0000041459

Sempra Energy
Solutions℠

ORIGINAL

NEW APPLICATION

March 15, 2006

Docket Control Center
Arizona Corporation Commission
1200 West Washington Street
Phoenix, AZ 85007

E-03964A-06-0168

Re: Application for a Certificate of Convenience and Necessity for Competitive Retail Electric Services

To Whom It May Concern:

Please find attached one (1) original, notarized copy of Sempra Energy Solutions' Application for a Certificate of Convenience and Necessity for Competitive Retail Electric Services plus the additional thirteen (13) copies required. Also enclosed is a self-addressed stamped envelope for the return of a date-stamped copy of the Application.

As instructed, written notice of compliance with A.A.C. R14-2-1603(E) will be provided to the respective parties within 10 days. Please see Attachment T for a complete list of the utilities to be notified.

If you have any further questions or need any additional information, please contact me at 619-696-3177 or via email at GBass@SempraSolutions.com.

Sincerely,

Greg

Greg Bass
Director

Enclosures

RECEIVED
2006 MAR 16 A 11: 37
AZ CORP COMMISSION
DOCUMENT CONTROL

Sempra Energy Solutions is not the same company as the utility, SDG&E or SoCalGas, and the California Public Utilities Commission does not regulate the terms of Sempra Energy Solutions' products and services.

ARIZONA CORPORATION COMMISSION

Application for Certificate of Convenience and Necessity (CC&N) to Provide Competitive Retail Electric Services

Mail original plus 13 copies of completed application to:

Docket Control Center
Arizona Corporation Commission
1200 West Washington Street
Phoenix, Arizona 85007-2927

If you have current applications pending or have a CC&N in Arizona as a competitive retail electric service provider, list:

Type of Service: Competitive Retail Electric Service
Docket No.: E-03964A-00-0951 Date: 08/23/2002
Decision No.65123 (if applicable)

Type of Service: E-03964A-06-0168
Docket No.:_____ Date:_____
Decision No._____ (if applicable)

For Docket Control Only:
(Please Stamp Here)

The Applicant is applying for approval to provide the following competitive retail services:

- [x] Electric Generation
- [ ] Aggregation
- [ ] Brokering
- [ ] Meter Service Provider
- [ ] Meter Reading Service Provider
- [ ] Reseller of Meter Service
- [ ] Reseller of Meter Reading Service
- [ ] Other_____

RECEIVED
2006 MAR 16 A 11: 37
AZ CORP COMMISSION
DOCUMENT CONTROL

SECTION A

Applicant Information

(A-1) The exact legal name of Applicant, current address, and telephone number (including area code). Include any other business address and telephone number of the principal place of business if different from current address and telephone number: (Include E-mail addresses and fax numbers.)

Sempra Energy Solutions
101 Ash Street, HQ09
San Diego, CA 92101

Phone: (877) 2-SEMPRA
Fax: (619) 696-3101
Email: email@semprasolutions.com

(A-2) If doing business under a name other than the Applicant name listed above, specify all names and addresses of business activity:

N/A

(A-3) The name, address, telephone number, fax number, and e-mail address of the management contact:

Greg Bass
101 Ash Street, HQ09
San Diego, CA 92101

Phone: (619) 696-3177
Fax: (619) 696-3104
Email: gbass@semprasolutions.com

(A-4) The name, address, telephone number, fax number, and e-mail address of the attorney, if any, representing the Applicant:

Lawrence V. Robertson, Jr.
P.O. Box 1448
Tubac, AZ 85646

Phone: (520) 398-0411
Fax: (520) 398-0412
Email: N/A

(A-5) What type of legal entity is the Applicant?

☐ Sole proprietorship

☐ Partnership: ____limited, ____general, ____ Arizona, _____ foreign

☐ Limited liability company

☑ Corporation: ____ S, ____ C, _____ non-profit, ____ Arizona, __✓__ foreign

☐ Other, specify:

Describe any affiliate or subsidiary interest the Applicant has and include the parent company's name and address.

Parent Company: **Sempra Energy**
101 Ash Street
San Diego, CA 92101

Affiliates: **San Diego Gas & Electric**
Southern California Gas
Sempra Energy Trading, Inc.
Sempra Generation

(A-6)	Submit as Attachment "A" the names of all owners, partners, limited liability company managers, or corporate officers and directors and indicate the percentages of ownership of each. If the Applicant is a corporation, list the names and addresses of all persons or entities which directly or indirectly own, control, or hold the power to vote 10% or more of the Applicant's outstanding voting securities. Include the most recent report required by the Securities and Exchange Commission that details such information. **See Attachment A.**
(A-7)	Does the Applicant plan to sell retail electric services in Arizona? If "yes", provide the anticipated service date(s). Submit as Attachment "B" a copy of all relevant tax licenses from lawful taxing authorities within the State of Arizona. You may contact the Dept. of Revenue at 602-542-4576 to obtain information. **Yes. Anticipated service date is soon as practicable after March 15, 2006. See Attachment B.**
(A-8)	The Applicant must comply with the tariff filing requirements of A.A.C. R14-2-1611. The maximum rates specified in any tariff shall not be less than the Applicant's marginal cost of providing the service. Any changes in the maximum rates or in the terms and conditions of service are not effective until approved by the Commission. Submit as Attachment "C" the Applicant's proposed tariff that must include a description of each service to be provided, the maximum rate for each service, and any other terms and conditions that apply to each service to be provided. **See Attachment C. SES's believes that the proposed tariff complies with the requirements set forth in the Phelps Dodge Corporation, et al. vs. Arizona Electric Power Cooperative, Inc., et al. court decision and the rules and regulations of the Arizona Corporation Commission.**
(A-9)	The CC&N may permit statewide provision of each service except for areas determined by the Commission not to be open to competition. Describe the geographic areas in which the Applicant will provide each service. **Service will be provided exclusively to the Arizona Public Service Company, Salt River Project, and Tucson Electric Power Company service areas.**
(A-10)	List the states in which the Applicant currently provides retail electric services similar to those it proposes to sell in Arizona. Submit as Attachment "E" a copy of any authority given to the Applicant to provide electric services. **See Attachment E – Refer to ACC Decision 65123.**
(A-11)	Provide a list of states in which the Applicant sought authority to provide retail electric services and in which the state denied the authority or granted authority with major changes or conditions for those services. For each state listed, submit as Attachment "F" a copy of the decision modifying the application for authority to provide retail electric services. **SES has never been denied authority to provide retail electric services.**
(A-12)	Has the Applicant been granted authority to provide retail electric services in any state where such authority was later revoked? If "yes", submit as Attachment "G" a copy of each decision revoking the authority. **No.**
(A-13)	Has the Applicant been involved in any formal complaint proceedings before any state or federal regulatory body? If "yes", list the regulatory body, the nature of the complaint, and submit as Attachment "H" a copy of the order resolving the complaint. **No.**

(A-14) Has the Applicant been involved in any civil or criminal investigations related to any state or federal consumer protection laws or regulations within the last five years? If "yes", submit as Attachment "I" the state and the nature of each investigation, and when such investigation occurred.

No.

(A-15) Has the Applicant had judgment entered against it in any civil matter or been convicted of criminal acts related to any state or federal consumer protection laws or regulations within the last five years? If "yes", list the states where judgment or conviction was entered and submit as Attachment "J" a copy of each applicable court order.

No.

SECTION B

Applicant Technical Information

(B-1) Submit as Attachment "K":

(a) A description of the Applicant's computer capabilities to store and process large volumes of customer account data. Include a resource list, e.g., modem with dedicated telephone line and facsimile machine;
(b) A description of the Applicant's capabilities to exchange data with other market participants, i.e., Utility Distribution Company and Independent Scheduling Administrator; and
(c) Identification of Applicant's staff who will prepare the reports to the Commission required by the retail electric competition rules.

See Attachment K – Testimony of Greg Bass.

(B-2) Submit as Attachment "L" :

(a) A description of the specific services that Applicant will offer, the customer classes to be served, the expected number customers in each class, and the average number of kWhs which the Applicant will market each month; and
(b) A description of the Applicant's technical ability to provide the services described in (B-2). Identify the Applicant's key technical and operational personnel including their names, titles, and length of experience in the sale, procurement, metering, and billing of energy services or similar products. If some entity other than the Applicant will provide the metering or billing for the Applicant, identify the company and describe its experience in providing these services.

See Attachment K – Testimony of Greg Bass.

(B-3) If the Applicant is an Electric Service Provider (excluding a Meter Service Provider or Meter Reading Service Provider), it must provide a copy of its Service Acquisition Agreement with a Scheduling Coordinator as required in R14-2-1603(G)(3). Submit a copy of the Service Acquisition Agreement as Attachment "M". If the Applicant has been authorized to act as a Scheduling Coordinator, submit a copy of that authorization in Attachment "M". (Note: This requirement is contingent upon the existence of a Scheduling Coordinator at the time of application.) A copy of the service agreement will be required prior to providing service.

After the ACC has authorized SES to act as a retail supplier, SES will execute the necessary scheduling coordinator agreements and will provide copies of those agreements for the ACC's records.

(B-4) The Applicant must provide its service agreement with each Utility Distribution Company in whose territory the Applicant plans to do business as required in R14-2-1603(G)(3).. Submit a copy of that service agreement as Attachment "N". A copy of the service agreement will be required prior to providing service.

After the ACC has authorized SES to act as a retail supplier, SES will execute the necessary service agreements and will provide copies of those agreements for the ACC's records.

(B-5) If the Applicant will provide Meter Service, but not Meter Reading Service, submit as Attachment "O":

(a) Identification of the meter class to be served;
(b) Proof of current liability insurance in the amount of $2,000,000 per incident;
(c) A detailed description of each of the Applicant's employees' electric meter testing, installation, maintenance, repair, and removal experience including their Meter Worker Class level. (Note: The Applicant must have at least one employee who is a Class 3 Meter Worker who is available at all times the function is performed by the MSP);
(d) A detailed description of the Applicant's training program and procedures and policies regarding testing, installation, maintenance, repair, or removal of electrical devices. (Note: The Applicant's policies must provide that its employees wear uniforms and carry proper identification while on site to perform any of these functions);
(e) If the Applicant also will provide incidental or backup meter servicing, include a detailed description of its training programs, procedures and policies regarding meter servicing. (Note: The Applicant's policies must provide that its employees wear uniforms and carry proper identification while on site for meter servicing); and
(f) A detailed description of the educational and training in electrical work and electrical safety required by the Applicant of its employees before they are allowed to install, maintain, repair, or remove electrical meters or metering devices.

By responding to (B-5), the Applicant agrees to comply with:

(a) The Meter Services Provider standards approved by the Commission, including *Meter Testing, Calibration and Installation* and *Meter Worker Qualifications*. An Applicant's failure to comply shall be grounds for revocation of its Certificate for Convenience and Necessity;
(b) All of the Commission's Meter Service Provider filing and reporting requirements; and
(c) The meter services safety requirements of the American Public Power Association (APPA) *Safety Manual For an Electric Utility*.

Prior to initiating service, SES will contract with a CC&N – approved Meter Service Provider. Currently, SES has a long-established business relationship with Applied Metering Technologies (AMT). AMT is currently operating as an approved electrical contractor for Tucson Electric Power Company. AMT provides metering and meter reading services for SES in a number of deregulated states including California.

(B-6) If the Applicant will perform Meter Reading Service Provider (MRSP) functions, submit the following as Attachment "P":

(a) A description of the Applicant's training program or means to ensure that its employees are properly trained to perform MRSP functions;
(b) A description of the Applicant's processes and standard operating procedures to ensure that meter data is processed accurately and audit records are maintained;
(c) The Applicant's disaster recovery plan, covering a "minor" disaster, such as a computer failure, and a "major disaster," such as a facility fire;
(d) An Applicant's plan for obtaining back-up meter reads in the event of communications failure, if the Applicant uses remote communications to read meters;
(e) A description of the Applicant's security measures, including restricting physical and electronic access to data and data servers;
(f) A description of the Applicant's procedures for identifying potential energy theft and reporting it to the Utility Distribution Company and the Electric Service Provider; and
(g) Identification of the employee whom the Applicant is requesting take a Commission approved and administered data test. (Note: The Applicant is required to pass a test that includes retrieving raw data, performing validation, editing and estimation, posting data to a server, and exchanging data with other market participants including at least one Utility Distribution Company via a Commission approved format.)

Prior to initiating service, SES will contract with a CC&N – approved Meter Reading Service Provider. Currently, SES has a long-established business relationship with Hunt Power. Hunt Power provides meter reading services for SES in a number of deregulated states including California.

SECTION C

Financial Information

(C-1) Submit as Attachment "Q" the applicant must submit the following audited financial information for the most recent two years that the Applicant has been in business: balance sheets, income statements, cash flow statements, and other financial information evidencing financial resources.

See Attachment Q.

(C-2) If the Applicant will collect funds, including deposits or advances, from customers prior to providing services, submit as Attachment "R" one of the following:

(1) A credit evaluation from Moody's of "Baa2" or higher or an evaluation from Standard and Poor's, Fitch, or Duff and Phelps of "BBB" or higher; or

(2) A security deposit sufficient to cover one half of the expected sales price of the kWhs that the Applicant forecasts it will sell to small customers over a 12 month period (# of kWhs per month * # of customers * 12 months * price per kWhs / 2); or

(3) A financial guarantee bond in an amount sufficient to provide adequate recourse for customers in the event of fraud or nonperformance by Applicant. The bond amount could be based upon sales value and any amounts that the Applicant collects by way of deposits or advance payments.

Attachment "R" must indicate which method will be used and include the appropriate documentation, if currently available.

In compliance with earlier ACC decisions, SES has a bond in the amount of $100,000 on file with the ACC.

(C-3) Prior to certification the Commission will require the Applicant to procure a bond or insurance coverage in an amount sufficient to protect customers in the event of the Applicant's default or non-performance. Check which of the following methods the Applicant intends to use:

_✓_ The Applicant will obtain a bond. The amount of the bond will be based on the number of customers expected to be served and number of kWhs of electricity that the Applicant expects to provide.

_____ The Applicant will obtain insurance. The amount of the insurance policy will be based on the number of customers the Applicant expects to be served and number of kWhs of electricity that the Applicant expects to provide.

_____ The Applicant will provide proof that it has been found creditworthy by the Utility Distribution Company (UDC) under the credit terms imposed by the UDC. Is this a method to procure a bond or insurance coverage?

SECTION D

Customer Protection

(D-1) Submit as Attachment "S":

(1) The name, address, and telephone number of the Applicant's customer complaint contact person; and

(2) An explanation of the Applicant's plan to ensure that the electric service provided to its customers will not be interrupted in the event that the Applicant fails to provide the competitive services set forth in its application.

See Attachment S.

I certify that if the Applicant is an Arizona corporation, a current copy of the Articles of Incorporation is on file with the Arizona Corporation Commission and the Applicant holds a Certificate of Good Standing from the Commission. If the company is a foreign corporation or partnership, I certify that the company has authority to transact business in Arizona. I certify that all appropriate city, county and/or State agency approvals have been obtained. Upon signing of this application, I attest that I have read the Commission's rules and regulations relating to the regulations of electric energy services and that the company will abide by Arizona State Law including the Arizona Corporation Commission Rules and Regulations. I agree that the Commission's rules apply in the event there is a conflict between those rules and the company's tariff, unless otherwise ordered by the Commission. I certify that to the best of my knowledge the information provided in this Application and Petition is true and correct.

Greg Bass
(Signature of Authorized Representative)

3.15.06
(Date)

Greg Bass
(Print Name of Authorized Representative)

Director
(Title)

SUBSCRIBED AND SWORN to before me this 15th day of March, 2006

Annamarie Buscemi
NOTARY PUBLIC

My Commission Expires June 18, 2008

ANNAMARIE BUSCEMI
Comm. # 1495389
NOTARY PUBLIC - CALIFORNIA
San Diego County
My Comm. Expires JUNE 18, 2008

Attachment A

List names, titles and ownership percentages of corporate officers

SEMPRA ENERGY SOLUTIONS
OFFICERS AS OF SEPTEMBER 7, 2005

Name	Title and Ownership Percentage	
Householder, Joseph A.	Director	0%
Schmale, Neal E.	Director	0%
Snell, Mark A.	Director	0%
Cantor, Christine	President	0%
Allman, Michael W.	Vice President and Chief Financial Officer	0%
McMonagle, Charles A.	Vice President and Treasurer	0%
Goddard, William B.	Vice President - Commodity Operations	0%
Thomas, Sheri L.	Vice President - Back Office Operations	0%
Wood, James M.	Vice President - Commodity Sales	0%
Lee, Catherine C.	Secretary	0%
Clark, Randall L.	Assistant Secretary	0%
Kent, Mara E.	Assistant Secretary	0%
Palmer, Terry F.	Assistant Treasurer	0%
Wapner, Beth L.	Assistant Treasurer	0%

Sempra Energy Solutions is 100% owned by Sempra Energy Global Enterprises which in turn is 100% owned by Sempra Energy, a Fortune 100 diversified utility listed on the New York Stock Exchange under the ticker symbol SRE.

Attachment B

Copy of Relevant Tax License

ARIZONA DEPARTMENT OF REVENUE
LICENSE & REGISTRATION SECTION
1600 WEST MONROE
PHOENIX, ARIZONA 85007-2650

MUST BE
DISPLAYED IN A
CONSPICUOUS PLACE

TRANSACTION PRIVILEGE TAX LICENSE

-NOT TRANSFERABLE-

THIS LICENSE IS ISSUED TO THE BUSINESS NAMED BELOW FOR THE ADDRESS SHOWN. LICENSES, BY LAW, MAY NOT BE TRANSFERRED FROM ONE PERSON TO ANOTHER NOR CAN THEY BE TRANSFERRED FROM ONE LOCATION TO ANOTHER. ARIZONA LAW REQUIRES LICENSEES TO NOTIFY THE DEPARTMENT OF REVENUE IF THERE IS A CHANGE IN BUSINESS NAME, TRADE NAME, LOCATION, MAILING ADDRESS OR OWNERSHIP. IN ADDITION, WHEN BUSINESS IS DISCONTINUED OR BUSINESS LOCATION CHANGES AND A NEW LICENSE IS ISSUED, THIS LICENSE MUST BE RETURNED TO THE ARIZONA DEPARTMENT OF REVENUE.

THE LICENSEE LISTED BELOW IS LICENSED TO CONDUCT BUSINESS UPON THE CONDITION THAT TAXES ARE PAID TO THE ARIZONA DEPARTMENT OF REVENUE AS ACCRUED UNDER PROVISIONS OF ARS TITLE 42, CHAPTER 8, ARTICLE 1.

ISSUED
TO

SEMPRA ENERGY SOLUTIONS INC
C/O TAX SERVICES
101 ASH ST HQ06B
SAN DIEGO, CA 92101-3017

07-625395-Y

ALL communications and Reports MUST REFER to this LICENSE NO.

15 BUSINESS CODE

11/01/00 EFFECTIVE DATE

---- (DBA) SEMPRA ENERGY SOLUTIONS INC
---- 4625 S. WEDNELER DR #111
TEMPE, AZ 85282

01/03/01 PRINT DATE

DOR 87026 (1/88)

ATTACHMENT C
COMPETITIVE ELECTRICITY TARIFF

Sempra Energy Solutions, Inc.
San Diego, CA

A.C.C. No. XXXXX
Tariff No. NRSES01
Effective: XXXX XX, 2006

NON-RESIDENTIAL TARIFF

DESCRIPTION

Under this Tariff, Sempra Energy Solutions ("Sempra") provides competitive retail electricity supply and other competitive energy services to NON-RESIDENTIAL customers eligible for direct access within the **Arizona Public Service Company, Salt River Project and Tucson Electric Power Company** service areas. Both single and aggregation accounts may receive service under this Tariff. Sempra is providing electricity as an Electric Service Provider ("ESP") as defined in A.A.C. R14-2-1601 (15).

Pursuant to this Tariff, Sempra will provide and sell competitive electricity supply and billing services. Sempra will also sell, but not physically provide, the meter services of A.C.C. certificated providers.

Sempra will serve as agent for customers in arranging and coordinating regulated services including electric delivery services. Sempra does not provide non-competitive electric delivery services.

Sempra intends to sell and provide to customers who take service under this Tariff other competitive energy services (including financing options) which are not regulated by the Commission. These energy services are not addressed in this Tariff.

THIS IS NOT A "PROVIDER OF LAST RESORT" TARIFF. Retail customers are not required to select Sempra. This Tariff is not available to residential customers. Sempra is not a utility distribution company. Sempra is not the same company as either Southern California Gas Company or San Diego Gas & Electric Company, its California based utility affiliates.

AVAILABILITY

Sempra makes electric energy and capacity available under this Tariff to non-residential retail customers who are eligible under the Commission's applicable rules. This Tariff is available only to customers within the service territory of **Arizona Public Service Company, Salt River Project and Tucson Electric Power Company** service areas at transmission and distribution voltage levels.

Sempra may refuse service to a customer for any of the following reasons: 1) The customer is not credit worthy; 2) The customer refuses to pay the price at which Sempra offers electricity supply; 3) Sempra is unwilling or incapable of providing the service requested by the customer at a price the customer is willing to pay; 4) The customer is located in a geographic area where Sempra is either not certificated to serve (or related agreements are not established) or the customer is not eligible to receive direct access services; 5) The customer refuses to sign a contract for service or refuses to accept offered prices, terms and conditions for electricity supply;

6) The customer is unwilling to wait for the period of time Sempra (or the UDC) deems is necessary to begin receiving service from Sempra; or 7) The customer does not have the proper electrical equipment infrastructure to receive electricity from Sempra.

Sempra shall not be deemed as having refused service to any potential customer if, in the opinion of such customer, Sempra did not respond to a sales inquiry or otherwise present or follow up on a specific sales contract proposal in a time frame desired by said customer. Sempra has the right to evaluate each and every potential customer opportunity and determine whether and in what time period to respond to such opportunity.

Sempra is not required to respond to any request for proposal issued by a potential customer seeking competitive bids from Energy Service Providers.

THIS TARIFF IS NOT AVAILABLE ON A PROVIDER OF LAST RESORT BASIS.

CHARGES

Sempra's monthly charges may include:

1. Electricity Supply: A market based energy charge, as negotiated, not to exceed, on an average monthly basis $6 per kilowatt-hour for a fixed energy price or as the adder to a variable index price, developed upon customer's historical load and historical load patterns. This not to exceed price excludes any negotiated, non-utility, pass-through charges (e.g. scheduling coordinator charges and fees, distribution and transmission losses, unaccounted for energy, network transmission, and transmission congestion). Services include energy and may include capacity. Electricity and demand charges shall likewise be established through negotiation (e.g., a demand charge). Energy supply prices may be a fixed price with negotiated pass-through costs or a variable index price with an adder and negotiated pass-through costs and will be set forth in the ELECTRICITY SALES AND PURCHASE AGREEMENT executed with the customer. Energy supply volumes, including whether the product is load following, will be set forth in the ELECTRICITY SALES AND PURCHASE AGREEMENT executed with the customer. All volumes of energy consumed in excess of the contract volumes will be passed through to the customer at the relevant imbalance prices. All volumes of energy not consumed

2. Competitive Transition Charge: If applicable, a charge, as approved by the Commission for the UDC of the customer passed through without mark-up by Sempra.

3. Fuel or purchased power: If applicable, a charge, as approved by the Commission for the UDC of the customer passed through without mark-up by Sempra.

4. Distribution Services: A charge, as approved by the Commission for the UDC of the customer, passed though by Sempra as agent without mark-up to the customer.

5. Transmission Services: A charge, as approved by the F.E.R.C. for the UDC of the customer, passed through Sempra as agent without mark-up to the customer.

6. Ancillary Services: A charge for transmission related services, as approved by the F.E.R.C. for the UDC of the customer, passed through by Sempra as agent without mark-up to the customer.

7. Metering Services: As provided by a Commission certificated meter service provider, a market based charge not to exceed the provider's maximum approved charge, passed through by Sempra without mark-up to the customer.

8. Meter Reading Service: As provided by a Commission certificated meter reading provider, a market based charge of the provider, not to exceed the provider's maximum approved charge, passed through by Sempra without further mark-up to the customer.

9. Billing and Collection: A market based charge included in the charge for electricity supply. Only specialized billing and collections services charges, if any, will be itemized on a customer's bill.

10. Systems Benefits: A charge, as approved by the Commission, and passed through by Sempra without mark-up to the customer.

11. Environmental Portfolio Surcharge: A charge, mandated by the Corporation Commission, and passed through by Sempra without mark-up to the customer.

12. Applicable taxes.

13. Such other charges as the Commission or the UDC may require which will be passed through by Sempra without mark-up.

14. Other charges for services provided by Sempra that are not subject to this Tariff.

All of the above charges will appear only when Sempra provides consolidated ESP billing. In the case of consolidated UDC billing, the UDC controls the entire billing format although it is also required by the Commission to provide identical billing components. For dual billing, Sempra bills will display items: 1, 7 , 8, 9, 12, and 13 (if appropriate). The UDC's bill would be expected to contain the remaining billing items.

Sempra has the right to express market based electricity supply prices in terms of discounts (percentage or otherwise) from bundled regulated services (i.e., Standard Offer Service) in contracts and monthly bills, or in any other manner or pricing structure. Sempra may include in the price for electricity supply the costs of any other energy services purchased by the customer pursuant to the contract between the customer and Sempra. Sempra shall be permitted to use any financing mechanisms (e.g., balanced payment) over the life of the contract that result in a customer's actual monthly charges in any month being different than the amount determined for the charges above pursuant to the contract.

Terms and conditions for all other items listed in this "CHARGES" section shall be as approved by the Commission for the individual UDC or certificated meter provider, as set forth in their filed tariffs for these services. Sempra and, in turn, customers shall comply with the Commission's Rules and UDC Open Access tariffs as regards loan profiling or meter specifications.

CONTRACT

Customer must execute a contract (i.e., ELECTRICITY SALES AND PURCHASE AGREEMENT) with Sempra. Contract duration, market-based prices, UDC name(s), UDC account number(s), customer address(es), and other terms and conditions of service to be negotiated by the parties must be stated in the contract.

MISCELLANEOUS

Sempra may seek to change, amend or revise this Tariff at any time upon application to the Commission. Any such amendments, changes, or revisions shall become effective only upon approval by the Commission, and shall be implemented by Sempra only prospectively. Such approved changes, amendments or revisions shall not operate to amend, modify, change or revise contracts entered into prior to the effective date of such approved changes, amendments or revisions of this Tariff.

ATTACHMENT E
Operations License Numbers

STATE/ENTITY	Electric License #	Gas License #
Arizona	Decision No. 61742	N/A
California	ESP #1364	N/A
Connecticut	Docket No. 03-07-07	N/A
Delaware	Order No. 6138	N/A
Department of Energy	EA-284	Order No. 1918 and FE Docket No. 03-69-NG
District of Columbia	ORDER NO. 13361 Docket EA04-8	N/A
Illinois	01-0673	N/A
Maine	Docket No. 2003-610	N/A
Maryland	IR-442	IR-464
Massachusetts	CS-038	N/A
Michigan	U-13361	N/A
Nevada	N/A	G-6
New Jersey	PESL0051	PGSL0059
New York	Letters of compliance	Letters of compliance
Ohio	01-052 (2)	N/A
Oregon	02-133	N/A
Pennsylvania	A-110141	A-125121
Texas	10017	N/A

ATTACHMENT K
BEFORE THE ARIZONA CORPORATION COMMISSION
OF THE STATE OF ARIZONA

Application for a Certificate of Convenience and Necessity for Competitive Retail Electric Services A.R.S. 40-281 and A.C.C. R14-2-202.

TESTIMONY OF GREG BASS ON BEHALF OF SEMPRA ENERGY SOLUTIONS

March 15, 2005

Q1: Please state your name and business address.

A1: My name is Greg Bass. I am Director of Retail Market Operations for Sempra Energy Solutions (SES), a retail energy service provider ("Supplier") serving retail end-use commercial and industrial customers throughout the United States of America and Mexico since 1999. My business address is 101 Ash St., HQ09, San Diego, California 92101.

Q2: Please summarize your professional background and experience.

A2: I have been in the energy business since 1991 and have been working for SES since 2000. For my first 10 years I worked for PacifiCorp in Portland, Oregon and Southern California Edison in Los Angeles, California. My professional background is in regulatory affairs. For SES I have primarily been involved in retail operations, retail licensing, and utility certification and set-up. My full resume is attached hereto as Exhibit GRB-1.

Q3: Briefly describe Sempra Energy Solutions

A3: Sempra Energy Solutions is a retail energy supplier that serves commercial and industrial end-use customers in 14 states, the District of Columbia and Baja California. Besides acting in the role of a competitive energy provider, SES was also selected by the Texas Public Utilities Commission to act as Provider of Last Resort in the AEP North service territory – which is a regulated energy service – for 2005 and 2006.

Q4: Have you previously testified before the Arizona Corporation Commission ("ACC")?

A4: No. However, I helped prepare and submit Sempra Energy Solutions first Application for a Certificate of Convenience and Necessity for Competitive Retail Electric Services – which was approved in Decision No. 65123 on August 23, 2002. I believe that the CC&N associated with that Decision is in effect and as such, SES has maintained our bond with the ACC and has dutifully and timely complied with all known reporting requirements.

Q5: If you believe that your CC&N is in effect, why do you come now before the Commission?

A5: Apparently, there is some doubt regarding the validity of CC&Ns issued in compliance with Arizona Revised Statutes Section 40-101 et.seq. and A.C.C. R14-2-1603. SES has a compelling business interest that requires a timely and speedy resolution to this issue. It appears as though the most expeditious method to resolve the validation issue is for SES to re-apply for another CC&N under A.R.S. 40-281 and AC R14-2-202. Re-issuance of the CC&N under a different section of the A.C.C. appears to achieve that business objective.

Q6: Do you believe SES has the technical expertise to establish itself as an operational retail supplier in Arizona?

A6: SES has successfully become operational behind more than 35 separate utility distribution companies ("UDC"), 5 regional transmission organizations ("RTO") as

well as a handful of individual utility open access transmission tariffs ("OATT"). SES has served annually upwards of 1,000 mega-watts ("MW") of retail load in California, over 500 MWs of retail load in Texas and hundreds of MWs of retail load throughout the Eastern markets (e.g. New Jersey, New York, Pennsylvania, Massachusetts, and Maryland). SES is also active in the mid-western states notably Illinois, Ohio and Michigan. SES is also the number one retail supplier (in terms of market share) in Oregon. SES commonly uses the dual billing option. Dual billing retains the UDC's billing arrangements with the customer and SES bills separately for our power charges. Once active in Arizona, SES will utilize the dual billing option. However, in Ohio SES uses utility-consolidated billing and in Texas SES consolidates the UDC's charges with ours and invoices the end-use customer for both (supplier-consolidated billing). The technical expertise required in order to be a successful nation-wide supplier is immense; SES has made the necessary hardware, software and personnel investments in order to achieve this status.

Q7: Would you please provide a description of the Applicant's computer capabilities to store and process large volumes of customer account data? Include a resource list, e.g., modem with dedicated telephone line and facsimile machine?

A7: SES has invested millions of dollars in state-of-the-art billing and storage systems. SES uses Excelergy to create billing invoices and LodeStar as the billing engine. Excelergy is used by a number of UDCs throughout the United

States. SES currently invoices over 12,000 meters per month. SES has multiple facsimile machines throughout the organization. SES's billing operations are ISO 9001 certified, the only competitive retail supplier to achieve this international recognition of quality processes.

Q8: Would you please provide a description of the Applicant's capabilities to exchange data with other market participants, i.e., Utility Distribution Company and Independent Scheduling Administrator?

A8: SES has two primary methods with which we exchange data with UDCs; in California we manage our own Electronic Data Interchange (EDI) translator and EDI maps with three trading partners (i.e. Southern California Edison, Pacific Gas and Electric, San Diego Gas & Electric). SES uses the Automated Power Exchange (APX) to facilitate power scheduling into the California Independent System Operator. Outside of California, SES uses an EDI vendor, Energy Services Group, to facilitate EDI exchange with over 30 separate UDCs. SES also uses the APX to facilitate power scheduling into ERCOT and PJM, however, SES directly schedules power into Portland General, PacifiCorp, New England Independent System Operator, and the Midwest Independent System Operator.

Q9: Please identify SES staff that will prepare the reports to the Commission required by the retail electric competition rules.

A9: SES received a CC&N from the ACC in 2002. Since that time, SES staff has diligently filed the necessary compliance reports and maintained the required

bond. This function has been under my direction in the past and will continue to do so in the future.

Q10: Please provide a description of the specific services that SES will offer, the customer classes to be served, the expected number customers in each class, and the average number of kWhs which the Applicant will market each month; also provide a description of the Applicant's technical ability to provide the services as described. Identify the Applicant's key technical and operational personnel including their names, titles, and length of experience in the sale, procurement, metering, and billing of energy services or similar products. If some entity other than the Applicant will provide the metering or billing for the Applicant, identify the company and describe its experience in providing these services.

A10: SES will offer power and related energy services at both a fixed price with pass-through costs and at a variable indexed price with pass through costs to commercial and industrial customers in the Arizona Public Service territory, the Salt River Project territory and the Tucson Electric territory exclusively. SES has no desire, nor any plans to serve customers outside those three UDC service areas. SES will procure the necessary power to fulfill the term of the customer agreement and will ensure that the power is scheduled to the necessary delivery point (s). SES will acquire, on a monthly basis, the meter reads, using an ACC-approved meter reading vendor, of our customers for billing and settlement purposes. SES will settle with both the UDC under the terms of their OATT for

wholesale deliveries (if applicable) and ancillary services and with the customer under the terms of their agreement with SES for the retail deliveries. SES plans to serve upwards of 100 MWs in each service territory. SES's technical abilities have been addressed earlier in my testimony, however as an appendix to this testimony (Appendix A), I have listed the names and addresses of key operational and sales personnel. SES has a portfolio of metering and meter reading vendors authorized to perform metering and meter reading services in other deregulated states, such as California. For example, SES has an on going business relationship for years with Applied Metering Technologies (AMT). AMT is a certified Meter Service Provider (MSP) in California. Certified MSPs are allowed to install, service, and program customer meters. AMT is also currently a metering services vendor for TEP, performing electrical contracting services on their behalf. SES also uses MeterSmart, a qualified Meter Data Management Agent (MDMA) in California. As a qualified MDMA, MeterSmart is the official meter reader, for revenue calculation purposes, for select customer meters. MDMAs read the meter within performance guidelines, perform VEE (validate, edit and estimate) anlaysis on the meter data and provide the reads to both the retail supplier and the UDC. SES intends to use these established business relationships in a partnership to move forward with obtaining CC&Ns for these vendors.

Q11: SES has filed a tariff, please discuss, in detail, the pricing provisions of this proposed tariff.

A11: SES offers two general pricing products for energy: Fixed volume of energy or a fixed volume of energy with a load following provision, either of these two aforementioned products can be purchased with either a fixed price with pass-through costs or a variable index price with an adder and pass-through costs. A popular index that customers elect in California, for example, are the Dow Jones NP-15 and SP-15 indices. SES will likely offer to Arizona customers the Dow Jones Palo Verde index. Either product, fixed volume or load following, also includes a monthly or hourly balancing provision, depending on how the customer wants to be settled. As an aside, SES has offered, from time-to-time, a full requirements product with a fixed price and no pass-through of additional costs, however such price certainty is usually too expensive and ultimately unacceptable to the customer. The fixed volume product, without load following provisions, is often sold with a fixed price for energy and a pass-through of all other costs. Because customer usage varies, this product is most often sold with an hourly balancing provision. This product is one of the oldest and most popular products SES offers. It affords customers the most competitive price obtainable for the fixed volume portion of their energy. However, from a price certainty aspect, it is also one of the riskiest products SES has available – with risk defined as price volatility. Prior to contract execution, SES analyzes the customer's historical load shape and recommends on and off peak monthly energy volumes. There are no premiums in the product price to account for a customer's variation in usage (swing). At any moment in time (most often calculated at an hourly interval) the customer will either be over consuming

energy versus the fixed block of energy purchased for that time period, under consuming the fixed block of energy or they will be consuming exactly the quantity purchased. If the customer under-consumes per the contract quantity, they receive a credit for the increment of energy under consumed at the underlying Open Access Transmission Tariff (OATT) rate in effect at that moment of under consumption, this is the balancing provision that our products offer. If they over-consume they pay for the energy in excess of their contracted quantity as per the underlying OATT rate in effect at that moment of over consumption. If the customer consumes exactly the contract quantity for the energy consumed, they pay only the contract price for the energy plus any pass-through costs (e.g. scheduling coordinator charges and fees, distribution and transmission losses, unaccounted for energy, network transmission, and transmission congestion). The pass-through costs associated with energy procurement may or may not be fixed at time of contract execution, of which I will further elaborate.

In my testimony, when I refer to energy, energy is but one component of the total electricity product. In addition to energy, SES can also offer to lock-in the price for other market-based or tariff-based aspects of power procurement or the customer can elect to have them passed through at no mark-up. These other items in addition to energy include, but are not limited to, ancillary services, RTO/OATT fees, scheduling charges, transmission congestion, and transmission and distribution losses. If the customer elects to lock-in these costs at time of

contract execution, rather than risk paying these costs as they are incurred as a pass-through, the fixed price of the energy block will also increase. Essentially, what is occurring is that SES is assuming the price risk associated with the potential volatility in price of these services required to purchase and deliver energy, as that risk is assumed by SES, the price SES charges for the product and associated price certainty for that product may cause the energy price to rise accordingly.

Another product that SES offers that enjoys high demand from our customers is a load following product. This product also has monthly on and off peak volumes associated with it, however, the customer can elect to "swing" their load (either monthly or hourly) within a predefined percentage band around their monthly on and off peak contractual volumes. In other words, the balancing provisions described above do not apply as long as the customer's usage is within the band, both high and low This banded product offers the customer greater usage flexibility along with increased price certainty, again, as long as they keep their electricity usage within the band. For usage outside the band, the balancing provisions and associated credits or debits apply accordingly.

Q12: Why are SES's proposed market-based prices reasonable?

A11: SES's market-based prices are reasonable in that SES does not intentionally sell power to end-use customers at a loss nor can SES charge more than the maximum price listed in the proposed tariff. Essentially, SES has a floor and

ceiling price set by market and regulatory conditions. There have been innumerable instances in which SES has walked away from either a market or a customer because the highest price SES can charge is below SES' floor price (procurement cost) and sales at that price would have created a loss. SES's procurement costs change every hour of every day and are driven by market conditions. Factors that drive market conditions, for example, are the price of natural gas, the demand for energy, transmission constraints, weather forecasts, and hydro availability. Often a competitor with a different cost and business structure creates this situation, wholesale prices that systematically move higher over a period of time will also, but more recently regulatory lag is creating this situation.

SES has proposed, in Attachment C, $6 per kWh per month as the highest energy price that SES would offer to customers. This price does not include any pass-through costs and is approximately the tariff rate that the UDCs in Arizona currently have as their rate for generation service. Ultimately it is the customer, using the vehicle of economic freedom that determines the reasonableness of the prices offered. With $6 per kWh being slightly higher than the price that the UDCs offer for a fully-bundled, no pass-through, 100% load following product to their largest C&I customers, SES does not expect to close any sales at the ceiling price. The customer's ability to choose between a regulated rate offered by the utility, which is defined as a reasonable rate by the determination of the ACC, versus a myriad of negotiated and freely accepted pricing terms, quantities, prices and conditions with a retail supplier defines freedom of choice and hence

reasonableness. In every market SES sells electricity to end-use customers, SES has to meet or beat either a state-approved default rate or a liquid, visible wholesale price. Price competition ensures that the customer, at the time of contracting, is obtaining as reasonably priced a product as is appropriate for their individual risk appetite and due diligence. In addition, from a policy standpoint, states that allow for a market-based energy retail sector are, in the long run, affording the price protections associated with competition to their entire constituency.

Q13: What are SES's sources of wholesale power and levels of profitability?

A13: SES is not in the merchant generation business. Sempra Energy, SES's parent company, has a separate non-regulated affiliate that invests in the development, construction, and on going ownership of generation facilities throughout the United States. With that in mind, SES's business model includes the schedule and dispatch of a number of merchant generation facilities in Texas and California on behalf of their owners. SES is an active participant in the wholesale energy trading markets throughout the United States, buying blocks of power for delivery to our retail load directly from merchant generators, wholesale brokers and energy trading shops. In the normal course of business, SES is a net purchaser of power, our business model incorporates backing our retail portfolio of energy contracts (sales to end-use customers) with a corresponding volume of wholesale energy (purchases from wholesale energy suppliers).

SES has experienced many different levels of profitability over the years depending primarily on market conditions, regulatory lag and competitive pressures. These ever changing factors influence the business strategy, forcing SES to realign sales resources and target markets in response.

Q14: Does that conclude your testimony?

A14: Yes.

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Greg Bass

8595-F Via Mallorca, La Jolla, CA
(858) 638-1514 • thebasses@earthlink.net

PROFESSIONAL SUMMARY

Corporate Director with transaction, regulatory and business management experience, including business development and advising executive management on issues affecting business operations and strategic direction. Background includes:

- Regulatory and legislative strategy and compliance
- Contract creation, negotiation and management
- Representation of legal and business interests
- Regulatory negotiation
- Business plan creation, analysis and implementation
- Headroom and customer savings analysis
- Analysis of regulatory proceedings, filings and cases
- Intervention and creation of testimony

EXPERIENCE

Sempra Energy Solutions, San Diego, California, 2000 – current

Director, Retail Market Operations, 2004 – current

- Business Development - Research, plan, develop, and direct the implementation of Solutions' Commodity Operations throughout the United States using industry best practices and risk management guidelines. Identify roadblocks and commit the organization to deadlines and drive commitments to a timely conclusion so that commodity deals are executed and transacted upon with best-of-class customer service. Engage and manage outside counsel to represent corporate interests in multiple jurisdictions.
- Resource Management - Create systems and processes that actively monitor and interact with a complex portfolio of customers, meters, state regulatory bodies, state laws, trading partners and vendors in order to effectively compete and bring value-added products to the marketplace. Identify, prioritize and implement different levels of operational capabilities in order to meet delivery commitments, all with limited resources, competitive pressures and performance risk.
- Leadership and Team Building - Direct, educate, train, empower, and lead operations management and staff to independently handle the multiple decisions and risk management implications of on going growth in the business. In addition, evaluate and communicate marketplace regulatory and rule changes, evaluate their impacts to operations including, but not limited to, procurement, deal structures, scheduling, settlement, and billing. Formulate and develop regulatory responses to regulatory policy changes (e.g. intervene, write and file testimony).
- Business and Process Improvement - Continually review and develop processes to improve productivity that included obtaining ISO 9001 Certification for Commodity Operations. Search out and successfully implement new forms of technology to improve productivity and scalability of business operations and process efficiencies. Train and direct a team of analysts to perform headroom and customer savings analysis. Educate customers on service options and regulatory changes that affect their energy purchases.

Achievements:

- Successfully filed a complaint at FERC regarding PacifiCorp's OATT – saving Solutions over $750,000.
- Negotiated retail sale agreements with large power plants in Texas, creating a reoccurring $250,000 a year in margin.
- Identified Oregon as a business opportunity, participated in the regulatory construct, organized Solutions to act with urgency resulting in over 125 MW of retail load with over $1.5 million in margin per year.
- Negotiated a settlement with Detroit Edison to resolve an on going FERC dispute regarding provisions of their OATT. Saved Solutions over $500,000.
- Entrusted with multiple responsibilities including structuring deals, negotiating contracts and terms of agreement, drafting detailed testimony and ensuring compliance with federal and state laws to maintain Solutions' power and gas licenses.

Manager, Customer Activation, 2000 – 2004

- Managed the portfolio of 12,000 power and gas customers ensuring that operational requirements and the integrity of the information is complete, timely and accurate for billing purposes.
- Trained and directed Portfolio Analysts towards flawless execution.
- Created, developed, and maintained robust and efficient enrollment and customer set-up processes and systems and ensured that these processes and systems were in compliance with industry best practices.
- Created, developed, reviewed, and maintained a system of internal controls surrounding the set-up and activation processes.
- Managed the on going trading partner and vendor relationships required to be a retail power and gas provider.
- Resolved specific customer level inconsistencies, as they arose, by developing and maintaining key operational relationships both internally and externally.
- Worked effectively as part of a team and worked independently to successfully resolve on going exceptions.

Achievements:

- Developed and successfully implemented an ISO 9001 compliant retail supplier mid-office that facilitated over $350 million in margin.
- Negotiated ISDA, NASB and EEI wholesale supply and multiple vendor contracts, agreements and other enabling documents.
- Awarded the Sempra Energy Chairman's Award in 2003 for business growth and achievement.

Southern California Edison (SCE), Los Angeles, California, 1997 – 2000

Account Manager III

- Managed the Electric Service Provider (ESP) relationship with SCE and acted as primary contact for NewEnergy, New West Energy, Enron Energy Services, and Sempra Energy Solutions.
- Communicated SCE's policies and procedures as they affected ESPs and the deregulated retail electric marketplace.
- Obtained timely resolution of operational and policy issues in order to maintain high-levels of ESP satisfaction.
- Reviewed, analyzed, proposed and debated operational policies and procedures for national retail electric Uniform Business Practices developed at the Edison Electric Institute's consensus workshops.

PacifiCorp, Portland, Oregon, 1991 – 1997

Senior Pricing Analyst, 1995 – 1997

Pricing Analyst, 1992 – 1995

Assistant Pricing Analyst, 1991 – 1992

EDUCATION

Master of Business Administration, Finance, 1990, University of San Diego

Bachelor of Arts, Economics, 1987, San Diego State University

Appendix A to Attachment K

JIM WOOD

VICE-PRESIDENT, COMMODITY SALES
SEMPRA ENERGY SOLUTIONS

Mr. Wood has over 15 years of experience in the energy service business. His career in energy includes various positions at companies including Enron Corporation, CMS Energy, and presently Sempra Energy. During his time at Enron, Mr. Wood held roles such as Manager of District Sales/Purchases, Director of Regional Sales, Senior Director – Consulting Services and Senior Director – Product, Market Management/Development, and President of Clinton Energy Management (a wholly-owned subsidiary of Enron Energy Services). He was also previously the Managing Director of Retail Commodity, Marketing, Services, and Trading at CMS Energy before coming aboard Sempra Energy. Currently, Mr. Wood serves as the Vice-President of Commodity Sales for Sempra Energy Solutions.

EDUCATION:

- **Bachelor of Science – Miami University (Oxford, Ohio)**

BILL GODDARD

VICE-PRESIDENT, OPERATIONS
SEMPRA ENERGY SOLUTIONS

Mr. Goddard has over 25 years experience in the electric utility business. He has held various positions at San Diego Gas & Electric with increasing levels of responsibility such as Resource Scheduler, Power Dispatcher, Operations Shift Supervisor, Transaction Scheduling Supervisor, Acting Manager of Grid Control and Transaction Scheduling and Generation Operations Manager.

His responsibilities included planning daily generation and purchasing power to meet daily and weekly load forecasts; system transmission, generation and interchange dispatch; developing training and procedures for Grid Control operations, being a member of the California ISO and California PX systems implementation and protocols start-up committees; and bidding and scheduling of SDGE demand and supply resources into California PX and ISO.

Currently, the Vice-President of Operations for Sempra Energy Solutions, Mr. Goddard is in charge of existing power operations throughout the United States including California, Delaware, Illinois, Maryland, Massachusetts, Michigan, Maine, New Jersey, New York, Ohio, Oregon, Pennsylvania, Texas, Washington D.C.

EDUCATION:

- **B.A., Psychology, University of California, San Diego**

GREG BASS

DIRECTOR, RETAIL MARKET OPERATIONS
SEMPRA ENERGY SOLUTIONS

Mr. Bass has 15 years experience in the energy delivery business. His knowledge of the energy business is drawn from his direct experience with Direct Access operations in California, metering operations, meter data acquisition and system implementation, Direct Access customer enrollments, project management, demand-side management program development, power procurement, contract administration, and customer service.

For the past 5-years, Mr. Bass was instrumental in building the operations and nation-wide reach of Sempra Energy Solutions (SES). This included obtaining more than a dozen state retail power licenses, import and export permits for power and natural gas, and obtaining certification behind more than 30 utility distribution companies. Prior to his work at SES, his most recent experience was obtained while working for Southern California Edison's ESP Services Division as an account manager for such notable ESPs as Arizona Public Service Energy Services, Enron Energy Services, New West Energy, AES/New Energy and other predominant California retail power providers. His knowledge and experience is also derived from his past work in the regulatory arena for both PacifiCorp and Southern California Edison.

EDUCATION:

- **MBA, University of San Diego, San Diego**
- **B.A., Economics, San Diego State University, San Diego**

DRAKE WELCH

MANAGER, CUSTOMER BILLING
SEMPRA ENERGY SOLUTIONS

Mr. Welch has over 6 years of utility billing experience, which includes utility invoicing, consolidated billing services and ESP invoicing. Most recently, Mr. Welch oversaw the implementation of supplier consolidated billing for several customers in the State of California.

His most recent experience was obtained while working for Sempra Energy Information Solutions and San Diego Gas & Electric where he resolved commodity billing issues, performed statistical exception research and resolution, reconciled major accounts and performed rate, usage, and cost analysis reporting.

Currently the Manager of Billing Services for Sempra Energy Solutions, Mr. Welch is in charge of existing commodity billing in all regions. His responsibilities included set up process, procedures and controls for all commodity invoicing.

EDUCATION:

- **Bachelor of Arts, Business Economics – University of California, Los Angeles**

Attachment Q

Audited Financial Information for the Most Recent Two Years

ATTACHMENT S
CUSTOMER PROTECTION

The name, address, and telephone number of the Applicant's customer complaint contact person:

Gayle McCutchin, Regional Vice President
101 Ash Street, HQ09
San Diego, CA 92101-3017
877-2SEMPRA
(619) 696-3103 (fax)
Email: email@semprasolutions.com
Web page: www.semprasolutions.com

An explanation of the Applicant's plan to ensure that the electric service provided to its customers will not be interrupted in the event that the Applicant fails to provide the competitive services set forth in its application:

In the 5-years that SES has been in the retail power business, serving well over tens-of-thousands of customers, SES has not created an interruption event due to failure of any kind. SES customers have experienced power interruptions, unfortunately, due to force majure events as well as UDC maintenance issues.

ATTACHMENT T

LISTING OF NAME AND ADDRESSES OF AFFECTED UTILITIES, UTILITY DISTRIBUTION COMPANIES, OR ELECTRIC UTILITIES NOT SUBJECT TO THE JURISDICTION OF THE ARIZONA CORPORATION COMMISSION

Mark W. Hackney
Arizona Public Service
PO Box 53933 Sta. 3200
Phoenix, AZ 85072-3933
Tel. (602) 250-1128
Mark.Hackney@aps.com

Wendy D. Weathers
Salt River Project
1521 N. Project Drive
Tempe, AZ 85281-1298
Tel. (602) 236-4376
wdweathe@srpnet.com

Raquel Aguilar
Tucson Electric Power
P.O. Box 711
Tucson, AZ 85702
Tel. (520) 745-7193
raqaguilar@tep.com

Sempra Energy
Solutions℠

Sempra Energy Annual Financial Report
and
Supplemental Consolidating Information
(Sempra Energy Solutions and Its Other Subsidiaries)

December 31, 2004

Sempra Energy Solutions is not the same company as the utility, SDG&E or SoCalGas, and the California Public Utilities Commission does not regulate the terms of Sempra Energy Solutions' products and services.

Sempra Energy Annual Financial Report
and
Supplemental Consolidating Information
(Sempra Energy Solutions and Its Other Subsidiaries)

December 31, 2004

Sempra Energy Annual Financial Report and Supplemental Consolidating Information (Sempra Energy Solutions and Its Other Subsidiaries)

Table of Contents

	Page
Independent Auditors' Report	1
Annual Financial Report	
Statements of Consolidated Income	2
Consolidated Balance Sheets	3-4
Statements of Consolidated Cash Flows	5-6
Statements of Consolidated Changes in Stockholders' Equity	7
Notes to Consolidated Financial Statements	8-77
Supplemental Consolidating Information (Sempra Energy Solutions and Its Other Subsidiaries)	
Supplemental Consolidating Balance Sheet Information	78
Supplemental Consolidating Statement of Income Information	79
Supplemental Consolidating Statement of Cash Flows Information	80

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors and Shareholders of Sempra Energy:

We have audited the accompanying consolidated balance sheets of Sempra Energy and subsidiaries (the "Company") as of December 31, 2004 and 2003, and the related consolidated statements of income, shareholders' equity, and cash flows for each of the three years in the period ended December 31, 2004. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements based on our audits.

We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, such consolidated financial statements present fairly, in all material respects, the financial position of Sempra Energy and subsidiaries as of December 31, 2004 and 2003, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2004, in conformity with accounting principles generally accepted in the United States of America.

As described in Note 1 to the financial statements, the Company adopted Statement of Financial Accounting Standards No. 143, *Accounting for Asset Retirement Obligations*, effective January 1, 2003, and Financial Accounting Standards Board Interpretation No. 46, *Consolidation of Variable Interest Entities – an Interpretation of ARB No. 51*, effective December 31, 2003.

Our audits were conducted for the purpose of forming an opinion on the basic consolidated financial statements taken as a whole. The supplemental consolidating information for 2004 on pages 78 through 80 is presented for the purpose of additional analysis of the basic consolidated financial statements rather than to present the financial position, results of operations, and cash flows of the individual companies, and is not a required part of the basic consolidated financial statements. This supplemental consolidating information is the responsibility of the Company's management. Such information has been subjected to the auditing procedures applied in our audit of the basic 2004 consolidated financial statements and, in our opinion, is fairly stated in all material respects when considered in relation to the basic 2004 consolidated financial statements taken as a whole.

We have also audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the effectiveness of the Company's internal control over financial reporting as of December 31, 2004, based on he criteria established in *Internal Control—Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission and our report (not presented herein) dated February 22, 2005 expressed an unqualified opinion on management's assessment of the effectiveness of the Company's internal control over financial reporting and an unqualified opinion on the effectiveness of the Company's internal control over financial reporting.

Deloitte & Touche LLP

February 22, 2005
San Diego, California

SEMPRA ENERGY
STATEMENTS OF CONSOLIDATED INCOME

(Dollars in millions, except per share amounts)	Years ended December 31, 2004	2003	2002
OPERATING REVENUES			
California utilities:			
Natural gas	**$ 4,537**	$ 4,010	$ 3,263
Electric	**1,658**	1,787	1,282
Other	**3,215**	2,090	1,503
Total operating revenues	**9,410**	7,887	6,048
OPERATING EXPENSES			
California utilities:			
Cost of natural gas	**2,593**	2,071	1,381
Cost of electric fuel and purchased power	**576**	541	297
Other cost of sales	**1,741**	1,204	709
Other operating expenses	**2,371**	2,287	1,901
Depreciation and amortization	**621**	615	596
Franchise fees and other taxes	**236**	230	177
Total operating expenses	**8,138**	6,948	5,061
Operating income	**1,272**	939	987
Other income, net	**104**	26	15
Interest income	**69**	104	42
Interest expense	**(322)**	(308)	(294)
Preferred dividends of subsidiaries	**(10)**	(10)	(11)
Trust preferred distributions by subsidiary	**—**	(9)	(18)
Income from continuing operations before income taxes	**1,113**	742	721
Income tax expense	**193**	47	146
Income from continuing operations	**920**	695	575
Loss from discontinued operations, net of tax (Note 4)	**(23)**	—	—
Loss on disposal of discontinued operations, net of tax (Note 4)	**(2)**	—	—
Income before extraordinary item and cumulative effect of changes in accounting principles	**895**	695	575
Extraordinary item, net of tax (Note 1)	**—**	—	16
Income before cumulative effect of changes in accounting principles	**895**	695	591
Cumulative effect of changes in accounting principles, net of tax (Note 1)	**—**	(46)	—
Net income	**$ 895**	$ 649	$ 591
Basic earnings per share:			
Income from continuing operations	**$ 4.03**	$ 3.29	$ 2.80
Discontinued operations, net of tax	**(0.11)**	—	—
Extraordinary item, net of tax	**—**	—	0.08
Cumulative effect of changes in accounting principles, net of tax	**—**	(0.22)	—
Net income	**$ 3.92**	$ 3.07	$ 2.88
Weighted-average number of shares outstanding (thousands)	**228,271**	211,740	205,003
Diluted earnings per share:			
Income from continuing operations	**$ 3.93**	$ 3.24	$ 2.79
Discontinued operations, net of tax	**(0.10)**	—	—
Extraordinary item, net of tax	**—**	—	0.08
Cumulative effect of changes in accounting principles, net of tax	**—**	(0.21)	—
Net income	**$ 3.83**	$ 3.03	$ 2.87
Weighted-average number of shares outstanding (thousands)	**233,852**	214,482	206,062
Dividends declared per share of common stock	**$ 1.00**	$ 1.00	$ 1.00

See notes to Consolidated Financial Statements.

SEMPRA ENERGY
CONSOLIDATED BALANCE SHEETS

(Dollars in millions)	December 31, 2004	December 31, 2003
ASSETS		
Current assets:		
Cash and cash equivalents	$ 419	$ 409
Short-term investments	15	386
Trade accounts receivable, net	950	749
Other accounts and notes receivable, net	82	125
Due from unconsolidated affiliate	4	—
Deferred income taxes	15	—
Interest receivable	80	62
Trading-related receivables and deposits, net	2,606	2,350
Derivative trading instruments	2,339	1,607
Commodities owned	1,547	1,420
Regulatory assets arising from fixed-price contracts and other derivatives	152	144
Other regulatory assets	103	89
Inventories	172	147
Other	222	158
Current assets of continuing operations	8,706	7,646
Current assets of discontinued operations	70	220
Total current assets	8,776	7,866
Investments and other assets:		
Due from unconsolidated affiliates	42	55
Regulatory assets arising from fixed-price contracts and other derivatives	500	650
Other regulatory assets	619	552
Nuclear decommissioning trusts	612	570
Investments	1,164	1,112
Sundry	844	707
Total investments and other assets	3,781	3,646
Property, plant and equipment:		
Property, plant and equipment	16,203	15,319
Less accumulated depreciation and amortization	(5,117)	(4,843)
Property, plant and equipment, net	11,086	10,476
Total assets	$23,643	$21,988

See notes to Consolidated Financial Statements.

SEMPRA ENERGY
CONSOLIDATED BALANCE SHEETS

(Dollars in millions)	December 31, 2004	December 31, 2003
LIABILITIES AND SHAREHOLDERS' EQUITY		
Current liabilities:		
Short-term debt	$ 405	$ 28
Accounts payable — trade	1,020	725
Accounts payable — other	106	63
Due to unconsolidated affiliates	205	1
Income taxes payable	187	336
Deferred income taxes	—	31
Trading-related payables	3,182	2,255
Derivative trading instruments sold, not yet purchased	1,484	1,340
Commodities sold with agreement to repurchase	513	922
Dividends and interest payable	123	136
Regulatory balancing accounts, net	509	424
Fixed-price contracts and other derivatives	157	148
Current portion of long-term debt	398	1,433
Other	776	675
Current liabilities of continuing operations	9,065	8,517
Current liabilities of discontinued operations	17	52
Total current liabilities	9,082	8,569
Long-term debt	4,192	3,841
Deferred credits and other liabilities:		
Due to unconsolidated affiliates	162	362
Customer advances for construction	97	89
Postretirement benefits other than pensions	129	131
Deferred income taxes	420	368
Deferred investment tax credits	78	84
Regulatory liabilities arising from cost of removal obligations	2,359	2,238
Regulatory liabilities arising from asset retirement obligations	333	303
Other regulatory liabilities	67	109
Fixed-price contracts and other derivatives	500	680
Asset retirement obligations	326	313
Deferred credits and other	854	832
Total deferred credits and other liabilities	5,325	5,509
Preferred stock of subsidiaries	179	179
Commitments and contingencies (Note 16)		
SHAREHOLDERS' EQUITY		
Preferred stock (50 million shares authorized; none issued)	—	—
Common stock (750 million shares authorized; 234 million and 227 million shares outstanding at December 31, 2004 and 2003, respectively)	2,301	2,028
Retained earnings	2,961	2,298
Deferred compensation relating to ESOP	(32)	(35)
Accumulated other comprehensive income (loss)	(365)	(401)
Total shareholders' equity	4,865	3,890
Total liabilities and shareholders' equity	$23,643	$21,988

See notes to Consolidated Financial Statements.

SEMPRA ENERGY
STATEMENTS OF CONSOLIDATED CASH FLOWS

(Dollars in millions)	Years ended December 31, 2004	2003	2002
CASH FLOWS FROM OPERATING ACTIVITIES			
Net income	**$ 895**	$ 649	$ 591
Adjustments to reconcile net income to net cash provided by operating activities:			
Discontinued operations, net of tax	**25**	—	—
Depreciation and amortization	**621**	615	596
Deferred income taxes and investment tax credits	**13**	(118)	(143)
Non-cash rate reduction bond expense	**75**	68	82
Equity in (income) losses of unconsolidated affiliates	**(36)**	(8)	55
Impairment losses	**12**	101	—
Loss (gain) on sale and disposition of assets	**(15)**	8	14
Foreign currency loss (gain)	**—**	8	(63)
Extraordinary item, net of tax	**—**	—	(16)
Cumulative effect of changes in accounting principles, net of tax	**—**	46	—
Other, net	**37**	23	(2)
Net changes in other working capital components	**(427)**	(154)	203
Changes in other assets	**(200)**	(71)	84
Changes in other liabilities	**(21)**	(26)	40
Net cash provided by continuing operations	**979**	1,141	1,441
Net cash used in discontinued operations	**(30)**	—	—
Net cash provided by operating activities	**949**	1,141	1,441
CASH FLOWS FROM INVESTING ACTIVITIES			
Expenditures for property, plant and equipment	**(1,083)**	(1,049)	(1,214)
Investments in and acquisitions of subsidiaries, net of cash acquired	**(74)**	(202)	(429)
Proceeds from disposal of discontinued operations	**157**	—	—
Proceeds from sale of assets	**372**	29	—
Dividends received from unconsolidated affiliates	**59**	72	11
Affiliate loans	**—**	(99)	(82)
Other, net	**10**	1	(9)
Net cash used in investing activities	**(559)**	(1,248)	(1,723)
CASH FLOWS FROM FINANCING ACTIVITIES			
Common dividends paid	**(195)**	(182)	(201)
Issuances of common stock	**110**	505	9
Repurchases of common stock	**(5)**	(7)	(17)
Issuances of long-term debt	**997**	900	1,150
Payments on long-term debt	**(1,670)**	(601)	(479)
Increase (decrease) in short-term debt, net	**397**	(518)	(307)
Other, net	**(14)**	(8)	(18)
Net cash (used in) provided by financing activities	**(380)**	89	137
Increase (decrease) in cash and cash equivalents	**10**	(18)	(145)
Cash and cash equivalents, January 1	**409**	427	572
Cash and cash equivalents, December 31	**$ 419**	$ 409	$ 427

See notes to Consolidated Financial Statements.

	Years ended December 31,		
	2004	2003	2002
CHANGES IN OTHER WORKING CAPITAL COMPONENTS			
(Excluding cash and cash equivalents, and debt due within one year)			
Accounts and notes receivable	**$(346)**	$(231)	$ (121)
Net trading assets	**(442)**	81	66
Income taxes, net	**(66)**	72	137
Inventories	**(25)**	(13)	(11)
Regulatory balancing accounts	**79**	(156)	170
Regulatory assets and liabilities	**(23)**	(30)	1
Other current assets	**(31)**	(8)	51
Accounts payable	**324**	98	(103)
Other current liabilities	**103**	33	13
Net changes in other working capital components	**$(427)**	$(154)	$ 203
SUPPLEMENTAL DISCLOSURE OF CASH FLOW INFORMATION			
Interest payments, net of amounts capitalized	**$ 318**	$ 296	$ 279
Income tax payments, net of refunds	**$ 254**	$ 118	$ 140
SUPPLEMENTAL SCHEDULE OF NON-CASH INVESTING AND FINANCING ACTIVITIES			
Common dividends paid in stock	**$ 35**	$ 25	$ 4
Acquisition of subsidiaries:			
Assets acquired	**$ —**	$ —	$1,134
Cash paid, net of cash acquired	**—**	—	(119)
Liabilities assumed	**$ —**	$ —	$1,015
Consolidation of variable interest entities:			
Assets recorded	**$ —**	$ 820	$ —
Liabilities recorded	**—**	(881)	—
Total	**$ —**	$ (61)	$ —

See notes to Consolidated Financial Statements.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

NOTE 1. SIGNIFICANT ACCOUNTING POLICIES

Principles of Consolidation

The Consolidated Financial Statements include the accounts of Sempra Energy (the company), its majority-owned subsidiaries and the variable-interest entities of which it is the primary beneficiary (as discussed further in New Accounting Standards below). Investments in affiliated companies over which Sempra Energy has the ability to exercise significant influence, but not control, are accounted for using the equity method. Further discussion of investments in unconsolidated subsidiaries is provided in Note 3. All material intercompany accounts and transactions have been eliminated.

During the fourth quarter of 2004, Sempra Commodities assumed the management of the commodities business of Sempra Energy Solutions, and Sempra Generation assumed the management of Sempra Energy Solutions' other two business lines — energy services and facilities management. Since Sempra Commodities and Sempra Generation are each separate reportable segments of the company, in accordance with Statement of Financial Accounting Standards (SFAS) 131, *Disclosures about Segments of an Enterprise and Related Information*, the prior years' financial statements have been restated to reflect the change in reporting of Sempra Energy Solutions' results of operation and financial position.

Quasi-Reorganization

In 1993, Pacific Enterprises (PE) effected a quasi-reorganization for financial reporting purposes as of December 31, 1992. Certain of the liabilities established in connection with the quasi-reorganization were favorably resolved in 2003 and 2004, resulting in adjustments to common stock in these years. The remaining liabilities will be resolved in future years and management believes the provisions established for these matters are adequate.

Use of Estimates in the Preparation of the Financial Statements

The preparation of financial statements in conformity with generally accepted accounting principles requires management to make estimates and assumptions that affect the reported amounts of revenues and expenses during the reporting period, and the reported amounts of assets and liabilities and the disclosure of contingent assets and liabilities at the date of the financial statements. Actual amounts can differ significantly from those estimates.

Basis of Presentation

Certain prior-year amounts have been reclassified to conform to the current year's presentation.

Regulatory Matters

Effects of Regulation

The accounting policies of the company's principal utility subsidiaries, San Diego Gas & Electric (SDG&E) and Southern California Gas Company (SoCalGas) (collectively, the California Utilities), conform with generally accepted accounting principles for regulated enterprises and reflect the policies of the California Public Utilities Commission (CPUC) and the Federal Energy Regulatory Commission (FERC).

The California Utilities prepare their financial statements in accordance with the provisions of SFAS 71, *Accounting for the Effects of Certain Types of Regulation*, under which a regulated utility records a regulatory asset if it is probable that, through the ratemaking process, the utility will recover that asset from customers. To the extent that recovery is no longer probable as a result of changes in regulation or the utility's competitive position, the related regulatory assets would be written off. In addition, SFAS 144, *Accounting for the Impairment or Disposal of Long-Lived Assets*, requires that a loss be recognized whenever a regulator excludes all or part of utility plant or regulatory assets from ratebase.

SEMPRA ENERGY
STATEMENTS OF CONSOLIDATED CHANGES IN SHAREHOLDERS' EQUITY
Years ended December 31, 2004, 2003 and 2002

(Dollars in millions)	Comprehensive Income	Common Stock	Retained Earnings	Deferred Compensation Relating to ESOP	Accumulated Other Comprehensive Income (Loss)	Total Shareholders' Equity
Balance at December 31, 2001		$1,495	$1,475	$(36)	$(242)	$2,692
Net income	$ 591		591			591
Comprehensive income adjustments:						
Foreign currency translation losses (Note 1)	(162)				(162)	(162)
Pension	(35)				(35)	(35)
Comprehensive income	$ 394					
Common stock dividends declared			(205)			(205)
Issuance of equity units (Note 13)		(61)				(61)
Issuance of common stock		18				18
Repurchase of common stock		(16)				(16)
Common stock released from ESOP				3		3
Balance at December 31, 2002		1,436	1,861	(33)	(439)	2,825
Net income	$ 649		649			649
Comprehensive income adjustments:						
Foreign currency translation gains (Note 1)	57				57	57
Pension	(16)				(16)	(16)
SFAS 133	(3)				(3)	(3)
Comprehensive income	$ 687					
Common stock dividends declared			(212)			(212)
Equity units adjustment		6				6
Quasi-reorganization adjustment (Note 1)		19				19
Issuance of common stock		553				553
Tax benefit related to employee stock options		13				13
Repurchase of common stock		(6)				(6)
Common stock released from ESOP		7		(2)		5
Balance at December 31, 2003		2,028	2,298	(35)	(401)	3,890
Net income	**$ 895**		**895**			**895**
Comprehensive income adjustments:						
Foreign currency translation gains (Note 1)	**40**				**40**	**40**
Pension	**28**				**28**	**28**
Available-for-sale securities	**4**				**4**	**4**
SFAS 133	**(36)**				**(36)**	**(36)**
Comprehensive income	**$ 931**					
Common stock dividends declared			**(232)**			**(232)**
Quasi-reorganization adjustment (Note 1)		**86**				**86**
Issuance of common stock		**172**				**172**
Tax benefit related to employee stock options		**16**				**16**
Repurchase of common stock		**(5)**				**(5)**
Common stock released from ESOP		**4**		**3**		**7**
Balance at December 31, 2004		**$2,301**	**$2,961**	**$(32)**	**$(365)**	**$4,865**

See notes to Consolidated Financial Statements.

Regulatory liabilities represent reductions in future rates for amounts due to customers. Information concerning regulatory assets and liabilities is provided below in "Revenues," "Regulatory Balancing Accounts" and "Regulatory Assets and Liabilities."

Regulatory Balancing Accounts

The amounts included in regulatory balancing accounts at December 31, 2004, represent net payables (payables net of receivables) of $178 million and $331 million for SoCalGas and SDG&E, respectively. The corresponding amounts at December 31, 2003 were net payables of $86 million and $338 million, respectively.

Except for certain costs subject to balancing account treatment, fluctuations in most operating and maintenance accounts affect utility earnings. Balancing accounts provide a mechanism for charging utility customers the amount actually incurred for certain costs, primarily commodity costs. The CPUC has also approved balancing account treatment for variances between forecast and actual for SoCalGas' and SDG&E's commodity costs and volumes, eliminating the impact on earnings from any throughput and revenue variances from adopted forecast levels. Additional information on regulatory matters is included in Notes 14 and 15.

Regulatory Assets and Liabilities

In accordance with the accounting principles of SFAS 71, the company records regulatory assets and regulatory liabilities as discussed above.

Regulatory assets (liabilities) as of December 31 relate to the following matters:

(Dollars in millions)	**2004**	2003
SDG&E		
Fixed-price contracts and other derivatives	**$ 500**	$ 560
Recapture of temporary rate reduction*	**183**	259
Deferred taxes recoverable in rates	**278**	271
Unamortized loss on retirement of debt, net	**46**	44
Employee benefit costs	**160**	35
Cost of removal obligation**	**(913)**	(846)
Asset retirement obligation**	**(333)**	(303)
Other	**29**	24
Total	**(50)**	44
SoCalGas		
Fixed-price contracts and other derivatives	**148**	233
Environmental remediation	**42**	44
Unamortized loss on retirement of debt, net	**44**	45
Cost of removal obligation**	**(1,446)**	(1,392)
Deferred taxes refundable in rates	**(199)**	(194)
Employee benefit costs	**65**	(77)
Other	**7**	9
Total	**(1,339)**	(1,332)
PE — Employee benefit costs (transferred to SoCalGas in 2004)	**—**	72
Total PE consolidated	**(1,339)**	(1,260)
Total	**$(1,389)**	$(1,216)

* In connection with electric industry restructuring, which is described in Note 14, SDG&E temporarily reduced rates to its small-usage customers. That reduction is being recovered in rates through 2007.

** This is related to SFAS 143, *Accounting for Asset Retirement Obligations*, which is discussed below in "New Accounting Standards."

Net regulatory assets (liabilities) are recorded on the Consolidated Balance Sheets at December 31 as follows:

(Dollars in millions)	2004	2003
Current regulatory assets	**$ 255**	$ 233
Noncurrent regulatory assets	**1,119**	1,202
Current regulatory liabilities*	**(4)**	(1)
Noncurrent regulatory liabilities	**(2,759)**	(2,650)
Total	**$(1,389)**	$(1,216)

* Included in Other Current Liabilities.

All of these assets either earn a return, generally at short-term rates, or the cash has not yet been expended and the assets are offset by liabilities that do not incur a carrying cost.

Cash and Cash Equivalents

Cash equivalents are highly liquid investments with maturities of three months or less at the date of purchase.

Restricted cash

Restricted cash was $15 million and $23 million at December 31, 2004 and 2003, respectively. The amounts are included in current assets under the caption Short-term Investments and are primarily used to serve as cash collateral for certain debt agreements.

Collection Allowances

The allowance for doubtful accounts was $8 million, $19 million and $12 million at December 31, 2004, 2003 and 2002, respectively. The company recorded a provision for doubtful accounts of $12 million, $5 million and $13 million in 2004, 2003 and 2002, respectively.

The allowance for realization of trading assets was $56 million, $67 million and $86 million at December 31, 2004, 2003 and 2002, respectively. The company recorded a provision (reduction thereof) for trading assets of $3 million, $(4) million and $20 million in 2004, 2003 and 2002, respectively.

Trading Instruments

Trading assets and trading liabilities (described further in Note 11) include option premiums paid and received, unrealized gains and losses from exchange-traded futures and options, over-the-counter (OTC) swaps, forwards, physical commodities and options. Trading instruments are recorded by Sempra Commodities on a trade-date basis and the majority of such derivative instruments are adjusted daily to current market value. Unrealized gains and losses on OTC transactions reflect amounts which would be received from or paid to a third party upon net settlement of the contracts. Unrealized gains and losses on OTC transactions are reported separately as assets and liabilities unless a legal right of setoff exists under an enforceable netting arrangement.

In October 2002, the Emerging Issues Task Force (EITF) rescinded fair value accounting for recording energy-trading activities and required contracts subsequently entered into to be accounted for at historical cost or the lower of cost or market, unless the contracts meet the requirements for fair value accounting under SFAS 133 and 149, as discussed below in "New Accounting Standards." Energy

transportation and storage contracts are recorded at cost. Energy commodity inventory is being recorded at the lower of cost or market. The company's base metals and concentrates inventory continues to be recorded at fair value in accordance with Accounting Research Bulletin (ARB) No. 43, *Restatement and Revision of Accounting Research Bulletins*. Further discussion of EITF Issue 98-10 is provided below in "New Accounting Standards."

Futures and exchange-traded option transactions are recorded as contractual commitments on a trade-date basis and carried at current market value based on current closing exchange quotations. Derivative commodity swaps and forward transactions are accounted for as contractual commitments on a trade-date basis and carried at fair value derived from current dealer quotations and underlying commodity-exchange quotations. OTC options are carried at fair value based on the use of valuation models that utilize, among other things, current interest, commodity and volatility rates. For long-dated forward transactions, current market values are derived using internally developed valuation methodologies based on available market information. When there is an absence of observable market data at inception, the value of the transaction is its cost. Where market rates are not quoted, current interest, commodity and volatility rates are estimated by reference to current market levels. Given the nature, size and timing of transactions, estimated values may differ significantly from realized values. Changes in market values are reflected in net income. Although trading instruments may have scheduled maturities in excess of one year, the actual settlement of these transactions can occur sooner, resulting in the current classification of trading assets and liabilities on the Consolidated Balance Sheets.

Inventories

At December 31, 2004, inventory shown on the Consolidated Balance Sheets, which does not include Commodities Owned, included natural gas of $115 million, and materials and supplies of $57 million. The corresponding balances at December 31, 2003 were $89 million and $58 million, respectively. Natural gas at the California Utilities ($111 million and $84 million at December 31, 2004 and 2003, respectively) is valued by the last-in first-out (LIFO) method. When the California Utilities' inventory is consumed, differences between the LIFO valuation and replacement cost are reflected in customer rates. Materials and supplies at the California Utilities are generally valued at the lower of average cost or market.

Income Taxes

Income tax expense includes current and deferred income taxes from operations during the year. In accordance with SFAS 109, *Accounting for Income Taxes*, the company records deferred income taxes for temporary differences between the book and tax bases of assets and liabilities. Investment tax credits from prior years are being amortized to income by the California Utilities over the estimated service lives of the properties. Other credits, mainly low-income housing and synthetic-fuel tax credits, are recognized in income as earned. The company follows certain provisions of SFAS 109 that permit regulated enterprises to recognize deferred taxes as regulatory assets or liabilities if it is probable that such amounts will be recovered from, or returned to, customers. The company follows Accounting Principles Board Opinion (APBO) 23, *Accounting for Income Taxes — Special Areas*, in recording deferred taxes for investments in foreign subsidiaries and the undistributed earnings of foreign subsidiaries.

Property, Plant and Equipment

Property, plant and equipment primarily represents the buildings, equipment and other facilities used by the California Utilities to provide natural gas and electric utility services, and by Sempra Generation.

The cost of plant includes labor, materials, contract services and certain expenditures, including refurbishments, replacement of major component parts and labor and overheads incurred to install the

parts, incurred during a major maintenance outage of a generating plant. Maintenance costs are expensed as incurred. In addition, the cost of utility plant includes an allowance for funds used during construction (AFUDC). The cost of non-utility plant includes capitalized interest. The cost of most retired depreciable utility plant minus salvage value is charged to accumulated depreciation.

Property, plant and equipment balances by major functional categories are as follows:

	Property, Plant and Equipment at December 31,		Depreciation rates for years ended December 31,		
(Dollars in billions)	**2004**	2003	**2004**	2003	2002
California Utilities:					
Natural gas operations	**$ 8.1**	$ 7.8	**3.65%**	4.27%	4.25%
Electric distribution	**3.4**	3.2	**4.11%**	4.70%	4.66%
Electric transmission	**1.0**	0.9	**3.06%**	3.09%	3.17%
Construction work in progress	**0.5**	0.4	**NA**	NA	NA
Other electric	**0.6**	0.5	**11.33%**	9.53%	9.37%
Total	**13.6**	12.8			
Other operations:					
Land and land rights	**0.1**	0.1			
Buildings and leasehold improvements	**0.2**	0.2			
Machinery and equipment	**1.9**	1.8			
Construction work in progress	**0.3**	0.3			
Other	**0.1**	0.1			
	2.6	2.5	**various**	various	various
Total	**$16.2**	$15.3			

Accumulated depreciation and decommissioning of natural gas and electric utility plant in service were $3.3 billion and $1.4 billion, respectively, at December 31, 2004, and were $3.1 billion and $1.4 billion, respectively, at December 31, 2003. The discussion of SFAS 143 under "New Accounting Standards" describes a change in presentation of accumulated depreciation. Depreciation expense is based on the straight-line method over the useful lives of the assets or, for the California Utilities, a shorter period prescribed by the CPUC. Notes 14 and 15 include a discussion of the industry restructuring, which affected recorded depreciation. Accumulated depreciation for power plants at Sempra Generation was $47 million and $17 million at December 31, 2004 and 2003, respectively. Depreciation expense is computed using the straight-line method over the asset's estimated original composite useful life or the remaining term of the site leases, whichever is lower.

AFUDC, which represents the cost of debt and equity funds used to finance the construction of utility plant, is added to the cost of utility plant. Although it is not a current source of cash, AFUDC increases income and is recorded partly as an offset to interest charges and partly as a component of Other Income, Net in the Statements of Consolidated Income. AFUDC amounted to $18 million, $29 million and $34 million for 2004, 2003 and 2002, respectively. Total capitalized carrying costs, including AFUDC and the impact of Sempra Generation's construction projects, were $27 million, $55 million and $63 million for 2004, 2003 and 2002, respectively.

Goodwill and Intangible Assets

Goodwill represents the excess of the purchase price over the fair value of the net assets of acquired companies. Goodwill is not amortized, but is tested annually for impairment in accordance with SFAS 142, *Goodwill and Other Intangible Assets*.

In accordance with the transitional guidance of SFAS 142, recorded goodwill attributable to the company was tested for impairment in 2002 by comparing its fair value to its carrying value, using a discounted cash flow methodology. As a result, in 2002, Sempra Pipelines & Storage recorded a pre-tax charge of $6 million related to the impairment of goodwill associated with its two domestic subsidiaries. Impairment losses are reflected in Other Operating Expenses in the Statements of Consolidated Income. Also during 2002, Sempra Commodities completed several acquisitions as further discussed in Note 2. As a result of Sempra Commodities' acquisition of the metals warehousing business, the company recorded $21 million of goodwill on the Consolidated Balance Sheets. In addition, a $16 million after-tax extraordinary gain, which reflected a tax benefit of $2 million, was recorded in 2002 related to the purchase of the base metals and concentrates businesses at prices below the net sums of the fair values of the assets and liabilities acquired.

During 2003, Sempra Pipelines & Storage purchased the remaining minority interests in its Mexican subsidiaries, which resulted in the recording of an addition to goodwill of $6 million and of another intangible asset of $4 million.

The changes in the carrying amount of goodwill (included in Noncurrent Sundry Assets on the Consolidated Balance Sheets) since January 1, 2003 are as follows:

(Dollars in millions)	Sempra Commodities	Sempra Generation	Other	Total
Balance as of January 1, 2003	$164	$18	$—	$182
Goodwill acquired during 2003	—	—	6	6
Balance as of December 31, 2003 and 2004	$164	$18	$ 6	$188

Sempra Commodities and Sempra Generation are the only reportable segments that have goodwill. In addition, the unamortized goodwill related to unconsolidated subsidiaries (included in Investments on the Consolidated Balance Sheets), primarily those located in South America, was $296 million and $299 million at December 31, 2004 and 2003, respectively, before foreign-currency translation adjustments. Including foreign-currency translation adjustments, these amounts were $238 million and $232 million, respectively. Other intangible assets were not material at December 31, 2004 or 2003.

Long-Lived Assets

The company periodically evaluates whether events or circumstances have occurred that may affect the recoverability or the estimated useful lives of long-lived assets, the definition of which does not include unconsolidated subsidiaries. Impairment of long-lived assets occurs when the estimated future undiscounted cash flows are less than the carrying amount of the assets. If that comparison indicates that the assets' carrying value may be permanently impaired, the potential impairment is measured based on the difference between the carrying amount and the fair value of the assets based on quoted market prices or, if market prices are not available, on the estimated discounted cash flows. This calculation is performed at the lowest level for which separately identifiable cash flows exist. Further discussion of SFAS 144 is provided in "New Accounting Standards." During the third and fourth quarters of 2003, the company recorded before-tax impairment charges of $77 million and $24 million, respectively, to write down the carrying value of the assets of Frontier Energy and Atlantic Electric & Gas Limited (AEG), respectively. This is discussed further in "New Accounting Standards" below and in Note 4. The carrying value of unconsolidated subsidiaries is evaluated for impairment based on the requirements of APBO 18, *The Equity Method of Accounting for Investments in Common Stock.*

Nuclear Decommissioning Liability

At December 31, 2004 and 2003, as the result of implementing SFAS 143, SDG&E had asset retirement obligations of $328 million and $316 million, respectively, and related regulatory liabilities of

$333 million and $303 million, respectively. Additional information on San Onofre Nuclear Generating Station (SONGS) decommissioning costs is included below in "New Accounting Standards."

Legal Fees

Legal fees that are associated with a past event and not expected to be recovered in the future are accrued when it is probable that they will be incurred.

Comprehensive Income

Comprehensive income includes all changes, except those resulting from investments by owners and distributions to owners, in the equity of a business enterprise from transactions and other events, including foreign-currency translation adjustments, minimum pension liability adjustments and certain hedging activities. The components of other comprehensive income, which consists of all these changes other than net income as shown on the Statements of Consolidated Income, are shown in the Statements of Consolidated Changes in Shareholders' Equity.

The components of Accumulated Other Comprehensive Income, net of income taxes, at December 31, 2004 are as follows:

Foreign-currency translation loss	$(294)
Financial instruments	(39)
Minimum pension liability adjustments	(36)
Unrealized gains on available-for-sale securities	4
Balance as of December 31, 2004	$(365)

Stock-Based Compensation

The company has stock-based employee compensation plans, which are described in Note 10. The company accounts for these plans under the recognition and measurement principles of APBO 25, *Accounting for Stock Issued to Employees,* and related Interpretations. No stock-based employee compensation cost is reflected in net income for options granted after 1998 since those options had an exercise price equal to the market value of the underlying common stock on the date of grant. The following table provides the pro forma effects of recognizing compensation expense in accordance with SFAS 123, *Accounting for Stock-Based Compensation*:

	Years ended December 31,		
	2004	2003	2002
Net income as reported	**$ 895**	$ 649	$ 591
Stock-based employee compensation expense included in the computation of net income, net of tax (attributable to stock option grants before 1999 and restricted stock awards)	**24**	13	3
Total stock-based employee compensation under fair value method for all grants and awards, net of tax	**(30)**	(20)	(11)
Pro forma net income	**$ 889**	$ 642	$ 583
Earnings per share:			
Basic — as reported	**$3.92**	$3.07	$2.88
Basic — pro forma	**$3.89**	$3.03	$2.84
Diluted — as reported	**$3.83**	$3.03	$2.87
Diluted — pro forma	**$3.80**	$2.99	$2.83

Revenues

Revenues of the California Utilities are primarily derived from deliveries of electricity and natural gas to customers and changes in related regulatory balancing accounts. Revenues from electricity and natural gas sales and services are generally recorded under the accrual method and recognized upon delivery. The portion of SDG&E's electric commodity that was procured for its customers by the California Department of Water Resources (DWR) and delivered by SDG&E is not included in SDG&E's revenues or costs. Costs associated with long-term contracts allocated to SDG&E from the DWR also were not included in the Statements of Consolidated Income, since the DWR retains legal and financial responsibility for these contracts. Note 14 includes a discussion of the electric industry restructuring. Natural gas storage contract revenues are accrued on a monthly basis and reflect reservation, storage and injection charges in accordance with negotiated agreements, which have terms of up to three years. Operating revenue includes amounts for services rendered but unbilled (approximately one-half month's deliveries) at the end of each year.

Through 2003, operating costs of SONGS Units 2 and 3, including nuclear fuel and related financing costs, and incremental capital expenditures were recovered through the Incremental Cost Incentive Pricing (ICIP) mechanism, which allowed SDG&E to receive 4.4 cents per kilowatt-hour for SONGS generation. Any differences between these costs and the incentive price affected net income. For the year ended December 31, 2003, ICIP contributed $53 million to SDG&E's net income. Beginning in 2004, the CPUC has provided for traditional rate-making treatment, under which the SONGS ratebase started over at January 1, 2004, essentially eliminating earnings from SONGS except from increases in ratebase in 2004 and beyond.

Additional information concerning utility revenue recognition is discussed above under "Regulatory Matters."

Sempra Commodities generates a substantial portion of its revenues from market making and trading activities, as a principal, in natural gas, electricity, petroleum, metals and other commodities, for which it quotes bid and ask prices to end users and other market makers. Principal transaction revenues are recognized on a trade-date basis, and include realized gains and losses, and the net change in the fair value of unrealized gains and losses. Sempra Commodities also earns trading profits as a dealer by structuring and executing transactions. Sempra Commodities utilizes derivative instruments to reduce its exposure to unfavorable changes in market prices, which are subject to significant and volatile fluctuation. These instruments include futures, forwards, swaps and options. Options, which are either exchange-traded or directly negotiated between counterparties, provide the holder with the right to buy from or sell to the other party an agreed amount of a commodity at a specified price within a specified period or at a specified time.

As a writer of options, Sempra Commodities generally receives an option premium and then manages the risk of an unfavorable change in the value of the underlying commodity by entering into related transactions or by other means. Forward and future transactions are contracts for delivery of commodities in which the counterparty agrees to make or take delivery at a specified price. Commodity swap transactions may involve the exchange of fixed and floating payment obligations without the exchange of the underlying commodity. Sempra Commodities' financial instruments represent contracts with counterparties whereby payments are linked to or derived from market indices or on terms predetermined by the contract.

Non-derivative contracts are being carried at cost and accounted for on an accrual basis and, therefore, the related profit or loss will be recognized as the contract is performed. Derivative instruments are discussed further in Note 11.

Sempra Generation's revenues are derived primarily from the sale of electric energy to governmental and wholesale power marketing entities and are recognized in accordance with the provisions of

EITF 91-6, *Revenue Recognition of Long-term Power Supply Contracts,* and EITF 96-17, *Revenue Recognition Under Long-term Power Sales Contracts that Contain Both Fixed and Variable Terms.* During 2004 and 2003, electric energy sales to the DWR accounted for a significant portion of total Sempra Generation's revenues. Additionally, a small portion of Sempra Generation's revenue, formerly included in the operations of Sempra Energy Solutions, is generated from energy related products and services to commercial, industrial, government and institutional markets.

The consolidated foreign subsidiaries of Sempra Pipelines & Storage, all of which operate in Mexico, recognize revenue similarly to the California Utilities, except that SFAS 71 is not applicable due to the different regulatory environment.

Extraordinary Gain

During 2002, Sempra Commodities acquired two businesses for amounts less than the fair values of the businesses' net assets. In accordance with SFAS 141, *Business Combinations*, those differences were recorded as extraordinary income.

Foreign Currency Translation

The assets and liabilities of the company's foreign operations are generally translated into U.S. dollars at current exchange rates, and revenues and expenses are translated at average exchange rates for the year. Resulting translation adjustments do not enter into the calculation of net income or retained earnings, but are reflected in Comprehensive Income and Accumulated Other Comprehensive Income, a component of shareholders' equity, as described in Note 3. To reflect the fluctuation in the Argentine peso, the functional currency of the company's Argentine operations, Sempra Pipelines & Storage adjusted its investment in its two Argentine natural gas utility holding companies downward by $1 million, upward by $26 million and downward by $102 million in 2004, 2003 and 2002, respectively. A similar adjustment has been made to its investment in Chile to reflect the fluctuation in the Chilean peso, the functional currency of the company's Chilean operations, upward by $22 million and $43 million in 2004 and 2003, respectively, and downward by $8 million in 2002. These non-cash adjustments did not affect net income, but did reduce or increase comprehensive income and accumulated other comprehensive income (loss). Smaller adjustments have been made to operations in other countries. Additional information concerning these investments is described in Note 3.

Currency transaction gains and losses in a currency other than the entity's functional currency are included in the calculation of consolidated net income. The company recorded $8 million of currency transaction losses in 2003 and $63 million of gains in 2002. In 2004, the currency transaction gains were not material.

Transactions with Affiliates

Loans to Unconsolidated Affiliates

In December 2001, Sempra Pipelines & Storage issued two U.S. dollar denominated loans totaling $35 million and $22 million to its affiliates Camuzzi Gas Pampeana S. A. and Camuzzi Gas del Sur S. A., respectively. These loans have variable interest rates (9.02% at December 31, 2004) and are due in January 2006 and June 2005, respectively. The balances outstanding under the notes were $42 million and $55 million at December 31, 2004 and 2003, respectively. These amounts are included in non-current assets under Due from Unconsolidated Affiliates, because they are expected to be refinanced for longer terms.

Loans from Unconsolidated Affiliates

At both December 31, 2004 and 2003, Sempra Pipelines & Storage had long-term notes payable to affiliates which include $60 million at 6.47% due April 1, 2008 and $100 million at 6.62% due April 1,

2011. The loans are due to Chilquinta Energía Finance Co. LLC and are secured by Sempra Pipelines & Storage's investments in Chilquinta Energía S.A. and Luz del Sur S.A.A. (Luz del Sur), which are discussed in Note 3.

In February 2000, a wholly owned subsidiary trust of the company issued 8,000,000 shares of preferred stock in the form of 8.90% Cumulative Quarterly Income Preferred Securities, Series A (QUIPS). The QUIPS have cumulative preferences as to distributions, are nonvoting and have par and liquidation values of $25 per share. Cash dividends are paid quarterly and the QUIPS were scheduled to mature on February 23, 2030, subject to extension to a date not later than February 23, 2049, and shortening to a date not earlier than February 23, 2015. The QUIPS are subject to mandatory redemption and the company has guaranteed payments to the extent that the trust does not have funds available to make distributions. The trust has no assets except its corresponding receivable from Sempra Energy. The QUIPS are callable on or after February 23, 2005 and there are no sinking fund provisions. The company reclassified the $200 million of mandatorily redeemable trust preferred securities to Due to Unconsolidated Affiliates as a result of the adoption of Financial Accounting Standard Board Interpretation (FIN) 46 effective December 31, 2003. In addition, dividend payments required on these instruments, previously recorded as Preferred Dividends of Subsidiaries and Trust Preferred Distributions, were recorded as Interest Expense in 2004 and for the last six months of 2003 on the company's Statements of Consolidated Income. The company intends to redeem the $200 million of mandatorily redeemable trust preferred securities prior to the end of February 2005. Therefore, that amount is classified as a current liability under Due to Unconsolidated Affiliates at December 31, 2004.

Revenues and Expenses with Unconsolidated Affiliates

During 2004 and 2003, Sempra Generation recorded $60 million and $61 million, respectively, in sales to El Dorado, an unconsolidated affiliate, and recorded $71 million and $69 million, respectively, of purchases from El Dorado for those same years. Additionally, during 2004, Sempra Commodities recorded $28 million of purchases from Topaz Power Partners (Topaz), an unconsolidated affiliate. The sales to Topaz were not material.

New Accounting Standards

SFAS 123 (revised 2004), "Share-Based Payment" (SFAS 123R): In December 2004, the Financial Accounting Standards Board (FASB) issued SFAS 123R, a revision of SFAS 123, *Accounting for Stock-Based Compensation* (SFAS 123), which establishes the accounting for transactions in which an entity exchanges its equity instruments for goods or services received. This statement requires companies to measure and record the cost of employee services received in exchange for an award of equity instruments based on the grant-date fair value of the award and gives companies three alternative transition methods. The modified prospective method requires companies to recognize compensation cost for unvested awards that are outstanding on the effective date based on the fair value that the company had originally estimated for purposes of preparing its SFAS 123 pro forma disclosures. For all new awards that are granted or modified after the effective date, a company would use SFAS 123R's measurement model. The second alternative is a variation of the modified prospective method, allowing companies to restate earlier interim periods in the year that SFAS 123R is adopted using applicable SFAS 123 pro forma amounts. Under the third alternative, the modified retrospective method, companies would apply the modified prospective method, but also restate their prior financial statements to include the amounts that were previously reported in their pro forma disclosures under the original provisions of SFAS 123. The company has not determined the transition method it will use. The effective date of this statement is July 1, 2005 for the company.

SFAS 132 (revised 2003), "Employers' Disclosures about Pensions and Other Postretirement Benefits": This statement revised employers' disclosures about pension plans and other

postretirement benefit plans. It requires disclosures beyond those in the original SFAS 132 about the assets, obligations, cash flows and net periodic benefit cost of defined benefit pension plans and other defined postretirement plans. It does not change the measurement or recognition of those plans. Note 9 provides additional information on employee benefit plans.

SFAS 143, "Accounting for Asset Retirement Obligations": Beginning in 2003, SFAS 143 requires entities to record liabilities for future costs expected to be incurred when assets are retired from service, if the retirement process is legally required. It requires recording of the estimated retirement cost over the life of the related asset by depreciating the present value of the obligation (measured at the time of the asset's acquisition) and by accreting the present value of the estimated future obligation over the asset's estimated useful life. The adoption of SFAS 143 on January 1, 2003 resulted in the recording of an addition to utility plant of $71 million, representing the company's share of SONGS' estimated future decommissioning costs (as discounted to the present value at the dates the units began operation), and accumulated depreciation of $41 million related to the increase to utility plant, for a net increase of $30 million. It also requires the reclassification of utilities' estimated removal costs, which had historically been recorded in accumulated depreciation, to a regulatory liability. At December 31, 2004 and 2003, these costs were $1.4 billion at both dates for SoCalGas, and $913 million and $846 million, respectively, for SDG&E. Implementation of SFAS 143 has had no effect on results of operations and is not expected to have a significant effect in the future.

On January 1, 2003, the company recorded additional asset retirement obligations of $20 million associated with the future retirement of a former power plant and three storage facilities.

In accordance with SFAS 143, Sempra Energy identified several other assets for which retirement obligations exist, but whose lives are indeterminate. A liability for these asset retirement obligations will be recorded if and when a life is determinable.

The changes in the asset retirement obligations for the years ended December 31, 2004 and 2003 are as follows (dollars in millions):

	2004	2003
Balance as of January 1	**$337***	$ —
Adoption of SFAS 143	**—**	329
Accretion expense	**24**	22
Payments	**(10)**	(14)
Revision of estimated cash flows	**(3)**	—
Balance as of December 31	**$348***	$337*

* The current portion of the obligation is included in Other Current Liabilities on the Consolidated Balance Sheets.

In June 2004, the FASB issued a proposed interpretation, *Accounting for Conditional Asset Retirement Obligations, an interpretation of FASB Statement No. 143.* The interpretation would clarify that a legal obligation to perform an asset retirement activity that is conditional on a future event is within the scope of SFAS 143. Accordingly, the interpretation would require an entity to recognize a liability for a conditional asset retirement obligation if the liability's fair value can be reasonably estimated. A final interpretation is expected to be issued by the FASB in the first quarter of 2005 and would be effective for the company on December 31, 2005. The company has not determined the effect the proposed interpretation would have on its financial statements if the proposed interpretation is adopted.

SFAS 144, "Accounting for Impairment or Disposal of Long-Lived Assets": In August 2001, the FASB issued SFAS 144, which replaces SFAS 121, *Accounting for the Impairment of Long-Lived Assets and for Long-Lived Assets to Be Disposed Of.* It applies to all long-lived assets. Among other things, SFAS 144 requires that an impairment loss be recorded if the carrying amount of a long-lived asset is not recoverable from its undiscounted cash flows.

During the third and fourth quarters of 2003, the company recorded impairment charges of $77 million and $24 million to write down the carrying value of the assets of Frontier Energy and AEG, respectively. The Frontier Energy impairment resulted from reductions in actual and anticipated sales of natural gas by the utility. The AEG impairment was due to less-than-anticipated customer growth. These charges are included in Other Operating Expenses in the Statements of Consolidated Income. In applying the provisions of SFAS 144, management determined the fair value of such assets based on its estimates of discounted future cash flows.

SFAS 149, "Amendment of Statement 133 on Derivative Instruments and Hedging Activities": Effective July 1, 2003, SFAS 149 amended and clarified accounting for derivative instruments, including certain derivative instruments embedded in other contracts, and for hedging activities under SFAS 133. Under SFAS 149, natural gas forward contracts that are subject to unplanned netting generally do not qualify for the normal purchases and normal sales exception. ("Unplanned netting" refers to situations whereby contracts are settled by paying or receiving money for the difference between the contract price and the market price at the date on which physical delivery would have occurred. The "normal purchases and normal sales exception" provides for not marking to market contracts that are very rarely settled by means other than physical delivery of the commodity involved in the transaction.) In addition, effective January 1, 2004, power contracts that are subject to unplanned netting and that do not meet the normal purchases and normal sales exception under SFAS 149 will continue to be marked to market. Implementation of SFAS 149 did not have a material impact on reported net income.

SFAS 150, "Accounting for Certain Financial Instruments with Characteristics of Both Liabilities and Equity": This statement establishes standards for how an issuer classifies and measures certain financial instruments with characteristics of both liabilities and equity. SFAS 150 requires that certain mandatorily redeemable financial instruments previously classified in the mezzanine section of the balance sheet be reclassified as liabilities. The company adopted SFAS 150 beginning July 1, 2003 by reclassifying $200 million of mandatorily redeemable trust preferred securities to Deferred Credits and Other Liabilities and $24 million of mandatorily redeemable preferred stock of subsidiaries to Deferred Credits and Other Liabilities and to Other Current Liabilities on the Consolidated Balance Sheets. In addition, dividend payments required on these instruments, previously recorded as Preferred Dividends of Subsidiaries and Trust Preferred Distributions, are now recorded as Interest Expense on the company's Statements of Consolidated Income. For the six months ended December 31, 2003, the related amount recorded as interest expense totaled $9 million. On December 31, 2003, the $200 million of mandatorily redeemable trust preferred securities was further reclassified to Due to Unconsolidated Affiliates as a result of the adoption of FIN 46 as discussed below.

SFAS 151, "Inventory Costs, an amendment of ARB No. 43, Chapter 4": This statement amends the guidance in ARB No. 43, Chapter 4, *Inventory Pricing*, to clarify the accounting for abnormal amounts of idle facility expense, freight, handling cost and wasted material. This statement requires that those items be recognized as current-period charges regardless of whether they meet the criteria of "abnormal". The statement is effective for inventory costs incurred during fiscal years beginning after June 15, 2005. The company does not expect that this statement will have a material impact on the company's financial statements.

EITF 98-10, "Accounting for Contracts Involved in Energy Trading and Risk Management Activities": EITF 98-10 provided for marking to market commodities and arrangements that are not marked to market by SFAS 133 unless certain hedging standards specified in SFAS 133 are complied with. For the company, this consists of certain inventory, and contracts involving transportation and storage. The specified hedging standards have been complied with for a portion of the otherwise-excluded items. A substantial majority of the company's items covered by EITF 98-10 are covered by SFAS 133. On January 1, 2003, the company recorded the initial effect of Issue 98-10's rescission as a

cumulative effect of a change in accounting principle, which reduced after-tax earnings by $29 million. Neither the cumulative nor the ongoing effect impacts the company's cash flow or liquidity. Additional information on derivative instruments is provided in Note 11.

FIN 46, "Consolidation of Variable Interest Entities, an interpretation of ARB No. 51": FIN 46, as revised by FIN 46R, requires an enterprise to consolidate a variable interest entity (VIE), as defined in FIN 46, if the company is the primary beneficiary of a VIE's activities. VIEs are enterprises that have certain characteristics defined in FIN 46.

Sempra Energy adopted FIN 46 on December 31, 2003, resulting in the consolidation of two VIEs for which it is the primary beneficiary. One of the VIEs (Mesquite Trust) was the owner of the Mesquite Power plant for which the company had a synthetic lease agreement. The company recorded an after-tax credit of $9 million in the fourth quarter of 2003 for the cumulative effect of the change in accounting principle. The company bought out the lease in January 2004 and now owns the plant.

The other VIE is AEG. Consolidation of AEG resulted in Sempra Energy's recording of 100 percent of AEG's balance sheet and results of operations, whereas it previously recorded only its share of AEG's net operating results. Due to AEG's consolidation, the company recorded an after-tax charge of $26 million in the fourth quarter of 2003 for the cumulative effect of the change in accounting principle. During the first quarter of 2004, Sempra Energy's board of directors approved management's plan to dispose of AEG. Note 4 provides further discussion concerning this matter and the April 2004 disposal of AEG. Had AEG and the Mesquite Trust been consolidated in 2003 and 2002, the company's net income would have been $662 million and $578 million, respectively.

The $46 million cumulative effect recorded in 2003 on the Statements of Consolidated Income, net of the tax benefit of $26 million, consists of the following items which are described above (dollars in millions):

FIN 46:	
Mesquite Trust	$ 9
AEG	(26)
Net charge	(17)
EITF 98-10	(29)
Total charge	$(46)

In addition, contracts under which SDG&E acquires power from generation facilities otherwise unrelated to SDG&E could result in a requirement for SDG&E to consolidate the entity that owns the facility. As permitted by the interpretation, SDG&E is continuing the process of determining whether it has any such situations and, if so, gathering the information that would be needed to perform the consolidation. The effects of this, if any, are not expected to significantly affect the financial position of SDG&E and there would be no effect on results of operations or liquidity.

FASB Staff Position (FSP) 106-2, "Accounting and Disclosure Requirements Related to the Medicare Prescription Drug, Improvement and Modernization Act of 2003": The Medicare Prescription Drug, Improvement and Modernization Act of 2003 (the "Act") was enacted in December of 2003. The Act establishes a prescription drug benefit under Medicare, known as "Medicare Part D," and a tax-exempt federal subsidy to sponsors of retiree health care benefit plans that provide a benefit that actuarially is at least equivalent to Medicare Part D. At December 31, 2003, the company elected a one-time deferral of the accounting for the Act, as permitted by FSP 106-1, *Accounting and Disclosure Requirements Related to the Medicare Prescription Drug, Improvement and Modernization Act of 2003.*

In May 2004, the FASB issued FSP 106-2, which supersedes FSP 106-1 and provides guidance on the accounting, disclosure, effective date and transition requirements related to the Medicare Prescription Drug Act. During 2004, the company adopted FSP 106-2 retroactive to the beginning of the year.

The company and its actuarial advisors determined that benefits provided to certain participants will actuarially be at least equivalent to Medicare Part D, and, accordingly, the company will be entitled to an expected tax-exempt subsidy that reduces the company's accumulated postretirement benefit obligation under the plan at January 1, 2004 by $102 million and the net postretirement benefit cost for 2004 by $13 million. Employee benefit plans are discussed further in Note 9.

NOTE 2. RECENT ACQUISITIONS AND INVESTMENTS

Sempra Commodities

Sempra Commodities spent $74 million and $27 million in 2004 and 2003, respectively, related to the development of Bluewater Gas Storage, LLC, a natural gas storage facility in Michigan. Sempra Commodities owns the rights to develop the facility and to utilize its capacity to store natural gas for customers who buy, sell or transport natural gas in Michigan. The Bluewater Gas Storage facility commenced commercial operations in May 2004.

During 2002, Sempra Commodities completed $119 million of acquisitions that added base metals trading and warehousing to its trading business. In February 2002, Sempra Commodities completed the acquisition of London-based Sempra Metals Limited, a leading metals trader on the London Metals Exchange, for $65 million, net of cash acquired. In April 2002, Sempra Commodities completed the acquisition of the assets of New York-based Sempra Metals & Concentrates Corp., a leading global trader of copper, lead and zinc concentrates, for $24 million. Also in April 2002, Sempra Commodities completed the acquisition of Henry Bath & Sons Limited, which provides warehousing services for non-ferrous metals in Europe and Asia, and the assets of the U.S. warehousing business of Henry Bath, Inc., for a total of $30 million, net of cash acquired.

As discussed further in Note 1, the company recognized an extraordinary after-tax gain of $16 million for negative goodwill for the acquisitions of the base metals and concentrates businesses. Goodwill of $21 million was recorded in connection with the acquisition of the metals warehousing business.

Sempra Generation

In August 2003, Sempra Generation obtained approvals by the California Energy Commission for the company's 550-megawatt (MW) Palomar power plant in Escondido, California. In June 2004, SDG&E received CPUC approval of its plans to purchase the Palomar plant from Sempra Generation after construction is completed in 2006. Construction of the project began in July 2004.

The 1,250-MW Mesquite Power plant, located near Phoenix, Arizona, cost $686 million and provides electricity to wholesale energy markets in the Southwest. The first phase of commercial operations (50 percent of the plant's total capacity) began in June 2003. The second phase of commercial operations (the remaining 50 percent) began in December 2003. As of December 31, 2003, this project was owned by the Mesquite Trust and financed through a synthetic lease agreement. Through December 31, 2003, Sempra Generation had borrowed $630 million under this facility. All amounts above $280 million required collateralization through purchases of U.S. Treasury obligations. The collateralized U.S. Treasury obligations amounted to $363 million at December 31, 2003. This is included in Short-Term Investments on the Consolidated Balance Sheets at December 31, 2003. As a result of implementing FIN 46, Sempra Energy consolidated the Mesquite Trust, which had total assets and total liabilities of $643 million and $630 million, respectively, at December 31, 2003. Further discussion of this is provided under "New Accounting Standards" in Note 1. In January 2004, Sempra Generation

purchased all of the power plant assets of Mesquite Trust for $631 million and extinguished the related debt. The purchase required cash of $268 million and the liquidation of the $363 million in treasury securities held by the Mesquite Trust as collateral.

Termoeléctrica de Mexicali (TDM), a 625-MW power plant near Mexicali, Baja California, Mexico, commenced operations in July 2003. In May 2003, a federal judge issued an order finding that the U.S. Department of Energy's (DOE) abbreviated assessment of TDM and another, unaffiliated Mexicali power plant, failed to evaluate the plants' environmental impact adequately and called into question the U.S. permits they received to build their cross-border transmission lines. On July 8, 2003, the judge ordered the DOE to conduct additional environmental studies, but denied the plaintiffs' request for an injunction blocking operation of the transmission lines, thus allowing the continued operation of the TDM plant. The DOE finalized its environmental analysis per the court order on December 17, 2004, and is expected to issue a Record of Decision during the second quarter of 2005. The DOE will then determine whether to grant new permits for the cross-border transmission lines. Plaintiffs may elect to dismiss their complaint or to further challenge the agency action. If a stipulation of dismissal is not filed to terminate the litigation by August 15, 2005, the DOE will file a motion by August 22, 2005, showing cause why the court should not set aside the permits. In that event, court hearings may take place in the fourth quarter of 2005. Through December 31, 2004, TDM has made capital expenditures of $343 million.

In October 2002, Sempra Generation purchased the 305-MW, coal-fired Twin Oaks power plant for $120 million. Sempra Generation sells substantially all of the output of the plant under a five-year contract expiring on October 1, 2007. In connection with the acquisition, Sempra Generation also assumed a contract that includes annual commitments to purchase lignite coal for the plant until an aggregate minimum volume has been achieved or through 2025. Note 16 provides additional information on the commitments.

Sempra LNG

In April 2004, Sempra LNG announced plans to develop and construct a $600 million liquefied natural gas (LNG) receiving terminal near Port Arthur, Texas. The terminal would be capable of processing 1.5 billion cubic feet (bcf) of natural gas per day and could be expanded to 3 bcf per day. The company is currently in the process of obtaining FERC approval for the construction of the terminal. The project is expected to begin construction in 2006, with start-up slated for 2009.

In October 2004, Sempra LNG signed a sale and purchase agreement with British Petroleum for the supply of 500 million cubic feet of natural gas per day from Indonesia's Tangguh liquefaction facility to Sempra LNG's Energía Costa Azul regasification terminal. The terminal is expected to cost between $900 million and $1 billion, including related pipeline costs. The 20-year agreement provides for pricing tied to the Southern California border index for natural gas and will supply half the capacity of Energía Costa Azul.

Also in October 2004, Sempra LNG entered into an agreement with Shell International Gas Limited (Shell) by which Shell has contracted to purchase half of the initial capacity of Energía Costa Azul for an initial period of 20 years. This replaces a prior arrangement that contemplated that Shell would have a 50% equity interest in Energía Costa Azul. In December 2004, Sempra LNG entered into two additional contracts: one for the construction of the terminal and one for the construction of the project's breakwater. Note 16 provides additional discussion on commitments related to these contracts.

Also in connection with this project, Mexico's national environmental agency issued an environmental permit in April 2003. Three other significant permits, an operating permit from Mexico's energy

regulatory commission, a local land-use permit from the City of Ensenada and a costal zone use permit, were granted in 2003. The permit to construct marine facilities was received in 2004. Construction of Energía Costa Azul began in January 2005.

In January 2005, Sempra LNG was awarded a 15-year natural gas supply contract by Mexico's state-owned electric utility, Comisión Federal de Electricidad (CFE). The contract is estimated at $1.4 billion over its life and supports the CFE's future energy needs in northern Baja California, including the Presidente Juarez power plant in Rosarito, and it is anticipated that it will use natural gas processed at Energía Costa Azul. Starting in 2008 and running through 2022, the agreement provides the CFE with an average of about 130 million cubic feet per day of natural gas.

In April 2003, Sempra LNG completed its acquisition of the proposed Cameron LNG project in Hackberry, Louisiana from a subsidiary of Dynegy, Inc. Sempra LNG paid Dynegy $36 million for the acquisition, which included rights to the location and to the project as it stood in the licensing stage. In 2004, an additional payment of $17 million was made as certain benchmarks and milestones of the project were met. The total cost of the project is expected to be $700 million. The terminal is currently designed to supply 1.5 bcf of natural gas per day. Construction is expected to begin in 2005 and commercial operations are expected to begin in 2008. The FERC approved the construction and operation of the project in September 2003. Cameron LNG is currently seeking from the FERC a modest design change to its marine facilities. In December 2004, Sempra LNG contracted with Norway's Aker Kvaerner and Japan's Ishikawajima-Harima Heavy Industries to build the terminal. The contract is valued at approximately $500 million, but is not yet binding.

Sempra LNG currently leases land in Louisiana for the development of the Cameron terminal. In connection with the purchase of Cameron, Sempra LNG and the lessor agreed to certain lease amendments, including an increase in the annual rent, addition of wharfage fees and extension of the lease term for another 30 years. The lease amendments are contingent upon obtaining project financing or commencement of construction. In December 2004, Sempra LNG renewed the terms under the original land lease for another five-year period. Rent payments included in the table of future minimum rental payment obligations in Note 16 are based on the original land lease. Should the terms of the amended lease be triggered, total rent payments and wharfage fees would be $47 million over 30 years.

Sempra Pipelines & Storage

In April 2004, the company acquired land and associated rights for the development of a salt-cavern natural gas storage facility in Evangeline Parish, Louisiana. This facility, operating as the Pine Prairie Energy Center, will consist of three salt caverns with a total capacity of 24 bcf of natural gas. The facility is expected to cost $175 million and to begin operations in 2006. The company is negotiating contracts to sell the capacity of this facility. FERC has issued a certificate of public convenience and necessity for the project and authorized Pine Prairie to charge market-based rates.

In July 2004, the company acquired the rights to develop a salt-cavern natural gas storage facility located in Calcasieu Parish, Louisiana. This facility, operating as Liberty Gas Storage (Liberty), is expected to have capacity of 17 bcf. Liberty is estimated to cost $150 million and to begin operation in 2006.

In 2002, Sempra Pipelines & Storage completed construction of the 140-mile Gasoducto Bajanorte Pipeline that connects the Rosarito Pipeline south of Tijuana, Mexico with a TransCanada pipeline that connects to Arizona. Sempra Pipelines & Storage continues to incur costs for the development of a spur line connecting the Energía Costa Azul terminal to Gasoducto Bajanorte and for the expansion of the pipeline. The company has made capital expenditures of $5 million, $7 million and $37 million in the pipeline in 2004, 2003 and 2002, respectively, and a total through December 31, 2004 of $123 million.

Sempra Pipelines & Storage's Mexican subsidiaries build and operate natural gas distribution systems in Mexicali, Chihuahua and the La Laguna-Durango zone in north-central Mexico. In February 2003, Sempra Pipelines & Storage purchased the remaining minority interests in its Mexican subsidiaries. Through December 31, 2004, the distribution companies have made capital expenditures aggregating $142 million. Total capital expenditures for these subsidiaries were $15 million in each of 2004, 2003 and 2002.

These projects are further discussed in Note 16.

NOTE 3. INVESTMENTS IN UNCONSOLIDATED SUBSIDIARIES

Investments are generally accounted for under the equity method when the company has an ownership interest of twenty to fifty percent. In these cases, the company's pro rata shares of the subsidiaries' net assets are included in Investments on the Consolidated Balance Sheets, and are adjusted for the company's share of each investee's earnings or losses, dividends and foreign currency translation effects. Earnings are recorded as equity earnings on the Statements of Consolidated Income in Other Income, Net. The company accounts for certain investments in housing partnerships made before May 19, 1995 under the cost method, whereby they are amortized over ten years based on the expected residual value. The company has no unconsolidated subsidiaries where its ability to influence or control an investee differs from its ownership percentage.

The company's long-term investments are summarized as follows:

	December 31,	
(Dollars in millions)	**2004**	2003
Equity method investments:		
Chilquinta Energía	**$ 376**	$ 337
Luz del Sur	**157**	177
Sodigas Pampeana and Sodigas Sur	**82**	66
Elk Hills Power	**217**	218
El Dorado Energy	**55**	68
Topaz Power Partners	**66**	—
Housing partnerships	**146**	175
Sempra Financial synthetic-fuel partnerships	**12**	14
Total	**1,111**	1,055
Cost method investments — housing partnerships	**36**	47
Investments in unconsolidated subsidiaries	**1,147**	1,102
Other	**17**	10
Total long-term investments	**$1,164**	$1,112

For equity method investments, costs in excess of equity in net assets (goodwill) were $238 million and $232 million at December 31, 2004 and 2003, respectively. Through December 31, 2001, the excess of the investment over the related equity in net assets had been amortized over various periods, primarily forty years. In accordance with SFAS 142, amortization ceased in 2002. Costs in excess of the underlying equity in net assets will continue to be reviewed for impairment in accordance with APBO 18. Descriptive information concerning each of these investments follows.

Sempra Pipelines & Storage

Sempra Pipelines & Storage and PSEG Global (PSEG), an unaffiliated company, each own a 50-percent interest in Chilquinta Energía S.A., a Chilean electric utility.

On April 1, 2004, Sempra Pipelines & Storage and PSEG sold a portion of their interests in Luz del Sur, a Peruvian electric utility, for a total of $62 million. Each party had a 44-percent interest in Luz del Sur prior to the sale and a 38-percent interest after the sale was completed. As a result of the sale, Sempra Pipelines & Storage recognized a $5 million after-tax gain, which is included in Other Income, Net on the Statements of Consolidated Income.

Sempra Pipelines & Storage also owns 43 percent of two Argentine natural gas utility holding companies, Sodigas Pampeana and Sodigas Sur. As a result of the devaluation of the Argentine peso at the end of 2001 and subsequent declines in the value of the peso, Sempra Pipelines & Storage had reduced the carrying value of its investment downward by a cumulative total of $198 million as of December 31, 2004. These non-cash adjustments continue to occur based on fluctuations in the Argentine peso. They do not affect net income, but increase or decrease other comprehensive income (loss) and accumulated other comprehensive income (loss).

The related Argentine economic decline and government responses (including Argentina's unilateral, retroactive abrogation of utility agreements early in 2002) continue to adversely affect the operations of these Argentine utilities. In 2002, Sempra Pipelines & Storage initiated arbitration proceedings under the 1994 Bilateral Investment Treaty between the United States and Argentina for recovery of the diminution of the value of its investments that has resulted from Argentine governmental actions. In 2003, Sempra Pipelines & Storage filed its legal brief with the International Center for Settlement of Investment Disputes, outlining its claims for $258 million. The company has also presented additional information that may provide a basis for a larger award. A decision is expected in 2006. Sempra Energy also has a $48.5 million political-risk insurance policy under which it has filed a claim to recover a portion of the investments' diminution in value and has commenced the arbitration procedure with the insurance company to determine coverage and the amount of the loss under the policy.

Sempra Generation

The 550-MW Elk Hills Power (Elk Hills) project, which is located near Bakersfield, California, began commercial operations in July 2003. Elk Hills is 50 percent owned by Sempra Generation in a joint venture with Occidental Energy Ventures Corporation.

The 480-MW El Dorado power plant, located near Las Vegas, Nevada, began commercial operations in May 2000. The El Dorado Energy project is 50 percent owned by Sempra Generation in a joint venture partnership with Reliant Energy Power Generation.

On July 1, 2004, Topaz, a 50/50 joint venture between Sempra Energy Partners and Carlyle/ Riverstone, acquired ten Texas power plants from American Electric Power (AEP), including the 632-MW coal-fired Coleto Creek Power Station. Topaz acquired these assets for $430 million in cash and the assumption of various environmental and asset retirement liabilities currently estimated at $50 million. $355 million of the purchase price was provided by non-recourse project financing related solely to the acquisition of the Coleto Creek Power Station. Because of possible revisions to the valuation of the environmental and asset retirement obligations, the allocation of the purchase price remains subject to adjustment until June 30, 2005.

The transaction included the acquisition of six operating power plants with generating capacity of 1,950 MW and four inactive power plants capable of generating 1,863 MW. Concurrently with the acquisition, Topaz sold one of the inactive power plants and no gain or loss was recorded on the transaction. Topaz has entered into several power sales agreements for 572 MW of Coleto Creek Power Station's capacity. As of December 31, 2004, these power sales agreements had a remaining weighted-average life of 4.4 years. Sempra Generation manages the plants.

In conjunction with the acquisition of the plants, Sempra Energy provided AEP a guarantee for certain specified liabilities described in the acquisition agreement. This guarantee is limited to $75 million for

the first five years after the acquisition date and $25 million for the next five years, but not more than $75 million over the entire 10-year period. Management does not expect any material losses to result from the guarantee because performance is not expected to be required and, therefore, management believes that the fair value of the guarantee is immaterial.

Sempra Financial

Sempra Financial invests as a limited partner in affordable-housing properties. Sempra Financial's portfolio includes 1,300 properties throughout the United States that are expected to provide income tax benefits (primarily from income tax credits) over 10-year periods. Whether Sempra Financial will invest in additional properties will depend on Sempra Energy's income tax position.

On July 1, 2004, Sempra Financial sold its investment in an enterprise that earns Section 29 income tax credits. That investment comprised one-third of Sempra Energy's Section 29 participation, the rest being held by Sempra Commodities, and was sold because the company's alternative minimum tax position defers utilization of the credits in the determination of income taxes currently payable. The transaction has been accounted for under the cost-recovery method, whereby future proceeds in excess of the carrying value of the investment will be recorded as income when they are received. As a result of this sale, Sempra Financial will not be receiving Section 29 income tax credits in the future. Additional discussion of related income tax issues is provided in Note 8.

Sempra Commodities

At December 31, 2004 and 2003, Sempra Commodities had $14 million and $2 million, respectively, of available-for-sale securities included in Other Investments. Purchases of available-for-sale securities were $5 million in 2004. Unrealized gains, net of tax, reported in other comprehensive income were $4 million in 2004. No sales have been recorded since inception.

NOTE 4. DISCONTINUED OPERATIONS

In the first quarter of 2004, Sempra Energy's board of directors approved management's plan to dispose of its interest in AEG, which markets power and natural gas commodities to commercial and residential customers in the United Kingdom. This disposal met the criteria established for recognition as discontinued operations under SFAS 144, *Accounting for the Impairment or Disposal of Long-Lived Assets.* In April 2004, AEG went into administrative receivership and substantially all of the assets were sold. This transaction resulted in an after-tax loss of $2 million in 2004, which has been reported separately on the Statements of Consolidated Income.

The net losses from discontinued operations were $25 million for the year ended December 31, 2004 (including the $2 million loss on disposal). During 2003 and 2002, the company accounted for its investment in AEG under the equity method of accounting. As such, for the years ended December 31, 2003 and 2002, the company recorded its share of AEG's net losses, $5 million and $10 million, respectively, in Other Income, Net on the Statements of Consolidated Income. Additionally, during the fourth quarter of 2003, the company recorded an after-tax charge of $21 million to write down the carrying value of assets at AEG. Effective December 31, 2003, AEG was consolidated as a result of the adoption of FIN 46, as discussed in Note 1.

Included within the net loss from discontinued operations are AEG's operating results, summarized below:

(Dollars in millions)	Year ended December 31, 2004
Operating revenues	$201
Loss from discontinued operations, before income tax benefit of $7	$ (30)
Loss on disposal of discontinued operations, before income tax benefit of $4	$ (6)

AEG's balance sheet data, excluding intercompany balances (which are significant) eliminated in consolidation, are summarized below:

(Dollars in millions)	**December 31, 2004**	December 31, 2003
Assets:		
Accounts receivable	**$37**	$137
Other current assets	**33**	83
Total assets	**$70**	$220
Liabilities:		
Accounts payable	**$—**	$ 36
Other current liabilities	**17**	16
Total liabilities	**$17**	$ 52

NOTE 5. SHORT-TERM BORROWINGS

Committed Lines of Credit

At December 31, 2004, the company had available $4.5 billion in unused, committed lines of credit to provide liquidity and support commercial paper. As of December 31, 2004, $34 million of the lines supported variable-rate debt.

The California Utilities have a combined $500 million three-year syndicated revolving credit facility under which each utility individually may borrow up to $300 million, subject to a combined borrowing limit for both utilities of $500 million. Borrowings under the agreement bear interest at rates varying with market rates and the utility's credit rating. The agreement requires each utility to maintain, at the end of each quarter, a ratio of total indebtedness to total capitalization (as defined in the agreement) of no more than 60 percent. Borrowings under the agreement are individual obligations of the borrowing utility and a default by one utility would not constitute a default, or preclude borrowings by, the other. At December 31, 2004, the California Utilities had no amounts outstanding under this facility. SoCalGas had $30 million of commercial paper outstanding as of December 31, 2004.

Sempra Commodities has a two-year syndicated revolving line of credit providing up to $1 billion of extensions of credit (consisting of borrowings, letters of credit and other credit support accommodations) to Sempra Commodities and certain of its affiliates. The agreement expires in 2006. The amount of credit extended on a non-guaranteed basis is limited by the amount of a borrowing base consisting of receivables, inventories and other assets of Sempra Commodities that secure the credit facility and that are valued for purposes of the borrowing base at varying percentages of current market value. Credit utilization above the borrowing base (up to a maximum of $500 million) is guaranteed by Sempra Energy subject to the overall $1 billion credit limit. Non-guaranteed extensions of credit bear interest and fees that vary with Sempra Commodities' tangible net worth, and guaranteed extensions bear interest and fees varying with Sempra Energy's credit ratings. Extensions of credit are subject to the absence of any development or event that has had or would reasonably be expected to have a material adverse effect on Sempra Commodities. The facility also requires Sempra Commodities to meet certain financial tests at the end of each quarter (including current ratio, leverage ratio and minimum consolidated net worth tests) and (while guaranteed borrowings are outstanding) also requires Sempra Energy to meet, at the end of each quarter and as defined in the credit facility, a leverage ratio of consolidated indebtedness to consolidated total capitalization of not more than 65 percent. It also imposes certain other limitations on Sempra Commodities, including limitations on other indebtedness, capital expenditures, liens, transfers of assets, investments, loans, advances, dividends, other distributions, modifications of risk-management policies and transactions with affiliates. At December 31, 2004, outstanding extensions of credit under the facility totaled $489 million, including $439 million in letters of credit and $50 million in borrowings outstanding.

Sempra Global has a $1.5 billion three-year syndicated revolving credit facility that expires in 2007, and a substantially identical $500 million three-year revolving credit facility that expires in 2006. Borrowings under each facility are guaranteed by Sempra Energy and bear interest at rates varying with market rates and Sempra Energy's credit rating. Each facility requires Sempra Energy to maintain, at the end of each quarter, a ratio of total indebtedness to total capitalization (as identically defined in each facility) of no more than 65 percent. Sempra Global had letters of credit of $36 million and $220 million of commercial paper, guaranteed by Sempra Energy, outstanding at December 31, 2004. As of December 31, 2003, Sempra Global had no commercial paper and a letter of credit of $18 million outstanding.

PE has a revolving credit commitment of $500 million that expires in September 2005. Borrowings under the credit agreement are available to provide loans to Sempra Global and would bear interest at rates varying with market rates, PE's credit ratings and amounts borrowed. Borrowings are guaranteed by Sempra Energy and would be subject to mandatory repayment if Sempra Energy's or SoCalGas' ratio of debt to total capitalization (as defined in the agreement) were to exceed 65 percent, or should there be a change in law materially and adversely affecting the ability of SoCalGas to pay dividends or make other distributions to PE. No amounts were outstanding under this facility at December 31, 2004.

Sempra LNG has a $1.25 billion five-year syndicated revolving credit facility that expires in 2009. The $1.25 billion also provides for the issuance of letters of credit not exceeding $200 million outstanding at any one time. Borrowings, letter of credit obligations and other obligations under the facility are guaranteed by Sempra Energy and bear interest at rates varying with market rates and Sempra Energy's credit ratings. The facility requires Sempra Energy to maintain, at the end of each quarter, a ratio of total indebtedness to total capitalization (as defined in the agreement) of no more than 65 percent. Sempra LNG did not have any outstanding borrowings against this line at December 31, 2004.

Uncommitted Lines of Credit

At December 31, 2004, Sempra Commodities had $226 million in various uncommitted lines of credit that are guaranteed by Sempra Energy and bear interest at rates varying with market rates and Sempra Energy's credit rating. At December 31, 2004, Sempra Commodities had $103 million of letters of credit and $25 million of short-term borrowings outstanding against these lines. At December 31, 2003, Sempra Commodities had letters of credit of $420 million, and no short-term borrowings outstanding.

Other

In addition to the lines of credit, Sempra Energy had $80 million and $28 million of other short-term debt outstanding at December 31, 2004 and 2003, respectively, that was due to parties other than financial institutions. The company's weighted average interest rate on the total short-term debt outstanding was 2.82% and 7.56% at December 31, 2004 and 2003, respectively.

NOTE 6. LONG-TERM DEBT

(Dollars in millions)	December 31, 2004	2003
First mortgage bonds		
Variable rate (2.63% at December 31, 2004) December 1, 2009	**$ 100**	$ —
4.375% January 15, 2011	**100**	100
Variable rates after fixed-to-floating rate swaps (2.69% at December 31, 2004) January 15, 2011	**150**	150
4.8% October 1, 2012	**250**	250
6.8% June 1, 2015	**14**	14
5.45% April 15, 2018	**250**	250
5.9% June 1, 2018	**68**	68
5.9% September 1, 2018	**93**	176
5.85% June 1, 2021	**60**	60
5.25% to 7% December 1, 2027	**150**	225
After floating-to fixed rate swap expiring 2009:		
2.516% to 2.832% January and February 2034	**176**	—
2.8275% May 1, 2039	**75**	—
6.1% September 1, 2019	**—**	35
Variable rates September 1, 2020	**—**	58
6.875% November 1, 2025	**—**	175
	1,486	1,561
Other long-term debt		
5.60% Equity Units May 17, 2007*	**600**	600
7.95% Notes March 1, 2010	**200**	500
Notes at variable rates after fixed-to-floating swap (5.97% at December 31, 2004) March 1, 2010	**300**	—
6.0% Notes February 1, 2013	**400**	400
6.95% Notes December 1, 2005	**300**	300
Notes at variable rates (2.82% at December 31, 2004) May 21, 2008	**300**	—
4.75% Notes May 15, 2009	**300**	—
Rate-reduction bonds, 6.31% to 6.37% at December 31, 2004 payable annually through 2007	**198**	263
5.9% June 1, 2014	**130**	130
Debt incurred to acquire limited partnerships, secured by real estate, at 7.13% to 9.35% annually through 2009	**76**	110
Employee Stock Ownership Plan		
Bonds at 4.213% November 1, 2014	**82**	82
Bonds at variable rates (3.00% at December 31, 2004) November 1, 2014	**33**	19
5.5% December 1, 2021	**60**	60
5.3% July 1, 2021	**39**	39
4.9% March 1, 2023	**25**	25
6.375% May 14, 2006	**8**	8
5.67% January 18, 2028	**5**	5
Variable rates September 2005	**—**	630
Notes at variable rates after a fixed-to-floating rate swap July 1, 2004	**—**	500
Other debt	**33**	15
Capitalized leases	**6**	8
Market value adjustments for interest rate swaps, net (expiring 2009 — 2011)	**13**	23
	4,594	5,278
Current portion of long-term debt	**(398)**	(1,433)
Unamortized discount on long-term debt	**(4)**	(4)
Total	**$4,192**	$ 3,841

* 4.62% after remarketing in February 2005, as discussed in Note 13.

Excluding capital leases, which are described in Note 16, and market value adjustments for interest-rate swaps, maturities of long-term debt are:

(Dollars in millions)	
2005	$ 398
2006	100
2007	683
2008	308
2009	425
Thereafter	2,661
Total	$4,575

Holders of variable-rate bonds may require the issuer to repurchase them prior to scheduled maturity. However, since repurchased bonds would be remarketed and funds for repurchase are provided by long-term revolving credit agreements (which are generally renewed upon expiration and which are described in Note 5), it is expected that the bonds will be held to the maturities stated above.

Callable Bonds

At the company's option, certain bonds are callable at various dates: $611 million in 2005, $308 million in 2006, $82 million in 2007, and $169 million thereafter.

First Mortgage Bonds

First mortgage bonds are issued by the California Utilities and secured by a lien on their respective utility plant. The California Utilities may issue additional first mortgage bonds upon compliance with the provisions of their bond indentures, which require, among other things, the satisfaction of pro forma earnings-coverage tests on first mortgage bond interest and the availability of sufficient mortgaged property to support the additional bonds, after giving effect to prior bond redemptions. The most restrictive of these tests (the property test) would permit the issuance, subject to CPUC authorization, of an additional $3 billion of first mortgage bonds at December 31, 2004.

In June 2004, SDG&E issued $251 million of first mortgage bonds and applied the proceeds in July to refund an identical amount of first mortgage bonds and related tax-exempt industrial development bonds of a shorter maturity. The bonds secure the repayment of tax-exempt industrial development bonds of an identical amount, maturity and interest rate issued by the City of Chula Vista, the proceeds of which were loaned to SDG&E and which are being repaid with payments on the first mortgage bonds. When SDG&E called the $251 million of refunded first mortgage bonds in July 2004, it incurred $6 million in call premium costs. These costs were recorded as regulatory assets and are being amortized over the life of the retired debt. The bonds were initially issued as auction-rate securities, but SDG&E entered into floating-for-fixed interest-rate swap agreements that effectively changed the refunding bonds' interest rates to fixed interest rates in September 2004. The swaps are set to expire in 2009.

SoCalGas called $175 million of long-term debt in January 2004 and incurred $2 million in call premium costs. This amount has been recorded as a regulatory asset and is being amortized over the life of the original issue.

In December 2004, SoCalGas issued $100 million of first mortgage bonds maturing in 2009. The bonds bear interest at 0.17% above LIBOR.

Mesquite Power

The company consolidated Mesquite Trust, the owner of Mesquite Power, on its financial statements as of December 31, 2003 as a result of implementing FIN 46, as described in Notes 1 and 2. The debt outstanding of $630 million consisted of notes payable due in 2005. In January 2004, Sempra Generation purchased all of the power plant assets of Mesquite Trust for $631 million and extinguished the related debt. Therefore the liability is classified as short-term at December 31, 2003.

Equity Units

In April and May of 2002, the company publicly offered and issued $600 million of equity units. Additional information on the equity units is provided in Note 13.

Unsecured Long-term Debt

Various long-term obligations totaling $2.8 billion are unsecured at December 31, 2004.

On January 15, 2003, $70 million of SoCalGas' 5.67% $75 million medium-term notes were put back to the company.

In May 2004, the company issued $600 million of senior unsecured notes, consisting of $300 million of 4.75% fixed-rate notes and $300 million of floating-rate notes maturing May 15, 2009 and May 21, 2008, respectively. The proceeds of the issuance were used to repay $500 million of debt maturing July 1, 2004, and for general corporate purposes.

Rate-Reduction Bonds

In December 1997, $658 million of rate-reduction bonds were issued on behalf of SDG&E at an average interest rate of 6.26%. These bonds were issued to facilitate the 10-percent rate reduction mandated by California's electric-restructuring law, which is described in Note 14. They are being repaid over ten years by SDG&E's residential and small-commercial customers through a specified charge on their electricity bills. These bonds are secured by the revenue streams collected from customers and are not secured by, or payable from, utility assets.

Debt of Employee Stock Ownership Plan (ESOP) and Trust (Trust)

The Trust covers substantially all of the employees of the parent organization, SoCalGas and most of Sempra Global's subsidiaries. The Trust is used to fund part of the retirement savings plan described in Note 9. The notes, which mature in 2014, are repriced weekly and subject to repurchase by the company at the holder's option, depending on market demand. ESOP debt was paid down by $13 million during the last three years when approximately 538,000 shares of company common stock were released from the Trust in order to fund the employer contribution to the company savings plan. Interest on the ESOP debt amounted to $5 million in 2004, $6 million in 2003 and $7 million in 2002. Dividends used for debt service amounted to $2 million in 2004 and 2003, and $3 million in 2002.

Interest-Rate Swaps

The company periodically enters into interest-rate swap agreements to moderate its exposure to interest-rate changes and to lower its overall cost of borrowing. In May 2004, Sempra Energy entered into interest-rate swaps which effectively exchanged the fixed rate on $300 million of its $500 million 7.95% notes for a floating rate. The swaps expire in 2010. In September 2004, SDG&E entered into interest-rate swaps to exchange the floating rates on its $251 million Chula Vista Series 2004 bonds for fixed rates. The swaps expire in 2009. In December 2003, SoCalGas entered into an interest-rate

swap that effectively exchanged the fixed rate on $150 million of its $250 million 4.375% first mortgage bonds for a floating rate. The swap expires in 2011. The schedule of long-term debt reflects previous interest-rate swaps related to other debt. Accordingly, market value adjustments to long-term debt of $10 million and $19 million were recorded in 2004 and 2003, respectively, to reflect, without affecting net income or other comprehensive income, the unfavorable economic consequences (as measured at December 31, 2004 and 2003) of having entered into the swap transactions.

NOTE 7. FACILITIES UNDER JOINT OWNERSHIP

SONGS and the Southwest Powerlink transmission line are owned jointly with other utilities. The company's interests at December 31, 2004, are as follows:

(Dollars in millions)	SONGS	Southwest Powerlink
Percentage ownership	20%	91%
Utility plant in service	$19	$290
Accumulated depreciation and amortization	$—	$149
Construction work in progress	$16	$ 1

The company and the other owners each holds its interest as an undivided interest as tenants in common. Each owner is responsible for financing its share of each project and participates in decisions concerning operations and capital expenditures.

The company's share of operating expenses is included in the Statements of Consolidated Income.

SONGS Decommissioning

Objectives, work scope and procedures for the dismantling and decontamination of the SONGS units must meet the requirements of the Nuclear Regulatory Commission (NRC), the Environmental Protection Agency, the CPUC and other regulatory bodies.

The company's share of decommissioning costs for the SONGS units is estimated to be $328 million in 2004 dollars. Cost studies are updated every three years, with the next update expected to be submitted to the CPUC for its approval in 2006. Rate recovery of decommissioning costs is allowed until the time that the costs are fully recovered, and is subject to adjustment every three years based on the costs allowed by regulators. Collections are authorized to continue until 2013, at which time sufficient funds are expected to have been collected to fully decommission SONGS, but may be extended by CPUC approval until 2022, when the SONGS' operating license ends and the decommissioning of SONGS Units 2 and 3 would be expected to begin.

The amounts collected in rates are invested in externally managed trust funds. Amounts held by the trusts are invested in accordance with CPUC regulations that establish maximum amounts for investments in equity securities (50 percent of the qualified trust and 60 percent of the nonqualified trust), international equity securities (20 percent) and securities of electric utilities having ownership interests in nuclear power plants (10 percent). Not less than 50 percent of the equity portion of the trusts must be invested passively. The securities held by the trust are considered available for sale. These trusts are shown on the Consolidated Balance Sheets at market value. At December 31, 2004, these trusts reflected unrealized gains of $182 million with the offsetting credits recorded on the Consolidated Balance Sheets in Asset Retirement Obligations and the related regulatory liabilities.

Unit 1 was permanently shut down in 1992, and physical decommissioning began in January 2000. Several structures, foundations and large components have been dismantled, removed and disposed of. Spent nuclear fuel has been removed from the Unit 1 Spent Fuel Pool and stored on-site in an

Independent Spent Fuel Storage Facility (ISFSI) licensed by the NRC. The remaining major work will include dismantling, removal and disposal of all remaining Unit 1 equipment and facilities (both nuclear and non-nuclear components), and decontamination of the site. These activities are expected to be completed in 2008. The ISFSI and the reactor vessel will remain on site until a permanent storage facility becomes available.

Trust investments include:

(Dollars in millions)	Maturity dates	December 31, **2004**	2003
Municipal bonds	2005 — 2034	**$ 45**	$ 47
U.S. government issues	2005 — 2034	**209**	181
Short-term cash and other	2005	**55**	49
Stocks		**303**	293
Total		**$612**	$570

Net earnings (loss) were $45 million in 2004, $82 million in 2003, and $(25) million in 2002. Proceeds from sales of securities (which are reinvested) were $237 million in 2004, $266 million in 2003 and $409 million in 2002.

Customer contribution amounts are determined by estimates of after-tax investment returns, decommissioning costs and decommissioning cost escalation rates. Lower actual investment returns or higher actual decommissioning costs would result in an increase in future customer contributions.

Discussion regarding the impact of SFAS 143 is provided in Note 1. Additional information regarding SONGS is included in Notes 14 and 16.

NOTE 8. INCOME TAXES

The reconciliation of the statutory federal income tax rate to the effective income tax rate is as follows:

	Years ended December 31, **2004**	2003	2002
Statutory federal income tax rate	**35.0%**	35.0%	35.0%
Utility depreciation	**3.7**	6.7	5.2
State income taxes, net of federal income tax benefit	**3.8**	7.0	7.0
Tax credits	**(13.5)**	(22.6)	(18.5)
Income from unconsolidated foreign subsidiaries	**(4.2)**	(4.3)	(2.0)
Settlement of Internal Revenue Service audit	**—**	(11.2)	(3.6)
Reduction of prior period state income tax accruals, net of federal income tax benefit	**(3.1)**	—	—
Reduction of interest rate on prior period federal income tax liabilities, net of tax	**(1.7)**	—	—
Other, net	**(2.7)**	(4.3)	(2.9)
Effective income tax rate	**17.3%**	6.3%	20.2%

The geographic components of total income from operations before income taxes are as follows:

(Dollars in millions)	Years ended December 31, **2004**	2003	2002
Domestic	**$ 796**	$551	$584
Foreign	**317**	191	137
Total income before income taxes	**$1,113**	$742	$721

The components of income tax expense are as follows:

(Dollars in millions)	Years ended December 31, 2004	2003	2002
Current:			
Federal	**$120**	$ 80	$ 220
State	**21**	74	56
Foreign	**39**	11	13
Total	**180**	165	289
Deferred:			
Federal	**17**	(126)	(138)
State	**(24)**	(4)	5
Foreign	**26**	18	(5)
Total	**19**	(112)	(138)
Deferred investment tax credits	**(6)**	(6)	(5)
Total income tax expense	**$193**	$ 47	$ 146

Accumulated deferred income taxes at December 31 relate to the following:

(Dollars in millions)	2004	2003
Deferred tax liabilities:		
Differences in financial and tax bases of depreciable and amortizable assets	**$ 861**	$ 891
Balancing accounts and regulatory assets	**124**	239
Unrealized revenue	**79**	63
Partnership income	**56**	34
Loss on reacquired debt	**38**	38
Property taxes	**25**	22
Equity units	**21**	12
Other	**11**	—
Total deferred tax liabilities	**1,215**	1,299
Deferred tax assets:		
General business tax credit carryforward	**193**	152
Credits from alternative minimum tax	**111**	77
Investment tax credits	**55**	61
Net operating losses of foreign entities	**104**	112
Compensation-related items	**173**	134
Postretirement benefits	**51**	31
Other deferred liabilities	**29**	190
State income taxes	**48**	57
Bad debt allowance	**18**	28
Other accruals not yet deductible	**35**	27
Other	**32**	51
Total deferred tax assets	**849**	920
Net deferred income tax liability before valuation allowance	**366**	379
Valuation allowance	**39**	20
Net deferred income tax liability	**$ 405**	$ 399

The net deferred income tax liability is recorded on the Consolidated Balance Sheets at December 31 as follows:

(Dollars in millions)	2004	2003
Current (asset) liability	**$ (15)**	$ 31
Noncurrent liability	**420**	368
Total	**$405**	$399

In connection with its affordable-housing investments, the company has $193 million of unused general business tax credits in varying amounts dating back to 1999. The ability to offset these credits against future taxable income will expire between the years 2019 and 2024. The company expects to utilize the credits prior to expiration. In addition, the company has $111 million of alternative minimum tax credits with no expiration date. All of these credits have been included in the calculation of income tax expense.

Foreign subsidiaries have $314 million in unused net operating losses available to reduce future income taxes, primarily in Mexico, Canada and the United Kingdom. Significant amounts of these losses become unavailable to reduce future incomes taxes beginning in 2009. Financial statement benefits have been recorded on all but $88 million of these losses, primarily by offsetting them against deferred tax liabilities with the same expiration pattern and country of jurisdiction. No benefits have been recorded on $88 million of the losses because they have been incurred in jurisdictions where utilization is sufficiently in doubt.

The company has not provided for U.S. income taxes on foreign subsidiaries' undistributed earnings ($606 million at December 31, 2004), since they are expected to be reinvested indefinitely outside the U.S. It is not possible to predict the amount of U.S. income taxes that might be payable if these earnings were eventually repatriated.

The company believes it has adequately provided for income tax issues not yet resolved with federal, state and foreign tax authorities. At December 31, 2004, $186 million was accrued for such matters. Although not probable, the most adverse resolution of these issues could result in additional charges to earnings in future periods. Based upon a consideration of all relevant facts and circumstances, the company does not believe the ultimate resolution of tax issues for all open tax periods will have a materially adverse effect upon its results of operations or financial condition.

The new American Jobs Creation Act enables companies to repatriate monies earned outside the U.S. at an income tax cost of only 15 percent of the normal rate. To achieve this reduction, the repatriation must occur by the end of 2005. The company has not completed its analysis and does not expect to be able to make a decision on the amount of such repatriations, if any, until the fourth quarter of 2005. Among other things, the decision will depend on the level of earnings outside the U.S., the debt level between the company's U.S. and non-U.S. affiliates, and administrative guidance from the Internal Revenue Service.

Section 29 Income Tax Credits

On July 1, 2004, Sempra Financial sold its investment in an enterprise that earns Section 29 income tax credits. That investment comprised one-third of Sempra Energy's Section 29 participation and was sold because the company's alternative minimum tax position defers utilization of the credits in the determination of income taxes currently payable. The transaction has been accounted for under the cost-recovery method, whereby future proceeds in excess of the carrying value of the investment will be recorded as income as received. As a result of this sale, Sempra Financial will not be receiving Section 29 income tax credits in the future.

The IRS has conducted various examinations of the partnerships associated with the Section 29 income tax credits, covering various years as recent as 2000, depending on the partnership. It has reported no change in the credits. From acquisition of the facilities in 1998, the company has generated Section 29 income tax credits of $349 million through December 31, 2004, of which $98 million were recorded for the year ended December 31, 2004.

In the next three years, if the annual average wellhead price per barrel of oil reaches a certain price, a phase-out of Section 29 credits will begin. For 2005, 2006 and 2007, those prices are $52.17, $53.21, and $54.27, respectively.

Pacific Enterprises' Quasi-Reorganization

Effective December 31, 1992, PE effected a quasi-reorganization for financial reporting purposes. The reorganization resulted in a restatement of the company's assets and liabilities to their estimated fair value at December 31, 1992 and the elimination of PE's retained earnings deficit. Since the reorganization was for financial purposes and not a taxable transaction, the company established deferred taxes relative to the book and tax bases differences.

During 2004, the company completed an extensive analysis of PE's deferred tax accounts. The analysis resulted in a $72 million reduction of the deferred tax liabilities and an offsetting credit to equity. The credit was recorded to equity because the balances related to tax effects of transactions prior to the quasi-reorganization. In 2004, the company also concluded its outstanding IRS examinations and appeals related to PE and its subsidiaries. As of December 31, 2004, the company's balance sheet includes a net deferred tax asset of $15 million related to remaining reserves arising from the quasi-reorganization.

NOTE 9. EMPLOYEE BENEFIT PLANS

The information presented below covers the plans of the company and its principal subsidiaries.

Pension and Other Postretirement Benefits

The company has funded and unfunded noncontributory defined benefit plans that together cover substantially all of its employees. The plans provide defined benefits based on years of service and either final average or career salary.

The company also has other postretirement benefit plans covering substantially all of its employees. The life insurance plans are both contributory and noncontributory, and the health care plans are contributory, with participants' contributions adjusted annually. Other postretirement benefits include retiree life insurance, medical benefits for retirees and their spouses, and Medicare Part B reimbursement for certain retirees.

The company maintains dedicated assets in support of its Supplemental Executive Retirement Plan.

There were no amendments to the company's pension and other postretirement benefit plans in 2003 or 2004. During 2002, the company had amendments reflecting retiree cost of living adjustments, which resulted in an increase in the pension plan benefit obligation of $51 million. Amendments to other postretirement benefit plans related to the transfer of employees to SDG&E and changes to their specific benefits resulted in a decrease in the benefits obligation of $7 million. The amortization of these changes will affect pension expense in future years.

December 31 is the measurement date for the pension and other postretirement benefit plans. The following table provides a reconciliation of the changes in the plans' projected benefit obligations during the latest two years, the fair value of assets and a statement of the funded status as of the latest two year ends:

	Pension Benefits		Other Postretirement Benefits	
(Dollars in millions)	**2004**	2003	**2004**	2003
CHANGE IN PROJECTED BENEFIT OBLIGATION:				
Net obligation at January 1	**$2,578**	$2,290	**$ 954**	$ 797
Service cost	**49**	52	**21**	19
Interest cost	**154**	152	**51**	55
Actuarial loss (gain)	**132**	285	**(64)**	116
Benefit payments	**(219)**	(201)	**(40)**	(33)
Net obligation at December 31	**2,694**	2,578	**922**	954
CHANGE IN PLAN ASSETS:				
Fair value of plan assets at January 1	**2,263**	1,984	**519**	409
Actual return on plan assets	**269**	453	**56**	90
Employer contributions	**27**	27	**50**	53
Benefit payments	**(219)**	(201)	**(40)**	(33)
Fair value of plan assets at December 31	**2,340**	2,263	**585**	519
Benefit obligation, net of plan assets at December 31	**(354)**	(315)	**(337)**	(435)
Unrecognized net actuarial loss	**278**	273	**221**	317
Unrecognized prior service cost	**74**	83	**(13)**	(13)
Unrecognized net transition obligation	**—**	1	**—**	—
Net recorded asset (liability) at December 31	**$ (2)**	$ 42	**$(129)**	$(131)

The net asset (liability) is recorded on the Consolidated Balance Sheets at December 31 as follows:

	Pension Benefits		Other Postretirement Benefits	
(Dollars in millions)	**2004**	2003	**2004**	2003
Prepaid benefit cost	**$ 147**	$ 178	**$ —**	$ —
Accrued benefit cost	**(149)**	(136)	**(129)**	(131)
Additional minimum liability	**(131)**	(118)	**—**	—
Intangible asset	**7**	9	**—**	—
Regulatory asset	**62**	—	**—**	—
Accumulated other comprehensive income (pretax)	**62**	109	**—**	—
Net recorded asset (liability)	**$ (2)**	$ 42	**$(129)**	$(131)

The accumulated benefit obligation for defined benefit pension plans was $2.5 billion and $2.4 billion at December 31, 2004 and 2003, respectively. The following table provides information concerning pension plans with benefit obligations in excess of plan assets as of December 31.

	Projected Benefit Obligation Exceeds the Fair Value of Plan Assets		Accumulated Benefit Obligation Exceeds the Fair Value of Plan Assets	
(Dollars in millions)	**2004**	2003	**2004**	2003
Projected benefit obligation	**$2,290**	$2,189	**$694**	$662
Accumulated benefit obligation	**$2,076**	$1,994	**$692**	$661
Fair value of plan assets	**$2,085**	$2,012	**$569**	$538

The following table provides the components of net periodic benefit costs (income) for the years ended December 31:

(Dollars in millions)	Pension Benefits 2004	2003	2002	Other Postretirement Benefits 2004	2003	2002
Service cost	**$ 49**	$ 52	$ 57	**$ 21**	$ 19	$ 13
Interest cost	**154**	152	149	**51**	55	42
Expected return on assets	**(154)**	(161)	(204)	**(36)**	(35)	(39)
Amortization of:						
Transition obligation	**—**	1	1	**—**	9	9
Prior service cost	**9**	9	7	**(1)**	(1)	(1)
Actuarial (gain) loss	**12**	9	(18)	**10**	10	—
Regulatory adjustment	**(116)**	(14)	32	**2**	(4)	25
Total net periodic benefit cost (income)	**$ (46)**	$ 48	$ 24	**$ 47**	$ 53	$ 49

As described in Note 1, the company adopted FSP 106-2 in 2004 retroactive to the beginning of the year. The company and its actuarial advisors determined that benefits provided to certain participants will actuarially be at least equivalent to Medicare Part D, and, accordingly, the company will be entitled to an expected tax-exempt subsidy that reduces the company's accumulated postretirement benefit obligation under the plan at January 1, 2004 by $102 million and the net postretirement benefit cost for 2004 by $13 million.

The significant assumptions related to the company's pension and other postretirement benefit plans are as follows:

	Pension Benefits 2004	2003	Other Postretirement Benefits 2004	2003
WEIGHTED-AVERAGE ASSUMPTIONS USED TO DETERMINE BENEFIT OBLIGATION AS OF DECEMBER 31:				
Discount rate	**5.66%**	6.00%	**5.66%**	6.00%
Rate of compensation increase	**4.50%**	4.50%	**4.50%**	4.50%
WEIGHTED-AVERAGE ASSUMPTIONS USED TO DETERMINE NET PERIODIC BENEFIT COSTS FOR YEARS ENDED DECEMBER 31:				
Discount rate	**6.00%**	6.50%	**6.00%**	6.50%
Expected return on plan assets	**7.50%**	7.50%	**7.32%**	7.30%
Rate of compensation increase	**4.50%**	4.50%	**4.50%**	4.50%

The expected long-term rate of return on plan assets is derived from historical returns for broad asset classes consistent with expectations from a variety of sources, including pension consultants and investment advisors.

	2004	2003
ASSUMED HEALTH CARE COST TREND RATES AT DECEMBER 31:		
Health-care cost trend rate	**19.00%***	30.00%*
Rate to which the cost trend rate is assumed to decline (the ultimate trend)	**5.50%**	5.50%
Year that the rate reaches the ultimate trend	**2008**	2008

* This is the weighted average of the increases for all health plans. The rate for these plans ranged from 10% to 20% in 2004 and from 15% to 40% in 2003, respectively.

Assumed health-care cost trend rates have a significant effect on the amounts reported for the health-care plan costs. A one-percent change in assumed health-care cost trend rates would have the following effects:

(Dollars in millions)	1% Increase	1% Decrease
Effect on total of service and interest cost components of net periodic postretirement health-care benefit cost	$ 13	$ 10
Effect on the health-care component of the accumulated other postretirement benefit obligation	$134	$106

Pension Plan Investment Strategy

The asset allocation for the company's pension trust (which includes other postretirement benefit plans, except for those of the California Utilities separately described below) at December 31, 2004 and 2003 and the target allocation for 2005 by asset categories are as follows:

	Target Allocation	Percentage of Plan Assets at December 31,	
Asset Category	2005	**2004**	2003
U.S. Equity	45%	**45%**	45%
Foreign Equity	25	**32**	30
Fixed Income	30	**23**	25
Total	100%	**100%**	100%

The company's investment strategy is to stay fully invested at all times and maintain its strategic asset allocation, keeping the investment structure relatively simple. The equity portfolio is balanced to maintain risk characteristics similar to the S&P 1500 with respect to market capitalization, and industry and sector exposures. The foreign equity portfolios are managed to track the MSCI Europe, Pacific Rim and Emerging Markets indexes. Bond portfolios are managed with respect to the Lehman Aggregate Index. The plan does not invest in securities of the company.

Investment Strategy for SoCalGas' Other Postretirement Benefit Plans

The asset allocation for SoCalGas' other postretirement benefit plans at December 31, 2004 and 2003 and the target allocation for 2005 by asset categories are as follows:

	Target Allocation	Percentage of Plan Assets at December 31,	
Asset Category	2005	**2004**	2003
U.S. Equity	70%	**73%**	71%
Fixed Income	30	**27**	27
Cash	0	**0**	2
Total	100%	**100%**	100%

SoCalGas' other postretirement benefit plans, which are distinct from other postretirement benefit plans included in the company's pension trust (shown above), are funded by cash contributions from SoCalGas and the retirees. The asset allocation is designed to match the long-term growth of the plan's liability. These plans are managed using index funds.

Investment Strategy for SDG&E's Postretirement Health Plans

The asset allocation for SDG&E's postretirement health plans at December 31, 2004 and 2003 and the target allocation for 2005 by asset categories are as follows:

Asset Category	Target Allocation 2005	Percentage of Plan Assets at December 31, **2004**	2003
U.S. Equity	25%	**25%**	26%
Foreign Equity	5	**6**	5
Fixed Income	70	**69**	69
Total	100%	**100%**	100%

SDG&E's postretirement health plans, which also are distinct from other postretirement benefit plans included in the company's pension trust (shown above), pay premiums to the health maintenance organization and point-of-service plans from company and participant contributions. SDG&E's investment strategy is to match the long-term growth rate of the liability primarily through the use of tax-exempt California municipal bonds.

Future Payments

The company expects to contribute $34 million to the pension plans and $58 million to the other postretirement benefit plans in 2005.

The following table reflects the total benefits expected to be paid for the next 10 years to current employees and retirees from the plans or from the company's assets, including both the company's share of the benefit cost and, where applicable, the participants' share of the costs, which is funded by participant contributions to the plans.

(Dollars in millions)	Pension Benefits	Other Postretirement Benefits
2005	$ 175	$ 42
2006	$ 194	$ 45
2007	$ 190	$ 48
2008	$ 200	$ 50
2009	$ 208	$ 52
2010 — 2014	$1,168	$295

The expected future Medicare Part D subsidy payments are as follows:

(Dollars in millions)	
2005	$—
2006	$ 3
2007	$ 3
2008	$ 4
2009	$ 4
2010 — 2014	$24

Savings Plans

The company offers trusteed savings plans to all eligible employees. Eligibility to participate in the plans is immediate for salary deferrals. Employees may contribute, subject to plan provisions, from one

percent to 25 percent of their regular earnings. After one year of completed service, the company begins to make matching contributions. Employer contribution amounts and methodology vary by plan, but generally the contributions are equal to 50 percent of the first 6 percent of eligible base salary contributed by employees and, if certain company goals are met, an additional amount related to incentive compensation payments.

Employer contributions are invested in company stock and had been required to remain so invested until termination of employment or until the employee's attainment of age 55, when they could be transitioned into other investments. Effective January 1, 2005, all employees have the ability to transfer employer contributions into other investments. The employees' contributions are invested in company stock, mutual funds, institutional trusts or guaranteed investment contracts (the same investments in which employees may now direct the employer contributions). The plans of certain non-wholly owned subsidiaries prohibit investments in stock of the company. In this case, the employer matching contributions are invested to mirror the employee-directed contributions. Employer contributions for the Sempra Energy and SoCalGas plans are partially funded by the Employee Stock Ownership Plan referred to below. Company contributions to the savings plans were $25 million in 2004, $22 million in 2003 and $20 million in 2002. The market value of company stock held by the savings plans was $801 million and $675 million at December 31, 2004 and 2003, respectively.

Sempra Commodities also operates defined contribution plans outside of the United States. The contributions made by the company to such plans were $3 million, $3 million and $2 million in 2004, 2003 and 2002, respectively.

Employee Stock Ownership Plan

All contributions to the ESOP Trust (described in Note 6) are made by the company; there are no contributions made by the participants. As the company makes contributions, the ESOP debt service is paid and shares are released in proportion to the total expected debt service. Compensation expense is charged and equity is credited for the market value of the shares released. Dividends on unallocated shares are used to pay debt service and are applied against the liability. The Trust held 2.1 million shares and 2.4 million shares, respectively, of Sempra Energy common stock, with fair values of $78.7 million and $71.6 million, at December 31, 2004 and 2003, respectively.

NOTE 10. STOCK-BASED COMPENSATION

Sempra Energy has stock-based compensation plans intended to align employee and shareholder objectives related to the long-term growth of the company. The plans permit a wide variety of stock-based awards, including nonqualified stock options, incentive stock options, restricted stock, stock appreciation rights, performance awards, stock payments and dividend equivalents.

In 2004, 2003 and 2002, 1,223,000, 1,359,500, and 544,100 shares of restricted company stock, respectively, were awarded to key employees. Compensation expense for the issuance of the restricted stock was $37 million in 2004, $16 million in 2003 and $7 million in 2002. The corresponding weighted average market values per share at the time of grant were $30.57, $24.42 and $24.77, respectively. Subject to earlier forfeitures upon termination of employment, the 2004 and 2003 awards are scheduled to vest at the end of four years if performance-based goals are satisfied, except in the event of a change in control or in certain cases where employment agreements provide alternate methods of vesting. The 2002 award is scheduled to vest at the end of seven years, but is also subject to earlier vesting over a four-year period upon satisfaction of objective performance-based goals. Holders of restricted stock have full voting rights. They also have full dividend rights, except for senior officers, whose dividends are reinvested to purchase additional shares that become subject to the same performance-based vesting conditions as the restricted stock to which they relate.

In 2004, 2003 and 2002, the company granted to directors, officers and key employees options to acquire 1,389,000, 1,848,000 and 3,444,300 shares of stock, respectively. The option prices were equal to the market price of common stock at the dates of grant. The officers' and key employees' options vest over four-year periods (sooner in the event of a change in control or in certain cases of employment agreements) and expire 10 years from the dates of grant, subject to earlier expiration upon termination of employment. Compensation expense (or reduction thereof) for stock option grants (all associated with outstanding options with dividend equivalents that were issued before 2001 as discussed below) and similar awards was $4 million, $6 million and ($2 million) in 2004, 2003 and 2002, respectively.

The plans permit the granting of dividend equivalents with the stock option grants. For such grants, all of which are now fully vested, recipients receive dividends during the period they hold the options.

As of December 31, 2004, 14,358,630 shares were authorized and available for future grants of restricted stock and/or stock options. In addition, on January 1 of each year, additional shares equal to 1.5 percent of the outstanding shares of Sempra Energy common stock become available for grant.

In 1995, SFAS 123 was issued. It encourages a fair-value-based method of accounting for stock-based compensation. As permitted by SFAS 123, the company adopted only its disclosure requirements and continues to account for stock-based compensation in accordance with the provisions of APBO 25. Discussion of SFAS 123R (a revision of SFAS 123) is provided in Note 1.

STOCK OPTION ACTIVITY

	Shares Under Option	Weighted Average Exercise Price	Options Exercisable at December 31
OPTIONS WITH DIVIDEND EQUIVALENTS			
December 31, 2001	3,320,347	$22.38	2,508,328
Exercised	(172,358)	$19.87	
Cancelled	(68,124)	$24.03	
December 31, 2002	3,079,865	$22.48	2,777,590
Exercised	(876,391)	$20.81	
Cancelled	(17,649)	$24.72	
Transfer (see table below)	(1,536,775)	$23.24	
December 31, 2003	649,050	$22.89	649,050
Exercised	**(286,539)**	**$21.04**	
December 31, 2004	**362,511**	**$22.44**	**362,511**

	Shares Under Option	Weighted Average Exercise Price	Options Exercisable at December 31
OPTIONS WITHOUT DIVIDEND EQUIVALENTS			
December 31, 2001	9,874,454	$21.19	3,143,319
Granted	3,444,300	$24.71	
Exercised	(223,430)	$17.70	
Cancelled	(84,137)	$21.70	
December 31, 2002	13,011,187	$22.18	5,287,437
Granted	1,848,000	$24.44	
Exercised	(1,050,199)	$20.16	
Cancelled	(111,906)	$23.83	
Transfer (see table above)	1,536,775	$23.24	
December 31, 2003	15,233,857	$22.69	8,610,732
Granted	**1,389,000**	**$30.33**	
Exercised	**(3,837,541)**	**$20.96**	
Cancelled	**(73,110)**	**$25.79**	
December 31, 2004	**12,712,206**	**$24.06**	**7,771,556**

Additional information on options outstanding at December 31, 2004, is as follows:

Range of Exercise Prices	Number of Shares	Weighted Average Remaining Life	Weighted Average Exercise Price
Outstanding Options			
$ 16.87 - $ 21.00	2,797,522	4.55	$20.08
$ 22.50 - $ 25.20	7,663,183	6.80	$23.90
$ 26.31 - $ 35.73	2,614,012	6.51	$28.54
	13,074,717	6.26	$24.01
Exercisable Options			
$ 16.87 - $ 21.00	2,769,397		$20.09
$ 22.50 - $ 25.20	4,120,658		$23.66
$ 26.31 - $ 35.73	1,244,012		$26.50
	8,134,067		$22.88

The grant-date fair value of each option grant (including dividend equivalents where applicable) was estimated using a modified Black-Scholes option-pricing model. Weighted average grant-date fair values for options granted in 2004, 2003 and 2002 were $6.32, $4.31 and $4.45, respectively.

The assumptions that were used to determine these grant-date fair values are as follows:

	2004	2003	2002
Stock price volatility	**25%**	25%	22%
Risk-free rate of return	**3.7%**	3.4%	4.8%
Annual dividend yield	**3.3%**	4.1%	4.1%
Expected life	**6 Years**	6 Years	6 Years

NOTE 11. FINANCIAL INSTRUMENTS

Fair Value

The fair values of certain of the company's financial instruments (cash, temporary investments, notes receivable, dividends payable, short-term debt, debt related to Mesquite Power and customer deposits) approximate their carrying amounts. The following table provides the carrying amounts and fair values of the remaining financial instruments at December 31:

	2004		2003	
(Dollars in millions)	Carrying Amount	Fair Value	Carrying Amount	Fair Value
Investments in limited partnerships	**$ 194**	**$ 262**	$ 236	$ 352
First mortgage bonds	**$1,486**	**$1,521**	$1,561	$1,578
Notes payable	**1,800**	**1,876**	1,700	1,842
Equity units	**600**	**747**	600	680
SDG&E rate-reduction bonds	**198**	**241**	263	284
Debt incurred to acquire limited partnerships	**76**	**87**	110	128
Long-term debt	**434**	**451**	414	436
Total long-term debt	**$4,594**	**$4,923**	$4,648	$4,948
Due to unconsolidated affiliates	**$ 362***	**$ 383**	$ 362*	$ 392
Preferred stock of subsidiaries	**$ 200****	**$ 186**	$ 203**	$ 184

* Includes $200 million of mandatorily redeemable trust preferred securities.

** $21 million and $24 million in 2004 and 2003, respectively, of mandatorily redeemable preferred stock of subsidiaries is included in Deferred Credits and Other Liabilities and in Other Current Liabilities on the Consolidated Balance Sheets.

The fair values of investments in limited partnerships were based on the present value of estimated future cash flows, discounted at rates available for similar investments. The fair values of debt incurred to acquire limited partnerships were estimated based on the present value of the future cash flows, discounted at rates available for similar notes with comparable maturities. The fair values of the other long-term debt, preferred stock and mandatorily redeemable trust preferred securities are based on their quoted market prices or quoted market prices for similar securities.

Accounting for Derivative Instruments and Hedging Activities

The company follows the guidance of SFAS 133 and related amendments SFAS 138 and 149 (collectively SFAS 133) to account for its derivative instruments and hedging activities. Derivative instruments and related hedges are recognized as either assets or liabilities on the balance sheet, measured at fair value. Changes in the fair value of derivatives are recognized in earnings in the period of change unless the derivative qualifies as an effective hedge that offsets certain exposure.

SFAS 133 provides for hedge accounting treatment when certain criteria are met. For derivative instruments designated as fair value hedges, the gain or loss is recognized in earnings in the period of change (favorable impacts of $68 million in 2004 and $16 million in 2003 related to fair value hedges, and unfavorable impacts of $3 million in 2004 and $1 million in 2003 related to cash flow hedges) together with the offsetting gain or loss on the hedged item attributable to the risk being hedged; therefore, there is no effect on net income. For derivative instruments designated as cash flow hedges, the effective portion of the derivative gain or loss is included in other comprehensive income, but not reflected in the Statements of Consolidated Income until the corresponding hedged transaction is similarly reflected. The ineffective portion is reported in earnings immediately. The effect on other comprehensive income for the years ended December 31, 2004 and 2003 was $36 million and

$3 million, respectively, all related to cash flow hedges. The balance in Accumulated Other Comprehensive Income at December 31, 2004 related to cash flow hedges was $39 million. In instances where derivatives do not qualify for hedge accounting, gains and losses are recorded in earnings immediately.

The company utilizes derivative instruments to reduce its exposure to unfavorable changes in commodity prices, which are subject to significant and often volatile fluctuation. Derivative instruments include futures, forwards, swaps, options and long-term delivery contracts. These contracts allow the company to predict with greater certainty the effective prices to be received by the company and, in the case of the California Utilities, the prices to be charged to their customers. At the California Utilities, the use of derivative financial instruments is subject to certain limitations imposed by company policy and regulatory requirements. The company classifies its forward contracts as follows:

Contracts that meet the definition of normal purchases and sales, i.e., those that rarely settle by means other than physical delivery of the commodities involved in the transaction, are eligible for the normal purchases and sales exception of SFAS 133, whereby they are accounted for under accrual accounting and recorded in Revenues or Cost of Sales on the Statements of Consolidated Income at the time of delivery. Due to the adoption of SFAS 149, the company has determined that its natural gas contracts entered into after June 30, 2003 generally do not qualify for the normal purchases and sales exception.

Electric and Natural Gas Purchases and Sales: As they relate to the California Utilities, the unrealized gains and losses related to these forward contracts are offset by regulatory assets and liabilities on the Consolidated Balance Sheets to the extent derivative gains and losses will be recoverable or payable in future rates. If gains and losses at the California Utilities are not recoverable or payable through future rates, the California Utilities apply hedge accounting if certain criteria are met. When a contract no longer meets the requirements of SFAS 133, the unrealized gains and losses and the related regulatory asset or liability will be amortized over the remaining contract life.

The following were recorded on the Consolidated Balance Sheets at December 31 related to derivatives:

(Dollars in millions)	**2004**	2003
Fixed-price Contracts and Other Derivatives:		
Current liabilities	**$157**	$148
Noncurrent liabilities	**500**	680
Total liabilities	**657**	828
Other current assets	**8**	26
Sundry assets	**14**	—
Total assets	**22**	26
Net liabilities	**$635**	$802

Regulatory assets and liabilities related to derivatives held by the California Utilities at December 31 were:

(Dollars in millions)	**2004**	2003
Regulatory Assets and Liabilities:		
Current regulatory assets	**$152**	$144
Other regulatory assets	**500**	650
Total	**652**	794
Current regulatory liabilities	**4**	1
Net regulatory assets	**$648**	$793

As of December 31, 2004, the difference between net liabilities and net regulatory assets ($13 million) was due to market value adjustments related to fixed-to-floating interest-rate swaps. As of December 31, 2003, the difference between net liabilities and net regulatory assets ($9 million) was primarily due to $30 million related to a derivative contract associated with the purchase of the Cameron LNG facility offset by $23 million related to a fixed-to-floating interest-rate swap.

Pre-tax income from transactions associated with fixed-price contracts and other derivatives included $13 million of income in 2004 recorded in Other Income, Net and $2 million of losses in 2003 recorded in Operating Revenues in the Statements of Consolidated Income.

Market Risk

The company's policy is to use derivative physical and financial instruments to reduce its exposure to fluctuations in interest rates, foreign currency exchange rates and commodity prices. The company also uses and trades derivative instruments in its trading and marketing of energy and other commodities. Transactions involving these instruments are with major exchanges and other firms believed to be credit-worthy. The use of these instruments exposes the company to market and credit risk, which may at times be concentrated with certain counterparties, although counterparty nonperformance is not anticipated.

Interest-Rate Risk Management

The company periodically enters into interest-rate swap agreements to moderate its exposure to interest-rate changes and to lower the overall cost of borrowing. This is described in Note 6.

Energy Derivatives

The company utilizes derivative instruments to reduce its exposure to unfavorable changes in energy prices, which are subject to significant and often volatile fluctuation. Derivative instruments are comprised of futures, forwards, swaps, options and long-term delivery contracts. These contracts allow the company to predict with greater certainty the effective prices to be received.

Energy Contracts

The California Utilities record transactions for natural gas and electric energy contracts in Cost of Natural Gas and Cost of Electric Fuel and Purchased Power, respectively, in the Statements of Consolidated Income. For open contracts not expected to result in physical delivery, changes in market value of the contracts are recorded in these accounts during the period the contracts are open, with an offsetting entry to a regulatory asset or liability. The majority of the California Utilities' contracts result in physical delivery, which is infrequent at the trading operations.

Sempra Commodities

Sempra Commodities derives revenue from market making and trading activities, as a principal, in natural gas, electricity, petroleum products, metals and other commodities, for which it quotes bid and asked prices to other market makers and end users. It also earns trading profits as a dealer by structuring and executing transactions that permit its counterparties to manage their risk profiles. Sempra Commodities utilizes derivative instruments to reduce its exposure to unfavorable changes in market prices, which are subject to significant and often volatile fluctuation. These instruments include futures, forwards, swaps and options, and represent contracts with counterparties under which payments are linked to or derived from energy market indices or on terms predetermined by the contract, which may or may not be financially settled by Sempra Commodities. Sempra Energy guarantees many of Sempra Commodities' transactions.

Sempra Commodities also derives a portion of its revenue from delivering electric and natural gas supplies to its commercial and industrial customers. Such contracts are hedged to preserve margin and reduce market risk. The derivative instruments used to hedge the transactions include swaps, forwards, futures, options or combinations thereof.

Trading instruments for all activities are recorded by Sempra Commodities on a trade-date basis and the majority of such derivative instruments are adjusted daily to current market value with gains and losses recognized in Other Operating Revenues on the Statements of Consolidated Income. These instruments are included on the Consolidated Balance Sheets as trading assets or trading liabilities and include amounts due from commodity clearing organizations, amounts due to or from trading counterparties, unrealized gains and losses from exchange-traded futures and options, derivative OTC swaps, forwards and options. Unrealized gains and losses on OTC transactions reflect amounts that would be received from or paid to a third party upon settlement of the contracts. Unrealized gains and losses on OTC transactions are reported separately as assets and liabilities unless a legal right of setoff exists under an enforceable netting arrangement. Other derivatives which qualify as hedges are accordingly recorded under hedge accounting.

As a result of the rescission of EITF 98-10 (discussed in Note 1) energy commodity inventory is being recorded at the lower of cost or market; however metals inventories continue to be recorded at fair value in accordance with ARB 43. Note 2 discusses Sempra Commodities' acquisitions made in 2002, some of which were affected by EITF 98-10.

Futures and exchange-traded option transactions are recorded as contractual commitments on a trade-date basis and are carried at fair value based on closing exchange quotations. Commodity swaps and forward transactions are accounted for as contractual commitments on a trade-date basis and are carried at fair value derived from dealer quotations and underlying commodity exchange quotations. OTC options purchased and written are recorded on a trade-date basis. OTC options are carried at fair value based on the use of valuation models that utilize, among other things, current interest, commodity and volatility rates, as applicable.

The carrying values of trading assets and trading liabilities, primarily at Sempra Commodities, approximate the following:

	December 31,	
(Dollars in millions)	**2004**	2003
TRADING ASSETS		
Trading-related receivables and deposits, net:		
Due from trading counterparties	**$2,371**	$2,215
Due from commodity clearing organizations and clearing brokers	**235**	135
	2,606	2,350
Derivative trading instruments:		
Unrealized gains on swaps and forwards	**1,607**	1,148
OTC commodity options purchased	**732**	459
	2,339	1,607
Commodities owned	**1,547**	1,420
Total trading assets	**$6,492**	$5,377
TRADING LIABILITIES		
Trading-related payables	**$3,182**	$2,255
Derivative trading instruments sold, not yet purchased:		
Unrealized losses on swaps and forwards	**1,232**	1,114
OTC commodity options written	**252**	226
	1,484	1,340
Commodities sold with agreement to repurchase	**513**	922
Total trading liabilities	**$5,179**	$4,517

Based on quarterly measurements, the average fair values during 2004 for trading assets and liabilities approximate $5.7 billion and $4.6 billion, respectively. For 2003, the amounts were $5.1 billion and $4.4 billion, respectively.

At Sempra Commodities, market risk from market making and trading activities arises from the potential for changes in the value of physical and financial instruments resulting from fluctuations in prices and basis for natural gas, electricity, petroleum, petroleum products, metals and other commodities. Market risk is also affected by changes in volatility and liquidity in markets in which these instruments are traded. Market risk for electric and natural gas delivery contract activity from fluctuations in natural gas or electricity prices is reduced by Sempra Commodities' hedging strategy as described above.

Sempra Commodities' credit risk from physical and financial instruments as of December 31, 2004 is represented by their positive fair value after consideration of collateral. Options written do not expose Sempra Commodities to credit risk. Exchange traded futures and options are not deemed to have significant credit exposure since the exchanges guarantee that every contract will be properly settled on a daily basis. Credit risk is also associated with its retail customers.

The following table summarizes the counterparty credit quality and exposure for Sempra Commodities at December 31, 2004 and 2003, expressed in terms of net replacement value. These exposures are net of collateral in the form of customer margin and/or letters of credit of $1.1 billion and $569 million at December 31, 2004 and 2003, respectively.

	December 31,	
(Dollars in millions)	**2004**	2003
Counterparty credit quality*		
Commodity exchanges	**$ 235**	$ 135
AAA	**7**	5
AA	**259**	316
A	**562**	484
BBB	**680**	371
Below investment grade and not rated	**532**	417
Total	**$2,275**	$1,728

* As determined by rating agencies or internal models intended to approximate rating-agency determinations.

NOTE 12. PREFERRED STOCK OF SUBSIDIARIES

(in millions)	Call/ Redemption Price	December 31, 2004	2003
Not subject to mandatory redemption:			
Pacific Enterprises:			
Without par value, authorized 15,000,000 shares:			
$4.75 Dividend, 200,000 shares outstanding	$100.00	**$ 20**	$ 20
$4.50 Dividend, 300,000 shares outstanding	$100.00	**30**	30
$4.40 Dividend, 100,000 shares outstanding	$101.50	**10**	10
$4.36 Dividend, 200,000 shares outstanding	$101.00	**20**	20
$4.75 Dividend, 253 shares outstanding	$101.00	**—**	—
Total		**80**	80
SoCalGas:			
$25 par value, authorized 1,000,000 shares:			
6% Series, 28,041 shares outstanding		**1**	1
6% Series A, 783,032 shares outstanding		**19**	19
Without par value, authorized 10,000,000 shares		**—**	—
Total		**20**	20
SDG&E:			
$20 par value, authorized 1,375,000 shares:			
5% Series, 375,000 shares outstanding	$ 24.00	**8**	8
4.5% Series, 300,000 shares outstanding	$ 21.20	**6**	6
4.4% Series, 325,000 shares outstanding	$ 21.00	**7**	7
4.6% Series, 373,770 shares outstanding	$ 20.25	**7**	7
Without par value:			
$1.70 Series, 1,400,000 shares outstanding	$ 25.85	**35**	35
$1.82 Series, 640,000 shares outstanding	$ 26.00	**16**	16
Total		**79**	79
Total not subject to mandatory redemption		**179**	179
Subject to mandatory redemption:			
SDG&E:			
Without par value: $1.7625 Series, 850,000 and 950,000 shares outstanding at December 31, 2004 and December 31, 2003, respectively	$ 25.00	**21***	24*
Total preferred stock		**$200**	$203

* At December 31, 2004 and 2003, $19 million and $21 million, respectively, were included in Deferred Credits and Other Liabilities and $2 million and $3 million, respectively, were included in Other Current Liabilities on the Consolidated Balance Sheets.

PE preferred stock is callable at the applicable redemption price of each series, plus any unpaid dividends. The preferred stock is subject to redemption at PE's option at any time upon not less than 30 days' notice, at the applicable redemption price for each series, plus any unpaid dividends. All series have one vote per share and cumulative preferences as to dividends, and have a liquidation value of $100 per share plus any unpaid dividends.

None of SoCalGas' preferred stock is callable. All series have one vote per share and cumulative preferences as to dividends, and have a liquidation value of $25 per share plus any unpaid dividends.

All series of SDG&E's preferred stock have cumulative preferences as to dividends. The $20 par value preferred stock has two votes per share on matters being voted upon by shareholders of SDG&E and a liquidation value at par, whereas the no-par-value preferred stock is nonvoting and has a liquidation value of $25 per share plus any unpaid dividends. SDG&E is authorized to issue 10,000,000 shares of no-par-value preferred stock (both subject to and not subject to mandatory redemption). All series are callable at December 31, 2004. The $1.7625 Series has a sinking fund requirement to redeem 50,000 shares at $25 per share per year from 2005 to 2007; all remaining shares must be redeemed in 2008. On January 15, 2005, SDG&E redeemed 100,000 shares.

NOTE 13. SHAREHOLDERS' EQUITY AND EARNINGS PER SHARE (EPS)

The following table provides the per share computations for income from continuing operations for the year ended December 31, 2004:

	Income (millions) (numerator)	Shares (thousands) (denominator)	Per Share Amounts
Basic EPS—income from continuing operations	$920	228,271	$ 4.03
Effect of dilutive securities:			
Stock options and restricted stock awards		3,595	(0.06)
Equity Units		1,986	(0.04)
Diluted EPS—income from continuing operations	$920	233,852	$ 3.93

The only difference between basic and diluted earnings per share in 2003 and 2002 was the effect of common stock options. For 2003 and 2002, the effect of dilutive options was equivalent to an additional 2,742,000 and 1,059,000 shares, respectively. The dilution from common stock options is based on the treasury stock method, whereby the proceeds from the exercise price are assumed to be used to repurchase shares on the open market at the average market price for the year. The calculation excludes options covering an average of 0.1 million and 6.0 million shares for 2003 and 2002, respectively, for which the exercise price was greater than the average market price for common stock during the respective year. In 2004, there were no such options. The company's equity units, described below, had no dilutive effect in 2003 or 2002.

The dilution from unvested restricted stock awards is based on the treasury stock method, whereby assumed proceeds equivalent to the unearned compensation related to the awards are assumed to be used to repurchase shares on the open market at the average market price for the year. In 2003 and 2002, there were restricted awards representing an average of 1.3 million and 0.7 million shares, respectively, that did not affect the calculation since their grant price was greater than the average market price for common stock during the respective year. In 2004 there were no such awards.

The company is authorized to issue 750,000,000 shares of no-par-value common stock and 50,000,000 shares of preferred stock.

Excluding shares held by the ESOP, common stock activity consisted of the following:

	2004	2003	2002
Common shares outstanding, January 1	**226,598,619**	204,911,572	204,475,362
Public issuance	—	16,500,000	—
Savings plan issuance*	**1,638,581**	1,436,526	—
Shares released from ESOP	**236,620**	170,613	130,486
Stock options exercised	**4,124,080**	1,926,590	395,788
Restricted stock	**1,223,000**	1,359,500	544,100
Common stock investment plan**	**611,259**	728,241	212,411
Shares repurchased	**(181,819)**	(262,286)	(818,639)
Shares forfeited and other	**(74,360)**	(172,137)	(27,936)
Common shares outstanding, December 31	**234,175,980**	226,598,619	204,911,572

* Prior to 2003, the plan purchased shares in the open market to cover the company's contributions to the savings plan.

** Participants in the Direct Stock Purchase Plan may reinvest dividends to purchase newly issued shares.

The payment of future dividends and the amount thereof are within the discretion of the company's board of directors. The CPUC's regulation of the California Utilities' capital structure limits the amounts that are available for dividends and loans to the company from the California Utilities. At December 31, 2004, SDG&E and SoCalGas could have provided a total of $160 million and $200 million, respectively, to Sempra Energy, through dividends and loans.

Equity Units

In 2002, the company issued $600 million of equity units. Each unit consists of $25 principal amount of the company's 5.60% senior notes due May 17, 2007 and a contract to purchase for $25 on May 17, 2005, between .8190 and .9992 of a share of the company's common stock (with the precise number to be determined by the then-average market price). The number of shares to be issued ranges from 20 million to 24 million. The equity units are included in Long-Term Debt on the Consolidated Balance Sheets. Through December 31, 2004, $55 million had been charged to the common stock account in connection with the transaction. In February 2005, the company remarketed the senior notes for their remaining term at a rate of 4.62%.

Common Stock Offering

On October 14, 2003, Sempra Energy completed a common stock offering of 16.5 million shares priced at $28 per common share, resulting in net proceeds of $448 million. The proceeds were used primarily to pay off short-term debt.

NOTE 14. ELECTRIC INDUSTRY REGULATION

Background

The restructuring of California's electric utility industry has significantly affected the company's electric utility operations, and the power crisis of 2000-2001 caused the CPUC to significantly modify its plan for restructuring the electricity industry. Supply/demand imbalances and a number of other factors resulted in abnormally high electric-commodity prices beginning in mid-2000 and continuing into 2001. These higher prices were initially passed through to customers and resulted in bills that in most cases were double or triple those from 1999 and early 2000. This resulted in several legislative and regulatory responses, including California Assembly Bill (AB) 265. AB 265 imposed a ceiling on the cost of the electric commodity that SDG&E could pass on to its small-usage customers from June 1, 2000 to December 31, 2002.

SDG&E accumulated the amount that it paid for electricity in excess of the ceiling rate in an interest-bearing balancing account (the AB 265 undercollection, which is included in Regulatory Balancing Accounts, Net on the Consolidated Balance Sheets) and began recovering these amounts in rates charged to customers following the end of the rate-ceiling period. The remaining AB 265 undercollection was fully collected in 2004.

Another legislative response to the power crisis resulted in the purchase by the DWR of a substantial portion of the power requirements of California's electricity users. In 2001, the DWR entered into long-term contracts with suppliers, including Sempra Generation, to provide power for the utility procurement customers of each of the California investor-owned utilities (IOUs). The CPUC has established the allocation of the power and its administrative responsibility, including collection of power contract costs from utility customers, among the IOUs. Beginning on January 1, 2003, the IOUs resumed responsibility for electric commodity procurement above their allocated share of the DWR's long-term contracts.

Department of Water Resources

The DWR's operating agreement with SDG&E, approved by the CPUC, provides that SDG&E is acting as a limited agent on behalf of the DWR in undertaking energy sales and natural gas procurement functions under the DWR contracts allocated to SDG&E's customers. Legal and financial responsibility associated with these activities continues to reside with the DWR. Therefore, the revenues and costs associated with the contracts are not included in the Statements of Consolidated Income.

In October 2003, the CPUC initiated a proceeding to consider a permanent methodology for allocating the DWR's revenue requirement beginning in 2004 through the remaining life of the DWR contracts. On December 2, 2004, the CPUC issued a decision that would shift $790 million of the costs to SDG&E's customers over the period between implementation of the decision and 2013. On December 20, 2004, SDG&E filed an application for rehearing of the decision, arguing that the CPUC reached its decision without the proper evidentiary review of the method of calculating above-market costs. On January 13, 2005, the CPUC acted to grant rehearing on that limited issue.

Such a shift would not affect SDG&E's net income, but would adversely affect its customers' commodity costs. In the near term, the effect on SDG&E's cash flows would be minor, but could become significant in the later years unless rate ceilings imposed by Assembly Bill 1X, which freeze total rates for most residential customers at the February 2001 level, are increased to provide more-contemporaneous recovery. Until January 1, 2016, CPUC Decision 04-12-048 provides SDG&E with a true-up triggering mechanism when an overcollection or undercollection in SDG&E's power procurement balancing account exceeds approximately five percent of the prior year's recorded electric commodity revenue.

Power Procurement and Resource Planning

In 2001, the CPUC directed the IOUs to resume electric commodity procurement to cover their net short energy requirements by January 1, 2003 and also implemented legislation regarding procurement and renewables portfolio standards. In addition, the CPUC established a process for review and approval of the utilities' long-term resource and procurement plans, which is intended to identify forecasted needs for generation and transmission resources within a utility's service territory to support transmission grid reliability and to serve customers. An updated 10-year resource plan was approved by the CPUC in December 2004, in a proceeding to consider utility resource planning, including energy efficiency, contracted power, demand response, qualifying facilities, renewable generation and distributed generation. SDG&E's updated long-term resource plan incorporates the resources approved by the CPUC that are discussed below, and recognizes updated CPUC goals to

reach a 20-percent renewable resources target by 2010. The updated plan recommends a 500-kV transmission line addition in 2010, which would be processed for approval in a subsequent CPUC proceeding. The CPUC also endorsed SDG&E's continued analysis and planning for a 500-kV transmission line, adopted SDG&E's proposal for cost recovery related to utility-owned generation, recognized the debt-equivalent impact associated with long-term power purchase contracts, adopted a greenhouse gas adder for assessing new resource acquisitions, and established a cap on initial costs for new utility-owned generation resources to level the playing field with respect to power purchase options. The estimated capital cost related to this updated plan is $700 million, to be spent by 2007, for capital projects approved by the CPUC in June 2004, as described below.

On June 9, 2004, the CPUC approved SDG&E's entering into five new electric resource contracts (including two under which SDG&E would take ownership, on a turnkey basis, of new generating assets, including the 550-MW combined-cycle Palomar plant being developed by Sempra Generation for completion in 2006). An additional, demand-response contract was also approved. The decision authorized SDG&E to recover the costs of both contracted resources and turnkey resources, but did not adopt SDG&E's specific cost recovery, ratemaking and revenue requirement proposals for the proposed turnkey resources. On July 15, 2004, three parties filed requests for rehearing of the decision. SDG&E filed its response on July 30, 2004, opposing the requests. The CPUC is expected to rule on the requests by mid-2005. In September 2004, SDG&E filed its revenue requirement and ratemaking proposals for the 45-MW combustion turbine which SDG&E will acquire as a turnkey project and filed its revenue requirement and ratemaking proposals for the Palomar plant on November 1, 2004. On January 27, 2005, the CPUC approved the revenue requirement and ratemaking proposals for the 45-MW combustion turbine. The June 9, 2004, decision did not approve SDG&E's proposals for a return on equity (ROE) for SDG&E's new generation investments higher than SDG&E's ROE on distribution assets, an equity offset for the debt-equivalent of purchase power contracts or an equity buildup for construction. These matters may be re-introduced for consideration in future CPUC proceedings.

SONGS

Southern California Edison's (Edison) CPUC decision on its 2003 General Rate Case application sets rates for SONGS, 20 percent of which is owned by SDG&E. Through December 31, 2003, the operating and capital costs of SONGS Units 2 and 3 were recovered through the ICIP mechanism which allowed SDG&E to receive 4.4 cents per kilowatt-hour for SONGS generation. For the year ended December 31, 2003, ICIP contributed $53 million to SDG&E's net income. SDG&E's SONGS ratebase restarted at $0 on January 1, 2004 and, therefore, SDG&E's earnings from SONGS are now generally limited to a return on new capital additions.

Edison has applied for CPUC approval to replace SONGS' steam generators, which would require an estimated capital expenditure of $782 million. Hearings before the CPUC on Edison's application were completed on February 11, 2005 and a final decision addressing the cost effectiveness of the steam generator project is expected during the second half of 2005. SDG&E had elected not to participate in the project. SDG&E nonparticipation would result in a reduction in its share ownership in the project and a proportionate reduction in its share of SONGS' output. On February 18, 2005, an arbitrator issued a decision that, based upon Edison's cost calculations, would result in SDG&E's interest in SONGS being reduced to zero if SDG&E continues to decline to participate in the project. The arbitration decision is subject to CPUC review and approval, with a CPUC decision expected in the second half of 2006. The CPUC could require SDG&E to participate in the project or, if the reductions of SDG&E's ownership percentage resulting from the CPUC final decision were to be unacceptable, SDG&E may elect to participate.

During the most recent SONGS Unit 3 refueling outage which ended on December 28, 2004, Edison reported that it had performed inspections of two pressurizer sleeves and found evidence of

degradation. Degradation of the pressurizer sleeves has been a concern in the nuclear industry for some time. Edison had been planning to replace all of the sleeves in Units 2 and 3 during the next refueling for each unit in 2005 and 2006, but decided to move the planned replacement of Unit 3's pressurizer sleeves forward from 2006 to 2004. This extra work lengthened the 2004 outage, but allowed Edison to move the 2006 refueling outage out of the peak summer period to the fall or winter of 2006. Edison reported that it will incur about $9 million of capital expenditures during 2005 that otherwise would have occurred in 2006. SDG&E's share would be approximately $2 million. Edison plans to replace the pressurizer sleeves in Unit 2 during its next scheduled outage in 2005.

Also during the 2004 outage, Edison reported that it had conducted a planned inspection of the Unit 3 reactor vessel head and found indications of degradation. Although the degradation is far below the level at which leakage would occur, Edison made the repairs during the 2004 outage. While Edison reports that this is the first experience at SONGS of this kind of degradation to the reactor vessel heads, the detection and repair of similar degradation at other plants are now common in the industry. Edison reports that it plans to replace the Unit 2 and Unit 3 reactor vessel heads during refueling outages in 2009-2010.

Spent Nuclear Fuel

SONGS owners have responsibility for the interim storage of spent nuclear fuel generated at SONGS until it is accepted by the DOE for final disposal. Spent nuclear fuel has been stored in the SONGS Units 1, 2 and 3 spent fuel pools and the ISFSI. Movement of all spent fuel to the ISFSI was completed as of December 31, 2004, except for the movement of Unit 1 spent fuel stored at the Unit 2 spent fuel pool, which is expected to be completed by the end of 2005. With these moves, there will be sufficient space for the Units 2 and 3 spent fuel pools to meet requirements through mid-2007 and mid-2008, respectively.

NOTE 15. OTHER REGULATORY MATTERS

Natural Gas Industry Restructuring (GIR)

In December 2001, the CPUC issued a decision related to GIR, with implementation anticipated during 2002. On April 1, 2004, after many delays and changes, the CPUC issued a decision that adopts tariffs to implement the 2001 decision. However, by that same decision, the CPUC stayed implementation of the GIR tariffs until it issues a decision in Phase I of the Natural Gas Market Order Instituting Ratemaking (OIR) discussed below. At that time, the CPUC will reconcile the GIR market structure with whatever structure results from the Phase I decision of the Natural Gas Market OIR. If implemented, the stayed decision would unbundle the costs of SoCalGas' backbone transmission system from rates and result in revising noncore balancing account treatment to exclude the balancing of SoCalGas' backbone transmission costs and place SoCalGas at risk for recovery of $80 million for transmission and $81 million for storage (current dollars). The decision would create firm tradable rights for the transmission system. Other noncore costs/revenues would continue to be fully balanced until the decision in the next Biennial Cost Allocation Proceeding (BCAP) discussed below.

Natural Gas Market OIR

The CPUC's Natural Gas Market OIR was instituted in January 2004, and will be addressed in two phases. A decision on Phase I was issued in September 2004 and Phase II is awaiting CPUC direction on further proceedings. In Phase I, the CPUC's objective was to develop a process enabling the CPUC to review and pre-approve new interstate capacity contracts before they are executed. In addition, the California Utilities must submit proposals on any LNG project to which interconnection is planned, providing costs and terms, including access to the pipelines in Mexico. Phase II will primarily address emergency reserves and ratemaking policies. The CPUC's objective in the ratemaking policy

component of Phase II is to identify and propose changes to policies that create incentives that are consistent with the goal of providing adequate and reliable long-term supplies and that do not conflict with energy efficiency programs. The focus of the Gas OIR is the period from 2006 to 2016. Since GIR, discussed above, would end in August 2006 and there is overlap between GIR and the OIR issues, a number of parties (including SoCalGas) have requested the CPUC not to implement GIR.

The California Utilities have made comprehensive filings in the OIR outlining a proposed market structure that is intended to create access to new natural gas supply sources (such as LNG) for California. In their Phase I and Phase II filings, SoCalGas and SDG&E proposed a framework to provide firm tradable access rights for intrastate natural gas transportation; provide SoCalGas with continued balancing account protection for intrastate transmission and distribution revenues, thereby eliminating throughput risk; and integrate the transmission systems of SoCalGas and SDG&E so as to have common rates and rules. The California Utilities also proposed that the capital expenditures necessary to access new sources of supply be included in ratebase and that the total amount of the expenditures would be $200 million to $300 million.

The California Utilities also proposed a methodology and framework to be used by the CPUC for granting pre-approval of new interstate transportation agreements. The Phase I decision approved the California Utilities' transportation capacity pre-approval procedures with some modifications. SoCalGas' existing pipeline capacity contracts with Transwestern Pipeline Company expire in November 2005 and its primary contracts with El Paso Natural Gas Company (El Paso) expire in August 2006. SoCalGas recently was granted pre-approval by the CPUC of a contract for released capacity on the Kern River Gas Transmission Company system, and four capacity contracts with El Paso. The contracts would expire between 2007 and 2011. In January 2005, SDG&E was granted pre-approval of a capacity contract with El Paso that would expire in 2007. In February 2005, SoCalGas filed for pre-approval of two new capacity contracts with Transwestern that would expire in 2009 and 2011. The CPUC's decision on pre-approval of the Transwestern contracts is expected to be received by March 2005. All interstate transportation capacity under the pre-approved contracts will be used to transport natural gas supplies on behalf of the California Utilities' core residential and small commercial customers, and all costs of the capacity will be recovered in the customers' rates through each utility's Purchased Gas Account, a balancing account. In December 2004, pursuant to the Phase I decision, SoCalGas filed an application to implement proposals for transmission system integration, firm access rights, and off-system delivery services. The CPUC has determined that the ratemaking treatment and cost responsibility for any access-related infrastructure will be addressed in future applications to be filed when more is known about the particular projects. Phase II of the Gas Market OIR will review the CPUC's ratemaking policies on throughput risk to better align these with its objectives of promoting energy conservation and adequate infrastructure. Phase II will also investigate the need for emergency natural gas storage reserves and the role of the utility in backstopping the noncore market.

Cost of Service

On December 2, 2004, the CPUC issued a decision in the California Utilities' cost of service proceedings that essentially approved settlements recommended by most major parties to the proceedings. The decision reduces the California Utilities' annual rate revenues, effective retroactively to January 1, 2004, by an aggregate net amount of approximately $56 million from the rates in effect during 2003. The reduced rates will remain in effect through 2007, subject to annual attrition allowances. Of the reduction, $10 million relates to what SDG&E believes to be a computational error concerning its nuclear electric rate revenues. With respect to the $10 million reduction, a Petition for Modification and an Application for Rehearing were filed in December 2004 and January 2005, respectively.

Attrition allowances, performance-based incentive mechanisms (PBR), which are described in the following section, and related matters are being addressed by the CPUC in Phase II of the cost of

service proceedings, expected to be decided in the first quarter of 2005. In addition to recommending changes in the PBR formulas, the CPUC's Office of Ratepayer Advocates (ORA) also proposed the possibility of performance penalties for service quality, safety and electric service reliability, without the possibility of performance awards. Hearings took place in June 2004. In July 2004, all of the active parties in Phase II who dealt with post-test-year ratemaking and performance incentives filed for adoption by the CPUC of an all-party settlement agreement for most of the Phase II issues, including annual inflation adjustments and earnings sharing. The proposed settlement does not cover performance incentives. For the interim years of 2005–2007, the Consumer Price Index would be used to adjust the escalatable authorized base rate revenues within identified floors and ceilings, each of which limits the adjustment to approximately two to five percent of the prior year's authorized base rate revenues.

The California Utilities had filed for continuation of existing PBR mechanisms for service quality and safety that would otherwise expire at the end of 2003. In January 2004, the CPUC issued a decision that extended 2003 service and safety targets through 2004, but did not determine the extent of rewards or penalties. As part of the proposed Phase II Settlement Agreement, earnings sharing, under which IOUs return to customers a percentage of earnings above specified levels, would be suspended for 2004 and resume for 2005 through 2007. The proposed earnings sharing mechanism also provides either utility the option to file for suspension of the earnings sharing mechanism if earnings fall 175 basis points or more below its authorized rate of return; however, if earnings are more than 300 basis points above the utility's authorized rate of return, the earnings sharing mechanism would be automatically suspended and trigger a formal regulatory review by the CPUC to determine whether modification of the ratemaking mechanism is required.

On February 15, 2005, the Administrative Law Judge (ALJ) and the CPUC Commissioner assigned to Phase II of the cost of service proceedings issued differing proposed decisions for consideration by the CPUC. If adopted by the CPUC, the ALJ's decision would not approve the parties' settlement of the Phase II issues, but would authorize the California Utilities to adjust their authorized revenues in each of years 2005 through 2007 on a formula basis similar to that proposed by the California Utilities and also establish performance measures with reward and penalty potentials of approximately $20 million. In addition, the ALJ's decision would have the utilities' cost of capital reviewed on an annual basis. If adopted by the CPUC, the Commissioner's proposed decision would approve the parties' settlement and also approve performance measures for customer service, safety and reliability with the same reward and penalty provisions as the ALJ's proposed decision. The Commissioner's proposed decision also would continue the use of the cost of capital adjustment mechanism currently in place, which adjusts each utility's rate of return automatically based on market indices. The CPUC may adopt either proposed decision, as proposed or with modifications, or reject both and adopt a different result.

The California Utilities had been equally sharing between ratepayers and shareholders the estimated savings for the 1998 business combination that created Sempra Energy. Pursuant to an October 2001 CPUC decision, that sharing has ceased and all merger savings go to ratepayers beginning with 2003.

Performance-Based Regulation

PBR consists of three primary components. The first is a mechanism to adjust rates in years between general rate cases or cost of service cases. It annually adjusts base rates from those of the prior year to provide for inflation, changes in the number of customers and efficiencies.

The second component is a mechanism whereby any earnings in excess of those authorized plus a narrow band above that are shared with customers in varying degrees depending upon the amount of the additional earnings.

The third component consists of a series of measures of utility performance. Generally, if performance is outside of a band around the specified benchmark, the utility is rewarded or penalized certain dollar amounts.

The three areas that have been eligible for PBR rewards or penalties are operational incentives based on measurements of safety, reliability and customer satisfaction; demand-side management (DSM) rewards based on the effectiveness of the programs; and natural gas procurement rewards or penalties. The CPUC is also considering a new reward/penalty related to electricity procurement, now that the utilities have resumed this activity. However, as noted under "Cost of Service," Phase II of the California Utilities' current cost of service proceeding is not complete. As a result, these safety, reliability and customer satisfaction incentive mechanisms (i.e., those that are reviewed in the Cost of Service proceeding) were not in effect during 2004. However, it is not expected that the effect would be other than a one-year moratorium of the mechanisms.

PBR, DSM and Gas Cost Incentive Mechanism (GCIM) rewards are not included in the company's earnings before CPUC approval is received. The only incentive rewards approved during 2004 consisted of $6.3 million related to SoCalGas' Year 9 GCIM, which was approved in February 2004, and $1.5 million related to SDG&E's Year 10 natural gas PBR, which was approved in August 2004. These rewards were awarded by the CPUC subject to refund based on the outcome of the Border Price Investigation discussed below. The cumulative amount of rewards subject to refund based on the outcome of the Border Price Investigation is $65.3 million, substantially all of which has been included in net income in 2004 or previously.

On December 30, 2004, a joint settlement agreement between the California Utilities and the ORA (collectively, the joint parties) was filed with the CPUC for approval. The settlement agreement resolves all outstanding shareholder earnings claims filed with the CPUC commencing in 2000 and those claims that would have been filed through 2007 and 2009, respectively, for SDG&E and SoCalGas, associated with DSM, energy efficiency and low-income energy efficiency programs. The proposed settlement is for $73 million and $14 million, respectively, for SDG&E and SoCalGas (including interest, franchise fees, uncollectible amounts and awards earned in prior years that had not yet then been requested). The joint parties requested expeditious approval of the settlement agreement, without modification. A CPUC decision is expected by the end of the second quarter of 2005.

At December 31, 2004, other performance incentives were pending CPUC approval and, therefore, were not included in the company's earnings (dollars in millions):

Program	SoCalGas	SDG&E	Total
2003 Distribution PBR	$ —	$8.2	$ 8.2
GCIM/natural gas PBR	2.4	.2	2.6
2003 safety	.5	—	.5
Total	$2.9	$8.4	$11.3

Cost of Capital

Effective January 1, 2005, SDG&E's authorized return on ratebase (ROR) and ROE became 8.18 percent and 10.37 percent, respectively, for its electric distribution and natural gas businesses, down from 8.77 percent and 10.9 percent, respectively. The decrease is a result of the CPUC's automatic triggering mechanism, which resets these rates whenever Moody's Aa utility bond yield as published by Mergent Bond Record changes by more than a specified amount. The current benchmark is 6.19 percent and an automatic adjustment would be triggered if the Mergent Aa utility bond yield were to average less than 5.19 percent or greater than 7.19 percent during the April — September timeframe of any year. The effect of the 2004 changes in ROR and ROE will be to decrease net income in 2005 by $10 million from what it would have been if the 2005 rates had not changed from the 2004 rates. In December 2004, the CPUC ordered SDG&E to file a cost of capital application in 2005 to take effect

January 1, 2006. SDG&E had recommended that the CPUC approve a policy allowing utilities to increase the equity in their authorized capital structure to adjust for the debt equivalent effect of purchased power agreements. The CPUC has directed that such adjustment only be considered in the context of a full review of the cost of capital. The electric-transmission cost of capital is determined under a FERC proceeding and is currently at an 11.25% ROE.

Effective January 1, 2003, SoCalGas' authorized ROE is 10.82 percent and its ROR is 8.68 percent. These rates are subject to automatic adjustment if the 12-month trailing average of 30-year Treasury bond rates and the Global Insight forecast of the 30-year Treasury bond rate 12 months ahead vary by greater than 150 basis points from a benchmark, which is currently 5.38 percent. The 12-month trailing average was 5.03 percent and the Global Insight forecast was 5.44 percent at December 31, 2004.

Potential changes to this process are described above in "Cost of Service."

Biennial Cost Allocation Proceeding

The BCAP determines the allocation of authorized costs between customer classes for natural gas transportation service provided by the California Utilities and adjusts rates to reflect variances in sales volumes as compared to the forecasts previously used in establishing transportation rates. The California Utilities filed with the CPUC their 2005 BCAP applications in September 2003, requesting updated transportation rates effective January 1, 2005. In November 2003, an Assigned Commissioner Ruling stayed the BCAP applications until a decision is issued in the GIR implementation proceeding. As a result of the April 1, 2004 decision on GIR implementation as described in Natural Gas Industry Restructuring above, in May 2004 the ALJ in the 2005 BCAP issued a decision dismissing the BCAP applications. The California Utilities are required to file new BCAP applications after the stay in the GIR implementation proceeding is lifted. As a result of the deferrals and the significant decline forecasted in noncore gas throughput on SoCalGas' system, in December 2002 the CPUC issued a decision approving balancing account protection for SoCalGas' risk on local transmission and distribution revenues from January 1, 2003 until the CPUC issues its next BCAP decision. SoCalGas is seeking to continue this balancing account protection in the Natural Gas OIR proceeding.

CPUC Investigation of Energy-Utility Holding Companies

The CPUC has initiated an investigation into the relationship between California's IOUs and their parent holding companies. The CPUC broadly determined that it could, in appropriate circumstances, require the holding company to provide cash to a utility subsidiary to cover its operating expenses and working capital to the extent they are not adequately funded through retail rates. This would be in addition to the requirement of holding companies to provide for their utility subsidiaries' capital requirements, as the IOUs previously acknowledged in connection with their holding companies' formations. In January 2002, the CPUC ruled that it had jurisdiction to create the holding company system and, therefore, retains jurisdiction to enforce conditions to which the holding companies had agreed.

In a May 2004 opinion, the California Court of Appeal upheld the CPUC's assertion of limited enforcement jurisdiction, but concluded that the CPUC's interpretation of the "first priority" condition (that the holding companies could be required to infuse cash into the utilities as necessary to meet the utilities' obligation to serve) was not ripe for review. In September 2004, the California Supreme Court declined to review the California Court of Appeal's decision.

CPUC Investigation of Compliance With Affiliate Rules

In February 2003, the CPUC opened an investigation of the business activities of SDG&E, SoCalGas and Sempra Energy to determine if they have complied with statutes and CPUC decisions in the management, oversight and operations of their companies. In September 2003, the CPUC suspended

the procedural schedule until it completes an independent audit to evaluate energy-related holding company systems and affiliate activities undertaken by Sempra Energy within the service territories of SDG&E and SoCalGas. The audit, covering years 1997 through 2003, is expected to be completed by the third quarter of 2005. The scope of the audit will be broader than the annual affiliate audit. In accordance with existing CPUC requirements, the California Utilities' transactions with other Sempra Energy affiliates have been audited by an independent auditing firm each year, with results reported to the CPUC, and there have been no material adverse findings in those audits.

Recovery of Certain Disallowed Transmission Costs

In August 2002, the FERC issued Opinion No. 458, which effectively disallowed SDG&E's recovery in its transmission rates of the differentials between certain payments to SDG&E by its co-owners of the Southwest Powerlink (SWPL) under the SWPL Participation Agreements, and charges assessed to SDG&E under the California Independent System Operator (ISO) FERC tariff related to energy schedules of its SWPL co-owners. As a result, SDG&E is incurring unreimbursed costs of $4 million to $8 million per year. SDG&E has appealed the FERC decision to the Federal Court of Appeals, which has set oral argument for May 9, 2005.

SDG&E has challenged the propriety of the disallowed ISO charges in several proceedings. In July 2001, SDG&E filed an arbitration claim against the ISO, claiming the ISO should not charge SDG&E for the transmission losses attributable to its SWPL co-owners' energy schedules. In October 2003, the arbitrator awarded SDG&E all amounts claimed, which totaled $22 million, including interest, as of the time of the award. The ISO appealed this result to the FERC and decision on this appeal is pending.

SDG&E has also challenged at the FERC the ISO's grid management charges assessed on the subject SWPL schedules. In January 2004, the FERC denied rehearing of its Opinion No. 463, which upheld such charges on the subject SWPL schedules for 2001 through 2003, but ordered certain refunds to SDG&E. The refunds are pending before the FERC, as is a separate proceeding involving application of the charges to the subject schedules from 2004 forward. In addition, in March 2004, SDG&E petitioned the U.S. Court of Appeals for review of these FERC orders. The court has held SDG&E's appeal in abeyance pending the FERC's disposition of other parties' rehearing requests.

SDG&E has also commenced a private arbitration to reform the SWPL Participation Agreements to remove prospectively SDG&E's obligation to provide to its SWPL co-owners the services that result in unreimbursed ISO tariff charges. The parties have agreed to hold the arbitration in abeyance pending resolution of the related FERC proceedings.

Southern California Wildfires

On June 28, 2004, SDG&E filed its catastrophic event memorandum accounts (CEMA) application with the CPUC to recover incremental operating and maintenance and capital costs of its natural gas and electric distribution systems associated with the 2003 California wildfires. In that application, SDG&E is requesting a 2005 revenue requirement of $20 million, representing the operating and maintenance costs of $12 million plus the 2004 and 2005 ongoing annual amounts of $4 million to recover the $26 million of capital costs and the authorized return thereon. The company expects no significant effect on earnings from the fires. The assigned ALJ indicated that he expects to issue a proposed decision during the first quarter of 2005.

Gain on Sale Rulemaking

A gain on sale rulemaking was issued in September 2004 in order to standardize the treatment of gains on sales of property by utilities. This rulemaking may result in the adoption of a general

ratemaking policy for allocation between utility shareholders and ratepayers of any gain or loss on sale of utility property. The CPUC will consider adopting a standard percentage allocation, probably between 5 percent and 50 percent to shareholders, rather than resolving such allocations on a case-by-case basis, as is now its practice. In unusual circumstances the CPUC would be able to depart from the standard allocation to be adopted. The CPUC intends to apply this standard percentage to sales of both depreciable property and non-depreciable property. The Rulemaking states that the new policy would replace the CPUC'S current policy of allocating to shareholders all gain or loss on sale to a municipality of a utility operating system. The final outcome of the Rulemaking may be different than that proposed for comment in the order instituting the rulemaking. No schedule has been announced yet for this proceeding.

NOTE 16. COMMITMENTS AND CONTINGENCIES

Natural Gas Contracts

The California Utilities buy natural gas under short-term and long-term contracts. Purchases are from various Southwest U.S. and Canadian suppliers and are primarily based on monthly spot-market prices. The California Utilities transport natural gas under long-term firm pipeline capacity agreements that provide for annual reservation charges, which are recovered in rates. SoCalGas has commitments with pipeline companies for firm pipeline capacity under contracts that expire at various dates through 2007. Note 15 discusses the CPUC Gas Market OIR.

SDG&E has long-term natural gas transportation contracts with various interstate pipelines that expire on various dates between 2005 and 2023. SDG&E currently purchases natural gas on a spot basis to fill its long-term pipeline capacity, and purchases additional spot market supplies delivered directly to California for its remaining requirements. SDG&E continues its ongoing assessment of its long-term pipeline capacity portfolio, including the release of a portion of this capacity to third parties. In accordance with regulatory directives, SDG&E will reconfigure its pipeline capacity portfolio by November 2005 to secure firm transportation rights from a diverse mix of U.S. and Canadian supply sources for its projected core customer natural gas requirements.

At December 31, 2004, the future minimum payments under existing natural gas contracts were:

(Dollars in millions)	Storage and Transportation	Natural Gas	Total
2005	$202	$ 897	$1,099
2006	123	179	302
2007	21	158	179
2008	20	3	23
2009	16	2	18
Thereafter	189	—	189
Total minimum payments	$571	$1,239	$1,810

Total payments under natural gas contracts were $2.8 billion in 2004, $2.2 billion in 2003 and $1.4 billion in 2002.

In October 2004, Sempra LNG signed a sale and purchase agreement with British Petroleum for the supply of 500 million cubic feet of natural gas per day from Indonesia's Tangguh liquefaction facility to Sempra LNG's Energía Costa Azul regasification terminal. The 20-year agreement provides for pricing tied to the Southern California border index for natural gas and will supply half of the capacity of Energía Costa Azul.

Purchased-Power Contracts

For 2005, SDG&E expects to receive 49 percent of its customer power requirement from DWR allocations. Of the remaining requirements, SONGS is expected to account for 21 percent, long-term contracts for 19 percent and spot market purchases for 11 percent. The contracts expire on various dates through 2032. In addition, during 2002 SDG&E entered into contracts which will provide five percent of its 2005 total energy sales from renewable sources. These contracts expire on various dates through 2025.

Sempra Commodities is committed to purchasing $199 million of power from an unconsolidated affiliate in varying amounts through 2014.

At December 31, 2004, the estimated future minimum payments under the long-term contracts (not including the DWR allocations) were:

(Dollars in millions)	
2005	$ 256
2006	279
2007	313
2008	358
2009	343
Thereafter	4,035
Total minimum payments	$5,584

The payments represent capacity charges and minimum energy purchases. SDG&E is required to pay additional amounts for actual purchases of energy that exceed the minimum energy commitments. Excluding DWR-allocated contracts, total payments under the contracts were $329 million in 2004, $396 million in 2003 and $235 million in 2002.

Coal Commitments

In October 2002, Sempra Generation acquired the 305-MW Twin Oaks Power plant. In connection with the acquisition, Sempra Generation assumed a contract that includes annual commitments to purchase lignite coal either until an aggregate minimum volume has been achieved or through 2025. As of December 31, 2004, Sempra Generation's future minimum payments under the lignite coal agreement totaled $425 million, for which payments of $31 million are due for 2005, $28 million for 2006, $27 million for 2007, $27 million for 2008, $27 million for 2009 and $285 million thereafter. The minimum payments have been adjusted for allowed shortfalls and 90-percent minimum take-or-pay requirements under the contract.

Leases

The company has leases (primarily operating) on real and personal property expiring at various dates from 2005 to 2045. Certain leases on office facilities contain escalation clauses requiring annual increases in rent ranging from 2 percent to 5 percent. The rentals payable under these leases are determined on both fixed and percentage bases, and most leases contain extension options which are exercisable by the company. The company also has long-term capital leases on real property. Property, plant and equipment included $28 million at December 31, 2004 and $36 million at December 31, 2003, related to these leases. The associated accumulated amortization was $24 million and $23 million, respectively.

At December 31, 2004, the minimum rental commitments payable in future years under all noncancellable leases were as follows:

(Dollars in millions)	Operating Leases	Capitalized Leases
2005	$107	$ 2
2006	97	1
2007	93	1
2008	84	1
2009	82	—
Thereafter	178	1
Total future rental commitments	$641	6
Imputed interest (6% to 10%)		(1)
Net commitments		$ 5

In connection with the quasi-reorganization described in Note 1, PE recorded liabilities of $102 million to adjust to fair value the operating leases related to its headquarters and other facilities at December 31, 1992. The remaining amount of these liabilities was $30 million at December 31, 2004. These leases are included in the above table at the amounts provided in the lease.

Rent expense for operating leases totaled $88 million in 2004, $90 million in 2003 and $81 million in 2002. Depreciation expense for capitalized leases is included in Depreciation and Amortization on the Statements of Consolidated Income.

Construction Projects

Sempra Global has several subsidiaries which have developed or are in the process of constructing various capital projects in the United States and in Mexico. The following is a summary of commitments related to the projects developed or under development, the background of which is provided in Note 2.

Sempra Generation

Sempra Generation is primarily in the business of acquiring, developing and operating power plants throughout the U.S. and Mexico. As of the end of 2004, Sempra Generation had eleven power plants in operation, including eight that are 50% owned.

Sempra Generation has a long-term service agreement expiring in 2023 for maintenance of the turbines at the Mesquite power plant. As of December 31, 2004, commitments under this agreement totaled $264 million, including amounts due of $14 million in 2005, $14 million in 2006, $15 million in 2007, $15 million in 2008, $15 million in 2009 and $191 million thereafter.

Transportation of TDM's natural gas from Ehrenberg, Arizona to the interconnection with Gasoducto Bajanorte is being provided under an agreement with an unrelated party. Under the agreement, Sempra Generation is obligated to pay a monthly reservation charge for the transport of certain quantities until 2022. The future commitments related to this contract are $79 million. Sempra Generation also has a 20-year agreement expiring in 2023 for maintenance of the turbines at TDM. As of December 31, 2004, commitments under this agreement totaled $83 million, including amounts due of $6 million in 2005, $6 million in 2006, $7 million in 2007, $7 million in 2008, $7 million in 2009 and $50 million thereafter.

Sempra Generation also has commitments for general contracting work at Palomar totaling $99 million as of December 31, 2004. It expects to pay $94 million in 2005 and $5 million in 2006.

Sempra Generation continues to investigate opportunities for new projects, either independently or with unrelated parties. The success of these investigations cannot be predicted. As of December 31, 2004, Sempra Generation has no other significant construction commitments.

Sempra LNG

Sempra LNG develops, builds and operates LNG receipt terminals and will be supplying gas to CFE.

In December 2004, Sempra LNG entered into an agreement with a group of companies for the construction of the Energía Costa Azul LNG receipt facility. The companies included Techint SA de CV, Black & Veatch, Mitsubishi Heavy Industries and Vinci Construction Grands Projects. As of December 31, 2004, expected payments under this contract include $196 million in 2005, $191 million in 2006 and $95 million in 2007, for a total of $482 million over the term of the contract. Also in December 2004, a joint venture involving the Costain Group PLC and China Harbour was awarded a construction contract for the project's breakwater. As of December 31, 2004, Sempra LNG expects to make payments under this contract of $161 million, including $58 million in 2005, $81 million in 2006, $14 million in 2007 and $8 million in 2008.

Sempra Pipelines & Storage

In 2002, Sempra Pipelines & Storage completed construction of the 140-mile Gasoducto Bajanorte Pipeline that connects the Rosarito Pipeline south of Tijuana, Mexico with the TransCanada pipeline that connects to Arizona. The 30-inch pipeline can deliver up to 500 million cubic feet per day of natural gas to new generation facilities in Baja California, including Sempra Generation's TDM power plant discussed above. Capacity on the pipeline is over 90 percent subscribed. The company had no other commitments for this pipeline at December 31, 2004.

If Sempra Pipelines & Storage proceeds with development of its Liberty project, it will pay the prior owner of its development rights $2 million upon receipt of the related FERC permit and seven percent of the project's revenues over the first five years of operations. A liability instrument will be recorded for these earn-out provisions if and when the company completes its feasibility studies and decides to proceed with this investment.

Guarantees

As of December 31, 2004, substantially all of the company's guarantees were intercompany, whereby the parent issues the guarantees on behalf of its consolidated subsidiaries. Significant other guarantees are the $25 million related to debt issued by Chilquinta Energía Finance Co., LLC, an unconsolidated affiliate, and the mandatorily redeemable trust preferred securities, which were redeemed in February 2005.

In conjunction with the acquisition of the former AEP power plants, Sempra Energy provided AEP a guarantee for certain specified liabilities described in the acquisition agreement. Note 3 provides additional discussion related to the guarantee.

Sempra Generation's Contract with the DWR

In May 2001, Sempra Generation entered into a ten-year agreement with the DWR to supply up to 1,900 MW of power to California. Sempra Generation may, but is not obligated to, deliver this electricity from its portfolio of natural gas-fired plants in the western United States and Baja California, Mexico. If

and when Sempra Generation uses these plants to supply the entire 1,900 MW, those sales would comprise more than two-thirds of the plants' capacity. Subsequent to the state's signing of this contract and electricity-supply contracts with other vendors, various state officials have contended that the rates called for by the contracts are too high. Based on current natural gas prices, the price of power under the long-term contracts exceeds the current spot market price for electricity. Information concerning the validity of this contract, the FERC's orders upholding this contract and the pending appeal is provided under "Legal Proceedings — DWR Contract" below.

Environmental Issues

The company's operations are subject to federal, state and local environmental laws and regulations governing hazardous wastes, air and water quality, land use, solid waste disposal and the protection of wildlife. Most of the environmental issues faced by the company have occurred at the California Utilities. However, now that Sempra Generation owns and operates several power plants and Sempra LNG is developing LNG regasification terminals, additional environmental issues will arise. As applicable, appropriate and relevant, these laws and regulations require that the company investigate and remediate the effects of the release or disposal of materials at sites associated with past and present operations, including sites at which the company has been identified as a Potentially Responsible Party (PRP) under the federal Superfund laws and comparable state laws. The company is required to obtain numerous governmental permits, licenses and other approvals to construct facilities and operate its businesses. Additionally, to comply with these legal requirements, it must spend significant sums on environmental monitoring, pollution control equipment and emissions fees. Increasing national and international concerns regarding global warming and mercury, nitrogen oxide and sulfur dioxide emissions could result in requirements for additional pollution control equipment or significant emissions fees or taxes, particularly with respect to coal-fired generation facilities, that could adversely affect Sempra Generation. In addition, existing environmental regulations could be revised or reinterpreted and other new laws and regulations could be adopted or become applicable to the company and its facilities. Costs incurred at the California Utilities to operate the facilities in compliance with these laws and regulations generally have been recovered in customer rates.

Significant costs incurred to mitigate or prevent future environmental contamination or extend the life, increase the capacity or improve the safety or efficiency of property utilized in current operations are capitalized. The company's capital expenditures to comply with environmental laws and regulations were $22 million in 2004, $14 million in 2003 and $8 million in 2002 (includes only the company's share in cases of non-wholly owned affiliates). The cost of compliance with these regulations over the next five years is not expected to be significant.

The company has identified no significant environmental issues outside the United States, except for the additional environmental impact studies the DOE is conducting of the TDM power plant near Mexicali, Baja California, Mexico. Additional information regarding the environmental studies is provided below under "Legal Proceedings."

At the California Utilities, costs that relate to current operations or an existing condition caused by past operations are generally recorded as a regulatory asset due to the assurance that these costs will be recovered in rates.

The environmental issues currently facing the company or resolved during the last three years include investigation and remediation of the California Utilities' manufactured-gas sites (29 completed as of December 31, 2004 and 15 to be completed), cleanup at SDG&E's former fossil fuel power plants (all sold in 1999 and actual or estimated cleanup costs included in the transactions), cleanup of third-party waste-disposal sites used by the company, which has been identified as a PRP (investigations and remediations are continuing) and mitigation of damage to the marine environment caused by the cooling-water discharge from SONGS (the requirements for enhanced fish protection, a 150-acre artificial reef and restoration of 150 acres of coastal wetlands are in process).

Environmental liabilities are recorded when the company's liability is probable and the costs are reasonably estimable. In many cases, however, investigations are not yet at a stage where the company has been able to determine whether it is liable or, if the liability is probable, to reasonably estimate the amount or range of amounts of the cost or certain components thereof. Estimates of the company's liability are further subject to other uncertainties, such as the nature and extent of site contamination, evolving remediation standards and imprecise engineering evaluations. The accruals are reviewed periodically and, as investigations and remediation proceed, adjustments are made as necessary. Costs of future expenditures for environmental remediation obligations are not discounted to their present value. Not including the liability for SONGS marine mitigation, which SDG&E is participating in jointly with Edison, at December 31, 2004, the company's accrued liability for environmental matters was $53.6 million, of which $42.3 million is related to manufactured-gas sites, $8.7 million to cleanup at SDG&E's former fossil-fueled power plants, $2.1 million to waste-disposal sites used by the company (which has been identified as a PRP) and $0.5 million to other hazardous waste sites. These accruals are expected to be paid ratably over the next three years.

Nuclear Insurance

SDG&E and the other owners of SONGS have insurance to respond to nuclear liability claims related to SONGS. The insurance policy provides $300 million in coverage, which is the maximum amount available. In addition to this primary financial protection, the Price-Anderson Act provides for up to $10.5 billion of secondary financial protection if the liability loss exceeds the insurance limit. Should any of the licensed/commercial reactors in the United States experience a nuclear liability loss which exceeds the $300 million insurance limit, all utilities owning nuclear reactors could be assessed under the Price-Anderson Act to provide the secondary financial protection. SDG&E and the other co-owners of SONGS could be assessed up to $201 million under the Price-Anderson Act. SDG&E's share would be $40 million unless a default were to occur by any other SONGS owner. In the event the secondary financial protection limit were insufficient to cover the liability loss, the Price-Anderson Act provides for Congress to enact further revenue-raising measures to pay claims. These measures could include an additional assessment on all licensed reactor operators.

SDG&E and the other owners of SONGS have $2.75 billion of nuclear property, decontamination and debris removal insurance. The coverage also provides the SONGS owners up to $490 million for outage expenses/replacement power incurred because of accidental property damage. This coverage is limited to $3.5 million per week for the first 52 weeks, and $2.8 million per week for up to 110 additional weeks. There is a deductible waiting period of 12 weeks prior to receiving indemnity payments. The insurance is provided through a mutual insurance company owned by utilities with nuclear facilities. Under the policy's risk sharing arrangements, insured members are subject to retrospective premium assessments if losses at any covered facility exceed the insurance company's surplus and reinsurance funds. Should there be a retrospective premium call, SDG&E could be assessed up to $8.8 million.

Both the nuclear liability and property insurance programs subscribed to by members of the nuclear power generating industry include industry aggregate limits for non-certified acts (as defined by the Terrorism Risk Insurance Act) of terrorism-related SONGS losses, including replacement power costs. An industry aggregate limit of $300 million exists for liability claims, regardless of the number of non-certified acts affecting SONGS or any other nuclear energy liability policy or the number of policies in place. An industry aggregate limit of $3.24 billion exists for property claims, including replacement power costs, for non-certified acts of terrorism affecting SONGS or any other nuclear energy facility property policy within twelve months from the date of the first act. These limits are the maximum amount to be paid to members who sustain losses or damages from these non-certified terrorist acts.

For certified acts of terrorism, the individual policy limits stated above apply.

Legal Proceedings

Except for the matters referred to below, neither the company nor its subsidiaries are party to, nor is their property the subject of, any material pending legal proceedings other than routine litigation incidental to their businesses. At December 31, 2004, the company had accrued approximately $250 million to provide for the costs of its legal proceedings, of which approximately $240 million related to cases arising from the 2000-2001 California energy crisis. Management believes that none of these matters will have further material adverse effect on the company's financial condition or results of operations.

DWR Contract

In 2003, Sempra Generation was awarded judgment in its favor in a state civil action between Sempra Generation and the DWR, in which the DWR sought to void its 10-year contract expiring in 2011 under which the company sells electricity to the DWR. The DWR filed an appeal of this ruling in January 2004. A decision by the appellate court is expected during 2005.

The DWR continues to accept scheduled power from Sempra Generation and, although it has disputed a portion of the billings and the manner of certain deliveries, it has paid all amounts billed, as required by the contract in the event of disputes. However, the DWR has commenced an arbitration proceeding disputing Sempra Generation's performance on various operational matters. Among other proposed remedies, the DWR has requested a declaration by the arbitration panel that Sempra Generation's performance violates the terms of the contract and constitutes a material breach of the agreement, permitting it to terminate the contract. Sempra Generation believes these claims are without merit. In November 2004, the arbitration panel denied Sempra Generation's motion to dismiss claims. Arbitration is expected to occur in mid-2005.

On June 25, 2003, the FERC issued orders upholding Sempra Generation's long-term energy supply contract with the DWR, as well as contracts between the DWR and other power suppliers. The order affirmed a previous FERC conclusion that those advocating termination or alteration of the contract would have to satisfy a "heavy" burden of proof, and cited its long-standing policy to recognize the sanctity of contracts. In the order, the FERC noted that CPUC and court precedent clearly establish that allegations that contracts have become uneconomic by the passage of time do not render them contrary to the public interest under the Federal Power Act. The FERC pointed out that the contracts were entered into voluntarily in a market-based environment. The FERC found no evidence of unfairness, bad faith or duress in the original contract negotiations. It said there was no credible evidence that the contracts placed the complainants in financial distress or that ratepayers will bear an excessive burden. In December 2003, appeals of this matter filed by a number of parties, including the California Energy Oversight Board and the CPUC, were consolidated and assigned to the Ninth Circuit Court of Appeals. Oral argument on the appeal was held in December 2004, with a decision by the appellate court expected in 2005.

California Energy Crisis

In 2000 and 2001, California experienced a severe energy crisis characterized by dramatic increases in the prices of electricity and natural gas. The energy crisis has generated many, often duplicative, governmental investigations, regulatory proceedings and lawsuits involving numerous energy companies seeking recovery of tens of billions of dollars for allegedly unlawful activities asserted to have caused or contributed to the energy crisis. The material proceedings arising out of the energy crisis that involve the company are summarized below.

Natural Gas Cases

Class-action and individual antitrust and unfair competition lawsuits filed in 2000 and thereafter, and currently consolidated in San Diego Superior Court, seek damages, alleging that Sempra Energy, SoCalGas and SDG&E, along with El Paso and several of its affiliates, unlawfully sought to control natural gas and electricity markets. In December 2003, the Court approved a settlement whereby the applicable El Paso entities will pay approximately $1.6 billion to resolve these claims (including cases involving unrelated claims not applicable to Sempra Energy, SoCalGas or SDG&E). The proceeding against Sempra Energy and the California Utilities has not been settled and continues to be litigated. In October 2004, certain of the plaintiffs issued a news release asserting that they could recover as much as $24 billion from Sempra Energy and the California Utilities if their allegations were upheld at trial. During the third quarter of 2004, the court denied motions for summary judgment in favor of Sempra Energy and the California Utilities. The Court of Appeal has declined to review the summary judgment denial and the companies have petitioned for review by the California Supreme Court. Interim review pending a final decision on the merits of the case is entirely at the discretion of the California Supreme Court. On January 18, 2005, the judge stated that pre-trial motions will be heard on June 3, 2005, and set a trial date of September 2, 2005.

Similar lawsuits have been filed by the Attorneys General of Arizona and Nevada, alleging that El Paso and certain Sempra Energy subsidiaries unlawfully sought to control the natural gas market in their respective states. The claims against the Sempra Energy defendants in the Arizona lawsuit were settled in September 2004 for $150,000 and have been dismissed with prejudice. The Nevada Attorney General's lawsuit remains pending.

The company is cooperating with an investigation being conducted by the California Attorney General into possible anti-competitive behavior in the natural gas and electricity markets during the 2000-2001 energy crisis. In December 2004, several of the company's senior officers testified at investigational hearings conducted by the California Attorney General's Office. The company expects additional hearings to take place in early 2005.

In April 2003, Sierra Pacific Resources and its utility subsidiary Nevada Power filed a lawsuit in U.S. District Court in Las Vegas against major natural gas suppliers, and included Sempra Energy, the California Utilities and other company subsidiaries, seeking recovery of damages alleged to aggregate in excess of $150 million (before trebling) from an alleged conspiracy to drive up or control natural gas prices, eliminate competition and increase market volatility, breach of contract and wire fraud. On January 27, 2004, the U.S. District Court dismissed the Sierra Pacific Resources case against all of the defendants, determining that this is a matter for the FERC to resolve. However, the court granted plaintiffs' request to amend their complaint. Sempra Energy filed another motion to dismiss on plaintiffs' amended complaint. After argument on November 29, 2004, the federal court dismissed the Sierra Pacific case with prejudice. Plaintiffs have filed a notice of appeal with the Ninth Circuit Court of Appeals.

In May 2003 and February 2004, two antitrust actions against various energy companies, including Sempra Energy and Sempra Commodities, were filed in San Diego Superior Court alleging that energy prices were unlawfully manipulated by defendants' reporting artificially inflated natural gas prices to trade publications and by entering into wash trades. Both actions were removed to U.S. District Court. In November 2003, an additional suit was filed in U.S. District Court. In September 2004, two additional lawsuits alleging substantially identical claims were filed against Sempra Energy and Sempra Commodities, among various other entities, in San Diego Superior and U.S. District Courts. Two additional, substantially identical lawsuits were filed against Sempra Commodities in November and December 2004 in the U.S. District Court in Fresno, California. In November 2004, the federal district court judge assigned to hear these cases determined that the cases originally filed in state court should

return to that court system. On February 14, 2005, the California state court cases, including those described below, were assigned to the same judge overseeing the El Paso-related cases.

In July 2004, the City and County of San Francisco, the County of Santa Clara and the County of San Diego brought similar actions in San Diego Superior Court against various entities, including Sempra Energy, Sempra Commodities, SoCalGas and SDG&E. Six identical lawsuits were filed in the fourth quarter of 2004 in the Alameda and San Mateo Superior Courts and one in Sacramento Superior Court. In December 2004, the City of San Diego also filed an identical suit in San Diego Superior Court. These suits are also now pending before the same San Diego Superior Court judge described above.

In August 2003, a lawsuit was filed in the Southern District of New York against Sempra Energy and its subsidiary, Sempra Energy Solutions, alleging that the prices of natural gas options traded on the New York Mercantile Exchange (NYMEX) were unlawfully increased under the Federal Commodity Exchange Act by defendants' manipulation of transaction data provided to natural gas trade publications. In November 2003, another suit containing identical allegations was filed and consolidated with the New York action. Subsequently, plaintiffs dismissed Sempra Energy and Sempra Energy Solutions from these cases. On January 20, 2004, plaintiffs filed an amended consolidated complaint that named Sempra Commodities as a defendant in this lawsuit. In March 2004, defendants filed a motion to dismiss the action, which was denied by the court in September 2004. In October 2004, plaintiffs amended their complaint to allege that Sempra Commodities had engaged in natural gas wash trade transactions.

Electricity Cases

Various antitrust lawsuits, which seek class-action certification, allege that numerous entities, including Sempra Energy and certain subsidiaries (SDG&E, Sempra Commodities and Sempra Generation, depending on the lawsuit), that participated in the wholesale electricity markets unlawfully manipulated those markets. Collectively, these lawsuits allege damages against all defendants in an aggregate amount in excess of $16 billion (before trebling). In January 2003, the federal court granted a motion to dismiss one of these lawsuits, filed by the Snohomish County, Washington Public Utility District, on the grounds that the claims contained in the complaint were subject to the filed rate doctrine and were preempted by the Federal Power Act. That ruling was appealed to the Ninth Circuit U.S. Court of Appeals. In addition, in May 2003, the Port of Seattle filed a similar complaint against a number of energy companies, including Sempra Energy, Sempra Generation and Sempra Commodities. That action was dismissed by the San Diego U.S. District Court in May 2004. Plaintiff has appealed the decision. In May and June 2004, two lawsuits substantially identical to the Port of Seattle case were filed in Washington and Oregon U.S. District Courts. These cases were transferred to the San Diego U.S. District Court and motions to dismiss were granted in both cases on February 11, 2005. In October 2004, another case was filed in Santa Clara Superior Court against Sempra Generation, alleging substantively identical claims to those in the Port of Seattle case.

In September 2004, the Ninth Circuit U.S. Court of Appeals dismissed the suit against Sempra Energy, Sempra Commodities and Sempra Generation by the Snohomish County, Washington Public Utility District. The court ruled that the FERC, not civil courts, has exclusive jurisdiction over the matter. The company believes that this decision provides a precedent for the dismissal on the basis of federal preemption and the filed rate doctrine of the other lawsuits against the Sempra Energy companies claiming manipulation of the electricity markets. Snohomish County has appealed the Ninth Circuit decision to the U.S. Supreme Court.

CPUC Border Price Investigation

In November 2002, the CPUC instituted an investigation into the Southern California natural gas market and the price of natural gas delivered to the California — Arizona border between March 2000

and May 2001. The California Utilities are the parties to the first phase of the investigation. If the investigation were to determine that the conduct of either of the California Utilities contributed to the natural gas price spikes that occurred during the investigation period, the CPUC may modify the party's natural gas procurement incentive mechanism, reduce the amount of any shareholder award for the period involved, and/or order the party to issue a refund to ratepayers. At December 31, 2004, the cumulative amount of shareholder awards, substantially all of which has been included in net income, was $65.3 million.

On November 16, 2004, the CPUC Administrative Law Judge assigned to the investigation issued a proposed decision for consideration by the full CPUC in the first phase of the investigation that was highly critical of SoCalGas' natural gas purchase, sales, hedging and storage activities and would find that SoCalGas exercised market power and manipulated the natural gas market, significantly contributing to natural gas price spikes that also increased electricity prices. The proposed decision did not include any adverse findings or make any adverse recommendations regarding SDG&E.

On December 16, 2004, the CPUC rejected the amended proposed decision by a 3-2 vote. The two commissioners who voted in favor of the proposed decision were Commissioners Lynch and Wood, whose terms on the CPUC expired at year end. It is now up to the remaining commissioners plus any new appointees to determine whether to issue an alternate proposed decision, hold additional hearings, or issue an order terminating the investigation.

The CPUC may hold additional rounds of hearings to consider whether other companies, including other California utilities as well as the company and its non-utility subsidiaries, contributed to the natural gas price spikes. No hearings have yet been scheduled.

FERC Refund Proceedings

The FERC is investigating prices charged to buyers in the California Power Exchange (PX) and ISO markets by various electric suppliers. The FERC is seeking to determine the extent to which individual sellers have yet to be paid for power supplied during the period of October 2, 2000 through June 20, 2001 and to estimate the amounts by which individual buyers and sellers paid and were paid in excess of competitive market prices. Based on these estimates, the FERC could find that individual net buyers, such as SDG&E, are entitled to refunds and individual net sellers, such as Sempra Commodities, are required to provide refunds. To the extent any such refunds are actually realized by SDG&E, they would be refunded to ratepayers. To the extent that Sempra Commodities is required to provide refunds, they could result in payments by Sempra Commodities after adjusting for any amounts still owed to Sempra Commodities for power supplied during the relevant period (or reduced receipts if refunds are less than amounts owed to Sempra Commodities).

In December 2002, a FERC ALJ issued preliminary findings indicating that the California PX and ISO owe power suppliers $1.2 billion for the October 2, 2000 through June 20, 2001 period (the $3.0 billion that the California PX and ISO still owe energy companies less $1.8 billion that the energy companies charged California customers in excess of the preliminarily determined competitive market clearing prices). On March 26, 2003, the FERC adopted its ALJ's findings, but changed the calculation of the refund by basing it on a different estimate of natural gas prices. The March 26 order estimates that the replacement formula for estimating natural gas prices will increase the refund obligations from $1.8 billion to more than $3 billion for the same time period. Pending in the Ninth Circuit are various parties' appeals on aspects of the FERC's order.

In a series of orders in 2004, the FERC has provided further direction and clarifications regarding the methodology to be used by the ISO and PX to recalculate the precise refund obligations and entitlements through their settlement models.

Sempra Commodities previously established reserves for its likely share of the original $1.8 billion discussed above. During 2004, Sempra Commodities recorded additional reserves to reflect the estimated effect of the FERC's revision of the benchmark prices to be used by the FERC to calculate refunds, and Sempra Generation recorded its share of the 2004 amounts related to its transactions with Sempra Commodities.

In a separate complaint filed with the FERC in 2002, the California Attorney General challenged the FERC's authority to establish a market-based rate regime, and further contended that, even if such a regime were valid, electricity sellers had failed to comply with the FERC's quarterly reporting requirements. The Attorney General requested that the FERC order refunds from suppliers to the California PX and ISO for the period prior to October 2, 2000, and for short-term bilateral transactions entered into with the California Energy Resources Scheduler. In May 2003, and upon rehearing in September 2003, the FERC dismissed the complaint, determining that its market-based rate system was lawful, and that refunds for non-compliance with its reporting requirements were unnecessary, and instead ordered sellers to restate their reports. After an appeal by the California Attorney General, in September 2004, the Ninth Circuit Court of Appeals upheld the FERC's authority to establish a market-based rate regime, but ordered remand of the case to the FERC for further proceedings, stating that failure to file transaction-specific quarterly reports gave the FERC authority to order refunds with respect to jurisdictional sellers. In October 2004, the FERC announced that it will not appeal the court's decision. Although a group of sellers has requested the Ninth Circuit to rehear this matter, the timing and substance of the FERC's response to the remand is not yet known. However, it is possible that the FERC could order refunds or disgorgement of profits for periods in addition to those covered by its prior refund orders and substantially increase the refunds that ultimately may be required to be paid by Sempra Commodities and other power suppliers.

FERC Manipulation Investigation

The FERC is separately investigating whether there was manipulation of short-term energy markets in the western United States that would constitute violations of applicable tariffs and warrant disgorgement of associated profits. In this proceeding, the FERC's authority is not confined to the periods relevant to the refund proceeding. In May 2002, the FERC ordered all energy companies engaged in electric energy trading activities to state whether they had engaged in various specific trading activities (generally described as manipulating or "gaming" the California energy markets) in violation of the PX and ISO tariffs.

On June 25, 2003, the FERC issued several orders requiring various entities to show cause why they should not be found to have violated California ISO and PX tariffs. First, the FERC directed 43 entities, including Sempra Commodities and SDG&E, to show cause why they should not disgorge profits from certain transactions between January 1, 2000 and June 20, 2001 that are asserted to have constituted gaming and/or anomalous market behavior under the California ISO and/or PX tariffs. Second, the FERC directed more than 20 entities, including Sempra Commodities, to show cause why their activities, in partnership or in alliance with others, during the period between January 1, 2000 and June 20, 2001 did not constitute gaming and/or anomalous market behavior in violation of the tariffs. Remedies for confirmed violations could include disgorgement of profits and revocation of market-based rate authority. The FERC has encouraged the various entities to settle these issues. On October 31, 2003, Sempra Commodities agreed to pay $7.2 million in full resolution of these investigations. That liability was recorded as of December 31, 2003. The Sempra Commodities settlement was approved by the FERC on August 2, 2004. Certain California parties have sought rehearing of this order. SDG&E and the FERC resolved the matter through a settlement, which documents the ISO's finding that SDG&E did not engage in market activities in violation of the ISO or PX tariffs, and in which SDG&E agreed to pay $27,792 into a FERC-established fund.

On February 16, 2005, in connection with the California Senate Select Committee's investigation into Price Manipulation in the Wholesale Energy Market, Senator Dunn held a press conference and asserted that Sempra Commodities committed perjury in denying that it had engaged in three types of Enron-like strategies. Senator Dunn stated that he intends to refer the matter to the Sacramento District Attorney's Office and to seek contempt charges from the state Senate. The company denies these charges and will defend the matters vigorously.

On June 25, 2003, the FERC determined that it was appropriate to initiate an investigation into possible physical and economic withholding in the California ISO and PX markets. On August 1, 2003, the FERC staff issued an initial report that determined there was no need to further investigate particular entities, including Sempra Commodities, for physical withholding of generation. For the purpose of investigating economic withholding, both SDG&E and Sempra Commodities received data requests from the FERC staff and provided responses. In May 2004, based on the results of its investigation, the FERC's Office of Market Oversight and Investigation informed SDG&E and Sempra Commodities that their bidding procedures are no longer being investigated by the FERC.

Settlement of Claims Associated with the FERC's Investigations

During 2004, three settlements of claims associated with the FERC's investigations were announced. One settlement, in which SDG&E received a net payment of $11.6 million in August 2004, resolves all but a few claims against The Williams Companies and Williams Power Company for the period May 1, 2000 through June 20, 2001. Another settlement, in which SDG&E received a net payment of $13.5 million (of the $13.8 million total SDG&E settlement allocation) in November 2004, resolves all claims against Dynegy, NRG Energy and West Coast Power LLC for the period January 1, 2000 through June 20, 2001. A third settlement, in which SDG&E received a net payment of $14.4 million (of the $14.7 million total SDG&E settlement allocation) in January 2005, resolves specified claims against Duke Energy for the period January 1, 2000 though June 20, 2001. On January 13, 2005, SDG&E announced a $23.8 million settlement (including an unsecured claim in the Mirant bankruptcy proceeding valued at approximately $2.4 million), which resolves specified claims against merchant generator Mirant Corp. for the 2000-2001 energy crisis period. The settlement is pending final CPUC, FERC and U.S. Bankruptcy Court (for Mirant) approval. In all cases, the majority of the funds was received within 20 days of receiving FERC approval with the remainder contingent on certain actions by the FERC, the ISO and the PX. Receipt of the remaining amounts by SDG&E would take place at the conclusion of the FERC refund proceeding, now expected to be in early 2006. These funds would be received for the benefit of SDG&E's bundled customers and will reimburse SDG&E for the costs of litigating this matter. In November 2004, the CPUC approved SDG&E's proposal to apply 70 percent (about $17 million) of the refunds due to ratepayers to the AB 265 undercollection, thus facilitating the full recovery of the undercollections, as further discussed in Note 14. Claims alleged against Sempra Commodities are still pending.

Other Litigation

The Utility Consumers' Action Network (UCAN), a consumer-advocacy group which had requested a CPUC rehearing of a CPUC decision concerning the allocation of certain power contract gains between SDG&E customers and the company, appealed the CPUC's rehearing denial to the California Court of Appeal. On July 12, 2004, the Court of Appeal affirmed the CPUC's decision. On August 20, 2004, UCAN filed a Petition for Review in the California Supreme Court. On November 10, 2004, the Supreme Court denied review.

In May 2003, a federal judge issued an order finding that the DOE's environmental assessment of the TDM plant and another, unrelated Mexicali power plant failed to evaluate the plants' environmental impact adequately and called into question the U.S. permits they received to build their cross-border transmission lines. In July 2003, the judge ordered the DOE to conduct additional environmental

studies and denied the plaintiffs' request for an injunction blocking operation of the transmission lines, thus allowing the continued operation of the TDM plant. The DOE undertook to perform an Environmental Impact Study, which was completed in December 2004. Plaintiff may elect to dismiss its complaint or to further challenge the agency action. If a stipulation of dismissal is not filed to terminate the litigation by August 15, 2005, the DOE will file a motion by August 22, 2005, showing cause why the court should not set aside the permits. In that event, court hearings may take place in the fourth quarter of 2005.

The Peruvian appellate court has affirmed the dismissal of the charges against officers of Luz del Sur and others concerning the price of some utility networks transferred from the Peruvian government to Luz del Sur.

The Peruvian tax authorities (Sunat) continue to claim that Luz del Sur owes additional income taxes, interest and penalties related to a 1996 revaluation of assets. The tax court held a final hearing on November 10, 2004, with both parties presenting their cases. On November 17, 2004, Luz del Sur submitted a summary of its arguments to the tax court. The tax court ruled in December 2004 that a third revaluation study be done, which will be used as a basis for its decision. The Conata, the national assessors association, was selected to do the study. After the Conata completes its study (expected in mid 2005), the tax court has 90 business days to issue a verdict.

At December 31, 2004, Sempra Commodities remains due approximately $100 million from energy sales made in 2000 and 2001 through the ISO and the PX markets. The collection of these receivables depends on several factors, including the FERC refund case. The company believes adequate reserves have been recorded.

Argentine Investments

As a result of the devaluation of the Argentine peso at the end of 2001 and subsequent further declines, Sempra Pipelines & Storage reduced the carrying value of its investment downward by a cumulative total of $198 million as of December 31, 2004 ($197 million as of December 31, 2003). These non-cash adjustments continue to occur based on fluctuations in the Argentine peso. They do not affect net income, but increase or decrease other comprehensive income (loss) and Accumulated Other Comprehensive Income (Loss).

A decision is expected in 2006 on Sempra Pipelines & Storage's arbitration proceedings under the 1994 Bilateral Investment Treaty between the United States and Argentina for recovery of the diminution of the value of Sempra Pipelines & Storage's investments that has resulted from Argentine governmental actions. Sempra Energy also has a $48.5 million political-risk insurance policy under which it filed a claim to recover a portion of the investments' diminution in value.

Department Of Energy Nuclear Fuel Disposal

The Nuclear Waste Policy Act of 1982 made the DOE responsible for the disposal of spent nuclear fuel. However, it is uncertain when the DOE will begin accepting spent nuclear fuel from SONGS. This delay by the DOE will lead to increased cost for spent fuel storage. This cost will be recovered through SONGS revenue unless the company is able to recover the increased cost from the federal government.

Electric Distribution System Conversion

Under a CPUC-mandated program, the cost of which is included in utility rates, and through franchise agreements with various cities, SDG&E is committed, in varying amounts, to converting overhead distribution facilities to underground. As of December 31, 2004, the aggregate unexpended amount of

this commitment was $80 million. Capital expenditures for underground conversions were $23 million in 2004, $28 million in 2003 and $33 million in 2002.

Concentration Of Credit Risk

The company maintains credit policies and systems to manage overall credit risk. These policies include an evaluation of potential counterparties' financial condition and an assignment of credit limits. These credit limits are established based on risk and return considerations under terms customarily available in the industry. The California Utilities grant credit to utility customers and counterparties, substantially all of whom are located in their service territories, which together cover most of Southern California and a portion of central California.

As described above, Sempra Generation has a contract with the DWR to supply up to 1,900 MW of power to the state over 10 years, beginning in 2001. Sempra Generation would be at risk for the amounts of outstanding billings and the continued viability of the contract if the DWR were to default on its payments under this contract. At any given time, the average outstanding billings related to this contract are $50 million to $60 million.

Sempra Commodities monitors and controls its credit-risk exposures through various systems which evaluate its credit risk, and through credit approvals and limits. To manage the level of credit risk, Sempra Commodities deals with a majority of counterparties with good credit standing, enters into netting arrangements whenever possible and, where appropriate, obtains collateral or other security such as lock-box liens and downgrade triggers. Netting agreements incorporate rights of setoff that provide for the net settlement of subject contracts with the same counterparty in the event of default.

The developing LNG projects will result in significant reliance on the credit-worthiness of its major suppliers and customers of those projects.

NOTE 17. SEGMENT INFORMATION

The company has four separately managed reportable segments: SoCalGas, SDG&E, Sempra Commodities and Sempra Generation. The California Utilities operate in essentially separate service territories under separate regulatory frameworks and rate structures set by the CPUC. SoCalGas is a natural gas distribution utility, serving customers throughout most of southern California and part of central California. SDG&E provides electric service to San Diego and southern Orange counties and natural gas service to San Diego County. Sempra Commodities, based in Stamford, Connecticut, is primarily a wholesale trader of physical and financial energy products and other commodities, and a trader and wholesaler of metals, serving a broad range of customers in the United States, Canada, Europe and Asia. As a result of the movement of the former Sempra Energy Solutions' commodities business into Sempra Commodities, Sempra Commodities' business also includes commodity sales on a retail basis to electricity and natural gas consumers. Sempra Generation primarily acquires, develops and operates power plants throughout the U.S. and Mexico and, as a result of the movement of the former Sempra Energy Solutions' energy businesses into Sempra Generation, provides energy services and facilities management. Sempra Generation also owns mineral rights in properties that produce petroleum and natural gas.

The accounting policies of the segments are described in Note 1, and segment performance is evaluated by management based on reported net income. California Utility transactions are based on rates set by the CPUC and the FERC.

(Dollars in millions)	Years ended December 31, 2004		2003		2002	
OPERATING REVENUES						
Southern California Gas Company	**$3,997**	**42%**	$3,544	45%	$2,858	47%
San Diego Gas & Electric	**2,274**	**24**	2,311	29	1,725	29
Sempra Commodities	**1,680**	**18**	1,217	16	910	15
Sempra Generation	**1,647**	**18**	773	10	437	7
All other	**146**	**2**	99	1	155	3
Intersegment revenues	**(334)**	**(4)**	(57)	(1)	(37)	(1)
Total	**$9,410**	**100%**	$7,887	100%	$6,048	100%
INTEREST EXPENSE						
Southern California Gas Company	**$ 39**		$ 45		$ 44	
San Diego Gas & Electric	**68**		73		77	
Sempra Commodities	**23**		31		45	
Sempra Generation	**34**		33		10	
All other	**331**		256		190	
Intercompany elimination	**(173)**		(130)		(72)	
Total	**$ 322**		$ 308		$ 294	
INTEREST INCOME						
Southern California Gas Company	**$ 4**		$ 34		$ 5	
San Diego Gas & Electric	**25**		42		10	
Sempra Commodities	**8**		12		11	
Sempra Generation	**7**		17		4	
All other	**198**		129		84	
Intercompany elimination	**(173)**		(130)		(72)	
Total	**$ 69**		$ 104		$ 42	
DEPRECIATION AND AMORTIZATION						
Southern California Gas Company	**$ 255**	**41%**	$ 289	47%	$ 276	46%
San Diego Gas & Electric	**259**	**42**	242	39	230	39
Sempra Commodities	**23**	**4**	23	4	21	3
Sempra Generation	**44**	**7**	21	3	10	2
All other	**40**	**6**	40	7	59	10
Total	**$ 621**	**100%**	$ 615	100%	$ 596	100%
INCOME TAX EXPENSE (BENEFIT)						
Southern California Gas Company	**$ 154**	**80%**	$ 150	319%	$ 178	122%
San Diego Gas & Electric	**148**	**77**	148	315	91	62
Sempra Commodities	**161**	**83**	67	143	75	51
Sempra Generation	**91**	**47**	27	57	40	28
All other	**(361)**	**(187)**	(345)	(734)	(238)	(163)
Total	**$ 193**	**100%**	$ 47	100%	$ 146	100%
NET INCOME (LOSS)						
Southern California Gas Company	**$ 232**	**26%**	$ 209	32%	$ 212	36%
San Diego Gas & Electric	**208**	**23**	334	52	203	34
Sempra Commodities	**320**	**36**	128	20	165	28
Sempra Generation	**137**	**15**	80	12	42	7
All other	**(2)**	**—**	(102)	(16)	(31)	(5)
Total	**$ 895**	**100%**	$ 649	100%	$ 591	100%

(Dollars in millions)	At December 31 or years ended December 31, 2004		2003		2002	
ASSETS						
Southern California Gas Company	**$ 5,502**	**23%**	$ 5,349	24%	$ 5,403	27%
San Diego Gas & Electric	**6,834**	**29**	6,461	29	6,285	31
Sempra Commodities	**7,574**	**32**	6,144	28	5,780	28
Sempra Generation	**2,738**	**12**	2,550	12	1,633	8
All other	**1,997**	**8**	1,988	9	1,783	9
Intersegment receivables	**(1,002)**	**(4)**	(504)	(2)	(642)	(3)
Total	**$23,643**	**100%**	$21,988	100%	$20,242	100%
CAPITAL EXPENDITURES						
Southern California Gas Company	**$ 311**	**29%**	$ 318	30%	$ 331	27%
San Diego Gas & Electric	**414**	**38**	444	42	400	33
Sempra Commodities	**126**	**12**	51	5	21	2
Sempra Generation	**141**	**13**	144	14	359	30
All other	**91**	**8**	92	9	103	8
Total	**$ 1,083**	**100%**	$ 1,049	100%	$ 1,214	100%
GEOGRAPHIC INFORMATION						
Long-lived assets						
United States	**$10,975**	**89%**	$10,380	89%	$ 9,548	90%
Latin America	**1,177**	**10**	1,121	10	1,062	10
Europe	**98**	**1**	87	1	18	—
Canada	**—**	**—**	—	—	3	—
Total	**$12,250**	**100%**	$11,588	100%	$10,631	100%
Operating revenues						
United States	**$ 8,518**	**91%**	$ 7,211	92%	$ 5,503	91%
Latin America	**311**	**3**	315	4	168	3
Europe	**519**	**6**	323	4	328	6
Canada	**37**	**—**	10	—	28	—
Asia	**25**	**—**	28	—	21	—
Total	**$ 9,410**	**100%**	$ 7,887	100%	$ 6,048	100%

NOTE 18. QUARTERLY FINANCIAL DATA (UNAUDITED)

(Dollars and shares in millions, except per share amounts)	Quarters ended March 31	June 30	September 30	December 31
2004				
Operating revenues	**$2,360**	**$1,996**	**$2,165**	**$2,889**
Operating expenses	**2,028**	**1,776**	**1,820**	**2,514**
Operating income	**$ 332**	**$ 220**	**$ 345**	**$ 375**
Income from continuing operations	**$ 221**	**$ 129**	**$ 231**	**$ 339**
Net income	**$ 197**	**$ 121**	**$ 231**	**$ 346**
Basic earnings per share:				
Income from continuing operations	**$ 0.97**	**$ 0.56**	**$ 1.01**	**$ 1.47**
Net income	**$ 0.86**	**$ 0.52**	**$ 1.01**	**$ 1.50**
Average common shares outstanding	**228.1**	**230.4**	**229.4**	**230.8**
Diluted earnings per share:				
Income from continuing operations	**$ 0.96**	**$ 0.55**	**$ 0.98**	**$ 1.43**
Net income	**$ 0.85**	**$ 0.52**	**$ 0.98**	**$ 1.46**
Average common shares outstanding	**231.1**	**234.3**	**235.9**	**237.5**
2003				
Operating revenues	$1,923	$1,840	$2,058	$2,066
Operating expenses	1,708	1,637	1,751	1,852
Operating income	$ 215	$ 203	$ 307	$ 214
Income before cumulative effect of changes in accounting principles	$ 117	$ 116	$ 211	$ 251
Net income	$ 88	$ 116	$ 211	$ 234
Basic earnings per share:				
Income before cumulative effect of changes in accounting principles	$ 0.57	$ 0.56	$ 1.01	$ 1.12
Net income	$ 0.43	$ 0.56	$ 1.01	$ 1.05
Average common shares outstanding	206.4	207.6	208.8	224.0
Diluted earnings per shares:				
Income before cumulative effect of changes in accounting principles	$ 0.56	$ 0.55	$ 1.00	$ 1.11
Net income	$ 0.42	$ 0.55	$ 1.00	$ 1.03
Average common shares outstanding	207.8	210.2	212.3	227.2

Operating revenues and expenses in the fourth quarter of 2004 included the favorable impact of the final cost of service decision and operating expenses included litigation costs recorded in the fourth quarter. Net income in the first and second quarters of 2004 included $24 million and $8 million, respectively, of losses related to the discontinuance and disposal of AEG. Net income in the fourth quarter of 2004 included the $38 million favorable impact of income tax issues related to the reduced estimate of federal and state income tax liabilities for certain prior years and the $7 million favorable tax adjustment related to AEG. Note 4 provides a discussion of discontinued operations.

Operating revenues in the third quarter of 2003 included the recognition of $116 million before-tax related to the approved settlement of intermediate-term purchase power contracts at SDG&E and $48 million of natural gas procurement awards at SoCalGas. The after-tax impacts to net income were $65 million and $29 million, respectively. Additionally, operating expenses in the third quarter of 2003 were impacted by a $77 million impairment charge to write down the carrying value of the assets of Frontier

Energy and a $74 million before-tax charge for litigation and for losses associated with a sublease of portions of the SoCalGas headquarters building. The after-tax impacts to net income were $47 million and $43 million, respectively.

In the first quarter of 2003, net income reflected a $29 million charge related to the cumulative effect of a change in accounting principle at Sempra Commodities. Net income in the fourth quarter of 2003 included $118 million related to the favorable resolution of income tax issues at the California Utilities and the unfavorable net impact of $17 million related to the cumulative effect of changes in accounting principles.

QUARTERLY COMMON STOCK DATA (UNAUDITED)

	First Quarter	Second Quarter	Third Quarter	Fourth Quarter
2004				
Market price				
High	**$32.99**	**$34.90**	**$37.19**	**$37.93**
Low	**$29.51**	**$30.80**	**$33.97**	**$31.00**
2003				
Market price				
High	$26.00	$29.40	$30.33	$30.90
Low	$22.25	$24.05	$27.31	$26.36

Dividends declared were $0.25 per share in each quarter.

Supplemental Consolidating Information

December 31, 2004

Supplemental Consolidating Balance Sheet Information
Sempra Energy Solutions
December 31, 2004

(Dollars in millions)	Sempra Energy Solutions (1)	Sempra Energy and Other Subsidiaries	Intercompany Eliminations	Sempra Energy Consolidated
Assets				
Current assets:				
Cash and cash equivalents	$ -	$ 419	$ -	$ 419
Short-term investments	-	15	-	15
Trade accounts receivable, net	-	950	-	950
Other accounts and notes receivable, net	-	82	-	82
Due from unconsolidated affiliates	69	48	(113)	4
Income taxes receivable	5	-	(5)	-
Deferred income taxes	16	-	(1)	15
Interest receivable	-	80	-	80
Trading-related receivables and deposits, net	165	2,467	(26)	2,606
Derivative trading instruments	97	2,271	(29)	2,339
Commodities owned	-	1,547	-	1,547
Regulatory assets arising from fixed-price contracts and other derivatives	-	152	-	152
Other regulatory assets	-	103	-	103
Inventories	2	170	-	172
Other	1	222	(1)	222
Current assets of continuing operations	355	8,526	(175)	8,706
Current assets of discontinued operations	-	70	-	70
Total current assets	355	8,596	(175)	8,776
Investments and other assets:				
Due from unconsolidated affiliates	-	42	-	42
Regulatory assets arising from fixed-price contracts and other derivatives	-	500	-	500
Other regulatory assets	-	619	-	619
Nuclear decommissioning trusts	-	612	-	612
Investments	-	1,237	(73)	1,164
Sundry	24	820	-	844
Total investments and other assets	24	3,830	(73)	3,781
Property, plant and equipment, net	8	11,078	-	11,086
Total assets	$ 387	$ 23,504	$ (248)	$ 23,643

	Sempra Energy Solutions (1)	Sempra Energy and Other Subsidiaries	Intercompany Eliminations	Sempra Energy Consolidated
Liabilities and Shareholders' Equity				
Current liabilities:				
Short-term debt	$ -	$ 405	$ -	$ 405
Accounts payable, trade	-	1,020	-	1,020
Accounts payable, other	2	104	-	106
Due to unconsolidated affiliates	144	200	(139)	205
Income taxes payable	-	192	(5)	187
Trading-related payables	86	3,098	(2)	3,182
Derivative trading instruments sold, not yet purchased	48	1,465	(29)	1,484
Commodities sold with agreement to repurchase	-	513	-	513
Dividends and interest payable	-	123	-	123
Regulatory balancing accounts, net	-	509	-	509
Fixed-price contracts and other derivatives	-	157	-	157
Current portion of long-term debt	-	398	-	398
Other	3	773	-	776
Current liabilities of continuing operations	283	8,957	(175)	9,065
Current liabilities of discontinued operations	-	17	-	17
Total current liabilities	283	8,974	(175)	9,082
Long-term debt	-	4,192	-	4,192
Deferred credits and other liabilities:				
Due to unconsolidated affiliates	-	162	-	162
Customer advances for construction	-	97	-	97
Postretirement benefits other than pensions	-	129	-	129
Deferred income taxes	31	389	-	420
Deferred investment tax credits	-	78	-	78
Regulatory liabilities arising from cost of removal obligations	-	2,359	-	2,359
Regulatory liabilities arising from asset retirement obligations	-	333	-	333
Other regulatory liabilities	-	67	-	67
Fixed-price contracts and other derivatives	-	500	-	500
Asset retirement obligations	-	326	-	326
Deferred credits and other	-	854	-	854
Total deferred credits and other liabilities	31	5,294	-	5,325
Preferred stock of subsidiaries	-	179	-	179
Shareholders' equity	73	4,865	(73)	4,865
Total liabilities and shareholders' equity	$ 387	$ 23,504	$ (248)	$ 23,643

(1) Sempra Energy Solutions is included in the Sempra Commodities business unit of Sempra Energy.

Supplemental Consolidating Statement of Income Information
Sempra Energy Solutions
Year ended December 31, 2004

(Dollars in millions)	Sempra Energy Solutions (1)	Sempra Energy and Other Subsidiaries	Intercompany Eliminations	Sempra Energy Consolidated
Operating revenues				
California utilities:				
Natural gas	$ -	$ 4,537	$ -	$ 4,537
Electric	-	1,658	-	1,658
Other	37	3,178	-	3,215
Total operating revenues	37	9,373	-	9,410
Operating expenses				
California utilities:				
Cost of natural gas	-	2,593	-	2,593
Cost of electric fuel and purchased power	-	576	-	576
Other cost of sales	-	1,741	-	1,741
Other operating expenses	36	2,335	-	2,371
Depreciation and amortization	-	621	-	621
Franchise fees and other taxes	-	236	-	236
Total operating expenses	36	8,102	-	8,138
Operating income	1	1,271	-	1,272
Other income, net	-	104	-	104
Interest income	(2)	69	2	69
Interest expense	-	(320)	(2)	(322)
Preferred dividends of subsidiaries	-	(10)	-	(10)
Income (loss) from continuing operations before income taxes	(1)	1,114	-	1,113
Income tax expense		193	-	193
Income (loss) from continuing operations	(1)	921	-	920
Loss from discontinued operations, net of tax	-	(23)	-	(23)
Loss on disposal of discontinued operations, net of tax	-	(2)	-	(2)
Net income (loss)	$ (1)	$ 896	$ -	$ 895

(1) Sempra Energy Solutions is included in the Sempra Commodities business unit of Sempra Energy.

Supplemental Consolidating Statement of Cash Flows Information
Sempra Energy Solutions
Year ended December 31, 2004

(Dollars in millions)	Sempra Energy Solutions (1)	Sempra Energy and Other Subsidiaries	Sempra Energy Consolidated
Cash Flows from Operating Activities			
Net income (loss)	$ (1)	$ 896	$ 895
Adjustments to reconcile net income (loss) to net cash provided by operating activities:			
Discontinued operations, net of tax	-	25	25
Depreciation and amortization	-	621	621
Deferred income taxes and investment tax credits	-	13	13
Non-cash rate reduction bond expense	-	75	75
Equity in income of unconsolidated affiliates	-	(36)	(36)
Impairment losses	-	12	12
Gain on sale and disposition of assets	-	(15)	(15)
Other, net	-	37	37
Net changes in other working capital components	1	(428)	(427)
Changes in other assets	-	(200)	(200)
Changes in other liabilities	-	(21)	(21)
Net cash provided by continuing operations	-	979	979
Net cash used in discontinued operations	-	(30)	(30)
Net cash provided by operating activities	-	949	949
Cash Flows from Investing Activities			
Expenditures for property, plant and equipment	-	(1,083)	(1,083)
Investments in and acquisitions of subsidiaries, net of cash acquired	-	(74)	(74)
Proceeds from disposal of discontinued operations	-	157	157
Net proceeds from sale of assets	-	372	372
Dividends received from affiliates	-	59	59
Other, net	-	10	10
Net cash used in investing activities	-	(559)	(559)
Cash Flows from Financing Activities			
Common dividends paid	-	(195)	(195)
Issuances of common stock	-	110	110
Repurchases of common stock	-	(5)	(5)
Issuances of long-term debt	-	997	997
Payments on long-term debt	-	(1,670)	(1,670)
Increase in short-term debt, net	-	397	397
Other, net	-	(14)	(14)
Net cash used in financing activities	-	(380)	(380)
Increase in cash and cash equivalents	-	10	10
Cash and cash equivalents, January 1	-	409	409
Cash and cash equivalents, December 31	$ -	$ 419	$ 419

(1) Sempra Energy Solutions is included in the Sempra Commodities business unit of Sempra Energy.

Sempra Energy℠
Solutions

Sempra Energy Annual Financial Report
and
Supplemental Consolidating Information
(Sempra Energy Solutions and Its Other Subsidiaries)

December 31, 2003

Sempra Energy Solutions (SES) is not the same company as the utility, SDG&E or SoCalGas,
and the California Public Utilities Commission does not regulate the terms of SES' products and services.

Sempra Energy Annual Financial Report
and
Supplemental Consolidating Information
(Sempra Energy Solutions and Its Other Subsidiaries)

December 31, 2003

Sempra Energy Annual Financial Report and Supplemental Consolidating Information (Sempra Energy Solutions and Its Other Subsidiaries)

Table of Contents

	Page
Independent Auditors' Report	1
Annual Financial Report	
Statements of Consolidated Income	2
Consolidated Balance Sheets	3-4
Statements of Consolidated Cash Flows	5-6
Statements of Consolidated Changes in Stockholders' Equity	7
Notes to Consolidated Financial Statements	8-73
Supplemental Consolidating Information (Sempra Energy Solutions and Its Other Subsidiaries)	
Supplemental Consolidating Balance Sheet Information	74
Supplemental Consolidating Statement of Income Information	75
Supplemental Consolidating Statement of Cash Flows Information	76

INDEPENDENT AUDITORS' REPORT

Board of Directors and Shareholders of Sempra Energy

We have audited the accompanying consolidated balance sheets of Sempra Energy and subsidiaries (the "Company") as of December 31, 2003 and 2002, and the related statements of consolidated income, cash flows and changes in shareholders' equity for each of the three years in the period ended December 31, 2003. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements based on our audits.

We conducted our audits in accordance with auditing standards generally accepted in the United States of America. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, such consolidated financial statements present fairly, in all material respects, the financial position of Sempra Energy and subsidiaries as of December 31, 2003 and 2002, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2003, in conformity with accounting principles generally accepted in the United States of America.

As described in Note 1 to the financial statements, the Company adopted Statement of Financial Accounting Standards No. 143, Accounting for Asset Retirement Obligations, effective January 1, 2003, and Financial Accounting Standards Board Interpretation No. 46, Consolidation of Variable Interest Entities an interpretation of ARB No. 51, effective December 31, 2003.

Our audits were conducted for the purpose of forming an opinion on the basic consolidated financial statements taken as a whole. The supplemental consolidating information for 2003 on pages 74 through 76 is presented for the purpose of additional analysis of the basic consolidated financial statements rather than to present the financial position, results of operations, and cash flows of the individual companies, and is not a required part of the basic consolidated financial statements. This supplemental consolidating information is the responsibility of the company's management. Such information has be subjected to the auditing procedures applied in our audit of the basic 2003 consolidated financial statements and, in our opinion, is fairly stated in all material respects when considered in relation to the basic 2003 consolidated financial statements taken as a whole.

Deloitte & Touche LLP

February 23, 2004
San Diego, California

SEMPRA ENERGY
STATEMENTS OF CONSOLIDATED INCOME

(Dollars in millions, except per share amounts)	Years ended December 31, 2003	2002	2001
OPERATING REVENUES			
California utilities:			
Natural gas	**$ 4,010**	$ 3,263	$ 4,371
Electric	**1,787**	1,282	1,676
Other	**2,090**	1,503	1,683
Total	**7,887**	6,048	7,730
OPERATING EXPENSES			
California utilities:			
Cost of natural gas	**2,071**	1,381	2,549
Cost of electric fuel and purchased power	**541**	297	782
Other cost of sales	**1,204**	709	873
Other operating expenses	**2,287**	1,901	1,760
Depreciation and amortization	**615**	596	579
Franchise fees and other taxes	**230**	177	190
Total	**6,948**	5,061	6,733
Operating income	**939**	987	997
Other income — net	**26**	15	3
Interest income	**104**	42	83
Interest expense	**(308)**	(294)	(323)
Preferred dividends of subsidiaries	**(10)**	(11)	(11)
Trust preferred distributions by subsidiary	**(9)**	(18)	(18)
Income before income taxes	**742**	721	731
Income tax expense	**47**	146	213
Income before extraordinary item and cumulative effect of changes in accounting principles	**695**	575	518
Extraordinary item, net of tax (Note 1)	**—**	16	—
Income before cumulative effect of changes in accounting principles	**695**	591	518
Cumulative effect of changes in accounting principles, net of tax (Note 1)	**(46)**	—	—
Net income	**$ 649**	$ 591	$ 518
Weighted-average number of shares outstanding (thousands):			
Basic	**211,740**	205,003	203,593
Diluted	**214,482**	206,062	205,338
Income before extraordinary item and cumulative effect of changes in accounting principles per share of common stock			
Basic	**$ 3.29**	$ 2.80	$ 2.54
Diluted	**$ 3.24**	$ 2.79	$ 2.52
Income before cumulative effect of changes in accounting principles per share of common stock			
Basic	**$ 3.29**	$ 2.88	$ 2.54
Diluted	**$ 3.24**	$ 2.87	$ 2.52
Net income per share of common stock			
Basic	**$ 3.07**	$ 2.88	$ 2.54
Diluted	**$ 3.03**	$ 2.87	$ 2.52
Common dividends declared per share	**$ 1.00**	$ 1.00	$ 1.00

See notes to Consolidated Financial Statements.

SEMPRA ENERGY
CONSOLIDATED BALANCE SHEETS

(Dollars in millions)	December 31, 2003	2002
ASSETS		
Current assets:		
Cash and cash equivalents	**$ 432**	$ 455
Short-term investments	**363**	—
Accounts receivable — trade	**1,012**	754
Accounts and notes receivable — other	**127**	132
Interest receivable	**62**	3
Due from unconsolidated affiliates	**—**	80
Income taxes receivable	**20**	—
Deferred income taxes	**—**	20
Trading assets	**5,250**	5,064
Regulatory assets arising from fixed-price contracts and other derivatives	**144**	151
Other regulatory assets	**89**	75
Inventories	**147**	134
Other	**240**	142
Total current assets	**7,886**	7,010
Investments and other assets:		
Due from unconsolidated affiliates	**55**	57
Regulatory assets arising from fixed-price contracts and other derivatives	**650**	812
Other regulatory assets	**554**	532
Nuclear decommissioning trusts	**570**	494
Investments	**1,114**	1,313
Fixed-price contracts and other derivatives	**—**	42
Sundry	**706**	664
Total investments and other assets	**3,649**	3,914
Property, plant and equipment:		
Property, plant and equipment	**15,317**	13,816
Less accumulated depreciation and amortization	**(4,843)**	(4,498)
Total property, plant and equipment — net	**10,474**	9,318
Total assets	**$22,009**	$20,242

See notes to Consolidated Financial Statements.

SEMPRA ENERGY
CONSOLIDATED BALANCE SHEETS

(Dollars in millions)	December 31, 2003	2002
LIABILITIES AND SHAREHOLDERS' EQUITY		
Current liabilities:		
Short-term debt	**$ 28**	$ 570
Accounts payable — trade	**815**	694
Accounts payable — other	**64**	50
Income taxes payable	**—**	22
Deferred income taxes	**123**	—
Trading liabilities	**4,457**	4,094
Dividends and interest payable	**136**	133
Regulatory balancing accounts — net	**424**	578
Fixed-price contracts and other derivatives	**148**	153
Current portion of long-term debt	**1,433**	281
Other	**720**	672
Total current liabilities	**8,348**	7,247
Long-term debt	**3,841**	4,083
Deferred credits and other liabilities:		
Due to unconsolidated affiliates	**362**	162
Customer advances for construction	**89**	91
Postretirement benefits other than pensions	**131**	136
Deferred income taxes	**634**	800
Deferred investment tax credits	**84**	90
Regulatory liabilities arising from cost of removal obligations	**2,238**	2,486
Regulatory liabilities arising from asset retirement obligations	**281**	—
Other regulatory liabilities	**108**	121
Fixed-price contracts and other derivatives	**680**	813
Asset retirement obligations	**313**	—
Deferred credits and other	**831**	984
Total deferred credits and other liabilities	**5,751**	5,683
Preferred stock of subsidiaries	**179**	204
Mandatorily redeemable trust preferred securities	**—**	200
Commitments and contingent liabilities (Note 15)		
SHAREHOLDERS' EQUITY		
Preferred stock (50 million shares authorized, none issued)	**—**	—
Common stock (750 million shares authorized; 227 million and 205 million shares outstanding at December 31, 2003 and December 31, 2002, respectively)	**2,028**	1,436
Retained earnings	**2,298**	1,861
Deferred compensation relating to ESOP	**(35)**	(33)
Accumulated other comprehensive income (loss)	**(401)**	(439)
Total shareholders' equity	**3,890**	2,825
Total liabilities and shareholders' equity	**$22,009**	$20,242

See notes to Consolidated Financial Statements.

SEMPRA ENERGY
STATEMENTS OF CONSOLIDATED CASH FLOWS

(Dollars in millions)	Years ended December 31, 2003	2002	2001
CASH FLOWS FROM OPERATING ACTIVITIES			
Net income	**$ 649**	$ 591	$ 518
Adjustments to reconcile net income to net cash provided by operating activities:			
Extraordinary item, net of tax	**—**	(16)	—
Cumulative effect of changes in accounting principles	**46**	—	—
Depreciation and amortization	**615**	596	579
Foreign currency loss (gain)	**8**	(63)	—
Deferred income taxes and investment tax credits	**(73)**	(92)	106
Non-cash rate reduction bond expense	**68**	82	66
Equity in (income) losses of unconsolidated affiliates	**(8)**	55	(12)
Impairment losses	**101**	—	—
Loss (gain) on sale and disposition of assets	**8**	14	(14)
Other — net	**2**	(5)	—
Net changes in other working capital components	**(224)**	151	(203)
Customer refunds paid	**—**	—	(127)
Changes in other assets	**(66)**	87	(280)
Changes in other liabilities	**(5)**	40	99
Net cash provided by operating activities	**1,121**	1,440	732
CASH FLOWS FROM INVESTING ACTIVITIES			
Expenditures for property, plant and equipment	**(1,049)**	(1,214)	(1,068)
Investments and acquisitions of subsidiaries, net of cash acquired	**(202)**	(429)	(111)
Dividends received from unconsolidated affiliates	**72**	11	80
Net proceeds from sale of assets	**29**	—	128
Loans to unconsolidated affiliates	**(99)**	(82)	(57)
Other — net	**(4)**	(14)	(11)
Net cash used in investing activities	**(1,253)**	(1,728)	(1,039)
CASH FLOWS FROM FINANCING ACTIVITIES			
Common dividends paid	**(207)**	(205)	(203)
Issuances of common stock	**549**	13	41
Repurchases of common stock	**(6)**	(16)	(1)
Issuances of long-term debt	**900**	1,150	675
Payments on long-term debt	**(601)**	(479)	(681)
Loan from unconsolidated affiliate	**—**	—	160
Increase (decrease) in short-term debt — net	**(518)**	(307)	310
Other — net	**(8)**	(18)	(26)
Net cash provided by financing activities	**109**	138	275
Decrease in cash and cash equivalents	**(23)**	(150)	(32)
Cash and cash equivalents, January 1	**455**	605	637
Cash and cash equivalents, December 31	**$ 432**	$ 455	$ 605

See notes to Consolidated Financial Statements.

	Years ended December 31,		
	2003	2002	2001
CHANGES IN OTHER WORKING CAPITAL COMPONENTS			
(Excluding cash and cash equivalents, and debt due within one year)			
Accounts and notes receivable	**$(231)**	$ (121)	$ 353
Net trading assets	**81**	66	(362)
Income taxes — net	**6**	86	(121)
Inventories	**(13)**	(11)	33
Regulatory balancing accounts	**(156)**	170	88
Regulatory assets and liabilities	**(30)**	1	39
Other current assets	**(8)**	51	33
Accounts payable	**98**	(103)	(302)
Other current liabilities	**29**	12	36
Net changes in other working capital components	**$(224)**	$ 151	$(203)
SUPPLEMENTAL DISCLOSURE OF CASH FLOW INFORMATION			
Interest payments, net of amounts capitalized	**$ 296**	$ 279	$ 302
Income tax payments, net of refunds	**$ 118**	$ 140	$ 138
SUPPLEMENTAL SCHEDULE OF NON-CASH INVESTING AND FINANCING ACTIVITIES			
Acquisition of subsidiaries:			
Assets acquired	**$ —**	$1,134	$ —
Cash paid, net of cash acquired	**—**	(119)	—
Liabilities assumed	**$ —**	$1,015	$ —
Consolidation of variable interest entities:			
Assets recorded	**$ 820**	$ —	$ —
Liabilities recorded	**(881)**	—	—
Total	**$ (61)**	$ —	$ —

See notes to Consolidated Financial Statements.

SEMPRA ENERGY
STATEMENTS OF CONSOLIDATED CHANGES IN SHAREHOLDERS' EQUITY
Years ended December 31, 2003, 2002 and 2001

(Dollars in millions)	Comprehensive Income	Common Stock	Retained Earnings	Deferred Compensation Relating to ESOP	Accumulated Other Comprehensive Income (Loss)	Total Shareholders' Equity
Balance at December 31, 2000		$1,420	$1,162	$(39)	$ (49)	$2,494
Net income	$ 518		518			518
Comprehensive income adjustments:						
Foreign currency translation losses (Note 1)	(186)				(186)	(186)
Pension	(7)				(7)	(7)
Comprehensive income	$ 325					
Common stock dividends declared			(205)			(205)
Quasi-reorganization adjustment (Note 1)		35				35
Sale of common stock		41				41
Repurchase of common stock		(1)				(1)
Common stock released from ESOP				3		3
Balance at December 31, 2001		1,495	1,475	(36)	(242)	2,692
Net income	$ 591		591			591
Comprehensive income adjustments:						
Foreign currency translation losses (Note 1)	(162)				(162)	(162)
Pension	(35)				(35)	(35)
Comprehensive income	$ 394					
Common stock dividends declared			(205)			(205)
Issuance of equity units (Note 5)		(61)				(61)
Sale of common stock		18				18
Repurchase of common stock		(16)				(16)
Common stock released from ESOP				3		3
Balance at December 31, 2002		1,436	1,861	(33)	(439)	2,825
Net income	**$ 649**		**649**			**649**
Comprehensive income adjustments:						
Foreign currency translation gains (Note 1)	**57**				**57**	**57**
Pension	**(16)**				**(16)**	**(16)**
SFAS 133	**(3)**				**(3)**	**(3)**
Comprehensive income	**$ 687**					
Common stock dividends declared			**(212)**			**(212)**
Equity units adjustment		**6**				**6**
Quasi-reorganization adjustment (Note 1)		**19**				**19**
Sale of common stock		**566**				**566**
Repurchase of common stock		**(6)**				**(6)**
Common stock released from ESOP		**7**		**(2)**		**5**
Balance at December 31, 2003		**$2,028**	**$2,298**	**$(35)**	**$(401)**	**$3,890**

See notes to Consolidated Financial Statements.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

NOTE 1. SIGNIFICANT ACCOUNTING POLICIES

Principles of Consolidation

The Consolidated Financial Statements include the accounts of Sempra Energy (the company) and all majority-owned subsidiaries. Investments in affiliated companies over which Sempra Energy has the ability to exercise significant influence, but not control, are accounted for using the equity method. All material intercompany accounts and transactions have been eliminated.

Quasi-Reorganization

In 1993, Pacific Enterprises (PE) divested substantially all of its non-utility business and effected a quasi-reorganization for financial reporting purposes as of December 31, 1992. Certain of the liabilities established in connection with the quasi-reorganization, including various income-tax issues, were favorably resolved, resulting in restoring $35 million and $19 million to shareholders' equity in 2001 and 2003, respectively. These restorations did not affect the calculation of net income or comprehensive income. The remaining liabilities will be resolved in future years and management believes the provisions established for these matters are adequate.

Use of Estimates in the Preparation of the Financial Statements

The preparation of financial statements in conformity with generally accepted accounting principles requires management to make estimates and assumptions that affect the reported amounts of revenues and expenses during the reporting period, and the reported amounts of assets and liabilities and the disclosure of contingent assets and liabilities at the date of the financial statements. Actual amounts can differ significantly from those estimates.

Basis of Presentation

Certain prior-year amounts have been reclassified to conform to the current year's presentation.

Regulatory Matters

Effects of Regulation

The accounting policies of the company's principal utility subsidiaries, San Diego Gas & Electric (SDG&E) and Southern California Gas Company (SoCalGas) (collectively, the California Utilities), conform with generally accepted accounting principles for regulated enterprises and reflect the policies of the California Public Utilities Commission (CPUC) and the Federal Energy Regulatory Commission (FERC).

The California Utilities prepare their financial statements in accordance with the provisions of *Statement of Financial Accounting Standards* (SFAS) *71, "Accounting for the Effects of Certain Types of Regulation,"* under which a regulated utility records a regulatory asset if it is probable that, through the ratemaking process, the utility will recover that asset from customers. Regulatory liabilities represent reductions in future rates for amounts due to customers. To the extent that recovery is no longer probable as a result of changes in regulation or the utility's competitive position, the related regulatory assets and liabilities would be written off. In addition, *SFAS 144,"Accounting for the Impairment or Disposal of Long-Lived Assets"* requires that a loss must be recognized whenever a regulator excludes all or part of utility plant or regulatory assets from ratebase. Information concerning regulatory assets and liabilities is described in "Revenues," "Regulatory Balancing Accounts," and "Regulatory Assets and Liabilities."

Regulatory Balancing Accounts

The amounts included in regulatory balancing accounts at December 31, 2003, represent net payables (payables net of receivables) of $86 million and $338 million for SoCalGas and SDG&E, respectively. The corresponding amounts at December 31, 2002 were net payables of $184 million and $394 million. The payables normally are returned by reducing future rates.

Balancing accounts provide a mechanism for charging utility customers the amount actually incurred for certain costs, primarily commodity costs. However, fluctuations in most operating and maintenance costs affect earnings. In addition, fluctuations in consumption levels affect earnings at SDG&E. The CPUC approved 100 percent balancing account treatment for variances between forecast and actual for SoCalGas' noncore revenues and throughput, eliminating the impact on earnings from any throughput and revenue variances from adopted forecast levels. Additional information on regulatory matters is included in Notes 13 and 14.

Regulatory Assets and Liabilities

In accordance with the accounting principles of SFAS 71, the company records regulatory assets and regulatory liabilities as discussed above.

Regulatory assets (liabilities) as of December 31 relate to the following matters:

(Dollars in millions)	**2003**	2002
SDG&E		
Fixed-price contracts and other derivatives	**$ 560**	$ 636
Recapture of temporary rate reduction*	**259**	326
Deferred taxes recoverable in rates	**273**	190
Unamortized loss on retirement of debt — net	**44**	49
Employee benefit costs	**35**	35
Cost of removal obligations**	**(846)**	(1,162)
Asset retirement obligations**	**(303)**	—
Other	**24**	7
Total	**46**	81
SoCalGas		
Fixed-price contracts and other derivatives	**233**	325
Environmental remediation	**44**	43
Unamortized loss on retirement of debt — net	**45**	38
Cost of removal obligation**	**(1,392)**	(1,324)
Deferred taxes refundable in rates	**(192)**	(164)
Employee benefit costs	**(77)**	(142)
Other	**8**	8
Total	**(1,331)**	(1,216)
PE — Employee benefit costs	**72**	80
Total PE consolidated	**(1,259)**	(1,136)
Total	**$(1,213)**	$(1,055)

* In connection with electric industry restructuring, which is described in Note 13, SDG&E temporarily reduced rates to its small-usage customers. That reduction is being recovered in rates through 2007.

** See discussion of SFAS 143 in "New Accounting Standards."

Net regulatory liabilities are recorded on the Consolidated Balance Sheets at December 31 as follows:

(Dollars in millions)	**2003**	2002
Current regulatory assets	**$ 233**	$ 226
Noncurrent regulatory assets	**1,204**	1,344
Current regulatory liabilities*	**(23)**	(18)
Noncurrent regulatory liabilities	**(2,627)**	(2,607)
Total	**$(1,213)**	$(1,055)

* Amount is included in Other Current Liabilities.

All of the assets either earn a return, generally at short-term rates, or the cash has not yet been expended and the assets are offset by liabilities that do not incur a carrying cost.

Cash and Cash Equivalents

Cash equivalents are highly liquid investments with maturities of three months or less at the date of purchase.

Collection Allowances

The allowance for doubtful accounts was $19 million, $12 million and $22 million at December 31, 2003, 2002 and 2001, respectively. The company recorded a provision for doubtful accounts of $5 million, $13 million and $21 million in 2003, 2002 and 2001, respectively.

The allowance for realization of trading assets was $67 million, $86 million and $23 million, at December 31, 2003, 2002 and 2001, respectively. The company recorded a provision (reduction thereof) for trading assets of ($4) million, $20 million and $15 million in 2003, 2002 and 2001, respectively.

Trading Instruments

Trading assets and trading liabilities include option premiums paid and received; unrealized gains and losses from exchange-traded futures and options, over-the-counter (OTC) swaps, forwards, physical commodities and options; and base metals. Trading instruments are recorded by Sempra Energy Trading (SET) and Sempra Energy Solutions (SES) on a trade-date basis and the majority of such derivative instruments are adjusted daily to current market value. Unrealized gains and losses on OTC transactions reflect amounts which would be received from or paid to a third party upon net settlement of the contracts. Unrealized gains and losses on OTC transactions are reported separately as assets and liabilities unless a legal right of setoff exists under an enforceable netting arrangement. Additionally, as a result of SET's acquisitions in 2002, the company acquired $0.8 billion of base metals inventory. As of December 31, 2003 and 2002, trading assets included commodity inventory of $1.4 billion and $2.0 billion, respectively.

In October 2002, the Emerging Issues Task Force (EITF) rescinded fair value accounting for recording energy-trading activities and required contracts subsequently entered into to be accounted for at historical cost or the lower of cost or market, unless the contracts meet the requirements for fair value accounting under SFAS 133 and 149 (see below in "New Accounting Standards"). Energy transportation and storage contracts are recorded at cost. Energy commodity inventory is being recorded at the lower of cost or market. The company's base metals and concentrates inventory continue to be recorded at fair value in accordance with *Accounting Research Bulletin (ARB) No. 43 "Restatement and Revision of Accounting Research Bulletins."* See further discussion of EITF Issue 02-3 below in "New Accounting Standards."

Futures and exchange-traded option transactions are recorded as contractual commitments on a trade-date basis and carried at current market value based on current closing exchange quotations. Derivative commodity swaps and forward transactions are accounted for as contractual commitments on a trade-date basis and carried at fair value derived from current dealer quotations and underlying commodity-exchange quotations. OTC options are carried at fair value based on the use of valuation models that utilize, among other things, current interest, commodity and volatility rates. For long-dated forward transactions, current market values are derived using internally developed valuation methodologies based on available market information. When there is an absence of observable market data at inception, the value of the transaction is its cost. Where market rates are not quoted, current interest, commodity and volatility rates are estimated by reference to current market levels. Given the nature, size and timing of transactions, estimated values may differ significantly from realized values. Changes in market values are reflected in net income. Although trading instruments may have scheduled maturities in excess of one year, the actual settlement of these transactions can occur sooner, resulting in the current classification of trading assets and liabilities on the Consolidated Balance Sheets. "New Accounting Standards" below provides a discussion of the rescission of EITF 98-10.

Inventories

At December 31, 2003, inventory shown on the Consolidated Balance Sheets, which does not include amounts included in trading assets, included natural gas of $89 million and materials and supplies of $58 million. The corresponding balances at December 31, 2002 were $77 million and $57 million, respectively. Natural gas at the California Utilities ($84 million and $74 million at December 31, 2003 and 2002, respectively) is valued by the last-in first-out (LIFO) method. When the California Utilities' inventory is consumed, differences between the LIFO valuation and replacement cost are reflected in customer rates. Materials and supplies at the California Utilities are generally valued at the lower of average cost or market.

Property, Plant and Equipment

Property, plant and equipment primarily represents the buildings, equipment and other facilities used by the California Utilities to provide natural gas and electric utility services, and the newly constructed power plants at Sempra Energy Resources (SER).

The cost of plant includes labor, materials, contract services and related items. In addition, the cost of utility plant includes an allowance for funds used during construction (AFUDC). The cost of non-utility plant includes capitalized interest. The cost of most retired depreciable utility plant minus salvage value is charged to accumulated depreciation.

Property, plant and equipment balances by major functional categories are as follows:

	Property, Plant and Equipment at December 31,		Depreciation rates for years ended December 31,		
(Dollars in billions)	**2003**	2002	**2003**	2002	2001
California Utilities:					
Natural gas operations	**$ 8.0**	$ 7.7	**4.28%**	4.25%	4.25%
Electric distribution	**3.2**	3.0	**4.70%**	4.66%	4.67%
Electric transmission	**0.9**	0.9	**3.09%**	3.17%	3.19%
Other electric	**0.7**	0.6	**9.53%**	9.37%	8.46%
Total	**12.8**	12.2			
Other operations	**2.5**	1.6	**various**	various	various
Total	**$15.3**	$13.8			

Accumulated depreciation and decommissioning of natural gas and electric utility plant in service were $3.1 billion and $1.4 billion, respectively, at December 31, 2003, and were $2.9 billion and $1.3 billion, respectively, at December 31, 2002. See discussion of SFAS 143 under "New Accounting Standards." Depreciation expense is based on the straight-line method over the useful lives of the assets or a shorter period prescribed by the CPUC. See Note 13 for discussion of the sale of generation facilities and industry restructuring. Maintenance costs are expensed as incurred.

AFUDC, which represents the cost of funds used to finance the construction of utility plant, is added to the cost of utility plant. AFUDC also increases income, partly as an offset to interest charges and partly as a component of Other Income—Net, in the Statements of Consolidated Income, although it is not a current source of cash. AFUDC amounted to $29 million, $34 million and $17 million for 2003, 2002 and 2001, respectively. Total capitalized carrying costs, including AFUDC and the impact of SER's construction projects, were $55 million, $63 million and $28 million for 2003, 2002 and 2001, respectively.

Long-Lived Assets

The company periodically evaluates whether events or circumstances have occurred that may affect the recoverability or the estimated useful lives of long-lived assets. Impairment occurs when the estimated future undiscounted cash flows are less than the carrying amount of the assets. If that comparison indicates that the assets' carrying value may be permanently impaired, the potential impairment is measured based on the difference between the carrying amount and the fair value of the assets based on quoted market prices or, if market prices are not available, on the estimated discounted cash flows. This calculation is performed at the lowest level for which separately identifiable cash flows exist. See further discussion of SFAS 144 in "New Accounting Standards." During the third and fourth quarters of 2003, the company recorded impairment charges of $77 million and $24 million to write down the carrying value of the assets of Frontier Energy and Atlantic Electric & Gas Limited (AEG), respectively. This is discussed further in "New Accounting Standards" below.

Nuclear Decommissioning Liability

At December 31, 2002, in accordance with SFAS 71, SDG&E had recorded a $355 million regulatory liability representing SDG&E's share of the estimated future decommissioning costs of the San Onofre Nuclear Generating Station (SONGS). In addition, Deferred Credits and Other Liabilities included $139 million of accrued decommissioning costs associated with SONGS. As of December 31, 2003, as the result of implementing SFAS 143, "*Accounting for Asset Retirement Obligations,*" SDG&E had asset retirement obligations and related regulatory liabilities of $316 million and $303 million, respectively. Additional information on SONGS decommissioning costs is included below in "New Accounting Standards."

Legal Fees

Legal fees that are associated with a past event and not expected to be recovered in the future are accrued when it is probable that they will be incurred.

Comprehensive Income

Comprehensive income includes all changes, except those resulting from investments by owners and distributions to owners, in the equity of a business enterprise from transactions and other events, including foreign-currency translation adjustments, minimum pension liability adjustments, and certain hedging activities. The components of other comprehensive income are shown in the Statements of Consolidated Changes in Shareholders' Equity.

Stock-Based Compensation

The company has stock-based employee compensation plans, which are described in Note 9. The company accounts for these plans under the recognition and measurement principles of *Accounting Principles Board (APB) Opinion 25, "Accounting for Stock Issued to Employees,"* and related Interpretations. For certain grants, no stock-based employee compensation cost is reflected in net income, since the options granted under those plans had an exercise price equal to the market value of the underlying common stock on the date of grant. See "New Accounting Standards" below for further discussion. The following table provides the pro forma effects of recognizing compensation expense in accordance with *SFAS 123, "Accounting for Stock-Based Compensation"*:

	Years ended December 31,		
	2003	2002	2001
Net income as reported	**$ 649**	$ 591	$ 518
Stock-based employee compensation expense included in the computation of net income, net of tax	**13**	3	7
Total stock-based employee compensation under fair value method for all awards, net of tax	**(20)**	(11)	(8)
Pro forma net income	**$ 642**	$ 583	$ 517
Earnings per share:			
Basic — as reported	**$3.07**	$2.88	$2.54
Basic — pro forma	**$3.03**	$2.84	$2.54
Diluted — as reported	**$3.03**	$2.87	$2.52
Diluted — pro forma	**$2.99**	$2.83	$2.52

Revenues

Revenues of the California Utilities are primarily derived from deliveries of electricity and natural gas to customers and changes in related regulatory balancing accounts. Revenues from electricity and natural gas sales and services are generally recorded under the accrual method and recognized upon delivery. The portion of SDG&E's electric commodity that was procured for its customers by the California Department of Water Resources (DWR) and delivered by SDG&E is not included in SDG&E's revenues or costs. For 2001, California Power Exchange (PX) and Independent System Operator (ISO) power revenues have been netted against purchased-power expense to avoid double-counting of power sold into and then repurchased from the PX/ISO. During 2003, costs associated with long-term contracts allocated to SDG&E from the DWR were also not included in the Statements of Consolidated Income, since the DWR retains legal and financial responsibility for these contracts. Refer to Note 13 for a discussion of the electric industry restructuring. Natural gas storage contract revenues are accrued on a monthly basis and reflect reservation, storage and injection charges in accordance with negotiated agreements, which have terms of up to three years. Operating revenue includes amounts for services rendered but unbilled (approximately one-half month's deliveries) at the end of each year.

Through 2003, operating costs of SONGS Units 2 and 3, including nuclear fuel and related financing costs, and incremental capital expenditures were recovered through the Incremental Cost Incentive Pricing (ICIP) mechanism which allowed SDG&E to receive 4.4 cents per kilowatt-hour for SONGS generation. Any differences between these costs and the incentive price affected net income. For the year ended December 31, 2003, ICIP contributed $53 million to SDG&E's net income. Beginning in 2004 the CPUC has provided for traditional rate-making treatment, under which the SONGS ratebase would start over at January 1, 2004, essentially eliminating earnings from SONGS except from future increases in ratebase.

Additional information concerning utility revenue recognition is discussed above under "Regulatory Matters."

SET generates a substantial portion of its revenues from market making and trading activities, as a principal, in natural gas, electricity, petroleum, metals and other commodities, for which it quotes bid and ask prices to end users and other market makers. Principal transaction revenues are recognized on a trade-date basis, and include realized gains and losses, and the net change in the fair value of unrealized gains and losses. SET also earns trading profits as a dealer by structuring and executing transactions. SET utilizes derivative instruments to reduce its exposure to unfavorable changes in market prices, which are subject to significant and volatile fluctuations. These instruments include futures, forwards, swaps and options. Options, which are either exchange-traded or directly negotiated between counterparties, provide the holder with the right to buy from or sell to the other party an agreed amount of a commodity at a specified price within a specified period or at a specified time.

As a writer of options, SET generally receives an option premium and then manages the risk of an unfavorable change in the value of the underlying commodity by entering into related transactions or by other means. Forward and future transactions are contracts for delivery of commodities in which the counterparty agrees to make or take delivery at a specified price. Commodity swap transactions may involve the exchange of fixed and floating payment obligations without the exchange of the underlying commodity. SET's financial instruments represent contracts with counterparties whereby payments are linked to or derived from market indices or on terms predetermined by the contract.

Non-derivative contracts are being carried at cost and accounted for on an accrual basis. Hence, the related profit or loss will be recognized as the contract is performed. Derivative instruments are discussed further in Note 10.

Revenues of SES are generated from commodity sales and energy-related products and services to commercial, industrial, government and institutional markets. Energy supply revenues from natural gas and electricity commodity sales are recognized on a current fair value basis and include realized gains and losses and the net change in unrealized gains and losses measured at fair value. Revenues on construction projects are recognized during the construction period using the percentage-of-completion method, and revenues from other operating and maintenance service contracts are recorded under the accrual method and recognized as service is rendered.

SET and SES record revenues from trading activities on a net basis in accordance with EITF 02-3. See further discussion of this matter and the rescission of EITF 98-10 under "New Accounting Standards."

Revenues of SER are derived primarily from the sale of electric energy to governmental and wholesale power marketing entities, which are recognized in accordance with provisions of *EITF 91-6, "Revenue Recognition of Long-term Power Supply Contracts,"* and *EITF 96-17, "Revenue Recognition Under Long-term Power Sales Contacts that Contain Both Fixed and Variable Terms."* During 2003 and 2002, electric energy sales to the DWR accounted for a significant portion of total SER revenues.

The consolidated foreign subsidiaries of Sempra Energy International (SEI), all of which operate in Mexico, recognize revenue similarly to the California Utilities, except that SFAS 71 is not applicable due to the different regulatory environment.

Extraordinary Gain

During 2002, SET acquired two businesses for amounts less than the fair values of the business' net assets. In accordance with *SFAS 141, "Business Combinations,"* those differences were recorded as extraordinary income. The $16 million of extraordinary income was recorded in the second quarter ($2 million) and in the fourth quarter ($14 million).

Foreign Currency Translation

The assets and liabilities of the company's foreign operations are generally translated into U.S. dollars at current exchange rates, and revenues and expenses are translated at average exchange rates for the year. Resulting translation adjustments do not enter into the calculation of net income or retained earnings, but are reflected in comprehensive income and accumulated other comprehensive income, a component of shareholders' equity, as described below. Foreign currency transaction gains and losses are included in consolidated net income. To reflect the fluctuation in the Argentine peso, the functional currency of the company's Argentine operations, SEI adjusted its investment in its two Argentine natural gas utility holding companies upward by $26 million and downward by $102 million in 2003 and 2002, respectively. These non-cash adjustments did not affect net income, but did increase or reduce comprehensive income and accumulated other comprehensive income (loss). Smaller adjustments have been made to operations in other countries. Additional information concerning these investments is described in Note 3.

Transactions with Affiliates

Loans to Unconsolidated Affiliates

In December 2001, SEI issued two U.S. dollar denominated loans totaling $35 million and $22 million to its affiliates Camuzzi Gas Pampeana S. A. and Camuzzi Gas del Sur S. A., respectively. These loans have variable interest rates (8.168% at December 31, 2003) and are due on March 13, 2004. The total balance outstanding under the notes was $55 million and $56 million at December 31, 2003 and 2002, respectively. At December 31, 2003, this amount is included in non-current assets, under the caption Due from Unconsolidated Affiliates because they will be refinanced on longer terms.

Additionally, at December 31, 2002, SET had $79 million due from AEG and the company had $1 million due from other affiliates. At December 31, 2002, the outstanding loans are included in current assets under the caption Due from Unconsolidated Affiliates. In addition, SET had $44 million of trading assets due from AEG at December 31, 2002. At December 31, 2003, as a result of the adoption of FASB Interpretation No. (FIN) 46, AEG was consolidated. See "New Accounting Standards" below for a discussion of FIN 46.

Loans from Unconsolidated Affiliates

At both December 31, 2003 and 2002, SEI had long-term notes payable to affiliates which include $60 million at 6.47% due April 1, 2008 and $100 million at 6.62% due April 1, 2011. The loans are due to Chilquinta Energía Finance, LLC and are secured by SEI's investments in Chilquinta Energía S.A. and Luz del Sur S.A.A. (Luz del Sur) (See Note 3).

The company also reclassified $200 million of mandatorily redeemable trust preferred securities to Due to Unconsolidated Affiliates as a result of the adoption of FIN 46 effective December 31, 2003. In addition, dividend payments required on these instruments, previously recorded to Preferred Dividends of Subsidiaries and Trust Preferred Distributions, were recorded to Interest Expense for the last six months of 2003 on the company's Statements of Consolidated Income, in accordance with SFAS 150. See discussion of SFAS 150 in "New Accounting Standards" below.

Revenues and Expenses with Unconsolidated Affiliates

During 2003 and 2002 SER recorded $61 million and $39 million, respectively, in sales to El Dorado, an unconsolidated affiliate, and recorded $69 million and $49 million, respectively, of purchases for those same years.

New Accounting Standards

SFAS 132 (revised 2003), "Employers Disclosures about Pensions and Other Postretirement Benefits": This statement revised employers' disclosures about pension plans and other postretirement benefit plans. It requires disclosures beyond those in the original SFAS 132 about the assets, obligations, cash flows and net periodic benefit cost of defined benefit pension plans and other defined postretirement plans. It does not change the measurement or recognition of those plans. This statement is effective for financial statements with fiscal years ending after December 15, 2003.

SFAS 142, "Goodwill and Other Intangible Assets": In July 2001, the FASB issued SFAS 142, which provides guidance on how to account for goodwill and other intangible assets after an acquisition is complete. SFAS 142 calls for amortization of goodwill to cease and requires goodwill and certain other intangibles to be tested for impairment at least annually. Amortization of goodwill, including the company's share of amounts recorded by unconsolidated subsidiaries, was $24 million in 2001. In accordance with the transitional guidance of SFAS 142, recorded goodwill attributable to the company was tested for impairment in 2002 by comparing the fair value to its carrying value, using a discounted cash flow methodology. As a result, during the first quarter of 2002, SEI recorded a pre-tax charge of $6 million related to the impairment of goodwill associated with its two domestic subsidiaries. Impairment losses are reflected in Other Operating Expenses in the Statements of Consolidated Income.

If goodwill amortization had not been recorded in 2001, reported net income for 2001 would have increased by $15 million to $533 million. Basic and diluted earnings per share would have increased by $0.07 to $2.61 and $2.59 respectively.

During 2002, SET completed several acquisitions as further discussed in Note 2. As a result of SET's acquisition of the metals warehousing business, the company recorded $21 million of goodwill on the Consolidated Balance Sheets. In addition, a $16 million after-tax extraordinary gain reflecting negative goodwill was recorded in 2002 for the purchase of the base metals and concentrates businesses.

During the first quarter of 2003 SEI purchased the remaining minority interests in its Mexican subsidiaries, which resulted in the recording of an addition to goodwill of $6 million and to an intangible asset of $4 million.

The changes in the carrying amount of goodwill (included in Noncurrent Sundry Assets on the Consolidated Balance Sheets) for the years ended December 31, 2003 and 2002 are as follows:

(Dollars in millions)	SET	Other	Total
Balance as of January 1, 2002	$120	$52	$172
Goodwill acquired during the year	21	—	21
Impairment losses	—	(6)	(6)
Other	—	(5)	(5)
Balance as of December 31, 2002	141	41	182
Goodwill acquired during the year	—	**6**	**6**
Balance as of December 31, 2003	**$141**	**$47**	**$188**

SET is the only reportable segment that has goodwill. In addition, the unamortized goodwill related to unconsolidated subsidiaries (included in Investments on the Consolidated Balance Sheets), primarily those located in South America, was $299 million and $294 million at December 31, 2003 and 2002, respectively, before foreign currency translation adjustments. Including foreign currency translation adjustments, these amounts were $232 million and $219 million, respectively. Unamortized other intangible assets were not material at December 31, 2003 and 2002.

SFAS 143, "Accounting for Asset Retirement Obligations": SFAS 143, issued in July 2001, addresses financial accounting and reporting for obligations associated with the retirement of tangible long-lived assets and the associated asset retirement costs. It applies to legal obligations associated with the retirement of long-lived assets that result from the acquisition, construction, development and/or normal operation of long-lived assets, such as nuclear plants. It requires entities to record the fair value of a liability for an asset retirement obligation in the period in which it is incurred. When the liability is initially recorded, the entity increases the carrying amount of the related long-lived asset by the present value of the future retirement cost. Over time, the liability is accreted to its full value and paid, and the capitalized cost is depreciated over the useful life of the related asset.

The adoption of SFAS 143 on January 1, 2003 resulted in the recording of an addition to utility plant of $71 million, representing the company's share of SONGS estimated future decommissioning costs (as discounted to the present value at the dates the units began operation), and accumulated depreciation of $41 million related to the increase to utility plant, for a net increase of $30 million. In addition, the company recorded a corresponding retirement obligation liability of $309 million (which includes accretion of that discounted value to December 31, 2002) and a regulatory liability of $215 million to reflect that SDG&E has collected the funds from its customers more quickly than SFAS 143 would accrete the retirement liability and depreciate the asset. These liabilities, less the $494 million already recorded (which represents amounts collected for future decommissioning costs), comprise the offsetting $30 million. See further discussion of SONGS' decommissioning and the related nuclear decommissioning trusts in Note 6.

On January 1, 2003, the company recorded additional asset retirement obligations of $20 million associated with the future retirement of a former power plant and three storage facilities.

In accordance with SFAS 143, Sempra Energy identified several other assets for which retirement obligations exist, but whose lives are indeterminate. A liability for these asset retirement obligations will be recorded if and when a life is determinable.

The change in the asset retirement obligations for the year ended December 31, 2003 is as follows (dollars in millions):

Balance as of January 1, 2003	$ —
Adoption of SFAS 143	329
Accretion expense	22
Payments	(14)
Balance as of December 31, 2003	$337*

* The current portion of the obligation is included in Other Current Liabilities on the Consolidated Balance Sheets.

Had SFAS 143 been in effect on January 1, 2002, the asset retirement obligation liability would have been $363 million as of that date.

Except for the items noted above, the company has determined that there is no other material retirement obligation associated with tangible long-lived assets.

Implementation of SFAS 143 has had no effect on results of operations and is not expected to have a significant effect in the future.

In accordance with CPUC regulations, the California Utilities collect estimated removal costs in rates through depreciation. SFAS 143 also requires the company to reclassify estimated removal costs,

Credits and Other Liabilities and to Other Current Liabilities on the Consolidated Balance Sheets. In addition, dividend payments required on these instruments, previously recorded to Preferred Dividends of Subsidiaries and Trust Preferred Distributions, were recorded to Interest Expense on the company's Statements of Consolidated Income. For the year ended December 31, 2003, the related amount recorded as interest expense for the last six months totaled $9 million. On December 31, 2003, the $200 million of mandatorily redeemable trust preferred securities were reclassified to Due to Unconsolidated Affiliates due to the adoption of FIN 46 as discussed below.

EITF 98-10, "Accounting for Contracts Involved in Energy Trading and Risk Management Activities": In accordance with the EITF's rescission of Issue 98-10 by the release of Issue 02-3, the company no longer recognizes energy-related contracts under mark-to-market accounting unless the contracts meet the requirements stated under *SFAS 133 and SFAS 149,* which is the case for a substantial majority of the company's contracts. On January 1, 2003, the company recorded the initial effect of Issue 98-10's rescission as a cumulative effect of a change in accounting principle, which reduced after-tax earnings by $29 million. On a net basis, $9 million of the $29 million was realized during the year ended December 31, 2003. Neither the cumulative nor the ongoing effect impacts the company's cash flow or liquidity.

EITF 02-3, "Issues Involved in Accounting for Derivative Contracts Held for Trading Purposes and Contracts Involved in Energy Trading and Risk Management Activities": In June 2002, a consensus was reached in EITF 02-3, which codifies and reconciles existing guidance on the recognition and reporting of gains and losses on energy trading contracts, and addresses other aspects of the accounting for contracts involved in energy trading and risk management activities. Among other things, the consensus requires that mark-to-market gains and losses on energy trading contracts should be shown on a net basis in the income statement, effective for financial statements issued for periods ending after July 15, 2002. Adoption of EITF 02-3 in 2002 required that SES change its method of recording trading activities from gross to net, which had no impact on previously recorded gross margin, net income or cash provided by operating activities. SET was already recording revenues from trading activities on a net basis and required no change.

For 2001, recording revenues for all trading activities on a net basis decreased previously reported revenues by $348 million to $7.7 billion. There was no impact on reported revenues for the years ending December 31, 2003 and 2002 as trading activities were already reported on a net basis.

EITF 03-11, "Reporting Realized Gains and Losses on Derivative Instruments that are Subject to FASB Statement No. 133, Accounting for Derivative Instruments and Hedging Activities and Not 'Held for Trading Purposes' as Defined in EITF Issue No. 02-3, Issues Involved in Accounting for Derivative Contracts Held for Trading Purposes and Contracts Involved in Energy Trading and Risk Management Activities": During 2003, the EITF reached a consensus that determining whether realized gains and losses on physically settled derivative contracts not held for trading purposes should be reported in the income statement on a gross or net basis is a matter of judgment that depends on the relevant facts and circumstances. Adoption of EITF 03-11 in 2003 did not have a significant impact to the company's financial statements and the company does not expect a significant impact in the future.

FIN 45, "Guarantor's Accounting and Disclosure Requirements for Guarantees": In November 2002, the FASB issued FIN 45, which elaborates on the disclosures to be made in interim and annual financial statements of a guarantor about its obligations under certain guarantees that it has issued. It also clarifies that a guarantor is required to recognize, at the inception of a guarantee, a liability for the fair value of the obligation undertaken in issuing a guarantee. As of December 31, 2003, substantially all of the company's guarantees were intercompany, whereby the parent issues the guarantees on behalf of its consolidated subsidiaries. The only significant guarantees for which disclosure is required are that of the synthetic lease for the Mesquite Power plant, the mandatorily redeemable trust preferred

securities and $25 million related to debt issued by Chilquinta Energía Finance, LLC, an unconsolidated affiliate. The synthetic lease for the Mesquite Power plant and the mandatorily redeemable trust preferred securities were also affected by FIN 46, as described below.

FIN 46, "Consolidation of Variable Interest Entities an interpretation of ARB No. 51": FIN 46 requires the primary beneficiary of a variable interest entity's activities to consolidate the entity. During December 2003, the FASB issued FIN 46 revised (FIN 46R) to defer the implementation date for pre-existing variable interest entities (VIEs) that are special purpose entities (SPEs) until the end of the first interim or annual period ending after December 15, 2003. For VIEs that are not SPEs, companies must apply FIN 46R no later than the end of the first reporting period ending after March 15, 2004.

Sempra Energy has identified two VIEs for which it is the primary beneficiary. One of the VIEs (Mesquite Trust), which is an SPE, is the owner of the Mesquite Power plant for which the company had a synthetic lease agreement, as described in Notes 2 and 5. The Mesquite Power plant is a 1,250-megawatt (MW) project that provides electricity to wholesale energy markets in the Southwest. Construction began in September 2001 and the first phase of commercial operations (50 percent of the plant's total capacity) began in June 2003. The second phase of commercial operations (the remaining 50 percent) began in December 2003. Accordingly, as the FASB's deliberations during the deferral period did not result in the exclusion of Mesquite Trust from FIN 46's definitions, Sempra Energy consolidated this entity in its financial statements at December 31, 2003. The company bought out the lease in January 2004. At December 31, 2003, the total assets and total liabilities of Mesquite Trust were $643 million and $630 million, respectively. The company also recorded an after-tax credit for the cumulative effect from the change in accounting principle of $9 million.

The other variable interest entity is AEG, which markets power and natural gas commodities to commercial and residential customers in the United Kingdom. Sempra Energy consolidated AEG in its financial statements at December 31, 2003. Consolidation of AEG required Sempra Energy to record 100 percent of AEG's December 31, 2003 balance sheet, whereas it previously recorded only its share of AEG's net operating results. As of December 31, 2003 total assets and total liabilities of this unconsolidated subsidiary were $180 million and $251 million, respectively. Due to AEG's consolidation, the company recorded an after-tax charge for the cumulative effect of the change in accounting principle of $26 million.

In accordance with FIN 46R, the company deconsolidated a wholly owned subsidiary trust from its financial statements at December 31, 2003. The trust has no assets except for its corresponding receivable from the company. Due to the deconsolidation of this entity, Sempra Energy has reclassified $200 million of mandatorily redeemable trust preferred securities to Due to Unconsolidated Affiliates on its Consolidated Balance Sheets.

FASB Staff Position (FSP) 106-1, "Accounting and Disclosure Requirements Related to the Medicare Prescription Drug, Improvement and Modernization Act of 2003": Issued January 12, 2004, FSP 106-1 permits a sponsor of a postretirement health care plan that provides a prescription drug benefit to make a one-time election to defer accounting for the effects of the Medicare Prescription Drug, Improvement and Modernization Act of 2003 (the Act). The company has elected to defer the effects of the Act as provided by FSP 106-1. Any measure of the accumulated postretirement benefit obligation or net periodic postretirement benefit cost in the financial statements or the accompanying notes do not reflect the impact of the Act on the plans. At this time, specific authoritative guidance on the accounting for the federal subsidy provided by the Act is pending and that guidance could require the company to change previously reported information.

Other Accounting Standards: During 2003 and 2002 the FASB and the EITF issued several statements that are not applicable to the company but could be in the future. In April 2002, the FASB

issued SFAS 145, which rescinds *SFAS 4, "Reporting Gains and Losses from Extinguishment of Debt,"* and *SFAS 64, "Extinguishments of Debt Made to Satisfy Sinking-Fund Requirements."* In June 2002, the FASB issued *SFAS 146, "Accounting for Costs Associated with Exit or Disposal Activities."* SFAS 146 supersedes previous accounting guidance, principally *EITF 94-3, "Liability Recognition for Certain Employee Termination Benefits and Other Costs to Exit an Activity (including Certain Costs Incurred in a Restructuring)."*

NOTE 2. RECENT ACQUISITIONS AND INVESTMENTS

Sempra Energy Trading

In 2003, SET spent $27 million related to the development of Bluewater Gas Storage, LLC, a natural gas storage facility in Michigan. SET owns the rights to develop the facility and to utilize its capacity to store natural gas for customers who buy, sell or transport natural gas in Michigan. The facility is expected to commence operations in 2004.

During 2002, SET completed $119 million of acquisitions that added base metals trading and warehousing to its trading business. On February 4, 2002, SET completed the acquisition of London-based Sempra Metals Limited, a leading metals trader on the London Metals Exchange, for $65 million, net of cash acquired. In April 2002 SET completed the acquisition of the assets of New York-based Sempra Metals & Concentrates Corp., a leading global trader of copper, lead and zinc concentrates, for $24 million. Also in April 2002, SET completed the acquisition of Henry Bath & Sons Limited, which provides warehousing services for non-ferrous metals in Europe and Asia, and the assets of the U.S. warehousing business of Henry Bath, Inc., for a total of $30 million, net of cash acquired.

As discussed in Note 1, the company recognized an extraordinary after-tax gain of $16 million for negative goodwill for the acquisitions of the base metals and concentrates businesses. Additional information on the extraordinary gain is provided in Note 1. In addition, goodwill of $21 million related to the acquisition of the metals warehousing business was recorded on the Consolidated Balance Sheets and is expected to be fully deductible for tax purposes.

Sempra Energy Resources

In October 2002 SER purchased a 305-MW, coal-fired power plant (renamed Twin Oaks Power) for $120 million. SER sells substantially all of the output of the plant under a five-year contract expiring on October 1, 2007. In connection with the acquisition, SER also assumed a contract that includes annual commitments to purchase coal for the plant until an aggregate minimum volume has been achieved or through 2025.

Termoeléctrica De Mexicali (TDM), a 600-MW power plant near Mexicali, Baja California, Mexico, commenced operations in July 2003. In May 2003, a federal judge issued an order finding that the U.S. Department of Energy's (DOE) abbreviated assessment of two Mexicali power plants, including SER's TDM plant, failed to evaluate the plants' environmental impact adequately and called into question the U.S. permits they received to build their cross-border transmission lines. On July 8, 2003, the judge ordered the DOE to conduct additional environmental studies, but denied the plaintiffs' request for an injunction blocking operation of the transmission lines, thus allowing the continued operation of the TDM plant. The DOE has until May 15, 2004, to demonstrate why the court should not set aside the permits. Through December 31, 2003, TDM has made capital expenditures of $342 million.

The 1,250-MW Mesquite Power plant, located near Phoenix, Arizona, cost $686 million and provides electricity to wholesale energy markets in the Southwest. The first phase of commercial operations (50

percent of the plant's total capacity) began in June 2003. The second phase of commercial operations (the remaining 50 percent) began in December 2003. As of December 31, 2003, this project was owned by the Mesquite Trust and financed through a synthetic lease agreement. Through December 31, 2003, SER had borrowed $630 million under this facility. All amounts above $280 million required collateralization through purchases of U.S. Treasury obligations. The collateralized U.S. Treasury obligations amounted to $363 million at December 31, 2003. This is included in Short-Term Investments on the Consolidated Balance Sheets. As a result of implementing FIN 46, Sempra Energy consolidated the Mesquite Trust, which had total assets and total liabilities of $643 million and $630 million, respectively, at December 31, 2003. See further discussion under "New Accounting Standards" in Note 1. On January 21, 2004, SER elected to purchase all of the power plant assets of Mesquite Trust for $631 million. The purchase required cash of $268 million and the liquidation of the $363 million in treasury securities held by the Mesquite Trust as collateral.

Sempra Energy LNG Corp.

In April 2003, Sempra Energy LNG Corp. (SELNG) completed its acquisition of the proposed Cameron liquefied natural gas (LNG) project in Hackberry, Louisiana from a subsidiary of Dynegy, Inc. SELNG has paid Dynegy $36 million for the acquisition, which includes rights to the location, licensing and FERC approval of the project, which is still in the permitting stage. Additional payments are contingent on meeting certain benchmarks and milestones and the performance of the project. As of December 31, 2003, the company had accrued $30 million as an estimate of the contingent payment. The total cost of the project is expected to be $700 million. The terminal will be capable of supplying 1.5 billion cubic feet (bcf) of natural gas per day. Construction is expected to begin in 2004 and commercial operations could begin in 2007. FERC approved the construction and operation of the project in September 2003.

In December 2003, SELNG and Shell International Gas Limited (Shell) announced plans to form a 50/50 joint venture to build, own and operate Energía Costa Azul, a LNG receiving terminal in Baja California on the west coast of Mexico, approximately 50 miles south of San Diego. The proposed joint venture will combine the two separate Baja California LNG receiving terminals proposed by Shell and SELNG into a single project. It is expected that construction will begin in 2004 with terminal operations commencing in 2007. The cost of the project is estimated to be $600 million. The terminal will be capable of supplying 1 billion cubic feet (bcf) of natural gas per day, half of which will be used to meet the growing energy demands in western Mexico. The proposed joint venture contemplates that SELNG and Shell would share the investment costs of the terminal equally and each would take 50 percent of the capacity of the terminal. Any surplus natural gas from the facility will be used to provide new natural gas supplies for the southwestern United States.

Also in December 2003, SELNG, British Petroleum and BPMiGas signed a non-binding Heads of Agreement (HOA) for the supply of 500 million cubic feet of gas a day from Indonesia's Tangguh LNG liquefaction facility to Energía Costa Azul. The non-binding HOA is expected to be the precursor to a full 20-year purchase/supply agreement.

Also in connection with this project, Mexico's national environmental agency issued an environmental permit in April 2003. Three other significant permits, an operating permit from Mexico's energy regulatory commission, a local land-use permit from the City of Ensenada and a coastal zone use permit, were granted in 2003. The permit to construct marine facilities is pending and expected to be received in the near future. In November 2003, a Mexican tribunal issued the equivalent of a preliminary injunction against a Mexican environmental agency's adoption of the environmental impact authorization covering the project. The injunction temporarily suspends the permit until the matter can proceed to a hearing on the merits of the authorization. Sempra Energy believes the suspension of these permits will be temporary and will not delay the 2007 commercial start date of the terminal.

Sempra Energy International

SEI's Mexican subsidiaries build and operate natural gas distribution systems in Mexicali, Chihuahua and the La Laguna-Durango zone in north-central Mexico. On February 7, 2003, SEI purchased the remaining minority interests in its Mexican subsidiaries.

NOTE 3. INVESTMENTS IN UNCONSOLIDATED SUBSIDIARIES

Investments are accounted for under the equity method when the company has an ownership interest of twenty to fifty percent. In these cases the company's pro rata shares of the subsidiaries' net assets are included in Investments on the Consolidated Balance Sheets, and are adjusted for the company's share of each investee's earnings or losses, dividends and foreign currency translation effects. Earnings are recorded as equity earnings in Other Income—Net on the Statements of Consolidated Income. The company accounts for certain investments in housing partnerships made before May 19, 1995 under the cost method, whereby they are amortized over ten years based on the expected residual value. The company has no unconsolidated subsidiaries where its ability to influence or control an investee differs from its ownership percentage.

The company's long-term investments are summarized as follows:

(Dollars in millions)	December 31, **2003**	2002
Equity method investments:		
Chilquinta Energía	**$ 337**	$ 387
Luz del Sur	**177**	117
Sodigas Pampeana and Sodigas Sur	**66**	17
Elk Hills power project	**218**	172
El Dorado Energy	**68**	73
Sempra Energy Financial housing partnerships	**175**	206
Sempra Energy Financial synthetic fuel partnerships	**14**	8
Total	**1,055**	980
Cost method investments:		
Sempra Energy Financial housing partnerships	**47**	57
Other	**12**	3
Total	**59**	60
Investments in unconsolidated subsidiaries	**1,114**	1,040
Other:		
Mesquite power plant project		
Collateralized U.S. Treasury obligations*	**—**	228
Reimbursable project costs	**—**	45
Total	**—**	273
Total long-term investments	**$1,114**	$1,313

* The balance of $363 million at December 31, 2003 was reclassified to Short-Term Investments.

For equity method investments, costs in excess of equity in net assets were $232 million and $219 million at December 31, 2003 and 2002, respectively. Through December 31, 2001, the excess of the investment over the related equity in net assets had been amortized over various periods, primarily forty years (see Note 1). In accordance with SFAS 142, amortization ceased in 2002. Costs in excess of the underlying equity in net assets will continue to be reviewed for impairment in accordance with

APB Opinion 18, "The Equity Method of Accounting for Investments in Common Equity." See additional discussion of SFAS 142 in "New Accounting Standards" in Note 1. Descriptive information concerning each of these subsidiaries follows.

Sempra Energy International

SEI and PSEG Global (PSEG), an unaffiliated company, each own a 50-percent interest in Chilquinta Energía S.A., a Chilean electric utility, and 44 percent interests in Luz del Sur S.A.A. (Luz del Sur), a Peruvian electric utility.

SEI also owns 43 percent of two Argentine natural gas utility holding companies, Sodigas Pampeana S.A. and Sodigas Sur S.A. As a result of the devaluation of the Argentine peso at the end of 2001 and subsequent declines in the value of the peso, SEI had reduced the carrying value of its investment downward by a cumulative total of $197 million as of December 31, 2003. These non-cash adjustments continue to occur based on fluctuations in the Argentine peso. They do not affect net income, but increase or decrease other comprehensive income (loss) and accumulated other comprehensive income (loss).

The related Argentine economic decline and government responses (including Argentina's unilateral, retroactive abrogation of utility agreements early in 2002) continue to adversely affect the operations of these Argentine utilities. In 2002, SEI initiated arbitration proceedings under the 1994 Bilateral Investment Treaty between the United States and Argentina for recovery of the diminution of the value of its investments that has resulted from Argentine governmental actions. In 2003, SEI filed its legal brief with the International Center for Settlement of Investment Disputes, outlining its claims for $258 million. The company has also presented additional information that may provide a basis for a larger award. A decision is expected in early 2005. Sempra Energy also has a $48.5 million political-risk insurance policy under which it filed a claim to recover a portion of the investments' diminution in value.

Sempra Energy Resources

The 550-MW Elk Hills Power (Elk Hills) project, which is located near Bakersfield, California, began commercial operations in July 2003. Elk Hills is 50 percent owned by SER in a joint venture with Occidental Energy Ventures Corporation.

The 480-MW El Dorado power plant, located near Las Vegas, Nevada, began commercial operations in May 2000. The El Dorado Energy project is 50 percent owned by SER in a joint venture partnership with Reliant Energy Power Generation.

At December 31, 2003, the investments in U.S. Treasury obligations related to the Mesquite project was reclassified to Short-Term Investments as the result of the company buying out the lease in January 2004. See discussion in Note 1.

Sempra Energy Financial (SEF)

SEF invests as a limited partner in affordable-housing properties. SEF's portfolio includes 1,300 properties throughout the United States that are expected to provide income tax benefits (primarily from income tax credits) over 10-year periods. SEF also has an investment in a limited partnership which produces synthetic fuel from coal. Whether SEF will invest in additional properties will depend on Sempra Energy's income tax position. See additional discussion of income tax issues in Note 7.

NOTE 4. SHORT-TERM BORROWINGS

At December 31, 2003, the company had available $2.1 billion in unused, committed lines of credit to provide liquidity and support commercial paper.

Committed Lines of Credit

Sempra Energy Global Enterprises (Global) has two syndicated revolving credit agreements, each permitting revolving credit borrowings of $500 million. One is a 364-day credit agreement that may be converted into a one-year term loan upon the August 2004 expiration of the revolving credit period. The other is a three-year agreement permitting revolving credit borrowings until the expiration of the agreement in August 2006. Borrowings under the agreements are guaranteed by Sempra Energy and bear interest at rates varying with market rates and Sempra Energy's credit ratings. Both agreements require Sempra Energy to maintain a debt-to-total capitalization ratio (as identically defined in each agreement) of not to exceed 65 percent. Global had no commercial paper outstanding at December 31, 2003 and $422 million of commercial paper outstanding at December 31, 2002. As of December 31, 2003, a letter of credit for $18 million was outstanding under the second agreement.

SER has a syndicated $400 million revolving credit agreement guaranteed by Sempra Energy. The agreement requires Sempra Energy to maintain a debt-to-total capitalization ratio (as defined in the agreement) of not to exceed 65 percent. The agreement expires in August 2004 and borrowings bear interest at rates varying with market rates and Sempra Energy's credit rating. At December 31, 2003, SER had no outstanding borrowings under the agreement. At December 31, 2002, there was $100 million outstanding under the agreement. See Note 5 for additional information on SER's borrowings.

The California Utilities have a combined revolving line of credit, under which each utility individually may borrow up to $300 million, subject to a combined borrowing limit for both utilities of $500 million. Borrowings under the agreement bear interest at rates varying with market rates and the utility's credit rating. The revolving credit commitment expires in May 2004, at which time outstanding borrowings may be converted into a one-year term loan subject to any requisite regulatory approvals related to long-term debt. The agreement requires each utility to maintain a debt-to-total capitalization ratio (as defined in the agreement) of not to exceed 60 percent. Borrowings under the agreement are individual obligations of the borrowing utility and a default by one utility would not constitute a default or preclude borrowings by the other. These lines of credit have never been drawn upon. At December 31, 2003 and 2002, the California Utilities had no commercial paper outstanding.

PE has a $375 million revolving agreement, guaranteed by Sempra Energy, for the purpose of providing loans to Global. The revolving credit commitment, initially $500 million, and $375 million at December 31, 2003, declines semi-annually by $125 million until expiration on April 5, 2005. Borrowings are guaranteed by Sempra and are subject to mandatory repayment prior to the maturity date should SoCalGas' unsecured long-term credit ratings cease to be at least BBB by Standard & Poor's (S&P) and Baa2 by Moody's Investor Services, Inc. (Moody's), should Sempra Energy's or SoCalGas' debt-to-total capitalization ratio (as defined in the agreement) exceed 65 percent, or should there be a change in law materially and adversely affecting the ability of SoCalGas to pay dividends or make distributions to PE. Borrowings bear interest at rates varying with market rates, PE's credit ratings and the amount of outstanding borrowings. This line of credit has never been used.

Uncommitted Lines of Credit

SET has $770 million in various uncommitted lines of credit that are guaranteed by Sempra Energy and bear interest at rates varying with market rates and Sempra Energy's credit rating. At December 31, 2003, SET had $420 million of letters of credit, but no short-term borrowings, outstanding against these lines. The corresponding amounts outstanding at December 31, 2002 were $345 million and $115 million, respectively.

Other

Sempra Energy Solutions had $28 million of short-term debt with an average interest rate of 7.56% outstanding at December 31, 2003 and $33 million at December 31, 2002. Sempra Energy had no other short-term debt at December 31, 2003. The company's weighted average interest rate for short-term borrowings outstanding at December 31, 2002 was 2.02%.

NOTE 5. LONG-TERM DEBT

(Dollars in millions)	December 31, 2003	2002
First mortgage bonds		
4.375% January 15, 2011	**$ 100**	$ —
Variable rates after fixed to floating rate swaps (1.43% at December 31, 2003) January 15, 2011	**150**	—
4.8% October 1, 2012	**250**	250
6.8% June 1, 2015	**14**	14
5.45% April 15, 2018	**250**	—
5.9% June 1, 2018	**68**	68
5.9% to 6.4% September 1, 2018	**176**	176
6.1% September 1, 2019	**35**	35
Variable rates (1.25% at December 31, 2003) September 1, 2020	**58**	58
5.85% June 1, 2021	**60**	60
6.875% November 1, 2025	**175**	175
5.25% to 7% December 1, 2027	**225**	225
5.75% November 15, 2003	**—**	100
7.375% March 1, 2023	**—**	100
7.5% June 15, 2023	**—**	125
Total	**1,561**	1,386
Other long-term debt		
Variable rates (2.02% to 5.12% at December 31, 2003) September 2005	**630**	—
5.60% equity units May 17, 2007	**600**	600
Notes payable at variable rates after a fixed-to-floating rate swap (2.49% at December 31, 2003) July 1, 2004	**500**	500
7.95% Notes March 1, 2010	**500**	500
6.0% Notes February 1, 2013	**400**	—
6.95% Notes December 1, 2005	**300**	300
Rate-reduction bonds, 6.31% to 6.37% annually through 2007	**263**	329
5.9% June 1, 2014	**130**	130
Debt incurred to acquire limited partnerships, secured by real estate, at 7.13% to 9.35% annually through 2009	**110**	145
Employee Stock Ownership Plan		
Bonds at 7.375% November 1, 2014	**82**	82
Bonds at variable rates (1.65% at December 31, 2003) November 1, 2014	**19**	19
Variable rates (1.45% at December 31, 2003) December 1, 2021	**60**	60
Variable rates (1.46% at December 31, 2003) July 1, 2021	**39**	39
6.75% March 1, 2023	**25**	25
6.375% May 14, 2006	**8**	8
5.67% January 18, 2028	**5**	75
Other variable-rate debt	**15**	18
Capitalized leases	**8**	10
SER line of credit at variable rates August 21, 2004	**—**	100
Market value adjustments for interest rate swaps — net (expires July 1, 2004)	**23**	42
	5,278	4,368
Current portion of long-term debt	**(1,433)**	(281)
Unamortized discount on long-term debt	**(4)**	(4)
Total	**$ 3,841**	$4,083

Excluding capital leases, which are described in Note 15, and market value adjustments for interest-rate swaps, maturities of long-term debt are $1.4 billion in 2004, $397 million in 2005, $101 million in 2006, $682 million in 2007, $8 million in 2008 and $2.7 billion thereafter.

On January 26, 2004, SoCalGas optionally redeemed its $175 million 6.875% first mortgage bonds. Therefore that liability is classified as current at December 31, 2003. On January 21, 2004, SER elected to purchase the assets of Mesquite Trust and extinguish the $630 million of related debt outstanding. Therefore that liability also is classified as short-term at December 31, 2003. Holders of variable-rate bonds may require the issuer to repurchase them prior to scheduled maturity. However, since repurchased bonds would be remarketed and funds for repurchase are provided by revolving credit agreements (which are generally renewed upon expiration and which are described in Note 4), it is expected that the bonds will be held to the maturities stated above. Interest rates on the $500 million of notes maturing in 2004 can vary with the company's credit ratings.

Issuances of $900 million, $1.2 billion and $675 million of long-term debt, and payments of $601 million, $479 million and $681 million on long-term debt were made in 2003, 2002 and 2001, respectively.

Callable Bonds

At the company's option, certain bonds are callable at various dates. Of the company's callable bonds, $873 million are callable in 2004, $105 million in 2005, $8 million in 2006 and $45 million thereafter.

First Mortgage Bonds

The first mortgage bonds were issued by the California Utilities and are secured by a lien on their respective utility plant. The California Utilities may issue additional first mortgage bonds upon compliance with the provisions of their bond indentures, which require, among other things, the satisfaction of pro forma earnings-coverage tests on first mortgage bond interest and the availability of sufficient mortgaged property to support the additional bonds, after giving effect to prior bond redemptions. The most restrictive of these tests (the property test) would permit the issuance, subject to CPUC authorization, of an additional $2.8 billion of first mortgage bonds at December 31, 2003.

During the first quarter of 2001, SDG&E remarketed $150 million of variable-rate first mortgage bonds for various terms at a fixed rate of 7%. $45 million of these bonds came to term on December 1, 2003 and were remarketed to maturity with a rate of 5.25%. At SDG&E's option, the remaining bonds may be remarketed at a fixed or floating rate at December 1, 2005, the expiration of the fixed terms.

In November 2001, SoCalGas optionally redeemed its $150 million 8.75% first mortgage bonds. In December 2001, SoCalGas entered into an interest-rate swap which effectively exchanged the fixed rate on its $175 million 6.875% first mortgage bonds for a floating rate. In September 2002, SoCalGas terminated the swap, receiving cash proceeds of $10 million, comprised of $4 million in accrued interest and a $6 million amortizable gain.

In June 2002, SDG&E paid at maturity its $28 million 7.625% first mortgage bonds. In July 2002 the company optionally redeemed its $10 million 8.5% first mortgage bonds.

In August 2002, SoCalGas paid at maturity its $100 million 6.875% first mortgage bonds. In October 2002, SoCalGas publicly offered and sold $250 million of 4.8% first mortgage bonds, maturing on October 1, 2012. The bonds are not subject to a sinking fund and are redeemable prior to maturity only through a make-whole mechanism. Proceeds from the bond sale were used to replenish amounts previously expended to refund and retire indebtedness, and for working capital and other general corporate purposes.

On April 7, 2003, SoCalGas optionally redeemed its $100 million 7.375% first mortgage bonds. On August 21, 2003, SoCalGas optionally redeemed its $125 million 7.5% first mortgage bonds.

On October 17, 2003, SoCalGas issued $250 million of 5.45% first mortgage bonds due in April 2018. The proceeds were used to replenish amounts previously expended to refund and retire indebtedness and for general corporate purposes. On November 17, 2003, SoCalGas paid off its $100 million 5.75% first mortgage bonds.

On December 15, 2003, SoCalGas issued $250 million of 4.375% first mortgage bonds maturing in January 2011. The proceeds were used to retire outstanding debt and for other general corporate purposes. On December 15, 2003, SoCalGas entered into an interest-rate swap which effectively exchanged the fixed rate on $150 million of the 4.375% first mortgage bonds for a floating rate.

Mesquite Power

The company consolidated Mesquite Trust, the owner of Mesquite Power, on its financial statements as of December 31, 2003 as a result of implementing FIN 46. The debt outstanding was $630 million comprised of notes payable due in 2005 at various interest rates. On January 21, 2004, SER elected to purchase all of the power plant assets of Mesquite Trust for $631 million and extinguished the related Mesquite debt. Therefore the liability is classified as short-term at December 31, 2003. See further discussion under New Accounting Standards in Note 1. For additional information on the Mesquite Power synthetic lease, refer to Note 2.

Equity Units

In April and May of 2002, the company publicly offered and issued $600 million of Equity Units. For additional information on Equity Units refer to Note 12.

Unsecured Long-term Debt

Various long-term obligations totaling $2.7 billion are unsecured at December 31, 2003.

In February 2001, SDG&E remarketed $25 million of variable-rate unsecured bonds as 6.75 percent fixed-rate debt for a three-year term. In June 2001, the company issued $500 million of 6.8% notes due July 1, 2004. Sempra Energy has a fixed-to-floating rate swap on these notes. In October 2001, SoCalGas paid at maturity its $120 million of 6.38% medium-term notes.

SER borrowed $100 million on its $400 million line of credit in October 2002 and repaid it in March 2003. There were no loans outstanding on SER's line of credit at December 31, 2003. This agreement expires in August 2004 and bears interest at rates varying with market rates and Sempra Energy's credit ratings. For additional information regarding this line of credit see Note 4.

On January 15, 2003, $70 million of SoCalGas' 5.67% $75 million medium-term notes were put back to the company. The remaining $5 million matures in 2028.

In January 2003, the company issued $400 million of long-term 6% notes due in February 2013. The bonds are not subject to a sinking fund and are redeemable prior to maturity only through a make-whole mechanism. The proceeds were used to pay down commercial paper.

Rate-Reduction Bonds

In December 1997, $658 million of rate-reduction bonds were issued on behalf of SDG&E at an average interest rate of 6.26 percent. These bonds were issued to facilitate the 10 percent rate

reduction mandated by California's electric restructuring law. They are being repaid over ten years by SDG&E's residential and small-commercial customers through a specified charge on their electricity bills. These bonds are secured by the revenue streams collected from customers and are not secured by, or payable from, utility assets.

Debt of Employee Stock Ownership Plan (ESOP) and Trust (Trust)

The Trust covers substantially all of the employees of the parent organization, SoCalGas and most of Global's subsidiaries. The Trust is used to fund part of the retirement savings plan described in Note 8. The 15-year notes are repriced weekly and subject to repurchase by the company at the holder's option, depending on market demand. In June 2001, utilizing the term option provisions of the notes, $82 million of the notes were remarketed at a fixed rate of 7.375 percent for three years. The variable interest rate and weekly repricing resume in May 2004. ESOP debt was reduced by $4.2 million during the last three years when 70,000 shares of company common stock were released from the Trust in order to fund the employer contribution to the company savings plan. Interest on the ESOP debt amounted to $6 million in 2003, $7 million in 2002 and $6 million in 2001. Dividends used for debt service amounted to $2 million in 2003, $3 million in 2002, and $3 million in 2001.

Interest-Rate Swaps

The company periodically enters into interest-rate swap agreements to moderate its exposure to interest-rate changes and to lower its overall cost of borrowing. The schedule of long-term debt reflects past swap interest rates. The company believes the swaps have been fully effective in their purpose of converting the underlying debt's fixed rates to floating rates and meet the criteria for accounting under one of the methods defined in SFAS 133 for fair value hedges of debt instruments. Accordingly, market value adjustments to long-term debt of ($19) million and $20 million were recorded in 2003 and 2002, respectively, to reflect, without affecting net income or other comprehensive income, the favorable or (unfavorable) economic consequences (as measured at December 31, 2003 and 2002) of having entered into the swap transactions.

During 2002 and 2001, SDG&E had an interest-rate swap agreement that effectively fixed the interest rate on $45 million of variable-rate underlying debt at 5.4 percent. This floating-to-fixed-rate swap did not qualify for hedge accounting and, therefore, the gains and losses associated with the change in fair value are recorded in the Statements of Consolidated Income. The effect on net income was a $1 million gain in 2002 and a $1 million loss in 2001.

Foreign Currency Hedges

The company's primary objective with respect to currency risk is to reduce net income volatility that would otherwise occur due to exchange-rate fluctuations.

Sempra Energy's net investment in its Latin American operating companies and the resulting cash flows are partially protected against normal exchange-rate fluctuations by rate-setting mechanisms that are intended to compensate for local inflation and currency exchange-rate fluctuations. In addition to establishing such tariff-based protections, the company offsets material cross-currency transactions and net income exposure through various means, including financial instruments and short-term investments.

Because the company does not hedge its net investment in foreign countries, it is susceptible to volatility in other comprehensive income, as occurred in the last three years primarily as a result of decoupling the Argentine peso from the U.S. dollar, as discussed in Note 3.

NOTE 6. FACILITIES UNDER JOINT OWNERSHIP

SONGS and the Southwest Powerlink transmission line are owned jointly with other utilities. The company's interests at December 31, 2003, are as follows:

(Dollars in millions)	SONGS*	Southwest Powerlink
Percentage ownership	20%	89%
Utility plant in service	$—	$237
Accumulated depreciation and amortization	$—	$141
Construction work in progress	$—	$ 27

* SDG&E's 20% ownership in SONGS has been fully recovered and is no longer included under utility plant and accumulated depreciation.

As of December 31, 2003, the company has fully recovered its interest in SONGS through the ICIP mechanism. Additional information concerning the ICIP mechanism is provided in Note 13.

The company and the other owners each hold its interest as an undivided interest as tenants in common. Each owner is responsible for financing its share of each project and participates in decisions concerning operations and capital expenditures.

The company's share of operating expenses is included in the Statements of Consolidated Income.

SONGS Decommissioning

Objectives, work scope and procedures for the dismantling and decontamination of the SONGS units must meet the requirements of the Nuclear Regulatory Commission, the Environmental Protection Agency, the CPUC and other regulatory bodies.

The company's share of decommissioning costs for the SONGS units is estimated to be $316 million in 2003 dollars. Cost studies are updated every three years, with the next update expected to be submitted to the CPUC for its approval in 2005. Rate recovery of decommissioning costs is allowed until the time that the costs are fully recovered, and is subject to adjustment every three years based on the costs allowed by regulators. Collections are authorized to continue until 2013, but may be extended by CPUC approval until 2022, at which time the SONGS' operating license ends and the decommissioning of SONGS 2 and 3 would be expected to begin. Payments to the nuclear decommissioning trusts (described in "Nuclear Decommissioning Trusts") are expected to continue until 2013 at which time sufficient funds are expected to be collected to fully decommission SONGS. If funds are not sufficient, additional future rate recovery is expected to occur.

The amounts collected in rates are invested in the externally managed trust funds. The securities held by the nuclear decommissioning trusts are considered available for sale. These trusts are shown on the Consolidated Balance Sheets at market value. At December 31, 2003, these trusts reflected unrealized gains of $159 million with the offsetting credits recorded on the Consolidated Balance Sheets to Asset Retirement Obligations and the related regulatory liabilities. At December 31, 2002, these trusts reflected unrealized gains of $95 million with the offsetting credits recorded to Deferred Credits and Other Liabilities and the related regulatory liabilities.

Unit 1 was permanently shut down in 1992, and physical decommissioning began in January 2000. Several structures, foundations and large components have been dismantled, removed and disposed of. Preparations have been made for the remaining major work to be performed in 2004 and beyond. That work will include dismantling, removal and disposal of all remaining Unit 1 equipment and facilities

(both nuclear and non-nuclear components), decontamination of the site and completion of an on-site storage facility for Unit 1 spent fuel. These activities are expected to be completed in 2008.

See discussion regarding the impact of SFAS 143 in Note 1.

Nuclear Decommissioning Trusts

SDG&E has established a Nonqualified Nuclear Decommissioning Trust and a Qualified Nuclear Decommissioning Trust to provide funds for the decommissioning of SONGS as described above. Amounts held by these trusts are invested in accordance with CPUC regulations that establish maximum amounts for investments in equity securities (50 percent of the qualified trust and 60 percent of the nonqualified trust), international equity securities (20 percent) and securities of electric utilities having ownership interests in nuclear power plants (10 percent). Not less than 50 percent of the equity portion of these trusts must be invested passively.

At December 31, 2003 and 2002, trust assets were allocated as follows (dollars in millions):

	Qualified Trust		Nonqualified Trust	
	2003	2002	**2003**	2002
Domestic equity	**$163**	$143	**$43**	$36
Foreign equity	**88**	69	**—**	—
Total equity	**251**	212	**43**	36
Total fixed income	**249**	220	**27**	26
Total	**$500**	$432	**$70**	$62

Customer contribution amounts are determined by estimates of after-tax investment returns, decommissioning costs and decommissioning cost escalation rates. Lower actual investment returns or higher actual decommissioning costs would result in an increase in customer contributions.

Additional information regarding SONGS is included in Notes 13 and 15.

NOTE 7. INCOME TAXES

The reconciliation of the statutory federal income tax rate to the effective income tax rate is as follows:

	Years ended December 31,		
	2003	2002	2001
Statutory federal income tax rate	**35.0%**	35.0%	35.0%
Utility depreciation	**6.7**	5.2	5.9
State income taxes—net of federal income tax benefit	**7.0**	7.0	6.4
Tax credits	**(22.6)**	(18.5)	(13.7)
Income from unconsolidated foreign subsidiaries	**(4.3)**	(2.0)	(3.0)
Settlement of Internal Revenue Service audit	**(11.2)**	(3.6)	—
Other—net	**(4.3)**	(2.9)	(1.5)
Effective income tax rate	**6.3%**	20.2%	29.1%

The components of total income (loss) from operations (including continuing extraordinary items) before income taxes are as follows:

(Dollars in millions)	Years ended December 31, 2003	2002	2001
Domestic	**$ 551**	$ 584	$ 651
Foreign	**191**	137	80
Total income before income taxes	**$ 742**	$ 721	$ 731

The components of income tax expense are as follows:

(Dollars in millions)	Years ended December 31, 2003	2002	2001
Current:			
Federal	**$ 93**	$ 195	$ 36
State	**16**	30	60
Foreign	**11**	13	11
Total	**120**	238	107
Deferred:			
Federal	**(138)**	(113)	104
State	**53**	31	1
Foreign	**18**	(5)	7
Total	**(67)**	(87)	112
Deferred investment tax credits	**(6)**	(5)	(6)
Total income tax expense	**$ 47**	$ 146	$ 213

Accumulated deferred income taxes at December 31 relate to the following:

(Dollars in millions)	2003	2002
Deferred tax liabilities:		
Differences in financial and tax bases of property, plant and equipment	**$1,094**	$ 883
Balancing accounts and regulatory assets	**314**	298
Partnership income	**34**	45
Unrealized revenue	**63**	53
Other	**211**	266
Total deferred tax liabilities	**1,716**	1,545
Deferred tax assets:		
Investment tax credits	**61**	62
General business tax credit carryforward	**192**	148
Net operating losses of foreign entities	**112**	89
Postretirement benefits	**31**	32
Other deferred liabilities	**190**	157
Restructuring costs	**—**	40
Compensation-related items	**134**	154
Bad debt allowance	**28**	—
State income taxes	**57**	46
Credits from Alternative Minimum Tax	**74**	19
Valuation allowance	**(20)**	(10)
Other	**100**	28
Total deferred tax assets	**959**	765
Net deferred income tax liability	**$ 757**	$ 780

The net deferred income tax liability is recorded on the Consolidated Balance Sheets at December 31 as follows:

(Dollars in millions)	**2003**	2002
Current (asset) liability	**$123**	$ (20)
Noncurrent liability	**634**	800
Total	**$757**	$780

In connection with its affordable-housing investments, the company has $192 million of unused general business tax credits in varying amounts dating back to 1999. The ability to offset these credits against future taxable income will expire between the years 2019 and 2022. The company expects to utilize the credits in future years. In addition, the company has $74 million of alternative minimum tax credits with no expiration date. All of these credits have been included in the company's calculation of income tax expense.

Foreign subsidiaries have $340 million in unused net operating losses available to reduce future income taxes, primarily in Mexico, Canada and the United Kingdom. Utilization of these losses began to expire in 2002. Financial statement benefits have been recorded on all but $66 million of these losses, primarily by offsetting them against deferred tax liabilities with the same expiration pattern and country of jurisdiction. No benefits have been recorded on $66 million of the losses because they have been incurred in jurisdictions where utilization is sufficiently in doubt.

The company has not provided for U.S. income taxes on foreign subsidiaries' undistributed earnings ($360 million at December 31, 2003), since they are expected to be reinvested indefinitely outside the U.S. It is not possible to predict the amount of U.S. income taxes that might be payable if these earnings were eventually repatriated.

Section 29 Income Tax Credits

In 2003 the Internal Revenue Service (IRS) issued Announcement 2003-46, stating it has reason to question the scientific validity of testing procedures and results related to Section 29 income tax credits. The notice also announced that it would suspend the issuance of new rulings until its review is complete and that rulings could be revoked if the IRS did not determine that the test procedures demonstrate a significant chemical change between the feedstock coal and the synthetic fuel. The IRS completed its review and on October 29, 2003, announced that it would again be issuing private letter rulings based on the previous requirements. Many such rulings have been issued since that date, including one involving operations owned by the company. The Permanent Subcommittee on Investigations of the U.S. Senate's Committee on Governmental Affairs has initiated an investigation on the subject of these income tax credits. In January 2004, the company received a letter from the Committee requesting certain information about its synthetic fuel operations and it is in the process of responding to this inquiry.

As part of its recently commenced normal audit program for the company for the period 1998-2001, the IRS notified the company of its intention to audit the synthetic fuel operations of SET and SEF. From acquisition of the facilities in 1998 through December 31, 2003, the company has recorded Section 29 income tax credits of $251 million of which $107 million were recorded for the year ended December 31, 2003. The company believes disallowance of Section 29 income tax credits is unlikely.

Luz del Sur

The Peruvian tax authorities (SUNAT) had assessed additional taxes for 1999 based on their challenge of Luz del Sur's revaluation of its assets and also previously announced that they would assess

additional taxes for the years 1996 through 1998 for the same concept. The Peruvian Tax Court recently ruled that no additional taxes could be assessed for 1996 through 1998 and that any additional taxes for 1999 could only be assessed if the SUNAT showed that Luz del Sur had revalued its assets beyond their market value. If the SUNAT is successful in its challenge, income tax deductions for depreciation will be reduced, resulting in additional income taxes, interest and penalties aggregating as much as $10 million for the company's share for the period being questioned (1999) and $12 million for subsequent periods. The company believes that it has substantial defenses to such challenges and that the imposition of any additional taxes is not probable.

Spanish Holding Company

The IRS has issued Notice 2003-50, stating that regulations will be issued that will adversely affect foreign tax credit utilization by companies with "stapled-stock" affiliates. The company's intermediate parent company for many of its non-domestic subsidiaries is such a company. Although not probable, the most adverse resolution of this issue could result in a charge to net income of $13 million by the company.

Resolution of Certain Internal Revenue Service Matters

The company favorably resolved matters related to various prior years' returns during 2003. The primary issue involving the treatment of utility balancing accounts for the California Utilities was resolved following the issuance of an IRS Revenue Ruling and resolution of factual issues involving these claims with the IRS. The total effect on after-tax earnings and future cash flows for all IRS issues was $118 million, of which $79 million was at SDG&E and $29 million was at SoCalGas.

NOTE 8. EMPLOYEE BENEFIT PLANS

The information presented below covers the plans of the company and its principal subsidiaries.

Pension and Other Postretirement Benefits

The company has funded and unfunded noncontributory defined benefit plans that together cover substantially all of its employees. The plans provide defined benefits based on years of service and final average salary.

The company also has other postretirement benefit plans covering substantially all of its employees. The life insurance plans are noncontributory and the health care plans are contributory, with participants' contributions adjusted annually. Other postretirement benefits include retiree life insurance, medical benefits for retirees and their spouses and Medicare Part B reimbursement for certain retirees.

The company maintains dedicated assets in support of its Supplemental Executive Retirement Plan.

During 2002, the company had amendments reflecting retiree cost of living adjustments, which resulted in an increase in the pension plan benefit obligation of $51 million. Amendments to other postretirement benefit plans related to the transfer of employees to SDG&E and changes to their specific benefits resulted in a decrease in the benefits obligation of $7 million. The amortization of these changes will affect pension expense in future years.

During 2001, the company participated in a voluntary separation program. As a result, it recorded a $13 million special termination benefit, a $1 million curtailment cost and a $19 million settlement gain.

There were no amendments to the company's pension and other postretirement benefit plans in 2003.

December 31 is the measurement date for the pension and other postretirement benefit plans.

The following tables provide a reconciliation of the changes in the plans' projected benefit obligations during the latest two years, the fair value of assets and a statement of the funded status as of the latest two year ends:

	Pension Benefits		Other Postretirement Benefits	
(Dollars in millions)	**2003**	2002	**2003**	2002
CHANGE IN PROJECTED BENEFIT OBLIGATION:				
Net obligation at January 1	**$2,290**	$2,010	**$ 797**	$ 590
Service cost	**52**	57	**19**	13
Interest cost	**152**	149	**55**	42
Actuarial loss	**285**	197	**116**	191
Benefit payments	**(201)**	(187)	**(33)**	(32)
Plan amendments	**—**	51	**—**	(7)
Other	**—**	13	**—**	—
Net obligation at December 31	**2,578**	2,290	**954**	797
CHANGE IN PLAN ASSETS:				
Fair value of plan assets at January 1	**1,984**	2,449	**409**	469
Actual return on plan assets	**453**	(281)	**90**	(50)
Employer contributions	**27**	3	**53**	22
Benefit payments	**(201)**	(187)	**(33)**	(32)
Fair value of plan assets at December 31	**2,263**	1,984	**519**	409
Benefit obligation, net of plan assets at December 31	**(315)**	(306)	**(435)**	(388)
Unrecognized net actuarial loss	**273**	283	**317**	266
Unrecognized prior service cost	**83**	93	**(13)**	(14)
Unrecognized net transition obligation	**1**	1	**—**	—
Net recorded asset (liability) at December 31	**$ 42**	$ 71	**$(131)**	$(136)

The following table provides the amounts recognized on the Consolidated Balance Sheets (in Noncurrent Sundry Assets, Deferred Credits and Other Liabilities, and Postretirement Benefits Other Than Pensions) at December 31:

	Pension Benefits		Other Postretirement Benefits	
(Dollars in millions)	**2003**	2002	**2003**	2002
Prepaid benefit cost	**$ 178**	$ 203	**$ —**	$ —
Accrued benefit cost	**(136)**	(132)	**(131)**	(136)
Additional minimum liability	**(118)**	(93)	**—**	—
Intangible asset	**9**	12	**—**	—
Accumulated other comprehensive income, pretax	**109**	81	**—**	—
Net recorded asset (liability)	**$ 42**	$ 71	**$(131)**	$(136)

The accumulated benefit obligation for defined benefit pension plans was $2.4 billion and $2 billion at December 31, 2003 and 2002, respectively. The following table provides information concerning pension plans with benefit obligations in excess of plan assets as of December 31.

	Projected Benefit Obligation Exceeds the Fair Value of Plan Assets		Accumulated Benefit Obligation Exceeds the Fair Value of Plan Assets	
(Dollars in millions)	**2003**	2002	**2003**	2002
Projected benefit obligation	**$2,341**	$2,091	**$815**	$736
Accumulated benefit obligation	**$2,126**	$1,849	**$793**	$684
Fair value of plan assets	**$2,011**	$1,757	**$538**	$468

The following table provides the components of net periodic benefit costs (income) for the years ended December 31:

	Pension Benefits			Other Postretirement Benefits		
(Dollars in millions)	**2003**	2002	2001	**2003**	2002	2001
Service cost	**$ 52**	$ 57	$ 49	**$ 19**	$ 13	$ 11
Interest cost	**152**	149	141	**55**	42	41
Expected return on assets	**(161)**	(204)	(219)	**(35)**	(39)	(39)
Amortization of:						
Transition obligation	**1**	1	1	**9**	9	10
Prior service cost	**9**	7	6	**(1)**	(1)	(1)
Actuarial (gain) loss	**9**	(18)	(39)	**10**	—	(3)
Special termination benefit	**—**	—	13	**—**	—	—
Curtailment cost (credit)	**—**	—	1	**—**	—	—
Settlement credit	**—**	—	(19)	**—**	—	—
Regulatory adjustment	**(14)**	32	51	**(4)**	25	30
Total net periodic benefit cost (income)	**$ 48**	$ 24	$ (15)	$ 53	$ 49	$ 49

The significant assumptions related to the company's pension and other postretirement benefit plans are as follows:

	Pension Benefits		Other Postretirement Benefits	
	2003	2002	**2003**	2002
WEIGHTED-AVERAGE ASSUMPTIONS USED TO DETERMINE BENEFIT OBLIGATION AS OF DECEMBER 31:				
Discount rate	**6.00%**	6.50%	**6.00%**	6.50%
Rate of compensation increase	**4.50%**	4.50%	**4.50%**	4.50%
WEIGHTED-AVERAGE ASSUMPTIONS USED TO DETERMINE NET PERIODIC BENEFIT COSTS FOR YEARS ENDED DECEMBER 31:				
Discount rate	**6.50%**	7.25%	**6.50%**	7.25%
Expected return on plan assets	**7.50%**	8.00%	**7.30%**	7.80%
Rate of compensation increase	**4.50%**	4.50%	**4.50%**	4.50%

The expected long-term rate of return on plan assets is derived from historical returns for broad asset classes consistent with expectations from a variety of sources, including pension consultants and investment advisors.

	2003	2002
ASSUMED HEALTH CARE COST TREND RATES AT DECEMBER 31:		
Health-care cost trend rate	**30.00%***	7.00%
Rate to which the cost trend rate is assumed to decline (the ultimate trend)	**5.50%**	6.50%
Year that the rate reaches the ultimate trend	**2008**	2004

* This is the weighted average of the increases for all health plans. The 2003 rate for these plans ranged from 15% to 40%.

Assumed health-care cost trend rates have a significant effect on the amounts reported for the health-care plan costs. A one-percent change in assumed health-care cost trend rates would have the following effects:

(Dollars in millions)	1% Increase	1% Decrease
Effect on total of service and interest cost components of net periodic postretirement health-care benefit cost	$ 13	$ (11)
Effect on the health-care component of the accumulated other postretirement benefit obligation	$152	$(121)

Pension Plan Investment Strategy

The asset allocation for the company's pension trust (which includes other postretirement benefit plans, except for those described below) at December 31, 2003 and 2002 and the target allocation for 2004 by asset categories are as follows:

	Target Allocation	Percentage of Plan Assets at December 31,	
Asset Category	2004	**2003**	2002
U.S. Equity	45%	**45%**	44%
Foreign Equity	25%	**30%**	26%
Fixed Income	30%	**25%**	30%
Total	100%	**100%**	100%

The company's goal is to remain within a reasonable risk tolerance shown above. Its investment strategy is to stay fully invested at all times and maintain its strategic asset allocation, keeping the investment structure relatively simple. The equity portfolio is balanced to maintain risk characteristics similar to the S&P 1500 with respect to market capitalization, industry and sector exposures. The foreign equity portfolios are managed to track the MSCI Europe, Pacific Rim and Emerging Markets indexes. Bond portfolios are managed with respect to the Lehman Aggregate Index. The plan does not invest in Sempra Energy securities.

Investment Strategy for SoCalGas' Other Postretirement Benefit Plans

The asset allocation for SoCalGas' other postretirement benefit plans at December 31, 2003 and 2002 and the target allocation for 2004 by asset categories are as follows:

Asset Category	Target Allocation 2004	Percentage of Plan Assets at December 31, **2003**	2002
U.S. Equity	70%	**71%**	63%
Fixed Income	30%	**27%**	34%
Cash	—	**2%**	3%
Total	100%	**100%**	100%

SoCalGas' other postretirement benefit plans, which are distinct from other postretirement benefit plans included in the company's pension trust (see above), are funded by cash contributions from SoCalGas and the retirees. The asset allocation is designed to match the long-term growth of the plan's liability. This plan is managed using 100% index funds.

Investment Strategy for SDG&E's Postretirement Health Plans

The asset allocation for SDG&E's postretirement health plans at December 31, 2003 and 2002 and the target allocation for 2004 by asset categories are as follows:

Asset Category	Target Allocation 2004	Percentage of Plan Assets at December 31, **2003**	2002
U.S. Equity	25%	**26%**	23%
Foreign Equity	5%	**5%**	4%
Fixed Income	70%	**69%**	73%
Total	100%	**100%**	100%

SDG&E's postretirement health plans, which also are distinct from other postretirement benefit plans included in the company's pension trust (see above), pay premiums to the health maintenance organization and point-of-service plans from company and participant contributions. The company's investment strategy is to match the long-term growth rate of the liability primarily through the use of tax-exempt California municipal bonds.

Future Payments

The company expects to contribute $32 million to the pension plans and $62 million to its other postretirement benefit plans in 2004.

The following table reflects the total benefits expected to be paid to current employees and retirees from the plans or from the company's assets, including both the company's share of the benefit cost and, where applicable, the participants' share of the costs, which is funded by participant contributions to the plans.

(Dollars in millions)	Pension Benefits	Other Postretirement Benefits
2004	$ 164	$ 35
2005	$ 167	$ 41
2006	$ 200	$ 44
2007	$ 184	$ 47
2008	$ 192	$ 49
Thereafter	$1,078	$270

Savings Plans

The company offers trusteed savings plans to all eligible employees. Eligibility to participate in the plans is immediate for salary deferrals. Employees may contribute, subject to plan provisions, from one percent to 25 percent of their regular earnings. After one year of completed service, the company begins to make matching contributions. Employer contribution amounts and methodology vary by plan, but generally the contributions are equal to 50 percent of the first 6 percent of eligible base salary contributed by employees and, if certain company goals are met, an additional amount related to incentive compensation payments.

Employer contributions are invested in company stock and must remain so invested until termination of employment or until the employee's attainment of age 55, when they may be transitioned into other investments. At the direction of the employees, the employees' contributions are invested in company stock, mutual funds, institutional trusts or guaranteed investment contracts. The plans of certain non-wholly owned subsidiaries prohibit investments in Sempra Energy stock. In this case, the employer matching contributions are invested to mirror the employee-directed contributions. Employer contributions for the Sempra Energy and SoCalGas plans are partially funded by the Employee Stock Ownership Plan referred to below. Company contributions to the savings plans were $22 million in 2003, $20 million in 2002 and $17 million in 2001. The market value of company stock held by the savings plan was $675 million and $533 million at December 31, 2003 and 2002, respectively.

Employee Stock Ownership Plan

All contributions to the ESOP Trust (See Note 5) are made by the company; there are no contributions made by the participants. As the company makes contributions, the ESOP debt service is paid and shares are released in proportion to the total expected debt service. Compensation expense is charged and equity is credited for the market value of the shares released. Dividends on unallocated shares are used to pay debt service and are applied against the liability. The Trust held 2.4 million shares and 2.6 million shares, respectively, of Sempra Energy common stock, with fair values of $71.6 million and $61.0 million, at December 31, 2003 and 2002, respectively.

NOTE 9. STOCK-BASED COMPENSATION

Sempra Energy has stock-based compensation plans intended to align employee and shareholder objectives related to the long-term growth of the company. The plans permit a wide variety of stock-based awards, including nonqualified stock options, incentive stock options, restricted stock, stock appreciation rights, performance awards, stock payments and dividend equivalents.

In 2003, 2002 and 2001, 1,359,500, 544,100, and 777,500 shares of restricted company stock, respectively, were awarded to key employees. The corresponding weighted average market values of the shares at the time of grant were $24.42, $24.77 and $23.37, respectively. Subject to earlier forfeitures upon termination of employment, the 2003 award is scheduled to vest at the end of four years if performance-based goals are satisfied. The 2002 and 2001 awards are scheduled to vest at the end of seven years, but are also subject to earlier vesting over a four-year period upon satisfaction of objective performance-based goals. Holders of restricted stock have full voting and dividend rights except for senior officers, whose dividends are conditional. Compensation expense for the issuance of restricted stock was $16 million in 2003, $7 million in 2002 and $5 million in 2001.

In 2003, 2002 and 2001, Sempra Energy granted to officers and key employees 1,848,000, 3,444,300 and 2,934,800 stock options, respectively. The option prices were equal to the market price of common stock at the dates of grant. The options vest over four-year periods and expire 10 years from the dates of grant, subject to earlier expiration upon termination of employment. Compensation expense (or

reduction thereof) for stock option grants (all associated with outstanding options with dividend equivalents that were issued before 2000—see below) and similar awards was $6 million, ($2 million) and $7 million in 2003, 2002 and 2001, respectively.

As of December 31, 2003, 13,410,138 shares were authorized and available for future grants of restricted stock and/or stock options. In addition, on January 1 of each year, additional shares amounting to 1.5 percent of the outstanding shares of Sempra Energy common stock become available for grant.

The plans permit the granting of dividend equivalents with the stock option grants. This provides grantees the opportunity to receive some or all of the cash dividends that would have been paid on the shares since the grant date. All grants that have included dividend equivalents have made the dividend equivalents dependent on the attainment of certain performance goals. For grants prior to July 1, 1998, payment of the dividend equivalents is also contingent upon an in-the-money exercise of the related options.

In 1995, *SFAS 123, "Accounting for Stock-Based Compensation,"* was issued. It encourages a fair-value-based method of accounting for stock-based compensation. As permitted by SFAS 123, the company adopted only its disclosure requirements and continues to account for stock-based compensation in accordance with the provisions of APB Opinion 25. See additional discussion of SFAS 148, the amendment to SFAS 123, in Note 1.

STOCK OPTION ACTIVITY

	Shares Under Option	Weighted Average Exercise Price	Options Exercisable at December 31
OPTIONS WITH DIVIDEND EQUIVALENTS			
December 31, 2000	4,028,573	$22.17	2,462,574
Exercised	(588,315)	$20.92	
Cancelled	(119,911)	$22.46	
December 31, 2001	3,320,347	$22.38	2,508,328
Exercised	(172,358)	$19.87	
Cancelled	(68,124)	$24.03	
December 31, 2002	3,079,865	$22.48	2,777,590
Exercised	**(876,391)**	**$20.81**	
Cancelled	**(17,649)**	**$24.72**	
Transfer (see table below)	**(1,536,775)**	**$23.24**	
December 31, 2003	**649,050**	**$22.89**	**649,050**

	Shares Under Option	Weighted Average Exercise Price	Options Exercisable at December 31
OPTIONS WITHOUT DIVIDEND EQUIVALENTS			
December 31, 2000	7,565,421	$20.61	1,659,244
Granted	2,934,800	$22.50	
Exercised	(421,633)	$18.79	
Cancelled	(204,134)	$23.59	
December 31, 2001	9,874,454	$21.19	3,143,319
Granted	3,444,300	$24.71	
Exercised	(223,430)	$17.70	
Cancelled	(84,137)	$21.70	
December 31, 2002	13,011,187	$22.18	5,287,437
Granted	**1,848,000**	**$24.44**	
Exercised	**(1,050,199)**	**$20.16**	
Cancelled	**(111,906)**	**$23.83**	
Transfer (see table above)	**1,536,775**	**$23.24**	
December 31, 2003	**15,233,857**	**$22.69**	**8,610,732**

Additional information on options outstanding at December 31, 2003, is as follows:

Range of Exercise Prices	Number of Shares	Weighted Average Remaining Life	Weighted Average Exercise Price
Outstanding Options			
$ 16.12-$ 19.06	3,348,195	6.04	$18.79
$ 20.36-$ 22.65	5,082,028	6.14	$21.76
$ 23.45-$ 27.64	7,452,684	5.12	$25.05
	15,882,907	5.64	$22.68
Exercisable Options			
$ 16.12-$ 19.06	2,302,520		$18.75
$ 20.36-$ 22.65	3,734,303		$21.50
$ 23.45-$ 27.64	3,222,959		$25.65
	9,259,782		$22.26

The grant-date market value of each option grant (including dividend equivalents where applicable) was estimated using a modified Black-Scholes option-pricing model. Weighted average grant-date market values for options granted in 2003, 2002 and 2001 were $4.31, $4.45 and $4.29, respectively.

The assumptions that were used to determine these grant-date market values are as follows:

	2003	2002	2001
Stock price volatility	**25%**	22%	24%
Risk-free rate of return	**1.8%**	4.8%	4.6%
Annual dividend yield	**2.2%**	4.1%	4.3%
Expected life	**6 Years**	6 Years	6 Years

NOTE 10. FINANCIAL INSTRUMENTS

Fair Value

The fair values of certain of the company's financial instruments (cash, temporary investments, notes receivable, dividends payable, short-term debt and customer deposits) approximate their carrying amounts. The following table provides the carrying amounts and fair values of the remaining financial instruments at December 31:

	2003		2002	
(Dollars in millions)	Carrying Amount	Fair Value	Carrying Amount	Fair Value
Investments in limited partnerships	**$ 236**	**$ 352**	$ 271	$ 346
First mortgage bonds	**$1,561**	**$1,578**	$1,386	$1,452
Notes payable	**1,700**	**1,842**	1,300	1,424
Equity units	**600**	**680**	600	577
SDG&E rate-reduction bonds	**263**	**284**	329	357
Debt incurred to acquire limited partnerships	**110**	**128**	145	169
Mesquite Power debt	**630**	**630**	—	—
Other long-term debt	**414**	**436**	608	623
Total long-term debt	**$5,278**	**$5,578**	$4,368	$4,602
Due to unconsolidated affiliates	**$ 362***	**$ 392**	$ 162	$ 185
Preferred stock of subsidiaries	**$ 203***	**$ 184**	$ 204	$ 168
Mandatorily redeemable trust preferred securities	**$ —***	**—**	$ 200	$ 205

* $200 million of mandatorily redeemable trust preferred securities have been reclassified to Due to Unconsolidated Affiliates and $24 million of mandatorily redeemable preferred stock of subsidiaries have been reclassified to Deferred Credits and Other Liabilities and to Other Current Liabilities on the Consolidated Balance Sheets.

The fair values of investments in limited partnerships accounted for under the equity and cost methods were estimated based on the present value of remaining cash flows, discounted at rates available for similar investments. The fair values of debt incurred to acquire limited partnerships were estimated based on the present value of the future cash flows, discounted at rates available for similar notes with comparable maturities. The fair values of the other long-term debt, preferred stock of subsidiaries and mandatorily redeemable trust preferred securities were estimated based on quoted market prices for them or for similar issues.

Accounting for Derivative Instruments and Hedging Activities

The company follows the guidance of SFAS 133 and related amendments SFAS 138 and 149 (collectively SFAS 133) to account for its derivative instruments and hedging activities. Derivative instruments and related hedges are recognized as either assets or liabilities on the balance sheet, measured at fair value. Changes in the fair value of derivatives are recognized in earnings in the period of change unless the derivative qualifies as an effective hedge that offsets certain exposure.

SFAS 133 provides for hedge accounting treatment when certain criteria are met. For derivative instruments designated as fair value hedges, the gain or loss is recognized in earnings in the period of change together with the offsetting gain or loss on the hedged item attributable to the risk being hedged. For derivative instruments designated as cash flow hedges, the effective portion of the derivative gain or loss is included in other comprehensive income, but not reflected in the Statements of Consolidated Income until the corresponding hedged transaction is settled. The ineffective portion is reported in earnings immediately. The effect on other comprehensive income for the years ended

December 31, 2003 and 2002 was not material. In instances where derivatives do not qualify for hedge accounting, gains and losses are recorded in the Statements of Consolidated Income.

The company utilizes derivative instruments to reduce its exposure to unfavorable changes in commodity prices, which are subject to significant and often volatile fluctuation. Derivative instruments include futures, forwards, swaps, options and long-term delivery contracts. These contracts allow the company to predict with greater certainty the effective prices to be received. The company classifies its forward contracts as follows:

Contracts that meet the definition of normal purchase and sales generally are long-term contracts that are settled by physical delivery and, therefore, are eligible for the normal purchases and sales exception of SFAS 133. The contracts are accounted for under accrual accounting and recorded in Revenues or Cost of Sales on the Statements of Consolidated Income when physical delivery occurs. Due to the adoption of SFAS 149, the company has determined that its natural gas contracts entered into after June 30, 2003 generally do not qualify for the normal purchases and sales exception.

Electric and Natural Gas Purchases and Sales: The unrealized gains and losses related to these forward contracts, as they relate to the California Utilities, are reflected on the Consolidated Balance Sheets as regulatory assets and liabilities to the extent derivative gains and losses will be recoverable or payable in future rates. If gains and losses at the California Utilities are not recoverable or payable through future rates, the California Utilities will apply hedge accounting when certain criteria are met. When a contract no longer meets the requirements of SFAS 133, the unrealized gains and losses and the related regulatory asset or liability will be amortized over the remaining contract life.

The following were recorded on the Consolidated Balance Sheets at December 31 related to derivatives:

(Dollars in millions)	**2003**	2002
Fixed-priced contracts and other derivatives:		
Current liabilities	**$148**	$153
Noncurrent liabilities	**680**	813
Total	**828**	966
Current assets	**26**	3
Noncurrent assets	**—**	42
Total	**26**	45
Net liabilities	**$802**	$921

Regulatory assets and liabilities related to derivatives held by the California Utilities at December 31 were:

(Dollars in millions)	**2003**	2002
Regulatory assets and liabilities:		
Current regulatory assets	**$144**	$151
Noncurrent regulatory assets	**650**	812
Total	**794**	963
Current regulatory liabilities	**1**	2
Net regulatory assets	**$793**	$961

As of December 31, 2003, the difference between net liabilities and net regulatory assets was primarily due to $30 million related to a derivative contract associated with the purchase of the Cameron LNG

facility offset by $23 million related to a fixed-to-floating interest rate swap. At December 31, 2002, the difference was primarily due to market value adjustment of $42 million related to two fixed-to-floating interest rate swaps. The market value adjustment in 2002 included a reversing effect for the cancellation of one of the swap agreements on September 30, 2002. $2 million of losses in 2003 and $4 million of income in 2002 were recorded in Operating Revenues and $1 million of income in 2002 was recorded in Other Income—Net in the Statements of Consolidated Income.

Market Risk

The company's policy is to use physical and financial derivative instruments to reduce its exposure to fluctuations in interest rates, foreign currency exchange rates and commodity prices. The company also uses and trades derivative instruments in its trading and marketing of energy and other commodities. Transactions involving these instruments are with major exchanges and other firms believed to be creditworthy. The use of these instruments exposes the company to market and credit risks, which may at times be concentrated with certain counterparties, although counterparty nonperformance is not anticipated.

Interest-Rate Risk Management

The company periodically enters into interest-rate swap agreements to moderate exposure to interest-rate changes and to lower the overall cost of borrowing. This is described in Note 5.

Energy Derivatives

The company utilizes derivative instruments to reduce its exposure to unfavorable changes in energy prices, which are subject to significant and often volatile fluctuation. Derivative instruments are comprised of futures, forwards, swaps, options and long-term delivery contracts. These contracts allow the company to predict with greater certainty the effective prices to be received.

Energy Contracts

The California Utilities record transactions for natural gas and electric energy contracts in Cost of Natural Gas and Cost of Electric Fuel and Purchased Power, respectively, in the Statements of Consolidated Income. For open contracts not expected to result in physical delivery, changes in market value of the contracts are recorded in these accounts during the period the contracts are open, with an offsetting entry to a regulatory asset or liability. The majority of the California Utilities' contracts result in physical delivery, which is infrequent at the trading operations.

Sempra Energy Trading and Sempra Energy Solutions

SET derives revenue from market making and trading activities, as a principal, in natural gas, electricity, petroleum products, metals and other commodities, for which it quotes bid and ask prices to other market makers and end users. It also earns trading profits as a dealer by structuring and executing transactions that permit its counterparties to manage their risk profiles. SET utilizes derivative instruments to reduce its exposure to unfavorable changes in market prices, which are subject to significant and often volatile fluctuation. These instruments include futures, forwards, swaps and options, and represent contracts with counterparties under which payments are linked to or derived from energy market indices or on terms predetermined by the contract, which may or may not be financially settled by SET. Sempra Energy guarantees many of SET's transactions.

SES derives a major portion of its revenue from delivering electric and natural gas supplies to its commercial and industrial customers. Such contracts are hedged to preserve margin and reduce

market risk. The derivative instruments used to hedge the transactions include swaps, forwards, futures, options or combinations thereof.

Trading instruments are recorded by both SET and SES on a trade-date basis and the majority of such derivative instruments are adjusted daily to current market value with gains and losses recognized in Other Operating Revenues on the Statements of Consolidated Income. These instruments are included on the Consolidated Balance Sheets as Trading Assets or Trading Liabilities and include amounts due from commodity clearing organizations, amounts due to or from trading counterparties, unrealized gains and losses from exchange-traded futures and options, derivative OTC swaps, forwards and options. Unrealized gains and losses on OTC transactions reflect amounts that would be received from or paid to a third party upon settlement of the contracts. Unrealized gains and losses on OTC transactions are reported separately as assets and liabilities unless a legal right of setoff exists under an enforceable netting arrangement. Other derivatives which qualify as hedges are accordingly recorded under hedge accounting.

As a result of the rescission of EITF 98-10 (see Note 1), energy commodity inventory is being recorded at the lower of cost or market; however metals inventories continue to be recorded at fair value in accordance with ARB No. 43. As of December 31, 2003 and 2002, trading assets included commodity inventory of $1.4 billion and $2.0 billion, respectively. Note 2 discusses SET acquisitions made in 2002, some of which were affected by EITF 98-10.

Futures and exchange-traded option transactions are recorded as contractual commitments on a trade-date basis and are carried at fair value based on closing exchange quotations. Commodity swaps and forward transactions are accounted for as contractual commitments on a trade-date basis and are carried at fair value derived from dealer quotations and underlying commodity exchange quotations. OTC options purchased and written are recorded on a trade-date basis. OTC options are carried at fair value based on the use of valuation models that utilize, among other things, current interest, commodity and volatility rates, as applicable.

Based on quarterly measurements, the average fair values during 2003 for trading assets and liabilities approximate $5.1 billion and $4.4 billion, respectively. For 2002, the amounts were $4.9 billion and $3.7 billion, respectively.

The carrying values of trading assets and trading liabilities approximate the following:

(Dollars in millions)	December 31, 2003	2002
TRADING ASSETS		
SET:		
Unrealized gains on swaps and forwards	**$1,043**	$1,226
OTC commodity options purchased	**459**	480
Due from trading counterparties	**2,184**	1,279
Due from commodity clearing organizations and clearing brokers	**134**	49
Commodities owned	**1,420**	1,968
Total	**5,240**	5,002
SES:		
Unrealized gains on swaps and forwards	**113**	96
Intercompany eliminations	**(103)**	(34)
Total	**$5,250**	$5,064
TRADING LIABILITIES		
SET:		
Unrealized losses on swaps and forwards	**$1,095**	$ 816
OTC commodity options written	**226**	569
Due to trading counterparties	**2,195**	1,196
Repurchase obligations	**866**	1,511
Commodities not yet purchased	**56**	—
Total	**4,438**	4,092
SES:		
Unrealized losses on swaps and forwards	**35**	6
Intercompany eliminations	**(16)**	(4)
Total	**$4,457**	$4,094

At SET, market risk arises from the potential for changes in the value of physical and financial instruments resulting from fluctuations in prices and basis for natural gas, electricity, petroleum, petroleum products, metals and other commodities. Market risk is also affected by changes in volatility and liquidity in markets in which these instruments are traded. Market risk for SES from fluctuations in natural gas or electricity prices is reduced by SES' hedging strategy as described above.

SET's credit risk from physical and financial instruments as of December 31, 2003 is represented by their positive fair value after consideration of collateral. Options written do not expose SET to credit risk. Exchange-traded futures and options are not deemed to have significant credit exposure since the exchanges guarantee that every contract will be properly settled on a daily basis. For SES, credit risk is associated with its retail customers.

The following table summarizes the counterparty credit quality and exposure for SET and SES at December 31, 2003 and 2002, expressed in terms of net replacement value. These exposures are net of collateral in the form of customer margin and/or letters of credit of $569 million and $240 million at December 31, 2003 and 2002, respectively.

(Dollars in millions)	December 31, 2003	2002
Counterparty credit quality*		
SET:		
Commodity exchanges	**$ 134**	$ 49
AAA	**5**	69
AA	**310**	194
A	**463**	316
BBB	**345**	559
Below investment grade	**357**	504
Total	**$1,614**	$1,691
SES:		
AA	**$ 6**	$ 8
A	**21**	11
BBB	**26**	24
Below investment grade and not rated	**68**	86
Total	**$ 121**	$ 129

* As determined by rating agencies or internal models intended to approximate rating-agency determinations.

NOTE 11. PREFERRED STOCK OF SUBSIDIARIES

(Dollars in millions, except call/redemption price)	Call/ Redemption Price	December 31, 2003	2002
Not subject to mandatory redemption:			
Pacific Enterprises:			
Without par value, authorized 15,000,000 shares:			
$4.75 Dividend, 200,000 shares outstanding	$100.00	**$ 20**	$ 20
$4.50 Dividend, 300,000 shares outstanding	$100.00	**30**	30
$4.40 Dividend, 100,000 shares outstanding	$101.50	**10**	10
$4.36 Dividend, 200,000 shares outstanding	$101.00	**20**	20
$4.75 Dividend, 253 shares outstanding	$101.00	**—**	—
Total		**80**	80
SoCalGas:			
$25 par value, authorized 1,000,000 shares:			
6% Series, 28,041 shares outstanding		**1**	1
6% Series A, 783,032 shares outstanding		**19**	19
Without par value, authorized 10,000,000 shares		**—**	—
Total		**20**	20
SDG&E:			
$20 par value, authorized 1,375,000 shares:			
5% Series, 375,000 shares outstanding	$ 24.00	**8**	8
4.5% Series, 300,000 shares outstanding	$ 21.20	**6**	6
4.4% Series, 325,000 shares outstanding	$ 21.00	**7**	7
4.6% Series, 373,770 shares outstanding	$ 20.25	**7**	7
Without par value:			
$1.70 Series, 1,400,000 shares outstanding	$ 25.85	**35**	35
$1.82 Series, 640,000 shares outstanding	$ 26.00	**16**	16
Total		**79**	79
Total not subject to mandatory redemption		**179**	179
Subject to mandatory redemption:			
SDG&E:			
Without par value: $1.7625 Series, 950,000 and 1,000,000 shares outstanding at December 31, 2003 and December 31, 2002, respectively	$ 25.00	**24***	25
Total preferred stock		**$203**	$204

* Reclassified to Deferred Credits and Other Liabilities and to Other Current Liabilities.

PE preferred stock is callable at the applicable redemption price for each series, plus any unpaid dividends. The preferred stock is subject to redemption at PE's option at any time upon not less than 30 days' notice, at the applicable redemption price for each series, together with unpaid dividends. All series have one vote per share and cumulative preferences as to dividends, and have a liquidation value of $100 per share plus any unpaid dividends.

None of SoCalGas' preferred stock is callable. All series have one vote per share and cumulative preferences as to dividends, and have a liquidation value of $25 per share, plus any unpaid dividends.

All series of SDG&E's preferred stock have cumulative preferences as to dividends. The $20 par value preferred stock has two votes per share on matters being voted upon by shareholders of SDG&E and a

liquidation value at par, whereas the no-par-value preferred stock is nonvoting and has a liquidation value of $25 per share, plus any unpaid dividends. SDG&E is authorized to issue 10,000,000 shares of no-par-value preferred stock (both subject to and not subject to mandatory redemption). All series are callable at December 31, 2003. The $1.7625 Series has a sinking fund requirement to redeem 50,000 shares at $25 per share per year from 2004 to 2007; the remaining 750,000 shares must be redeemed in 2008. On January 15, 2004, SDG&E redeemed 50,000 shares at $25 per share.

NOTE 12. SHAREHOLDERS' EQUITY AND EARNINGS PER SHARE

The only difference between basic and diluted earnings per share is the effect of common stock options. For 2003, 2002 and 2001, the effect of dilutive options was equivalent to an additional 2,742,000, 1,059,000 and 1,745,000 shares, respectively. This is based on using the treasury stock method, whereby the proceeds from the exercise price are assumed to be used to repurchase shares on the open market at the average market price for the year. The calculation excludes options covering 0.1 million, 6.0 million and 2.1 million shares for 2003, 2002 and 2001, respectively, for which the exercise price was greater than the average market price for common stock during the respective year.

Additional dilution could arise from the Equity Units described below. Through December 31, 2003, the price of the company's common stock was high enough to cause such dilution on only two days and, therefore, the Equity Units had no dilutive effect. On January 31, 2004, the common stock price was $31.14. If the price had averaged that for the full year of 2003, the Equity Units would have reduced the company's earnings per share in 2003 by $0.01.

The company is authorized to issue 750,000,000 shares of no-par-value common stock and 50,000,000 shares of preferred stock.

Excluding shares held by the ESOP, common stock activity consisted of the following:

	2003	2002	2001
Common shares outstanding, January 1	**204,911,572**	204,475,362	201,927,524
Common stock issuance	**16,500,000**	—	—
Savings plan issuance*	**1,436,526**	—	—
Shares released from ESOP	**170,613**	130,486	134,645
Stock options exercised	**1,926,590**	395,788	1,009,948
Long-term incentive plan	**1,359,500**	544,100	777,500
Common stock investment plan**	**728,241**	212,411	762,439
Shares repurchased	**(262,286)**	(818,639)	(76,264)
Shares forfeited and other	**(172,137)**	(27,936)	(60,430)
Common shares outstanding, December 31	**226,598,619**	204,911,572	204,475,362

* In prior years, the plan purchased shares in the open market to cover these contributions.

** Participants in the Direct Stock Purchase Plan may reinvest dividends to purchase newly issued shares.

The payment of future dividends and the amount thereof are within the discretion of the company's board of directors. The CPUC's regulation of the California Utilities' capital structure limits the amounts that are available for dividends and loans to the company from the California Utilities. At December 31, 2003, SDG&E and SoCalGas could have provided a total of $290 million and $175 million, respectively, to Sempra Energy, through dividends and loans. At December 31, 2003, SDG&E and SoCalGas had loans to Sempra Energy net of intercompany payables, of $75 million and $21 million, respectively.

Equity Units

During the second quarter of 2002, the company issued $600 million of Equity Units. Each unit consists of $25 principal amount of the company's 5.60% senior notes due May 17, 2007 and a contract to purchase for $25 on May 17, 2005, between .8190 and .9992 of a share of the company's common stock (with the precise number to be determined by the then-prevailing market price). The number of shares to be issued ranges from 20 million to 24 million. The Equity Units are recorded as Long-Term Debt on the Consolidated Balance Sheets. Through December 31, 2003, $55 million had been charged to the common stock account in connection with the transaction.

Common Stock Offering

On October 14, 2003, Sempra Energy completed a common stock offering of 16.5 million shares priced at $28 per common share, resulting in net proceeds of $448 million. The proceeds were used primarily to pay off short-term debt.

NOTE 13. ELECTRIC INDUSTRY REGULATION

Background

The restructuring of California's electric utility industry has significantly affected the company's electric utility operations, and the power crisis of 2000-2001 caused the CPUC to significantly modify its plan for restructuring the electricity industry. Supply/demand imbalances and a number of other factors resulted in abnormally high electric-commodity prices beginning in mid-2000 and continuing into 2001. This caused SDG&E's customer bills to be substantially higher than normal. These higher prices were initially passed through to customers and resulted in bills that in most cases were double or triple those from 1999 and early 2000. This resulted in several legislative and regulatory responses, including California Assembly Bill (AB) 265. AB 265 imposed a ceiling on the cost of the electric commodity that SDG&E could pass on to its small-usage customers from June 1, 2000 to December 31, 2002.

SDG&E accumulated the amount that it paid for electricity in excess of the ceiling rate in an interest-bearing balancing account (the AB 265 undercollection) and began recovering these amounts in rates charged to customers following the end of the rate-ceiling period. At December 31, 2003, the AB 265 undercollection was $63 million (included in Regulatory Balancing Accounts—Net on the Consolidated Balance Sheets) and is being recovered in current rates.

Another legislative response to the power crisis resulted in the purchase by the DWR of a substantial portion of the power requirements of California's electricity users. Since early 2001, the DWR has procured power for the utility procurement customers of each of the California investor-owned utilities (IOUs) and the CPUC has established the allocation of the power and its related cost responsibility among the IOUs. Beginning on January 1, 2003, the IOUs resumed some of its electric commodity procurement, whereas previously the DWR had been purchasing the IOUs' entire net short position.

Department of Water Resources

The DWR's operating agreement with SDG&E, approved by the CPUC, governs SDG&E's administration of the allocated DWR contracts. The agreement provides that SDG&E is acting as a limited agent on behalf of the DWR in undertaking energy sales and natural gas procurement functions under the DWR contracts allocated to SDG&E's customers. Legal and financial responsibility and risks associated with these activities will continue to reside with the DWR. Therefore, revenues and costs associated with the contracts were not included in the Statements of Consolidated Income during 2003. From February 2001 until December 2002, the DWR was purchasing similar amounts of power for SDG&E; the cost of that power was not included in the Statements of Consolidated Income in 2001

or 2002. The reasonableness of the IOU's administration and dispatch of the allocated contracts will be reviewed by the CPUC in an annual proceeding.

In September 2003, the CPUC approved a $1 billion refund to consumers of the three major California IOUs as a result of the DWR's lowering its revenue requirement for 2003. The refund was returned to customers in the form of a one-time bill credit. SDG&E's portion was 13.51 percent or about $135 million. The bill credit had no effect on SDG&E's net income and net cash flows because customer savings are coming from lower charges by the DWR, and SDG&E is merely transmitting the electricity from the DWR to the customers, without taking title to the electricity.

On January 8, 2004, the CPUC issued a decision on the final true-up of DWR's 2001/2002 energy costs among California's three major investor-owned electric utilities, resulting in SDG&E's customers being allocated $59 million of additional costs. The amount from this true-up is recoverable from ratepayers and will be included with SDG&E's allocated share of DWR's 2004 revenue requirement and incorporated into electric charges for 2004, which are expected to be decided in the first half of 2004. This true-up will have a short-term effect on SDG&E's cash flow but will not otherwise affect its results of operations, since SDG&E merely passes through the costs to its customers.

In October 2003, the CPUC initiated a proceeding to consider a permanent methodology for allocating DWR's Revenue Requirement beginning in 2004 through the remaining life of the DWR contracts. An interim allocation based on the current 2003 methodology was utilized beginning January 1, 2004, and is in effect until a decision is reached on a permanent methodology (expected in the second quarter of 2004). Once a permanent methodology is established, the impacts of the decision will be applied retroactively back to January 1, 2004. This delay could have an effect on SDG&E's rates and cash flows, but not on its net income.

Power Procurement

In October 2001, the CPUC initiated an Order Instituting Ratemaking (OIR) to establish ratemaking mechanisms that would enable California investor-owned electric utilities to resume purchasing electric energy and related services and hedging instruments to fulfill their obligation to serve and meet the needs of their customers. In so doing, the CPUC acknowledged that the utilities desired assurance of more timely regulatory review and cost recovery for their procurement activities and costs. In connection therewith, the OIR directed the IOUs to resume electric commodity procurement to cover their net short energy requirements by January 1, 2003. The net short position is the difference between the amount of electricity needed to cover a utility's customer demand and the power provided by owned generation and existing contracts, including the long-term DWR power contracts allocated to the customers of each IOU by the CPUC (see above).

The OIR also implemented recent legislation regarding procurement and renewables portfolio standards and establishes a process for review and approval of the utilities' long-term (20-year) procurement plans. In December 2002, the CPUC adopted SDG&E's 2003 short-term procurement plan. That plan addressed SDG&E's procurement activities in calendar year 2003, authorized contract terms for up to five years for transactions entered into under the plans, and allowed for the hedging of first quarter 2004 residual net short positions with transactions entered into in 2003. SDG&E was required to purchase approximately 10 percent of its customer requirements in 2003, based on the allocation of the DWR power approved by the CPUC in December 2002. The CPUC authorized SDG&E to acquire a variety of resource types and demand side resources. A semiannual cost review and rate revision mechanism is established, and a trigger is established for more frequent changes if undercollected commodity costs exceed five percent of annual, non-DWR generation revenues, to provide for timely recovery of any undercollections. Approval of SDG&E's 2003 short-term procurement plan provided for SDG&E's return to procurement of its customers' needs on January 1, 2003, consistent with the intent of the legislature and the CPUC.

SDG&E filed its 20-year long-term resource plan covering its anticipated procurement needs between 2004 and 2023 and its short-term procurement plans for its anticipated procurement activities in 2004. In decisions issued in December 2003 and January 2004, the CPUC approved the 2004 procurement plan and provided policy guidance for the filing of an updated 20-year resource plan in the spring of 2004.

On December 18, 2003, the CPUC issued a decision adopting SDG&E's procurement plan for 2004. The decision delayed until 2004 further CPUC direction on comprehensive policy guidance for the IOUs' long-term resource plans. In the decision, the CPUC continued its moratorium (subject to certain exceptions) on the IOUs' ability to deal with their own affiliates in procurement transactions.

SDG&E's 20-year resource plan identified the near-term need for firm capacity resources within its service territory to support transmission grid reliability. As a result, SDG&E issued a Request for Proposals (RFP) for the years 2005-2007 of 69 MW in 2005 increasing to 291 MWs in 2007.

In October 2003, SDG&E filed a motion in the Procurement OIR that now requests the CPUC to authorize SDG&E to enter into five new electric resource contracts. They include:

The 550-megawatt combined-cycle Palomar power plant in Escondido, California to be constructed by SER for completion in 2006.

The 45-MW Ramco combustion turbine which SDG&E is proposing to acquire as a turnkey project and intends to use for intermediate load requirements beginning June 2005.

(SDG&E will not take ownership of these two facilities unless appropriate cost recovery and ratemaking mechanisms are instituted by the CPUC to ensure that SDG&E recovers all reasonable costs of, and a reasonable return on, the investments.)

A power purchase agreement (PPA) to buy up to 570 MW over ten years starting in 2008 from a power plant that Calpine Corporation (Calpine) would complete on its site within SDG&E's service territory. (SDG&E would recommend the Calpine PPA only if the CPUC orders the implementation of certain critical conditions intended to make the Calpine PPA a positive economic benefit to SDG&E's customers.)

One contract each for a demand-response resource and a renewable resource.

The capital cost related to the five contracts proposed by SDG&E is $640 million. Hearings concluded on February 20, 2004, and a decision is expected in May 2004. Given the CPUC's prior denial of the company's request for approval of additional transmissions facilities, the company believes that customer requirements for electricity could not be met without the requested resources or similar additions.

A June 2003 CPUC decision in the Procurement OIR directed each IOU to procure from renewable sources at least one percent of its 2003 total energy sales, increasing to 20 percent by 2017. SDG&E procured four percent of its 2003 total energy sales from renewable sources and existing contracts will increase this to five percent in 2004 and nine percent in 2007. A 2002 CPUC resolution permits the company to credit toward future years' compliance any excess over its one-percent annual requirement.

On July 11, 2003, the CPUC adopted a proposed decision continuing the level of the Direct Access (DA) cost responsibility surcharge (CRS) cap effective July 1, 2003 at 2.7 cents per kilowatt hour (kWh), subject to possible revision in the next DA CRS cap review proceeding. In each periodic DA CRS cap review proceeding, the cap is subject to adjustment to the extent necessary to maintain the goal of refunding to utility customers the full amounts to which they are entitled by the end of the DWR

and PX to recalculate the precise number through their settlement models. California is seeking $8.9 billion in refunds from its electricity suppliers and has appealed the FERC's preliminary findings and requested rehearing of the March 26 order. SET and other power suppliers have joined in appeal of the FERC's preliminary findings and requested rehearing.

SET had established reserves of $29 million for its likely share of the original $1.8 billion. SET is unable to determine its possible share of the additional refund amount. Accordingly, it has not recorded any additional reserves but the company does not believe that any additional amounts that SET may be required to pay would be material to the company's financial position or liquidity.

Manipulation Investigation

The FERC is also investigating whether there was manipulation of short-term energy markets in the West that would constitute violations of applicable tariffs and warrant disgorgement of associated profits. In this proceeding, the FERC's authority is not confined to the October 2, 2000 through June 20, 2001 period relevant to the refund proceeding. In May 2002, the FERC ordered all energy companies engaged in electric energy trading activities to state whether they had engaged in various specific trading activities in violation of the PX and ISO tariffs (generally described as manipulating or "gaming" the California energy markets).

On June 25, 2003, the FERC issued several orders requiring various entities to show cause why they should not be found to have violated California ISO and PX tariffs. First, FERC directed 43 entities, including SET and SDG&E, to show cause why they should not disgorge profits from certain transactions between January 1, 2000 and June 20, 2001 that are asserted to have constituted gaming and/or anomalous market behavior under the California ISO and/or PX tariffs. Second, the FERC directed more than 20 entities, including SET, to show cause why their activities during the period January 1, 2000 to June 20, 2001 did not constitute gaming and/or anomalous market behavior in violation of the tariffs. Remedies for confirmed violations could include disgorgement of profits and revocation of market-based rate authority. The FERC has encouraged the entities to settle the issues and on October 31, 2003, SET agreed to pay $7.2 million in full resolution of these investigations. The entire amount has been recorded as of December 31, 2003. The entire proceeding, including the settlement, is subject to final approval by the FERC, which is expected during 2004. SDG&E and the FERC resolved the matter by SDG&E's paying $28 thousand into a FERC-established fund.

On June 25, 2003, the FERC also determined that it was appropriate to initiate an investigation into possible physical and economic withholding in the California ISO and PX markets. For the purpose of investigating economic withholding, the FERC used an initial screen of all bids exceeding $250 per MW between May 1, 2000 and October 2, 2001. Both SDG&E and SET have received data requests from the FERC staff and have provided responses. The FERC staff will prepare a report to the FERC, which will be the basis to decide whether additional proceedings are warranted. SET and SDG&E believe that their bids and bidding procedures were consistent with ISO and PX tariffs and protocols and applicable FERC price caps. On August 1, 2003, the FERC staff issued an initial report that determined there was no need to further investigate particular entities, including SET, for physical withholding of generation.

NOTE 14. OTHER REGULATORY MATTERS

Natural Gas Industry Restructuring

In December 2001 the CPUC issued a decision related to natural gas industry restructuring (GIR), with implementation anticipated during 2002. On January 12, 2004, after many delays and changes, an ALJ issued a proposed decision that would implement the 2001 decision. The proposed decision would result in revising noncore balancing account treatment to exclude the balancing of SoCalGas' transmission costs; other noncore costs/revenues would continue to be fully balanced until the decision

contract term in 2011. The DA CRS has no impact on SDG&E; however, the surcharge may affect SES' ability to attract and maintain customers in California.

SONGS

Through December 31, 2003, the operating and capital costs of SONGS Units 2 and 3 were recovered through the ICIP mechanism which allowed SDG&E to receive 4.4 cents per kilowatt-hour for SONGS generation. Any differences between these costs and the incentive price affected net income. For the year ended December 31, 2003, ICIP contributed $53 million to SDG&E's net income. Beginning in 2004, the CPUC has provided for traditional rate-making treatment, under which the SONGS ratebase would start over at January 1, 2004, essentially eliminating earnings from SONGS except from future increases in ratebase.

FERC Actions

DWR Contract

On June 25, 2003, the FERC issued orders upholding the company's long-term energy supply contract with the DWR, as well as contracts between the DWR and other power suppliers. The order affirmed a previous FERC conclusion that those advocating termination or alteration of the contract would have to satisfy a "heavy" burden of proof, and cited its long-standing policy to recognize the sanctity of contracts. In the order, the CPUC noted that CPUC and court precedent clearly establish that allegations that contracts have become uneconomic by the passage of time do not render them contrary to the public interest under the Federal Power Act. The CPUC pointed out that the contracts were entered into voluntarily in a market-based environment. The CPUC found no evidence of unfairness, bad faith or duress in the original contract negotiations. It said there was no credible evidence that the contracts placed the complainants in financial distress or that ratepayers will bear an excessive burden. In December 2003, appeals of this matter filed by a number of parties, including the California Energy Oversight Board and the CPUC, were consolidated and assigned to the Ninth Circuit Court of Appeals (the Court). The company expects that the Court will affirm the FERC decision.

Refund Proceedings

The FERC is investigating prices charged to buyers in the PX and ISO markets by various electric suppliers. The FERC is seeking to determine the extent to which individual sellers have yet to be paid for power supplied during the period of October 2, 2000 through June 20, 2001 and to estimate the amounts by which individual buyers and sellers paid and were paid in excess of competitive market prices. Based on these estimates, the FERC could find that individual net buyers, such as SDG&E, are entitled to refunds and individual net sellers, such as SET, are required to provide refunds. To the extent any such refunds are actually realized by SDG&E, they would reduce SDG&E's rate-ceiling balancing account. To the extent that SET is required to provide refunds, they could result in payments by SET after adjusting for any amounts still owed to SET for power supplied during the relevant period (or receipts if refunds are less than amounts owed to SET).

In December 2002, a FERC Administrative Law Judge (ALJ) issued preliminary findings indicating that the California PX and ISO owe power suppliers $1.2 billion (the $3.0 billion that the California PX and ISO still owe energy companies less $1.8 billion that the energy companies charged California customers in excess of the preliminarily determined competitive market clearing prices). On March 26, 2003, the FERC largely adopted the ALJ's findings, but expanded the basis for refunds by adopting a staff recommendation from a separate investigation to change the natural gas proxy component of the mitigated market clearing price that is used to calculate refunds. The March 26 order estimates that the replacement formula for estimating natural gas prices will increase the refund obligations from $1.8 billion to more than $3 billion. The FERC recently released its final instructions, and ordered the ISO

in the next Biennial Cost Allocation Proceeding (BCAP) (see below). On February 11, 2004, a member of the CPUC issued an alternative decision that would vacate the December 2001 decision and defer GIR matters to the Natural Gas Market OIR (see below). A CPUC decision could be issued in March 2004.

Natural Gas Market OIR

The Natural Gas Market OIR was approved on January 22, 2004, and will be addressed in two concurrent phases. The schedule calls for a Phase I decision by summer 2004 and a Phase II decision by the end of 2004. In Phase I the CPUC's objective is to develop a process enabling the CPUC to review and pre-approve new interstate capacity contracts before they are executed. In addition, the California Utilities must submit proposals on any LNG project to which interconnection is planned, providing costs and terms, including access to the pipelines in Mexico. Phase II will primarily address emergency reserves and ratemaking policies. The OIR invites proposals on how utilities should provide emergency reserves consisting of slack intrastate pipeline capacity, contracts for additional capacity on the interstate pipelines and an emergency supply of natural gas storage. The CPUC's objective in the ratemaking policy component of Phase II is to identify and propose changes to policies that create incentives that are consistent with the goal of providing adequate and reliable long-term supplies and that do not conflict with energy efficiency programs. The focus of the Gas OIR is 2006 to 2016. Since GIR (see above) would end in August 2006 and there is overlap between GIR and the Gas OIR issues, a number of parties (including SoCalGas) are advising the CPUC not to implement GIR.

The company believes that regulation needs to consider sufficiently the adequacy and diversity of supplies to California, transportation infrastructure and cost recovery thereof, hedging opportunities to reduce cost volatility, and programs to encourage and reward conservation.

Cost of Service

The California Utilities have filed cost of service applications with the CPUC, seeking rate increases reflecting forecasts of 2004 capital and operating costs. The California Utilities are requesting revenue increases of $121 million. The CPUC's Office of Ratepayer Advocates (ORA) filed its prepared testimony on the applications in August 2003, recommending numerous rate decreases that would reduce annual revenues by $162 million from their current level. The Utility Consumers' Action Network (UCAN), a consumer-advocacy group, has proposed rates for SDG&E and The Utility Reform Network has proposed rates for SoCalGas that would reduce annual revenues by $88 million and $178 million, respectively, from their current level. Hearings concluded in November 2003. On December 19, 2003, settlements were filed with the CPUC that, if approved, would resolve most of the cost of service issues. The SoCalGas settlement was signed by SoCalGas and all parties active in its application. The SDG&E settlement was signed by SDG&E, ORA and other parties, but not by UCAN, the City of Chula Vista and other parties. The CPUC adopted a schedule for briefing and commenting on the proposed settlements that concluded on February 19, 2004. The SoCalGas settlement would reduce rates by $33 million from 2003 rates. The SDG&E settlement would reduce its electric rates by $19.6 million from 2003 rates and increase its natural gas rates by $1.8 million from 2003 rates. As part of the proposed settlement, SDG&E and the ORA would resolve their dispute concerning the allocation of the gain on sale of SDG&E's surplus property in Blythe, California, by increasing SDG&E's forecast of miscellaneous revenues by $1.3 million annually, thereby lowering its retail revenue requirement by that amount. The CPUC may accept one or both of the settlements or may adopt an outcome differing from both of the settlements. Resolution is likely in the second quarter of 2004.

On December 18, 2003, the CPUC issued a decision that creates memorandum accounts as of January 1, 2004, to record the difference between actual revenues and those that are later authorized in the CPUC's final decision in this case. The difference would then be amortized in rates. The

California Utilities have also filed for continuation through 2004 of existing performance-based regulation (PBR) mechanisms for service quality and safety that would otherwise expire at the end of 2003. In January 2004, the CPUC issued a decision that extended 2003 service and safety targets through 2004, but deferred action on applying any rewards or penalties for performance relative to these targets to a decision to be issued later in 2004 in a second phase of these applications discussed below.

The CPUC has established a procedural schedule for the second phase of these applications, addressing issues related to PBR (see below). The procedural schedule calls for hearings to be held in June 2004, with a decision during 2004. The scope of the second phase includes: (a) a formula for setting authorized cost of service for 2005 and succeeding years until the next full Cost of Service proceeding is scheduled; (b) whether and how rates should be adjusted if earned returns vary from authorized returns; and (c) prospective targets and rewards/penalties for service quality and safety.

An October 2001 decision denied the California Utilities' request to continue equal sharing between ratepayers and shareholders of the estimated savings for the 1998 business combination that created Sempra Energy and, instead, ordered that all of the estimated 2003 merger savings go to ratepayers. In 2002, merger savings to shareholders for the fourth quarter and for the year were $4 million and $17 million, respectively, at SoCalGas and $2 million and $8 million, respectively, at SDG&E. Pursuant to the decision, SoCalGas and SDG&E will return the 2003 merger savings related to natural gas operations of $83 million and $15 million, respectively, to ratepayers over a twelve-month period beginning January 1, 2004. The merger savings related to electric operations were previously returned to ratepayers.

Performance-Based Regulation

To promote efficient operations and improved productivity and to move away from reasonableness reviews and disallowances, the CPUC adopted PBR for SDG&E effective in 1994 and for SoCalGas effective in 1997. PBR has resulted in modification to the general rate case and certain other regulatory proceedings for the California Utilities. Under PBR, regulators require future income potential to be tied to achieving or exceeding specific performance and productivity goals, rather than relying solely on expanding utility plant to increase earnings.

PBR consists of three primary components. The first is a mechanism to adjust rates in years between general rate cases or cost of service cases. Similar to the pre-PBR Attrition Proceeding, it annually adjusts general rates from those of the prior year to provide for inflation, changes in the number of customers and efficiencies.

The second component is a mechanism whereby any earnings in excess of those authorized plus a narrow band above that are shared with customers in varying degrees depending upon the amount of the additional earnings.

The third component consists of a series of measures of utility performance. Generally, if performance is outside of a band around the specified benchmark, the utility is rewarded or penalized certain dollar amounts.

The three areas that are eligible for PBR rewards or penalties are operational incentives based on measurements of safety, reliability and customer satisfaction; demand-side management (DSM) rewards based on the effectiveness of the programs; and natural gas procurement rewards or penalties. The CPUC is also considering a new reward/penalty related to electricity procurement, now that the utilities are resuming this activity. However, as noted under Cost of Service, Phase II of the California Utilities' current cost of service proceeding is not scheduled for completion until late 2004. As

a result, it is possible that some or all of the safety, reliability and customer satisfaction incentive mechanisms (i.e., those that are reviewed in the Cost of Service proceeding) would not be in effect for 2004. Even if that were to occur, it is not expected that the effect would be other than a one-year moratorium on the mechanisms.

In July 2003, the CPUC issued a decision relative to SDG&E's Year 11 natural gas PBR application, which will permanently extend the PBR mechanism with some modification. The decision approved the Joint Parties' Motion for an Order Adopting Settlement Agreement filed by SDG&E and the ORA, which will apply to Year 10 and beyond. The effect of the modifications is to reduce slightly the potential size of future PBR rewards or penalties.

The Gas Cost Incentive Mechanism (GCIM) allows SoCalGas to receive a share of the savings it achieves by buying natural gas for customers below monthly benchmarks. The mechanism permits full recovery of all costs within a tolerance band above the benchmark price and refunds savings within a tolerance band below the benchmark price. The costs outside the tolerance band are shared between customers and shareholders.

Since the 1990s, IOUs have been eligible to earn awards for implementing and administering energy conservation and efficiency programs. The California Utilities have offered these programs to customers and have consistently achieved significant earnings from the program. On October 16, 2003, the CPUC issued a decision that the pre-1998 DSM earnings proceeding would not be reopened, leaving the earnings mechanism unchanged. The CPUC may adjust amounts determined pursuant to the earnings mechanism consistent with the application of known, standard measurement and verification protocols.

The CPUC has consolidated the 2000, 2001 and 2002 award applications. The 2003 award applications were filed on May 1, 2003. On May 2, 2003, the CPUC released RFPs to conduct a review of the IOUs' studies and reported program milestones/accomplishments used as the basis for the awards claims and program expenditures. The review should be completed in the second quarter of 2004. Additionally, the low-income awards will be subject to an independent review expected to commence in 2005. The majority of the outstanding claims are on hold pending completion of the independent review.

Incentive Awards Approved in 2003

PBR and GCIM rewards are not included in the company's earnings before CPUC approval is received. The following table reflects awards approved in 2003 (dollars in millions):

Program	SoCalGas	SDG&E	Total
GCIM/Natural Gas PBR	$48.2	$ 5.3	$53.5
Distribution/Other PBR	1.1	18.2	19.3
Total	$49.3	$23.5	$72.8

Pending Incentive Awards

At December 31, 2003, the following performance incentives were pending CPUC approval and, therefore, were not included in the company's earnings (dollars in millions):

Program	SoCalGas	SDG&E	Total
GCIM/Natural Gas PBR	$ 6.3	$ 1.9	$ 8.2
DSM/Energy Efficiency*	9.8	35.6	45.4
Total	$16.1	$37.5	$53.6

* Dollar amounts shown do not include interest, franchise fees or uncollectible amounts.

Cost of Capital

Effective January 1, 2003, SoCalGas' authorized rate of return on common equity (ROE) is 10.82 percent and its return on ratebase (ROR) is 8.68 percent. Effective January 1, 2003, SDG&E's authorized ROE is 10.9 percent and its ROR is 8.77 percent, for SDG&E's electric distribution and natural gas businesses. The electric-transmission cost of capital is determined under a separate FERC proceeding discussed below. These rates will continue to be effective until market interest-rate changes are large enough to trigger an automatic adjustment or until the CPUC orders a periodic review.

The objective of SDG&E's market-indexed capital adjustment mechanism is to revise SDG&E's rates to reflect changes in the six-month average of double-A rated utility bond rates, without lengthy Commission proceedings. The benchmark average is currently 7.24 percent, the six-month average at September 30, 2002, the year of SDG&E's last cost of capital proceeding. If in any year the difference between the current six-month average at September 30th and the benchmark exceeds 100 basis points, SDG&E's authorized ROE is adjusted by one-half of the difference, and the embedded costs of debt and preferred equity are adjusted to current levels. In addition, the triggering six-month average becomes the new benchmark until another automatic adjustment occurs. The six-month average was 6.32 percent at September 30, 2003 and, therefore, no triggering has occurred. The rate has not changed significantly since then.

SoCalGas' automatic adjustment mechanism provides for a trigger in any month when the 12-month trailing average of 30-year Treasury bond rates varies by greater than 150 basis points from the benchmark, and the current Global Insight forecast of the 30-year Treasury bond rate 12 months ahead varies by greater than 150 basis points from the benchmark. When these criteria are met, SoCalGas' authorized ROE is adjusted by one-half of the difference between the trailing 12-month average and the benchmark, and the embedded costs of debt and preferred equity are adjusted to current levels. Any time an automatic adjustment occurs, the new trailing 12-month average becomes the new benchmark. The benchmark is currently 5.38 percent, the 12-month trailing average of the 30-year Treasury bond as of October 2002. At December 31, 2003, the 12-month average of the 30-year Treasury bond was 4.92 percent and the estimated Global Insight year-ahead forecast was 5.90 percent and, therefore, no triggering has occurred. The rates have not changed significantly since then.

Border Price Investigation

In November 2002, the CPUC instituted an investigation into the Southern California natural gas market and the price of natural gas delivered to the California-Arizona border between March 2000 and May 2001. If the investigation determines that the conduct of any party to the investigation contributed to the natural gas price spikes, the CPUC may modify the party's natural gas procurement incentive mechanism, reduce the amount of any shareholder award for the period involved, and/or order the party to issue a refund to ratepayers. On December 10, 2003, Southern California Edison filed testimony alleging that SoCalGas significantly contributed to the price spikes and exercised market power and recommended to the CPUC that SoCalGas divest its storage assets and revise its GCIM to an incentive mechanism that would simply reward SoCalGas if it managed to procure natural gas supplies in the producing basins at a price below market. Hearings are scheduled to begin in late March 2004 with a decision expected by late 2004. The company believes that the CPUC will find that SoCalGas acted in the best interests of its core customers.

Biennial Cost Allocation Proceeding

The BCAP determines the allocation of authorized costs between customer classes for natural gas transportation service provided by the California Utilities and adjusts rates to reflect variances in

customer demand as compared to the forecasts previously used in establishing transportation rates. SoCalGas and SDG&E filed with the CPUC their 2005 BCAP applications in September 2003, requesting updated transportation rates effective January 1, 2005. The most recent BCAP decision allocating the California Utilities non-commodity natural gas costs of service and revising their respective natural gas transportation rates and rate designs was issued in April 2000 and is still in effect. In November 2003, an Assigned Commissioner Ruling delayed the current BCAP applications until a decision is issued in the GIR implementation proceeding discussed above. As a result, SoCalGas is required to amend its BCAP application within 21 days of a decision in the GIR and SDG&E is required to amend its BCAP application seven days thereafter. As a result of the deferrals and the forecasted significant decline in noncore gas throughput on SoCalGas' system, in December 2002 the CPUC issued a decision approving 100 percent balancing account protection for SoCalGas' risk on local transmission and distribution revenues from January 1, 2003 until the CPUC issues its next BCAP decision. SoCalGas is seeking to continue this balancing account protection through 2006. A CPUC decision on GIR could result in revising noncore balancing account treatment to exclude the balancing of transmission costs; other noncore costs/revenues would continue to be fully balanced until the BCAP decision.

CPUC Investigation of Energy-Utility Holding Companies

The CPUC has initiated an investigation into the relationship between California's IOUs and their parent holding companies. Among the matters to be considered in the investigation are utility dividend policies and practices and obligations of the holding companies to provide financial support for utility operations under the agreements with the CPUC permitting the formation of the holding companies. In January 2002 the CPUC issued a decision to clarify under what circumstances, if any, a holding company would be required to provide financial support to its utility subsidiaries. The CPUC broadly determined that it would require the holding company to provide cash to a utility subsidiary to cover its operating expenses and working capital to the extent they are not adequately funded through retail rates. This would be in addition to the requirement of holding companies to cover their utility subsidiaries' capital requirements, as the IOUs have previously acknowledged in connection with the holding companies' formations. In January 2002 the CPUC ruled on jurisdictional issues, deciding that it had jurisdiction to create the holding company system and, therefore, retains jurisdiction to enforce conditions to which the holding companies had agreed. The company's request for rehearing on the issues was denied by the CPUC and the company subsequently filed appeals in the California Court of Appeal. On November 26, 2003 the California Court of Appeal agreed to hear the company's appeal. Oral argument is set for March 5, 2004.

CPUC Investigation of Compliance with Affiliate Rules

In February 2003, the CPUC opened an investigation of the business activities of SDG&E, SoCalGas and Sempra Energy to determine if they have complied with statutes and CPUC decisions in the management, oversight and operations of their companies. In September 2003, the CPUC suspended the procedural schedule until it completes an independent audit to evaluate energy-related holding company systems and affiliate activities undertaken by Sempra Energy within the service territories of SDG&E and SoCalGas. The audit will cover years 1997 through 2003, is expected to commence in March 2004 and should be completed by the end of 2004. The scope of the audit will be broader than the annual affiliate audit. In accordance with existing CPUC requirements, the California Utilities' transactions with other Sempra Energy affiliates have been audited by an independent auditing firm each year, with results reported to the CPUC, and there have been no material adverse findings in those audits.

FERC Standards of Conduct

On November 25, 2003, the FERC established standards of conduct governing the relationship between transmission providers and their energy affiliates. They broaden the definition of an energy affiliate. Under the standards, SDG&E is a transmission provider and SoCalGas is an energy affiliate of SDG&E. The standards require transmission providers to offer service to all customers on a non-discriminatory basis. SER, SES and SET are also considered energy affiliates of SDG&E, and, among other things, SDG&E must apply the standards of conduct prohibiting unduly preferential information sharing with the energy affiliates. Impacts, if any, of the standards are being determined for SEI and SER.

FERC Transmission Cost of Service

On May 2, 2003, the FERC accepted SDG&E's request for modification of its Transmission Owner Tariff to adopt a transmission rate formula that would allow SDG&E to recover its actual prudent costs for transmission service. New transmission rates, which are subject to refund based on the FERC's final order, became effective October 1, 2003.

On December 18, 2003, the FERC approved the transmission formula, with rates effective October 1, 2003, whereby SDG&E's rates would be adjusted annually to cover actual prudent costs, including an ROE of 11.25 percent on its actual equity as of December 31 of the prior year. SDG&E's revenue requirements for its retail customers for the initial 12-month period beginning October 1, 2003, will be $142.1 million. SDG&E will fully recover its cancelled Valley-Rainbow Project costs of $19 million over a ten-year amortization period, with no return component. The transmission rate formula will be in effect through June 30, 2007.

Recovery of Certain Disallowed Transmission Costs

In August 2002 the FERC issued Opinion No. 458, which effectively disallowed SDG&E's recovery of the differentials between certain payments to SDG&E by its co-owners of the Southwest Powerlink under the Participation Agreements and charges assessed to SDG&E under the ISO FERC tariff for transmission line losses and grid management charges related to energy schedules of Arizona Public Service Co. (APS) and the Imperial Irrigation District (IID), its Southwest Powerlink co-owners. As a result, SDG&E is incurring unreimbursed costs of $4 million to $8 million per year. On November 17, 2003, SDG&E petitioned the United States Court of Appeals for review of these FERC orders and argued that the disallowed costs should be allowed for recovery through the Transmission Revenue Balancing Account Adjustment. On February 12, 2004, on the FERC's motion, the court remanded the case back to the FERC for further consideration, "based on the FERC's representation that it intends to act expeditiously on remand." The FERC has not yet issued further orders in this matter.

In a separate but related matter, on July 6, 2001, SDG&E filed an arbitration claim against the ISO, claiming the ISO should not charge SDG&E for the transmission losses attributable to energy schedules on the APS and IID shares of the Southwest Powerlink. As of October 2003 amounts under the claim totaled $22 million, including interest. The independent arbitrator found in SDG&E's favor on this matter. The ISO appealed this result to the FERC and a FERC decision is expected in 2004. SDG&E has also commenced a private arbitration to reform the Participation Agreements to remove prospectively SDG&E's obligation to provide services giving rise to unreimbursed ISO tariff charges.

Southern California Fires

Several major wildfires that began on October 26, 2003 severely damaged some of SDG&E's infrastructure, causing a significant number of customers to be without utility services. On October 27,

2003, Governor Gray Davis declared a "state of emergency" for counties within SoCalGas' and SDG&E's service territory.

The declaration of a state of emergency authorizes a public utility to establish a catastrophic event memorandum account (CEMA) to record all incremental costs (costs not already included in rates) associated with the repair of facilities and the restoration of service. Electric distribution and natural gas related costs are recovered through the CEMA. Electric transmission related costs are recovered through the annual true-up FERC proceeding. The CEMA related costs are recoverable in rates separate from ordinary costs currently recovered in rates. The CPUC is required to hold expedited hearings in response to the utilities' request for recovery. Total fire-related costs are estimated to be $70 million and $5 million for SDG&E and SoCalGas, respectively, with $60 million and $1 million, respectively, incurred during 2003, the majority of which were capital related. At December 31, 2003, the CEMA account included $14 million of incremental operating and maintenance costs. The company expects to file a CEMA application sometime in 2004. The company expects no significant effect on earnings from the fires.

NOTE 15. COMMITMENTS AND CONTINGENCIES

Natural Gas Contracts

The California Utilities buy natural gas under short-term contracts. Short-term purchases are from various Southwest U.S. and Canadian suppliers and are primarily based on monthly spot-market prices. The California Utilities transport natural gas under long-term firm pipeline capacity agreements that provide for annual reservation charges, which are recovered in rates. SoCalGas has commitments with pipeline companies for firm pipeline capacity under contracts that expire at various dates through 2007.

SDG&E has long-term natural gas transportation contracts with various interstate pipelines that expire on various dates between 2004 and 2023. SDG&E currently purchases natural gas on a spot basis to fill its long-term pipeline capacity and purchases additional spot market supplies delivered directly to California for its remaining requirements. SDG&E continues its ongoing assessment of its long-term pipeline capacity portfolio, including the release of a portion of this capacity to third parties.

At December 31, 2003, the future minimum payments under natural gas contracts were:

(Dollars in millions)	Storage and Transportation	Natural Gas	Total
2004	$221	$767	$ 988
2005	211	11	222
2006	125	11	136
2007	21	2	23
2008	20	3	23
Thereafter	207	—	207
Total minimum payments	$805	$794	$1,599

Total payments under natural gas contracts were $2.2 billion in 2003, $1.4 billion in 2002 and $2.6 billion in 2001.

Purchased-Power Contracts

In January 2001, the California Assembly passed AB X1 to allow the DWR to purchase power under long-term contracts for the benefit of California consumers. In accordance with AB X1, SDG&E entered

into an agreement with the DWR under which the DWR purchased SDG&E's full net short position (the power needed by SDG&E's customers, other than that provided by SDG&E's nuclear generating facilities or its previously existing purchased-power contracts) through December 31, 2002. Starting on January 1, 2003, SDG&E and the other IOUs resumed their electric commodity procurement function based on a CPUC decision issued in October 2002. In April 2003, the CPUC approved an operating agreement between the DWR and SDG&E that bestows upon SDG&E the role of a limited agent on behalf of the DWR in undertaking energy sales and natural gas procurement functions for the DWR contracts. For additional discussion of this matter see Note 13.

For 2004, SDG&E expects to receive 49 percent of its customer power requirement from DWR allocations. Of the remaining requirements, SONGS is expected to account for 21 percent, long-term contracts for 19 percent and spot market purchases for 11 percent. The contracts expire on various dates through 2025. Prior to January 1, 2001, the cost of these contracts was recovered by bidding them into the PX and receiving revenue from the PX for bids accepted. As of January 1, 2001, in compliance with a FERC order prohibiting sales to the PX, SDG&E no longer bids those contracts into the PX. Those contracts are now used to serve customers in compliance with a CPUC order. In addition, during 2002 SDG&E entered into contracts which will provide five percent of its 2004 total energy sales from renewable sources. These contracts expire on various dates through 2021.

At December 31, 2003, the estimated future minimum payments under the long-term contracts (not including the DWR allocations) were:

(Dollars in millions)	
2004	$ 214
2005	224
2006	233
2007	240
2008	218
Thereafter	2,235
Total minimum payments	$3,364

The payments represent capacity charges and minimum energy purchases. SDG&E is required to pay additional amounts for actual purchases of energy that exceed the minimum energy commitments. Excluding DWR-allocated contracts, total payments under the contracts were $396 million in 2003, $235 million in 2002 and $512 million in 2001.

Leases

The company has leases (primarily operating) on real and personal property expiring at various dates from 2004 to 2045. Certain leases on office facilities contain escalation clauses requiring annual increases in rent ranging from 3 percent to 6 percent. The rentals payable under these leases are determined on both fixed and percentage bases, and most leases contain extension options which are exercisable by the company. The company also has long-term capital leases on real property. Property, plant and equipment included $36 million at December 31, 2003 and $35 million at December 31, 2002, related to these leases. The associated accumulated amortization was $23 million and $21 million, respectively. SDG&E terminated its capital lease agreement for nuclear fuel in mid-2001 and now owns its nuclear fuel.

At December 31, 2003, the minimum rental commitments payable in future years under all noncancellable leases were as follows:

(Dollars in millions)	Operating Leases	Capitalized Leases
2004	$ 97	$ 4
2005	85	3
2006	77	1
2007	76	1
2008	69	1
Thereafter	213	1
Total future rental commitments	$617	11
Imputed interest (6% to 10%)		(3)
Net commitments		$ 8

In connection with the quasi-reorganization described in Note 1, PE recorded liabilities of $102 million to adjust to fair value the operating leases related to its headquarters and other facilities at December 31, 1992. The remaining amount of these liabilities was $35 million at December 31, 2003. These leases are included in the above table at the amounts provided in the lease.

Rent expense for operating leases totaled $98 million in 2003, $90 million in 2002 and $92 million in 2001. Depreciation expense for capitalized leases is included in Depreciation and Amortization on the Statements of Consolidated Income.

Global Construction Projects

Global has several subsidiaries which have developed or are in the process of constructing various capital projects in the United States and in Mexico. The following is a summary of construction projects developed or under development by the respective business units.

SER

SER acquires, develops and operates power plants throughout the U.S. and Mexico. As of the end of 2003, SER had five power plants in operations.

The 1,250-MW Mesquite Power plant commenced operations in two phases during 2003; the first phase of commercial operations began in June 2003 and the second phase started in December 2003. See further discussion on the Mesquite Power plant in Notes 1 and 2.

In the third quarter of 2003, SER completed construction and commenced operations of its $350 million 600-MW TDM power plant. The environmental issues concerning this facility are described under "Litigation" and in Note 2. TDM's natural gas from Ehrenberg, Arizona to the interconnection with Gasoducto Bajanorte is being delivered via the North Baja Pipeline. The transportation is provided through an agreement between SER and North Baja Pipeline LLC. Under the agreement, SER is obligated to pay a monthly reservation charge for the transport of certain quantities over a 20-year period. The future commitments related to this contract are $83 million.

In the third quarter of 2003, SER completed construction of the 550-MW Elk Hills power project located in Bakersfield, California. SER owns 50 percent of Elk Hills and has invested $219 million in Elk Hills through December 31, 2003.

On October 31, 2002, SER acquired the 305-MW Twin Oaks Power plant. In connection with the acquisition, SER also assumed a contract which includes annual commitments to purchase lignite coal either until an aggregate minimum volume has been achieved or through 2025. As of December 31, 2003, SER's future minimum payments under the lignite coal agreement totaled $455 million, for which payments of $29 million are due for 2004, $29 million for 2005, $25 million for 2006, $25 million for 2007, $25 million for 2008 and $322 million thereafter. The minimum payments have been adjusted for allowed shortfalls and 90 percent minimum contract requirements under the contract.

In August 2003, SER obtained approvals by the California Energy Commission for the company's planned 550-MW Palomar power plant in Escondido, California. The estimated two-year construction project will commence when power contracts for the project have been signed. SER currently is seeking contracts that would support advancement of the project. In January 2004, SDG&E contracted with SER to purchase the power plant from SER when construction is complete in 2006. The plant will then be owned and operated by SDG&E under CPUC regulation.

As of December 31, 2003, SER has no additional construction commitments concerning the facilities described above but has additional commitments of $7 million related to two natural gas turbines for use in future power plant development.

SELNG

SELNG is in the process of developing Energía Costa Azul, a major new LNG receiving terminal that will bring natural gas supplies into northwestern Mexico and Southern California. This is discussed in Note 2.

In April 2003, SELNG acquired Cameron LNG for $36 million. Additional payments are contingent on meeting certain benchmarks and milestones and the performance of the project. At December 31, 2003, the company has recorded a liability of $30 million related to this matter. The total cost of the project is expected to be about $700 million. The project could begin commercial operations as early as 2007.

SELNG currently leases land in Hackberry, Louisiana for the development of the Cameron LNG terminal. In connection with the purchase of Cameron LNG, SELNG and the lessor agreed to certain lease amendments, including an increase in the annual rent, addition of wharfage fees and extension of the lease term for another 30 years. The lease amendments are contingent upon obtaining project financing or commencement of construction. As of December 31, 2003, SELNG is still operating under the original land lease, which is up for renewal in February 2005. Accordingly, rent payments subsequent to January 2005 are not included in the table of future minimum rental payment obligations. Should the terms of the amended lease be triggered, total rent payments and wharfage fees would be $38 million over 30 years. See Note 2 for further discussion on the LNG facilities.

SEI

In 2002, SEI completed construction of the 140-mile Gasoducto Bajanorte Pipeline that connects the Rosarito Pipeline south of Tijuana, Mexico with a pipeline built by PG&E Corporation (PG&E) that connects to Arizona. The 30-inch pipeline can deliver up to 500 million cubic feet per day of natural gas to new generation facilities in Baja California, including SER's TDM power plant discussed above. Capacity on the pipeline is over 90 percent subscribed. The company had no additional construction costs or other commitments for this pipeline at December 31, 2003.

SER's Contract with the DWR

In May 2001, SER entered into a ten-year agreement with the DWR to supply up to 1,900 MW of power to the state. SER may, but is not obligated to, deliver this electricity from its portfolio of plants in the western United States and Baja California, Mexico. If SER elects to use these plants to supply the DWR, those sales would comprise more than two-thirds of the projected capacity of the plants. Subsequent to the state's signing of this contract and electricity-supply contracts with other vendors, various state officials have contended that the rates called for by the contracts are too high. These rates substantially exceed current spot-market prices for electricity, but are substantially lower than those prevailing at the time the contracts were signed. Information concerning the validity of this contract is provided under "Litigation—DWR Contract." Information concerning the FERC's orders upholding this contract and the pending appeal is provided in FERC Actions in Note 13.

Impact of Direct Access on SES

On March 21, 2002, the CPUC affirmed its decision prohibiting new direct access contracts after September 20, 2001, but rejected a proposal to make the prohibition retroactive to July 1, 2001. Contracts in place as of September 20, 2001 may be renewed or assigned to new parties. On November 7, 2002, the CPUC issued a decision adopting DA exit fees with an interim cap of 2.7 cents per kWh for rates effective January 1, 2003. The CPUC is conducting further proceedings to determine whether, and to what extent, the interim cap should be revised after July 1, 2003. The CPUC's decisions concerning direct access could affect the motivation of potential customers to enter into contracts for SES to sell them electricity in California.

Environmental Issues

The company has identified no significant environmental issues outside the United States, except for the additional environmental impact studies the DOE is conducting of the TDM power plant. Additional information regarding the environmental studies is provided below under "Litigation." The following discussion is related to environmental matters within the United States.

The company's operations are subject to federal, state and local environmental laws and regulations governing hazardous wastes, air and water quality, land use, solid waste disposal and the protection of wildlife. Most of the environmental issues faced by the company have occurred at the California Utilities. However, now that SER owns and operates several power plants and SELNG is developing LNG regasification terminals, additional environmental issues may arise. As applicable, appropriate and relevant, these laws and regulations require that the company investigate and remediate the effects of the release or disposal of materials at sites associated with past and present operations, including sites at which the company has been identified as a Potentially Responsible Party (PRP) under the federal Superfund laws and comparable state laws. Costs incurred at the California Utilities to operate the facilities in compliance with these laws and regulations generally have been recovered in customer rates.

Significant costs incurred to mitigate or prevent future environmental contamination or extend the life, increase the capacity, or improve the safety or efficiency of property utilized in current operations are capitalized. The company's capital expenditures to comply with environmental laws and regulations were $14 million in 2003, $8 million in 2002 and $6 million in 2001. The cost of compliance with these regulations over the next five years is not expected to be significant.

At the California Utilities, costs that relate to current operations or an existing condition caused by past operations are generally recorded as a regulatory asset due to the expectation that these costs will be recovered in rates.

The environmental issues currently facing the company or resolved during the latest three-year period include investigation and remediation of the California Utilities' manufactured-gas sites (29 completed as of December 31, 2003 and 16 to be completed), cleanup at SDG&E's former fossil fuel power plants (all sold in 1999 and actual or estimated cleanup costs included in the transactions), cleanup of third-party waste-disposal sites used by the company, which has been identified as a PRP (investigations and remediations are continuing) and mitigation of damage to the marine environment caused by the cooling-water discharge from SONGS (the requirements for enhanced fish protection, a 150-acre artificial reef and restoration of 150 acres of coastal wetlands are in process).

Environmental liabilities are recorded when the company's liability is probable and the costs are reasonably estimable. In many cases, however, investigations are not yet at a stage where the company has been able to determine whether it is liable or, if the liability is probable, to reasonably estimate the amount or range of amounts of the cost or certain components thereof. Estimates of the company's liability are further subject to other uncertainties, such as the nature and extent of site contamination, evolving remediation standards and imprecise engineering evaluations. The accruals are reviewed periodically and, as investigations and remediation proceed, adjustments are made as necessary. At December 31, 2003, the company's accrued liability for environmental matters was $61.4 million, of which $48.7 million related to manufactured-gas sites, $10.5 million to cleanup at SDG&E's former fossil-fueled power plants, $2.1 million to waste-disposal sites used by the company (which has been identified as a PRP) and $0.1 million to other hazardous waste sites. The accruals for the manufactured-gas and waste-disposal sites are expected to be paid ratably over the next three years. The accruals for SDG&E's former fossil-fueled power plants are expected to be paid ratably over the next two years.

Nuclear Insurance

SDG&E and the other owners of SONGS have insurance to respond to nuclear liability claims related to SONGS. The insurance policy provides $300 million in coverage, which is the maximum amount available. In addition to this primary financial protection, the Price-Anderson Act provides for up to $10.6 billion of secondary financial protection if the liability loss exceeds the insurance limit. Should any of the licensed/commercial reactors in the United States experience a nuclear liability loss which exceeds the $300 million insurance limit, all utilities owning nuclear reactors could be assessed under the Price-Anderson Act to provide the secondary financial protection. SDG&E and the other co-owners of SONGS could be assessed up to $201 million under the Price- Anderson Act. SDG&E's share would be $40 million unless a default were to occur by any other SONGS co-owner. In the event the secondary financial protection limit were insufficient to cover the liability loss, the Price-Anderson Act provides for Congress to enact further revenue-raising measures to pay claims. These measures could include an additional assessment on all licensed reactor operators.

SDG&E and the other owners of SONGS have $2.75 billion of nuclear property, decontamination and debris removal insurance. The coverage also provides the SONGS owners up to $490 million for outage expenses/replacement power incurred because of accidental property damage. This coverage is limited to $3.5 million per week for the first 52 weeks, and $2.8 million per week for up to 110 additional weeks. There is a deductible waiting period of 12 weeks prior to receiving indemnity payments. The insurance is provided through a mutual insurance company owned by utilities with nuclear facilities. Under the policy's risk sharing arrangements, insured members are subject to retrospective premium assessments if losses at any covered facility exceed the insurance company's surplus and reinsurance funds. Should there be a retrospective premium call, SDG&E could be assessed up to $7.4 million.

Both the nuclear liability and property insurance programs include industry aggregate limits for terrorism-related SONGS losses, including replacement power costs.

Litigation

During 2003, the company recorded $49 million of after-tax charges related to litigation costs and a SoCalGas sublease. Management believes that none of these matters will have further material adverse effect on the company's financial condition or results of operations. Except for the matters referred to below, neither the company nor its subsidiaries are party to, nor is their property the subject of, any material pending legal proceedings other than routine litigation incidental to their businesses.

DWR Contract

In May 2003, the San Diego Superior Court granted SER's motion for summary judgment on its complaint regarding its contract with the DWR (and the DWR's cross-complaint seeking to void the 10-year energy-supply contract). The court determined that "(a) Sempra is entitled to provide electrical energy from any source, including Market Sources, (b) Sempra is not in breach of the Agreement as framed by the pleadings in this matter, (c) DWR is obligated to take delivery and pay for deliveries under the Agreement, and (d) Sempra has no obligation to complete any specific Project." The DWR filed a motion for a new trial claiming irregularities in the Court's judgment. The Court subsequently clarified its earlier summary judgment ruling and effectively denied the motion for new trial. An amended judgment was entered by the Court. The DWR has filed a notice of appeal on the judgments and the Court's clarification. A decision by the appellate court is expected sometime during 2005. The DWR continues to accept all scheduled power from SER and, although it has disputed billings in an immaterial amount and the manner of certain deliveries, it has paid all amounts that have been billed under the contract.

Antitrust Litigation

Class-action and individual lawsuits filed in 2000 and currently consolidated in San Diego Superior Court seek damages, alleging that Sempra Energy, SoCalGas and SDG&E, along with El Paso Energy Corp. (El Paso) and several of its affiliates, unlawfully sought to control natural gas and electricity markets. In March 2003, plaintiffs in these cases and the applicable El Paso entities announced that they had reached a $1.5 billion settlement, of which $125 million is allocated to customers of the California Utilities. The Court approved that settlement in December 2003. The proceeding against Sempra Energy and the California Utilities has not been settled and continues to be litigated.

Natural Gas Cases: Similar lawsuits have been filed by the Attorneys General of Arizona and Nevada, alleging that El Paso and certain Sempra Energy subsidiaries unlawfully sought to control the natural gas market in their respective states. In April 2003, Sierra Pacific Resources and its utility subsidiary Nevada Power filed a lawsuit in U.S. District Court in Las Vegas against major natural gas suppliers, including Sempra Energy, the California Utilities and other company subsidiaries, seeking damages resulting from an alleged conspiracy to drive up or control natural gas prices, eliminate competition and increase market volatility, breach of contract and wire fraud. On January 27, 2004, the U.S. District Court dismissed the Sierra Pacific Resources case against all of the defendants, determining that this is a matter for the FERC.

Electricity Cases: Various lawsuits, which seek class-action certification, allege that Sempra Energy and certain company subsidiaries (SDG&E, SET and SER, depending on the lawsuit) unlawfully manipulated the electric-energy market. In January 2003, the applicable federal court granted a motion to dismiss a similar lawsuit on the grounds that the claims contained in the complaint were subject to the Filed Rate Doctrine and were preempted by the Federal Power Act. That ruling has been appealed in the Ninth Circuit Court of Appeals, which is expected to hear the appeal in the first quarter of 2004. Similar suits filed in Washington and Oregon were voluntarily dropped by the plaintiffs without court intervention in June 2003. In addition, in May 2003, the Port of Seattle filed an action alleging that a number of energy companies, including Sempra Energy, SER and SET, unlawfully manipulated the

electric energy market and committed wire fraud. That action has been transferred to San Diego Federal District Court and is currently pending a motion to dismiss on the grounds that the claims contained in the complaint were subject to the Filed Rate Doctrine and were preempted by the Federal Power Act.

SER, SET and SDG&E, along with all other sellers in the western power market, have been named defendants in a complaint filed at the FERC by the California Attorney General's office seeking refunds for electricity purchases based on alleged violations of FERC tariffs. The FERC has dismissed the complaint. The California Attorney General has filed an appeal in the 9th Circuit.

Price Reporting Practices

In the fourth quarter of 2002, Sempra Energy and SoCalGas were named as defendants in a lawsuit filed in Los Angeles Superior Court against various trade publications and other energy companies alleging that energy prices were unlawfully manipulated by defendants' reporting artificially inflated natural gas prices to trade publications. On July 8, 2003, the Superior Court granted the defendants' demurrer on the grounds that the claims contained in the complaint were subject to the Filed Rate Doctrine and were preempted by the Federal Power Act. Plaintiffs filed an amended complaint, and in September 2003 defendants filed a demurrer to the amended complaint, which was granted in part. In December 2003, the plaintiffs dismissed both Sempra Energy and SoCalGas from the lawsuit. In May 2003 and again in February 2004, similar actions were filed in San Diego Superior Court against Sempra Energy and SET, and the May 2003 action has been removed to Federal District Court. Another lawsuit containing identical allegations was filed against Sempra Energy and SET in Federal District Court in November of 2003. In addition, in August 2003, a lawsuit was filed in the Southern District of New York against Sempra Energy and SES, alleging that the prices of natural gas options traded on the NYMEX were unlawfully increased under the Federal Commodity Exchange Act by defendants' manipulation of transaction data to natural gas trade publications. In November of 2003, another suit containing identical allegations was filed and consolidated with the New York action. In December 2003, plaintiffs dismissed Sempra Energy from these cases and in January 2004, SES was also dismissed. On January 20, 2004, plaintiffs filed an amended consolidated complaint that named SET as a defendant in this lawsuit.

In January 2004, the Commodity Futures Trading Commission (CFTC) issued a subpoena to SoCalGas and SET in connection with the CFTC's "Activities Affecting the Price of Natural Gas in the Fall of 2003" investigation. The company is cooperating with the CFTC in the investigation.

Other

On August 21, 2003, the CPUC denied a rehearing requested by opponents of its December 2002 decision that had approved a settlement with SDG&E allocating between SDG&E customers and shareholders the profits from intermediate-term purchase power contracts that SDG&E had entered into during the early stages of California's electric utility industry restructuring. As previously reported, the settlement provided $199 million of these profits to customers, by reductions to balancing account undercollections in prior years. The settlement provided the remaining $173 million of profits to SDG&E shareholders, of which $57 million had been recognized for financial reporting purposes in prior years. As a result of the decision, SDG&E recognized additional after-tax income of $65 million in the third quarter of 2003. UCAN, a consumer-advocacy group which had requested the CPUC rehearing, appealed the decision to the California Court of Appeals and the court agreed to hear the case. Oral arguments are likely to occur in March or April 2004. A decision is expected by the third quarter of 2004. The company expects that the Court of Appeals will affirm the CPUC's decision.

SER was a defendant in an action brought by Occidental Energy Ventures Corporation (Occidental) with respect to the Elk Hills power project being jointly developed by the two companies. On

September 30, 2003, the arbitration proceeding found in favor of SER, determining that SER had not breached its joint development contract with Occidental.

In May 2003, a federal judge issued an order finding that the DOE's abbreviated assessment of two Mexicali power plants, including SER's TDM plant, failed to evaluate the plants' environmental impact adequately and called into question the U.S. permits they received to build their cross-border transmission lines. In July 2003, the judge ordered the DOE to conduct additional environmental studies and denied the plaintiffs' request for an injunction blocking operation of the transmission lines, thus allowing the continued operation of the TDM plant. The DOE has until May 15, 2004, to demonstrate why the court should not set aside the permits.

In 1999, Sempra Energy and PSEG each acquired a 44-percent interest in Luz Del Sur, a Peruvian electric distribution company. Local law required that assets built with government funds be purchased by the local utility and added to rate base. A dispute arose between the government and Luz Del Sur over the amount of compensation due for the 194 projects transferred to Luz Del Sur by the government. The government claims the amount owed was $36 million. Luz Del Sur argued that the amount was less and the matter was settled with the government for approximately $10 million. Following a change in the Peruvian government, a criminal charge was filed against certain government officials, and utility officials as accomplices, including the chief executive officer and chief financial officer of Luz Del Sur, alleging that the settlements were inadequate. In September 2003 a Peruvian court ordered the prosecutor's case to be dismissed. Although the prosecutor has indicated no evidence of wrongdoing in the case, the prosecutor has appealed this decision and the case rests in a higher Peruvian court. A decision is expected during the first half of 2004.

At December 31, 2003, SET remains due approximately $100 million from energy sales made in 2000 and 2001 through the ISO and the PX markets. The collection of these receivables depends on satisfactory resolution of the financial difficulties being experienced by other California IOUs as a result of the California electric industry crisis. SET has submitted relevant claims in the PG&E and PX bankruptcy proceedings. The company believes adequate reserves have been recorded.

FERC Actions

Information regarding FERC actions related to the company is provided in Note 13.

Department Of Energy Nuclear Fuel Disposal

The Nuclear Waste Policy Act of 1982 made the DOE responsible for the disposal of spent nuclear fuel. However, it is uncertain when the DOE will begin accepting spent nuclear fuel from SONGS. This delay by the DOE will lead to increased cost for spent fuel storage. This cost will be recovered through SONGS revenue unless the company is able to recover the increased cost from the federal government.

Electric Distribution System Conversion

Under a CPUC-mandated program, the cost of which is included in utility rates, and through franchise agreements with various cities, SDG&E is committed, in varying amounts, to converting overhead distribution facilities to underground. As of December 31, 2003, the aggregate unexpended amount of this commitment was $90 million. Capital expenditures for underground conversions were $28 million in 2003, $33 million in 2002 and $12 million in 2001.

Concentration Of Credit Risk

The company maintains credit policies and systems to manage overall credit risk. These policies include an evaluation of potential counterparties' financial condition and an assignment of credit limits. These credit limits are established based on risk and return considerations under terms customarily available in the industry. The California Utilities grant credit to utility customers and counterparties, substantially all of whom are located in their service territories, which together cover most of Southern California and a portion of central California.

As described above, SER has a contract with the DWR to supply up to 1,900 MW of power to the state over 10 years, beginning in 2001. SER would be at risk for the amounts of outstanding billings and the continued viability of the contract if the DWR were to default on its payments under this contract. At any given time, the average outstanding billings related to this contract is $50 million to $60 million.

SET monitors and controls its credit-risk exposures through various systems which evaluate its credit risk, and through credit approvals and limits. To manage the level of credit risk, SET deals with a majority of counterparties with good credit standing, enters into netting arrangements whenever possible and, where appropriate, obtains collateral or other security such as lock-box liens and downgrade triggers. Netting agreements incorporate rights of setoff that provide for the net settlement of subject contracts with the same counterparty in the event of default.

NOTE 16. SEGMENT INFORMATION

The company has four separately managed reportable segments comprised of SoCalGas, SDG&E, SET and SER. The California Utilities operate in essentially separate service territories under separate regulatory frameworks and rate structures set by the CPUC. SoCalGas is a natural gas distribution utility, serving customers throughout most of Southern California and part of central California. SDG&E provides electric service to San Diego and southern Orange counties and natural gas service to San Diego County. SET, based in Stamford, Connecticut, is a wholesale trader of physical and financial energy products and other commodities, and a trader and wholesaler of metals, serving a broad range of customers in the United States, Canada, Europe and Asia. SER acquires, develops and operates power plants throughout the U.S. and Mexico.

The accounting policies of the segments are described in Note 1, and segment performance is evaluated by management based on reported net income. California Utility transactions are based on rates set by the CPUC and FERC.

(Dollars in millions)	Years ended December 31, 2003	2002	2001
OPERATING REVENUES			
Southern California Gas Company	**$3,544**	$2,858	$3,716
San Diego Gas & Electric	**2,311**	1,725	2,362
Sempra Energy Trading	**1,144**	821	1,047
Sempra Energy Resources	**671**	349	178
All other	**274**	332	458
Intersegment revenues	**(57)**	(37)	(31)
Total	**$7,887**	$6,048	$7,730
INTEREST INCOME			
Southern California Gas Company	**$ 34**	$ 5	$ 22
San Diego Gas & Electric	**42**	10	21
Sempra Energy Trading	**12**	11	11
Sempra Energy Resources	**14**	4	6
All other	**132**	84	73
Intercompany elimination	**(130)**	(72)	(50)
Total	**$ 104**	$ 42	$ 83
DEPRECIATION AND AMORTIZATION			
Southern California Gas Company	**$ 289**	$ 276	$ 268
San Diego Gas & Electric	**242**	230	207
Sempra Energy Trading	**23**	21	27
Sempra Energy Resources	**13**	2	1
All other	**48**	67	76
Total	**$ 615**	$ 596	$ 579
INTEREST EXPENSE			
Southern California Gas Company	**$ 45**	$ 44	$ 68
San Diego Gas & Electric	**73**	77	92
Sempra Energy Trading	**30**	43	14
Sempra Energy Resources	**25**	6	7
All other	**265**	196	192
Intercompany elimination	**(130)**	(72)	(50)
Total	**$ 308**	$ 294	$ 323
INCOME TAX EXPENSE (BENEFIT)			
Southern California Gas Company	**$ 150**	$ 178	$ 169
San Diego Gas & Electric	**148**	91	141
Sempra Energy Trading	**62**	60	131
Sempra Energy Resources	**29**	36	(18)
All other	**(342)**	(219)	(210)
Total	**$ 47**	$ 146	$ 213
NET INCOME (LOSS)			
Southern California Gas Company	**$ 209**	$ 212	$ 207
San Diego Gas & Electric	**334**	203	177
Sempra Energy Trading	**98**	126	196
Sempra Energy Resources	**94**	60	(27)
All other	**(86)**	(10)	(35)
Total	**$ 649**	$ 591	$ 518

(Dollars in millions)	2003	At December 31 or years ended December 31, 2002	2001
ASSETS			
Southern California Gas Company	**$ 5,412**	$ 5,403	$ 4,986
San Diego Gas & Electric	**6,463**	6,285	6,542
Sempra Energy Trading	**5,923**	5,614	2,997
Sempra Energy Resources	**2,252**	1,347	577
All other	**2,780**	2,579	3,094
Intersegment receivables	**(821)**	(986)	(720)
Total	**$22,009**	$20,242	$17,476
CAPITAL EXPENDITURES			
Southern California Gas Company	**$ 318**	$ 331	$ 294
San Diego Gas & Electric	**444**	400	307
Sempra Energy Trading	**51**	21	45
Sempra Energy Resources	**142**	356	225
All other	**94**	106	197
Total	**$ 1,049**	$ 1,214	$ 1,068
GEOGRAPHIC INFORMATION			
Long-lived assets			
United States	**$10,380**	$ 9,548	$ 8,911
Latin America	**1,121**	1,062	836
Europe	**87**	18	10
Canada	**—**	3	24
Total	**$11,588**	$10,631	$ 9,781
Operating revenues			
United States	**$ 7,211**	$ 5,503	$ 7,169
Latin America	**315**	168	280
Europe	**323**	328	250
Canada	**10**	28	15
Asia	**28**	21	16
Total	**$ 7,887**	$ 6,048	$ 7,730

NOTE 17. QUARTERLY FINANCIAL DATA (UNAUDITED)

(Dollars in millions, except per share amounts)	Quarters ended March 31	June 30	September 30	December 31
2003				
Operating revenues	**$1,923**	**$1,840**	**$2,058**	**$2,066**
Operating expenses	**1,708**	**1,637**	**1,751**	**1,852**
Operating income	**$ 215**	**$ 203**	**$ 307**	**$ 214**
Income before cumulative effect of changes in accounting principles	**$ 117**	**$ 116**	**$ 211**	**$ 251**
Net income	**$ 88**	**$ 116**	**$ 211**	**$ 234**
Average common shares outstanding (diluted)	**207.8**	**210.2**	**212.3**	**227.2**
Income per common share before cumulative effect of changes in accounting principles (diluted)	**$ 0.56**	**$ 0.55**	**$ 1.00**	**$ 1.11**
Net income per common share (diluted)	**$ 0.42**	**$ 0.55**	**$ 1.00**	**$ 1.03**
2002				
Operating revenues	$1,475	$1,488	$1,385	$1,700
Operating expenses	1,224	1,260	1,075	1,502
Operating income	$ 251	$ 228	$ 310	$ 198
Income before extraordinary item	$ 146	$ 145	$ 150	$ 134
Net income	$ 146	$ 147	$ 150	$ 148
Average common shares outstanding (diluted)	206.4	207.1	205.4	205.6
Income per common share before extraordinary item (diluted)	$ 0.71	$ 0.70	$ 0.73	$ 0.65
Net income per common share (diluted)	$ 0.71	$ 0.71	$ 0.73	$ 0.72

Reclassifications have been made to certain of the amounts since they were presented in the Quarterly Reports on Form 10-Q.

QUARTERLY COMMON STOCK DATA (UNAUDITED)

	First Quarter	Second Quarter	Third Quarter	Fourth Quarter
2003				
Market price				
High	**$26.00**	**$29.40**	**$30.33**	**$30.90**
Low	**$22.25**	**$24.05**	**$27.31**	**$26.36**
2002				
Market price				
High	$25.92	$26.25	$24.11	$24.62
Low	$22.15	$21.52	$15.50	$16.70

Dividends declared were $0.25 in each quarter.

FORM 10-K

Sempra Energy's annual report to the Securities and Exchange Commission on Form 10-K is available to shareholders at no charge by writing to Shareholder Services at 101 Ash Street, San Diego, CA 92101.

Supplemental Consolidating Information

December 31, 2003

Supplemental Consolidating Balance Sheet Information
Sempra Energy Solutions and Its Other Subsidiaries
December 31, 2003

(Dollars in millions)	Sempra Energy Solutions *	Sempra Energy and Other Subsidiaries	Intercompany Eliminations & Consolidating Entries	Sempra Energy Consolidated
Assets				
Current assets:				
Cash and cash equivalents	$ 7	$ 425		$ 432
Short-term investments		363		363
Accounts receivable - trade	166	846		1,012
Accounts and notes receivable - other	1	126		127
Interest receivable		62		62
Due from affiliates	4	101	$ (105)	-
Income taxes receivable		20		20
Deferred income taxes	3		(3)	-
Trading assets	113	5,147	(10)	5,250
Regulatory assets arising from fixed-price contracts and other derivatives		144		144
Other regulatory assets		89		89
Inventories	4	143		147
Other	11	230	(1)	240
Total current assets	309	7,696	(119)	7,886
Investments and other assets:				
Due from unconsolidated affiliates		55		55
Regulatory assets arising from fixed-price contracts and other derivatives		650		650
Other regulatory assets		554		554
Nuclear decommissioning trusts		570		570
Investments	1	1,308	(195)	1,114
Sundry	95	611		706
Total investments and other assets	96	3,748	(195)	3,649
Property, plant and equipment:				
Property, plant and equipment	154	15,163		15,317
Accumulated depreciation and amortization	(48)	(4,795)		(4,843)
Total property, plant and equipment - net	106	10,368	-	10,474
Total assets	$ 511	$ 21,812	$ (314)	$ 22,009

	Sempra Energy Solutions	Sempra Energy and Other Subsidiaries	Intercompany Eliminations & Consolidating Entries	Sempra Energy Consolidated
Liabilities and Shareholders' Equity				
Current liabilities:				
Short-term debt	$ 28			$ 28
Accounts payable - trade	70	$ 745		815
Accounts payable - other	-	64		64
Due to affiliates	101	4	$ (105)	-
Deferred income taxes	47	79	(3)	123
Trading liabilities	35	4,432	(10)	4,457
Dividends and interest payable		136		136
Regulatory balancing accounts - net		424		424
Fixed-price contracts and other derivatives		148		148
Current portion of long-term debt	4	1,429		1,433
Other	17	704	(1)	720
Total current liabilities	302	8,165	(119)	8,348
Long-term debt	13	3,828		3,841
Deferred credits and other liabilities:				
Due to unconsolidated affiliates		362		362
Customer advances for construction		89		89
Postretirement benefits other than pensions		131		131
Deferred income taxes		634		634
Deferred investment tax credits		84		84
Regulartory liabilities arising from cost of removal obligations		2,238		2,238
Regulatory liabilities arising from asset retirement obligations		281		281
Other regulatory liabilities		108		108
Fixed-price contracts and other derivatives		680		680
Asset retirement obligations		313		313
Deferred credits and other	1	830		831
Total deferred credits and other liabilities	1	5,750	-	5,751
Preferred stock of subsidiaries		179		179
Shareholders' Equity				
Common stock	237	2,028	(237)	2,028
Retained earnings	(42)	2,298	42	2,298
Deferred compensation relating to ESOP		(35)		(35)
Accumulated other comprehensive income (loss)		(401)		(401)
Total shareholders' equity	195	3,890	(195)	3,890
Total liabilities and shareholders' equity	$ 511	$ 21,812	$ (314)	$ 22,009

* Sempra Energy Solutions is a Sempra Energy business unit.

Supplemental Consolidating Statement of Income Information
Sempra Energy Solutions and Its Other Subsidiaries
Year ended December 31, 2003

(Dollars in millions)	Sempra Energy Solutions *	Sempra Energy and Other Subsidiaries	Intercompany Eliminations	Sempra Energy Consolidated
Operating revenues				
California utilities:				
Natural gas		$ 4,010		$ 4,010
Electric		1,787		1,787
Other	$ 175	1,916	$ (1)	2,090
Total	175	7,713	(1)	7,887
Operating expenses				
California utilities:				
Cost of natural gas		2,071		2,071
Cost of electric fuel and purchased power		541		541
Other cost of sales	65	1,140	(1)	1,204
Other operating expenses	71	2,216		2,287
Depreciation and amortization	11	604		615
Franchise fees and other taxes	3	227		230
Total	150	6,799	(1)	6,948
Operating income	25	914	-	939
Other income - net	1	25		26
Interest income		109	(5)	104
Interest expense	(6)	(307)	5	(308)
Preferred dividends of subsidiaries		(10)		(10)
Trust preferred distributions by subsidiary		(9)		(9)
Income before income taxes	20	722	-	742
Income tax expense	3	44		47
Income before cumulative effect of changes in accounting principles	17	678	-	695
Cumulative effect of changes in accounting principles, net of tax	(1)	(45)		(46)
Net income	$ 16	$ 633	$ -	$ 649

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Supplemental Consolidating Statement of Cash Flows Information
Sempra Energy Solutions and Its Other Subsidiaries
Year ended December 31, 2003

(Dollars in millions)	Sempra Energy Solutions *	Sempra Energy and Other Subsidiaries	Sempra Energy Consolidated
Cash Flows from Operating Activities			
Net income	$ 16	$ 633	$ 649
Adjustments to reconcile net income to net cash provided by operating activities:			
Cumulative effect of changes in accounting principles	1	45	46
Depreciation and amortization	11	604	615
Foreign currency loss		8	8
Deferred income taxes and investment tax credits	3	(76)	(73)
Non-cash rate reduction bond expense		68	68
Equity in income of unconsolidated affiliates		(8)	(8)
Impairment losses		101	101
Loss on sale and disposition of assets	1	7	8
Other - net		2	2
Net changes in other working capital components	(21)	(203)	(224)
Changes in other assets		(66)	(66)
Changes in other liabilities		(5)	(5)
Net cash provided by operating activities	11	1,110	1,121
Cash Flows from Investing Activities			
Expenditures for property, plant and equipment	(6)	(1,043)	(1,049)
Investments and acquisitions of subsidiaries, net of cash acquired		(202)	(202)
Dividends received from unconsolidated affiliates		72	72
Net proceeds from sale of assets		29	29
Loans to unconsolidated affiliates		(99)	(99)
Other - net		(4)	(4)
Net cash used in investing activities	(6)	(1,247)	(1,253)
Cash Flows from Financing Activities			
Common dividends paid		(207)	(207)
Issuances of common stock		549	549
Repurchases of common stock		(6)	(6)
Issuances of long-term debt		900	900
Payments on long-term debt	(2)	(599)	(601)
Loans to/from affiliates - net	(25)	25	-
Increase (decrease) in short-term debt - net	19	(537)	(518)
Other - net		(8)	(8)
Net cash provided by (used in) financing activities	(8)	117	109
Decrease in cash and cash equivalents	(3)	(20)	(23)
Cash and cash equivalents, January 1	10	445	455
Cash and cash equivalents, December 31	$ 7	$ 425	$ 432

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