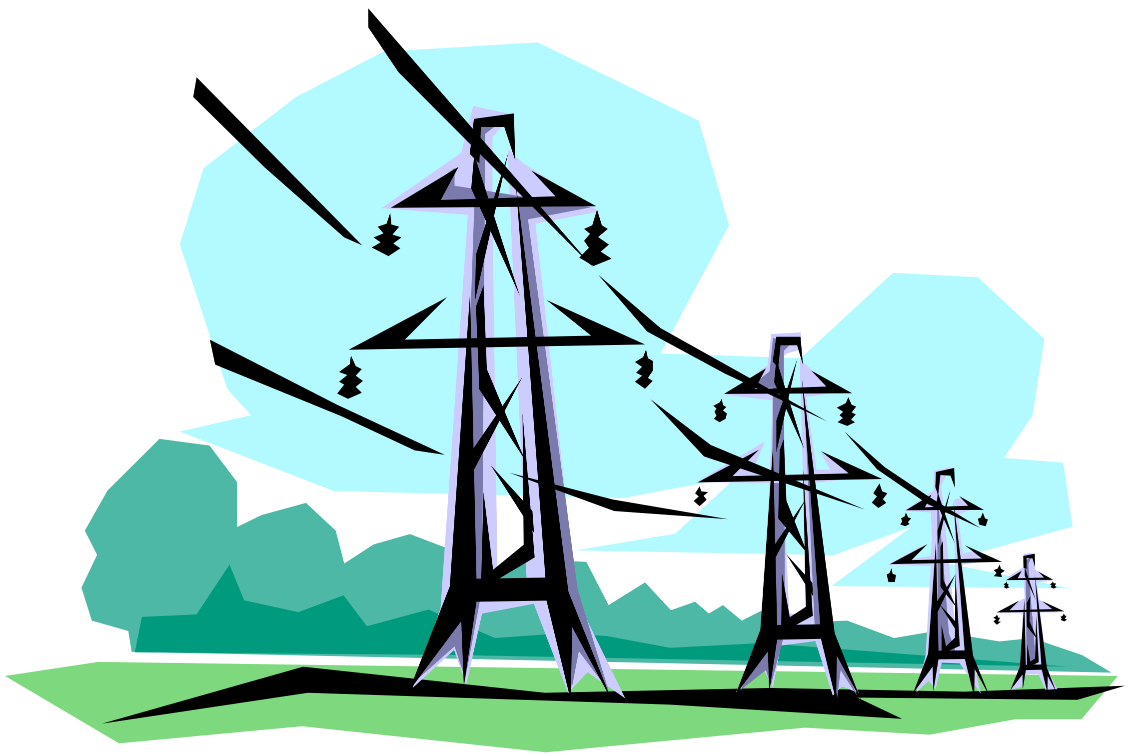
Restructuring in California, Costs of Transition and Stranded Assets



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Stranded Assets, Competition Transition Charges and Deregulation

Section 1. Stranded Cost Recovery for California's Utilities

1.1 Background

On January 1, 1998 the restructuring of California's electric industry will begin and the traditional role of a single utility providing all electrical services (i.e., power generation, transmission and distribution) will end. This change will have a significant impact on California's three investor owned utilities (Pacific Gas and Electric (PG&E), Southern California Edison (SCE), and San Diego Gas & Electric (SDG&E)), which provide approximately 80 percent of California's electricity service. Assembly Bill 1890 (AB 1890), which was signed into law on September 23, 1996 by Governor Pete Wilson, is the legislation that will dramatically change California's electric industry.

One important change made by AB1890 is to treat the generation, transmission and distribution of power by the three investor-owned utilities (IOUs) as three distinct functions. This change will be complemented by the creation of a competitive market for generation and a Power Exchange (PX), which is a spot price market where electricity will be bought and sold.[1] Moreover, utility control over transmission will be shifted to a newly created Independent System Operator (ISO). The ISO will oversee the operation of the high voltage electricity transmission lines, it will assure reliable and fair transfers of electricity from generator^ to distribution companies, and it will be governed by a board comprising market participants and industry experts. Distribution will remain under utility monopoly with regulatory oversight by the California Public Utilities Commission (CPUC).

Another important change created by AB1890 is retail wheeling, which will allow power producers or brokers to sell directly to retail customers. Retail competition will allow customers to choose direct access (i.e., a customer will be able to buy generation from any power provider or marketer). Although not all users will be able to pick their electric supplier in 1998, all users will have this choice by 2002.

AB1890 also allows for a 10% rate reduction for small residential and commercial customers by January 1, 1998. Finally, and most importantly, the three IOUs will have the opportunity to recover their transition costs (also referred to as competitive transition costs or stranded costs) from ratepayers. This report focuses on transition costs and briefly discusses the 10% rate reduction. There is also a review of the current developments in New Jersey's and Pennsylvania's electric market, and the stranded cost recovery of wholesale contracts.

[1] The PX, which will be subject to Federal Energy Regulatory Commission jurisdiction and regulatory oversight under the Federal Power Act, will be an independent agency that will conduct an auction for generators that want to sell energy in the PX and for loads not being served by bilateral contracts. The PX will schedule generation (e.g., day-ahead, hour-ahead), will determine hourly market clearing prices, and will perform settlement and billing for suppliers and utility distribution companies. Note that the PX is mandatory for the first five years for the investor-owned utilities seeking transition cost recovery.

1.2 Stranded Costs and their Recovery with the Competition Transition Charge

Stranded costs are investments and obligations that may become uneconomic (i.e., not recoverable) in a competitive generation market. Since these investments and obligations were made when the utilities were required to serve their service territory's generation needs the utilities will have the opportunity to recover their transition costs from ratepayers. AB1890 allows for the recovery of transition costs, on an accelerated basis, from 1998-2001[2] if the stranded costs have been fully mitigated (i.e., the value of the stranded costs have been reduced as much as possible). The accelerated payments will allow California's electricity market to be fully competitive by 2002.

Under AB1890 a non-bypassable Competition Transition Charge (CTC) will be used to recover stranded costs and costs related to the transition to the new market. The CTC will not be an additional charge incurred by customers: most components of the CTC are already included in rates.[3] On January 1, 1998 rates, which have been fixed since June 10, 1996, will remain fixed at the June 1996 levels (except for the 10% rate reduction for small residential and commercial customers), and the difference between the revenues from the fixed rates and the sum of cost components (e.g., public benefit program costs, distribution costs, transmission costs and power exchange costs – which will be declining) will be used to recover stranded costs. The rate freeze will end before Dec. 31, 2001 if generation-related transition costs are recovered before this date.

The CTC is a rate that will be multiplied by electricity consumption. Although the rate will change each year, the amount paid per month will vary according to electricity consumption. The CTC will be adjusted each year to reflect disposition of utility assets and repayment of various accounts. For example, if a utility sells a power plant at a price greater than its book value, the CTC will be reduced. The CTC will also vary by utility.

The CTC will appear as a distinct charge on the bills of customers that shift their electricity generation from their present utility to another generator. The total dollar cost per customer will not be fixed because it will depend on electricity consumption. Thus, customers can lower the CTC charged by reducing their electricity use. The CPUC will ensure recovery of transition costs from all existing and future customers in the service territory in which the utility provided service as of Dec. 20, 1995. The obligation to pay the CTC cannot be avoided by the formation of a local publicly owned corporation on or after Dec. 20, 1995. The CPUC will also require customers to pay the costs directly to the corporation providing electrical service. If customers leave the utility system measurement will be based on prior usage and an exit fee will be charged.

Below are the most significant stranded costs that can be recovered by the CTC:
•Generation Assets: The CPUC will identify utility-specific assets that may become uneconomic in a competitive generation market. Recovery will be allowed for assets that were in place and being recovered through commission-approved rates on Dec. 20,

[2] Some exceptions are: employee-related transition costs can be collected through 2006; above-market cost of power contract costs entered into before December 20, 1995 can be collected for the contract's duration; transition costs from the incentive pricing mechanism adopted for the San Onofre nuclear plant will be collected through 2003; and costs of contracts approved by the CPUC to settle issues associated with the Biennial Resource Plan Update can be collected through March 31, 2002.

[3] If the electricity market did not change customers would still have to pay the utilities or these costs through their electricity bill.

1995. Reasonable costs for modifying the generating facilities, which were incurred after Dec. 20, 1995 and were necessary to maintain the facilities through Dec. 31, 2001, will be allowed. The difference between the negative value of above-market assets and the positive value of below-market assets is recoverable. For fossil generation, the uneconomic costs shall be limited to the uneconomic portion of the net book value of the fossil capital investment existing as of Jan. 1, 1998.

The stranded cost of non-nuclear power plants is the amount by which the plant's book value (after accounting for depreciation) is greater than its market value. Although the recovery of the costs of nuclear power plants (investments in nuclear plants ran far over budget because of regulatory requirements) was originally denied to the utilities that built them (the construction of these plants is regarded as bad management decisions), as of August 1997 the legislation in various states indicated that utilities will be able to recover the fully mitigated costs of nuclear construction. Note that the shareholders will pay for the mitigation (e.g., PG&E wrote off $4 billion of the value of its Diablo Canyon Plant and cut its dividend by 40%).

•Power Purchase Contracts: Power purchase contracts are one of the largest components of stranded costs. The Public Utility Regulatory Policy Act[4] (PURPA), in an effort to encourage a non-regulated generation industry, required utilities to buy power from qualifying facilities (QFs) and independent power producers (IPPs), and long-term contracts were entered into at prices that are expected to be higher than future competitive market prices for electricity.[5] The difference between the long-term contract price and the market price is the stranded cost associated with the power purchase contracts. Mitigation strategies such as buy-out or buy-down of contracts can reduce the stranded cost of the power purchase contracts. The above-market cost of purchased power contract costs entered into before Dec. 20, 1995 can be collected for the contract's duration. Note that the CPUC must approve these costs.

•Regulatory Assets: Stranded costs also arise out of accounting procedures used in the regulatory system such as deferred tax credits, demand-side management, account correcting for efficiency amounts capitalized but not yet collected, vested post- retirement employee benefits, nuclear decommissioning costs, deferred debt costs, and accelerated depreciation. These assets appear on a utility's balance sheet and in a competitive market would be stranded because they would not be included in rates. Recovery is expected because these costs were incurred due to regulatory approvals.

[4] PURPA was signed into law by President Carter in 1978 as part of the National Energy Act. PURPA, together with the rules that the Federal Energy Regulatory Commission developed as a result of PURPA, mandated that IOUs enter into long-term contracts with Qualifying Facilities or Independent Power producers at avoided cost rates for power (i.e., the marginal cost for a public utility to produce one more unit of power). The CPUC determined utilities' avoided costs at public hearings.

[5] QFs are non-utility power producers that supply generating capacity and electric energy to electric utilities QFs are defined by PURPA and the Federal Energy Regulatory Commission rules that implemented PURPA. A QF is an independent power supplier that produces electricity with cogeneration or renewables, and meets Federal Energy Regulatory Commission criteria for ownership, size, and efficiency. IPPs, which are not QFs, are non-utility power generating entities. IPPs own or operate independent power production facilities.

•<u>PX and ISO Set-up Costs:</u> Utility expenses incurred to set up direct access, the PX and the ISO, which either the CPUC or the Federal Energy Regulatory Commission (FERC) deem recoverable, may be recovered through Dec. 31, 2001.

•<u>San Onofre Incentives:</u> On April 10, 1996 it was decided that an incremental cost incentive pricing (ICIP) mechanism would provide funds to recover the ongoing operating costs, including capital expenditures, for SCE's San Onofre Nuclear Generating Station (SONG) through 2003. The ICIP mechanism allows for the recovery of these costs with a preset cents per kilowatt-hour pricing schedule, which is based on SONG operating at an average capacity factor of 78%. The ICIP schedule is as follows:

Year	1996	1997	1998	1999	2000	2001	2002	2003
Cents Per KWh	3.80	3.85	4.00	4.00	4.05	4.10	4.15	4.15

The CPUC designated nuclear-power generation as must-take generation and thus it will not be bid into the PX, it will be sold through the pool at the PX market-clearing price, and the CTC will be used to recover ICIP transition costs. After 2003, SONG power will be sold at market prices, and ratepayers will receive 50% of the post-2003 benefits from SONG.

On April 15, 1996 the accelerated recovery of SCE's undepreciated book value of SONG totaled approximately $2.6 billion for the period from April 15, 1996 to Dec. 31, 2003. The rate base amount, which is the remaining book value less deferred taxes, was estimated to be $2.1 billion. A return on SONG sunk costs equal to the embedded cost of debt on the debt portion of the SONG rate base amount, and a return of 90 of the embedded cost of debt to be applied to the equity portion of the rate base amount, resulted in an overall rate of return on rate base of 7.35%.

•<u>Operating Costs for 'Must Run' Plants:</u> The CPUC shall allow the utility to retain any earnings from the plants designated to provide reactive power/voltage support, and shall not require the utility to apply any portions to offset recovery of transition costs. This provision terminates on Dec. 31, 2001.

•<u>SCE Fuel Costs:</u> AB1890 allows "an electrical corporation that, as of Dec. 20, 1995, served at least four million customers, and was also a gas corporation that served less than four thousand customers" to recover 100% of the uneconomic portion of the fixed costs paid under fuel contracts that were executed before Dec. 20, 1995, or 100% of buy-out or buy-down costs associated with the contracts.

•<u>Biennial Resource Plan Update (BRPU) Settlements:</u>[6] Costs associated with contracts approved by the CPUC to settle BRPU issues may be collected through March 31, 2002 (from January 1, 2002 to March 31, 2002 at an 80% rate).

•<u>Agricultural Exemptions:</u> The obligation to pay uneconomic costs does not apply to 110 MW of load allocated among the IOUs, in proportion to the share of each to the

[6] The BRPU, which is a separated competitive bidding process, was held under the guidance and direction of the CPUC. California's set-aside law, which is essentially a mandate that electricity suppliers purchase a certain percentage of their power from renewable generators, initiated the creation of the BRPU, which was designed to allow QFs to bid against one another for new capacity. BRPU caused utilities to enter into contracts that were above the utilities' avoided cost from other potential suppliers because the other potential generation sources were excluded from the bidding for the QF segment of the bid.

total number of irrigation districts served by all three. The total amount of load allocated to each utility is phased-in over a five year period starting Jan. 1, 1997.

•Nuclear Decommissioning Costs: These costs shall be recovered as a non-bypassable charge until fully recovered.

•Restructuring Costs: Costs incurred by utilities due to deregulation, restructuring of organizational functional units, and divestiture of generation assets, generally, will be recoverable.

•Social and Other Benefits Programs: Environmental compliance program costs are recovered over several years in rates, and these costs would become stranded in a competitive market. Recovery is expected to be allowed since these obligations were imposed upon utilities by the regulatory bodies.

AB1890 also allows for recovery of some employee related transition costs arising from industry restructuring (e.g., retraining, severance, and early retirement). This cost recovery will continue until fully collected or until Dec. 31, 2006.

1.3 Timeline for Cost Recovery

Although there is no simple timetable for all the complex events related to stranded costs, there are some significant dates that should be noted:

•January 1, 1998 is when California's electric customers will be able to choose from among competitive electricity suppliers, and is the base date for evaluation of the uneconomic portion of the net book value of fossil-fueled investment;

•December 31, 2001 is when the valuation has to be completed;

•December 31, 2003 is the limiting date for recovery of the San Onofre nuclear incremental cost incentives; and

•December 31, 2015 is the expiration of CPUC authority to issue financing orders pursuant to transition cost financing.

1.4 Rate Reduction Bonds

On Sept. 3, 1997 the CPUC approved plans by the three IOUs to issue up to $7.3 billion in bonds (PG&E $3.5 billion, SCE $3 billion, and SDG&E $800 million) through the California Infrastructure and Economic Development Bank (or a trust it authorizes). The rate reduction bonds will allow utilities to refinance existing debt. This financing mechanism will enable utilities to cut rates by 10 percent for residential and small commercial customers beginning in 1998.[7] AB1890 requires that utilities collect a Fixed Transition Amount (FTA) that will be used to repay the bonds. The FTA will be collected over a ten year period through customers' bills. During the rate freeze period the FTA will not be an additional charge: the FTA will come from CTC collection.

The bonds, which are secured by the income stream represented by the FTA; will simplify the debt structure, reduce interest rates, and advance to the utilities a portion of their stranded exposure. The bonds will reduce the costs to the consumers of dealing with the past while delivering rate reductions to residential consumers.

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[7] The CPUC will ultimately determine the adequacy of the size of the bond to achieve a 10 reduction in rates for residential and small commercial customers.

Section 2. Estimates of CTCs and Stranded Assets

2.1 Results of Agreed-Upon Procedures Review of Unrecorded Sunk Costs and Future Costs

In this section we use the CPUC's procedures to determine the stranded cost of all non-nuclear generating, regulatory assets and stranded future cost associated with power contracts. The sunk cost of non-nuclear generating assets is the book value of assets net of all depreciation and credits. The stranded cost for generation assets is the difference between the market value and the book value of assets. By 2001, the market value of these generating assets will be established by one of the following methods:

• The plant is sold and the sale price is the market value.

• The total net income (loss) of the plant for the transition years 1998 to 2001 is the total market revenues less the operating costs. The market value of the plant is the book value net of depreciation in 2001 minus the accumulated net income (loss), or

•The market value of the plant is determined after negotiations among utilities, commissions, and ratepayer advocates. The guidelines for the negotiations is expected to be based on one of the two above methods.

The stranded cost for each utility is calculated by adding all losses and income from their generating plants, regulatory obligations and power contracts until 2001. The stranded costs of power contracts for retail sales is regulated by the CPUC, and the ones for wholesale power contracts is governed by FERC. The estimated stranded cost for future contracts is calculated by accumulating the losses over the contract period. Although the utilities are encouraged to re-negotiate these contracts or buy them down, our estimates do not include the effect of such actions.

Exhibits 2.1 through 2.3 depict each IOU's estimated transition costs and the adjusted transition costs, audited by Mitchell and Titus. Exhibit 2.4 summarizes, by category, transition costs questioned by Mitchell and Titus's audit.

Exhibit 2.1
Pacific Gas and Electric
Reported and Adjusted Eligible Transition Costs
(In Millions)

Cost Item	Amount Per Transition Cost Statement	Adjusted Total Amount
Net Plant in Service	$2,683	$2,550
Other Plant Items	1,122	684
Plant Related Items	(222)	(265)
Regulatory Assets & Liabilities	1,243	1,072
Other Unrecorded and Future Contract Related Costs	30,567	27,250
Reported and Adjusted Eligible Transition Costs	**$35,393**	**$31,291**

Exhibit 2.2
Southern California Edison
Reported and Adjusted Eligible Transition Costs
(In Millions)

Cost Item	Amount Per Transition Cost Statement	Adjusted Total Amount
Net Plant in Service	$1,065	$993
Other Plant Items	449	446
Plant Related Items	24	(138)
Regulatory Assets & Liabilities	(44)	(44)
Contractual Obligations	32,217	29,529
Other Costs	528	-
Reported and Adjusted Eligible Transition Costs	**$34,239**	**$30,786**

Exhibit 2.3
San Diego Gas & Electric
Reported and Adjusted Eligible Transition Costs
(In Millions)

Cost Item	Amount Per Transition Cost Statement	Adjusted Total Amount
Net Plant in Service	$152	$151
Other Plant Items	128	128
Plant Related Items	49	26
Regulatory Assets & Liabilities	18	17
Other Unrecorded and Future Contract Related Costs	3,174	3,129
Reported and Adjusted Eligible Transition Costs	**$3,521**	**$3,451**

Exhibit 2.4
Summary of Questioned Costs by Category
(In Millions)

Description	PG&E	Edison	SDG&E
Amount per Transition Cost Statement	$35,939	$34,239	$3,521
AB1890	91	64	39
Commission Approval	81	632	-
Estimates & Assumptions	1,516	2,313	24
Inadequate Support	1,917	444	10
Company Adjustments	-	-	(3)
Accounting Problems	496	-	-
Adjusted Eligible Transition Costs	**$31,291**	**$30,786**	**$4,451**

2.2 Summary of Qualifying Facilities CTC Forecast

QFs are independent, non-utility power producers classified as cogeneration facilities or small power production facilities. Under PURPA, utilities were required to purchase energy from QFs. The policy decision (D.96-01-009, dated 1/10/1996) states the following objectives for the management of QF contracts during the transition period:

•Existing QF contracts will be honored by the remaining electric distribution utility.

•Contracts will be administered to maximize system wide benefits and minimize transition costs.

•Short-run avoided cost for energy will be set at the PX clearing price so transition costs will arise primarily from capacity and fixed energy payments.

•A 10% incentive will be offered to encourage voluntary renegotiations (buy-downs) of QF contracts.

•Contract renegotiations will be structured to provide ratepayer benefits.

•Policies will be established to encourage development of new renewable resources.

The CPUC must identify and determine the costs of power purchase contracts that were being collected in Commission-approved rates on Dec. 20, 1995, and that may become uneconomic in a competitive generation market.

The following exhibits summarize the three IOU's CTC filings of forecasted QF obligations for the next 30 years. Since the projected energy payment will be offset by sales revenue from the PX the QF's stranded cost is projected to be the capacity payment plus the energy payment after it has been offset by the PX sales revenue. Note that the PX price for electricity is expected to be lower than the QF contract price.

Exhibit 2-5
Pacific Gas & Electric
Projected Capacity and Energy Payments
($ Millions)

Year	Projected Capacity Payments	Projected Energy Payments	Total
1998	$541	$897	$1,438
1999	529	779	1,308
2000	531	665	1,196
2001	528	651	1,179
2002	525	646	1,171
2003	520	664	1,184
2004	508	686	1,194
2005	505	706	1,211
2006	504	729	1,233
2007	484	752	1,236
2008	472	782	1,254
2009	430	805	1,235
2010	406	831	1.237
2011	391	857	1,248
2012	366	887	1,253
2013	354	913	1,267
2014	336	942	1.278
2015	304	972	1,276
2016	283	933	1,216
2017	262	892	1,154
2018	214	753	967
2019	166	603	169
2020	100	375	475
2021	60	232	292
2022	52	209	261
2023	52	215	267
2024	52	222	274
2025	52	229	281
2026	14	65	79
Total	$9,541	$18,892	$28,433

Exhibit 2-6
Southern California Edison
Projected QF Capacity and Energy Payments ($ Millions)

Year	Projected Capacity Payments	Projected Energy Payments	Difference*	Total
1998	$670.3	$1,575.3	$59.2	$2,304.8
1999	677.0	1,323.7	59.6	2,060.3
2000	677.6	1,102.4	49.8	1,829.8
2001	671.3	924.8	32.4	1,628.5
2002	667.2	889.5	32.1	1,588.8
2003	661.1	901.3	19.3	1,581.7
2004	655.8	896.8	19.6	1,572.2
2005	651.6	901.6	20.2	1,573.4
2006	608.8	865.5	20.6	1,494.9
2007	594.1	826.3	16.0	1,436.4
2008	470.5	708.1	15.1	1,193.7
2009	457.3	681.9	12.6	1,151.8
2010	429.8	640.7	13.0	1,083.5
2011	414.0	618.2	13.4	1,045.6
2012	400.1	610.5	13.8	1,024.4
2013	400.1	624.2	14.2	1,038.5
2014	376.9	591.7	14.6	983.2
2015	373.2	599.8	8.2	981.2
2016	324.8	528.4	-	853.2
2017	292.0	468.8	-	760.8
2018	266.1	445.2	-	711.3
2019	204.6	318.9	-	523.5
2020	113.6	159.9	-	273.5
2021	38.3	76.5	-	114.8
2022	33.0	68.9	-	101.9
2023	23.2	55.9	-	79.1
2024	11.1	34.8	-	45.9
2025	9.4	32.5	-	41.9
2026	1.4	33.5	(0.1)	34.8
2027	0.5	11.4	(0.1)	11.8
2028	0.5	11.8	(0.2)	12.1
2029	0.5	11.9	(0.2)	12.2
2030	0.5	12.3	-	12.8
Total	$11,176	$17,553	$433	$29,162

*BRPU Settlement and existing contract buyouts.

Exhibit 2-7
San Diego Gas and Electric
QF Obligations ($ Millions)

Year	Projected Capacity Payments	Projected Energy Payments	Total
1998	$36.9	$64.8	$101.7
1999	36.9	62.8	99.7
2000	36.9	47.0	83.9
2001	36.9	47.7	84.6
2002	36.9	48.3	85.2
2003	36.9	49.8	86.7
2004	36.9	51.3	88.2
2005	36.9	53.0	89.9
2006	36.9	54.8	91.7
2007	36.8	56.5	93.3
2008	36.7	58.2	94.9
2009	36.7	60.3	97.0
2010	36.7	62.4	99.1
2011	36.3	63.8	100.1
2012	36.1	65.6	101.7
2013	36.1	67.9	104.0
2014	36.1	70.3	106.4
2015	36.1	72.9	109.0
2016	36.1	75.6	111.7
2017	36.1	67.2	103.3
2018	36.0	69.6	105.6
2019	34.5	69.0	103.5
2020	18.0	34.7	52.7
2021	18.0	36.0	54.0
2022	18.0	37.4	55.4
2023	18.0	38.8	56.8
2024	12.7	25.7	38.4
2025	1.3	2.4	3.7
Total	$888	$1,514	$2,402

Section 3. An Example of Calculating Stranded Assets

3.1 Stranded Costs for Generation Assets

Recall that the stranded cost for generation assets is the difference between the asset's market value and book value. The estimated stranded cost of non-nuclear generation assets (with asset values set until Dec. 31, 2001) are 4.8, 1.5 and .35 billion dollars respectively for PG&E, SCE and SDG&E. Note that utilities and regulators have limited experience in calculating market values, and no set procedure is established for calculating stranded costs for generation assets. For example, PG&E accepted non-bidding proposals until Oct. 6, 1997 for the sale of Morrow Bay, Moss Landing, and Oakland plants, and the plant's auction price will establish market value.

3.2 Stranded Costs for Power Purchase Contracts

Exhibits 2.5 through 2.7 are the forecasted QF obligations for the next 30 years. Although the IOUs will incur above market prices for electricity under these contracts, the projected energy payment will be offset by sales revenue from the PX. Thus, the stranded costs of these contracts will be less than the QF obligations of $28, $29 and $2.4 billion respectively for PG&E, SCE and SDG&E. For example, the projected stranded cost for energy payments is based on the contract price minus the PX price.

3.3 An Example

PG&E's estimates for stranded assets are used in this example and the costs and benefits are analyzed in constant 1996 dollars.

1998 Electric Rate

Rate excluding CTC component	$71.23/Mwh
CTC	$18.18/Mwh
10% Rate Reduction (residential & small commercial)	$3.93/Mwh
Total rate before the rate reduction	$93.34/Mwh

In 1998 PG&E's average rate after the 10% rate reduction for residential and small commercial customers, which are approximately 42.15% of PG&E's load, will be approximately $89.41/Mwh ($93.34-($9.33*.4215)). Note that this rate will be fixed until 2001. In Exhibit 3.1 the difference between the $89.41/Mwh rate and the rate for utility cost (column 6) is collected as CTC from 1998 to 2001, which allows PG&E to recover $4,430 million for stranded costs not related to QF stranded costs (column 9). The CTC rate component for QF stranded costs (column 5) is included in PG&E's rate (column 6) and is used to pay stranded costs for QF contracts (column 3) until the contracts expire. Note that column 3 is the estimated stranded cost for QF contracts that can be recovered through the CTC, and column 9 is the maximum estimated amount that can be collected from CTC for other stranded costs. Assuming that the interest rate on the current debt is 8.5% and the rate on the $3.5 billion bond is 5.25%, the present value of PG&E's savings from refinancing high cost debt with low cost bonds with a 10 year life is .868 billion dollars (column 10).

Exhibit 3.1

Estimates for Pacific Gas & Electric's CTC & Other Costs (in 1996 Dollars)

Year	Demand	QF Stranded Costs[1]	ELECTRIC RATES: Rate excluding CTC Rate Component[2]	CTC Component for QF losses (3)/(2)	Rate including CTC for QFs (4)+(5)	Total Electric Rate[3]	CTC Component for Other Stranded Costs[4]	CTC Revenue for Other Stranded Costs (8)*(2)	Savings[5] from Re-financing with Rate Reduction Bonds
	(GWh)	($Million)	($/MWh)	($/MWh)	($/MWh)	($/MWh)	($/MWh)	($Million)	($Billion)
(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
1998	92620	$ 1,008.5	71.23	10.89	82.12	89.41	7.29	$ 675.2	$ 0.108
1999	94195	$ 905.5	68.81	9.61	78.42	89.41	10.99	$ 1,035.2	$ 0.103
2000	95796	$ 826.2	67.01	8.62	75.63	89.41	13.78	$ 1,320.1	$ 0.098
2001	97424	$ 812.3	66.70	8.34	75.04	89.41	14.37	$ 1,400.0	$ 0.093
2002	99081	$ 801.4	59.22	8.09	67.31	67.31			$ 0.088
2003	100765	$ 802.6	60.81	7.97	68.78	68.78			$ 0.084
2004	102478	$ 802.0	62.37	7.83	70.20	70.20			$ 0.080
2005	104220	$ 810.0	63.72	7.77	71.49	71.49			$ 0.076
2006	105992	$ 820.4	65.12	7.74	72.86	72.86			$ 0.072
2007	107794	$ 817.7	66.37	7.59	73.96	73.96			$ 0.068
2008	109626	$ 824.3	67.48	7.52	75.00	75.00			
2009	111490	$ 807.9	68.40	7.25	75.65	75.65			
2010	113385	$ 806.6	69.44	7.11	76.55	76.55			
2011	115313	$ 813.8	69.39	7.06	76.45	76.45			
2012	117273	$ 818.1	69.31	6.98	76.29	76.29			
2013	119267	$ 826.4	69.25	6.93	76.18	76.18			
2014	121294	$ 834.0	69.20	6.88	76.08	76.08			
2015	123356	$ 832.3	69.07	6.75	75.82	75.82			
2016	125453	$ 791.4	68.61	6.31	74.92	74.92			
2017	127586	$ 744.4	68.11	5.83	73.94	73.94			
2018	129755	$ 623.3	67.04	4.80	71.84	71.84			
2019	131961	$ 486.1	65.87	3.68	69.55	69.55			
2020	134204	$ 288.1	64.28	2.15	66.43	66.43			
2021	136486	$ 168.3	63.32	1.23	64.55	64.55			
2022	138806	$ 145.1	63.13	1.05	64.18	64.18			
2023	141166	$ 149.2	63.14	1.06	64.20	64.20			
2024	143565	$ 153.9	63.15	1.07	64.22	64.22			
2025	146006	$ 158.9	63.18	1.09	64.27	64.27			
2026	148488	$ 43.0	62.34	0.29	62.63	62.63			
Total[6]		**$ 18.7**						**$ 4,430.0**	**$ 0.868**

1 Estimates were made with 12/97 WSCC Competitive Market Study's Northern CA market clearing prices.

2 The rate includes energy, generation, transmission, distribution and customer service.

3 For 1998 through 2001 the rate is fixed at 89.4 $/MWh. This includes a 10% rate reduction for residential and small commercial customers.

4 CTC for all other stranded assets, which is derived from Column 7 - Column 6.

5 It is assumed that the rate on the current debt is 8.5% and the rate on the $3.5 billion bond is 5.25%.

6 Total revenues collected: CTC for stranded QF payments is $18,722 million; and CTC for other stranded assets is $4,430 million.

Exhibit 3.2
Estimates for San Diego Gas & Electric's CTC & Other Costs (in 1996 Dollars)

			ELECTRIC RATES						
Year	**Demand**	**QF Stranded Costs1**	**Rate excluding CTC Rate Component2**	**CTC Component for QF losses (3)/(2)**	**Rate including CTC for QFs (4)+(5)**	**Total Electric Rate3**	**CTC Component for Other Stranded Costs4**	**CTC Revenue for Other Stranded Costs (8)*(2)**	**Savings5 from Re-financing with Rate Reduction Bonds**
	(GWh)	($Million)	($/MWh)	($/MWh)	($/MWh)	($/MWh)	($/MWh)	($Million)	($Billion)
(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
1998	18041	$ 74.8	63.84	4.15	67.99	68.75	0.76	$ 13.8	$ 0.025
1999	18348	$ 73.3	62.97	4.00	66.97	68.75	1.78	$ 32.7	$ 0.023
2000	18660	$ 60.9	60.66	3.26	63.92	68.75	4.83	$ 90.1	$ 0.022
2001	18977	$ 61.5	60.09	3.24	63.33	68.75	5.42	$ 102.8	$ 0.021
2002	19299	$ 61.5	58.07	3.19	61.26	61.26			$ 0.020
2003	19628	$ 62.3	60.00	3.17	63.17	63.17			$ 0.019
2004	19961	$ 63.0	61.95	3.16	65.11	65.11			$ 0.018
2005	20301	$ 63.6	64.52	3.13	67.65	67.65			$ 0.017
2006	20646	$ 64.4	67.12	3.12	70.24	70.24			$ 0.016
2007	20997	$ 65.2	69.72	3.11	72.83	72.83			$ 0.016
2008	21354	$ 65.6	73.00	3.07	76.07	76.07			
2009	21717	$ 66.4	76.33	3.06	79.39	79.39			
2010	22086	$ 67.3	79.65	3.05	82.70	82.70			
2011	22461	$ 68.1	79.62	3.03	82.65	82.65			
2012	22843	$ 69.4	79.63	3.04	82.67	82.67			
2013	23231	$ 71.0	79.66	3.06	82.72	82.72			
2014	23626	$ 72.9	79.69	3.09	82.78	82.78			
2015	24028	$ 75.0	79.73	3.12	82.85	82.85			
2016	24436	$ 77.1	79.77	3.16	82.93	82.93			
2017	24852	$ 70.6	79.40	2.84	82.24	82.24			
2018	25274	$ 72.2	79.42	2.86	82.28	82.28			
2019	25704	$ 70.9	79.31	2.76	82.07	82.07			
2020	26141	$ 33.3	77.56	1.27	78.83	78.83			
2021	26585	$ 34.3	77.58	1.29	78.87	78.87			
2022	27037	$ 35.3	77.60	1.31	78.91	78.91			
2023	27497	$ 36.2	77.61	1.32	78.93	78.93			
2024	27964	$ 24.2	77.09	0.87	77.96	77.96			
2025	28440	$ 2.3	76.16	0.08	76.24	76.24			
Total6		**$ 1,663**						**$ 239.4**	**$ 0.198**

1 Estimates were made with 12/97 WSCC Competitive Market Study's Southern CA market clearing prices.
2 The rate includes energy, generation, transmission, distribution and customer service.
3 For 1998 through 2001 the rate is fixed at 68.75 $/MWh. This includes a 10% rate reduction for residential and small commercial customers.
4 CTC for all other stranded assets, which is derived from Column 7 - Column 6.
5 It is assumed that the rate on the current debt is 8.5 and the rate on the $.8 billion bond is 5.25%.
6 Total revenues collected: CTC for stranded QF payments is $1,663 million; and CTC for other stranded assets is $239.4 million.

Exhibit 3.3
Estimates for Southern California Edison's CTC & Other Costs (in 1996 Dollars)

			ELECTRIC RATES						
Year	Demand	QF Stranded Costs[1]	Rate excluding CTC Rate Component[2]	CTC Component for QF losses (3)/(2)	Rate including CTC for QFs (4)+(5)	Total Electric Rate[3]	CTC Component for Other Stranded Costs[4]	CTC Revenue for Other Stranded Costs (8)*(2)	Savings[5] from Re-financing with Rate Reduction Bonds
	(GWh)	($Million)	($/MWh)	($/MWh)	($/MWh)	($/MWh)	($/MWh)	($Million)	($Billion)
(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
1998	99528	$ 1,839.0	77.92	18.48	96.40	111.17	14.77	$ 1,470.3	$ 0.093
1999	101220	$ 1,623.6	73.25	16.04	89.29	111.17	21.88	$ 2,214.7	$ 0.088
2000	102941	$ 1,423.4	68.97	13.83	82.80	111.17	28.37	$ 2,920.7	$ 0.084
2001	104691	$ 1,250.9	65.27	11.95	77.22	111.17	33.95	$ 3,554.4	$ 0.079
2002	106470	$ 1,202.4	55.90	11.29	67.19	67.19			$ 0.075
2003	108280	$ 1,178.6	57.21	10.88	68.09	68.09			$ 0.072
2004	110121	$ 1,161.3	58.60	10.55	69.15	69.15			$ 0.068
2005	111993	$ 1,152.6	60.60	10.29	70.89	70.89			$ 0.065
2006	113897	$ 1,082.6	62.16	9.51	71.67	71.67			$ 0.062
2007	115833	$ 1,034.1	63.88	8.93	72.81	72.81			$ 0.058
2008	117803	$ 830.8	65.12	7.05	72.17	72.17			
2009	119805	$ 793.5	67.60	6.62	74.22	74.22			
2010	121842	$ 735.9	69.94	6.04	75.98	75.98			
2011	123913	$ 706.9	69.65	5.70	75.35	75.35			
2012	126020	$ 691.8	69.47	5.49	74.96	74.96			
2013	128162	$ 700.7	69.46	5.47	74.93	74.93			
2014	130341	$ 661.9	69.12	5.08	74.20	74.20			
2015	132557	$ 666.6	69.08	5.03	74.11	74.11			
2016	134810	$ 581.3	68.47	4.31	72.78	72.78			
2017	137102	$ 516.0	68.00	3.76	71.76	71.76			
2018	139433	$ 480.5	67.74	3.45	71.19	71.19			
2019	141803	$ 351.8	66.91	2.48	69.39	69.39			
2020	144214	$ 183.0	65.88	1.27	67.15	67.15			
2021	146665	$ 73.0	65.22	0.50	65.72	65.72			
2022	149159	$ 63.9	65.16	0.43	65.59	65.59			
2023	151694	$ 47.8	65.07	0.32	65.39	65.39			
2024	154273	$ 26.4	64.94	0.17	65.11	65.11			
2025	156896	$ 23.6	64.92	0.15	65.07	65.07			
2026	159563	$ 160.0	64.88	0.10	64.98	64.98			
2027	162275	$ 5.3	64.82	0.03	64.85	64.85			
2028	165034	$ 5.3	64.82	0.03	64.85	64.85			
2029	167840	$ 5.4	64.82	0.03	64.85	64.85			
2030	170693	$ 5.7	64.82	0.03	64.85	64.85			
Total[6]		**$ 21,122**						**$ 10,160.0**	**$ 0.744**

1 Estimates were made with 12/97 WSCC Competitive Market Study's Southern CA market clearing prices.

2 The rate includes energy, generation, transmission, distribution and customer service.

3 For 1998 through 2001 the rate is fixed at 111.17 $/MWh. This includes a 10% rate reduction for residential and small commercial customers.

4 CTC for all other stranded assets, which is derived from Column 7 - Column 6.

5 It is assumed that the rate on the current debt is 8.5 and the rate on the $3.0 billion bond is 5.25~~%~~.

6 Total revenues collected: CTC for stranded QF payments is $21,122 million; and CTC for other stranded assets is $10,160 million.

Section 4. Stranded Cost Recovery for New Jersey and Pennsylvania

4.1 New Jersey

This section reviews the restructuring of New Jersey's electric market. New Jersey's stranded costs are approximately split between nuclear power plant investment and power purchase contracts with non-utility generators. The Board of Public Utilities (BPU) concluded that utilities should have the opportunity to recover from customers the costs associated with power purchase contracts and prior financial commitments made for procuring generation supplies to serve their retail customers. Allowable stranded costs will be recovered through a market transition charge (MTC). The MTC is a utility specific, non-bypassable component of customer's electric bills, and it will reflect the amount by which a utility's current production cost is above market. MTC was to be established in a July 15 filing.

BPU recommends that stranded costs be calculated net of stranded costs that can be reduced, and that periodic true-ups to the MTC be required to reflect changes to market value during the transition period. Stranded costs will be calculated on a net, system-wide basis that accounts for all generation-related assets (i.e., assets whose embedded costs are below market value, as well as those that are above).

The calculation of stranded costs should account for the changing value of assets over the long-run. For most utilities, the embedded costs of existing generation service is expected to decline over time due to depreciation and the ability to meet new demand with purchases at market prices. Thus, the gap between embedded cost-based generation rates and market prices for power is expected to narrow each year. If this trend continued, at some point embedded cost based generation rates would fall below market prices for power, which would imply negative stranded costs in later years. The time period for stranded cost calculation should reflect the expected lives of generation assets.

Any stranded cost calculation should reflect true mitigation efforts that focus on cost reduction. Some of the cost reduction measures include: sale of market commodities (energy, capacity, reserves, AGC) from generating facilities owned by the company; sale of market commodities from generating facilities with which the company has power purchase agreement; contract buy-out or renegotiation of power purchase agreements; and sales and voluntary write downs of company assets. The issuance of securities to refinance the debt associated with stranded investments is being considered.

4.2 State of Pennsylvania

This section discusses current developments in the restructuring of Pennsylvania's electric market. The proposed law in Pennsylvania supports changes in federal laws and regulations that will protect electric generators from competitive disadvantage. The law empowers the Pennsylvania Public Utilities Commission to determine the level of stranded costs for each utility and to provide a CTC for recovery of an appropriate amount of such costs. These costs are described as "an electric utility's known and measurable net electric generation-related costs, determined on a net present value basis over the life of the asset or liability as part of the restructuring plan, which the commission determines will remain following mitigation by the utility."

The market value of utility assets is the net present value of the stream of market revenues ((Gross revenue-production cost) x Energy) resulting from electricity sales from utility generation assets. This approach assumes that generation assets remain under the ownership of the utility, and it is incumbent upon the Commission to determine market value through an administrative process.

In another approach, the stranded cost is determined after the divestiture of utility assets or through sale or spin-off, in which case the stranded cost is the sale price minus the book value of assets. If these plants are sold for less than the book value, the shortfall would be recorded into the CTC account for collection. If these plants are sold above the book value, the surplus would be credited against any amounts in the CTC.

The following categories are permitted by law for recovery of stranded costs:

•Net present investments and costs attributable to the utility's power plants and facilities.
•Regulatory assets and other deferred charges.
•The unbundled portion of projected nuclear power plant decommissioning costs.
•The cost of spent nuclear fuel disposal.
•Cost obligations under contracts with non-utility plants.
•Costs from cancellation, buyout, buydown or renegotiation of non-utility plants.
•Long-term power purchase contracts.
•Costs related to restructuring.

Recovery of these costs is contingent upon a utility's efforts to mitigate them. The legislation anticipates that "transition bonds", a form of revenue bond backed by the future cash flow produced by generation assets, will be used to refinance at lower rates debt associated with stranded assets. Thus stretching out the recovery period.

Section 5. Stranded Cost Recovery of Wholesale Contracts

5.1 Background

On April 24, 1996 FERC issued Order No. 888 allowing utilities to seek extra-contractual recovery of stranded costs for a limited set of existing wholesale requirements contracts executed on or before July 11, 1994. It also allowed utilities to seek recovery of stranded costs caused by retail wheeling, but only in circumstances in which the state regulatory authority does not have authority to address retail stranded costs at the time retail wheeling is required.[8]

FERC proposed to define wholesale stranded cost as "any legitimate, prudent and verifiable cost incurred by a public utility or a transmitting utility to provide service to:

•a wholesale requirements customer that subsequently becomes, in whole or in part, an unbundled wholesale transmission services customer of such public utility or transmitting utility, or

•a retail customer, or a newly created wholesale power sales customer, that subsequently becomes, in whole or in part, an unbundled wholesale transmission services customer of such public utility or transmitting utility".

Thus, this definition will permit a public utility or transmitting utility to seek recovery of wholesale stranded costs as follows:

•First, for stranded costs associated with new wholesale requirements contracts (i.e., any wholesale requirements contract executed after July 11, 1994), the regulations will allow recovery of stranded costs if the contract contains an explicit stranded cost provision that permits recovery.

•Second, for existing wholesale requirements contracts a utility may not recover stranded costs if recovery is explicitly prohibited by the contract or by any power sales or transmission tariff on file with the Commission.

•Third, for existing wholesale requirements contracts that do not address stranded costs through exit fee or other explicit stranded cost provisions, a public utility may seek recovery of stranded costs only as follows:

l. if the parties to the existing contract renegotiate the contract and file a mutually agreeable amendment dealing with stranded costs, and the Commission accepts or approves the amendment;

2. if either or both parties seeks an amendment to the existing contract before the contract expires, and the Commission accepts or approves an amendment permitting stranded cost recovery; or

3. if a public utility files a request, before the contract expires, to recover stranded costs through a departing generation customer's transmission rates under existing rules.

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[8] Wheeling is the transfer of electrical power through transmission and distribution lines from one utility's service area to another's. The power is for retail or wholesale customers and there is a wheeling charge. Wholesale wheeling indicates that bulk power is transmitted over the grid to power companies. Retail wheeling indicates that power is transmitted to end users (e.g. homes, businesses and factories), and gives power producers direct access to retail customers.

•Fourth, if the selling utility under an existing wholesale requirements contract is a transmitting utility but not also a public utility, and the contract does not address stranded costs through an explicit exit fee or other stranded cost provision, the transmitting utility may seek to recover stranded costs through a surcharge to a departing generation customer's transmission rates.

•Fifth, for a retail-turned-wholesale customer, a public utility or transmitting utility may file a request to recover stranded costs from the newly-created wholesale customer through that customer's transmission rates.

•Sixth, for customers who obtain retail wheeling, a public utility or transmitting utility may seek recovery through Commission-jurisdictional transmission rates only if the state regulatory authority had no authority under state law to address stranded costs when retail wheeling is required.

5.2 Justification for Allowing Recovery of Stranded Costs

In the Stranded Cost Notice of Proposed Regulation (NOPR), the Commission noted that the Open Access Rule would give a utility's historical wholesale customers greatly enhanced opportunities to reach new suppliers. Thus affecting the way utilities have recovered costs under the traditional regulatory system that imposed an obligation to serve while permitting recovery of all prudently incurred costs.

If customers leave their utilities' generation systems without paying a share of these costs, the costs will become stranded unless they can be recovered from other customers. The Commission ensures recovery of the costs of the transition to a competitive industry by allowing utilities to recover their legitimate, prudent and verifiable stranded costs.

5.3 Responsibility for Wholesale Stranded Costs

In the Stranded Cost NOPR, the Commission's preliminary finding was that direct assignment of stranded costs to the departing wholesale generation customer is the appropriate method for recovery of such costs. The method requires assigning the costs to the departing wholesale generation customer through either an exit fee or a surcharge. The departing generation customers, and not the remaining generation or transmission customers (or shareholders), must bear their share of the legitimate and prudent obligations that the utility undertook on their behalf. Direct assignment of stranded costs is desirable because it is consistent with the well-established principle of cost causation, namely, that the party who has caused a cost to be incurred should pay it.

Direct assignment will result in a more accurate determination of a utility's stranded costs than an up-front, broad-based transmission surcharge. The direct assignment approach also can be readily applied to both wholesale and retail-turned-wholesale departing customers. It also can be adapted for retail customers. Further, it works for costs stranded by a section 211 order requiring either a public utility, or a transmitting utility that is not also a public utility, to provide transmission service.

5.4 Stranded Cost Recovery for New Wholesale Requirements Contracts

FERC indicated that recovery of wholesale stranded costs associated with any new contract will not be allowed unless such recovery is provided for in the contract.

FERC also stated that a contract that is extended or renegotiated for an effective date after July 11, 1994 will be allowed stranded cost recovery only if it is explicitly provided for in the contract. Future wholesale requirements contracts should address the mutual obligations of the seller and buyer, including the seller's obligation to continue to serve the buyer. FERC defines a stranded cost provision (for contracts executed after July 11, 1994) as a provision that identifies the specific amount of stranded cost liability of the customer(s) and a specific method for calculating the stranded cost charge or rate.

A requirements customer will be responsible for meeting its power needs beyond the end of the contract term by either building its own generation, signing a new power sales contract with its existing supplier, or contracting with new suppliers in conjunction with obtaining transmission service under its existing supplier's open access transmission tariff or another utility's transmission system.

5.5 Stranded Cost Recovery for Existing Wholesale Requirements Contracts

The Commission allows for the recovery of legitimate, prudent and verifiable stranded costs for a discrete set of "existing" wholesale requirements contracts (executed on or before July 11, 1994) - those that do not already contain exit fees or other explicit stranded cost provisions. Although FERC encouraged contract renegotiation to address stranded costs, it proposed to reject a unilateral stranded cost amendment for existing contracts that already contain an exit fee or explicit stranded cost provision.

5.6 Recovery of Stranded Costs Retail Turn Wholesale Customers

Federal and state commissions have the legal authority to address stranded costs that result from retail-turned-wholesale customers who obtain transmission under open access tariffs. FERC proposed that these commissions should be the primary forum for addressing the recovery of stranded costs caused by retail-turned-wholesale customers FERC believes that assets that are stranded as a result of wholesale transmission access should be viewed as wholesale stranded costs. Thus, FERC proposed to include in "wholesale stranded costs" stranded costs resulting from unbundled transmission for newly-created wholesale customers and sought comments on this definition.

5.7 Recovery of Stranded Costs Caused by Retail Wheeling

In the Stranded Cost NOPR, FERC stated that both the Commission and state commission have the legal authority to address stranded costs that result from retail customers who obtain retail wheeling from public utilities in order to reach a different generation supplier. FERC will entertain requests to recover stranded costs caused by retail wheeling only when the state regulatory authority does not have authority under state law to address stranded costs at the time when the retail wheeling is required. FERC noted that states have numerous ways to address stranded costs caused by retail wheeling, one of which is a surcharge to state-jurisdictional rates for local distribution. FERC also noted that states may use their jurisdiction over local distribution facilities to address "stranded benefits", such as environmental benefits associated with conservation, load management, and other demand-side management programs.

This Commission's authority to address retail stranded costs is based on their jurisdiction over the rates, terms, and conditions of unbundled retail transmission in interstate commerce. The authority of state commissions to address retail stranded costs is based on their jurisdiction over local distribution facilities and the service of delivering electric energy to end users.

5.8 Evidentiary Demonstration Necessary - Reasonable Expectation Standard

A public utility or transmitting utility seeking to recover stranded costs must demonstrate that it had a reasonable expectation of continuing to serve a customer.

5.9 Calculation of Recoverable Stranded Costs

In the Stranded Cost NOPR, the Commission proposed that the determination of recoverable stranded costs be based on a "revenues lost" approach. Under this approach, stranded costs are calculated by subtracting the competitive market value of the power the customer would have purchased from the revenues that the customer would have paid had it stayed on the utility's generation system. FERC cited several benefits that FERC believes a "revenues lost" approach offers over a hypothetical cost- of-service approach, including avoidance of an asset-by-asset review, minimization of cost allocation procedures, and ease of application.

FERC suggested that the revenues lost approach automatically takes account of mitigation measures because it reduces the amount of stranded costs recoverable by a utility by the market price of the power that the customer no longer takes. FERC noted that this is so if mitigation is reflected through a one-time, up-front estimate of the future market value of the power and is not trued-up over time.

After careful consideration of the comments submitted, FERC decided to adopt the following formula for calculating a departing generation customer's stranded cost obligation (SCO), on a present value basis, under a revenues lost approach:

SCO=(RSE - CMVE) x L where:

<u>RSE= Revenue Stream Estimate:</u> average annual revenues from the departing generation customer over the three years prior to the customer's departure (with the variable cost component of the revenues clearly identified), less the average transmission-related revenues that the host utility would have recovered from the departing generation customer over the same three years under its new wholesale transmission tariff.

<u>CMVE = Competitive Market Value Estimate:</u> the customer has two options: 1) the utility's estimate of the average annual revenues (over the reasonable expectation period "L" discussed below) that it can receive by selling the released capacity and associated energy, based on a market analysis performed by the utility; or 2) the average annual cost to the customer of replacement capacity and associated energy, based on the customer's contractual commitment with its new supplier(s).

<u>L= Length of Obligation</u> (reasonable expectation period when the utility could have reasonably expected to continue to serve the departing generation customer.

Application of the foregoing formula and collection of the resulting stranded costs are subject to the following conditions:

Cap on SCO.

The quantity (RSE - CMVE) can be no greater than the average annual contribution to fixed power supply costs (defined as RSE less variable costs) that would have been made by the departing generation customer had it remained a customer.

Changes in Customer Revenues.

If the customer's rates (or contract demand amounts, if relevant) changed during the three-year period prior to the termination of its existing requirements contract, then the RSE should be calculated using the customer's most recent 12 months of revenue.

CMVE Option 2 Conditions.

Option 2 (CMVE equal to the customer's average cost for replacement capacity and associated energy) would be available to a customer whose alternative purchase(s) runs concurrent with L, or, if longer than L, contains rates that do not fluctuate over the duration of the contract. The customer would be required to demonstrate (at the time it chooses this option) that the replacement capacity contract(s) is for service equivalent to the released capacity (i.e., firm power for a period at least equal to L), and must also clearly identify the rates to be paid for the replacement service.

Payment Options.

The method and term of payment should be negotiated, but is ultimately left to the customer's discretion. Possible payment options include a lump-sum payment, an amortization of a lump-sum payment over a reasonable period of time, or a surcharge on the customer's transmission rate.

Applicability.

The formula is designed for determining stranded costs associated with departing wholesale generation customers and for retail-turned-wholesale customers.

Marketing/Brokering Option.

The Commission will allow the customer, at its sole discretion, to market the released capacity and associated energy (or to contract with a marketer for such service). Alternatively, the customer may choose to broker the released capacity and associated energy (or to contract with a broker).

Released Capacity and Associated Energy.

A utility requesting stranded cost recovery must indicate the amount of system capacity and the amount of associated energy released by the departing generation customer and used in the revenues lost calculation. This will allow the departing generation customer to fairly consider exercising a choice to market or broker the released capacity and associated energy.

The formula balances a number of goals, including: ensuring full recovery of legitimate, prudent and verifiable stranded costs; requiring the utility to mitigate stranded costs; providing certainty for departing generation customers; and creating incentives for the parties to renegotiate their existing requirements contracts or otherwise settle stranded cost claims without resort to litigation.

Calculation of the Revenue Stream Estimate (RSE)

The RSE component of the formula is based on revenues paid by the departing generation customer during the last three years of its contract or retail service. The use of present revenues eliminates disputes over estimates of future revenues, thereby adding certainty to the calculation. It also eliminates the need for a detailed listing of includable costs, relying instead on the assumption that present rates include all of the utility's costs of providing service. Further, the rates that produce present revenues have been approved by regulators, which strongly suggests that the costs included in them are prudent, legitimate and verifiable.

Calculation of the Competitive Market Value Estimate (CMVE)

FERC recognizes the difficulty associated with estimating the competitive market value of the capacity and associated energy not purchased by the departing generation customer. However, FERC believes that an up-front estimate, which provides flexibility to the utility and a measure of certainty to customers, is superior to other proposals, provided the right mix of incentives and options is included in the formula. A utility requesting stranded cost recovery must estimate CMVE based on a market analysis, with all assumptions and work papers made available to the departing generation customer. This provides a utility with the flexibility to choose the methodology that it feels produces the best estimate of the competitive market value of the released capacity and associated energy.

Snapshot approach versus true-ups

The revenues lost formula is based on a one-time snapshot approach. FERC favors this approach over the true-up approach because it creates certainty and will produce reasonably accurate results.

5.10 Stranded Costs in the Context of Voluntary Restructuring

In the Stranded Cost NOPR, FERC noted that the functional unbundling of wholesale services does not require corporate unbundling (e.g., disposition of assets to a non-affiliate, or establishing a separate corporate affiliate to manage a utility's transmission assets). At the same time, FERC indicated that some utilities may ultimately choose some form of corporate unbundling. FERC reaffirmed in this Final Rule that it is willing to consider case-specific proposals for dealing with stranded costs in the context of any restructuring proceedings that may be instituted by a utility.

This Rule adopts a direct assignment approach for the recovery of stranded costs from departing generation customers. Under the revenues lost approach, stranded cost recovery is limited to the departing generation customer's contribution to fixed costs that the utility otherwise would not recover because of the customer's departure.