective catalytic reduction (SCR) equipment. In addition, these cost estimates do not include probable reductions in plant efficiency due to increased auxiliary power requirements, and increased maintenance and forced outages due to emission control equipment failures.

* Included in DRA's calculation of total production cost savings (see Section III).

The production cost model (SERASYM) provided data relating the NOx emissions to the hourly power output of each of SCE's oil or gas-fired power plants. SERASYM was run for each case (and Reference Case A) to calculate the reduction of oil/gas-fired generation (displaced by out-of-region purchases) and resulting reduction in NOx emissions. SCE and DRA agreed to use a $19,000 (unescalated) per ton retorfit cost to value the NOx reductions.

The maximum number of tons/year of NOx emissions saved by DPV2 in the study agreement analysis was 415 tons.

Limitations of This Methodology

This methodology does not reflect differences in plant-specific performance; all tons of NOx are considered equally costly to cleanup. Air pollution control costs are not internalized into the dispatch sequence of the production costing model. In addition, no attempt was made to quantify the health-related air quality benefits of reduced emissions in the South Coast Air Basin.

Total Value of Air Quality Benefit

The NPV of air quality benefits for DRA's analysis of the W(93) Case is $35 million. This amount is included in DRA's estimate of total production cost benefits (see Section III). Figure B-5 presents the annual net benefits of NOx reductions for all cases. As expected, these benefits are negative for Cases B and C due to the net reduction in total economy energy purchases under those scenarios (see Section III).

V. QF Payment Benefits*

Concept

California's utility companies pay QFs for the energy and capacity that they produce according to rules adopted by the CPUC. QF energy payments depend on the type of contract negotiated for the specific resource (i.e., fixed price, avoided cost-dependent, or heat rate-dependent). For Standard Offer #1 and Standard Offer #2, the energy payments made to QFs are based on the utility's avoided energy (marginal) costs.

Inclusion of the DPV2 line in SCE's system and the associated changes in SCE's access to the northwest due to the Exchange Agreement with LADWP, should enable SCE to make less use of its own most inefficient generation resources, thus lowering avoided energy costs. Consequently, the payments made to QFs with avoided cost-based rates will decline, providing an ancilliary benefit attributable to the new transmission line.

Background

Neither SCE nor DRA attempted to quantify the QF payments benefits attributable to DPV2 prior to the Study Agreement.

Study Agreement Methodology

The production costing model (SERASYM) determines the appropriate payment for avoided cost-dependent QF purchases based on the marginal costs it calculates. In order to make that calculation, SERA staff coded the contract types in the resource data base for the appropriate QFs, along with the vintage of the appropriate QF contracts. Vintage data for QFs were needed because, under certain standard offers, payment mechanisms change after the initial ten years that the QF is on-line.

Value of Benefit

To the extent that DPV2 improves the overall efficiency of the SCE system by lowering avoided energy costs, QF energy payments are adjusted (lowered) accordingly. As shown in Section III of this appendix, the NPV of reduced QF payments comprises approximately 15% of total production cost benefits for the W(93) Case.

* Included in DRA's calculation of total production cost savings. (See Section III)

VI. Reliability Benefits

An electric system's "reliability" is a relatively easy measurement for an end-user: how frequently and for how long does the power go off? However, from the utility's perspective it is more complicated. The utility is concerned not only with the frequency and duration of outages, but also with their extent, and these factors do not necessarily change in the same direction. Common sense (and economics) suggest that a utility will tend to design its system to avoid more widespread outages, even if these are less frequent and of shorter duration.

High-voltage transmission lines are big resources. DPV2 has a rated capacity of 1,200 MW, about the same as each of the units at Diablo Canyon. Furthermore, DPV2 occurs adjacent to, and utilizes the same substations and occasionally even the same towers as DPV1. Together these lines carry approximately 2,400 MW, more than SCE's allocation from SONGS 1, 2, and 3 put together. If these lines are both operating, they provide support to the system in case other resources have sudden failures. Conversely, if both these lines are heavily loaded and they simultaneously fail, then they pose quite a threat to the rest of the SCE system (and the entire WSCC) system. A new line cannot be characterized in simple terms as either increasing or reducing system reliability.

Of importance in the analysis of reliability is the time frame of events. These can be divided roughly into events which take place over periods of hours or days, and events which take place in a very few seconds. In one case human intervention is possible; in the other the control functions must be automatic. To use an end-user analogy, the user can run out and borrow flashlight batteries from one of his neighbors when he sees his batteries running down, but a hospital operating room must have an emergency generator to maintain continuous power even during outages.

To distinguish these two types of support, utility planners label one **"System Stability"** and the other **"Utility Interconnection Support"** (UIS). One can think of system stability as the hospital's planning to have an emergency backup system that will kick in almost instantly. The homeowner going to his neighbor to borrow batteries is more analogous to utility interconnection support.

With the above analogy in mind, it is possible to consider an electric utility's system. There should be redundancy and flexibility to absorb inevitable sudden disruptions of major units--either generating plants or transmission lines. This is the "stability" of the system. At a less immediate response level, a utility should be able to "borrow" resources from its neighboring utilities for short periods of time, so long as both utilities have a few hours advance warning. A utility's ability to call on its neighbors is its level of UIS.

Both system stability and UIS can be measured. The way in which they are measured and other contrasting features of these two aspects of reliability is shown in Table B-2.

A. System Stability

As noted above, system stability refers to what happens to the utility system when there is an instantaneous outage of one or or more major components of that utility's system or even a neighboring utility's system. Examples of such outages include failures of major transmission lines or substations, as well as generating stations. Such failures can literally threaten one or more utilities' entire systems. In less than a second, there is an imbalance between loads and resources. The system acts to restore the balance faster than human interaction can occur. Energy, moving in the direction of least impedence, automatically and instantly flows from other utilities toward the utility with the loss of plant or line regardless of contractual relationships until and unless circuit breakers or other protective devices act to isolate parts of the system or even one entire utility from others "islanding").

These events occur in a time span so short that human intervention is not possible. What will occur in terms of power flows is a function of the overall instantaneous load and resource mix at the time of the emergency. The concern of utility planners is to prevent the entire system from failing and to control and minimize the damage to each utility's system. Within milliseconds, automatic load shedding systems engage. Within less than a minute, human operators can intervene to shed load or begin to increase resources, for example, by ramping up spinning reserve, starting combustion turbines, or turning on hydroelectric resources. After the system has stabilized, utility dispatchers may begin to consider whether or not to acquire UIS for the next day.

Utility planners distinguish between "N-1" and "N-2" events. The former represents a situation where single transmission lines or generating plants are lost. Under an N-2 event, there is a simultaneous outage of two transmission lines, resulting in a major blackout.

System stability for N-1 events is enhanced by increasing the margin in transmission capacity. The construction of DPV2 adds to margin by reducing the loadings of other parallel lines in the Arizona-California transmission system. However, construction of DPV2 increases the risk of a simultaneous loss of DPV1 and DPV2 ("N-2" event). At the same time, DPV2 will increase SCE's ability to withstand N-2 events on other than the DPV1/DPV2 corridor.

Background

The value of stability has not been quantified in any of the previous analyses submitted for the DPV2 proceeding by either SCE or DRA.

Study Agreement Methodology

In order to establish a value for the stability component of increased reliability, SCE tested its system for substitute methods of achieving the same level of stability without the line as that exhibited with the addition of the line. Specifically, SCE measured stability benefits by simulating the performance of the Arizona-California transmission system, with and without DPV2, during a severe disturbance. A three-phase fault was simulated near the Palo Verde 500 kV switchyard, resulting in the loss of DPV1 (the single most critical outage in the system). Voltage fluctuations were then recorded.[23] Simulations were repeated where the system without DPV2 was augmented with Static VAR Compensators (SVCs) until the system performed comparably to the case with DPV2.[24] The costs of the substitute methods were then assigned to the value of increased stability.

The value of the stability benefits defined in this manner is calculated by the following formula:

Stability Benefits =
(Substation Rev.Req.Factor) * (MVAR of SVC) * ($/KVAR)

"Substation Revenue Requirement Factor" is the yearly factor used to indicate the share of the SVC capital costs that are assignable to individual years through the life of the project.

"MVAR of SVC" is the amount of Static VAR Compensators devices in millions of VARs.

"$/kVAR" is the cost per thousands of VARs of the SVC devices.

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23 Voltages at the Miguel 500 kV Substation were monitored since stability at Miguel is affected most by this disturbance.

24 "VAR" stands for Volt-Ampere-Reactive. It is a measure of reactive power. SVCs are a class of devices which quickly switch shunt capacitors and reactors on- and off-line in response to system reactive power needs. In this way, they can stabilize voltage fluctuations during the critical seconds immediately following a disturbance.

SCE's simulations of their system with DPV2 indicate that 350 MVAR of SVCs would be required to attain the same level of stability as their system without DPV2. SCE's current installed cost estimate for SVCs is approximately $60 per KVAR. For the DPV2 analysis, SVCs were conservatively assumed to cost $50/KVAR and no escalation factor was applied.

Value of Benefit

The results of SCE's studies show that DPV2 will enhance system stability under N-1 events. The levelized value of the stability benefits for the W(93) Case is approximately $2 million per year, with a net present value of $16 million (1990 $). No stability benefits are found in Cases B and C.

Neither DRA or SCE quantified the reliability impacts of DPV2 in terms of an N-2 event. However, DRA independently investigated this issue, and recommends further studies on the likelihood of an N-2 event and possible mitigation measures. (See Section VIII.C of this order.)

B. Utility Interconnection Support

Concept

Utility interconnection support (UIS) refers to the ability of one utility to draw on capacity and energy from neighboring utilities in times of unexpected supply outages or greatly increased demands. Occasionally, a utility has unscheduled outages on facilities (generating plant or transmission lines) which cause the utility to be short of capacity or energy for one or more days. In such cases, the utility usually makes it through the remainder of that day relying on its own resources. In the meantime, the utility's dispatchers contact dispatchers from neighboring utilities and acquire capacity or firm energy from those neighbors for the next day or two until the first utility's plant is back on line or back to full operation. The goal of this support is to avoid having to shed load or commit excessively expensive generating or transmitting resources the following day.

The presence of this capacity to meet short-term capacity shortages allows the utility to defer construction of new generating plants and aids in day-to-day operations. To the extent that a new transmission line such as DPV2 increases a utility's ability to rely on UIS it has measurable economic value.

UIS has two aspects: planning value and operating value. UIS has planning value because it (1) reduces the utility's probability of incurring outages (i.e. it reduces the Loss of Load Probability (LOLP)), or (2) allows the utility to defer construction of some other project, typically a generating plant(s), while maintaining the same LOLP. UIS also has some operating value in that it allows a utility to commit and dispatch their generating plants on a daily basis slightly more efficiently than without it.

Background

This is the first transmission line CPCN proceeding in which specific methodologies for quantifying UIS planning benefits have been proposed. DRA first presented a methodology, based on a SERA study, during the September 1987 hearings. The approach outlined in the SERA study formed the basis of both SCE's and DRA's revised testimony during the September 1988 hearings. This approach is described briefly below.

SERA's 1987 Study

To quantify UIS planning benefits, SERA determined the value of improved reliability (reduced outages) on SCE system by deriving a LOLP "shadow price".[25] The starting point for valuing LOLP reductions is the avoided cost of adding peaking capacity, represented by the avoided cost of a combustion turbine (CT). In its 1987 study, SERA assumed that the annual planning value of a CT is 90% of avoided costs.[26]

SERA argued that UIS planning benefits cannot be valued at 90% of avoided costs, the full planning value of a CT. CTs have numerous operational characteristics--lacking in transmission lines--which reduce system operating costs. The value of these cost savings must be netted out of the CT planning value, to yield an appropriate planning value for LOLP. SERA ran SERASYM with and without 200 MW of CTs to calculate the reduction in variable operating costs and LOLP associated with CT additions. The model results were used to derive the LOLP "shadow price" for valuing UIS planning benefits (see below). Specifically, the total value of LOLP was calculated as the difference between the planning value of a CT (90% of avoided costs) and the variable cost reductions associated with the CT additions. The "shadow price" of LOLP is the ratio between total LOLP value and the reduction in LOLP associated with adding CTs.

25 Incremental changes in LOLP do not have a direct market price, so a "shadow price" needed to be developed.

26 90% of the full cost of a CT was discounted by the appropriate Energy Reliability Index (ERI) to yield the planning value of a CT. The remaining 10% of the cost of a CT was assumed to represent the operating benefits of a CT (undiscounted).

Next, SERASYM was used to calculate the change in variable operating costs and LOLP, resulting from the addition of 200 MW of UIS (instead of CTs). The change in LOLP was multiplied by the LOLP shadow price. Increases in variable operating costs were subtracted from this total to yield the net planning benefits of UIS. Based on this analysis, SERA concluded that the value of increasing UIS by 200 MW is approximately one-half the value of adding an equivalent amount of CTs to the system.

Study Agreement Methodology

For the Study Agreement phase, DRA and SCE stipulated that the operating value of UIS is equal to 5% of the avoided capacity costs, or about half that estimated for a SCE owned and operated CT.[27] Both agreed to use SCE's planning assumption of 1,200 MW for the amount of existing UIS on SCE's system.

To estimate the amount of additional UIS attributable to DPV2, SCE uses an approach that bases the increase in UIS on the additional line share made available by DPV2.[28] SCE's calculations can be summarized as follows:

Planning assumption: 1,200 MW of existing UIS on SCE's system

Additional UIS capability: DPV2 1,200 MW capacity less firm schedules yields 400 MW

Existing transmission transfer capability (surplus, after firm schedules) coming into SCE's control area from neighbors: 6,651 MW

For every MW of surplus transmission capacity into SCE's system, there is approximately 1/6 MW of UIS: 1,200/6,651 = .18

DPV2 adds 400 MW, so additional UIS is .18 x 400 = 72 MW

72 MW x .50 x (CT discounted by ERI) = Value of planning benefits

72 MW x .05 x CT value = Value of operational benefits

In its updated testimony, DRA/SERA used a very different approach for estimating the increase in UIS attributable to DPV2. The key difference between the two approaches is DRA's assumption

27 In SERA's 1987 study, the operating benefits of UIS were assumed to be zero.

28 This is similar to the approach taken by SERA in the 1987 study.

that it is appropriate to (1) consider generating capacity in regions other than neighboring utilities, and (2) assume that for UIS purposes SCE would have access to other utilities' transmission capacity. In other words, DRA bases UIS benefits on the increase in surplus capability of the whole Southwest, including wheeling to SCE.[29]

The explicit calculations used in DRA's analysis are described in Chapter 6 of Exhibit 32 and in Exhibit 34. The bottom line is that DRA's approach attributes 157 MW of additional UIS to DPV2, twice the level calculated by SCE.

Value of UIS Benefits

As a result of its revised methodology, DRA's estimated value of UIS for the W(93) Case[30] is $63 million, more than twice SCE's estimate (see Table B-1).

The table below presents the results of DRA's analysis for all cases:

	UIS Benefits (NPV in 1990 million $)				
	W(93)-A	W(95)-A	W(97)-A	B-A	C-A
UIS Benefits	62	61	60	0	7

Figure B-6 presents the annual value of UIS benefits for all cases. UIS benefits sharply increase in all instances starting in 1997 when the ERI for SCE becomes non-zero and rises to one by 1998.

29 During the September 1988 evidentiary hearings, SCE stipulated to DRA's methodology for the purpose of this proceeding.

30 Under DRA's approach, there are no UIS benefits attributable to Case B, and only a very slight (17 MW) increase in Case C. (See Exhibit 34.) Using SCE's approach, on the other hand, yields large negative UIS benefits for Case B and (even more negative) for Case C. This is because SCE's "surplus" capacity on its own lines are reduced under those scenarios (and it is assumed that UIS cannot be "wheeled" to SCE).

VII. Transmission Loss Reduction And Reimbursement Benefits

Concept

Transmission lines cannot transmit power without losses, at least until superconductivity becomes a reality. Transmission line losses are a function of the square of the amount of electrical current carried on a transmission line. Losses are reduced when a given quantity of power is transported over a greater number of transmission lines. Adding DPV2 to the existing transmission system will cause power flows to shift onto the new line, reducing power flows on the lines which parallel it. This will serve to reduce average line losses on SCE's total system from Arizona. Later, as additional power transfers are made on DPV2, system losses will increase. However, increased losses from the anticipated additional transfers are less than the loss reductions which will result from adding the line.

Normally, to compensate for transmission losses on its system, SCE must provide additional resources and generate additional power. The net reduction in losses resulting from DPV2 means that SCE will not have to purchase or install as much generating capacity or burn as much fuel, thus reducing its cost of service.

Another aspect of loss-related benefits resulting from DPV2 is the reimbursement for losses SCE receives from utilities purchasing transmission service. When utilities enter into transmission service contracts, estimates of the expected transmission line losses from applicable transmission lines are made. Agreements are signed that specify how to account for (or reimburse the appropriate party for) these expected losses. If actual losses are less than the estimated losses, the party providing the transmission service reaps the benefits. If actual losses exceed the estimates (due to inadvertent power flow or loop flow, for instance), the wheeling utility is not reimbursed for the additional loss.[31]

DPV2 will reduce SCE's loss-related expenses in this manner as well, because of the SCE/SCPPA capacity exchange arrangement involving the Salt River Project (SRP). This exchange

31 Reimbursements for energy losses are based on an accounting of the power scheduled over a given contract transmission path in a specified period of time. Reimbursements for capacity losses are handled by reducing scheduled capacity deliveries in the amount of contract losses.

was instituted in order for the SCPPA participants in DPV2 to receive their Palo Verde power deliveries. The transmission service arrangements with the SCPPA participants will provide for SCE to be reimbursed for the loop flow-caused additional line losses that that arrangement has been imposing on SCE's system.

Background

SCE's original January 1986 application did not quantify the benefit of reduced transmission line losses at all, and assessed the elimination of the SCPPA/SRP exchange arrangement only for its loop flow mitigation benefit.

Study Agreement Methodology

SCE performed comparative flow studies with and without DPV2, and its associated 300 MW of additional schedules.[32] The loss reduction effects of the DPV2 line on both the 500 kV (Extra High Voltage) and the 230 kV (bulk power) systems were analyzed. (Most of the loss reduction occurs on the EHV system.) Results indicate that DPV2 reduces SCE's transmission losses by 13 MW in the peak summer case. This megawatt reduction was assumed to remain constant throughout the study period. The peak summer case data was extrapolated to yield an annual energy loss reduction of 43 gWh.

Loss savings attributable to the DPV2 line are calculated by adding together the values of both the real and non-reimbursed contract-related losses.

The real losses are derived from the:

- Difference in capacity losses with and without DPV2;
- Difference in energy losses with and without DPV2.

The contract-related losses are derived from the:

- Reimbursed transmission service energy losses;
- Reimbursed transmission service capacity losses.

The derivation of the value of these components follows.

32 SCE assumed an additional 300 MW of transfers scheduled over DPV2 for purposes of analyzing losses. This assumption is based on additional firm schedules anticipated over DPV2 together with SCE's SERASYM results regarding additional economy energy transfers expected on the line.

Capacity Losses. The value of the difference in capacity losses due to the DPV2 line is calculated by determining how much an equivalent amount of capacity would cost to make up for the losses. The capacity loss reduction from the power flow analysis is multiplied by the proxy value of capacity, discounted by the appropriate energy reliability index (ERI). The proxy value of capacity is determined by the CPUC in the OIR-2 process. The ERI was set by the CEC in ER 6. This forecast of capacity does not show any capacity value until 1997.

Value of capacity loss = Capacity loss reduction
* Proxy * ERI

Energy Losses. Annual energy losses can be correlated to the megawatt (capacity) losses which occur under peak load conditions through the use of "loss factors", which are analagous to capacity factors in that they relate capacity and energy.[33]

The reduction in annual energy losses resulting from the DPV2 line was calculated as follows:

Annual gWh Losses = MW Loss
* Loss Factor * (8.76 kWh/year)

(The 13 MW peak loss reduction represented a 43 gWh annual energy loss reduction.)

The value of the difference in energy losses due to the DPV2 line is calculated by determining how much an equivalent amount of fuel would cost to make up for the losses. More specifically, energy losses were valued using the cost of gas-fired generation and SCE's incremental energy rates (IER's), as calculated by SERASYM. The steps are:

Value of energy loss = (Fuel Cost) * (Net Btu Loss)
Net Btu Loss = (Btu Loss w/o DPV2) - (Btu Loss w/DPV2)

For both the without DPV2 and the with DPV2 cases:

Btu Loss = (Total gWh Losses) * (IER)
Total gWh Loss = (EHV Energy Loss) +
(Bulk Power Energy Loss)

Capacity and Energy Reimbursements. In the economic analysis, capacity and energy reimbursements are valued in the same manner as the loss reduction benefits just outlined. Specifically:

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33 The loss factors associated with the EHV and bulk power systems were calculated to be 0.366 and 0.432, respectively.

The value of the reimbursed transmission service energy losses due to contractual arrangements is calculated as follows:

Value of contractual reimbursed T/S energy losses = (Fuel Cost) * (Reimbursed gWh/Loss) * (IER)

The value of the reimbursed transmission service capacity losses due to contractual arrangements is calculated as follows:

Value of reimbursed capacity/loss = (Capacity loss reimbursed) * (Proxy) * (ERI)

Value of Loss Reduction Benefit

Figure B-7 displays DRA's base case results for the annual net loss reduction benefits. In terms of NPV, the results are summarized below:

	Loss Reduction/Reimbursement Benefits (in NPV, million 1990 $)				
	W(93)-A	W(95)-A	W(97)-A	B-A	C-A
Total Benefits	101	98	95	38	56

As indicated in the above table, the W Cases all yield substantially more loss reduction/reimbursement benefits than Case B or C. The results tend to follow a trajectory similar to a combination of capacity values and marginal generation costs. This is because the value of energy loss reductions (including reimbursements) is tied to production costs. The value of capacity loss reductions (and reimbursements) is tied to the proxy value of capacity, which increases dramatically (when the ERI goes to unity) in 1997.

These results differ slightly from those presented in SCE's Amended Application.[34] One difference is in the reimbursed losses due to DRA's assumption that MSR would only have 50 MW until 1995. The other difference is due to updated marginal costs employed in DRA's analyses, upon which less savings are based.

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34 For the W(93) Case, SCE's analysis produced loss reduction benefits of approximately $112 million (in NPV, 1990 $), see Table B-1.

Table B-1

Application No. 85-12-012
Devers-Palo Verde T/L No. 2

Comparison Exhibit
1993 Start-Up
($ millions)

	Net Present Value		Levelized Value	
	Edison	DRA	Edison	DRA
BENEFITS				
DPV2 T/S Revenues	63.04	64.20	7.60	7.74
WOD T/S Revenues	60.79	57.00	7.33	6.87
Total T/S Revenues	123.83	121.20	14.92	14.61
Prod. Cost Savings	188.27	203.69	22.69	24.55
Loss Reduction	111.78	100.95	13.47	12.17
Air Quality	24.76	35.12	2.98	4.23
Stability	16.40	16.40	1.98	1.98
UIS	31.04	61.91	3.74	7.46
Total Benefits	496.08	539.27	59.78	64.99
COSTS				
Capital Costs	165.77	171.85	19.98	20.71
O & M	3.01	3.05	.36	.37
Total Costs	168.78	174.90	20.34	21.08
NET BENEFITS	327.30	364.37	39.44	43.91

Sources

1. Edison estimates: Exhibit 25, Table 2-6, pages 2-74 to 2-83
2. DRA estimates: Exhibit 32, Table 8-1, pages 8-2 to 8-7; and page 8-9

Table B-2

Different Measurements of Reliability:
Utility Interconnection Support and System Stability

	UIS	System Stability
Time frame	Next day	Less than 1 second to several seconds
Analytic tools	Load flows	Stability models
Arranged by dispatchers	Yes	No, automatic
Scheduled flows	Yes	No
Operational limits	Transmission capacity; Nomograms	Protective equipment*
Measurement	MW	Probabilities**

* *See* Amended PEA at p. 2-118.

** TR at 692.

EDISON/LADWP EXCHANGE AGREEMENT PROVISIONS APPLICABLE TO THE DEVERS-PALO VERDE NO. 2 T/L PROJECT ANALYSIS

Use of 200 mW of LADWP's Castaic Pumped Storage capacity towards meeting Edison's spinning reserve

An additional 180 mW of non-firm Northwest transmission access,

LADWP's receiving a 217 mW ownership allocation in DPV#2 in lieu of firm transmission service from Edison,

LADWP's receiving 368 mW of "bridging" transmission service on DPV#1 from June 1, 1990 until DPV#2 goes into operation,

Waiver of transmission service charges for LADWP's 368 mW of firm service from Devers to Sylmar/Victorville for 22 years,

Waiver of transmission service charges for LADWP's 100 mW of firm service from Palo Verde to Sylmar/Victorville for 22 years.

FIGURE B-1

FIGURE B-2

Summary of Alternative Cases

Cases	PNW Intertie Access Swap*	Additional T/S Provided on DPV1/DPV2	Castaic Avail. for Spinning
"Reference" A	320/320	0	No
"Infinite Bridge" B	500/320	o Only LADWP on DPV1: o 368 MW paid T/S; o 100 MW free T/S (22 yrs) o All WOD T/S free	Yes
"Expanded Infinite Bridge" C	500/320	o Same as Case B for LADWP; o MSR and other SCPPA added to expanded DPV1 in 1993. o 72 MW paid T/S (SCPPA) o 150 MW paid T/S (MSR) o WOD T/S paid (SCPPA)	Yes

* Under the 500/320 swap, it is assumed that the Exchange Agreement results in 180 MW of additional transmission capacity (for non-firm purchases) to the Pacific Northwest (PNW).

(Continued)

FIGURE B-2

Summary of Alternative Cases
(Continued)

Cases	PNW Intertie Access Swap	Additional T/S Provided on DPV1/DPV2	Castaic Avail. for Spinning
"Build DPV2" W(93)	500/320	o Case B until line is built (LADWP on DPV1) o All participants on DPV2 after 1993** o 150 MW paid T/S (MSR) o 100 MW paid T/S after June 1995 (SDG&E) o WOD T/S paid (SCPPA, SDG&E)	Yes
W(95)	500/320	Case W(93) postponed until 1995	Yes
W(97)	500/320	Case W(93) postponed until 1997	Yes

** LADWP's 368 MW of paid T/S, MSR's 150 MW of paid T/S, and the other SCPPA participants 72 MW of paid T/S became "ownership shares" under the W Cases.

FIGURE B-3

TRANSMISSION SERVICE REVENUES

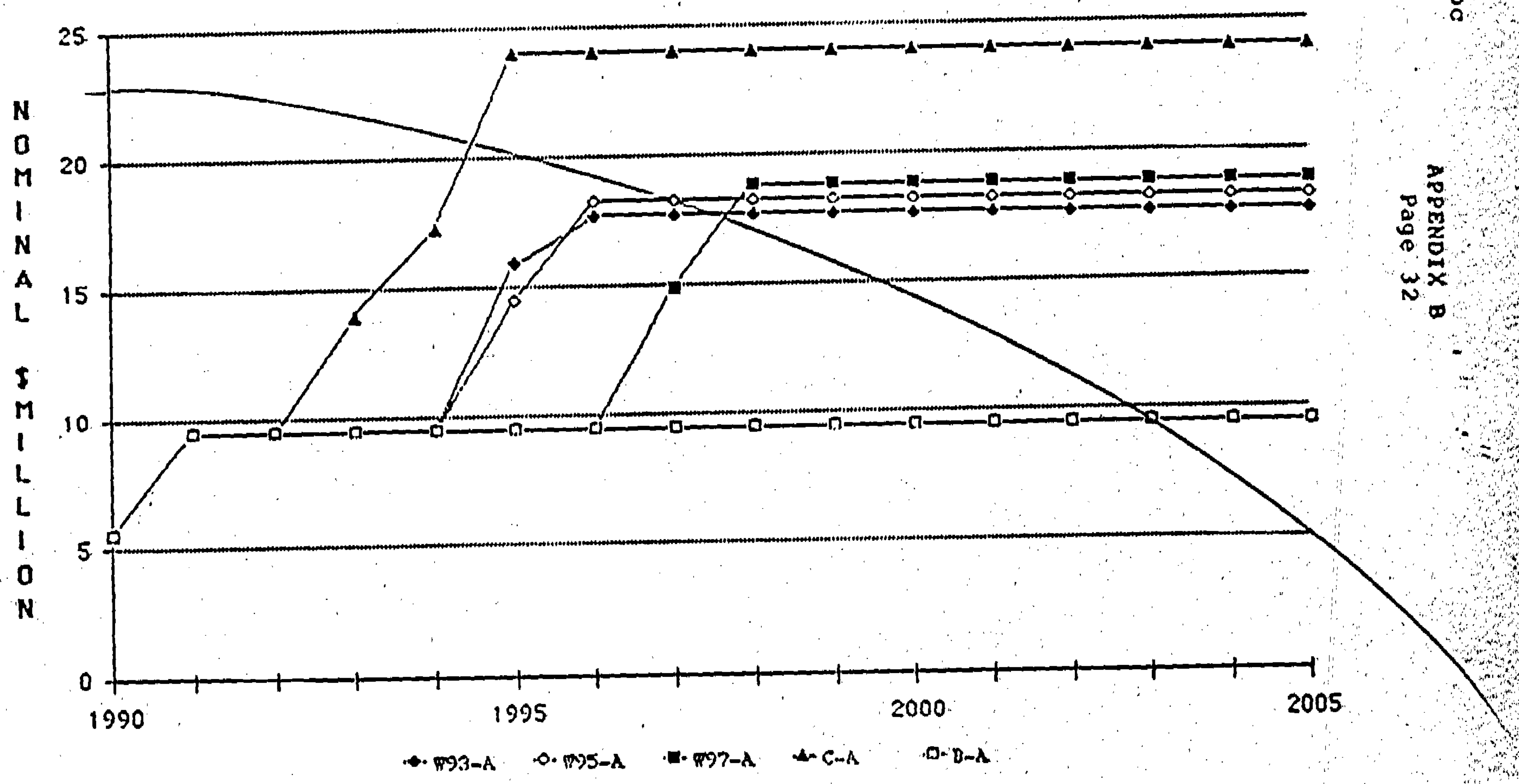


FIGURE B-4

TOTAL PRODUCTION COST BENEFITS

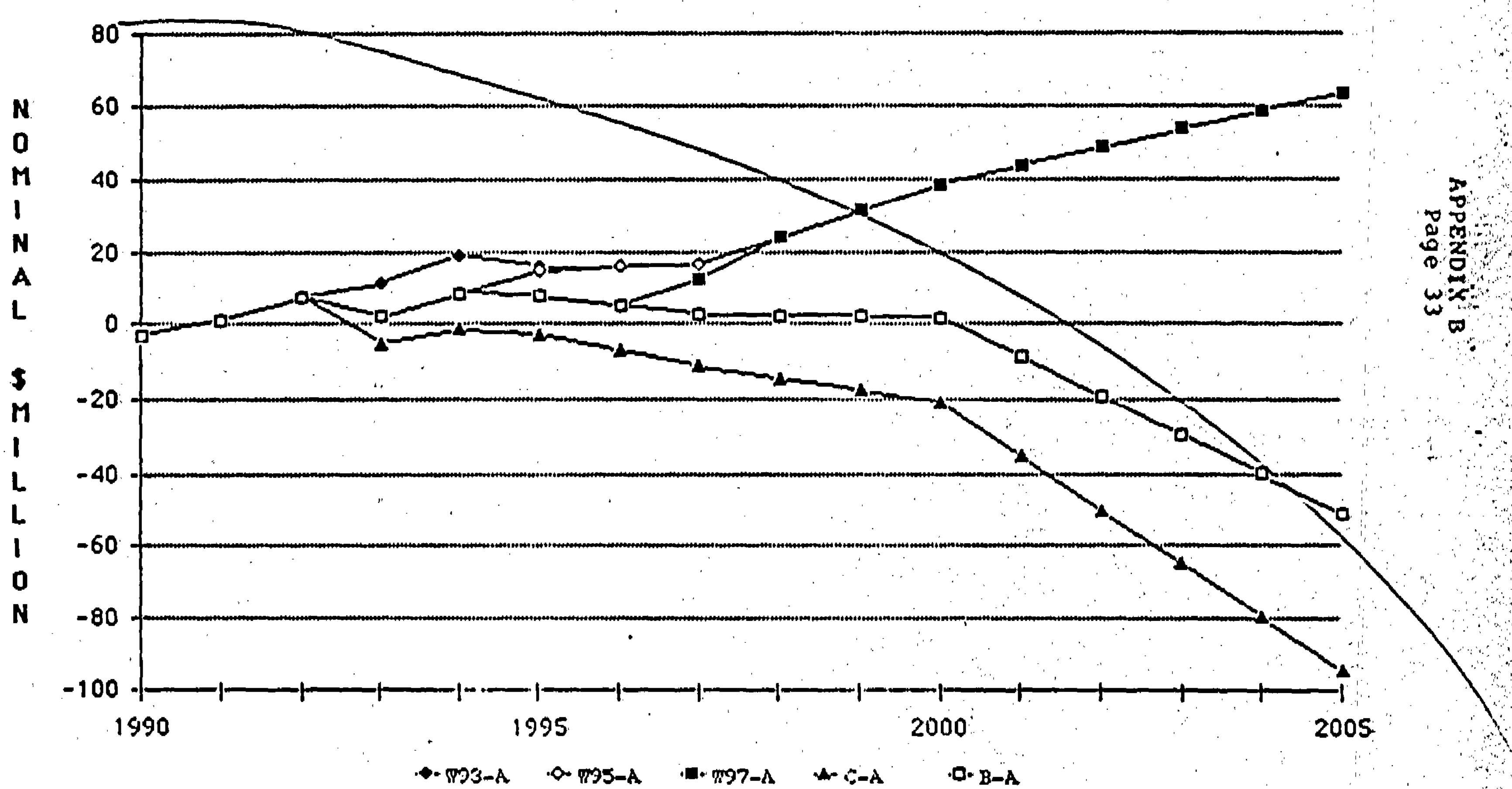


FIGURE B-5

REDUCED NOx EMISSIONS

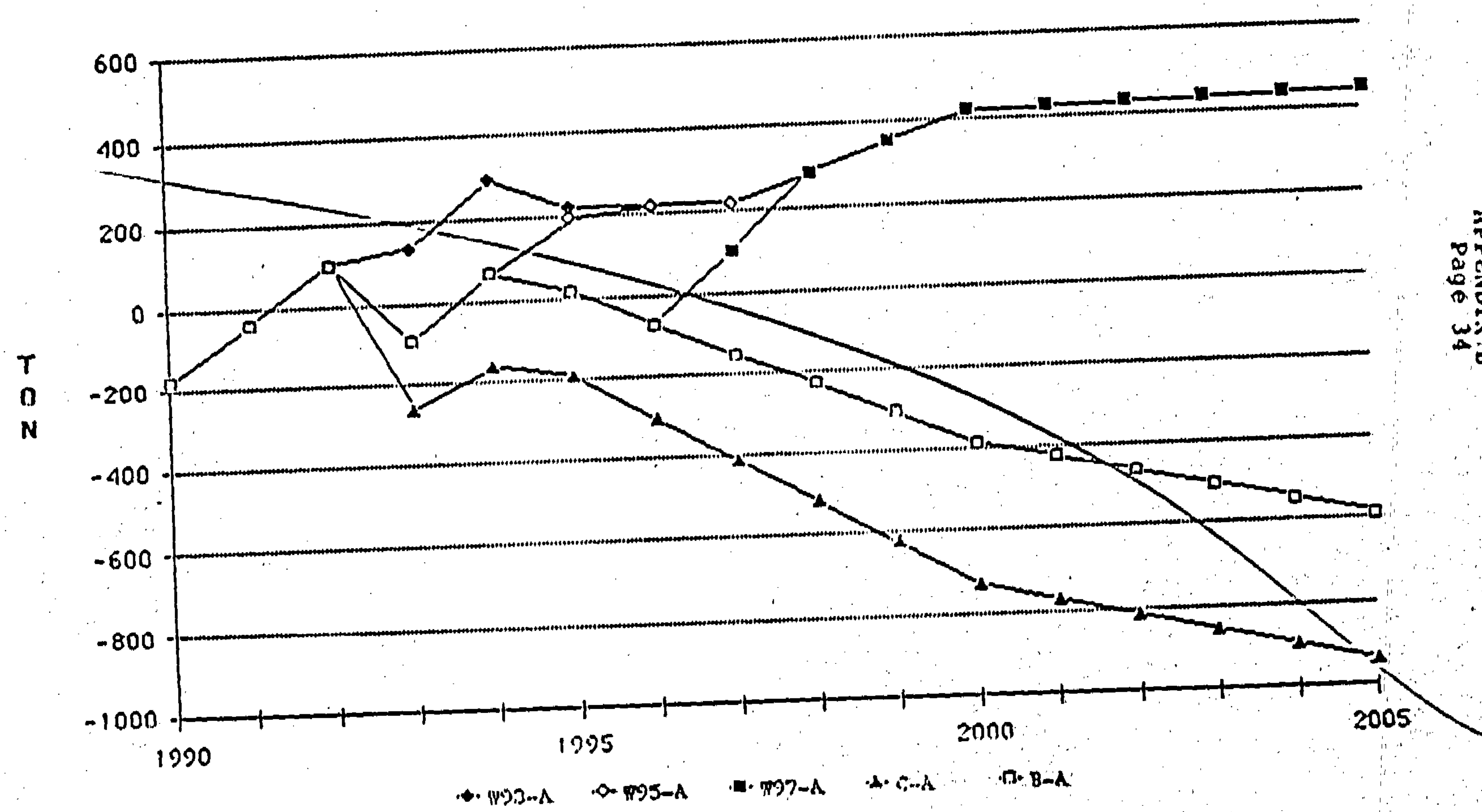
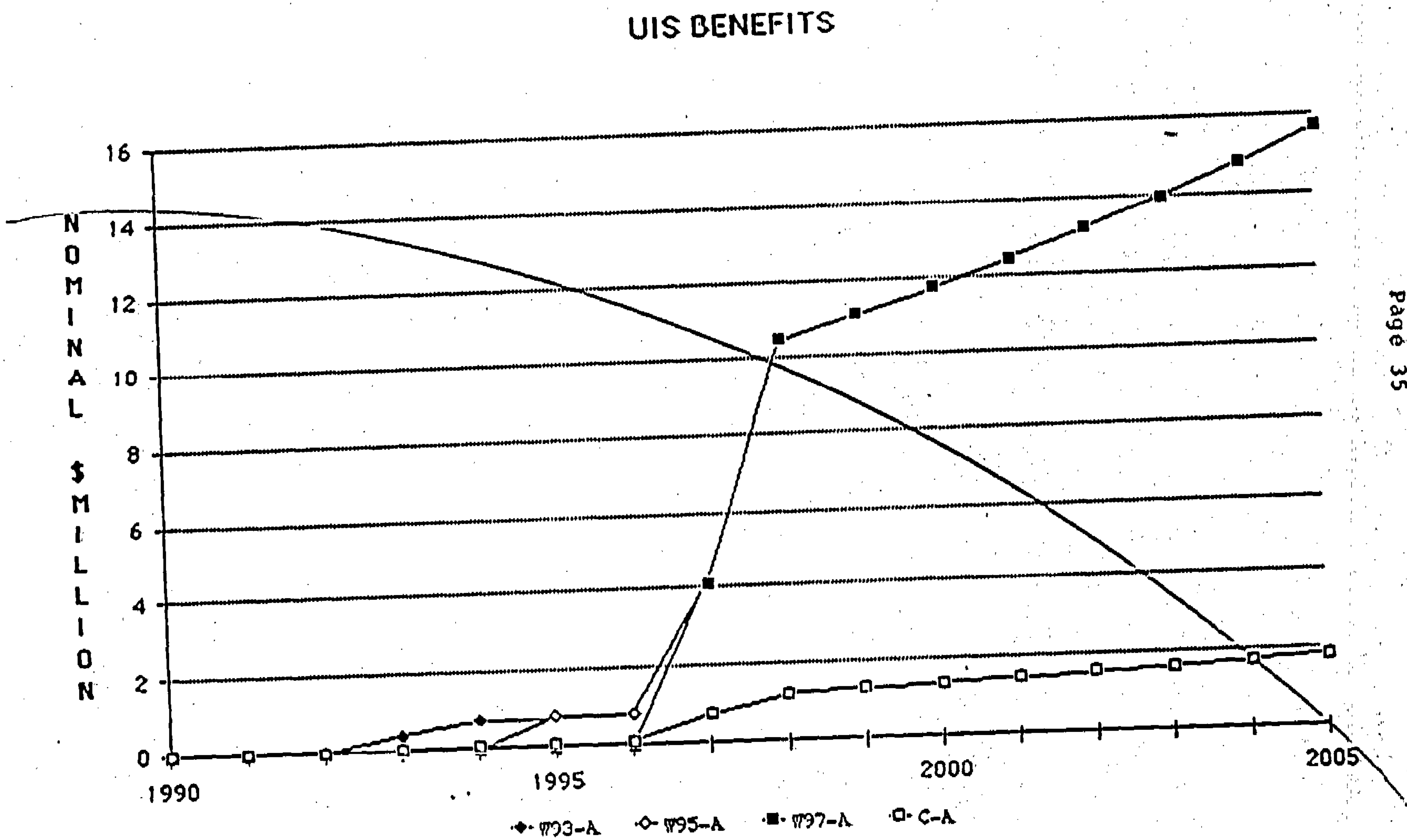


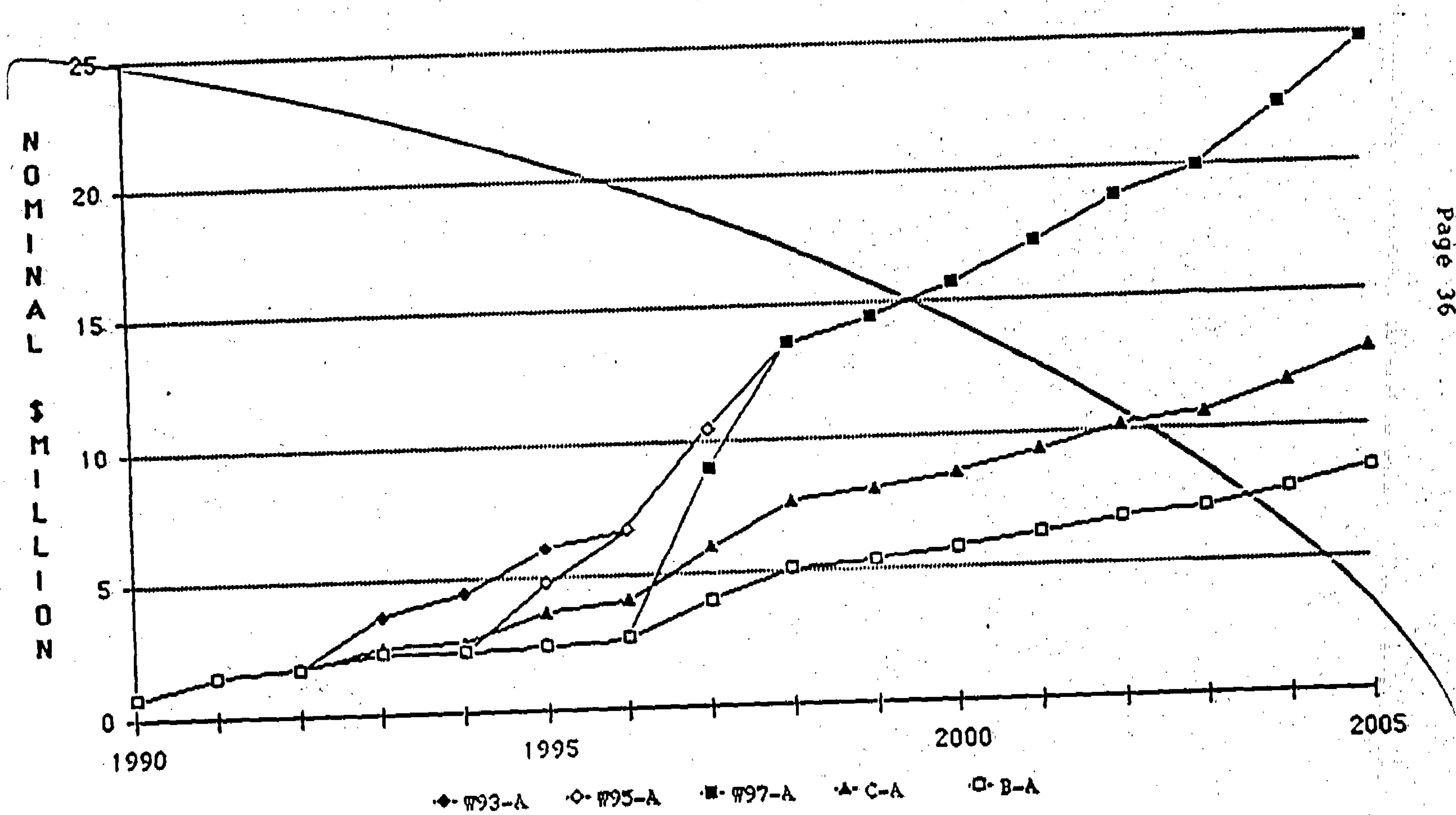
FIGURE B-6



Note: Case B's UIS benefits are zero.

FIGURE B-7

LOSS REDUCTION/REIMBURSEMENT BENEFITS



Attachment 1

Summary of Base Case Assumptions

During the joint study process, SCE and DRA agreed upon the use of common assumptions for the base case analysis of DPV2 and alternatives. These include:[1]

- Economy Pricing: Pricing by PNW and Southwest utilities would be based on their production cost plus 15 percent for all but the cheapest sources of energy. The cheapest sources are priced at production cost of the most expensive of the resources found in the lowest priced block of power.

- Use of Empty Transmission Capacity for Economy: Surplus line space of another utility (e.g., LADWP) would not be made available to carry additional SCE economy purchases during times that the SCE system is fully loaded.

- Use of SERASYM: DRA and SCE agreed to use SERA's proprietary production cost model SERASYM, for modeling the SCE service territory.

- Resource Plan/Load Forecast: The SCE Fall 1987 Resource Plan and compatible load forecast were used.[2]

- SCE Capacity Value: The capacity valuation produced using CEC Electricity Report IV assumptions was used.

- Gas/Oil Price Forecast: The 1988 California Gas Report price forecast for the second tier gas price and for residual oil pricing were used.

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1 See Exhibit 32, p. 1-11 to p. 1-15.

2 See SCE's Amended PEA (Exhibit 25) pp. 2-47 and 2-48 and Appendix A for a summary of resource plan assumptions.

- Gas Curtailments: Gas curtailments were modeled in the last two weeks of December for each year. In addition, the first week of January was assumed curtailed in 1997 and the first two weeks of January in 2000 and thereafter.
- Value of Stability: The value of stability improvements in the PSW transmission system due to DPV2 were assumed to be credited only to SCE ratepayers.
- Cost of Capital: SCE's 12.01 percent cost of capital was employed.
- SDG&E Line Usage: SDG&E was assumed to exercise its option for 100 MW of transmission service for 30 years on DPV1 or the later of June 1995 or the DPV2 on-line date.
- Line Reinforcements West of Devers (WOD): The line reinforcements formerly planned for WOD are not included in the project cost effectiveness assessment and their absence will not result in a line overload.

(END OF APPENDIX B)

Comparison of Project Alternatives

During this proceeding SCE and DRA evaluated a broad range of project alternatives to constructing DPV2, including:

1. Location Alternatives: Alternative routes to avoid the Blythe agricultural area.

2. Electrical System and Technical Alternatives: Alternative means of achieving the objective of the project through use of other existing and new transmission systems, upgrades or modifications to existing equipment. These include:

   a. Phoenix-Mead-Adelanto. Under this alternative, SCPPA and MSR participants would build a 500 kV DC line from Adelanto, California to Mead, Nevada and from Mead to Phoenix, Arizona. Neither SCE (or the CPUC) would be involved.

   b. Valley-Miguel Interconnect. Under this alternative, a 500 kV line would be built between Miguel (SDG&E) and Valley (SCE) to increase net east-to-west transfer capability.

   c. SWPL#2 Plus Interconnect. The Southwest Powerlink (SWPL) is a 500 kV AC transmission line connecting the Palo Verde switchyard with San Diego, California. Under this alternative, a second 500 kV line would be built along the same corridor, and the Valley-Miguel line would be built to interconnect SDG&E and SCE.

   d. All Intertie--70% Compensation. The power transfer capacity of existing equipment would be increased by increasing the series compensation on the existing AZ-CA Interties to 70 percent of each line's inductive reactance.

   e. DPV1, SWPL--70% Compensation. The overall AZ-CA transfer capability would be increased by increasing series compensation on DPV1 and segments of SWPL ("Expanded Infinite Bridge Case C").

f. DPV1 Convert to 500 kV DC. DPV1 would be converted from AC to DC operation. All of the insulators would be changed and converter stations would be added at each line terminal.

g. DPV1 Convert to 765 kV AC. DPV1 would be converted to 765 kV AC operation. Existing towers would need to be replaced and power transformers would be required at each line terminal. The line would be removed from service for the construction period.

h. Loop Flow Control Equipment. Loop flow control alternatives would be implemented to increase the allowable firm power transfer on existing lines.

3. No Project: Effects of not implementing the project, and using the existing SCE system:

   a. without providing any wheeling ("Reference Case A"); or

   b. providing wheeling service to LADWP ("Infinite Bridge Case B")

4. System Timing Alternatives: Delaying the project on-line date from 1993 to 1995 or 1997. (Cases W(95) and W(97))

As described below, each alternative was evaluated in terms of its relative environmental impacts, cost-effectiveness and technical/institutional considerations. Figure C-1 presents a matrix summarizing SCE's evaluation of the alternatives with less environmental impacts than DPV2.

A. Alternatives with Greater Environmental Impacts

1. Location Alternatives

SCE and DRA studied two alternative routes to avoid the Blythe agricultural area by skirting around Blythe to the north and south. These studies concluded that the proposed route minimized

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Figure C-1

ALTERNATIVE EVALUATION MATRIX

ALTERNATIVE DESCRIPTION	SYSTEM CHARACTERISTICS	ECONOMIC FACTORS: TOTAL PROJECT (1): CAPITAL COST	ECONOMIC FACTORS: TOTAL PROJECT (1): $/KW	ECONOMIC FACTORS: SCE SHARE: NET BENEFIT	ECONOMIC FACTORS: SCE SHARE: BENEFIT/COST RATIO	ENVIRONMENTAL FACTORS	TECHNICAL/INSTITUTIONAL FACTORS	KEY DECISION POINTS
Devers-Palo Verde #2 500 kV AC (Proposed Project)	• 1,200 MW additional capacity provided: – 602 MW firm power delivery for Participants; – SCE Benefits: Production Costs, T/S Revenues, UIS, Loss Reductions, Stability, Air Quality	$261	218	364	3.1	• No new access roads. • 26 acres permanent ground disturbance. • 125 acres temporary ground disturbance. • Parallels existing DPV1 line for its entire length, minimizing env. impacts due to construction.	• Positive and negative N-2 reliability effects. • No major SSR impact. • Participant negotiations underway.	• High SCE benefit/cost ratio. • Low environmental impact. • Maintains Exchange Agreement viability. • Meets Participants' needs.
No Project A. No additional use of existing SCE facilities.	• Participants' 602 MW capacity needs not met; likely to pursue alternative project or build DPV2 themselves.		(2)	0	N.A.	(2)	(2)	• Does not meet any of the Participants' needs. Alternative project likely to be built. – Does not assure less environmental impact. – Probable disbenefits for SCE customers.
B. Use of existing SCE facilities by LADWP.	• LADWP's desire for transmission ownership not satisfied; other Participants' 224 MW of capacity needs not met—possibility of an alternative project, or DPV2 built by Participants.	0	0 (3)	22 (3)	N.A.	(2)	(2)	• Does not meet all of the Participants' needs. Alternative project still a possibility: – Does not assure less environmental impact. – Effect on SCE benefits depends on Participants' actions.
Upgrade Series Compensation on DPV1 and Southwest Powerline to 70%	• 200 MW additional capacity. Meets Participants' 602 MW of capacity needs but with adverse economic effect on Edison.	32	160	-47 (4)	<1	Minimal Impact—Upgrades at sites of existing facilities.	• Potential SSR concerns. • Rating/allocation uncertainty.	• Adverse economic effect on SCE customers. • Adverse technical and institutional factors.
Upgrade Series Compensation on all Arizona-California Ties to 70%	• 400 MW additional capacity. Meets Participants' 602 MW of capacity needs but with adverse economic effect on Edison	157	390	–	–	Minimal Impact—Upgrades at sites of existing facilities.	• Potential SSR concerns. • Rating/allocation uncertainty.	• Adverse technical and institutional factors • Does not meet Participants' needs • Relatively high cost
Devers-Palo Verde #1 500 kV AC Conversion to 500 kV DC (6)	• 1,200 MW additional capacity provided: – 602 MW firm power delivery for Participants – SCE benefits: Production Costs, T/S Revenues, & Loss Reimb., UIS, Air Quality Reduced Disbenefits: • Increased Losses, Stability.	866	666	< 0 (5)	< 1 (5)	• New 20 acre conversion site and 5 acre ground grid at each end of the line.	• Adverse N-1 and N-2 reliability effects. • Control system coordination for DC line with PVNGS.	• Cost Prohibitive • Adverse Technical and Institutional Factors
Devers-Palo Verde #1 500 kV AC Conversion to 765 kV AC (6)	• 400 MW additional capacity; DPV1 removed from service 2 years; Meets Participants' 602 MW of capacity needs but with adverse economic effect on Edison.	380	972	–	–	• Extensive ground disturbance to remove existing towers and construct new towers. • Extensive use of access roads to move material and equipment. • Greater visual impact due to higher towers.	• Adverse N-1 and N-2 reliability effects. • Availability concerns—no 765 kV AC lines in West.	• Significant Environmental Impacts • Cost Prohibitive • Adverse Technical and Institutional Factors

NOTES:

(1) All capital costs are in 1992 dollars. DPV2 cost is per Amended PEA, adjusted for stipulation with DRA. 70% compensation cost on DPV1 and SWPL is per SCEA estimate. For other alternatives, a 5% annual escalation rate was applied to the 1986 costs presented in the EIR, Table 5-3.

(2) Depends on actions taken by the Participants.

(3) Assumes no project is built by the Participants.

(4) Assumes all Participants use existing SCE facilities.

(5) Assumes benefits equal to DPV2 and costs proportionally greater (i.e., $666/kW vs. $218/kW).

(6) Additional capacity from conversion alternatives assumes the loss of 1200 MW of present DPV1 capacity.

Source: Applicant's Concurrent Brief, page 36.

environmental impacts compared with alternative routes.[1] Table C-1 presents the EIR team's comparative evaluation of route alternatives.

2. Other Transmission Line Alternatives

a. Phoenix-Mead-Adelanto 500 kV DC

DRA reviewed both LADWP's Mead-Adelanto 500 kV DC line[2] and the Phoenix-Mead-Sylmar line studied by the Western Area Power Administration. The cost of these alternatives is estimated at $850 million (1990 $), about three times the cost of DPV2. These alternatives also have a significantly greater environmental impact than the proposed project. DRA concludes that the proposed project is preferable to these alternatives on both economic and environmental grounds.

b. Valley-Miguel/SDG&E Interconnect

This alternative would consist of a 500 kV line between SDG&E's Miguel Substation and SCE's Valley Substation. The strengthening of the SDG&E-SCE transfer capabilities would increase the transfer capacity of the existing SWPL line by approximately 200 MW. The cost of the Valley-Miguel line would be approximately $240 million. The line would involve the construction of 91 miles of new transmission line, only 9 of which are parallel to an existing line. The environmental impacts of this alternative are higher than for the proposed project. DRA concludes that, for a cost close to DPV2, this alternative would only increase the transfer capacity from Arizona by one-sixth as much.

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1 Exhibit 25, Amended PEA, pp. 10-24 through 10-93; Exhibit 6A, DEIR, Vol. 1, pp. 239-45.

2 Without an additional transmission line from Phoenix to Mead, the proposed Mead-Adelanto line does not increase transfer capability from the Palo Verde/Phoenix area to southern California. For the comparison of alternatives, Mead-Adelanto is coupled with the Westwing-Mead 500 kV DC project that would bring power out of the Phoenix area.

APPENDIX C
Page 5

Table C-1

Comparative Evaluation of Devers-Palo Verde
500 kV Transmission Line Route Alternatives[1]

Environmental Consideration	Transmission Line Routes: Proposed	Northern Blythe Alt.	Southern Blythe Alt.
Total Length	126 mi.	132 mi.(L)	125.5 mi.
New ROW Required	0 mi.(P)	17 mi.	16.0 mi.
Geology	Low	Mod	Mod
Soils	Mod	Mod	Mod
Hydrology	Low	Low	Low
Biological Resources	Low(P)	Low	Mod(L)
Land Use	High	High	High
Socioeconomic	Low	Low	Low
Visual	Mod	High	High
Acoustic	Low	Low	Low
Archaeol. and Historical Resources	Low(P)	Mod	Mod
Nat. Amer. Resources	High	High(L)	High
TOTALS			
No. High & Mod.	4	6	7
No. Pref. (P)	3	0	0
No. Least Pref. (L)	0	2	1

NOTES: Impact Ratings are High, Moderate, or Low
(P) = Clearly the preferred choice
(L) = Clearly the least preferred choice
If no (P) or (L) is indicated among the range of alternatives, no clear advantage or disadvantage could be identified.
All ratings are based on projected impacts and represent professional judgments of the EIR team.

[1]This analysis considers impacts in California only - comparative values for some resource areas would change when considering implications in Arizona.

Source: Exhibit 6A, page 244.

c. Second SWPL + Valley-Miguel

This alternative would consist of building a second SWPL 500 kV AC line and the Valley-Miguel line. DRA concludes that it would have all the adverse impacts of the Valley-Miguel line plus impacts associated with building a second SWPL.

B. Alternatives with less Environmental Impacts

1. The "No-Project" Alternative

DRA considers the no-project alternative, because it involves no construction of additional transmission lines, to be clearly one of the environmentally preferred alternatives. As described in the body of this order, the no-project alternative was reevaluated as "Reference Case A" during Phase I hearings, due to the major changes in economic context since the EIR was prepared. Under the no-project alternative, SCE would not provide transmission service to MSR, LADWP, or the other SCPPA coparticipants.[3] SCE would forego over $360 million worth of benefits to its ratepayers. DRA now believes that under most circumstances the no-project alternative cannot meet the project objectives.[4]

SCE argues that there is a significant negative regional impact associated with the no-project alternative. In SCE's view, the SCPPA participants and MSR would build either DPV2 or the proposed Phoenix-Mead-Adelanto DC project themselves, in order to have a long-term transmission path for their Palo Verde and San Juan entitlements. The latter would be three times as expensive, twice as long, and have a significantly greater environmental impact than DPV2.

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3 DRA states that the conclusions reached in the Draft EIR that the no-project alternative can meet all the project objectives are now anachronistic since the project objectives have changed both in substance and timing.

4 One important qualification to DRA's rejection of the no-project alternative is SCE's proposed merger with SDG&E. DRA argues that, if the merger occurs, then SCE's access to SPWL would allow the no-project alternative to meet all of SCE's objectives from the project with essentially no environmental impact. This issue is discussed in Section VIII of this order.

2. The "Infinite Bridge" Alternative

The Infinite Bridge scenario is similar to the no-project alternative except that SCE uses its existing system to wheel LADWP's power. As described in the body of this order, this alternative was reevaluated as "Case B" during Phase I hearings.

Both DRA and SCE consider this project substantially less cost-effective than the proposed project. Although this alternative is preferable during the initial years, it turns negative after 2002 due to opportunity costs. The total project life benefits of this alternative are $22 million (NPV). DRA and SCE conclude that choosing this alternative would force SCE to forego over $340 million (NPV) in ratepayer benefits. SCE also argues (as it did for the no-project alternative) that SCPPA and MSR would probably build their own line if the Infinite Bridge alternative was adopted.

3. The Series Compensation Alternatives

SCE and DRA examined two alternatives for raising SCE's transfer capacity from the Southwest by increasing the series compensation on one or more existing transmission lines. In layman's terms, increasing series compensation allows a utility to "pack" more power into a transmission line. Because no new towers would need to be built or new conductors strung, these alternatives would cause none of the environmental impacts associated with any of the DPV2 scenarios.

Increasing the series compensation on transmission lines increases the likelihood a utility will encounter problems with subsynchronous resonance (SSR) at a generating plant.[5] A variety of SSR mitigation devices are available at a range of prices. Until a detailed engineering study is done of the particular transmission line(s), it is not possible to tell which of these devices would be effective in correcting the problem. DRA's analysis made conservative assumptions that relatively expensive SSR mitigation devices would be required.

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5 SSR can be described as a phenomenon where the harmonic frequencies of the transmission system "beat" against the mechanical frequencies of turbine shafts. This can cause serious mechanical failures at generating stations, unless corrective measures are taken.

a. The "Expanded Infinite Bridge"

The Expanded Infinite Bridge alternative would increase series compensation from 50% to 70% on DPV1 and the Miguel-Palo Verde line (SWPL) thereby increasing the overall California-Arizona transfer capacity on DPV1 and SWPL by about 200 MW. SCE would then wheel MSR's, LADWP's, and the SCPPA cities' power over the expanded DPV1. This alternative was evaluated as "Case C" in DRA's and SCE's updated economic analysis. This alternative is estimated to cost $16 million.

Because this alternative would not involve the construction of new transmission lines, it is also one of the environmentally preferred alternatives.

SCE opposes this alternative, arguing that the technology is too risky, perhaps very expensive, and this alternative would require much cooperation with other utilities, particularly Arizona Public Service.

DRA does not recommend this alternative because it is substantially less cost-effective than the proposed project. It has a projected NPV of negative 47 million. DRA also notes the uncertainty about gaining the cooperation of other owners of Palo Verde to install the SSR suppression equipment that would be required.

4. All Lines 70% Compensation Alternatives

Another alternative studied involved increasing the series compensation on all the existing Arizona-California interties from various levels ranging from 26-70% to a uniform 70%. This would increase transfer capacity on the interties by 400 MW at a cost of approximately $118-136 million. Some of this 400 MW would be allocated to other utilities using the intertie.

Although SERA's initial analysis showed this alternative to be probably technically feasible, SERA did not do a detailed economic analysis because the SWPL-DPV1 series compensation alternative could achieve the same project objectives at much less expense, with less technical complexity, and without having to obtain cooperation from so many other utilities who may have little incentive in accepting increased risk of SSR.

5. Conversion of DPV1 to DC

This alternative would involve converting DPV1 to 500 kV DC line with a transfer capacity of approximately 2500 MW. Since new towers would not have to be installed, this alternative would have less environmental impacts than the proposed project. Although the increase in transfer capacity of 1300 MW would be slightly greater than DPV2, the expense would be much greater--$750 million.[6] On a per-kW basis, the cost would be approximately three times greater than DPV2.

Both SCE and DRA expressed concerns regarding the stability and reliability effects of this alternative. DRA witness Weatherwax characterized the effect of a single 2500 MW DC line on SCE's system stability as being, if not "unacceptable", at least "extremely discouraging."[7] SCE states that it is uncertain whether the Palo Verde plant could effectively coordinate its complex control system with that of the DC line. Loop flow benefits previously associated with this alternative in the Draft EIR are no longer material due to the installation of phase shifters elsewhere.[8]

6. <u>Non-Transmission Line Alternatives</u>

DRA's consultants examined QF's, conservation and load management, and additional loop flow control measures as alternatives to DPV2. DRA notes that important loop flow control measures have been taken independent of DPV2, and the exchange agreement with LADWP allows SCE through DPV2 to capture significant benefits from the PNW. DRA concludes that none of these alternatives would meet project objectives.

C. <u>Alternatives with the Same Environmental Impacts</u>

1. <u>Upgrading DPV1 to 765 kV AC</u>

This alternative would involve the reconstruction of the existing DPV1 line to a four-conductor configuration. All the towers would have to be replaced and DPV1 would be out of service during the construction period. During that period, SCE would be isolated from its Palo Verde generation entitlement. The net increase in transfer capacity would be approximately 400 MW at a cost of about $335 million, or $840 million per kW.

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6 The net increase in transfer capacity is only 1300 MW because converting the 500 kV AC DPV1 line to 500 kV DC operation results in the loss of about 1200 MW of existing AC transmission capacity.

7 Tr. at 800-801.

8 Tr. at 801.

The reason for this expense is that the existing towers and footings are not strong enough and do not provide adequate clearances for 765 kV operation. The existing towers and footings would therefore have to be removed and replaced with stronger and taller structures. In addition, new 765 kV transformers would be required at each end of the line to connect it to the existing transmission network. Environmental impacts of this alternative are extensive ground disturbance resulting from the removal of existing towers and constructing new towers and greater visual impact due to the higher towers. The EIR analysis concluded that this alternative "would entail virtually the same construction impacts as would the proposed new line."[9]

2. <u>1995 or 1997 In-Service Dates</u>

Under these alternatives, the physical impacts of line would be the same as described for the proposed project. The only difference is in the timing of the impacts--they would occur either two or four years later. DRA's evaluation of the relative net benefits of these alternatives is presented in the body of this order.

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9 Exhibit 6B at 83.

(END OF APPENDIX C)

DPV2

List of References of Specific
Environmental Mitigation Requirements
(Source: Exhibit 37)

References to Mitigation in the FEIR (Aug. '87)

(Letters (B,C,etc.) refer to those letters received in response to the DEIR.)

References where Vol. 1 of the DEIR is referred to:

p.7 (C-1)	DFG proposed 7 mitigation measures: -DEIR author generally agreed, but suggested modifications to #3. (Needs "stipulation" from Applicant.) (Reference to #3 in 1st bullet is wrong; should have been #4.) -CPUC "acknowledges" position expressed in DFG's #7; it will be "considered".
p.8 (C-2)	DFG: Notification to DFG will be required: comment "noted". (as called for in the Fish & Game Code)
p. 14 (D-21)	Accept SCE's revision to mitigation measure (last paragraph, line 7) on p. 210 of DEIR.
p. 14 (D-22)	Revise mitigation statements (1st paragraph) on p.211 of DEIR. (SCE's comments)
p. 14 (D-23)	Revise mitigation statements (2nd paragraph) on p.211 of DEIR. (SCE's comments)

References where Vol. 2 of the DEIR is referred to:

FEIR-p.19 (G-1)	Staff recommends condition of approval requiring SCE to document the Seismic Preparedness of Devers, providing responses to 5 topics. (City of Palm Springs' comments)

References to Mitigation in the DEIR, Vol. 1 (March 1987)

pp.135-238 Section 5.0 Environmental Impacts & Mitigation Measures

p.137 Geology. 5.1.4 Mitigation Measures
7 measures on pp.138-139.

p.144 Soils. 5.2.4 Mitigation Measures: 2 measures.

p.147 Hydrology. 5.3.4 Mitigation Measures: 4 measures.

p.159 Biological Resources. 5.4.4 Mitigation Measures
p.159-Vegetation: Details of proposed transplant efforts need to be identified. Additional mitigation guidelines, as given by E. Linwood Smith & Associates (1985: Appendix N) and presented in Appendix B of this DEIR Vol. 1, should be followed to the extent feasible.

pp.159-160-Summary of 8 primarily recommended mitigation measures.

p.160-Wildlife: Adhere to mitigation measures presented by the Applicant in Section 7.6 of the PEA, as well as adopting the Vegetation Mitigation Measures and 6 others listed on pp.160-161.

Land Use & Planning
p.172-Tower Siting & Design: The proposed transmission line meets all CAAA & ASAE recommended criteria with one exception. The proposed project should include measures to increase the visibility of the line:
1) use of specular conductors.
2) use of white reflective devices on towers.
3) expand system of lights.

p.182 5.5.3 Mitigation Measures

p.182 Consistency w/Relevant Plans & Policies - 1 measure.

p.183 Residential, Commercial & Industrial Land Use Mitigation - 1 measure.

p.183 Agricultural Land Use Mitigation
- To minimize reductions in crop productivity - 3 measures.

pp.183-184 - To minimize agricultural aircraft safety hazards - 2 measures.

p.184 Transportation & Utilities Mitigation - 4 measures.

p.184 Park, Recreation & Preservation Area Mitigation - 3 measures.

p.185 General Mitigation: at end of projects useful life - dismantling & removal. 1 paragraph.

p.189 Socioeconomic Impacts. 5.6.4 Mitigation Measures (1st paragraph)
No mitigation is proposed.
Recommended, however, to coordinate work crews to avoid significant impacts to temporary housing supply.

Visual Resources 5.7.3 Mitigation Measures
p.210 General Consideration - 3 measures.
p.211 Site-Specific Mitigation Measures for High Impact Areas - Proponent's Preferred Route: Mitigation measures for 3 route segments

p.218 Acoustic Considerations 5.8.4 Mitigation Measures
Transmission Line Noise: No measures required.
Construction Noise: 6 measures.

p.226 Archaeological & Historical Resources 5.9.3
Mitigation Measures: 2 measures.
p.227 Also, SCE will comply w/BLM policy...: 2 measures.

p.229 Native American Resources 5.10.3 Mitigation Measures
One paragraph.

References to Mitigation in Appendix A of the DEIR, Vol. 1 - Summary of Public Scoping Meetings & Workshop

Summary of Public Workshop: Blythe, 6/16/86.
Points Raised by Public Participants(no page #s):
Hazards to Aerial Applicators: 3 mitigation measures noted.
Production Losses: 2 mitigation measures noted.
Hazards to Field Workers: 1 mitigation "measure" noted.
Increased Pesticide Usage: 1 mitigation measure noted.
Electric Field Effects: Mitigation: Unknown.
Visual: 1 mitigation measure noted (Place lines underground.)

References to Mitigation in Appendix B of the DEIR, Vol. 1 - Biological Impact & Mitigation Planning Chart

Source: E. Linwood Smith & Associates, 1985. Biological Inventory & Impact Assessment. DPV2. Prepared for Edison. See pages 3 of 5 thru 5 of 5 & the Planning Chart. This Appendix was referred to on p.159 of the DEIR, Vol. 1 in the Vegetation section (as noted above).

References to Mitigation in the DEIR, Vol. 2, (March '87)

pp.99-105 Section 4.0 of DEIR, Vol.2 - Mitigation Programs for High-Voltage Transmission Lines

Generic mitigation for high-voltage transmission lines throughout CA.

Project-specific mitigation for DPV2 is described in Vol.1 of the DEIR.

p.99	4.1	Pre-construction surveys based on final design, marking and staking in the fields of tower locations and access roads.
p.100	4.2	All sensitive resources discovered in the survey to be suitably marked for later protection or avoidance.
p.101	4.3	Environmental Protection Plan (EPP) & Handbook
p.102	4.4	Monitoring & Supervision
p.103	4.5	Enforcement
p.103	4.6	Restoration Plan
p.104	4.7	Sanction
p.104	4.8	Periodic & final reports on the mitigation/ monitoring program.

References to Mitigation in the Original PEA (December 1985)

Section 7.0 Mitigation of Significant and Potentially Significant Impacts of the Proposed Project

Land Use Mitigation. Section 7.1
In Arizona, no mitigation was needed nor identified.
pp.7-2,3,4 In CA, mitigation measures were identified for sections of 3 "links".

Cultural Resource Mitigation Section 7.2
p.7-4 Precise mitigation measures: developed on a case-by-case basis.

Geologic & Pedologic Mitigation Section 7.3
p.7-4,5 One paragraph discussion of mitigation measures.

Meteorologic, Climatologic, Air Quality Mitigation Section 7.4
p.7-5 No significant impacts. No mitigation required.

Hydrologic Mitigation Section 7.5
p.7-5 No significant impacts.

Biological Mitigation Section 7.6
p.7-6,7,8 Mitigation recommendations listed for 6 project "links".

Sonic Mitigation Section 7.7
p.7-9 No significant impacts. No mitigation required.

Visual Mitigation Section 7.8
p.7-9 Link 1: 2 measures.
Link 2: 3 measures.
p.7-11 Links 6, 8, 10: 3 measures.
Link 12: 2 measures.
p.7-13 Links 13 and 14: 3 measures.
Link 16: 2 measures.

Socioeconomic Mitigation Section 7.9
p.7-16 No significant impacts. No mitigation.

Traffic & Transportation Mitigation Section 7.10
p.7-16 No significant impacts. No mitigation.

Public Health & Safety Mitigation Section 7.11
p.7-16 No significant impacts.
Line is designed to minimize exposures. Public concerns addressed as they arise.

References to Mitigation in the Amended PEA (August 1988)

General Comment: No new mitigation measures are necessary.

Section 7.0 Mitigation...
(Almost exactly the same as Section 7.0 of Original PEA)
See list of mitigation measures for Original PEA.

Added: General Mitigation Section 7.12
"Site specific areas that require mitigation measures will be coordinated with the agency specifically involved with those areas, such as governmental agencies listed in Exhibit F of the application."

CERTIFICATE OF SERVICE

I hereby certify that I have this day served the foregoing document upon all known parties of record in this proceeding by mailing by first-class or sending by overnight delivery a copy thereof properly addressed to each party.

Dated at San Francisco, California, this 12th day of October 1988.

/s/ RENITA Y. STONE

Renita Y. Stone

(END OF APPENDIX D)

BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA

In the Matter of the Application of SOUTHERN CALIFORNIA EDISON COMPANY (U 338-E) for a certificate that the present and future public convenience and necessity require or will require the construction and operation by Applicant of a 500 kV transmission line between Palo Verde Switchyard and Devers Substation.	Application No. 85-12-012

EDISON/DRA AGREEMENT RE CERTAIN CONDITIONS ON CERTIFICATE

As part of the continuing effort to narrow the issues and to expedite the proceedings in this case, Southern California Edison Company ("Edison"), the Applicant herein, and the Division of Ratepayer Advocates ("DRA") of the California Public Utilities Commission ("Commission") jointly recommend to the Commission that if a Certificate of Public Convenience and Necessity is issued for Edison's proposed Devers-Palo Verde No. 2 500 kV Transmission Line ("DPV2"), such certificate should include the following conditions:[1]

1. By January 15, 1990 Edison shall submit a report to the Commission describing the status of the efforts of SCEcorp (Edison's parent company) to merge with San Diego Gas & Electric Company ("SDG&E"). This report will indicate, as of January 1, 1990, whether (a) a merger agreement has been entered into by SCEcorp or Edison and SDG&E, (b) SCEcorp or Edison has commenced and is continuing a solicitation of SDG&E shareholders for the purpose of a merger, and

1. The dates for submission of the various reports and studies described herein have been chosen with the understanding that if Edison builds DPV2 for a June 1, 1993 operating date it will not be necessary to begin making commitments for purchasing material until February, 1990.

(c) SCEcorp or Edison has a public merger offer with SDG&E outstanding. If one or more of these conditions exist as of January 1, 1990, Edison (1) shall not commence construction of DPV2, and (2) shall petition the Commission for reevaluation of DPV2 in the context of the then status of the merger activity. To protect DPV2 project dates, Edison may solicit bids from material suppliers prior to January 1, 1990, but may not award any contracts for the purchase of material.

2. By July 1, 1989 Edison shall submit to the Commission a statement of its plans to enhance the net benefits attributable to DPV2 in the early years by measures such as increased transmission service revenues, transmission capacity layoffs, or other measures. This report shall include an analysis, including a production costing analysis, of the net benefits that would be derived from implementation of such plan, and showing that the enhanced benefits could not be realized without having DPV2 in service prior to 1997.

3. By July 1, 1989 Edison shall submit to the Commission a study on the likelihood and potential impact of a simultaneous outage of both the DPV1 and DPV2 lines. This study shall assess alternative measures for mitigating the impacts of such a simultaneous outage, and the effectiveness, cost, reliability, and feasibility of these measures. DRA recognizes that the final evaluation of strengthening the towers as a means of improving the reliability of these two lines will be made in the later report described in paragraph 5.

4. By November 1, 1989, Edison shall submit copies of the applicable signed agreements implementing the benefit enhancement measures referenced in Paragraph 2 above, and copies of signed contracts for transmission service over DPV1 from 1990-93, over DPV2, and over Edison's existing system west of the Devers Substation.

5. By November 1, 1989, Edison shall submit to the Commission a report analyzing the failures of the DPV1 line which occurred on August 21, 1986 and October 29, 1987 due to wind loading.

6. As soon as Edison can do so with a reasonable degree of certainty, it shall describe to the Commission what it believes will be the final provisions of the amendment to the "Los Angeles-Edison Exchange Agreement Between The Department of Water And Power Of The City Of Los Angeles And Southern California Edison Company", which is presently being negotiated to provide, inter alia, for the Department of Water and Power to receive transmission service over DPV1 from June 1, 1990 until the earlier of (1) the date when DPV2 commences commercial operation, or (2) June 1, 1993.

7. The reports described in Paragraphs 1 through 6 above shall be in the form of advice filings.

8. The project is cost-effective with a June 1, 1993 in-service date. However, if the in-service date is delayed to June, 1997, the Net Present Value ("NPV") of DPV2 for the initial period beginning on June 1, 1993 and ending on December 31, 1996 is $33.7 million greater, and the NPV attributable to DPV2 from 1997 on is reduced by almost $32 million (both in 1990 $). The goal in implementing the benefit enhancements referred to in Paragraphs 2 and 4 above will be to generate additional net benefits to enhance the near-term benefits so that the impact on the ratepayers during the 1993-97 time period will not be substantially different than under DRA's 1997 in-service date case (Case W(97) in Exh. 32).

9. Initially, the cost cap for Edison's share of DPV2, adopted pursuant to Public Utilities Code §1005.5, will be $172,400,000. By November 1, 1989, Edison will file with the Commission a summary of any changes in cost estimates to provide more current information with respect to the components of project costs, such as cost of materials and

cost of mitigation measures. At that time the cost cap will be adjusted, if appropriate.

10. Edison agrees that the firm summer rating of DPV2 will be 1200 MW (with all Palo Verde units on line), plus or minus five percent. Due to the coordination required between utilities in the Pacific Southwest to determine the actual rating of DPV2, the final determination will not occur until approximately six months prior to the project in-service date. If this rating is finally determined to be below 1140 MW, then the Commission may make further adjustments to the cost cap.

If a Certificate of Public Convenience and Necessity is issued by the Commission for DPV2, Edison and DRA respectfully request that the conditions described herein be included.

Respectfully submitted,

RICHARD K. DURANT
CAROL B. HENNINGSON
PHILIP WALSH

Philip Walsh

By: Philip Walsh

Attorneys for
SOUTHERN CALIFORNIA EDISON COMPANY

JAMES E. SCARFF

for E Scarff

By: James E. Scarff

Attorney for
DIVISION OF RATEPAYER ADVOCATES

Dated: September 29, 1988

(END OF APPENDIX E)

APPENDIX F

NOTICE OF DETERMINATION

TO: x Office of Planning and Research
1400 Tenth Street, Room 121
Sacramento, CA 95814

___ County Clerk
County of ______________

FROM: (Public Agency) CPUC
505 Van Ness Avenue
San Francisco, CA 94102

SUBJECT: Filing of Notice of Determination in compliance with Section 21108 or 21152 of the Public Resources Code.

Devers-Palo Verde No.2 500 kV Transmission Line
Project Title

86072810 — Mike Burke — (916) 322-7316
State Clearinghouse Number (If Submitted to Clearinghouse) — Contact Person — Area Code/Number/Extension

Western Arizona and Riverside County in California
Project Location

Construct a second 500 kV transmission line in an existing right-of-way between Edison's Devers Substation near Palms Springs and the Palo Verde Nuclear Plant in Arizona.
Project Description

This is to advise that the California Public Utilities Commission (Lead Agency or Responsible Agency) has approved the above described project on ________ (Date) and has made the following determinations regarding the above described project:

1. The project x will, ___ will not have a significant effect on the environment.
2. x An Environmental Impact Report was prepared for this project pursuant to the provisions of CEQA.
   ___ A Negative Declaration was prepared for this project pursuant to the provisions of CEQA.
3. Mitigation measures X were, ___ were not made a condition of the approval of the project.
4. A statement of Overriding Considerations X was, ___ was not adopted for this project.

This is to certify that the final EIR with comments and responses and record of project approval is available to the General Public at:

CPUC, 505 Van Ness Avenue, San Francisco, CA 94102

Date Received for Filing and Posting at OPR ______________

____
Signature (Public Agency) — Title

(END OF APPENDIX F)