EXHIBIT NO. ___(BAV-3)
DOCKET NO. UE-04____/UG-04____
2004 PSE GENERAL RATE CASE
WITNESS: BERTRAND A. VALDMAN

BEFORE THE
WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION

WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION, **Complainant,** **v.** **PUGET SOUND ENERGY, INC.,** **Respondent.**	**Docket No. UE-04____** **Docket No. UG-04____**

SECOND EXHIBIT TO PREFILED DIRECT TESTIMONY OF
BERTRAND A. VALDMAN (NONCONFIDENTIAL)
ON BEHALF OF PUGET SOUND ENERGY, INC.

APRIL 5, 2004

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- Energy Sector Equity Performance
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- Summer 2004 Spark Spread Outlook Promising
- Commodity Price Deck Revision and E&P Impact
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March 17, 2004

Credit Lyonnais Securities (USA) Inc.

IMPORTANT DISCLOSURES ARE FOUND ON INSIDE FRONT COVER

Please refer to report number EQ006-04 for all inquiries.

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VALUATION METHODOLOGY for price targets: DIVERSIFIED ENERGY, UTILITY & IPP UNIVERSE (G. Howald)—Sum-of-the-Parts EBITDA analysis, DCF analysis or NAV analysis. OIL SERVICES & EQUIPMENT UNIVERSE (K. David-Green)—Combination of P/E, cash flow and EV/EBITDA multiples and/or replacement value. OIL & GAS EXPLORATION UNIVERSE (B. Beago)—Combination of NAV analysis and cash flow and /EBITDA multiples.

RISKS TO TARGETS INCLUDE: Economic downturn or significant changes in commodity prices. Specific to OIL SERVICES & EQUIP.—Downturn in worldwide drilling markets.

FOR A HISTORY of the recommendations and price targets for companies mentioned in this report, please write to: Credit Lyonnais Securities (USA) Inc., Compliance Department, 1301 Avenue of the Americas, 37th Floor, New York, New York 10019-6022

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INVESTMENT BANKING CLIENTS as a % of rating category: BUY – 32%, NEUTRAL – 20%, SELL – 0%. Data for 12-month period ending December 31, 2003.

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ADDITIONAL INFORMATION on the securities mentioned herein is available upon request.

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Statistical Highlights and Observations

Energy Sector Equity Performance

For the six months ended March 12, 2003, the Refining & Marketing Composite increased 59.0%, outperforming the other CLS Energy Composites significantly. The E&P Composite and the Oil Field Services Composite also exhibited strong performances, advancing 26.6% and 25.8%, respectively. Overall, the CLS Energy sub-sectors have averaged returns of 28.0% over the last six months, outperforming the S&P 500's gains of 10.0%. The last six months' performance can be found in Exhibit 6.

Over the last two years, the E&P Composite had the best performance of the six CLS Energy Composites, advancing 57.6% while the Diversified Energy Composite had the worst performance over the same period, declining 53.2%. Overall, the CLS Energy sub-sectors have averaged returns of 9.0% over the last two years or 21.5% excluding the Diversified Energy Composite. Over the same period, the S&P 500 has declined 3.9%. Returns for the past two years can be found in Exhibit 7.

Hydro Outlook for Summer 2004 Positive for Western Power Prices

(A note to our readers- we have moved our Hydro Availability Analysis toward the end of the report, so that it now follows the Weather section. Our hydro analysis can now be found in Exhibits 85 –88)

As we move toward spring, we are beginning to get a better sense of the winter snowpack level and therefore of what shape hydro resources will be in the northwestern United States for the peak summer demand period. In February, the Northwest experienced lower-than-normal levels of precipitation across most of the important regions of the Columbia Basin. According to the United States Department of Agriculture Natural Resources Conservation Service (NRCS), which monitors snowpack, "overall, precipitation (where it counts) was way down over the Columbia Basin during February."

We would also highlight the U.S. National Oceanic and Atmospheric Administration Northwest River Forecast Center (NWRFC)'s discussion of water conditions in the Northwest, which points to reduced expectations for streamflows as a result of the lower precipitation in key areas. In its February Water Supply Summary, the NWRFC stated that: "Below average February precipitation and deficient snow water equivalent accumulations have reduced streamflow expectations. It is noteworthy that the Columbia River in Canada and the Pend Oreille river basin in Montana are most deficient in precipitation and snow water equivalents. Two-thirds of the runoff for the Columbia River at The Dalles comes from this area."

Based on the above trends, it is not surprising that snowpack in the Northwest was significantly lower at the end of February than at the end of January. As of March 1, snowpack in the Columbia Basin was 91% of average versus 101% a month before, as reported by the NRCS. We display summary data for the winter snowpack for key regions in the Northwest in the Table 1 below:

Table 1: Columbia Basin Snowpack Summary % of Normal – Winter 2004

	British Columbia	Above Grand Coulee*	Above Ice Harbor*	Average**
As of Jan. 1, 2004	90%	94%	109%	98%
As of Feb. 1, 2004	96%	99%	106%	101%
As of Mar. 1, 2004	84%	87%	100%	91%

*Please see map in Exhibit 88 for locations in the above table.
**Average based on additional locations besides those summarized in the above table.
Sources: United States Department of Agriculture Natural Resources Conservation Service and Credit Lyonnais Securities.

Relative to the above table, we would point out that snowpack above Grand Coulee Dam is especially significant due to the large generation capacity at the Grand Coulee (roughly 6,800 Mw) as well as at the large dams that are down river from it. We would view the lower-than-normal snowpack above the Grand Coulee as potentially being indicative of lower levels of hydro resources this spring (as mentioned earlier, the Grand Coulee and other major northwestern rivers and dams are illustrated on a map in Exhibit 88).

In its mid-March forecast, the NWRFC indicated that it expects the water supply at the Dalles Dam to be 86% of normal for January through July and 86% of normal for April through September. The NWRFC expects water supply at the Grand Coulee Dam to be 88% of normal for January through July and 88% of normal for April through September. Its mid-February predictions had been 5-6% higher for both regions, illustrating that the hydro picture is deteriorating rather quickly.

According to AccuWeather forecaster Dale Moler, precipitation in the Pacific Northwest will be 70%-80% of normal for the next 3-5 months, and that drought-like conditions are still possible. If temperatures are higher than – normal, water evaporation will increase, furthering the hydro problems in the West, which will force the Bonneville Power Administration to further limit exports into California this summer.

While March precipitation could still play a significant role in snowpack (as it did last year), we believe the scenario that is developing could lead to a lower-than-normal hydro supply and therefore higher power prices in the West this summer. We have already seen evidence of the power market's reacting to the developing situation in the West, with forward power prices for Mid-Columbia as of March 18 increasing by 21.7% from year-end levels. Forward prices for Palo Verde to the south have also increased by 11.4% from year-end levels.

Another significant factor will be temperatures this spring, which would influence the timing of snowmelt. Warmer-than-normal temperatures could result in an accelerated snowmelt, which could make the situation more positive for power prices thereafter.

Natural Gas Spark Spreads Resilient in New York and New England but Moderate Elsewhere

Spark spreads have been fairly strong in 2004 in New England and New York, averaging $17.27 per MWh and $12.98 per MWh, respectively. At the end of February, spark spreads in New England and New York were $14.15 per MWh and $18.41 per MWh, respectively. However, spark spreads in other regions have been lackluster with spark spreads for the nation as a whole averaging $8.94 per MWh in February, down from $10.88 at the end of January – we display our 7,000 heat rate natural gas spark spreads in Exhibit 25.

Natural gas prices have remained fairly high, pressuring the fuel cost portion of the spread. Cash Henry Hub closed February at $5.28 per MMBtu, as displayed in Exhibit 46. Additionally, warmer weather has undercut demand to some degree, especially at the end of February and into early March, when weather was substantially warmer than normal. Overall, weather for the 2004/2003 heating season has been 4% warmer than normal and 7% warmer than the previous year, as we display in Exhibit 79.

Strong Potential for Summer 2004 Spark Spreads

Despite the moderate national spark spreads exhibited year to date, it is important to note the strength that we are seeing in the forward curves for this summer. In Exhibit 27, we display our forward curve analysis, which is indicating average spark spreads above $25 in July and August. We believe that there is a strong potential that margins across the country will be fairly robust this summer. For example, developments in the West such as the hydro situation (discussed in the previous section) and the recently announced maintenance on the Pacific-DC Intertie transmission line could have a favorable impact on spark spreads this summer and have, in fact, already lifted forward prices to some degree.

It is important to keep in mind that all this is happening in an environment of increasing demand for electricity. As we show in Exhibit 36, electric output has increased 2.4% year over year through the end of February. We believe that demand could continue to grow at this rate or higher, which is in line with electric demand's historical growth rate. Our assumptions on electric growth are based on our assumptions of growth in the overall economy. Of course, a key variable will be the weather this summer, which is impossible to predict, but we have experienced several mild summers in a row. True "peak" demand should be measured during a period of economic strength AND warmer-than-normal summer temperatures – those two events have not occurred together for several years (and we believe could catch the market by surprise when they do occur together). Ultimately, we believe that this summer could provide companies leveraged to the wholesale markets, such as Calpine, with an opportunity to demonstrate their operating potential.

Increasing Benchmark Commodity Price Deck and Estimates for E&P Companies – Group Still Overvalued

(From Brad Beago – Oil and Gas Exploration Analyst)

Excerpted from our March 8 note titled: *"Are E&P Companies Overvalued? Increasing 2004 and 2005 Benchmark Price Deck Commodity Prices and Estimates; Examining Price Targets."*

We increased our benchmark Henry Hub natural gas price forecast for 2004 to $5/Mcf from $4.25/Mcf based on strong first-quarter prices, which could average close to $5.50/Mcf, as well as the strong futures market. In addition, we are increasing our 2005 price deck to $4.25 from $3.50. We have consistently been using $3.50/Mcf as our long-term equilibrium price. We demonstrate our commodity price deck in Exhibit 45. However, it appears that the industry's rising cost structure and inability to increase production point toward higher prices. The new trading range appears to be $4-$5, at least as long as crude oil prices remain at or above $30/bbl.

We are increasing our benchmark WTI crude oil price forecast for 2004 to $29/bbl from $26.50/bbl based on high actual January and February prices as well as strength in the futures market. We continue to believe that oil prices will begin to retreat from current levels during the second quarter of 2004 and could trend downward throughout the year. We are retaining our "equilibrium" crude oil price estimate of $25/bbl at this time. However, we note that the five-year average for futures prices is currently above $30/bbl. Like gas, we believe crude oil prices will continue to exhibit substantial volatility. Based on this, even if investors believe that $30/bbl for oil is here to stay, they will likely discount any E&P company valuation derived from such a perceived high price.

As a result of the upward revision in our commodity forecasts, our EPS estimates for the 11 companies in our universe increase by an average of 41%, CFPS projections increase by an average of 15% and EBITDA estimates increase by an average of 16%. For 2005, the impact is even greater, with an 86% average increase in our earnings estimates, an 18% increase in our CFPS projections and a 17% increase in our EBITDA forecasts. It makes sense that the impact of a $0.75/Mcf increase in natural gas prices would have a much more significant impact on our 2005 estimates than on our 2004 estimates because at our previous estimate of $3.50/Mcf, most of the companies in our universe were generating very modest earnings. In other words, the group barely breaks even at $3.50/Mcf. Further, we have ratcheted up most companies' cost structures for both 2004 and 2005 by an average of 5%-10% per year. In recent quarters, costs have been increasing for the group at a higher pace. It may be that by the time we actually get to 2005, most companies will not be breakeven at $3.50/Mcf, in our opinion. We believe this supports the contention that $4/Mcf natural gas prices are here to stay.

Today, we believe that the market is rewarding fairly high multiples to earnings based on high commodity prices. The change in our commodity price deck outlined above results in a 16% increase in our calculated price targets. However, this analysis is incomplete. Our Net Asset Value estimates account for 20% of our calculated price target. At this time, we have not increased NAVs for the higher commodity price assumptions. Once our NAVs are completed for year-end 2003, we will be in a better position to run them at various price decks.

Of course, the counter-argument is that $5/Mcf gas and $30/bbl oil may be the right future average commodity prices to use to value E&P companies. We are not convinced of this yet, even though the futures market currently implies similar pricing. In any case, if the $30/bbl and $5/Mcf are correct, stocks are still trading at a discount, but not by that much.

The group is trading on average at a 15% premium to our original calculated price targets (using our old commodity price assumptions). When we re-calculate these targets (except for the NAVs as mentioned previously), the group is trading on average at our new, higher calculated price targets, with some stocks trading well above. So the stocks are currently impounding average multiples on high commodity prices or high multiples on average commodity prices, in our opinion.

Coal Spark Spreads Moderate on Steadily Climbing Coal Prices

In Exhibit 30, we display coal spark spreads, which moderated in February, with the Composite Average decreasing to $27.14 per MWh from $38.83 per MWh in January. Increasing coal prices have impacted coal spark spreads, illustrated by examining Big Sandy Barge coal prices, which increased 5.8% from last month and 45.6% year over year (see Exhibit 68). The demand for coal has increased roughly 2.3% year over year, according to Energy Information Administration (EIA) coal consumption data accumulated through November 2003. Not surprisingly, the increase in consumption was largely driven by the electric power sector. We display this information in Exhibit 71.

Emissions Credits Mixed Versus January Levels

In February's Statistical Energy Monthly, we introduced the Platts U.S. Emissions Broker Indexes, which we display in Exhibits 91 and 92. In February, the NOx index for the current year contract declined from January's level by $235.00 per ton to $2,365.00 per ton. However, the SO2 current year contract rose by $12.50 per ton to $266.50 per ton from the January level. Both indices had previously been trending steadily higher since October 2003.

According to Platts, the continued appetite for SO2 credits can be attributed to sentiment that SO2 restrictions are likely to tighten in the future and that the "emissions bank" of utilities is growing smaller, meaning that some utilities may not have adequate credits for their generation. Volumes in both markets were fairly light, indicating that the price movements are likely the product of a few players' moves as opposed to being representative of large-scale trends. One explanation that Platts suggested for the lighter volumes was that utilities were putting emissions trading on the back burner while they devoted more resources toward securing coal supply in a tightening market.

Diversified Energy, Utility & IPP Statistics

Exhibit 1: Credit Lyonnais Diversified Energy, Utility & IPP Statistics—March 10, 2004

Diversified Energy	Symbol	3/10/04 Price	Rating	Dividend	Yield	Market Cap ($MM)	EPS 2002A	EPS 2003A (1)		EPS 2004E		P/E 2002A	P/E 2003A (1)	P/E 2004E
Aquila	ILA	$4.00	NR	NA	NA	$726.5	$0.06	($0.90)	^	($0.45)	^	66.7x	-4.4x	-8.9x
Dominion Resources	D	64.61	NR	2.58	4.0%	19,849.6	4.83	4.50		4.94	^	13.4	14.4	13.1
Duke Energy Corp.	DUK	21.60	NR	1.10	5.1%	19,258.4	1.88	1.28		1.17	^	11.5	16.9	18.5
Dynegy+	DYN	3.95	BUY	NA	NA	1,481.3	(0.85)	(0.97)		(0.34)		(4.6)	NA	NA
El Paso Corp.	EP	6.92	SELL	0.16	2.3%	4,147.8	0.64	0.15	~	0.15		10.8	46.1	46.1
NiSource	NI	21.87	NR	0.92	4.2%	5,331.7	2.00	1.61		1.70	^	10.9	13.6	12.9
Sempra	SRE	32.33	NR	1.00	3.1%	6,747.7	2.79	2.93		2.74	^	11.6	11.0	11.8
Williams+	WMB	9.39	BUY	0.04	0.4%	4,861.2	(0.16)	0.02		0.40		(58.7)	469.5	23.5
Average					**3.2%**							**NM**	**81.0x**	**16.7x**

LDCs	Symbol	3/10/04 Price	Rating	Dividend	Yield	Market Cap ($MM)	EPS 2002A	EPS 2003A (1)		EPS 2004E		P/E 2002A	P/E 2003A (1)	P/E 2004E
AGL Resources+	ATG	$28.49	ADD	$1.12	3.9%	$1,831.9	$1.82	$2.01		$2.10		15.7x	14.2x	13.6x
Atmos Energy	ATO	26.30	NEUTRAL	1.22	4.6%	1,359.7	1.45	1.54		1.59		18.1	17.1	16.5
KeySpan Energy	KSE	37.54	NEUTRAL	1.78	4.7%	5,972.6	2.75	2.48		2.60		13.7	15.1	14.4
Nicor	GAS	36.63	NR	1.86	5.1%	1,612.3	2.88	1.99		2.23	^	12.7	18.4	16.4
ONEOK	OKE	22.70	NR	0.76	3.3%	1,644.3	1.30	2.13		2.07	^	17.5	10.7	11.0
Peoples Energy	PGL	45.25	NR	2.16	4.8%	1,615.4	2.80	2.87		2.80	^	16.2	15.8	16.2
Piedmont Natural	PNY	42.49	NR	1.66	3.9%	1,409.7	1.89	2.22		2.39	^	22.5	19.1	17.8
Questar	STR	36.00	NR	0.82	2.3%	2,948.8	1.78	2.29		2.44	^	20.2	15.7	14.8
SEMCO	SEN	5.80	NEUTRAL	0.30	5.2%	162.4	0.48	0.14		0.24		12.1	41.4	24.2
Southern Union+*	SUG	18.80	BUY	Stock**	5.0%	1,370.5	0.59	0.97		1.39		31.9	19.4	13.5
Southwest Gas	SWX	23.06	NR	0.82	3.6%	765.7	1.43	1.13		1.55	^	16.1	20.4	14.9
Average					**4.2%**							**17.9x**	**18.8x**	**15.7x**

IPP Industry	Symbol	3/10/04 Price	Rating	Dividend	Yield	Market Cap ($MM)	EPS 2002A	EPS 2003A (1)		EPS 2004E		P/E 2002A	P/E 2003A (1)	P/E 2004E
AES Corp.	AES	$8.16	NR	NA	NA	$4,437.4	$0.78	$0.43		$0.61	^	10.5x	19.0x	13.4x
Calpine+	CPN	5.00	BUY	NA	NA	1,906.0	0.84	0.13		0.05		6.0	NA	NA
Mirant	MIR	0.48	NR	NA	NA	191.9	0.94	0.05	^	(0.05)	^	0.5	9.5	(9.5)
Reliant Resources	RRI	7.42	NR	NA	NA	2,155.1	1.23	0.55		0.30	^	6.0	13.5	24.7
Average					**NA**							**5.7x**	**14.0x**	**9.5x**

Electric Utilities	Symbol	3/10/04 Price	Rating	Dividend	Yield	Market Cap ($MM)	EPS 2002A	EPS 2003A (1)		EPS 2004E		P/E 2002A	P/E 2003A (1)	P/E 2004E
American Electric Power+	AEP	$33.90	NR	$1.40	4.1%	$11,486.5	$2.89	$2.21		$2.29	^	11.7x	15.3x	14.8x
Black Hills+	BKH	31.51	NEUTRAL	1.24	3.9%	1,011.5	2.33	1.97		2.16		13.5	16.0	14.6
Cinergy Corp.+	CIN	40.28	ADD	1.88	4.7%	7,165.8	2.68	2.54		2.76		15.0	15.9	14.6
CMS Energy Corp.	CMS	9.00	NR	NA	NA	1,296.8	1.53	0.74		0.83	^	5.9	12.2	10.8
Consolidated Edison Inc.	ED	44.33	NR	2.26	5.1%	9,469.9	3.13	2.83		2.72	^	14.2	15.7	16.3
Entergy Corp.+	ETR	58.93	BUY	1.80	3.1%	13,194.4	3.81	4.25		4.20		15.5	13.9	14.0
Exelon Corp.	EXC	67.83	NR	2.20	3.2%	21,908.1	4.83	5.22		5.53	^	14.0	13.0	12.3
FPL Group Inc.+	FPL	67.40	RESTRICTED	2.40	3.6%	12,199.4	4.80	4.89		NA		14.0	13.8	NA
PSE&G	PEG	46.01	NR	2.20	4.8%	10,233.6	3.76	3.72		3.73	^	12.2	12.4	12.3
PPL Corporation	PPL	46.04	NR	1.54	3.3%	7,571.4	3.54	3.71		3.70	^	13.0	12.4	12.4
TXU Corp.	TXU	27.70	NR	0.50	1.8%	8,921.6	2.42	2.00		2.13	^	11.4	13.9	13.0
Xcel Energy Inc.	XEL	17.78	NR	0.75	4.2%	7,089.1	1.43	1.29		1.23	^	12.4	13.8	14.5
Average					**3.8%**							**12.8x**	**14.0x**	**13.6x**

NA – Not Applicable. NM – Not Meaningful. ^First Call consensus estimates. **5% stock dividend.
For 2003, reflects actuals unless noted by ^ (FirstCall consensus) or ~ (CLS Estimate).
Effective April 22, 2003, Credit Lyonnais Securities (USA) Inc. changed the HOLD rating to NEUTRAL. *Market Cap. $ in Millions.*
+* See disclosures on inside front cover of this report.
Sources: Credit Lyonnais Securities, Bloomberg, FirstCall and Reuters.

Exhibit 2: Credit Lyonnais Diversified Energy, Utility & IPP Statistics—March 10, 2004 (Cont.)

	EV ($MM)			EBITDA ($MM)			EV (x)			Book/Share		
Diversified Energy	**2000A**	**2001A**	**2002A**	**2000A**	**2001A**	**2002A**	**2000A**	**2001A**	**2002A**	**2000A**	**2001A**	**2002A**
Aquila	$5,880	$4,302	$3,654	$708	$982	$404	8.3x	4.4x	9.0x	$17.94	$22.32	$8.30
Dominion Resources	29,806	29,886	33,941	3,352	3,338	4,359	8.9	9.0	7.8	28.48	31.61	33.16
Duke Energy Corp.	44,513	44,703	41,520	4,841	5,177	4,599	9.2	8.6	9.0	13.61	16.33	16.70
Dynegy+	21,881	15,221	7,630	1,291	1,471	122	16.9	10.3	62.5	11.15	13.88	5.64
El Paso Corp.	55,683	42,895	25,999	4,140	4,394	2,270	13.5	9.8	11.5	15.20	16.24	13.97
NiSource	14,996	13,167	12,571	654	1,058	1,206	22.9	12.4	10.4	16.55	16.61	16.78
Sempra	8,666	9,372	9,729	1,447	1,576	1,583	6.0	5.9	6.1	12.35	13.17	13.79
Williams+	28,615	24,613	15,628	2,489	2,723	1,279	11.5	9.0	12.2	13.21	12.07	9.25

	EV ($MM)			EBITDA ($MM)			EV (x)			Book/Share		
LDCs	**2000A**	**2001A**	**2002A**	**2000A**	**2001A**	**2002A**	**2000A**	**2001A**	**2002A**	**2000A**	**2001A**	**2002A**
AGL Resources+	$1,908	$2,511	$2,491	$250	$337	$336	7.6x	7.5x	7.4x	$11.25	$12.25	$12.52
Atmos Energy	1,282	1,715	1,734	164	204	235	7.8	8.4	7.4	15.27	14.54	13.75
KeySpan Energy	10,174	10,264	11,170	1,117	1,367	1,439	9.1	7.5	7.8	20.83	20.76	20.67
Nicor	2,786	2,783	2,313	378	360	346	7.4	7.7	6.7	15.27	16.10	16.55
ONEOK	3,732	4,676	2,976	462	390	513	8.1	12.0	5.8	20.70	21.08	22.47
Peoples Energy	2,151	2,335	2,126	278	214	291	7.7	10.9	7.3	22.02	23.78	22.74
Piedmont Natural	1,547	1,714	1,739	189	197	193	8.2	8.7	9.0	16.52	16.89	17.82
Questar	3,150	4,305	3,477	443	476	548	7.1	9.0	6.3	12.26	12.73	13.88
SEMCO	722	778	741	101	89	94	7.1	8.7	7.9	7.53	6.29	5.89
Southern Union+*	1,526	2,693	2,356	127	290	237	12.0	9.3	9.9	13.13	9.12	12.48
Southwest Gas	1,769	1,860	1,994	164	180	201	10.8	10.3	9.9	16.89	17.32	17.91

	EV ($MM)			EBITDA ($MM)			EV (x)			Book/Share		
IPP Industry	**2000A**	**2001A**	**2002A**	**2000A**	**2001A**	**2002A**	**2000A**	**2001A**	**2002A**	**2000A**	**2001A**	**2002A**
AES Corp.	$48,121	$31,971	$22,710	$3,332	$3,320	$829	14.4x	9.6x	27.4x	$10.79	$10.19	($0.61)
Calpine+	17,601	18,324	16,479	874	1,489	1,391	20.1	12.3	11.8	8.14	9.47	10.11
Mirant	17,245	14,695	9,987	1,463	1,476	1,175	11.8	10.0	8.5	14.33	16.09	7.32
Reliant Resources	NA	5,838	8,425	547	1,144	1,235	NA	5.1	6.8	NA	22.00	19.45

	EV ($MM)			EBITDA ($MM)			EV (x)			Book/Share		
Electric Utilities	**2000A**	**2001A**	**2002A**	**2000A**	**2001A**	**2002A**	**2000A**	**2001A**	**2002A**	**2000A**	**2001A**	**2002A**
American Electric Power+	$30,061	$29,235	$23,386	$3,184	$3,645	$3,340	9.4x	8.0x	7.0x	$25.01	$25.54	$20.85
Black Hills+	1,590	1,706	1,629	148	224	202	10.8	7.6	8.1	12.48	19.75	19.47
Cinergy Corp.+	9,629	10,219	10,999	1,315	1,478	1,338	7.3	6.9	8.2	17.54	18.45	19.53
CMS Energy Corp.	11,775	11,587	8,908	1,351	1,066	1,214	8.7	10.9	7.3	19.48	14.16	7.86
Consolidated Edison Inc.	13,281	13,822	15,221	1,914	2,125	2,019	6.9	6.5	7.5	28.98	29.99	31.05
Entergy Corp.+	18,235	17,318	19,302	2,501	2,487	2,741	7.3	7.0	7.0	31.89	33.78	35.24
Exelon Corp.	37,636	30,015	33,400	2,422	5,337	5,380	15.5	5.6	6.2	22.62	25.24	23.95
FPL Group Inc.+	17,810	16,758	19,307	2,417	2,497	2,365	7.4	6.7	8.2	31.82	34.20	34.96
PSE&G	18,962	21,399	21,133	1,716	1,732	1,789	11.1	12.4	11.8	19.21	20.10	17.70
PPL Corporation	12,385	10,805	13,701	1,646	1,842	1,992	7.5	5.9	6.9	13.85	12.67	13.42
TXU Corp.	32,785	26,207	21,919	2,990	2,901	2,102	11.0	9.0	10.4	28.96	28.88	14.80
Xcel Energy Inc.	19,568	25,290	20,834	2,556	2,902	2,536	7.7	8.7	8.2	16.32	16.74	11.70

NA – Not Applicable. NM – Not Meaningful.
+* See disclosures on inside front cover of this report.
Sources: Company reports and Credit Lyonnais Securities.

Exhibit 3: Credit Lyonnais Diversified Energy, Utility & IPP Performance—March 10, 2004

		3/10/2004		Y-O-Y Stock Performance				
	Ticker	Price	Rating	2000	2001	2002	2003	YTD 2004
Diversified Energy								
Aquila**	ILA	$4.00	NR	59.5%	-18.8%	-93.0%	91.5%	18.0%
Dominion Resources	D	64.61	NR	70.7%	-10.3%	-8.7%	16.3%	1.2%
Duke Energy Corp.	DUK	21.60	NR	70.1%	-7.9%	-50.2%	4.7%	5.6%
Dynegy+	DYN	3.95	BUY	361.2%	-54.5%	-95.4%	262.7%	-7.7%
El Paso Corp.	EP	6.92	SELL	84.6%	-37.7%	-84.4%	17.7%	-15.5%
NiSource	NI	21.87	NR	72.0%	-25.0%	-13.3%	9.7%	-0.3%
Sempra	SRE	32.33	NR	33.8%	5.6%	-3.7%	27.1%	7.6%
Williams***+	WMB	9.39	BUY	30.7%	-36.1%	-89.4%	263.7%	-4.4%
Average				**111.8%**	**-23.1%**	**-54.7%**	**86.7%**	**0.6%**
LDCs								
AGL Resources+	ATG	$28.49	NR	29.8%	4.3%	5.6%	19.8%	-2.1%
Atmos Energy	ATO	26.30	NEUTRAL	19.3%	-12.8%	9.7%	4.2%	8.2%
KeySpan Energy	KSE	37.54	NEUTRAL	83.2%	-18.2%	1.7%	4.4%	2.0%
Nicor	GAS	36.63	NR	-23.1%	32.9%	-21.2%	0.0%	7.6%
ONEOK	OKE	22.70	NR	91.5%	-25.9%	7.6%	15.0%	2.8%
Peoples Energy	PGL	45.25	NR	33.6%	-15.2%	1.9%	8.8%	7.6%
Piedmont Natural	PNY	42.49	NR	26.8%	-6.3%	-1.3%	22.9%	-2.2%
Questar	STR	36.00	NR	100.4%	-16.7%	11.1%	26.3%	2.4%
SEMCO	SEN	5.80	NEUTRAL	31.7%	-30.9%	-43.3%	-19.7%	18.4%
Southern Union+*	SUG	18.80	BUY	45.5%	-25.3%	-12.5%	11.5%	2.2%
Southwest Gas	SWX	23.06	NR	-4.9%	2.1%	4.9%	-4.3%	2.7%
Average				**39.4%**	**-10.2%**	**-3.2%**	**8.1%**	**4.5%**
IPPs								
AES Corp.	AES	$8.16	NR	48.2%	-70.5%	-81.5%	212.6%	-13.6%
Calpine+	CPN	5.00	BUY	181.6%	-62.7%	-80.6%	47.5%	4.0%
Mirant	MIR	0.48	NR	NA	-43.4%	-88.3%	-79.1%	21.8%
Reliant Resources	RRI	7.42	NR	NA	-45.0%	-80.6%	130.0%	0.8%
Average				**114.9%**	**-55.4%**	**-82.8%**	**77.7%**	**3.3%**
Electric Utilities								
American Electric Power+	AEP	$33.90	NR	44.7%	-6.4%	-37.2%	11.6%	11.1%
Black Hills+	BKH	$31.51	NEUTRAL	101.7%	-24.4%	-21.6%	12.5%	5.6%
Cinergy Corp.+	CIN	40.28	ADD	46.7%	-4.8%	0.9%	15.1%	3.8%
CMS Energy Corp.	CMS	9.00	NR	1.6%	-24.2%	-60.7%	-9.7%	5.6%
Consolidated Edison Inc.	ED	44.33	NR	11.6%	4.8%	6.1%	0.4%	3.1%
Entergy Corp.+	ETR	58.93	BUY	64.3%	-7.6%	16.6%	25.3%	3.2%
Exelon Corp.	EXC	67.83	NR	102.0%	-31.8%	10.2%	25.8%	2.2%
FPL Group Inc.+	FPL	67.40	RESTRICTED	67.6%	-21.4%	6.6%	8.8%	3.0%
PSE&G	PEG	46.01	NR	39.7%	-13.2%	-23.9%	36.4%	5.0%
PPL Corporation	PPL	46.04	NR	97.5%	-22.9%	-0.5%	26.2%	5.2%
TXU Corp.	TXU	27.70	NR	24.6%	6.4%	-60.4%	27.0%	16.8%
Xcel Energy Inc.	XEL	17.78	NR	49.0%	-4.6%	-60.3%	54.4%	4.7%
Average				**54.3%**	**-12.5%**	**-18.7%**	**19.5%**	**5.8%**

**Uses UtiliCorp performance prior to name change. ***Adjusted for spin-off of Williams Communications.
+* See disclosures on inside front cover of this report.
Sources: Credit Lyonnais Securities and Reuters.

Oil Services & Equipment Statistics

Exhibit 4: Credit Lyonnais Oil Services & Equipment Statistics—March 10, 2004

	FYE	Symbol	Rating	Stock Price 3/10/04	Stock Price 12/31/03	% YTD Change	52-Week Price Range High	52-Week Price Range Low	Shares Out. (MM)	Market Cap. (MM)	Yield %
Global Industries Ltd. m	Dec	GLBL	RESTRICTED	$5.83	$5.13	14%	$6.60	$3.54	100.9	$588.3	Nil
Newpark Resources, Inc.	Dec	NR	NEUTRAL	5.30	4.79	11%	6.24	3.67	81.0	429.1	Nil
Key Energy Services, Inc.+	Dec	KEG	ADD	12.80	10.31	24%	13.96	8.04	129.9	1,663.0	Nil
Pride International, Inc.	Dec	PDE	ADD	16.93	18.64	-9%	20.23	12.75	135.3	2,290.5	Nil
Smith International, Inc.*	Dec	SII	ADD	49.74	41.52	20%	52.68	31.81	100.2	4,981.5	Nil
The Shaw Group Inc. +*	Aug	SGR	NEUTRAL	11.73	13.62	-14%	14.45	6.80	55.5	650.5	Nil
Transocean Inc.	Dec	RIG	ADD	28.53	24.01	19%	31.94	18.40	319.9	9,127.5	Nil
Willbros Group, Inc. +	Dec	WG	NEUTRAL	14.26	12.02	19%	16.08	6.95	20.7	294.9	Nil
Average						*9%*					

	ST Debt	LT Debt	Preferred Stock	Market Cap.	Cash & Equiv.	Total Enterprise Value (TEV)	Book Common Equity	Book Total Cap.	Debt/ Cap.	Book Value/ Share	Price/ Book
Global Industries Ltd. m	$5.8	$113.1	$0.0	$588.3	$17.3	$690.0	$431.9	$550.8	22%	$5.46	1.1x
Newpark Resources, Inc.	10.9	169.7	30.0	429.1	3.7	635.9	315.6	496.1	36%	6.13	0.9
Key Energy Services, Inc.+	24.6	532.6	0.0	1,663.0	89.4	2,130.7	718.4	1,275.5	44%	9.82	1.3
Pride International, Inc.	219.0	1,815.1	0.0	2,290.5	69.1	4,255.5	1,702.8	3,736.9	54%	27.62	0.6
Smith International, Inc.*	89.7	488.5	0.0	4,981.5	51.3	5,508.5	1,235.8	1,814.1	32%	18.11	2.7
The Shaw Group Inc. +*	73.5	252.3	0.0	650.5	81.8	894.5	833.5	1,159.3	28%	20.90	0.6
Transocean Inc.	45.8	3,612.3	0.0	9,127.5	474.0	12,311.6	7,192.6	10,850.7	34%	33.92	0.8
Willbros Group, Inc. +	1.4	8.0	0.0	294.9	20.2	284.1	203.7	213.1	4%	10.30	1.4

	Earnings Per Share 2002	Earnings Per Share 2003	Earnings Per Share 2004E	Cash Flow Per Share 2002	Cash Flow Per Share 2003	Cash Flow Per Share 2004E	EBITDA (MM) 2003	EBITDA (MM) 2004E
Global Industries Ltd. m	$0.10	($0.47)	NM	$0.70	$0.07	NM	$24.6	NM
Newpark Resources, Inc.	0.01	0.00	0.10	0.44	0.27	0.36	41.0	50.3
Key Energy Services, Inc.+	0.01	0.11	0.35	1.17	0.91	1.17	176.7	219.3
Pride International, Inc.	(0.06)	0.02	0.23	1.67	1.64	2.53	370.6	475.4
Smith International, Inc.*	0.93	1.27	1.80	1.86	2.28	2.85	435.0	533.8
The Shaw Group Inc. +*	2.26	1.26	0.55	2.78	2.61	1.70	136.7	143.4
Transocean Inc.	1.14	0.17	0.45	2.65	1.75	2.07	784.5	889.6
Willbros Group, Inc. +	1.59	(0.16)	0.65	2.73	1.10	1.70	17.0	48.3

	Price/Earnings 2002	Price/Earnings 2003	Price/Earnings 2004E	Price/Cash Flow 2002	Price/Cash Flow 2003	Price/Cash Flow 2004E	TEV/EBITDA 2003	TEV/EBITDA 2004E
Global Industries Ltd. m	NM	NM	NM	8.3x	NM	NM	28.0x	NM
Newpark Resources, Inc.	NM	NM	NM	12.0	19.8	14.6	15.5	12.6
Key Energy Services, Inc.+	NM	NM	36.7	10.9	14.1	11.0	12.1	9.7
Pride International, Inc.	NM	NM	NM	10.1	10.3	6.7	11.5	9.0
Smith International, Inc.*	NM	39.3	27.6	NM	21.8	17.4	12.7	10.3
The Shaw Group Inc. +*	5.2	9.3	21.2	4.2	4.5	6.9	6.5	6.2
Transocean Inc.	25.0	NM	NM	10.8	16.3	13.8	15.7	13.8
Willbros Group, Inc. +	9.0	NM	21.9	5.2	13.0	8.4	16.7	5.9
Average	*13.1x*	*9.3x*	*26.6x*	*8.8x*	*13.0x*	*10.2x*	*15.1x*	*9.5x*

	Stock Price 3/10/04	12-Month Target
Global Industries Ltd. m	$5.83	NM
Newpark Resources, Inc.	5.30	4.30
Key Energy Services, Inc.+	12.80	13.50
Pride International, Inc.	16.93	20.00
Smith International, Inc.*	49.74	54.00
The Shaw Group Inc. +*	11.73	11.50
Transocean Inc.	28.53	30.00
Willbros Group, Inc. +	14.26	12.00

+* See disclosures on inside front cover of this report.

Sources: Karen David-Green—Oil Services and Equipment Analyst, Credit Lyonnais Securities, FactSet.

Oil & Gas Exploration Statistics

Exhibit 5: Credit Lyonnais Oil & Gas Exploration Statistics—March 10, 2004

	Ticker Symbol	Rating	12-Month Price Target	3/10/04 ($/Share)	Estimated NAV ($/Share)	Price/ NAV	Earnings Per Share (1) 2003	2004E	2005E	Price/Earnings (2) 2003	2004E	2005E
Large and Mid Capitalization Independents (> $2 billion)												
Anadarko Petroleum	APC	NEUTRAL	$50.00	$51.86	$56.69	91%	$5.29	$4.90	$3.77	9.8x	10.6x	13.8x
Apache Corporation @	APA	NEUTRAL	$35.00	$41.05	$33.50	123%	$3.75	$3.19	$2.27	10.9x	12.9x	18.1x
Devon Energy @	DVN	NEUTRAL	$55.00	$56.04	$55.72	101%	$7.30	$5.53	$3.15	7.7x	10.1x	17.8x
EOG Resources @	EOG	NEUTRAL	$48.00	$44.51	$39.11	114%	$3.69	$3.17	$2.02	12.0x	14.1x	22.0x
Newfield Exploration @	NFX	NEUTRAL	$45.00	$46.60	$36.42	128%	$3.92	$4.21	$2.55	11.9x	11.1x	18.2x
Noble Energy @	NBL	NEUTRAL	$42.00	$46.11	$37.49	123%	$2.59	$2.49	$1.26	17.8x	18.5x	36.6x
XTO Energy +@	XTO	NEUTRAL	$25.00	$31.21	$20.93	149%	$1.87	$2.28	$1.80	16.7x	13.7x	17.3x
Group Average						**118%**				**12.4x**	**13.0x**	**20.5x**
Small Capitalization Independents (< $2 billion)												
Comstock Resources	CRK	NEUTRAL	$17.00	$19.52	$17.50	112%	$1.55	$1.46	$0.97	12.6x	13.4x	20.1x
Denbury Resources @	DNR	NEUTRAL	$15.00	$15.10	$15.19	99%	$1.23	$0.96	$0.62	12.3x	15.7x	24.3x
Patina Oil & Gas @	POG	NEUTRAL	$22.50	$26.11	$19.00	137%	$1.52	$2.10	$1.81	17.2x	12.4x	14.4x
Vintage Petroleum @	VPI	NEUTRAL	$15.00	$15.00	$20.00	75%	$1.03	$1.21	$0.54	14.5x	12.4x	27.7x
Group Average						**106%**				**14.2x**	**13.5x**	**21.7x**

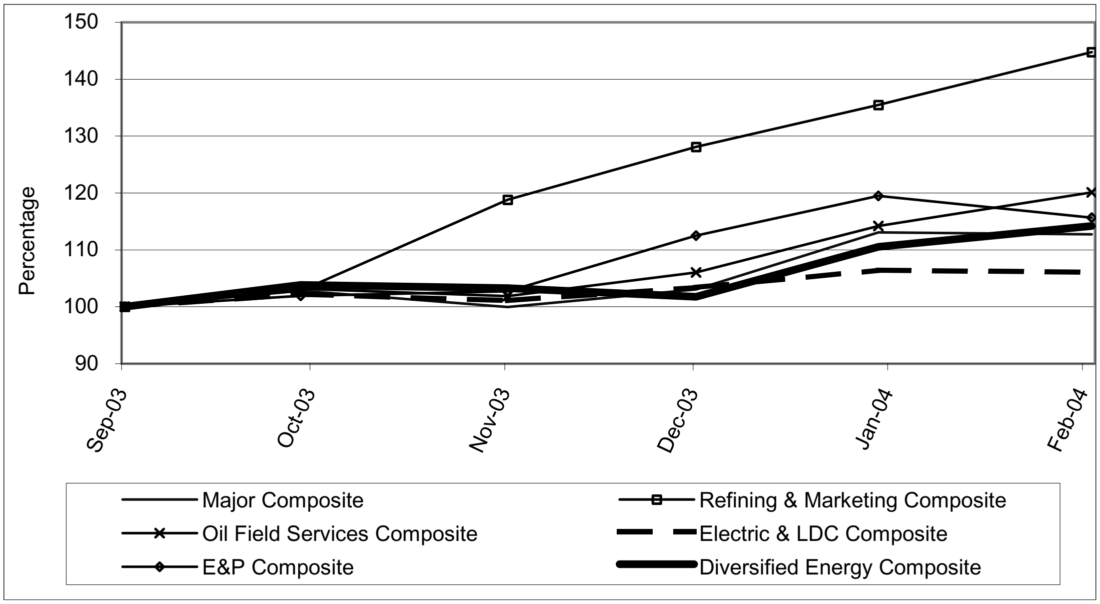
	EBITDA ($MM) 2003	2004E	2005E	TEV / EBITDA 2003	2004E	2005E	Cash Flow Per Share 2003	2004E	2005E	Price / Cash Flow 2003	2004E	2005E
Large and Mid Capitalization Independents (> $2 billion)												
Anadarko Petroleum	$3,681.8	$3,702.5	$3,358.5	5.1x	5.1x	5.6x	$12.46	$12.56	$11.59	4.2x	4.1x	4.5x
Apache Corporation @	$3,169.8	$3,103.2	$2,677.3	5.0x	5.1x	5.9x	$8.60	$8.08	$7.07	4.8x	5.1x	5.8x
Devon Energy @	$4,586.1	$4,930.2	$4,184.8	4.5x	4.2x	5.0x	$18.00	$17.22	$14.47	3.1x	3.3x	3.9x
EOG Resources @	$1,441.6	$1,386.8	$1,251.9	4.5x	4.7x	5.2x	$10.85	$10.56	$9.64	4.1x	4.2x	4.6x
Newfield Exploration @	$785.3	$819.8	$711.1	4.2x	4.0x	4.6x	$12.95	$13.11	$11.52	3.6x	3.6x	4.0x
Noble Energy @	$771.8	$779.1	$702.5	4.7x	4.7x	5.2x	$12.22	$11.84	$11.30	3.8x	3.9x	4.1x
XTO Energy +@	$884.9	$1,119.6	$1,024.2	8.6x	6.8x	7.4x	$4.52	$5.22	$4.70	6.9x	6.0x	6.6x
Group Average				**5.2x**	**4.9x**	**5.5x**				**4.3x**	**4.3x**	**4.8x**
Small Capitalization Independents (< $2 billion)												
Comstock Resources	$178.1	$186.6	$173.6	5.8x	5.5x	5.9x	$4.28	$4.44	$4.14	4.6x	4.4x	4.7x
Denbury Resources @	$212.1	$205.6	$181.7	5.4x	5.6x	6.3x	$3.42	$3.23	$2.77	4.4x	4.7x	5.5x
Patina Oil & Gas @	$303.3	$385.2	$363.7	7.6x	6.0x	6.3x	$3.96	$4.64	$4.41	6.6x	5.6x	5.9x
Vintage Petroleum @	$368.3	$348.7	$300.6	4.4x	4.7x	5.4x	$4.12	$4.23	$3.60	3.6x	3.5x	4.2x
Group Average				**5.8x**	**5.4x**	**6.0x**				**4.8x**	**4.6x**	**5.1x**

	3/10/04 ($/Share)	Shares Out. (MM)	Enterprise Value Calculation (TEV - $MM) Market Cap.	+ ST Debt	+ LT Debt	+ Pref. Stock	- Cash & Equiv.	= TEV	Book Common Equity	Book Total Cap.	Debt/ Cap.	Balance Sheet
Large and Mid Capitalization Independents (> $2 billion)												
Anadarko Petroleum	$51.86	254.0	$13,172.4	$0.0	$5,058.0	$89.0	($391.0)	$18,710.4	$8,599.0	$13,657.0	37%	Q4 2003 E
Apache Corporation @	$41.05	327.8	$13,455.4	$0.0	$2,327.0	$0.0	$78.7	$15,703.6	$6,532.8	$8,859.8	26%	Q4 2003 E
Devon Energy @	$56.04	242.0	$13,561.7	$338.0	$8,022.0	$150.0	$1,273.0	$20,798.7	$11,056.0	$19,416.0	43%	Q4 2003
EOG Resources @	$44.51	117.2	$5,217.0	$0.0	$1,108.9	$148.3	$4.4	$6,469.7	$2,223.4	$3,332.3	33%	Q4 2003
Newfield Exploration @	$46.60	56.6	$2,639.6	$0.0	$643.5	$0.0	$15.3	$3,267.7	$1,368.6	$2,012.0	32%	Q4 2003
Noble Energy @	$46.11	56.8	$2,619.8	$60.8	$776.0	$0.0	($174.1)	$3,630.7	$1,074.6	$1,911.4	44%	Q4 2003 E
XTO Energy +@	$31.21	188.3	$5,875.6	$0.0	$1,701.0	$0.0	$7.0	$7,569.6	$1,518.9	$3,219.9	53%	Q4 2003 PF
Small Capitalization Independents (< $2 billion)												
Comstock Resources	$19.52	36.4	$711.0	$0.0	$306.0	$0.0	($8.4)	$1,025.4	$289.7	$595.7	51%	Q4 2003 E
Denbury Resources @	$15.10	55.9	$843.7	$0.0	$300.0	$0.0	$0.0	$1,143.7	$421.2	$721.2	42%	Q4 2003 E
Patina Oil & Gas @	$26.11	72.4	$1,890.5	$0.0	$416.0	$0.0	$1.9	$2,304.6	$330.0	$746.0	56%	Q4 2003 E
Vintage Petroleum @	$15.00	66.0	$990.0	$3.0	$699.9	$0.0	$54.9	$1,638.0	$422.5	$1,125.4	62%	Q4 2003

(1) All companies have December fiscal years.
(2) P/E multiples above 99x are shown as "NM."
+@ See disclosures on inside front cover of this report.
Sources: Brad Beago—Oil & Gas Exploration Analyst, Credit Lyonnais Securities, FactSet.

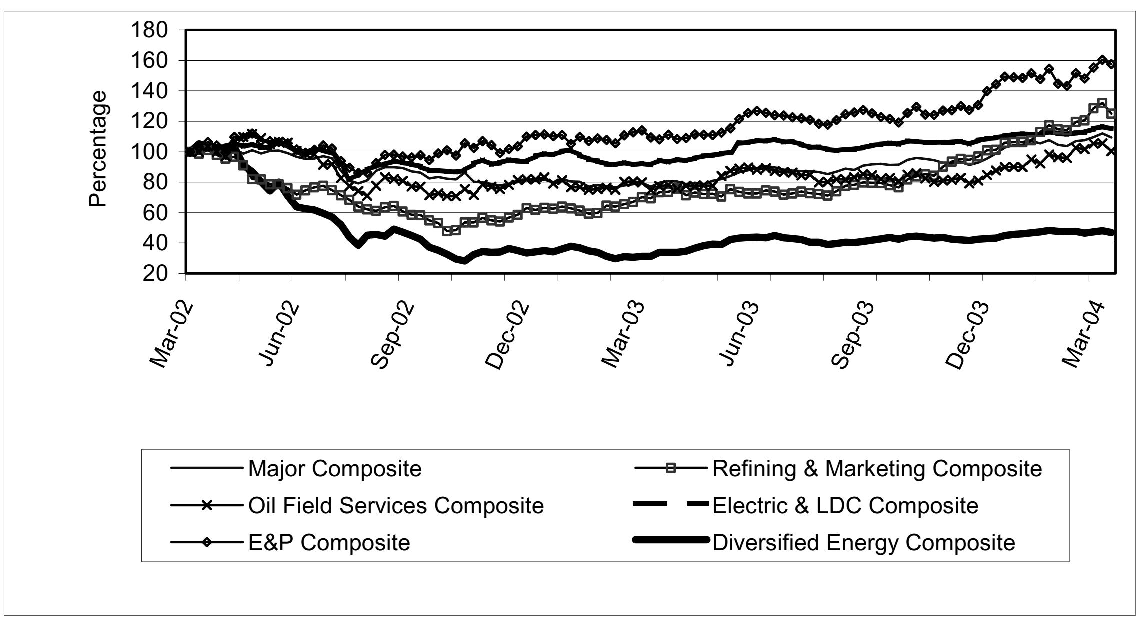
Relative Energy Industry Performance

Exhibit 6: Relative Energy Industry Performance (Trailing Six Months, March 12, 2004)



Diversified Energy index includes: AEP, ILA, D, DUK, DYN, EP, WMB.
Exploration & Production index includes: APC, APA, CRK, DNR, DVN, EOG, NBL.
Electric & LDC index includes: ATG, ATO, DTE, ED, EIX, ETR, FE, FPL, GAS, KSE, NI, PGL, PNY, STR, SEN, SO, SUG.
Oil Field Services index includes: BHI, BJS, CAM, DO, ESV, GSF, HAL, IO, MDR, NBR, NE, SLB, WFT, WF.
Refining and Marketing index includes: ASH, SUN, TSO, VLO.
Majors index includes: AHC, BP, COP, CVX, XOM, KMG, MRO, MUR, OXY.
Sources: Credit Lyonnais Securities, FactSet.

Exhibit 7: Relative Energy Industry Performance Two-Year Study, March 12, 2004



Diversified Energy index includes: AEP, ILA, D, DUK, DYN, EP, WMB.
Exploration & Production index includes: APC, APA, CRK, DNR, DVN, EOG, NBL.
Electric & LDC index includes: ATG, ATO, DTE, ED, EIX, ETR, FE, FPL, GAS, KSE, NI, PGL, PNY, STR, SEN, SO, SUG.
Oil Field Services index includes: BHI, BJS, CAM, DO, ESV, GSF, HAL, IO, MDR, NBR, NE, SLB, WFT, WF.
Refining and Marketing index includes: ASH, SUN, TSO, VLO.
Majors index includes: AHC, BP, COP, CVX, XOM, KMG, MRO, MUR, OXY.
Sources: Credit Lyonnais Securities, FactSet.

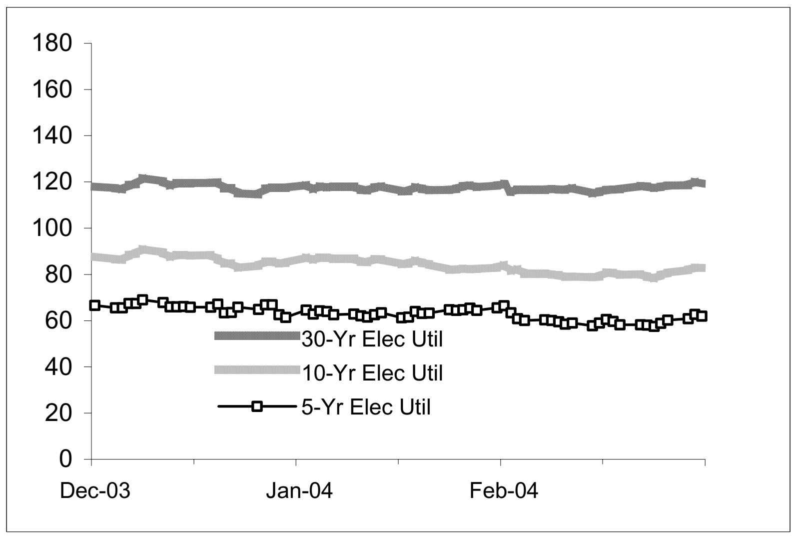
Fixed Income Analysis

Paul Clegg, Credit Lyonnais Fixed Income Analyst

Little Movement in Yield Spreads

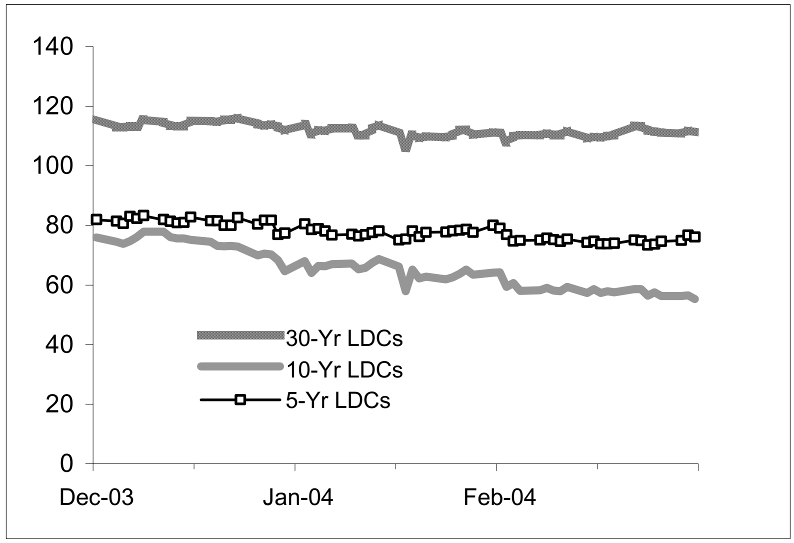
Our Electric Utility & Diversified indexes have showed almost no change over the last 30 days and were evenly split between issues that widened and those that tightened. Spreads for our LDC universe were mixed in direction, but also moved only modestly, with our 5-year curve tightening only 5 bps, while our 30-year curve widened slightly. Among electric utility and diversified issuers, TXU Corp and FPL Group Capital issues tightened noticeably, but were somewhat offset in our index by more modest widening among several issuers, particularly at the longer end of the curve. We provide yield spreads for selected issues in Exhibits 8 and 9.

Exhibit 8: Yield Spreads – Electric Utilities & Diversified (in bps)



Index values are based on mean bid yield spreads over the closest of 5-, 10- or 30-year Treasury securities.
Index bonds include a variety of secured and unsecured issues of AEP, CIN, CMS, DUK, ED, ETR, EXC, FPL, PPL, TXU and XEL.
Sources: Bloomberg, Credit Lyonnais Securities (USA) Inc.

Exhibit 9: Yield Spreads – LDCs (in bps)

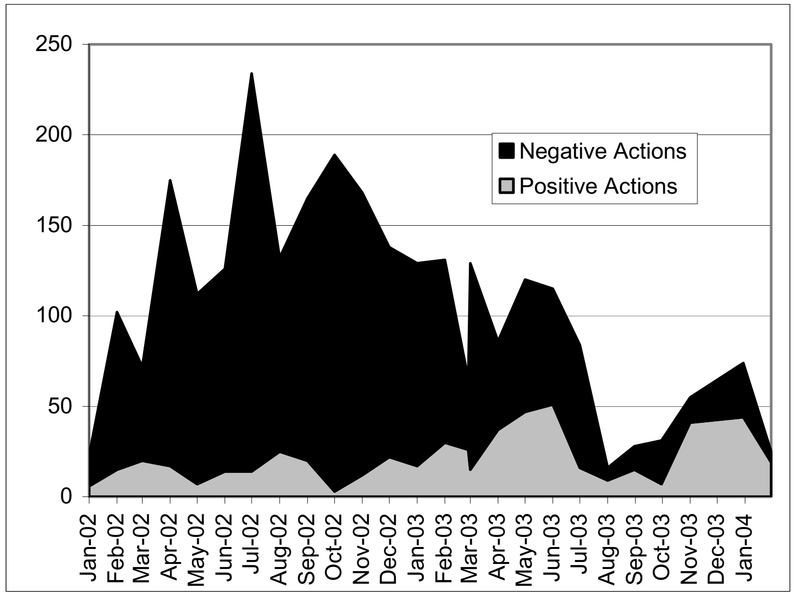


Index values are based on mean bid yield spreads over the closest of 5-, 10- or 30-year Treasury securities.
Index bonds include a variety of secured and unsecured issues of ATO, ATG, GAS, KSE, OKE, PGL, STR, SUG and SWX.
Sources: Bloomberg, Credit Lyonnais Securities (USA) Inc.

Rating Actions

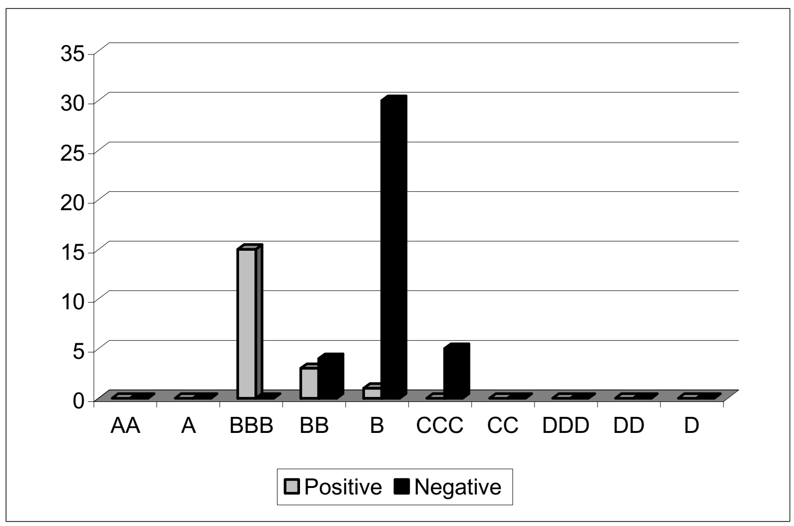
Negative ratings actions outpaced positive actions over the last 30 days 39 to 19. Activity was split fairly evenly between Moody's, which accounted for 21 of the negative actions, and S&P, which accounted for the remaining 18 negative actions. Notable negative actions include both Moody's and S&P's downgrades of El Paso and related entities following that company's announcement that it would take a $1 billion charge to account for a revision to its oil and gas reserve estimates. El Paso-related downgrades and negative ratings revisions accounted for almost half of total negative ratings actions. Of the 19 positive ratings actions in the last 30 days, Moody's accounted for 12, S&P four and Fitch three. Notable positive actions included Moody's shift to positive outlook on Entergy Arkansas and Louisiana as well as S&P and Moody's upgrades of Public Service Company of New Mexico.

Exhibit 10: Rating Agency Actions (January 2002-February 2004)



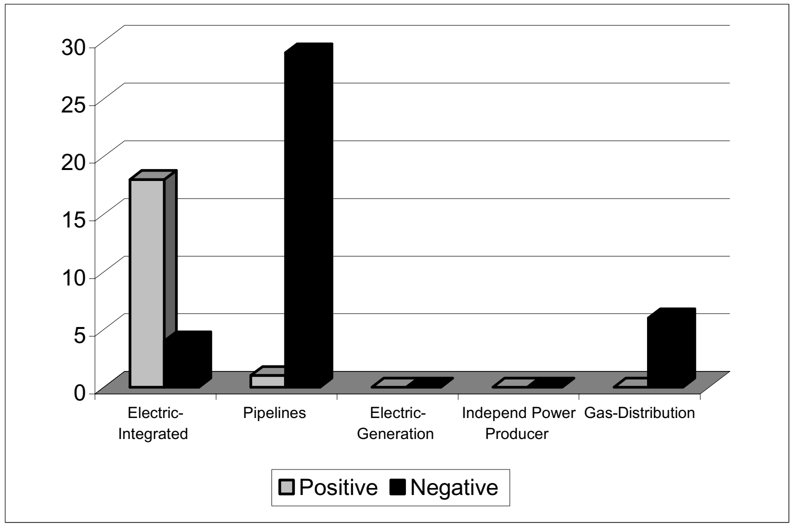
All categories of each ratings tier are included as one tier (e.g., BBB+, BBB and BBB- are all included as "BBB", etc.). In the case of split ratings, the lower rating is used.
Sources: Bloomberg, S&P, Moody's & Fitch.

Exhibit 11: Rating Actions by Latest Rating (February 2004)



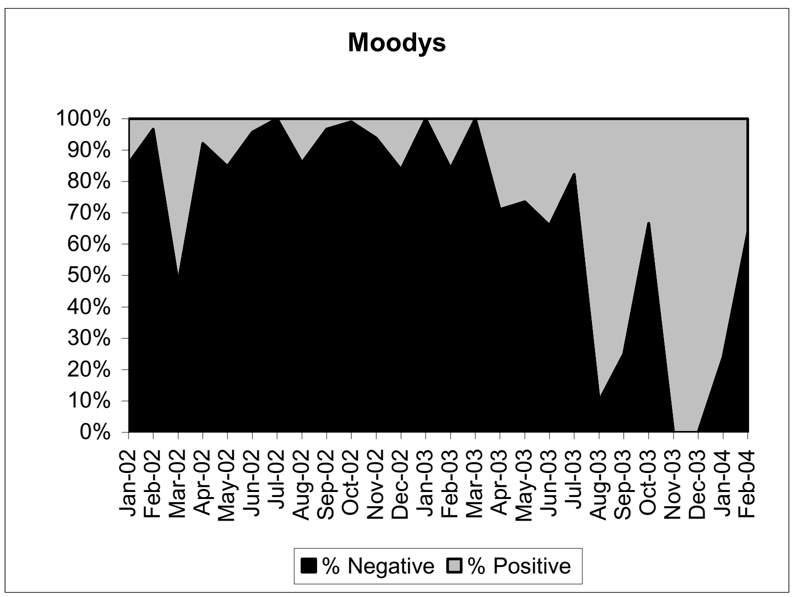
All categories of each ratings tier are included as one tier (e.g., BBB+, BBB and BBB- are all included as "BBB", etc.). In the case of split ratings, the lower rating is used.
Sources: Bloomberg, S&P, Moody's & Fitch.

Exhibit 12: Rating Actions by Sector (February 2004)



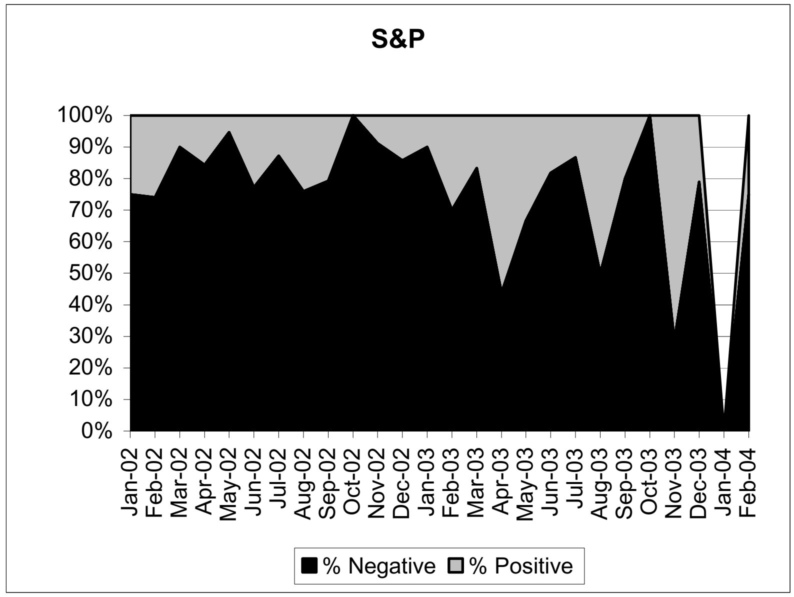
All categories of each ratings tier are included as one tier (e.g., BBB+, BBB and BBB- are all included as “BBB”, etc.). In the case of split ratings, the lower rating is used.
Sources: Bloomberg, S&P, Moody’s & Fitch.

Exhibit 13: Moody’s Rating Actions – Percent Positive vs. Negative (January 2002–February 2004)



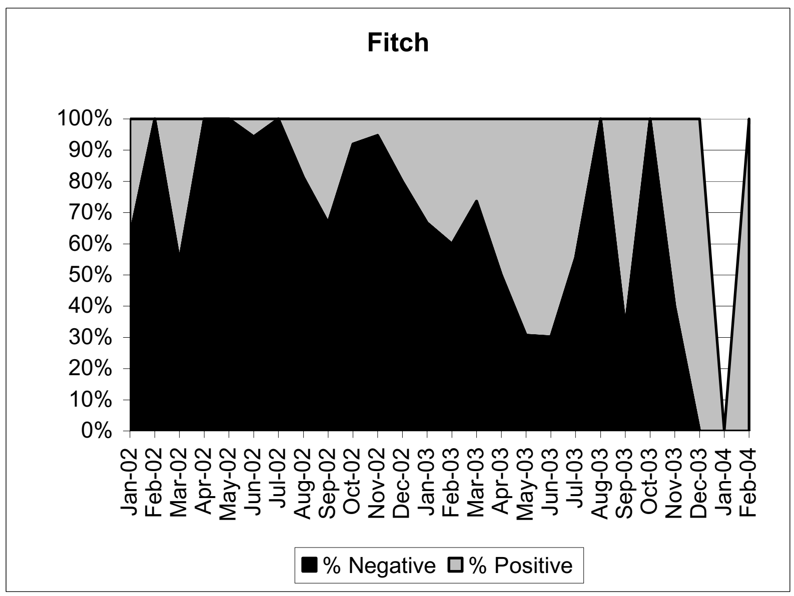
Sources: Bloomberg and Moody’s.

Exhibit 14: S&P Rating Actions – Percent Positive vs. Negative (January 2002–February 2004)



Sources: Bloomberg and S&P.

Exhibit 15: Fitch Rating Actions – Percent Positive vs. Negative (January 2002–February 2004)

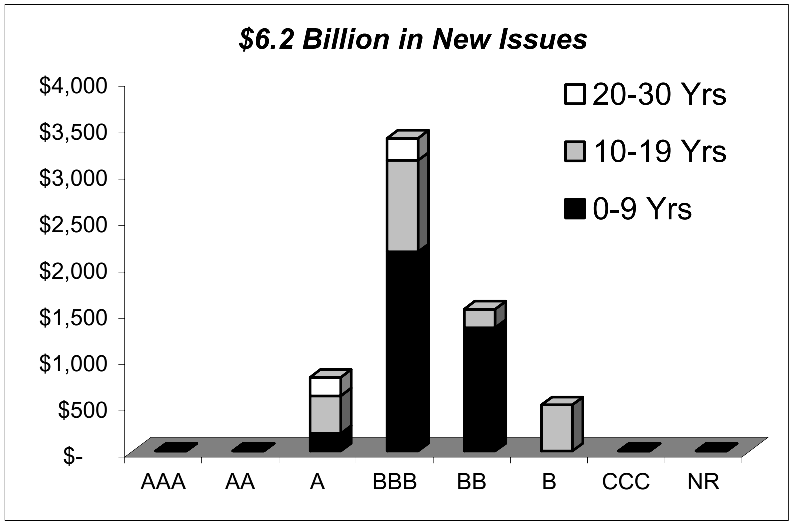


Sources: Bloomberg and Fitch.

New Issues

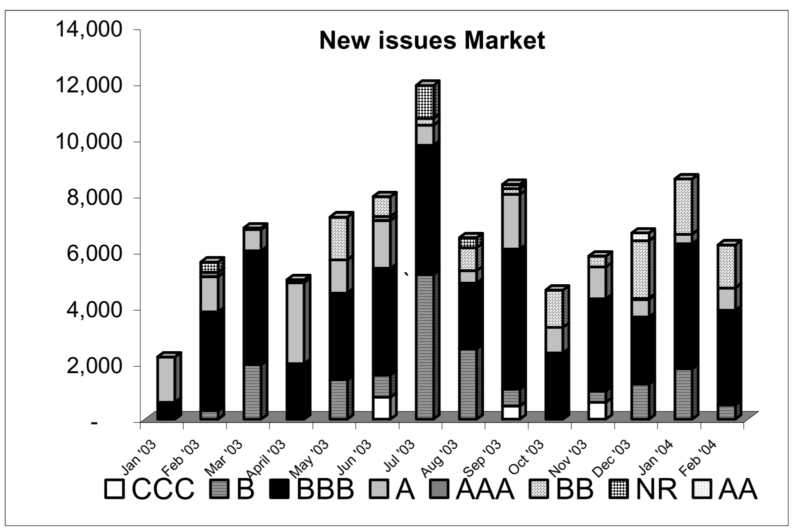
Fixed income investors bought $6.2 billion of new issuances for electric utility, diversified, LDC and pipeline companies over the last 30 days. Over 70% of the deals that came to market were investment grade, mostly BBB, but several single-A as well. There was little activity at the long end of the curve, although both Con Ed and Entergy managed longer-dated offerings with maturities in the environs of 30 years. Notable deals included several Duke Capital senior issues totaling $1.4 billion and ranging in maturity from May 2006 to March 2014, as well as a round of Entergy Gulf States FMBs totaling $765 million and ranging in maturity from June 2008 to July 2023. Among high yield issues, AES Corp.'s $500 million in senior notes due March 2014 and a series of FMB financings by CMS totaling $1.3 billion were notable issues.

Exhibit 16: New Issues by Rating - $ in MMs (February 2004)



All categories of each ratings tier are included as one tier (e.g., BBB+, BBB and BBB- are all included as "BBB", etc.). In the case of split ratings, the lower rating is used.
Sources: Bloomberg, S&P, Moody's & Fitch.

Exhibit 17: New Issues by Rating - $ in MMs (January 2003-February 2004)



All categories of each ratings tier are included as one tier (e.g., BBB+, BBB and BBB- are all included as "BBB", etc.). In the case of split ratings, the lower rating is used.
Sources: Bloomberg, S&P, Moody's & Fitch.

Exhibit 18: Credit Lyonnais Electric Utility & Diversified Universe Debt Statistics—03/10/04

			%					Current				1 Month Ago			
Company	Ticker		Coupon	Maturity	Amt (MMs)	Moodys	S&P	Price	Yield	T-Yield	Spread	Price	Yield	T-Yield	Spread
5-year															
FLORIDA POWER & LIGHT	FPL	+	6.00	6/1/2008	200.0	Aa3	A	111.90	2.99	2.66	34	110.07	3.46	3.12	34
CONS EDISON CO OF NY	ED		6.45	12/1/2007	330.0	A1	A	113.29	2.74	2.66	8	111.50	3.21	3.12	9
FPL GROUP CAPITAL INC	FPL	+	7.38	6/1/2009	625.0	A2	A-	118.05	3.56	2.66	90	115.38	4.11	3.12	99
DUKE ENERGY CORP	DUK		3.75	3/5/2008	500.0	A3	BBB+	102.30	3.13	2.66	47	100.54	3.61	3.12	49
COMMONWEALTH EDISON	EXC		3.70	2/1/2008	350.0	A3	A-	102.99	2.93	2.66	27	101.17	3.38	3.12	26
COMMONWEALTH EDISON	EXC		8.00	5/15/2008	140.0	A3	A-	118.00	3.36	2.66	71	116.37	3.80	3.12	68
NORTHERN STATES PWR-MINN	XEL		6.88	8/1/2009	250.0	Baa1 /*+	BBB- /*+	113.25	4.13	2.66	147	110.24	4.73	3.12	161
DOMINION RESOURCES INC	D		4.13	2/15/2008	400.0	Baa1	BBB+	104.24	3.02	2.66	36	102.23	3.52	3.12	40
CINERGY CORP	CIN	+	6.53	12/16/2008	200.0	Baa2	BBB	112.96	3.55	2.66	90	110.70	4.07	3.12	95
PUBLIC SVC CO OF COLORAD	XEL		6.88	7/15/2009	200.0	Baa2 /*+	BBB- /*+	115.55	3.67	2.66	101	113.36	4.10	3.12	98
SYSTEM ENERGY RESOURCES	ETR	+	4.88	10/1/2007	70.0	Baa3	BBB-	105.08	3.35	2.66	69	103.31	3.89	3.12	77
CONSUMERS ENERGY	CMS		6.38	2/1/2008	250.0	Baa3	BBB-	110.78	3.38	2.66	73	109.36	3.81	3.12	69
TXU CORP	TXU		6.38	1/1/2008	200.0	Ba1	BBB-	109.01	3.83	2.66	118	106.00	4.67	3.12	155
10-year															
FLORIDA POWER & LIGHT	FPL	+	4.85	2/1/2013	400.0	Aa3	A	105.34	4.20	3.72	48	101.91	4.59	4.11	47
CONS EDISON CO OF NY	ED		4.88	2/1/2013	500.0	A1	A	104.99	4.27	3.72	55	101.90	4.61	4.11	50
COMMONWEALTH EDISON	EXC		7.50	7/1/2013	150.0	A3	A-	123.30	4.70	3.72	98	118.93	4.95	4.11	84
COMMONWEALTH EDISON	EXC		7.63	4/15/2013	220.0	A3	A-	123.97	4.58	3.72	86	119.91	4.90	4.11	79
OHIO POWER COMPANY	AEP	+	5.50	2/15/2013	250.0	A3	BBB	106.66	4.58	3.72	86	103.74	4.98	4.11	87
VIRGINIA ELECTRIC &POWER	D		4.75	3/1/2013	400.0	A3	BBB+	102.72	4.41	3.72	69	99.50	4.82	4.11	70
DUKE ENERGY CORP	DUK		5.63	11/30/2012	400.0	Baa1	BBB	107.20	4.64	3.72	92	104.01	5.05	4.11	94
AEP TEXAS NORTH COMPANY	AEP	+	5.50	3/1/2013	225.0	Baa1	BBB	105.31	4.76	3.72	104	102.35	5.17	4.11	106
DOMINION RESOURCES INC	D		5.00	3/15/2013	300.0	Baa1	BBB+	102.81	4.67	3.72	95	99.29	5.10	4.11	98
PUBLIC SERV CO OF COLO	XEL		7.88	10/1/2012	600.0	Baa1 /*+	BBB+ /*+	119.77	5.01	3.72	128	116.51	5.45	4.11	134
PUBLIC SERVICE COLORADO	XEL		4.88	3/1/2013	250.0	Baa1 /*+	BBB+ /*+	102.78	4.49	3.72	77	99.81	4.90	4.11	79
AEP TEXAS CENTRAL CO	AEP	+	5.50	2/15/2013	275.0	Baa2	NA	105.07	4.79	3.72	107	102.13	5.20	4.11	109
TXU ENERGY CO	TXU		7.00	3/15/2013	1,000.0	Baa2	BBB	113.08	5.16	3.72	144	110.08	5.57	4.11	146
DUKE CAPITAL CORP	DUK		6.25	2/15/2013	500.0	Baa3	BBB-	107.52	5.13	3.72	141	104.67	5.58	4.11	147
ENTERGY MISSISSIPPI INC	ETR	+	5.15	2/1/2013	100.0	Baa2	BBB+	102.71	4.90	3.72	118	99.73	5.19	4.11	107
30-year															
TEXAS EASTERN TRANSMISS	DUK		7.00	7/15/2032	450.0	Baa2	BBB	115.52	5.89	4.67	122	111.36	6.15	4.95	120
DUKE ENERGY CORP	DUK		6.45	10/15/2032	350.0	Baa1	BBB	107.54	5.92	4.67	125	103.57	6.18	4.95	123
DOMINION RESOURCES INC	D		6.75	12/15/2032	300.0	Baa1	BBB+	111.88	5.91	4.67	124	107.59	6.18	4.95	123
DOMINION RESOURCES INC	D		6.30	3/15/2033	300.0	Baa1	BBB+	105.19	5.94	4.67	127	101.95	6.16	4.95	120
CENTERPOINT ENER HOUSTON	CNP		6.95	3/15/2033	312.3	Baa2	BBB	118.21	5.66	4.67	99	113.98	5.94	4.95	98
ONCOR ELECTRIC DELIVERY	TXU		7.25	1/15/2033	350.0	Baa1	BBB	119.00	5.87	4.67	120	114.86	6.15	4.95	119
ALABAMA POWER CO	SO		5.60	3/15/2033	200.0	A2	A	101.87	5.49	4.67	82	98.52	5.70	4.95	75
AEP TEXAS CENTRAL CO	AEP	+	6.65	2/15/2033	275.0	Baa2	NA	107.08	6.12	4.67	145	103.35	6.40	4.95	144

Notes: /*- = on watch negative outlook. /*+ = on watch positive outlook. Prices and yields based on available bid prices. Last reported price is used when bid price was unavailable for a specific date. NA – Not Applicable. NM – Not Meaningful.
+ See disclosures on inside front cover.
Sources: Bloomberg, Credit Lyonnais Securities (USA) Inc.

Exhibit 19: Credit Lyonnais LDC and Natural Gas Debt Statistics—03/10/04

			%					Current				1 Month Ago			
Company	Ticker		Coupon	Maturity	Amt (MMs)	Moodys	S&P	Price	Yield	T-Yield	Spread	Price	Yield	T-Yield	Spread
5-year															
KEYSPAN CORP	KSE		7.63	11/15/2010	700.0	A3	A	122.26	3.82	2.66	116	120.07	4.18	3.12	106
KEYSPAN GAS EAST	KSE		6.90	1/15/2008	125.0	A2	A+	114.57	2.96	2.66	30	112.61	3.44	3.12	32
NORTHERN ILLINOIS GAS CO	GAS		5.88	8/15/2008	75.0	Aa3	AA	110.86	3.14	2.66	48	109.26	3.63	3.12	51
ONEOK INC	OKE		6.00	2/1/2009	100.0	Baa1	A-	111.22	3.49	2.66	84	108.89	4.01	3.12	89
QUESTAR MARKET RESOURCES	STR		7.00	1/16/2007	200.0	Baa3	BBB+	111.53	2.78	2.66	13	110.66	3.16	3.12	4
10-year															
ATLANTA GAS LIGHT CO	ATG		8.40	6/5/2012	5.0	A3	A-	126.22	4.53	3.72	81	123.22	4.96	4.11	84
ATMOS ENERGY CORP	ATO		7.38	5/15/2011	350.0	A3	A-	101.90	6.07	3.72	235	107.51	6.08	4.11	196
KEYSPAN CORP	KSE		4.65	4/1/2013	150.0	A3	A	100.88	4.40	3.72	68	98.40	4.87	4.11	75
NORTHERN ILL GAS CO	GAS		6.63	2/1/2011	75.0	Aa3	AA	116.02	3.94	3.72	22	113.20	4.40	4.11	29
ONEOK INC	OKE		7.13	4/15/2011	400.0	Baa1	A-	118.62	4.07	3.72	35	116.58	4.40	4.11	29
PEOPLES ENERGY CORP	PGL		6.90	1/15/2011	325.0	A3	BBB+	116.94	4.05	3.72	33	113.73	4.56	4.11	45
QUESTAR MARKET RESOURCES	STR		7.50	3/1/2011	150.0	Baa3	BBB+	119.41	4.30	3.72	58	116.49	4.72	4.11	61
SOUTHWEST GAS CORP	SWX		8.38	2/15/2011	200.0	Baa2	BBB-	124.73	4.24	3.72	52	121.48	4.74	4.11	62
SOUTHWEST GAS CORP	SWX		7.63	5/15/2012	200.0	Baa2	BBB-	121.42	4.49	3.72	77	117.89	4.96	4.11	84
30-year															
ATMOS ENERGY CORP	ATO		6.75	7/15/2028	150.0	A3	A-	115.61	5.56	4.67	89	111.48	5.86	4.95	91
KEYSPAN CORP	KSE		5.88	4/1/2033	150.0	A3	A	104.01	5.55	4.67	88	99.70	5.90	4.95	95
ONEOK INC	OKE		6.88	9/30/2028	100.0	Baa1	A-	112.99	5.98	4.67	131	108.07	6.23	4.95	128
SOUTHERN UNION CO	SUG	+	7.60	2/1/2024	364.5	Baa3	BBB	115.66	6.23	4.67	156	111.74	6.54	4.95	159
SOUTHERN UNION CO	SUG	+	8.25	11/15/2029	300.0	Baa3	NA	125.39	6.27	4.67	160	121.45	6.52	4.95	157
SOUTHWEST GAS CORP	SWX		8.00	8/1/2026	75.0	Baa2	BBB-	127.60	5.82	4.67	115	123.14	6.10	4.95	114

Notes: *- = watch/negative outlook. *+ = watch/positive outlook. Prices and yields based on available bid prices. Last reported price is used when bid price was unavailable for a specific date. NA – Not Applicable. NM – Not Meaningful.
+*See disclosures on inside front cover.
Sources: Bloomberg, Credit Lyonnais Securities (USA) Inc.

Exhibit 20: Negative Rating Agency Actions – Natural Gas, Power and Utilities Universe (Feb. 2004 and Mar. 2004 YTD)

Company	Date	Rating Type	Agency	Current Rating	Last Rating	Sector
TECO Energy Inc	02/10/04	Senior Unsecured Debt	Moody's	Ba2	Ba1 *-	Electric-Integrated
TECO Energy Inc	02/10/04	Bank Loan Debt	Moody's	Ba2	Ba1 *-	Electric-Integrated
Centerpoint Energy Inc	02/27/04	Issuer Rating	Moody's	Ba2	Ba1 *-	Electric-Integrated
Centerpoint Energy Inc	02/27/04	Senior Unsecured Debt	Moody's	Ba2	Ba1 *-	Electric-Integrated
ANR Pipeline Co	02/18/04	LT Foreign Issuer Credit	S&P	B-	B	Pipelines
ANR Pipeline Co	02/18/04	LT Local Issuer Credit	S&P	B-	B	Pipelines
ANR Pipeline Co	02/18/04	Issuer Rating	Moody's	B1 *-	B1	Pipelines
ANR Pipeline Co	02/18/04	Senior Unsecured Debt	Moody's	B1 *-	B1	Pipelines
Coastal Natural Gas Co	02/18/04	LT Foreign Issuer Credit	S&P	B-	B	Gas-Distribution
Coastal Natural Gas Co	02/18/04	LT Local Issuer Credit	S&P	B-	B	Gas-Distribution
Colorado Interstate Gas Co	02/18/04	LT Local Issuer Credit	S&P	B-	B	Gas-Distribution
Colorado Interstate Gas Co	02/18/04	LT Foreign Issuer Credit	S&P	B-	B	Gas-Distribution
Colorado Interstate Gas Co	02/18/04	Senior Unsecured Debt	Moody's	B1 *-	B1	Gas-Distribution
Colorado Interstate Gas Co	02/18/04	Issuer Rating	Moody's	B1 *-	B1	Gas-Distribution
El Paso Corp	02/18/04	LT Foreign Issuer Credit	S&P	B-	B	Pipelines
El Paso Corp	02/18/04	LT Local Issuer Credit	S&P	B-	B	Pipelines
El Paso Corp	02/18/04	Subordinated Debt	Moody's	Caa3 *-	Caa3	Pipelines
El Paso Corp	02/18/04	Senior Unsecured Debt	Moody's	Caa1 *-	Caa1	Pipelines
El Paso Corp	02/18/04	Bank Loan Debt	Moody's	B3 *-	B3	Pipelines
El Paso Corp	02/18/04	Senior Implied Issuer	Moody's	B3 *-	B3	Pipelines
El Paso Natural Gas Co	02/18/04	LT Local Issuer Credit	S&P	B-	B	Pipelines
El Paso Natural Gas Co	02/18/04	LT Foreign Issuer Credit	S&P	B-	B	Pipelines
El Paso Natural Gas Co	02/18/04	Senior Unsecured Debt	Moody's	B1 *-	B1	Pipelines
El Paso Natural Gas Co	02/18/04	Issuer Rating	Moody's	B1 *-	B1	Pipelines
El Paso Production Holding Co	02/18/04	LT Foreign Issuer Credit	S&P	B-	B	Pipelines
El Paso Production Holding Co	02/18/04	LT Local Issuer Credit	S&P	B-	B	Pipelines
El Paso Production Holding Co	02/18/04	Senior Implied Issuer	Moody's	B3 *-	B2	Pipelines
El Paso Production Holding Co	02/18/04	Issuer Rating	Moody's	Caa1 *-	B3	Pipelines
El Paso Production Holding Co	02/18/04	Senior Unsecured Debt	Moody's	B3 *-	B2	Pipelines
El Paso Tennessee Pipeline Co	02/18/04	LT Foreign Issuer Credit	S&P	B-	B	Pipelines
El Paso Tennessee Pipeline Co	02/18/04	LT Local Issuer Credit	S&P	B-	B	Pipelines
El Paso Tennessee Pipeline Co	02/18/04	Senior Unsecured Debt	Moody's	Caa1 *-	Caa1	Pipelines
Sonat Inc	02/18/04	Senior Unsecured Debt	Moody's	Caa1 *-	Caa1	Pipelines
Southern Natural Gas Co	02/18/04	LT Local Issuer Credit	S&P	B-	B	Pipelines
Southern Natural Gas Co	02/18/04	LT Foreign Issuer Credit	S&P	B-	B	Pipelines
Southern Natural Gas Co	02/18/04	Senior Unsecured Debt	Moody's	B1 *-	B1	Pipelines
Tennessee Gas Pipeline Co	02/18/04	LT Foreign Issuer Credit	S&P	B-	B	Pipelines
Tennessee Gas Pipeline Co	02/18/04	LT Local Issuer Credit	S&P	B-	B	Pipelines
Tennessee Gas Pipeline Co	02/18/04	Senior Unsecured Debt	Moody's	B1 *-	B1	Pipelines

Notes: *- = watch/negative outlook. *+ = watch/positive outlook.
Sources: Bloomberg, S&P and Moody's.

Exhibit 21: Positive Rating Agency Actions – Natural Gas, Power and Utilities Universe (Feb. 2004 and Mar. 2004 YTD)

Company	Date	Rating Type	Agency	Current Rating	Last Rating	Sector
Public Service Co of New Mexico	02/13/04	Issuer Rating	Moody's	Baa3 *+	Baa3	Electric-Integrated
Public Service Co of New Mexico	02/13/04	Senior Unsecured Debt	Moody's	Baa3 *+	Baa3	Electric-Integrated
PG&E Gas Transmission Northwest Corp	02/26/04	Senior Unsecured Debt	Moody's	B2 *+	B2	Pipelines
PNM Resources Inc	02/27/04	LT Foreign Issuer Credit	S&P	BBB	BBB-	Electric-Integrated
PNM Resources Inc	02/27/04	LT Local Issuer Credit	S&P	BBB	BBB-	Electric-Integrated
Public Service Co of New Mexico	02/27/04	LT Local Issuer Credit	S&P	BBB	BBB-	Electric-Integrated
Public Service Co of New Mexico	02/27/04	LT Foreign Issuer Credit	S&P	BBB	BBB-	Electric-Integrated
Kansas Gas & Electric	03/02/04	Senior Secured Debt	Fitch	BBB-	BB+	Electric-Integrated
Westar Energy Inc	03/02/04	Senior Unsecured Debt	Fitch	BB+	BB-	Electric-Integrated
Westar Energy Inc	03/02/04	Senior Secured Debt	Fitch	BBB-	BB+	Electric-Integrated
Entergy Arkansas Inc +	03/05/04	Senior Secured Debt	Moody's	Baa2 *+	Baa2	Electric-Integrated
Entergy Arkansas Inc +	03/05/04	JR Subordinated Debt	Moody's	Ba1 *+	Ba1	Electric-Integrated
Entergy Arkansas Inc +	03/05/04	Issuer Rating	Moody's	Baa3 *+	Baa3	Electric-Integrated
Entergy Louisiana Inc +	03/05/04	JR Subordinated Debt	Moody's	Ba1 *+	Ba1	Electric-Integrated
Entergy Louisiana Inc +	03/05/04	Issuer Rating	Moody's	Baa3 *+	Baa3	Electric-Integrated
Entergy Louisiana Inc +	03/05/04	Senior Secured Debt	Moody's	Baa2 *+	Baa2	Electric-Integrated
Entergy Louisiana Inc +	03/05/04	Senior Unsecured Debt	Moody's	Baa3 *+	Baa3	Electric-Integrated
Public Service Co of New Mexico	03/09/04	Issuer Rating	Moody's	Baa2	Baa3 *+	Electric-Integrated
Public Service Co of New Mexico	03/09/04	Senior Unsecured Debt	Moody's	Baa2	Baa3 *+	Electric-Integrated

Notes: *- = watch/negative outlook. *+ = watch/positive outlook.
Sources: Bloomberg, S&P and Moody's.

Exhibit 22: Recent New Debt Issues – Natural Gas, Power and Utilities Universe (February and March 2004 MTD)

Issue Date	Ticker	Issuer	Ratings			Type	Sector	Amt ($MM)	% Coupon	Maturity	Call Prov
2/11/2004	ED	CONS EDISON CO OF NY	A	A1	A+	NOTES	Utilities	200.0	4.70	Feb/14	MW+15BP
2/11/2004	ED	CON EDISON CO OF NY	A	A1	A+	BONDS	Utilities	200.0	5.70	Feb/34	MW+20BP
2/12/2004	BRK	MIDAMERICAN ENERGY HLDGS	BBB-	Baa3	BBB	SENIOR NOTES	Utilities	250.0	5.00	Feb/14	MW+20BP
2/12/2004	BRK	MIDAMERICAN ENERGY HLDGS	BBB-	Baa3	BBB	SENIOR NOTES	Utilities	250.0	5.00	Feb/14	MW+20BP
2/13/2004	CMS	CONSUMERS ENERGY-ITC	BBB-	Baa3	BB+	1ST MORTGAGE	Utilities	250.0	4.25	Apr/08	MW+20BP
2/13/2004	CMS	CONSUMERS ENERGY CO	BBB-	Baa3	BB+	1ST MORTGAGE	Utilities	200.0	4.80	Feb/09	MW+25BP
2/13/2004	CMS	CONSUMERS ENERGY-ITC	BBB-	Baa3	BB+	1ST MORTGAGE	Utilities	250.0	4.00	May/10	MW+20BP
2/13/2004	CMS	CONSUMERS ENERGY CO	BBB-	Baa3	BB+	1ST MORTGAGE	Utilities	375.0	5.38	Apr/13	MW+25BP
2/13/2004	CMS	CONSUMERS ENERGY CO	BBB-	Baa3	BB+	1ST MORTGAGE	Utilities	200.0	6.00	Feb/14	MW+25BP
2/13/2004	AES	AES CORPORATION	B-	B3 /*+	B	SENIOR NOTES	Utilities	500.0	7.75	Mar/14	MW+75BP
2/17/2004	ETR +	ENTERGY GULF STATES	BBB-	Baa3	BBB	1ST MORTGAGE	Utilities	325.0	3.60	Jun/08	MW+25BP.
2/17/2004	SO	GEORGIA POWER COMPANY	A	A2	A+	NOTES	Utilities	150.0	1.30	Feb/09	NC
2/17/2004	ETR +	ENTERGY GULF STATES	BBB-	Baa3	BBB	1ST MORTGAGE	Utilities	200.0	5.25	Aug/15	MW+15BP
2/17/2004	SO	ALABAMA POWER CO	A	A2	A	SENIOR NOTES	Utilities	200.0	5.13	Feb/19	MW+20BP
2/17/2004	ETR +	ENTERGY GULF STATES	BBB-	Baa3	BBB	1ST MORTGAGE	Utilities	239.9	6.20	Jul/33	MW+15BP.
2/18/2004	PPL	PPL CAPITAL FUND TRUST I	BB+	Ba1	BBB-	NOTES	Utilities	257.2	7.29	May/06	NC
2/18/2004	DUK	DUKE CAPITAL CORP	BBB-	Baa3	NA	NOTES	Energy	875.0	4.30	May/06	NC
2/20/2004	DUK	DUKE CAPITAL CORP	BBB-	Baa3	BBB-	SENIOR NOTES	Energy	200.0	4.37	Mar/09	NC
2/20/2004	DUK	DUKE CAPITAL CORP	BBB-	Baa3	BBB-	SENIOR NOTES	Energy	288.3	5.50	Mar/14	NC
2/24/2004	SUG +	PANHANDLE EASTERN PIPELN	BBB	Baa3	BBB	SENIOR NOTES	Energy	300.0	4.80	Aug/08	MW+25 BP
2/24/2004	SUG +	PANHANDLE EASTERN PIPELN	BBB	Baa3	BBB	SENIOR NOTES	Energy	250.0	6.05	Aug/13	MW+25BP
2/26/2004	PPL	PPL CAPITAL FUNDING	BBB-	Baa3	NA	COMPANY GUARNT	Utilities	201.0	4.33	Mar/09	NC
2/27/2004	CHG	CENTRAL HUDSON GAS & ELE	A	A2	A	NOTES	Utilities	7.0	4.73	Feb/14	NC
3/9/2004	SO	MISSISSIPPI POWER CO	A	A1	A+	NOTES	Utilities	40.0	1.30	Mar/09	NC

Note: MW= Make Whole Provision, NC = No Call Provision. NA = Not Available.

+ See disclosures on inside front cover.

Sources: Bloomberg, Credit Lyonnais Securities (USA) Inc.

Power Sector Operating Analysis

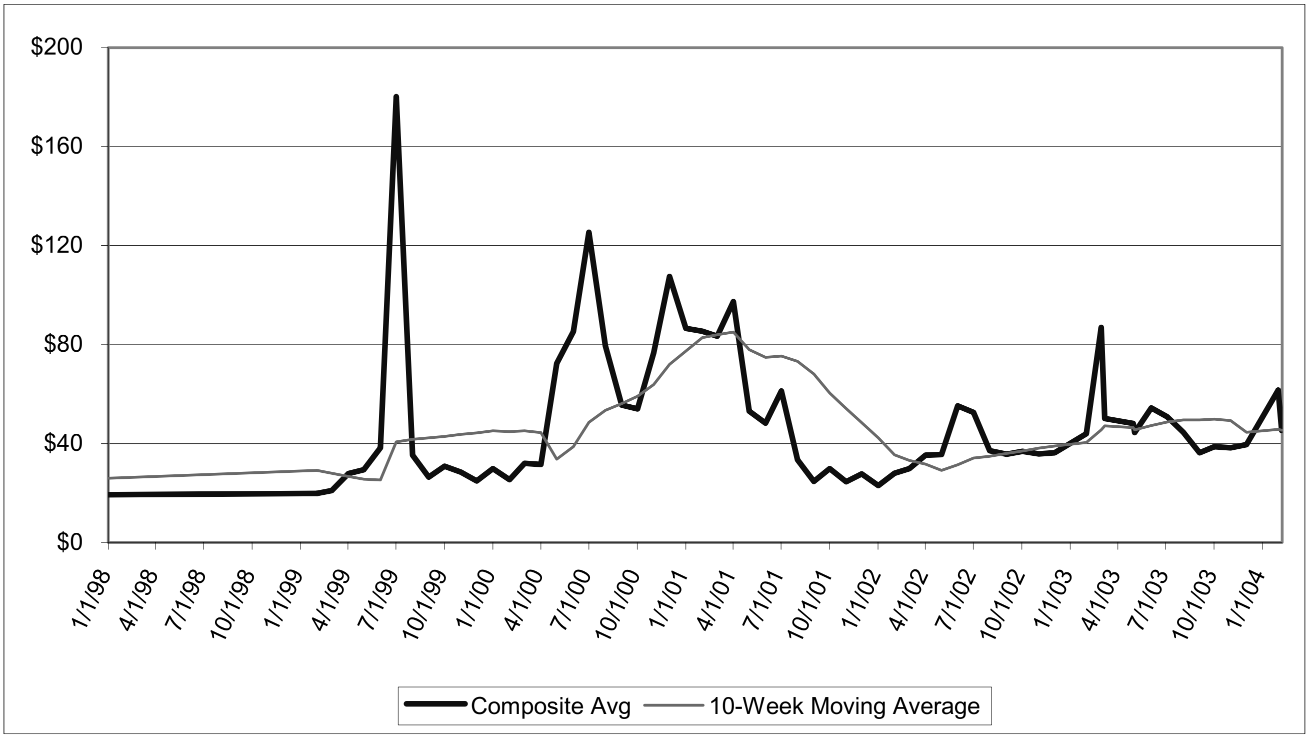
Exhibit 23: CLS Composite Power Price Index—Based on Firm On-Peak ($/MWh)

Date	COB	PV	MAPP*	SPP	ERCOT	MAIN	ECAR	NEPOOL	NY	PJM	SERC	FRCC*	Avg
Avg 98	**$30.04**	**$32.29**	**$27.17**	**$27.96**	**$25.90**	**$26.57**	**$27.24**	**$26.91**	**NA**	**$25.29**	**$28.58**	**$32.29**	**$28.20**
Avg 99	**$32.64**	**$33.73**	**$30.45**	**$44.07**	**$40.21**	**$41.28**	**$44.63**	**$33.55**	**NA**	**$38.23**	**$48.01**	**$54.60**	**$40.13**
Jan-00	$33.54	$32.03	$28.54	$30.00	$28.25	$26.14	$27.71	$39.50	NA	$26.54	$29.21	$26.25	$29.79
Feb-00	29.35	30.28	23.57	22.50	26.13	20.52	20.90	32.25	NA	22.58	23.33	28.75	25.47
Mar-00	34.29	34.96	31.13	31.00	33.00	27.50	27.83	28.88	NA	27.75	28.70	46.25	31.94
Apr-00	34.42	39.64	28.75	28.50	43.00	24.91	26.14	36.75	NA	27.69	27.85	29.50	31.56
May-00	71.25	72.85	43.38	55.63	85.00	71.17	71.98	98.17	NA	73.67	76.70	76.25	72.37
Jun-00	166.00	196.00	74.82	67.50	65.00	55.99	54.68	75.17	NA	63.77	67.43	51.25	85.24
Jul-00	434.17	494.58	58.20	48.00	44.00	43.00	43.00	49.83	NA	56.06	48.59	58.75	125.29
Aug-00	85.00	60.00	90.32	106.25	147.50	62.57	64.02	75.17	82.00	52.13	74.73	54.25	79.50
Sep-00	138.67	133.00	31.41	29.60	53.25	28.11	27.28	54.38	59.59	28.35	21.25	61.25	55.51
Oct-00	95.29	70.06	35.15	38.75	47.83	38.16	38.82	67.95	64.25	41.13	44.35	65.25	53.92
Nov-00	269.19	137.09	45.65	47.45	54.00	45.50	47.08	57.75	67.00	44.20	49.03	56.25	76.68
Dec-00	172.50	146.86	100.40	105.00	103.25	92.08	97.65	108.00	87.50	88.54	95.94	91.92	107.47
Avg 00	**$130.31**	**$120.61**	**$49.28**	**$50.85**	**$60.85**	**$44.64**	**$45.59**	**$60.32**	**$72.07**	**$46.03**	**$48.93**	**$53.83**	**$64.56**
Jan-01	$384.50	$237.50	$39.92	$39.50	$52.50	$31.32	$32.20	$53.15	$55.00	$35.50	$35.28	$42.00	$86.53
Feb-01	299.60	243.33	48.48	45.88	49.75	43.48	43.91	52.10	58.25	45.77	45.39	48.25	85.35
Mar-01	283.00	232.20	48.75	44.53	45.50	43.52	43.78	61.08	64.50	46.48	43.84	43.25	83.37
Apr-01	257.17	290.59	58.56	64.00	45.75	56.62	59.94	65.89	83.00	56.08	64.07	66.25	97.33
May-01	140.00	174.96	23.64	21.50	36.75	19.31	20.35	37.40	47.00	23.63	28.07	64.58	53.10
Jun-01	81.00	91.97	35.70	42.50	37.53	31.73	30.29	41.38	61.50	39.28	37.82	49.00	48.31
Jul-01	54.00	52.11	72.04	64.25	60.71	71.12	69.19	51.80	64.00	57.42	58.00	60.25	61.24
Aug-01	26.08	33.19	31.00	25.00	23.88	29.33	33.74	43.40	46.00	37.65	32.73	39.25	33.44
Sep-01	26.16	28.87	20.80	17.03	17.50	19.13	20.08	36.73	35.75	24.83	21.93	27.25	24.67
Oct-01	35.36	33.85	27.63	26.50	27.86	22.18	24.06	35.53	40.75	23.46	27.11	33.75	29.84
Nov-01	28.73	29.84	24.00	18.13	19.25	18.19	19.26	29.25	33.00	24.72	21.05	29.25	24.56
Dec-01	26.63	27.25	28.00	22.75	21.00	21.77	21.84	35.75	41.50	28.80	24.91	31.63	27.65
Avg 01	**$136.85**	**$122.97**	**$38.21**	**$35.96**	**$36.50**	**$33.98**	**$34.89**	**$45.29**	**$52.52**	**$36.97**	**$36.68**	**$44.56**	**$54.61**
Jan-02	$22.58	$24.95	$23.38	$18.20	$19.11	$19.55	$20.24	$29.25	$29.75	$21.99	$20.46	$26.92	$23.03
Feb-02	25.85	24.85	28.00	24.30	22.00	24.93	27.68	30.25	32.25	27.56	31.68	36.75	28.01
Mar-02	33.67	33.33	26.50	25.68	31.25	22.58	23.22	32.50	40.13	24.66	26.28	38.00	29.82
Apr-02	29.67	30.63	30.75	30.44	40.09	26.97	26.27	36.75	54.08	27.09	36.30	54.66	35.31
May-02	22.00	34.46	29.78	30.00	33.62	29.00	33.21	41.63	55.75	36.39	36.57	43.75	35.51
Jun-02	23.38	45.86	62.50	45.67	31.44	51.65	54.05	86.00	99.00	68.10	47.91	46.75	55.19
Jul-02	22.25	38.46	49.75	36.88	28.00	54.00	60.22	59.13	108.38	78.55	49.32	45.06	52.50
Aug-02	28.00	31.66	31.94	29.67	32.07	30.80	34.90	47.50	65.00	40.35	32.76	41.25	37.16
Sep-02	27.25	30.55	29.50	28.97	31.75	28.13	32.00	50.00	55.00	35.58	32.05	47.99	35.73
Oct-02	42.75	40.42	28.53	30.88	32.67	24.15	26.07	51.00	57.50	37.28	29.78	41.25	36.86
Nov-02	36.56	34.77	35.37	29.00	33.75	28.55	23.46	42.00	65.50	34.00	29.35	36.93	35.77
Dec-02	44.75	44.25	26.79	22.50	38.30	22.00	20.55	52.25	66.00	37.06	26.25	34.25	36.25
Avg 02	**$29.89**	**$34.52**	**$33.57**	**$29.35**	**$31.17**	**$30.19**	**$31.82**	**$46.52**	**$60.70**	**$39.05**	**$33.23**	**$41.13**	**$36.76**
Jan-03	$45.13	$47.40	$39.73	$27.63	$42.50	$27.67	$31.97	$57.32	$79.50	$42.46	$36.88	$49.25	$43.95
Feb-03	78.62	78.75	91.75	45.25	93.08	88.29	96.94	105.00	137.50	90.09	88.74	49.25	86.94
Mar-03	26.79	44.36	55.31	45.25	41.56	47.05	52.75	61.23	75.25	57.43	45.13	49.04	50.10
Apr-03	34.60	38.64	41.66	44.00	50.01	47.75	48.90	51.93	63.50	48.38	46.01	61.25	48.05
May-03	50.05	73.77	27.17	40.00	67.07	17.50	18.29	53.12	70.38	35.50	29.09	50.25	44.35
Jun-03	45.38	55.27	76.88	40.00	50.88	48.00	44.89	56.25	86.00	60.15	38.48	50.25	54.37
Jul-03	46.00	53.79	56.52	40.00	50.88	38.18	44.89	67.50	69.00	55.00	38.48	50.25	50.87
Aug-03	50.45	49.86	47.56	37.10	38.07	30.88	30.18	46.76	71.16	39.08	42.40	50.63	44.51
Sep-03	41.99	48.20	30.50	28.90	33.54	20.10	21.51	47.63	65.69	29.82	26.75	40.55	36.27
Oct-03	39.48	39.08	40.30	34.45	34.92	24.95	26.52	50.37	64.58	38.22	29.85	42.00	38.73
Nov-03	41.37	39.33	36.50	32.88	33.12	28.66	28.97	47.25	61.66	34.63	32.45	42.63	38.29
Dec-03	42.36	41.42	28.63	31.13	45.44	22.00	24.28	56.91	76.50	34.23	31.24	40.75	39.57
Avg 03	**$45.19**	**$50.82**	**$47.71**	**$37.22**	**$48.42**	**$36.75**	**$39.17**	**$58.44**	**$76.73**	**$47.08**	**$40.46**	**$48.01**	**$48.00**
Jan-04	$47.98	$48.58	$62.27	$49.70	$43.15	$54.00	$52.45	$94.86	$110.70	$72.33	$46.58	$55.35	$61.50
Feb-04	41.28	41.43	41.10	38.20	35.65	43.20	43.73	53.66	63.80	46.83	40.87	53.80	45.30

* MAPP and FRCC power prices are provided by Bloomberg as non-firm interruptible; we have added $3.00/MWh and $1.25/MWh, respectively, to approximate firm non-interruptible for the MAPP and FRCC regions.

Sources: Bloomberg, Platts and Credit Lyonnais Securities.

Exhibit 24: CLS Composite Power Price Index ($/MWh)



CLS Composite Power Price Index represents the unweighted composite average of PJM, Palo Verde, SPP, ERCOT, MAIN, SERC, PJM, NY and NEPOOL markets.

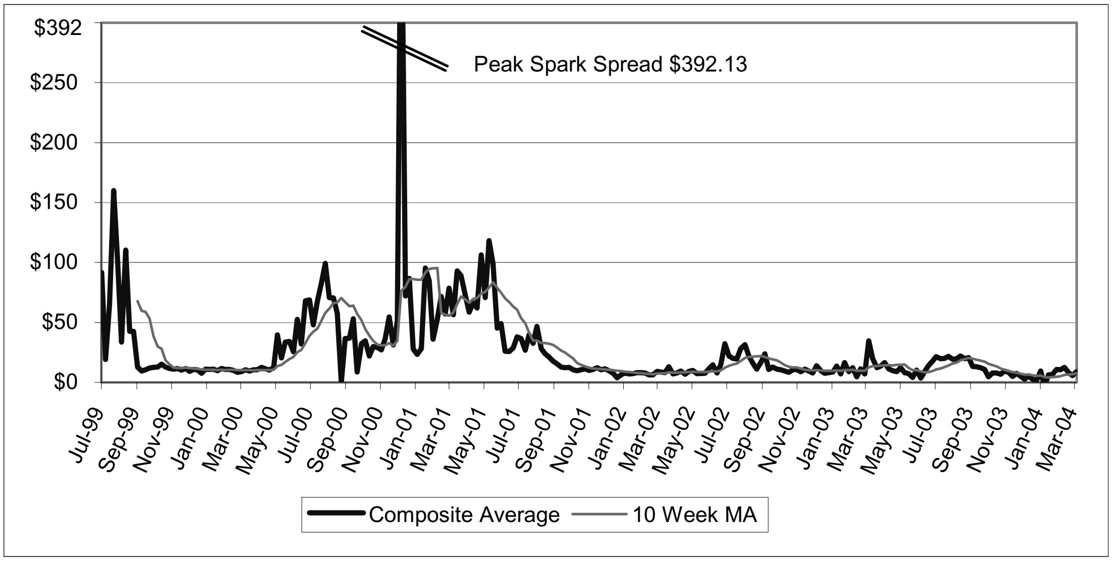
Sources: Credit Lyonnais Securities, Platts and Bloomberg.

Exhibit 25: Spark Spreads—7,000 Heat Rate Firm On-Peak ($/MWh)

Date	COB	PV	ENTERGY	ERCOT	MAIN	NEPOOL	NY	PJM	Avg
1Q03	**11.81**	**16.97**	**5.69**	**6.59**	**2.31**	**14.29**	**36.65**	**16.58**	**13.86**
4-Apr-03	8.29	28.74	5.29	4.16	9.38	21.97	34.38	20.48	16.59
11-Apr-03	6.43	26.79	5.32	4.73	7.49	9.04	24.90	6.05	11.34
18-Apr-03	2.57	18.02	2.41	11.24	5.88	9.18	25.87	2.61	9.72
25-Apr-03	6.33	15.02	4.81	8.21	6.58	12.70	20.41	(1.80)	9.03
2-May-03	3.44	10.47	5.70	15.96	7.28	18.28	26.19	11.00	12.29
9-May-03	(0.12)	8.43	1.38	10.30	4.13	11.15	21.16	7.69	8.02
16-May-03	3.35	25.60	(8.77)	25.14	(14.93)	11.60	15.70	0.70	7.30
23-May-03	5.93	37.90	(18.12)	9.87	(21.09)	7.97	14.95	(4.13)	4.16
30-May-03	13.79	38.21	(10.34)	25.28	(11.26)	9.83	25.93	(9.07)	10.30
6-Jun-03	0.92	21.89	(6.28)	13.41	(25.27)	11.72	21.31	(10.27)	3.43
13-Jun-03	(4.00)	20.84	2.34	19.15	(8.73)	16.20	24.60	3.42	9.23
20-Jun-03	11.59	19.93	(0.12)	16.91	6.68	15.64	23.62	17.65	13.99
20-Jun-03	11.59	19.93	(0.12)	16.91	6.68	15.64	23.62	17.65	13.99
27-Jun-03	15.66	27.61	8.88	20.62	(5.68)	17.50	46.29	9.62	17.56
2Q03	**6.13**	**22.81**	**(0.54)**	**14.42**	**(2.35)**	**13.46**	**24.92**	**5.11**	**10.50**
3-Jul-03	14.79	25.31	13.55	15.81	13.00	18.59	48.55	22.70	21.54
11-Jul-03	13.98	31.05	10.76	14.27	3.92	28.58	46.87	8.87	19.79
18-Jul-03	23.91	37.50	7.25	15.53	2.04	29.77	31.41	12.99	20.05
25-Jul-03	24.50	32.28	10.29	17.77	4.71	31.80	33.65	19.40	21.80
1-Aug-03	15.76	23.48	8.53	17.84	3.74	32.01	33.30	19.30	19.25
8-Aug-03	13.10	25.72	6.12	31.14	9.50	29.49	31.20	12.20	19.81
15-Aug-03	14.62	21.45	9.55	32.61	17.56	30.05	31.76	18.66	22.03
22-Aug-03	9.56	19.91	9.46	32.82	17.56	28.86	29.73	10.23	19.77
29-Aug-03	17.31	20.87	8.87	33.45	17.56	28.86	32.18	5.74	20.61
5-Sep-03	17.94	18.92	6.02	34.01	(0.93)	11.05	15.65	3.45	13.26
12-Sep-03	13.84	11.85	4.29	34.71	(4.50)	13.27	22.84	8.18	13.06
19-Sep-03	12.81	14.68	1.50	34.92	(6.80)	15.68	21.09	4.13	12.25
22-Aug-03	9.56	19.91	9.46	32.82	17.56	28.86	29.73	10.23	19.77
29-Aug-03	17.31	20.87	8.87	33.45	17.56	28.86	32.18	5.74	20.61
5-Sep-03	17.94	18.92	6.02	34.01	(0.93)	11.05	15.65	3.45	13.26
12-Sep-03	13.84	11.85	4.29	34.71	(4.50)	13.27	22.84	8.18	13.06
19-Sep-03	12.81	14.68	1.50	34.92	(6.80)	15.68	21.09	4.13	12.25
5-Sep-03	17.94	18.92	6.02	34.01	(0.93)	11.05	15.65	3.45	13.26
12-Sep-03	13.84	11.85	4.29	34.71	(4.50)	13.27	22.84	8.18	13.06
19-Sep-03	12.81	14.68	1.50	34.92	(6.80)	15.68	21.09	4.13	12.25
26-Sep-03	12.18	16.26	0.19	34.92	(6.89)	13.47	15.35	1.86	10.92
3Q03	**15.25**	**20.52**	**6.59**	**29.68**	**3.86**	**21.39**	**27.36**	**9.30**	**16.75**
3-Oct-03	11.72	15.53	(1.09)	3.39	(11.62)	14.04	11.82	(6.17)	4.70
10-Oct-03	13.40	19.05	5.49	4.32	(9.68)	14.88	14.79	0.23	7.81
17-Oct-03	11.76	19.72	2.19	5.89	(10.84)	14.54	19.62	0.27	7.89
17-Oct-03	11.76	19.72	2.19	5.89	(10.84)	14.54	19.62	0.27	7.89
24-Oct-03	13.79	17.22	(0.92)	2.87	(10.82)	14.22	13.86	3.61	6.73
31-Oct-03	11.44	10.87	5.40	8.98	(4.13)	16.61	19.57	7.59	9.54
7-Nov-03	10.50	10.07	3.36	5.17	(1.19)	13.57	15.82	9.33	8.33
14-Nov-03	7.44	8.65	0.37	3.51	(9.20)	14.27	11.14	1.99	4.77
21-Nov-03	12.63	11.48	5.58	4.64	(5.79)	14.96	15.32	0.92	7.47
28-Nov-03	10.43	9.63	(1.27)	2.07	(3.41)	14.13	10.22	(0.47)	5.17
5-Dec-03	6.26	10.37	(0.83)	4.13	(13.84)	12.49	4.04	(1.62)	2.63
12-Dec-03	4.23	7.72	2.94	3.62	(1.07)	16.66	8.66	1.01	5.47
19-Dec-03	7.21	6.78	(5.85)	3.93	(7.61)	14.57	7.41	(4.86)	2.70
26-Dec-03	9.90	5.81	(8.64)	6.88	(15.90)	10.35	10.28	(6.77)	1.49
4Q03	**10.18**	**12.33**	**0.64**	**4.66**	**(8.28)**	**14.27**	**13.01**	**0.38**	**5.90**
2-Jan-04	15.76	10.72	4.65	3.74	2.01	17.79	18.43	2.02	9.39
9-Jan-04	9.30	10.31	(8.30)	0.88	(22.17)	15.78	(18.42)	(14.02)	(3.33)
16-Jan-04	8.75	8.13	0.33	1.63	(9.82)	17.74	19.83	3.71	6.29
23-Jan-04	11.90	11.75	(3.49)	(0.40)	(4.98)	20.64	9.94	7.73	6.64
30-Jan-04	10.72	12.42	3.11	4.87	2.27	26.46	12.93	14.24	10.88
6-Feb-04	11.19	10.63	6.44	2.36	7.59	16.77	18.68	10.14	10.48
13-Feb-04	10.63	9.62	11.22	1.88	13.23	17.79	21.13	13.76	12.41
20-Feb-04	9.29	9.74	5.61	(0.74)	2.50	14.63	16.17	7.92	8.14
27-Feb-04	7.99	10.10	4.05	(0.07)	(0.88)	10.93	12.75	0.45	5.67
5-Mar-04	5.97	7.87	5.45	4.40	5.83	14.15	18.41	9.40	8.94

Note: We provide approximate quarterly average spark spreads for informational purposes only. They do not represent actual values.
The composite average represents the unweighted composite average of PJM, Palo Verde, SPP, ERCOT, MAIN, SERC, PJM, NY and NEPOOL markets.
We have revised historical spark spreads back to 10/3/03 to reflect Platts data as opposed to Bloomberg data, which we believe will offer a better representation of market spark spreads. Since 9/12/03, we have been using Platts data for MAIN, NEPOOL and NY. We will be using Platts spark spreads for all regions moving forward. Additionally, beginning this month we are introducing Entergy spark spreads and removing SPP spreads, which are not available. We have updated historical Entergy spark spreads back to 8/10/01.
Sources: Credit Lyonnais Securities, Platts and Bloomberg.

Exhibit 26: Spark Spreads—7,000 Heat Rate Firm On-Peak ($/MWh)



Represents the unweighted composite average of PJM, Palo Verde, SPP, ERCOT, MAIN, SERC, PJM, NY and NEPOOL markets.
Sources: Credit Lyonnais Securities, Platts and Bloomberg.

Exhibit 27: CLS Forward Spark Spread Analysis Regional Snapshot - 7,000 Heat Rate ($/MWh)

As of 3-05-04	Mar-04	Apr-04	May-04	Jun-04	Jul/Aug-04	Sep-04	Dec-04	Dec-05	Dec-06
East Average	NA	$24.45	$24.17	$26.95	$44.07	$33.49	$27.01	$28.37	$19.06
Central Average	NA	4.67	5.96	8.63	15.76	5.12	0.29	7.44	8.43
West Average	NA	7.01	NA	3.71	18.25	18.33	9.80	10.20	11.77
U.S. Average	**NA**	**$12.35**	**$11.87**	**$14.27**	**$27.00**	**$19.06**	**$12.69**	**$15.98**	**$12.42**

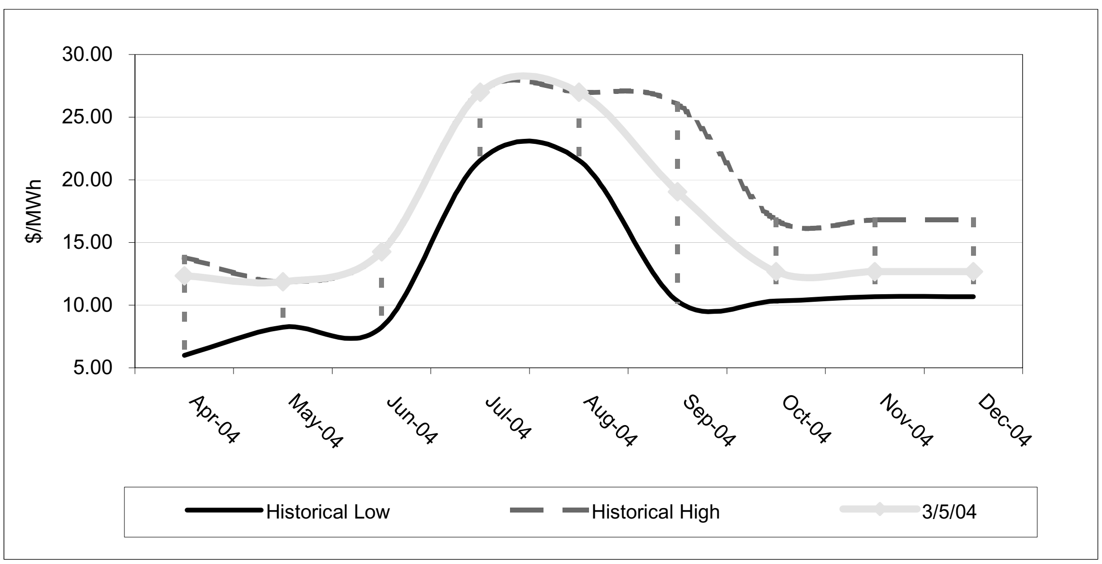
*September 2004 NY Zone J Forward Power Price as of July/August 2004.
**December 2004 NY Zone J Forward Power Price as of January/February 2005.
Spark spread calculated based upon PJM, NEPOOL, NY, Cinergy, MAIN, ERCOT, Mid-Columbia, and Palo Verde forward power prices and an approximation of forward natural gas city gate prices based on historical regression analysis applied to current NYMEX futures contracts.
Sources: Credit Lyonnais Securities, Platts and Bloomberg.

Exhibit 28: CLS Forward Spark Spread Analysis Historical U.S. Averages - 7,000 Heat Rate ($/MWh)*

	Feb-04	Mar/Apr-04	Jun-04	Jul/Aug-04	Sep-04	Dec-04	Dec-05	Dec-06
11/28/03	$14.14	$9.90	$9.46	$23.80	NA	$12.93	$13.64	$9.85
12/5/03	12.36	11.38	9.41	24.39	NA	14.73	14.75	11.32
12/12/03	12.19	12.87	9.82	24.69	NA	15.24	14.98	11.70
12/19/03	14.91	13.84	9.69	24.67	NA	14.98	14.92	11.99
12/26/03	13.74	11.57	8.69	23.09	NA	13.34	13.95	11.18
1/2/04	14.78	10.49	8.41	22.87	NA	16.80	14.73	11.70
1/9/04	15.06	12.17	9.01	24.41	NA	16.28	15.26	16.67
1/16/04	19.16	11.80	8.87	24.04	NA	10.76	14.16	15.51
1/23/04	19.21	10.31	9.98	24.68	NA	11.29	14.73	12.41
1/30/04	NA	13.74	10.02	21.57	10.33	11.32	15.11	12.59
2/6/04	NA	13.20	8.75	23.48	16.72	10.69	14.05	11.54
2/13/04	NA	13.35	9.18	24.60	17.14	11.13	14.96	11.95
2/20/04	NA	13.57	9.39	24.81	17.73	11.18	14.71	11.36
2/27/04	NA	12.41	13.61	26.07	18.50	11.89	15.21	11.53
3/5/04	NA	12.35	14.27	27.00	19.06	12.69	15.98	12.42

* We are displaying data beginning with the February front month contract, which was first available on 11/28/2003. For earlier data, please see previous versions of the *Statistical Energy Monthly*. Spark spread calculated based upon PJM, NEPOOL, NY, Cinergy, MAIN, ERCOT, Mid-Columbia, and Palo Verde forward power prices and an approximation of forward natural gas city gate prices based on historical regression analysis applied to current NYMEX futures contracts.
Sources: Credit Lyonnais Securities, Platts and Bloomberg.

Exhibit 29: CLS Forward Spark Spread Curve Current vs. Historical Range – 7,000 Heat Rate ($/MWh)



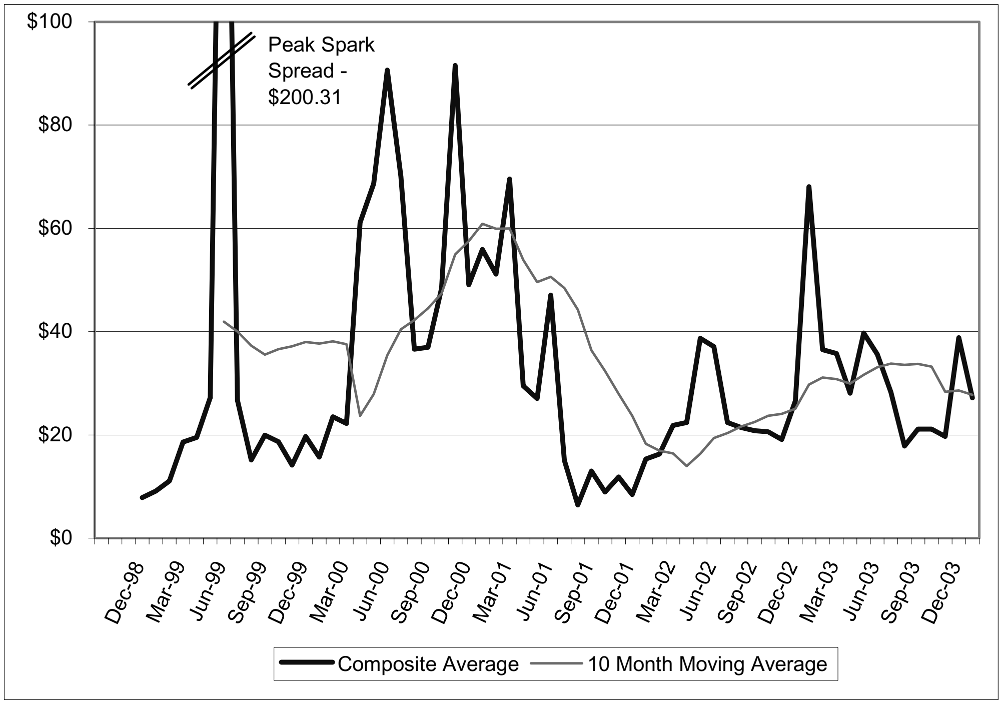
Spark spread calculated based on PJM, NEPOOL, NY, Cinergy, MAIN, ERCOT, Mid-Columbia and Palo Verde forward power prices and an approximation of forward natural gas city gate prices based on historical regression analysis applied to current NYMEX futures contracts.
Sources: Credit Lyonnais Securities, Platts and Bloomberg.

Exhibit 30: Spark Spreads—12,000 Coal Heat Rate Firm On-Peak ($/MWh)

	PV	MAPP	SPP	ERCOT	MAIN	ECAR	PJM	SERC	FRCC*	Composite Average
Avg 98	**$18.10**	**$23.03**	**$7.51**	**$5.47**	**$11.79**	**$11.29**	**$11.72**	**$8.54**	**$12.18**	**$12.18**
Avg 99	**$27.69**	**$28.26**	**$32.18**	**$28.32**	**$31.72**	**$35.07**	**$28.93**	**$36.12**	**$31.04**	**$31.04**
Jan-00	26.57	26.39	19.26	17.51	17.14	18.71	17.48	18.47	15.51	19.67
Feb-00	24.82	21.39	11.76	15.39	11.76	12.14	13.40	12.59	18.01	15.69
Mar-00	29.50	28.98	20.38	22.38	18.74	19.07	18.57	18.08	35.63	23.48
Apr-00	34.18	26.65	18.00	32.50	16.21	17.44	18.51	17.35	19.00	22.20
May-00	67.39	41.31	45.01	74.38	62.47	63.28	64.49	66.08	65.63	61.11
Jun-00	190.36	72.69	56.52	54.02	47.17	45.86	54.59	56.45	40.27	68.66
Jul-00	488.94	56.18	37.02	33.02	34.30	34.30	46.88	37.61	47.77	90.67
Aug-00	53.82	88.21	94.79	136.04	53.75	55.20	42.71	63.27	42.79	70.06
Sep-00	126.70	29.27	17.60	41.25	19.17	18.34	18.81	9.25	49.25	36.63
Oct-00	63.64	33.02	26.21	35.29	28.92	29.58	31.41	31.81	52.71	36.95
Nov-00	130.67	43.43	34.07	40.62	36.08	37.66	34.42	35.65	42.87	48.38
Dec-00	140.14	98.26	90.24	88.49	82.36	87.93	78.46	81.18	77.16	91.58
Avg 00	**$114.73**	**$47.15**	**$39.24**	**$49.24**	**$35.67**	**$36.62**	**$36.64**	**$37.31**	**$49.58**	**$49.58**
Jan-01	230.66	37.58	23.30	36.30	21.36	22.24	24.88	19.08	25.80	49.02
Feb-01	236.13	46.05	28.96	32.83	32.62	33.05	34.01	28.47	31.33	55.94
Mar-01	223.32	44.19	24.85	25.82	30.80	31.06	32.32	24.16	23.57	51.12
Apr-01	281.23	53.88	43.84	25.59	43.42	46.74	41.44	43.91	46.09	69.57
May-01	165.60	16.92	(0.58)	14.67	5.39	6.43	8.27	5.99	42.50	29.47
Jun-01	81.89	29.46	19.46	14.49	17.57	16.13	23.68	14.78	25.96	27.05
Jul-01	41.79	66.76	43.61	40.07	56.96	55.03	42.54	37.36	39.61	47.08
Aug-01	22.63	26.92	2.92	1.80	14.93	19.34	19.17	10.65	17.17	15.06
Sep-01	18.07	16.72	(1.69)	(1.22)	3.29	4.24	6.59	3.21	8.53	6.42
Oct-01	23.29	23.55	9.46	10.82	7.06	8.94	6.90	10.07	16.71	12.98
Nov-01	20.24	20.28	2.05	3.17	3.07	4.14	8.88	4.97	13.17	8.89
Dec-01	17.65	24.28	7.15	5.40	6.89	6.96	12.72	9.31	16.03	11.82
Avg 01	**$113.54**	**$33.88**	**$16.94**	**$17.48**	**$20.28**	**$21.19**	**$21.78**	**$17.66**	**$32.85**	**$32.85**
Jan-02	15.35	19.90	3.08	3.99	4.67	5.36	6.63	5.34	11.80	8.46
Feb-02	15.49	25.12	10.38	8.08	11.25	14.00	12.92	17.76	22.83	15.31
Mar-02	24.21	23.62	12.72	18.29	9.14	9.78	10.50	13.32	25.04	16.29
Apr-02	21.51	27.81	17.00	26.65	13.77	13.07	12.81	22.86	41.22	21.86
May-02	25.22	26.91	16.92	20.54	15.68	19.89	22.11	23.49	30.67	22.38
Jun-02	36.98	59.56	32.47	18.24	38.33	40.73	53.82	34.71	33.55	38.71
Jul-02	30.54	46.99	22.96	14.08	41.04	47.26	64.15	35.40	31.14	37.06
Aug-02	23.86	29.36	16.11	18.51	18.02	22.12	26.55	19.20	27.69	22.38
Sep-02	22.75	26.92	15.41	18.19	15.35	19.22	21.78	18.49	34.43	21.39
Oct-02	32.50	25.95	17.38	19.17	11.37	13.29	23.60	16.28	27.75	20.81
Nov-02	27.81	32.68	15.92	20.67	16.31	11.22	20.44	16.27	23.85	20.57
Dec-02	37.17	24.21	9.30	25.10	9.88	8.43	23.74	13.05	21.05	19.10
Avg 02	**$26.12**	**$30.75**	**$15.80**	**$17.63**	**$17.07**	**$18.70**	**$24.92**	**$19.68**	**$21.33**	**$21.33**
Jan-03	40.08	36.95	13.23	28.10	15.25	19.55	28.66	22.48	34.85	26.57
Feb-03	72.03	88.98	30.25	78.08	75.57	84.22	75.63	73.74	34.25	68.08
Mar-03	37.52	52.61	30.13	26.44	34.57	40.27	42.73	30.01	33.92	36.47
Apr-03	31.80	38.91	29.60	35.61	36.23	37.38	33.98	31.61	46.85	35.77
May-03	66.69	24.39	25.12	52.19	6.22	7.01	21.10	14.21	35.37	28.03
Jun-03	48.31	74.10	24.88	35.76	36.72	33.61	45.75	23.36	35.13	39.74
Jul-03	46.83	53.84	24.76	35.64	27.02	33.73	40.36	23.24	35.01	35.60
Aug-03	42.42	44.62	21.26	22.23	19.36	18.66	23.96	26.56	34.79	28.21
Sep-03	40.52	26.96	11.98	16.62	7.86	9.27	13.50	9.83	23.63	17.80
Oct-03	31.40	36.87	17.41	17.88	12.71	14.28	21.72	12.81	24.96	21.12
Nov-03	31.41	33.15	16.08	16.32	16.30	16.61	18.79	15.65	25.83	21.13
Dec-03	33.50	25.27	13.37	27.68	9.64	11.92	18.99	13.48	22.99	19.65
Avg 03	**$43.54**	**$44.72**	**$21.51**	**$32.71**	**$24.79**	**$27.21**	**$32.10**	**$24.75**	**$32.30**	**$31.51**
Jan-04	40.42	58.85	29.06	22.51	41.40	39.85	56.73	25.94	34.71	38.83
Feb-04	33.27	37.68	16.36	13.81	30.60	31.13	30.39	19.03	31.96	27.14

The composite average represents the unweighted composite average of Palo Verde, MAPP, SPP, ERCOT, MAIN, PJM, SERC and FRCC markets.
Note: We provide approximate annual average spark spreads for informational purposes only. They do not represent actual values.
Sources: Credit Lyonnais Securities, Platts and Bloomberg.

Exhibit 31: Spark Spreads—12,000 Coal Heat Rate Firm On-Peak ($/MWh)



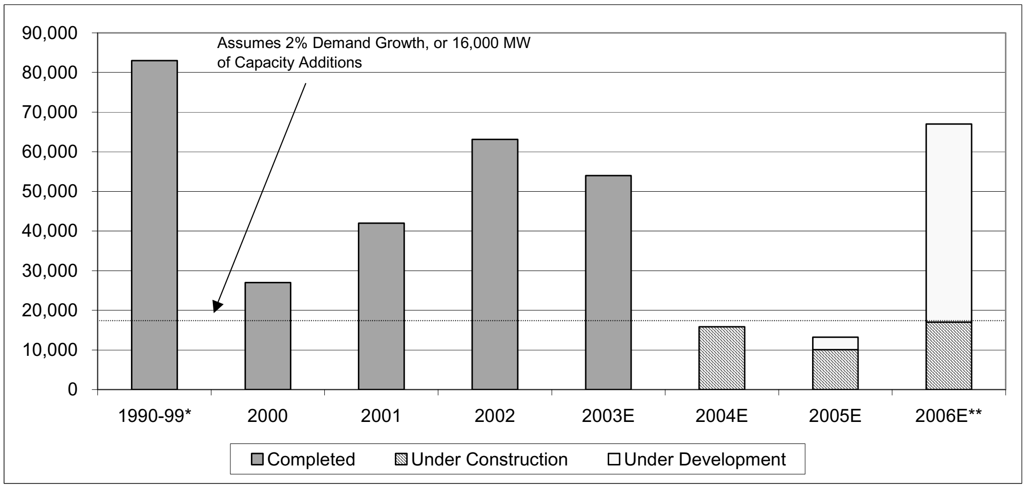
Represents the unweighted composite average of COB, Palo Verde, MAPP, SPP, ERCOT, MAIN, NEPOOL, NY and PJM.
Sources: Credit Lyonnais Securities, Bloomberg.

Exhibit 32: Power Generation Capacity Additions (Mw)

	1990-99*	2000	2001	2002	2003E	2004E	2005E	2006E**
Completed	83,000	27,000	42,000	63,100	54,000	NA	NA	NA
Under Construction	0	0	0	0	0	15,800	10,089	17,000
Completed or Under Construction	**83,000**	**27,000**	**42,000**	**63,100**	**54,000**	**15,800**	**10,089**	**17,000**
Under Development	NA	NA	NA	NA	NA	0	3,100	50,000
Total	**83,000**	**27,000**	**42,000**	**63,100**	**54,000**	**15,800**	**13,189**	**67,000**

*Approximate Capacity Additions.
**Our estimates for capacity under construction and under development in 2006 include generation that has been pushed out from earlier years and has been delayed at this point. It is possible that a portion of this capacity will be delayed further or will never be built.
Source: Credit Lyonnais Securities.

Exhibit 33: Power Generation Capacity Additions (Mw)



*Approximate Capacity Additions.
**Our estimates for capacity under construction and under development in 2006 include generation that has been pushed out from earlier years and has been delayed at this point. It is possible that a portion of this capacity will be delayed further or will never be built.
Source: Credit Lyonnais Securities.

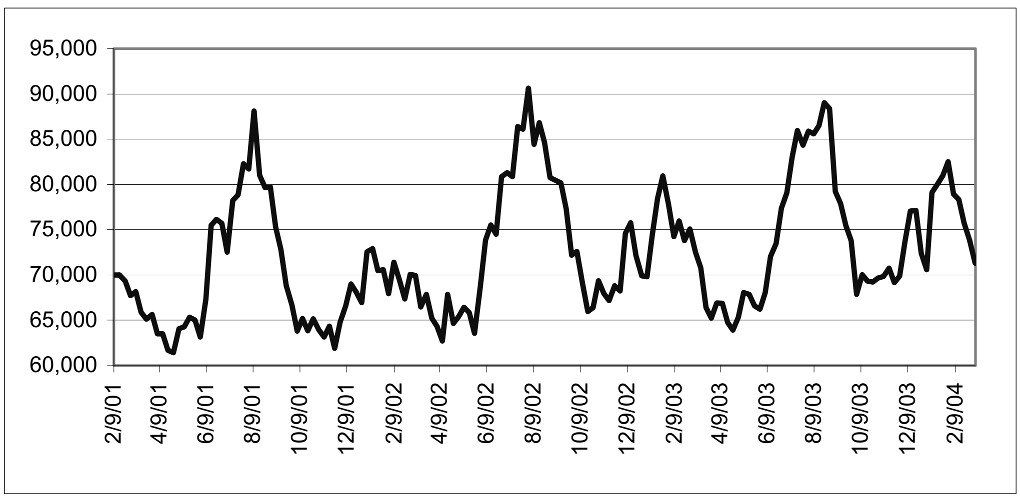
Exhibit 34: Regional Electricity Output (GWh)

	New England	Mid-Atlantic	Central Industrial	West Central	Southeast	South Central	Rocky Mountain	Pacific Northwest	Pacific Southwest	Total US
2-Jan-04	2,382	9,430	13,445	5,001	16,986	9,995	3,901	3,811	5,632	**70,583**
9-Jan-04	2,778	10,747	15,784	5,739	19,082	10,823	4,025	4,217	5,918	**79,113**
16-Jan-04	3,005	11,756	15,815	5,638	20,473	9,998	3,899	3,624	5,799	**80,007**
23-Jan-04	2,883	11,681	16,462	5,923	20,058	10,991	3,864	3,404	5,723	**80,989**
30-Jan-04	2,943	11,742	16,829	6,089	20,592	10,986	4,008	3,488	5,827	**82,504**
6-Feb-04	2,713	11,005	15,986	6,044	19,637	10,386	3,949	3,469	5,727	**78,916**
13-Feb-04	2,639	10,530	15,622	5,834	19,065	11,441	4,083	3,395	5,722	**78,331**
20-Feb-04	2,651	10,480	15,253	5,709	18,499	10,327	3,784	3,322	5,711	**75,736**
27-Feb-04	2,557	10,431	14,561	5,535	18,016	10,063	3,763	3,199	5,679	**73,804**
5-Mar-04	2,405	9,203	13,722	5,410	17,593	10,303	3,746	3,188	5,754	**71,324**

	New England	Mid-Atlantic	Central Industrial	West Central	Southeast	South Central	Rocky Mountain	Pacific Northwest	Pacific Southwest	Total US
Total 2003 YTD	**26,778**	**106,406**	**152,667**	**55,141**	**189,754**	**98,255**	**36,775**	**32,908**	**54,382**	**753,066**
Total 2004 YTD	**26,956**	**107,005**	**153,479**	**56,922**	**190,001**	**105,313**	**39,022**	**35,117**	**57,492**	**771,307**
2004/2003 Change	*0.7%*	*0.6%*	*0.5%*	*3.2%*	*0.1%*	*7.2%*	*6.1%*	*6.7%*	*5.7%*	*2.4%*

Sources: Credit Lyonnais Securities, Bloomberg and Edison Electric Institute.

Exhibit 35: Total U.S. Electricity Output (GWh)



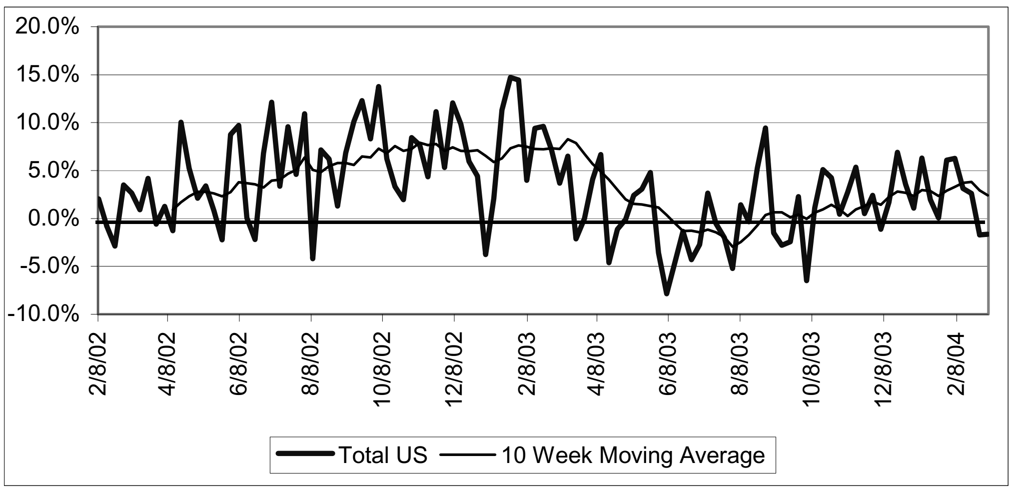
Sources: Credit Lyonnais Securities, Bloomberg and Edison Electric Institute.

Exhibit 36: Regional Electricity Output 2004/2003 % Change

	New England	Mid-Atlantic	Central Industrial	West Central	Southeast	South Central	Rocky Mountain	Pacific Northwest	Pacific Southwest	Total US
2-Jan-04	-4.3%	-1.1%	-2.6%	1.8%	-0.5%	4.2%	5.4%	13.6%	4.8%	**1.1%**
9-Jan-04	6.6%	7.1%	2.9%	8.7%	0.1%	14.1%	8.4%	25.0%	7.0%	**6.3%**
16-Jan-04	9.9%	6.5%	1.2%	-1.5%	0.4%	-2.6%	3.1%	6.3%	5.9%	**2.0%**
23-Jan-04	-0.6%	0.6%	-0.1%	-0.2%	-6.0%	5.0%	10.9%	1.7%	6.0%	**0.0%**
30-Jan-04	6.3%	6.0%	5.9%	6.6%	1.8%	9.9%	14.1%	12.4%	6.7%	**6.1%**
6-Feb-04	3.8%	6.1%	5.9%	8.6%	6.8%	6.8%	4.6%	6.6%	5.0%	**6.3%**
13-Feb-04	-4.6%	-3.4%	-0.4%	9.0%	0.9%	16.1%	7.6%	2.9%	5.9%	**3.1%**
20-Feb-04	0.9%	-1.3%	1.5%	3.8%	1.0%	7.4%	5.2%	4.1%	7.3%	**2.6%**
27-Feb-04	-3.4%	-3.7%	-3.2%	-3.1%	-2.1%	0.1%	1.3%	-3.7%	5.5%	**-1.7%**
5-Mar-04	-8.5%	-11.3%	-6.4%	-0.7%	-0.4%	11.7%	1.2%	-2.0%	3.2%	**-1.7%**
2004 YTD Average	**0.6%**	**0.5%**	**0.5%**	**3.3%**	**0.2%**	**7.3%**	**6.2%**	**6.7%**	**5.7%**	**2.4%**
1Q03 Average	**7.1%**	**10.0%**	**6.5%**	**4.1%**	**8.5%**	**6.0%**	**2.0%**	**2.4%**	**-3.7%**	**5.9%**
2Q03 Average	**1.1%**	**-0.4%**	**-3.7%**	**-1.2%**	**-1.3%**	**5.0%**	**1.0%**	**3.5%**	**-3.3%**	**-0.5%**
3Q03 Average	**0.5%**	**-0.3%**	**-4.4%**	**-0.6%**	**-0.9%**	**4.6%**	**6.3%**	**3.5%**	**4.6%**	**0.3%**
4Q03 Average	**-0.6%**	**0.6%**	**0.2%**	**2.8%**	**0.2%**	**6.9%**	**5.3%**	**3.7%**	**4.3%**	**2.0%**

Sources: Credit Lyonnais Securities, Bloomberg and Edison Electric Institute.

Exhibit 37: Total U.S. Electricity Output – Historical Year-over-Year % Change



Sources: Credit Lyonnais Securities, Bloomberg and Edison Electric Institute.

Exhibit 38: Electricity Supply/Demand Overview (Billion KWh)

	Net Generation						End Use		
Date	**Electric Utilities**	**Non-Utility Power Producers**	**Total**	**Imports**	**Exports**	**Losses and Unaccounted**	**Electric Utility Retail Sales**	**Non-Utility Power Producers**	**Total**
1989	2,848	119	2,967	26	15	223	2,647	108	2,755
1990	2,901	137	3,038	18	16	214	2,713	114	2,827
1991	2,936	139	3,074	22	2	213	2,762	118	2,880
1992	2,934	149	3,084	28	3	224	2,763	122	2,885
1993	3,044	153	3,197	31	4	236	2,861	128	2,989
1994	3,089	159	3,248	47	2	224	2,935	134	3,069
1995	3,194	159	3,353	43	4	235	3,013	144	3,157
1996	3,284	160	3,444	43	3	237	3,101	146	3,247
1997	3,329	163	3,492	43	9	232	3,146	148	3,294
1998	3,457	163	3,620	40	14	221	3,264	161	3,425
1999	3,530	165	3,695	43	14	229	3,312	183	3,495
2000	3,638	165	3,800	49	15	231	3,421	183	3,604
2001									
Jan-01	319	14	333	3	2	9	309	16	325
Feb-01	271	12	283	3	3	(2)	271	14	285
Mar-01	288	13	301	4	2	20	267	16	283
Apr-01	266	13	279	4	1	13	253	15	268
May-01	288	13	301	4	2	26	261	16	277
Jun-01	315	13	328	4	1	27	288	15	303
Jul-01	344	14	358	4	1	31	314	16	330
Aug-01	356	15	371	4	1	28	330	16	346
Sep-01	294	13	307	2	1	(1)	294	15	309
Oct-01	281	14	295	2	1	15	265	16	281
Nov-01	266	13	279	2	1	14	251	15	266
Year-to-Date	***3,288***	***147***	***3,435***	***36***	***16***	***180***	***3,103***	***170***	***3,273***
Dec-01	292	14	306	3	1	26	266	16	282
2001	**3,580**	**161**	**3,741**	**39**	**17**	**206**	**3,369**	**186**	**3,555**
2002									
Jan-02	306	14	320	3	1	15	292	16	308
Feb-02	269	13	282	3	1	5	264	14	278
Mar-02	289	14	303	3	2	21	267	16	283
Apr-02	277	13	290	3	1	18	259	15	274
May-02	295	14	309	2	2	24	269	16	285
Jun-02	328	14	342	3	1	30	298	15	313
Jul-02	367	15	382	4	1	32	337	16	353
Aug-02	360	14	374	4	1	24	338	16	354
Sep-02	318	14	332	3	1	8	309	15	324
Oct-02	294	13	307	2	1	10	283	16	299
Nov-02	283	13	296	2	1	20	262	15	277
Year-to-Date	***3,386***	***151***	***3,537***	***32***	***13***	***207***	***3,178***	***170***	***3,348***
Dec-02	312	14	326	2	1	26	284	16	300
2002	**3,698**	**165**	**3,863**	**34**	**14**	**233**	**3,462**	**186**	**3,648**
2003									
Jan-03	323	15	338	3	1	15	308	16	324
Feb-03	284	13	297	3	2	1	283	14	297
Mar-03	289	14	303	3	3	13	274	16	290
Apr-03	270	12	282	3	2	12	256	15	271
May-03	292	13	305	3	2	20	269	16	285
Jun-03	311	13	324	3	2	20	289	15	305
Jul-03	358	14	372	4	1	25	334	16	350
Aug-03	364	14	378	4	1	23	341	16	357
Sep-03	304	12	316	2	2	(7)	307	15	322
Oct-03	291	14	305	1	3	9	279	16	295
Nov-03	287	13	299	1	3	19	264	15	279
Year-to-Date	***3,373***	***147***	***3,519***	***30***	***22***	***150***	***3,204***	***170***	***3,375***

Sources: Credit Lyonnais Securities, Energy Information Administration.

Exhibit 39: Electric Generation by Fuel Type (Million KWh)

	Fossil Fuels				Nuclear	Hydroelectric	Renewable	
Date	Coal	Petroleum	Natural Gas	Other	Power	Pumped Storage*	Energy**	Total
1989	1,583,779	164,518	352,629	7,862	529,355	NA	325,333	2,963,476
1990	1,594,011	126,621	372,765	10,383	576,862	(3,508)	357,238	3,034,372
1991	1,590,623	119,752	381,553	11,336	612,565	(4,541)	357,773	3,069,061
1992	1,621,206	100,154	404,074	13,270	618,776	(4,177)	326,859	3,080,162
1993	1,690,070	112,788	414,927	12,956	610,291	(4,036)	356,707	3,193,703
1994	1,690,694	105,901	460,219	13,319	640,440	(3,378)	336,661	3,243,856
1995	1,709,426	74,554	496,058	13,870	673,402	(2,725)	384,798	3,349,383
1996	1,795,196	81,411	455,056	14,356	674,729	(3,088)	422,957	3,440,617
1997	1,845,016	92,555	479,399	13,351	628,644	(4,040)	433,635	3,488,560
1998	1,873,516	128,800	531,257	13,492	673,702	(4,467)	400,424	3,616,724
1999	1,881,087	118,061	556,396	14,126	728,254	(6,097)	398,959	3,690,786
2000	1,966,265	111,221	601,038	13,955	753,893	(5,539)	356,827	3,797,660
2001								
Jan-01	177,288	18,112	42,389	718	68,707	(589)	25,488	332,113
Feb-01	149,736	10,342	37,967	676	61,272	(707)	23,322	282,608
Mar-01	155,269	11,733	44,364	769	62,141	(773)	26,861	300,364
Apr-01	140,670	10,863	45,842	698	56,003	(796)	24,435	277,715
May-01	151,593	10,390	50,934	785	61,512	(623)	25,529	300,120
Jun-01	162,616	11,823	57,603	733	68,023	(774)	27,309	327,333
Jul-01	179,060	11,042	73,030	840	69,166	(871)	24,952	357,219
Aug-01	183,116	14,230	78,410	848	68,389	(715)	25,828	370,106
Sep-01	154,158	7,342	60,181	767	63,378	(928)	21,612	306,510
Oct-01	148,932	6,534	56,377	737	60,461	(615)	21,880	294,306
Nov-01	144,117	5,931	44,491	699	62,342	(811)	21,717	278,486
Year-to-Date	***1,746,555***	***118,342***	***591,588***	***8,270***	***701,394***	***(8,202)***	***268,933***	***3,426,880***
Dec-01	157,402	6,539	47,541	770	67,431	(623)	26,014	305,074
2001	**1,903,957**	**124,881**	**639,129**	**9,040**	**768,825**	**(8,825)**	**294,947**	**3,731,954**
2002								
Jan-02	164,358	6,690	48,413	923	70,926	(750)	29,381	319,941
Feb-02	143,049	5,664	44,308	760	61,658	(586)	26,973	281,826
Mar-02	151,486	8,217	51,214	904	63,041	(684)	28,371	302,549
Apr-02	142,305	7,834	49,146	890	58,437	(585)	31,821	289,848
May-02	151,406	8,127	50,275	910	63,032	(539)	34,464	307,675
Jun-02	164,668	7,796	65,631	1,009	66,372	(863)	36,410	341,023
Jul-02	183,195	9,913	83,917	1,071	70,421	(998)	34,023	381,542
Aug-02	179,955	9,737	94,477	1,117	70,778	(935)	19,457	374,586
Sep-02	165,366	8,075	68,161	1,053	64,481	(777)	24,920	331,279
Oct-02	159,099	8,116	54,201	908	60,493	(681)	24,923	307,059
Nov-02	156,054	6,287	45,161	894	61,520	(666)	27,040	296,290
Year-to-Date	***1,760,941***	***86,456***	***654,904***	***10,439***	***711,159***	***(8,064)***	***317,783***	***3,533,618***
Dec-02	172,190	8,112	46,100	1,025	68,905	(680)	29,182	324,834
2002	**1,933,131**	**94,568**	**701,004**	**11,464**	**780,064**	**(8,744)**	**346,965**	**3,858,452**
2003								
Jan-03	180,632	12,338	48,684	908	69,211	(760)	26,146	337,159
Feb-03	156,063	10,560	43,291	730	60,942	(774)	25,668	296,480
Mar-03	154,690	10,323	45,901	900	59,933	(797)	31,604	302,554
Apr-03	141,676	8,148	43,341	734	56,776	(554)	32,101	282,222
May-03	149,296	7,971	47,854	757	62,194	(619)	36,637	304,090
Jun-03	161,009	10,968	51,899	863	64,181	(780)	35,506	323,646
Jul-03	182,761	12,102	74,809	898	69,653	(755)	31,896	371,364
Aug-03	185,595	12,345	80,665	818	69,024	(818)	29,748	377,377
Sep-03	163,589	8,716	54,833	830	63,584	(785)	24,665	315,432
Oct-03	159,162	8,599	50,604	1,037	60,016	(634)	25,474	304,258
Nov-03	155,241	9,243	48,042	763	58,444	(704)	27,578	298,607
Year-to-Date	***1,789,714***	***111,313***	***589,923***	***9,238***	***693,958***	***(7,980)***	***327,023***	***3,513,189***

*1989 included in Renewable Energy.
** Renewables represent Conventional Hydro Electric Power, Geothermal, Wood, Waste, Wind and Solar.
Sources: Credit Lyonnais Securities, Energy Information Administration.

Exhibit 40: Electric Generation by Fuel Type—Percentage Use

	Fossil Fuels				Nuclear	Hydroelectric	Renewable	
Date	Coal	Petroleum	Natural Gas	Other	Power	Pumped Storage*	Energy**	Total
1989	53.4%	5.6%	11.9%	0.3%	17.9%	NA	11.0%	100.0%
1990	52.5%	4.2%	12.3%	0.3%	19.0%	-0.1%	11.8%	100.0%
1991	51.8%	3.9%	12.4%	0.4%	20.0%	-0.1%	11.7%	100.0%
1992	52.6%	3.3%	13.1%	0.4%	20.1%	-0.1%	10.6%	100.0%
1993	52.9%	3.5%	13.0%	0.4%	19.1%	-0.1%	11.2%	100.0%
1994	52.1%	3.3%	14.2%	0.4%	19.7%	-0.1%	10.4%	100.0%
1995	51.0%	2.2%	14.8%	0.4%	20.1%	-0.1%	11.5%	100.0%
1996	52.2%	2.4%	13.2%	0.4%	19.6%	-0.1%	12.3%	100.0%
1997	52.9%	2.7%	13.7%	0.4%	18.0%	-0.1%	12.4%	100.0%
1998	51.8%	3.6%	14.7%	0.4%	18.6%	-0.1%	11.1%	100.0%
1999	51.0%	3.2%	15.1%	0.4%	19.7%	-0.2%	10.8%	100.0%
2000	51.8%	2.9%	15.8%	0.4%	19.9%	-0.1%	9.4%	100.0%
2001								
Jan-01	53.4%	5.5%	12.8%	0.2%	20.7%	-0.2%	7.7%	100.0%
Feb-01	53.0%	3.7%	13.4%	0.2%	21.7%	-0.3%	8.3%	100.0%
Mar-01	51.7%	3.9%	14.8%	0.3%	20.7%	-0.3%	8.9%	100.0%
Apr-01	50.7%	3.9%	16.5%	0.3%	20.2%	-0.3%	8.8%	100.0%
May-01	50.5%	3.5%	17.0%	0.3%	20.5%	-0.2%	8.5%	100.0%
Jun-01	49.7%	3.6%	17.6%	0.2%	20.8%	-0.2%	8.3%	100.0%
Jul-01	50.1%	3.1%	20.4%	0.2%	19.4%	-0.2%	7.0%	100.0%
Aug-01	49.5%	3.8%	21.2%	0.2%	18.5%	-0.2%	7.0%	100.0%
Sep-01	50.3%	2.4%	19.6%	0.3%	20.7%	-0.3%	7.1%	100.0%
Oct-01	50.6%	2.2%	19.2%	0.3%	20.5%	-0.2%	7.4%	100.0%
Nov-01	51.8%	2.1%	16.0%	0.3%	22.4%	-0.3%	7.8%	100.0%
Dec-01	51.6%	2.1%	15.6%	0.3%	22.1%	-0.2%	8.5%	100.0%
2001	**51.0%**	**3.3%**	**17.1%**	**0.2%**	**20.6%**	**-0.2%**	**7.9%**	**100.0%**
2002								
Jan-02	51.4%	2.1%	15.1%	0.3%	22.2%	-0.2%	9.2%	100.0%
Feb-02	50.8%	2.0%	15.7%	0.3%	21.9%	-0.2%	9.6%	100.0%
Mar-02	50.1%	2.7%	16.9%	0.3%	20.8%	-0.2%	9.4%	100.0%
Apr-02	49.1%	2.7%	17.0%	0.3%	20.2%	-0.2%	11.0%	100.0%
May-02	49.2%	2.6%	16.3%	0.3%	20.5%	-0.2%	11.2%	100.0%
Jun-02	48.3%	2.3%	19.2%	0.3%	19.5%	-0.3%	10.7%	100.0%
Jul-02	48.0%	2.6%	22.0%	0.3%	18.5%	-0.3%	8.9%	100.0%
Aug-02	48.0%	2.6%	25.2%	0.3%	18.9%	-0.2%	5.2%	100.0%
Sep-02	49.9%	2.4%	20.6%	0.3%	19.5%	-0.2%	7.5%	100.0%
Oct-02	51.8%	2.6%	17.7%	0.3%	19.7%	-0.2%	8.1%	100.0%
Nov-02	52.7%	2.1%	15.2%	0.3%	20.8%	-0.2%	9.1%	100.0%
Dec-02	53.0%	2.5%	14.2%	0.3%	21.2%	-0.2%	9.0%	100.0%
2002	**50.1%**	**2.5%**	**18.2%**	**0.3%**	**20.2%**	**-0.2%**	**9.0%**	**100.0%**
2003								
Jan-03	53.6%	3.7%	14.4%	0.3%	20.5%	-0.2%	7.8%	100.0%
Feb-03	52.6%	3.6%	14.6%	0.2%	20.6%	-0.3%	8.7%	100.0%
Mar-03	51.1%	3.4%	15.2%	0.3%	19.8%	-0.3%	10.4%	100.0%
Apr-03	50.2%	2.9%	15.4%	0.3%	20.1%	-0.2%	11.4%	100.0%
May-03	49.1%	2.6%	15.7%	0.2%	20.5%	-0.2%	12.0%	100.0%
Jun-03	49.7%	3.4%	16.0%	0.3%	19.8%	-0.2%	11.0%	100.0%
Jul-03	49.2%	3.3%	20.1%	0.2%	18.8%	-0.2%	8.6%	100.0%
Aug-03	49.2%	3.3%	21.4%	0.2%	18.3%	-0.2%	7.9%	100.0%
Sep-03	51.9%	2.8%	17.4%	0.3%	20.2%	-0.2%	7.8%	100.0%
Oct-03	52.3%	2.8%	16.6%	0.3%	19.7%	-0.2%	8.4%	100.0%
Nov-03	52.0%	3.1%	16.1%	0.3%	19.6%	-0.2%	9.2%	100.0%

*1989 included in Renewable Energy.

** Renewables represent Conventional Hydro Electric Power, Geothermal, Wood, Waste, Wind and Solar.

Sources: Credit Lyonnais Securities, Energy Information Administration.

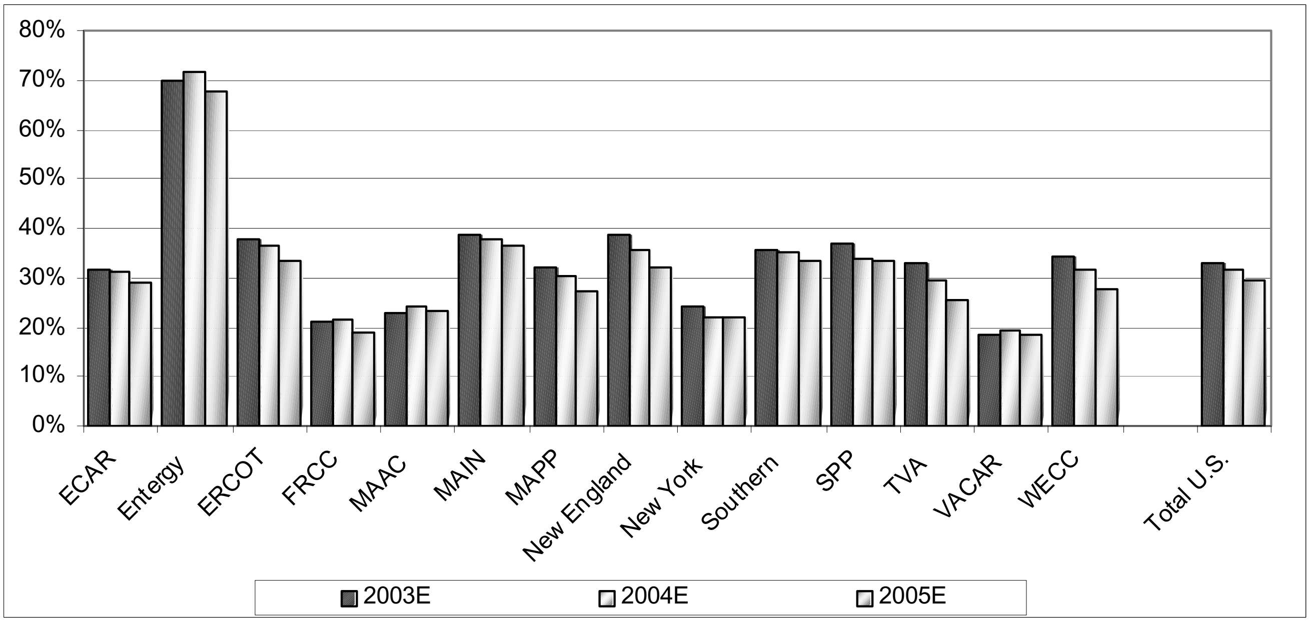
Exhibit 41: Electricity Consumption by End Use Customer (Million KWh)

Date	Residential	Pct.	Commercial	Pct.	Industrial	Pct.	Other	Pct.	Total
1989	905,525	34.2%	725,861	27%	925,659	35%	89,765	3.4%	2,646,809
1990	924,019	34.1%	751,027	27.7%	945,522	34.9%	91,988	3.4%	2,712,555
1991	955,417	34.6%	765,664	27.7%	946,583	34.3%	94,339	3.4%	2,762,003
1992	935,939	33.9%	761,271	27.5%	972,714	35.2%	93,442	3.4%	2,763,365
1993	994,781	34.8%	794,573	27.8%	977,164	34.1%	94,944	3.3%	2,861,462
1994	1,008,482	34.4%	820,269	28.0%	1,007,981	34.3%	97,830	3.3%	2,934,563
1995	1,042,501	34.6%	862,685	28.6%	1,012,693	33.6%	95,407	3.2%	3,013,287
1996	1,082,512	34.9%	887,445	28.6%	1,033,631	33.3%	97,539	3.1%	3,101,127
1997	1,075,880	34.2%	928,633	29.5%	1,038,197	33.0%	102,901	3.3%	3,145,610
1998	1,130,109	34.6%	979,401	30.0%	1,051,203	32.2%	103,518	3.2%	3,264,231
1999	1,144,923	34.6%	1,001,996	30.3%	1,058,217	32.0%	106,952	3.2%	3,312,087
2000	1,192,667	34.9%	1,055,232	30.8%	1,064,239	31.1%	109,496	3.2%	3,421,634
2001									
Jan-01	128,464	41.5%	91,407	29.6%	80,245	25.9%	9,167	3.0%	309,283
Feb-01	101,026	37.3%	82,072	30.3%	79,349	29.3%	8,636	3.2%	271,083
Mar-01	93,568	35.0%	84,477	31.6%	80,533	30.1%	8,730	3.3%	267,308
Apr-01	82,937	32.8%	81,538	32.3%	79,824	31.6%	8,525	3.4%	252,824
May-01	81,539	31.2%	87,955	33.7%	82,736	31.7%	9,038	3.5%	261,268
Jun-01	98,689	34.3%	96,153	33.4%	82,616	28.7%	10,075	3.5%	287,533
Jul-01	119,819	38.2%	102,863	32.8%	80,766	25.7%	10,355	3.3%	313,803
Aug-01	128,472	38.9%	106,234	32.2%	84,259	25.5%	11,024	3.3%	329,989
Sep-01	105,385	35.9%	97,267	33.1%	80,133	27.3%	10,925	3.7%	293,710
Oct-01	85,207	32.1%	89,818	33.9%	80,569	30.4%	9,660	3.6%	265,254
Nov-01	81,188	32.3%	83,539	33.2%	77,774	30.9%	8,902	3.5%	251,403
Year-to-Date	***1,106,294***	***35.6%***	***1,003,323***	***32.3%***	***888,804***	***28.6%***	***105,037***	***3.4%***	***3,103,458***
Dec-01	96,354	36.2%	85,830	32.2%	75,421	28.3%	8,717	3.3%	266,322
2001	**1,202,648**	**35.7%**	**1,089,153**	**32.3%**	**964,225**	**28.6%**	**113,754**	**3.4%**	**3,369,780**
2002									
Jan-02	117,742	40.3%	89,366	30.6%	76,600	26.2%	8,315	2.8%	292,023
Feb-02	97,309	36.8%	82,526	31.2%	76,413	28.9%	8,028	3.0%	264,276
Mar-02	95,919	35.9%	85,055	31.8%	78,122	29.2%	8,010	3.0%	267,106
Apr-02	86,103	33.3%	85,549	33.1%	78,918	30.5%	8,009	3.1%	258,579
May-02	87,494	32.5%	90,819	33.8%	82,242	30.6%	8,501	3.2%	269,056
Jun-02	107,853	36.2%	98,638	33.1%	82,432	27.6%	9,306	3.1%	298,229
Jul-02	133,389	39.5%	108,091	32.0%	85,724	25.4%	10,064	3.0%	337,268
Aug-02	133,951	39.6%	107,439	31.8%	86,739	25.6%	10,183	3.0%	338,312
Sep-02	114,951	37.1%	100,138	32.4%	84,107	27.2%	10,266	3.3%	309,462
Oct-02	94,237	33.3%	95,188	33.7%	83,783	29.6%	9,456	3.3%	282,664
Nov-02	88,926	34.0%	85,363	32.6%	79,057	30.2%	8,464	3.2%	261,810
Year-to-Date	***1,157,874***	***36.4%***	***1,028,172***	***32.3%***	***894,137***	***28.1%***	***98,602***	***3.1%***	***3,178,785***
Dec-02	109,085	38.4%	88,076	31.0%	78,032	27.5%	8,546	3.0%	283,739
2002	**1,266,959**	**36.6%**	**1,116,248**	**32.2%**	**972,169**	**28.1%**	**107,148**	**3.1%**	**3,462,524**
2003									
Jan-03	125,307	40.7%	93,712	30.4%	80,351	26.1%	8,743	2.8%	308,113
Feb-03	112,018	39.6%	84,863	30.0%	78,037	27.6%	8,291	2.9%	283,209
Mar-03	100,154	36.6%	86,482	31.6%	78,914	28.8%	8,265	3.0%	273,815
Apr-03	84,102	32.8%	83,470	32.6%	80,561	31.5%	7,924	3.1%	256,057
May-03	88,340	32.9%	89,391	33.3%	82,496	30.7%	8,581	3.2%	268,808
Jun-03	100,912	34.9%	94,911	32.8%	84,296	29.1%	9,353	3.2%	289,472
Jul-03	130,254	39.1%	106,961	32.1%	86,064	25.8%	10,232	3.1%	333,511
Aug-03	133,889	37.5%	108,218	30.3%	88,825	24.9%	10,550	3.0%	357,174
Sep-03	113,506	35.2%	99,408	30.8%	84,526	26.2%	9,939	3.1%	322,566
Oct-03	90,044	32.3%	93,497	33.6%	85,438	30.7%	9,525	3.4%	278,504
Nov-03	88,019	33.3%	85,042	32.2%	82,447	31.2%	8,493	3.2%	264,001
Year-to-Date	***1,166,545***	***36.1%***	***1,025,955***	***31.7%***	***911,955***	***28.2%***	***99,896***	***3.1%***	***3,235,230***

Sources: Credit Lyonnais Securities, Energy Information Administration.

Regional Power Market Overview

Exhibit 42: Estimated Reserve Margins by Region



ECAR- East-Central Area Reliability Council (OH, MI, IN, KY, WV); ERCOT - Electric Reliability Council of Texas; FRCC – Florida Reliability Coordinating Council; MAAC - Mid-Atlantic Area Council (a.k.a. PJM: PA, NJ, MD, DE, D.C.); MAIN – Mid-America Interconnected Network (IL, WI, MO); MAPP - Mid-Continent Area Power Pool; NPCC – Northeast Power Coordinating Council: NEPOOL (New England Power Pool) and NYPP (New York Power Pool); SERC – Southeast Electric Reliability Council: Entergy (AR, LA, MS), Southern (GA, AL), TVA (the Tennessee Valley Authority), and VACAR (Virginia-Carolinas); SPP – Southwest Power Pool (KS, OK); WECC – Western Electricity Coordinating Council: AZMNVA (Arizona-New Mexico-Nevada), CAMX (California-Baja Mexico), NWPA (Northwest Power Association), RMPA (Rocky Mountain Power Association).
Sources: Credit Lyonnais Securities, Energy Information Administration and North American Electric Reliability Council.

Exhibit 43: Regional Power Markets by Fuel Type

Region	Natural Gas	Coal	Petroleum	Other Fossil Fuel	Nuclear Power	Hydroelectric Pumped Storage	Renewable Energy	Other
ECAR	19.2%	68.0%	3.1%	0.7%	4.9%	2.8%	0.4%	0.8%
ERCOT	67.5%	20.1%	1.6%	0.3%	4.8%	0.7%	1.0%	4.0%
FRCC	32.1%	24.5%	26.7%	0.0%	8.3%	0.1%	1.6%	6.8%
MAAC	24.0%	33.5%	15.7%	0.8%	18.9%	3.9%	0.9%	2.3%
MAIN	30.2%	43.3%	5.6%	0.1%	17.5%	2.2%	0.3%	0.8%
MAPP	13.2%	56.2%	9.6%	0.0%	9.8%	7.6%	3.0%	0.6%
NPCC								
NYPP	30.3%	11.4%	22.0%	0.0%	14.0%	15.2%	1.0%	6.1%
NEPOOL	35.0%	8.6%	24.1%	0.0%	13.0%	10.3%	3.7%	5.3%
SERC								
Entergy	65.3%	18.1%	0.2%	0.6%	9.3%	2.9%	0.2%	3.4%
Southern	31.8%	37.9%	3.2%	0.1%	13.9%	10.5%	0.2%	2.4%
TVA	17.0%	43.0%	4.0%	0.0%	16.3%	19.2%	0.2%	0.1%
VACAR	18.8%	37.8%	6.4%	0.1%	21.6%	12.6%	0.7%	2.0%
SPP	50.2%	37.5%	2.7%	0.3%	4.2%	3.7%	0.5%	1.1%
WECC								
NWPP	14.6%	18.8%	0.7%	0.1%	1.8%	60.5%	1.6%	2.0%
RMPA	22.3%	64.2%	1.2%	0.0%	0.0%	8.9%	1.2%	2.2%
AZNMNV	39.3%	34.1%	0.9%	0.0%	13.6%	10.8%	0.0%	1.2%
CAMX	52.5%	0.6%	1.5%	0.8%	7.2%	23.3%	8.1%	6.1%
Average	**33.1%**	**32.8%**	**7.6%**	**0.2%**	**10.5%**	**11.5%**	**1.5%**	**2.8%**

ECAR: IN, KY, MI, OH, WV; ERCOT: TX; FRCC: FL; MAAC: DE, MD, NJ, PA, D.C.; MAIN: IL, MO, WI; MAPP: IA, MN, ND, NE, SD; NYPP: NY; NEPOOL: CT, MA, ME, NH, RI, VT; Entergy: AR, LA, MS; Southern: AL, GA; TVA: TN; VACAR: NC, SC, VA; SPP: KS, OK; NWPP: ID, MT, NV, OR, UT, WA; RMPA: CO, WY; AZNMNV: AZ, NM, NV; CAMX: CA.
Sources: Credit Lyonnais Securities, Energy Information Administration and North American Electricity Reliability Council.

Exhibit 44: Regional Power Markets by Generation Type

Region	Baseload	Intermediate	Peaking	Unknown
ECAR	75.1%	9.0%	10.0%	5.9%
ERCOT	46.0%	29.4%	8.6%	15.9%
FRCC	35.0%	35.5%	15.5%	14.0%
MAAC	50.8%	18.7%	18.0%	12.5%
MAIN	69.3%	15.9%	9.4%	5.4%
MAPP	56.3%	15.6%	21.7%	6.3%
NPCC				
NYPP	54.7%	19.1%	9.4%	16.7%
NEPOOL	30.1%	33.9%	11.1%	24.9%
SERC				
Entergy	44.1%	53.0%	1.6%	1.3%
Southern	29.3%	40.9%	20.1%	9.8%
TVA	41.7%	1.1%	54.9%	2.3%
VACAR	40.0%	23.1%	20.3%	16.6%
SPP	54.7%	16.5%	15.3%	13.5%
WECC				
NWPA	62.1%	25.3%	3.5%	9.0%
RMPA	71.3%	4.8%	13.7%	10.2%
AZNMNV	54.1%	28.6%	11.3%	6.0%
CAMX	22.7%	33.4%	18.9%	25.0%
Average	**49.2%**	**23.8%**	**15.5%**	**11.5%**

ECAR: IN, KY, MI, OH, WV; ERCOT: TX; FRCC: FL; MAAC: DE, MD, NJ, PA, D.C.; MAIN: IL, MO, WI; MAPP: IA, MN, ND, NE, SD; NYPP: NY; NEPOOL: CT, MA, ME, NH, RI, VT; Entergy: AR, LA, MS; Southern: AL, GA; TVA: TN; VACAR: NC, SC, VA; SPP: KS, OK; NWPP: ID, MT, NV, OR, UT, WA; RMPA: CO, WY; AZNMNV: AZ, NM, NV; CAMX: CA.
Sources: Credit Lyonnais Securities, Energy Information Administration and North American Electricity Reliability Council.

Natural Gas Sector Operating Analysis

Exhibit 45: Credit Lyonnais Securities Benchmark Commodity Price Estimates*

	New CLS Estimates				Old CLS Estimates			
	2003A	2004E	2005E	Equilibrium	2003E	2004E	2005E	Equilibrium
Crude Oil (WTI NYMEX, $/bbl)	$31.10	$29.00	$25.00	$25.00	$30.85	$26.50	$25.00	$25.00
Natural Gas (Henry Hub, $/Mcf)	$5.63	$5.00	$4.25	$4.00	$5.51	$4.25	$3.50	$3.50

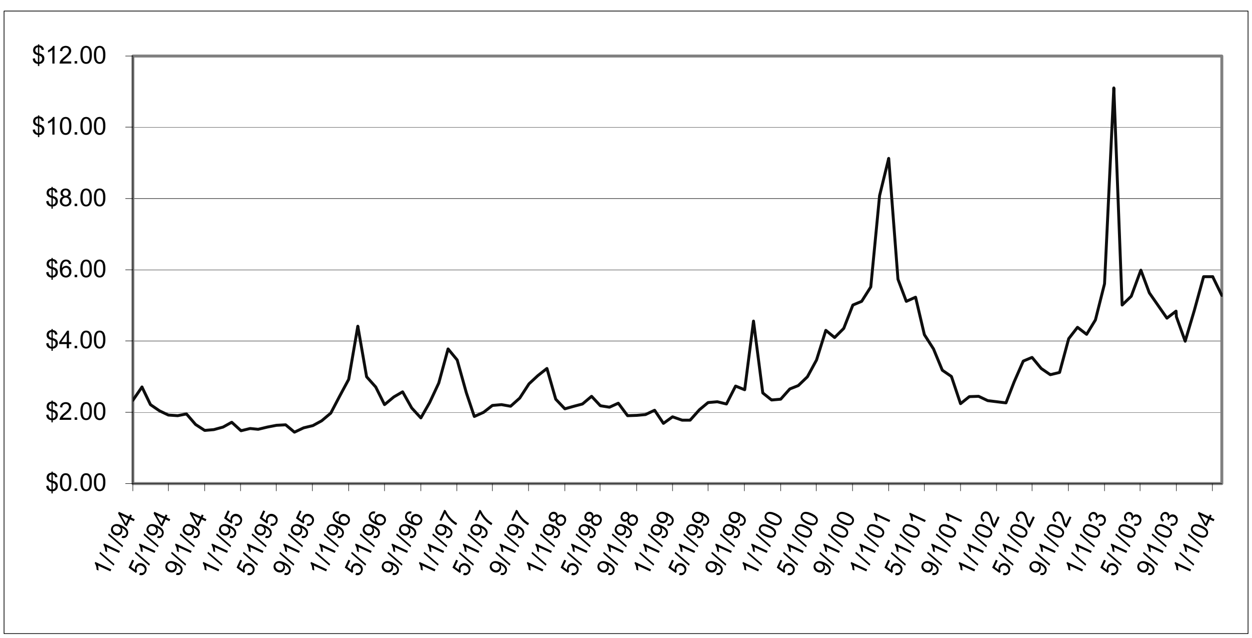
*Estimates were increased on March 8, 2004.
Sources: Brad Beago—Oil & Gas Exploration Analyst, Credit Lyonnais Securities and Bloomberg.

Exhibit 46: Cash Market at Henry Hub ($/MMBtu)*

	Jan.	Feb.	Mar	1Q	Apr	May	Jun	2Q	Jul	Aug	Sep	3Q	Oct	Nov	Dec	Average
1994	$2.34	$2.71	$2.21	**$2.42**	$2.04	$1.92	$1.90	**$1.95**	$1.96	$1.66	$1.49	**$1.70**	$1.51	$1.58	$1.72	**$1.92**
1995	1.48	1.54	1.52	**$1.51**	1.59	1.64	1.65	**$1.63**	1.44	1.56	1.63	**$1.54**	1.76	1.98	2.45	**$1.69**
1996	2.92	4.41	3.00	**$3.44**	2.71	2.21	2.43	**$2.45**	2.57	2.12	1.84	**$2.18**	2.27	2.82	3.78	**$2.76**
1997	3.47	2.55	1.88	**$2.63**	2.00	2.19	2.21	**$2.13**	2.17	2.40	2.80	**$2.46**	3.03	3.23	2.37	**$2.53**
1998	2.10	2.17	2.23	**$2.17**	2.45	2.18	2.14	**$2.26**	2.25	1.90	1.91	**$2.02**	1.93	2.06	1.69	**$2.08**
1999	1.87	1.78	1.78	**$1.81**	2.07	2.27	2.30	**$2.21**	2.23	2.74	2.63	**$2.53**	2.63	2.54	2.35	**$2.27**
2000	2.37	2.66	2.75	**$2.59**	2.99	3.47	4.30	**$3.59**	4.10	4.35	5.01	**$4.49**	5.11	5.52	8.08	**$4.23**
2001	9.13	5.73	5.12	**$6.66**	5.23	4.18	3.78	**$4.40**	3.18	3.01	2.24	**$2.81**	2.44	2.45	2.33	**$4.07**
2002	2.29	2.26	2.85	**$2.47**	3.44	3.54	3.23	**$3.40**	3.06	3.12	4.07	**$3.42**	4.38	4.19	4.59	**$3.42**
2003	4.59	5.61	11.10	**$7.10**	5.01	5.26	5.35	**$5.21**	4.64	4.64	4.68	**$4.65**	3.99	4.86	5.80	**$5.46**
2004	5.80	5.28		**$5.54**				**NA**				**NA**				**$5.54**

*Due to unavailability of month-end data, gas prices for November 2002 and 2003 were quoted on November 27, 2002 and November 26, 2003, respectively.
Sources: Credit Lyonnais Securities, Bloomberg.

Exhibit 47: Cash Market at Henry Hub ($/MMBtu)*



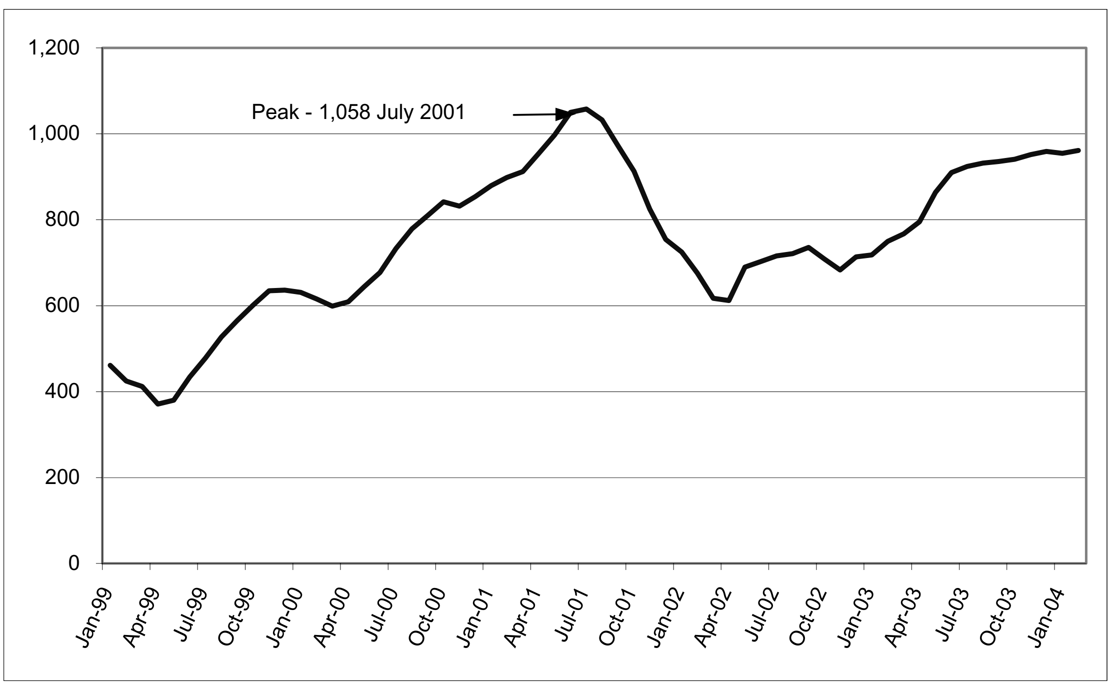
*Due to unavailability of month-end data, gas prices for November 2002 and 2003 were quoted on November 27, 2002 and November 26, 2003, respectively.
Sources: Credit Lyonnais Securities, Bloomberg.

Exhibit 48: Rig Count

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Average
1999													
Total	587	542	526	496	516	558	588	639	696	711	782	798	**625**
Gas	461	425	412	371	380	434	478	527	565	601	635	636	**496**
Pct Gas	**79%**	**78%**	**78%**	**75%**	**74%**	**78%**	**81%**	**82%**	**81%**	**85%**	**81%**	**80%**	**79%**
2000													
Total	774	763	773	805	844	878	942	987	1,011	1,055	1,067	1,097	**918**
Gas	631	616	599	609	644	677	733	779	810	842	832	854	**720**
Pct Gas	**82%**	**81%**	**77%**	**76%**	**76%**	**77%**	**78%**	**79%**	**80%**	**80%**	**78%**	**78%**	**78%**
2001													
Total	1,118	1,136	1,163	1,206	1,234	1,270	1,278	1,251	1,193	1,111	1,020	901	**1,158**
Gas	879	898	912	955	997	1,050	1,058	1,032	972	913	825	754	**939**
Pct Gas	**79%**	**79%**	**78%**	**79%**	**81%**	**83%**	**83%**	**82%**	**81%**	**82%**	**81%**	**84%**	**81%**
2002													
Total	867	824	763	750	826	842	851	848	860	852	834	856	**831**
Gas	725	676	617	612	690	703	716	721	736	709	683	714	**692**
Pct Gas	**84%**	**82%**	**81%**	**82%**	**84%**	**83%**	**84%**	**85%**	**86%**	**83%**	**82%**	**83%**	**83%**
2003													
Total	854	907	941	983	1,035	1,067	1,081	1,090	1,093	1,102	1,112	1,114	**1,032**
Gas	718	750	767	795	864	910	924	932	936	941	952	959	**871**
Pct Gas	**84%**	**83%**	**82%**	**81%**	**83%**	**85%**	**85%**	**86%**	**86%**	**85%**	**86%**	**86%**	**84%**
2004													
Total	1,101	1,119											**1,110**
Gas	955	961											**958**
Pct Gas	**87%**	**86%**											**86%**

Sources: Credit Lyonnais Securities, Baker Hughes Inc.

Exhibit 49: Natural Gas Rig Count



Sources: Credit Lyonnais Securities, Baker Hughes Inc.

Exhibit 50: Natural Gas Supply & Disposition (Bcf)

	Natural Gas Supply						
Date	Dry Gas Production	Supplemental Gaseous Fuels	Net Imports	Net Storage Withdrawals	Total Natural Gas Supply	Balancing Item	Natural Gas Consumption
1990	17,810	123	1,446	(513)	**18,865**	307	19,174
1991	17,698	113	1,644	80	**19,534**	27	19,562
1992	17,840	118	1,922	173	**20,053**	176	20,228
1993	18,095	119	2,210	(36)	**20,388**	401	20,790
1994	18,821	111	2,462	(286)	**21,108**	139	21,247
1995	18,599	110	2,687	415	**21,811**	396	22,207
1996	18,854	91	2,784	2	**21,731**	878	22,609
1997	18,902	77	2,837	24	**21,840**	897	22,737
1998	19,024	80	2,993	(529)	**21,568**	679	22,246
1999	18,832	82	3,423	172	**22,509**	(119)	22,405
2000	19,212	84	3,538	829	**23,663**	(270)	23,471
2001							
Jan-01	1,685	9	347	508	**2,549**	126	2,676
Feb-01	1,515	7	301	348	**2,171**	138	2,310
Mar-01	1,714	8	326	187	**2,235**	14	2,250
Apr-01	1,626	6	295	(284)	**1,643**	163	1,807
May-01	1,681	6	293	(487)	**1,493**	31	1,524
Jun-01	1,624	6	292	(449)	**1,473**	(29)	1,445
Jul-01	1,650	7	334	(392)	**1,599**	(1)	1,598
Aug-01	1,661	6	324	(313)	**1,678**	(10)	1,670
Sep-01	1,602	7	281	(379)	**1,511**	(17)	1,494
Oct-01	1,674	7	292	(193)	**1,780**	(129)	1,651
Nov-01	1,599	8	249	(74)	**1,782**	(81)	1,701
Year-to-Date	***18,031***	***77***	***3,334***	***(1,528)***	***19,914***	***205***	***20,126***
Dec-01	1,645	8	268	361	**2,282**	(160)	2,122
Total 2001	**19,676**	**85**	**3,602**	**(1,167)**	**22,196**	**45**	**22,248**
2002							
Jan-02	1,620	8	309	546	**2,483**	(21)	2,456
Feb-02	1,447	7	275	462	**2,191**	24	2,210
Mar-02	1,625	8	294	320	**2,247**	(21)	2,227
Apr-02	1,558	6	276	(126)	**1,714**	131	1,842
May-02	1,628	6	280	(323)	**1,591**	(12)	1,578
Jun-02	1,586	5	272	(339)	**1,524**	34	1,560
Jul-02	1,641	7	299	(240)	**1,707**	19	1,727
Aug-02	1,624	6	308	(233)	**1,705**	(11)	1,696
Sep-02	1,513	6	288	(292)	**1,515**	(3)	1,513
Oct-02	1,554	7	301	(84)	**1,778**	(160)	1,618
Nov-02	1,608	7	275	198	**2,088**	(205)	1,883
Year-to-Date	***17,404***	***73***	***3,177***	***(111)***	***20,543***	***(225)***	***20,310***
Dec-02	1,644	8	314	558	**2,524**	(183)	2,342
Total 2002	**19,048**	**81**	**3,491**	**447**	**23,067**	**(408)**	**22,652**
2003							
Jan-03	1,675	8	300	842	**2,825**	(186)	2,639
Feb-03	1,502	4	251	675	**2,432**	33	2,465
Mar-03	1,687	7	271	136	**2,101**	52	2,153
Apr-03	1,601	6	256	(159)	**1,704**	(11)	1,694
May-03	1,648	7	268	(412)	**1,511**	(34)	1,477
Jun-03	1,587	6	250	(470)	**1,373**	(51)	1,321
Jul-03	1,619	7	272	(362)	**1,536**	15	1,551
Aug-03	1,628	7	261	(309)	**1,587**	(1)	1,586
Sep-03	1,620	6	245	(410)	**1,461**	(97)	1,363
Oct-03	1,640	6	245	(284)	**1,607**	(77)	1,528
Nov-03	1,592	7	292	92	**1,983**	(189)	1,794
Year-to-Date	***17,799***	***71***	***2,911***	***(661)***	***20,120***	***(546)***	***19,571***

Sources: Credit Lyonnais Securities, Energy Information Administration.

Exhibit 51: Natural Gas Consumption (Bcf)

			Delivered to Consumers				
Date	**Lease and Plant Fuel**	**Pipeline Fuel**	**Commercial**	**Electric Utilities***	**Industrial**	**Residential**	**Total Consumption**
1980	1,026	635	2,611	3,682	7,172	4,752	19,878
1981	928	642	2,520	3,640	7,128	4,546	19,404
1982	1,109	596	2,606	3,226	5,831	4,633	18,001
1983	978	490	2,433	2,911	5,643	4,381	16,836
1984	1,077	529	2,524	3,111	6,154	4,555	17,950
1985	966	504	2,432	3,044	5,901	4,433	17,280
1986	923	485	2,318	2,602	5,579	4,314	16,221
1987	1,149	519	2,430	2,844	5,953	4,315	17,210
1988	1,096	614	2,670	2,636	6,383	4,630	18,029
1989	1,070	629	2,718	3,105	6,816	4,781	19,119
1990	1,236	660	2,623	3,245	7,018	4,391	19,173
1991	1,129	601	2,729	3,316	7,231	4,556	19,562
1992	1,171	588	2,803	3,448	7,527	4,690	20,227
1993	1,172	624	2,862	3,473	7,700	4,956	20,787
1994	1,124	685	2,895	3,903	7,790	4,848	21,245
1995	1,220	700	3,031	4,237	8,164	4,850	22,202
1996	1,250	711	3,158	3,807	8,435	5,241	22,602
1997	1,203	751	3,215	4,065	8,511	4,984	22,729
1998	1,173	635	2,999	4,588	8,320	4,520	22,235
1999	1,079	645	3,045	4,820	8,079	4,726	22,394
2000	1,144	644	3,218	5,206	8,254	4,992	23,458
2001							
Jan-01	93	76	503	340	684	977	2,676
Feb-01	85	66	425	313	640	781	2,310
Mar-01	95	64	378	363	667	682	2,250
Apr-01	90	51	257	385	622	401	1,807
May-01	92	42	165	434	581	209	1,524
Jun-01	89	40	136	493	539	147	1,445
Jul-01	91	44	131	634	575	124	1,598
Aug-01	92	47	134	687	592	117	1,670
Sep-01	89	41	144	510	580	128	1,492
Oct-01	93	46	186	466	619	239	1,649
Nov-01	89	48	232	351	620	361	1,701
Year-to-Date	***998***	***565***	***2,691***	***4,976***	***6,719***	***4,166***	***20,122***
Dec-01	92	60	347	367	643	610	2,119
Total 2002	**1,090**	**625**	**3,038**	**5,343**	**7,362**	**4,776**	**22,241**
2002							
Jan-02	90	69	439	381	661	819	2,460
Feb-02	80	61	402	344	607	717	2,214
Mar-02	90	62	373	407	627	665	2,225
Apr-02	86	52	267	404	617	416	1,844
May-02	90	44	192	410	585	255	1,578
Jun-02	88	44	147	551	568	161	1,559
Jul-02	91	48	138	734	589	125	1,727
Aug-02	90	48	138	718	584	117	1,695
Sep-02	84	42	142	569	550	124	1,512
Oct-02	86	45	200	442	591	251	1,617
Nov-02	89	53	299	352	606	484	1,883
Year-to-Date	***964***	***568***	***2,737***	***5,312***	***6,585***	***4,134***	***20,314***
Dec-02	91	66	417	360	635	772	2,342
Total 2002	**1,055**	**634**	**3,154**	**5,672**	**7,220**	**4,906**	**22,656**
2003							
Jan-03	93	74	490	367	659	955	2,639
Feb-03	83	69	473	329	621	889	2,465
Mar-03	93	60	380	353	587	678	2,153
Apr-03	88	48	256	333	551	417	1,694
May-03	91	41	176	381	536	250	1,477
Jun-03	88	37	135	411	490	159	1,321
Jul-03	89	43	129	609	551	127	1,551
Aug-03	90	44	127	654	552	117	1,586
Sep-03	90	38	133	434	539	128	1,363
Oct-03	92	44	180	391	591	229	1,528
Nov-03	90	54	267	361	602	419	1,794
Year-to-Date	***987***	***552***	***2,746***	***4,623***	***6,279***	***4,368***	***19,571***

1980–1988: Electric utilities only. Beginning in 1989, also includes independent power producers.
Sources: Credit Lyonnais Securities, Energy Information Administration.

Exhibit 52: Natural Gas in Underground Storage (Bcf)

	Natural Gas in Underground Storage			Year-Over-Year Change		Storage Activity		
Date	Base Gas	Working Gas	Total	Amount Over/(Under)	%	Withdrawals	Injections	Net
1980	3,642	2,655	6,297	(98)	-3.6%	1,910	1,896	(14)
1981	3,752	2,817	6,569	162	6.1%	1,887	2,180	293
1982	3,808	3,071	6,879	254	9.0%	2,094	2,399	305
1983	3,847	2,595	6,442	(476)	-15.5%	2,142	1,700	(442)
1984	3,830	2,876	6,706	281	10.8%	2,064	2,252	188
1985	3,842	2,607	6,449	(269)	-9.4%	2,359	2,128	(231)
1986	3,819	2,749	6,568	142	5.4%	1,812	1,952	140
1987	3,792	2,756	6,548	7	0.3%	1,881	1,887	6
1988	3,800	2,850	6,650	94	4.6%	2,244	2,174	(70)
1989	3,812	2,513	6,325	(337)	-15.2%	2,804	2,491	(313)
1990	3,868	3,068	6,936	555	28.8%	1,934	2,433	499
1991	3,954	2,824	6,778	(244)	-9.9%	2,689	2,608	(81)
1992	4,044	2,597	6,641	(227)	-8.9%	2,724	2,555	(169)
1993	4,327	2,322	6,649	(275)	-10.0%	2,717	2,760	43
1994	4,360	2,606	6,966	284	10.7%	2,508	2,796	288
1995	4,349	2,153	6,502	(453)	-16.1%	2,974	2,566	(408)
1996	4,341	2,173	6,514	20	0.7%	2,911	2,906	(5)
1997	4,350	2,175	6,525	2	0.1%	2,824	2,800	(24)
1998	4,326	2,730	7,056	555	19.3%	2,379	2,905	526
1999	4,383	2,523	6,906	(207)	-9.5%	2,772	2,598	(174)
2000	4,352	1,719	6,071	(806)	-31.9%	3,499	2,685	(814)
2001								
Jan-01	4,344	1,265	5,609	(459)	-26.1%	588	92	(496)
Feb-01	4,328	912	5,240	(391)	-30.0%	414	74	(340)
Mar-01	4,300	742	5,042	(412)	-35.7%	298	116	(182)
Apr-01	4,261	992	5,253	(210)	-17.5%	70	349	279
May-01	4,309	1,440	5,749	7	0.5%	41	520	479
Jun-01	4,310	1,882	6,192	165	9.6%	49	490	441
Jul-01	4,315	2,261	6,576	258	12.9%	66	451	385
Aug-01	4,313	2,576	6,889	377	17.1%	79	386	307
Sep-01	4,318	2,944	7,262	450	18.0%	41	413	372
Oct-01	4,310	3,144	7,454	412	15.1%	93	282	189
Nov-01	4,301	3,254	7,555	812	33.3%	138	210	72
Dec-01	4,301	2,904	7,205	1,185	68.9%	432	80	(352)
2001	**4,301**	**2,904**	**7,205**	**1,185**	**68.9%**	**2,309**	**3,463**	**1,154**
2002								
Jan-02	4,313	2,344	6,657	1,079	85.3%	605	59	(546)
Feb-02	4,356	1,838	6,194	926	101.5%	517	55	(462)
Mar-02	4,355	1,518	5,873	776	104.6%	425	105	(320)
Apr-02	4,355	1,659	6,014	667	67.2%	111	237	126
May-02	4,361	1,968	6,329	528	36.7%	58	381	323
Jun-02	4,355	2,308	6,663	426	22.6%	56	395	339
Jul-02	4,358	2,539	6,897	278	12.3%	101	340	239
Aug-02	4,357	2,773	7,130	197	7.6%	89	323	234
Sep-02	4,342	3,042	7,384	98	3.3%	72	364	292
Oct-02	4,342	3,116	7,458	(28)	-0.9%	145	229	84
Nov-02	4,344	2,929	7,273	(325)	-10.0%	322	124	(198)
Dec-02	4,340	2,375	6,715	(529)	-18.2%	624	66	(558)
2002	**4,340**	**2,375**	**6,715**	**(529)**	**68.9%**	**3,125**	**2,678**	**(447)**
2003								
Jan-03	4,342	1,534	5,876	(810)	-34.6%	886	48	(838)
Feb-03	4,334	864	5,198	(974)	-53.0%	723	48	(675)
Mar-03	4,324	730	5,054	(788)	-51.9%	305	169	(136)
Apr-03	4,315	896	5,211	(763)	-46.0%	118	277	159
May-03	4,322	1,300	5,622	(668)	-33.9%	41	453	412
Jun-03	4,323	1,768	6,091	(540)	-23.4%	36	506	470
Jul-03	4,323	2,129	6,451	(410)	-16.1%	64	426	362
Aug-03	4,324	2,435	6,760	(338)	-12.2%	62	371	309
Sep-03	4,328	2,843	7,171	(199)	-6.5%	31	441	410
Oct-03	4,327	3,130	7,457	14	0.4%	59	343	284
Nov-03	4,328	3,063	7,391	134	4.6%	224	132	(92)

Sources: Credit Lyonnais Securities, Energy Information Administration.

Exhibit 53: Weekly Natural Gas in Underground Storage (Bcf)*

	Consuming Region				Injection/	Year-Over-Year Comparison	
Week Ending	East	West	Producing	Total	(Withdrawal)	Amt Over/(Under)	%
03-Jan-03	1,333	342	656	2,331	(86)	(458)	84%
10-Jan-03	1,248	329	618	2,195	(136)	(453)	83%
17-Jan-03	1,111	314	551	1,976	(219)	(546)	78%
24-Jan-03	946	296	487	1,729	(247)	(681)	72%
31-Jan-03	805	285	431	1,521	(208)	(810)	65%
07-Feb-03	716	268	387	1,371	(150)	(789)	63%
14-Feb-03	594	241	333	1,168	(203)	(868)	57%
21-Feb-03	499	224	291	1,014	(154)	(949)	52%
28-Feb-03	403	198	237	838	(176)	(981)	46%
07-Mar-03	331	179	211	721	(117)	(1,007)	42%
14-Mar-03	267	172	197	636	(85)	(1,000)	39%
21-Mar-03	277	167	199	643	7	(918)	41%
28-Mar-03	305	167	208	680	37	(820)	45%
04-Apr-03	298	167	206	671	(9)	(820)	45%
11-Apr-03	264	167	192	623	(48)	(883)	41%
18-Apr-03	298	174	212	684	61	(891)	43%
25-Apr-03	333	180	228	741	57	(865)	46%
02-May-03	385	192	251	828	87	(817)	50%
09-May-03	438	198	264	900	72	(807)	53%
16-May-03	496	206	288	990	90	(785)	56%
23-May-03	559	216	310	1,085	95	(762)	59%
30-May-03	629	226	344	1,199	114	(755)	61%
06-Jun-03	697	241	386	1,324	125	(718)	65%
13-Jun-03	769	254	415	1,438	114	(685)	68%
20-Jun-03	847	265	453	1,565	127	(653)	71%
27-Jun-03	907	274	481	1,662	97	(624)	73%
04-Jul-03	979	280	550	1,809	147	(544)	77%
11-Jul-03	1,042	292	570	1,904	95	(518)	79%
18-Jul-03	1,102	295	584	1,981	77	(505)	80%
25-Jul-03	1,163	298	601	2,062	81	(472)	81%
01-Aug-03	1,222	303	613	2,138	76	(429)	83%
08-Aug-03	1,280	313	629	2,222	84	(398)	85%
15-Aug-03	1,335	317	647	2,299	77	(358)	87%
22-Aug-03	1,373	322	657	2,352	53	(364)	87%
29-Aug-03	1,424	328	667	2,419	67	(362)	87%
05-Sep-03	1,486	337	695	2,518	99	(337)	88%
12-Sep-03	1,550	346	723	2,619	101	(305)	90%
19-Sep-03	1,610	356	753	2,719	100	(271)	91%
26-Sep-03	1,674	363	783	2,820	101	(218)	93%
03-Oct-03	1,718	371	815	2,904	84	(176)	94%
10-Oct-03	1,767	378	836	2,981	77	(147)	95%
17-Oct-03	1,817	390	859	3,066	85	(95)	97%
24-Oct-03	1,847	396	878	3,121	55	(51)	98%
31-Oct-03	1,871	399	885	3,155	34	10	100%
07-Nov-03	1,891	392	904	3,187	32	90	103%
14-Nov-03	1,864	392	899	3,155	(32)	59	102%
21-Nov-03	1,859	392	903	3,154	(1)	107	104%
28-Nov-03	1,824	383	888	3,095	(59)	139	105%
05-Dec-03	1,756	371	857	2,984	(111)	190	107%
12-Dec-03	1,678	360	812	2,850	(134)	215	108%
19-Dec-03	1,584	343	772	2,699	(151)	159	106%
26-Dec-03	1,529	338	752	2,619	(80)	202	108%
02-Jan-04	1,495	319	753	2,567	(52)	236	110%
09-Jan-04	1,412	293	709	2,414	(153)	219	110%
16-Jan-04	1,297	278	683	2,258	(156)	282	114%
23-Jan-04	1,163	263	633	2,063	(195)	334	119%
30-Jan-04	1,009	243	575	1,827	(236)	306	120%
06-Feb-04	880	211	512	1,603	(224)	232	117%
13-Feb-04	788	187	456	1,431	(172)	263	123%
20-Feb-04	689	172	406	1,267	(164)	253	125%
27-Feb-04	630	162	379	1,171	(96)	333	140%
05-Mar-04	619	148	376	1,143	(28)	422	159%

The Energy Information Administration revised historical storage data from 7/4/03 – 10/17/03.
Sources: Credit Lyonnais Securities, Energy Information Administration.

Exhibit 54: Average Natural Gas Withdrawals (Bcf)

Year	Weeks	Cycle Total (Bcf)	Average (Bcf/wk)	Cumulative Monthly * Nov	Dec	Jan	Feb	Mar
1994/95	22	(1,739)	(79)	(114)	(325)	(634)	(510)	(156)
1995/96	21	(2,243)	(107)	(281)	(527)	(783)	(392)	(260)
1996/97	22	(1,811)	(82)	(229)	(383)	(680)	(357)	(162)
1997/98	22	(1,680)	(76)	(169)	(577)	(416)	(290)	(228)
1998/99	22	(1,778)	(81)	(40)	(438)	(608)	(336)	(356)
1999/00	22	(1,915)	(87)	(33)	(512)	(667)	(568)	(135)
2000/01	22	(1,975)	(90)	(279)	(669)	(527)	(344)	(156)
2001/02	21	(1,652)	(79)	102	(265)	(657)	(513)	(319)
2002/03	21	(2,465)	(117)	(189)	(625)	(810)	(683)	(158)
Average	**22**	**(1,918)**	**(89)**	**(137)**	**(480)**	**(642)**	**(444)**	**(214)**
2003/04	**17**	**(2,184)**	**(128)**	**(60)**	**(528)**	**(740)**	**(656)**	
Hist. Avg.	**17**	**(1671)**	**(98)**	**2003/04 Variance (%)**			**31%**	
2002/03	**17**	**(2307)**	**(136)**	**2002/03Variance (%)**			**-5%**	

*Subject to rounding errors due to timing of report date.
Sources: Brad Beago—Oil & Gas Exploration Analyst, Credit Lyonnais Securities and Energy Information Administration.

Exhibit 55: Storage Withdrawal Scenario (Bcf)

	Storage (Bcf)	Current Actual (Bcf)	Days/ Month	Estimated Withdrawals (Bcf/d)	Actual Withdrawals (Bcf/d)	Hist/avg. (1) (Bcf/d)	2002/03A (Bcf/d)	2001/02A (Bcf/d)
October Beginning Storage Level:	**3,155**	**3,155**						
Estimated Monthly Withdrawals:								
November	(60)	(60)	30	(2.0)	(2.0)	(4.6)	(6.3)	3.4
December	(528)	(528)	31	(17.0)	(17.0)	(15.5)	(20.2)	(8.5)
January	(741)	(741)	31	(23.9)	(23.9)	(20.7)	(26.1)	(21.2)
February	(656)	(656)	28	(23.4)	(23.4)	(15.9)	(24.4)	(18.3)
March	**(200)**		31	**(6.5)**	0.0	(6.9)	(5.1)	(10.3)
Total Withdrawals	**(2,185)**	**(1,985)**	**153**	**(14.3)**	**(9.6)**	**(12.5)**	**(16.1)**	**(10.8)**
Ending Storage Levels	**970**	**1,170**						
Inventories (4/03)	**671**							

(1) 1994-2002.
Sources: Brad Beago—Oil & Gas Exploration Analyst, Credit Lyonnais Securities estimates.

Exhibit 56: U.S. Natural Gas Imports and Exports by Country (Bcf)

	IMPORTS									EXPORTS			
	LNG					Total	Pipeline		Total				Total
Date	Algeria	Australia	Qatar	Trinidad	Other*	LNG	Canada	Mexico	Imports	Canada	Japan**	Mexico	Exports
1980	86	0	0	0	0	86	797	102	985	0	45	4	49
1981	37	0	0	0	0	37	762	105	904	0	56	3	59
1982	55	0	0	0	0	55	783	95	933	0	50	2	52
1983	131	0	0	0	0	131	712	75	918	0	53	2	55
1984	36	0	0	0	0	36	755	52	843	0	53	2	55
1985	24	0	0	0	0	24	926	0	950	0	53	2	55
1986	0	0	0	0	2	2	749	0	750	9	50	2	61
1987	0	0	0	0	0	0	993	0	993	3	49	2	54
1988	17	0	0	0	0	17	1,276	0	1,294	20	52	2	74
1989	42	0	0	0	0	42	1,339	0	1,382	38	51	17	107
1990	84	0	0	0	0	84	1,448	0	1,532	17	53	16	86
1991	64	0	0	0	0	64	1,710	0	1,773	15	54	60	129
1992	43	0	0	0	0	43	2,094	0	2,138	68	53	96	216
1993	82	0	0	0	0	82	2,267	2	2,350	45	56	40	140
1994	51	0	0	0	0	51	2,566	7	2,624	53	63	47	162
1995	18	0	0	0	0	18	2,816	7	2,841	28	65	61	154
1996	35	0	0	0	5	40	2,883	14	2,937	52	68	34	153
1997	66	10	0	0	2	78	2,899	17	2,994	56	62	38	157
1998	69	12	0	0	5	85	3,052	15	3,152	40	66	53	159
1999	76	12	20	51	5	163	3,368	55	3,586	39	64	61	163
2000	47	6	46	99	28	226	3,544	12	3,782	73	66	106	244
2001													
Jan-01	5	0	0	11	2	18	352	2	373	12	6	8	26
Feb-01	8	0	0	7	8	22	305	1	328	15	4	8	27
Mar-01	8	0	2	11	3	24	333	1	358	19	6	7	32
Apr-01	5	0	2	8	7	23	294	2	319	13	6	5	24
May-01	8	0	5	10	5	27	295	0	322	13	6	10	29
Jun-01	4	0	3	10	9	26	291	0	317	10	4	11	25
Jul-01	8	1	5	7	5	26	339	0	365	10	6	15	31
Aug-01	5	1	0	8	5	19	334	0	353	8	6	16	29
Sep-01	5	0	5	5	7	22	293	0	315	10	6	18	34
Oct-01	2	0	0	9	0	11	314	0	326	11	8	16	34
Nov-01	3	0	0	5	0	8	283	0	291	21	6	16	42
Year-to-Date	***60***	***2***	***23***	***90***	***51***	***226***	***3,433***	***7***	***3,666***	***142***	***62***	***130***	***333***
Dec-01	5	0	0	8	0	13	294	3	310	25	6	11	42
2001	**65**	**2**	**23**	**98**	**51**	**239**	**3,727**	**10**	**3,976**	**167**	**68**	**141**	**375**
2002													
Jan-02	3	0	0	5	0	8	334	1	343	16	6	13	34
Feb-02	0	0	0	8	0	8	297	1	305	16	4	11	30
Mar-02	0	0	0	10	0	10	322	0	332	14	6	18	38
Apr-02	1	0	5	10	0	17	297	0	314	13	7	19	39
May-02	7	0	6	10	5	28	291	0	319	15	2	23	40
Jun-02	5	0	14	6	0	25	292	0	317	14	6	25	45
Jul-02	5	0	5	11	0	21	323	0	344	12	6	28	46
Aug-02	0	0	3	16	6	25	331	0	356	12	6	29	47
Sep-02	0	0	3	14	0	17	318	0	335	13	6	28	47
Oct-02	0	0	0	22	5	28	315	0	343	10	6	26	42
Nov-02	3	0	0	19	0	22	308	0	330	28	6	21	55
Year-to-Date	***24***	***0***	***35***	***133***	***16***	***209***	***3,428***	***2***	***3,638***	***163***	***57***	***240***	***461***
Dec-02	3	0	0	18	0	20	349	0	369	26	6	23	55
2002	**27**	**0**	**35**	**151**	**16**	**229**	**3,777**	**2**	**4,008**	**189**	**63**	**263**	**516**
2003													
Jan-03	0	0	0	23	0	23	333	0	356	23	4	28	55
Feb-03	0	0	0	21	0	21	286	0	307	25	6	25	56
Mar-03	3	0	2	26	0	31	292	0	323	29	6	17	52
Apr-03	11	0	0	19	3	33	272	0	305	23	6	20	49
May-03	4	0	0	30	11	46	270	0	316	15	4	29	48
Jun-03	3	0	0	34	11	48	253	0	301	18	3	30	51
Jul-03	5	0	3	44	5	57	262	0	319	13	7	27	47
Aug-03	3	0	0	35	11	49	261	0	310	14	5	30	49
Sep-03	8	0	6	29	11	54	243	0	297	19	5	28	52
Oct-03	0	0	0	24	NA	NA	275	NA	299	18	8	28	54
Nov-03	NA	NA	NA	NA	NA	NA	NA	NA	344	NA	NA	NA	52
Year-to-Date	***37***	***0***	***11***	***285***	***52***	***362***	***2,747***	***0***	***3,477***	***197***	***54***	***262***	***565***

*Indonesia included in 1986, 2000; UAE included beginning in 1996, Malaysia included beginning in 1999, Nigeria and Oman included beginning in 2000 and Brunei included beginning in 2002.

** Japan exports are in the form of LNG, while Canadian and Mexican exports are via pipeline.

Sources: Credit Lyonnais Securities, Energy Information Administration.

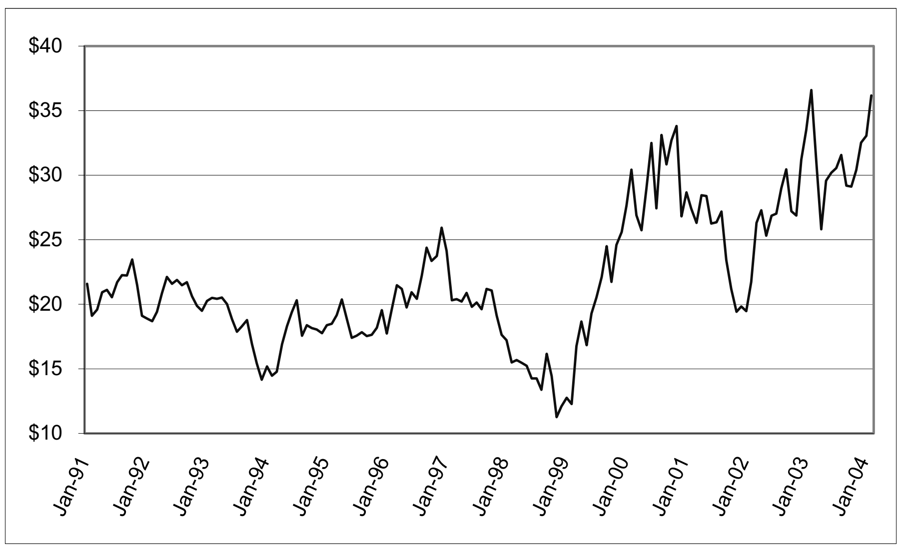
Crude Oil

Exhibit 57: West Texas Intermediate Cushing Crude ($/Barrel)

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Average
1991	$21.60	$19.12	$19.60	$20.94	$21.13	$20.54	$21.72	$22.26	$22.23	$23.48	$21.48	$19.12	$21.10
1992	$18.90	$18.68	$19.44	$20.85	$22.11	$21.60	$21.87	$21.48	$21.71	$20.62	$19.89	$19.50	$20.55
1993	$20.26	$20.51	$20.44	$20.53	$20.02	$18.85	$17.88	$18.29	$18.79	$16.92	$15.43	$14.17	$18.51
1994	$15.19	$14.48	$14.79	$16.90	$18.31	$19.37	$20.30	$17.58	$18.39	$18.17	$18.05	$17.76	$17.44
1995	$18.39	$18.49	$19.17	$20.38	$18.89	$17.40	$17.56	$17.84	$17.54	$17.64	$18.18	$19.55	$18.42
1996	$17.74	$19.54	$21.47	$21.20	$19.76	$20.92	$20.42	$22.25	$24.38	$23.35	$23.75	$25.92	$21.73
1997	$24.15	$20.30	$20.41	$20.21	$20.88	$19.80	$20.14	$19.61	$21.18	$21.08	$19.15	$17.64	$20.38
1998	$17.21	$15.50	$15.70	$15.48	$15.23	$14.26	$14.26	$13.38	$16.17	$14.45	$11.26	$12.09	$14.58
1999	$12.76	$12.28	$16.76	$18.66	$16.84	$19.29	$20.53	$22.11	$24.51	$21.75	$24.59	$25.60	$19.64
2000	$27.64	$30.43	$26.90	$25.74	$29.01	$32.50	$27.43	$33.13	$30.84	$32.70	$33.82	$26.80	$29.75
2001	$28.66	$27.40	$26.30	$28.46	$28.37	$26.26	$26.35	$27.20	$23.43	$21.18	$19.44	$19.84	$25.24
2002	$19.48	$21.74	$26.31	$27.29	$25.31	$26.86	$27.02	$28.98	$30.45	$27.22	$26.89	$31.20	$26.56
2003	$33.51	$36.60	$31.04	$25.80	$29.56	$30.19	$30.54	$31.57	$29.20	$29.11	$30.41	$32.52	$30.84
2004	$33.05	$36.16											$34.61

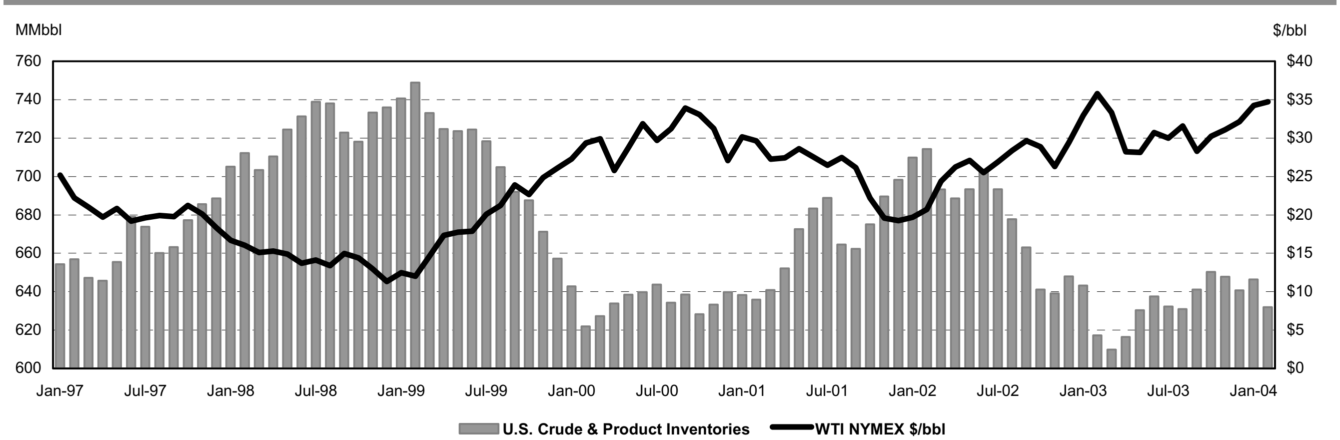
Sources: Credit Lyonnais Securities, Bloomberg.

Exhibit 58: West Texas Intermediate Cushing Crude ($/Barrel)



Sources: Credit Lyonnais Securities, Bloomberg.

Exhibit 59: Crude and Production Inventories and WTI NYMEX Price



Sources: Data provided by Brad Beago—Oil and Gas Exploration Analyst, Credit Lyonnais Securities, American Petroleum Institute and Bloomberg.

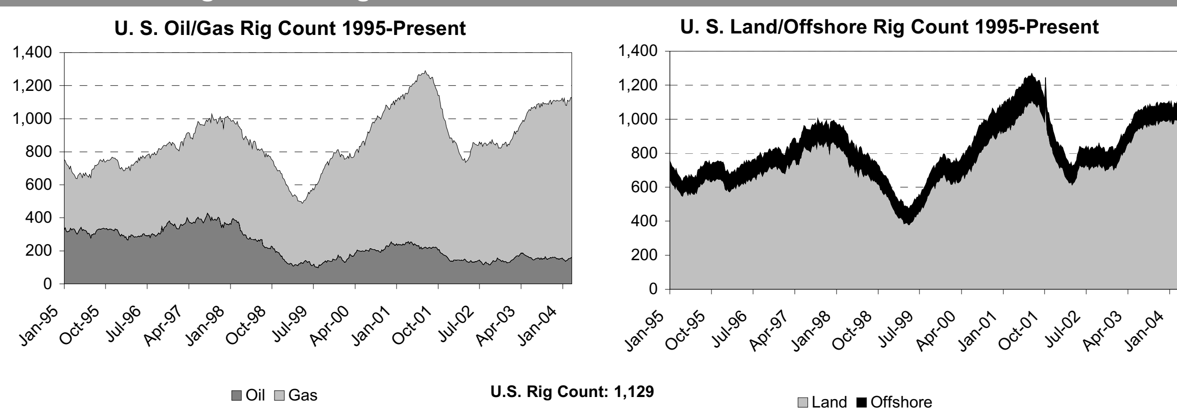
Worldwide Rig Count Analysis

Exhibit 60: CLS Worldwide Rig Count Forecast

	1995	1996	1997	1998	1999	2000	2001	2002					2003					2004E				
International Land								1Q	2Q	3Q	4Q	Avg	1Q	2Q	3Q	4Q	Avg	1QE	2QE	3QE	4QE	Avg
Europe	65	64	54	46	40	37	37	36	36	32	32	34	36	33	38	36	36	36	37	37	39	37
Middle East	103	106	127	136	118	135	147	155	162	166	177	165	179	177	186	181	181	183	185	188	190	187
Africa	43	45	48	44	26	26	30	32	33	33	37	34	37	37	35	34	36	37	39	41	42	40
Latin America	215	221	210	182	148	186	215	180	162	159	170	168	173	184	195	201	188	197	198	200	202	199
Asia Pacific	123	118	116	98	76	84	97	103	106	105	108	106	106	103	103	103	104	101	103	105	106	104
Total International Land	549	554	555	505	409	466	525	507	499	495	524	506	531	534	557	555	544	554	562	571	579	566
International Offshore																						
Europe	47	56	59	53	41	47	58	58	58	48	53	54	46	50	51	44	48	47	49	50	52	50
Middle East	25	30	32	30	22	21	32	38	36	37	35	36	34	31	26	32	31	33	35	37	40	36
Africa	24	34	32	30	16	20	23	22	24	27	22	24	17	20	15	20	18	22	23	25	26	24
Latin America	57	61	67	62	39	41	47	45	43	45	50	46	45	56	58	66	56	66	68	69	70	68
Asia Pacific	58	59	64	75	63	57	60	62	65	67	69	66	72	73	76	75	74	73	75	78	78	76
Total International Offshore	210	239	253	250	180	186	220	225	225	223	229	225	213	231	225	236	226	241	250	259	266	254
Total International	**759**	**793**	**809**	**755**	**588**	**652**	**745**	**731**	**725**	**718**	**753**	**732**	**744**	**765**	**782**	**791**	**771**	**795**	**812**	**830**	**845**	**820**
U.S.																						
Land	626	671	820	716	516	776	1,002	690	699	722	736	712	792	919	980	1,003	924	985	1,000	1,035	1,045	1,016
Offshore	101	106	122	124	106	140	154	121	107	112	111	113	108	109	109	106	108	103	107	110	113	108
Total U.S.	**726**	**777**	**942**	**840**	**622**	**916**	**1,156**	**811**	**806**	**835**	**847**	**825**	**901**	**1,028**	**1,088**	**1,108**	**1,031**	**1,088**	**1,107**	**1,145**	**1,158**	**1,125**
Canada																						
Land	229	270	373	257	241	340	336	377	140	243	279	260	490	199	378	406	369	520	250	405	445	405
Offshore	1	1	1	4	5	5	5	6	7	7	4	6	3	3	5	4	4	4	5	5	5	5
Total Canada	230	271	375	261	246	344	342	383	147	250	283	266	493	203	383	410	372	524	255	410	450	410
Total North America	**956**	**1,047**	**1,317**	**1,100**	**868**	**1,260**	**1,497**	**1,194**	**953**	**1,085**	**1,130**	**1,091**	**1,394**	**1,231**	**1,472**	**1,518**	**1,404**	**1,612**	**1,362**	**1,555**	**1,608**	**1,534**
Total World	**1,715**	**1,841**	**2,126**	**1,855**	**1,456**	**1,913**	**2,242**	**1,926**	**1,677**	**1,803**	**1,883**	**1,822**	**2,138**	**1,996**	**2,254**	**2,309**	**2,174**	**2,407**	**2,174**	**2,385**	**2,453**	**2,355**

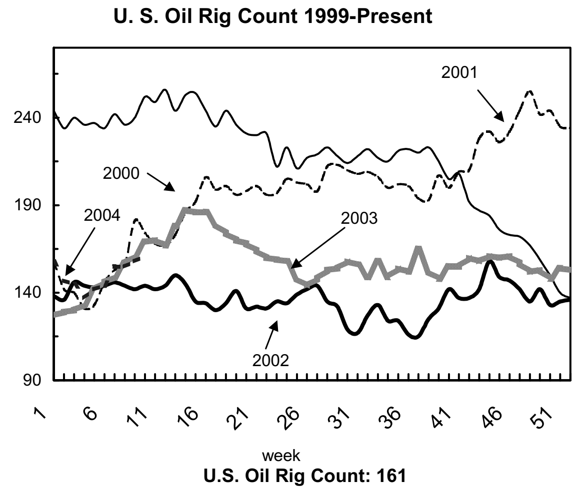
Sources: Baker Hughes, ODS Petrodata and Karen David-Green—Oil Services & Equipment Analyst, Credit Lyonnais Securities.

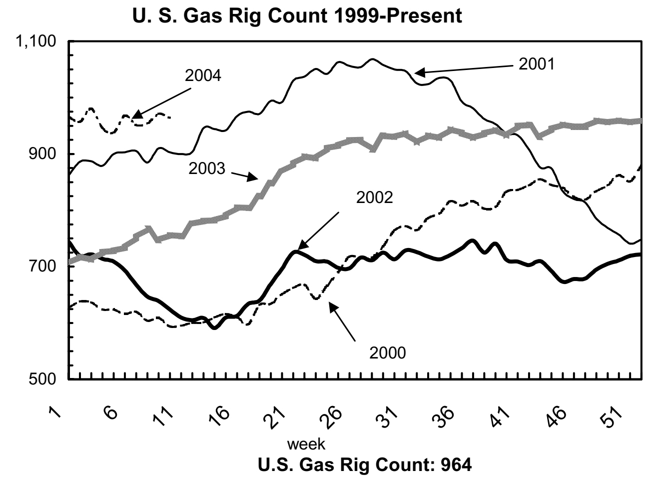
Exhibit 61: Baker Hughes U.S. Rig Counts Oil/Gas and Land/Offshore



Total U.S. rig count number is inclusive of rigs classified as miscellaneous.
Sources: Baker Hughes and Karen David-Green—Oil Services & Equipment Analyst, Credit Lyonnais Securities.

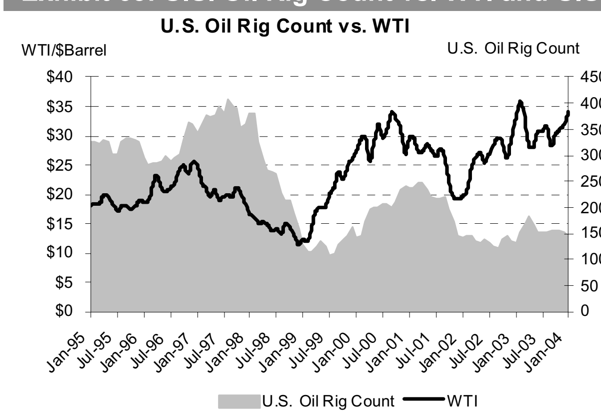
Exhibit 62: U.S. Rig Count 1999-Present

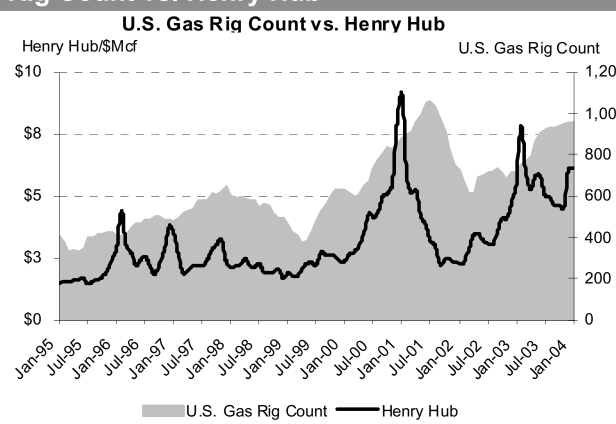




Numbers do not include miscellaneous rigs.
Sources: Baker Hughes and Karen David-Green—Oil Services & Equipment Analyst, Credit Lyonnais Securities.

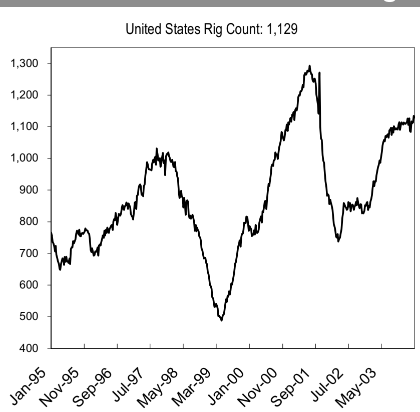
Exhibit 63: U.S. Oil Rig Count vs. WTI and U.S. Gas Rig Count vs. Henry Hub

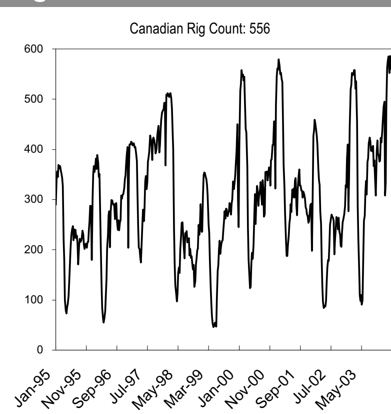


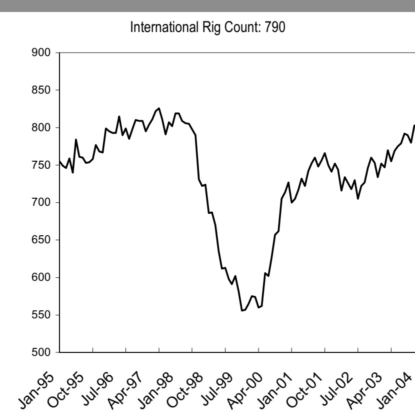


Numbers do not include miscellaneous rigs.
Sources: Baker Hughes and Karen David-Green—Oil Services & Equipment Analyst, Credit Lyonnais Securities.

Exhibit 64: Historical Baker Hughes Rig Counts

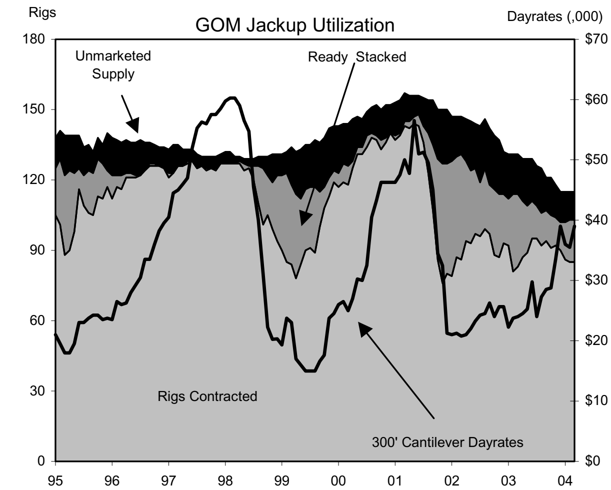


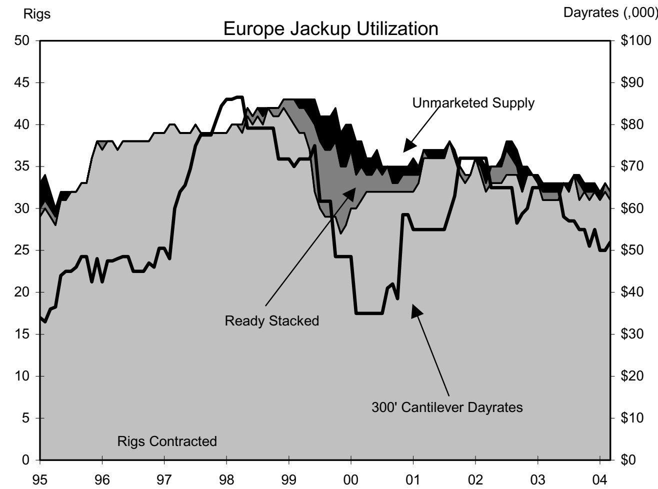




Sources: Baker Hughes and Karen David-Green—Oil Services & Equipment Analyst, Credit Lyonnais Securities.

Exhibit 65: Jackup Overview of Selected Geographic Markets



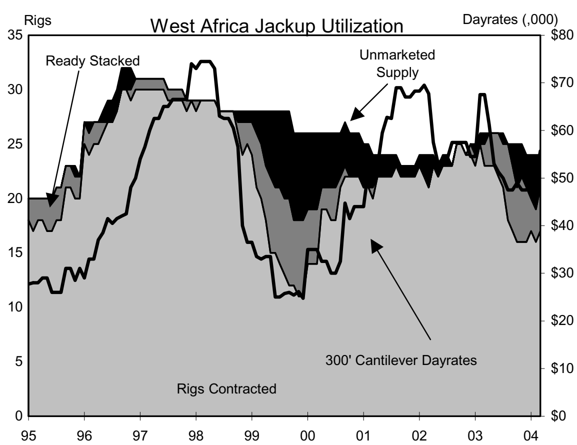


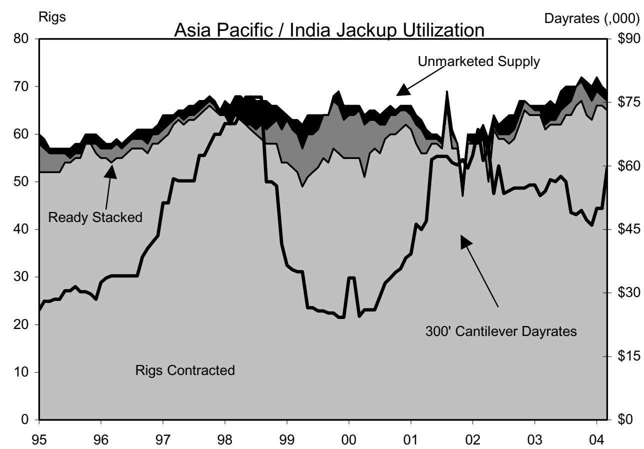
GOM Jackups

	Mar-04	Feb-04	Mar-03	Month % Change	Year % Change
Dayrates	$39.0	$35.5	$24.0	9.9%	62.5%
Utilization	76.4%	75.2%	63.4%	1.6%	20.6%

Europe Jackups

	Mar-04	Feb-04	Mar-03	Month % Change	Year % Change
Dayrates	$52.0	$50.0	$65.0	4.0%	-20.0%
Utilization	96.8%	100.0%	93.9%	-3.2%	3.0%





West Africa Jackups

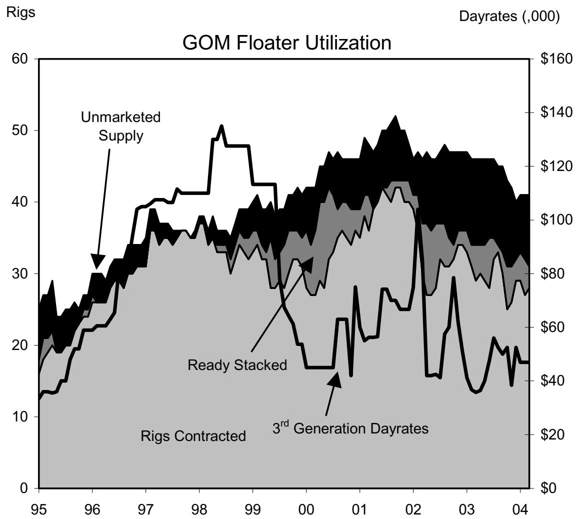
	Mar-04	Feb-04	Mar-03	Month % Change	Year % Change
Dayrates	$55.7	$50.3	$67.5	10.8%	-17.5%
Utilization	70.8%	66.7%	88.5%	6.2%	-19.9%

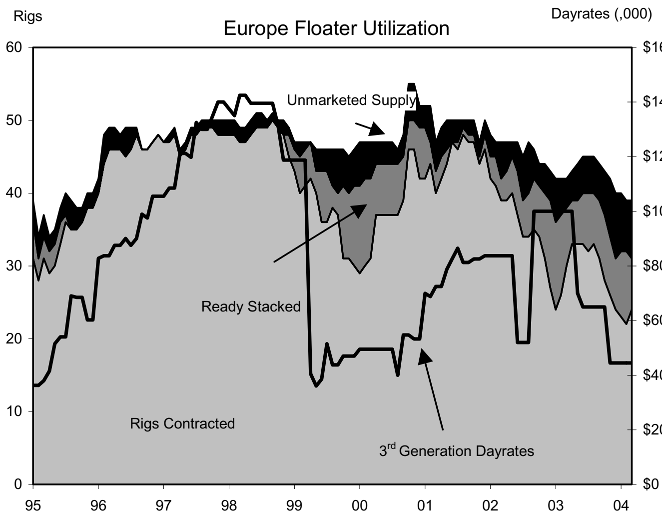
Asia Pacific / India Jackups

	Mar-04	Feb-04	Mar-03	Month % Change	Year % Change
Dayrates	$59.5	$50.0	$54.0	19.0%	10.2%
Utilization	94.6%	96.6%	92.4%	-2.0%	2.4%

Note: Data based on average dayrate for a 300' cantilever jackup. Data are based on prior month numbers.
Sources: ODS-Petrodata and Karen David-Green—Oil Services & Equipment Analyst, Credit Lyonnais Securities.

Exhibit 66: Floater Overview of Selected Geographic Markets



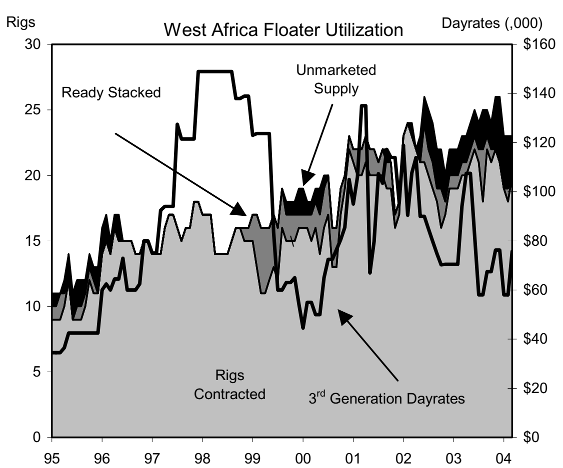


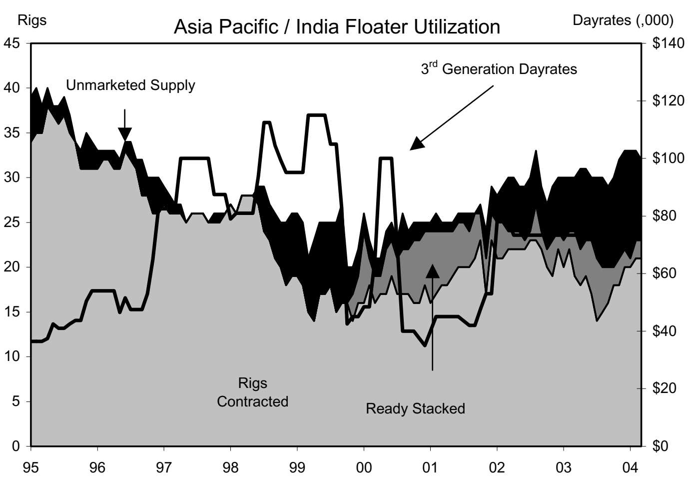
GOM Floaters

	Mar-04	Feb-04	Mar-03	Month % Change	Year % Change
Dayrates	$47.0	$47.0	$35.8	0.0%	31.5%
Utilization	88.4%	65.9%	57.9%	34.1%	52.7%

Europe Floaters

	Mar-04	Feb-04	Mar-03	Month % Change	Year % Change
Dayrates	$44.5	$44.5	$100.0	0.0%	-55.5%
Utilization	69.2%	61.5%	69.8%	12.6%	-0.8%





West Africa Floaters

	Mar-04	Feb-04	Mar-03	Month % Change	Year % Change
Dayrates	$75.8	$58.0	$94.0	30.6%	-19.4%
Utilization	79.2%	79.2%	89.5%	0.0%	-11.5%

Asia Pacific / India Floaters

	Mar-04	Feb-04	Mar-03	Month % Change	Year % Change
Dayrates	$85.0	$85.0	$73.3	0.0%	16.0%
Utilization	61.3%	61.3%	68.4%	0.0%	-10.4%

Note: Data based on average dayrate for a 300' cantilever jackup. Data are based on prior month numbers.
Sources: ODS-Petrodata and Karen David-Green—Oil Services & Equipment Analyst, Credit Lyonnais Securities.

Coal

Exhibit 67: Powder River 8800 Coal Prices ($/Short Ton)

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Average
1997	$3.63	$3.75	$4.00	$3.88	$4.13	$4.13	$4.13	$4.13	$4.13	$4.63	$4.63	$4.73	$4.16
1998	$4.88	$5.00	$4.88	$4.63	$4.53	$4.38	$4.55	$4.75	$4.63	$4.40	$4.45	$4.40	$4.62
1999	$4.47	$4.40	$4.45	$4.53	$4.55	$4.53	$4.70	$4.75	$4.68	$4.72	$4.45	$4.45	$4.56
2000	$4.47	$4.50	$4.43	$4.38	$4.47	$4.35	$4.25	$4.40	$4.45	$4.47	$4.70	$4.45	$4.44
2001	$4.95	$6.25	$10.50	$10.50	$12.50	$13.00	$8.25	$9.00	$8.25	$8.50	$8.00	$7.50	$8.93
2002	$6.50	$6.00	$6.00	$6.13	$5.97	$5.75	$5.38	$5.38	$5.38	$5.75	$5.60	$5.38	$5.77
2003	$5.80	$5.78	$5.63	$5.70	$5.80	$5.80	$5.58	$6.13	$7.38	$7.15	$6.98	$7.00	$6.23
2004	$7.13	$7.13											$7.13

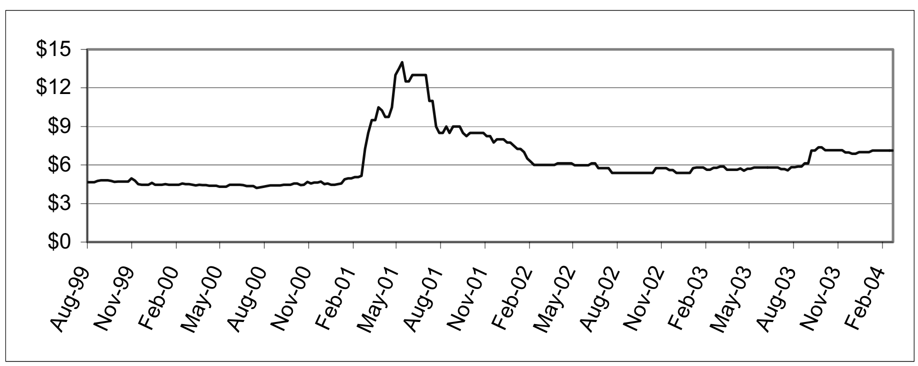
Sources: Credit Lyonnais Securities, Bloomberg.

Exhibit 68: Big Sandy Barge Coal Prices ($/Short Ton)

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Average
1997	$25.50	$26.00	$25.50	$26.50	$26.00	$25.25	$26.00	$26.25	$26.00	$27.00	$27.50	$27.75	$26.27
1998	$27.50	$27.13	$27.00	$26.13	$26.63	$26.25	$26.50	$27.00	$28.75	$30.00	$31.00	$29.50	$27.78
1999	$29.50	$28.00	$24.25	$24.88	$24.38	$23.25	$23.25	$24.25	$23.25	$23.38	$23.33	$21.75	$24.46
2000	$22.63	$22.13	$22.13	$21.88	$22.38	$22.88	$23.13	$24.13	$25.75	$26.38	$28.25	$30.75	$24.37
2001	$33.75	$36.00	$43.00	$42.00	$46.00	$48.00	$41.00	$41.00	$35.00	$35.00	$34.00	$31.50	$38.85
2002	$30.00	$27.50	$27.00	$28.00	$27.50	$27.50	$29.00	$28.75	$28.25	$28.25	$26.75	$27.50	$28.00
2003	$30.00	$31.25	$31.50	$30.00	$31.00	$31.50	$31.75	$33.00	$35.00	$35.50	$35.00	$37.00	$32.71
2004	$43.00	$45.50											$44.25

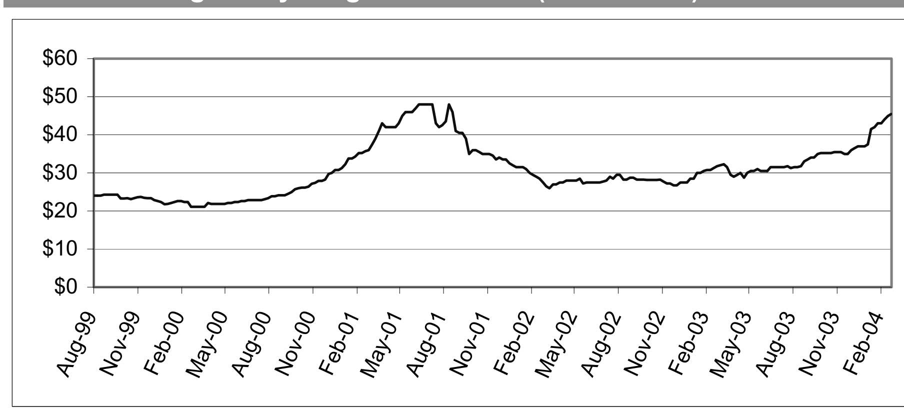
Sources: Credit Lyonnais Securities, Bloomberg.

Exhibit 69: Powder River 8800 Coal Prices ($/Short Ton)



Sources: Credit Lyonnais Securities, Bloomberg.

Exhibit 70: Big Sandy Barge Coal Prices ($/Short Ton)



Sources: Credit Lyonnais Securities, Bloomberg.

Exhibit 71: Coal Consumption by Sector (Thousand Short Tons)

	Commerical		Industrial		Electric Power Sector*		Total
1989	6,167	0.7%	116,643	13.0%	772,190	86.3%	895,000
1990	6,724	0.7%	115,207	12.7%	782,567	86.5%	904,498
1991	6,094	0.7%	109,259	12.2%	783,874	87.2%	899,227
1992	6,153	0.7%	106,408	11.7%	795,094	87.6%	907,655
1993	6,221	0.7%	106,215	11.3%	831,645	88.1%	944,081
1994	6,013	0.6%	106,919	11.2%	838,354	88.1%	951,286
1995	5,807	0.6%	106,067	11.0%	850,230	88.4%	962,104
1996	6,006	0.6%	103,395	10.3%	896,921	89.1%	1,006,322
1997	6,463	0.6%	101,718	9.9%	921,364	89.5%	1,029,545
1998	4,856	0.5%	95,628	9.2%	936,619	90.3%	1,037,103
1999	4,879	0.3%	92,846	4.9%	1,805,740	94.9%	1,903,465
2000	4,126	0.4%	94,147	8.7%	985,821	90.9%	1,084,094
2001							
Jan-01	520	0.5%	7,981	8.2%	88,400	91.2%	96,901
Feb-01	413	0.5%	7,958	9.5%	75,405	90.0%	83,776
Mar-01	378	0.4%	8,202	9.5%	77,923	90.1%	86,503
Apr-01	374	0.5%	7,613	9.7%	70,388	89.8%	78,375
May-01	235	0.3%	7,629	9.0%	76,746	90.7%	84,610
Jun-01	264	0.3%	7,515	8.3%	82,251	91.4%	90,030
Jul-01	324	0.3%	7,591	7.7%	91,247	92.0%	99,162
Aug-01	329	0.3%	7,588	7.5%	93,194	92.2%	101,111
Sep-01	221	0.3%	7,464	8.6%	79,025	91.1%	86,710
Oct-01	285	0.3%	7,592	9.1%	75,640	90.6%	83,517
Nov-01	382	0.5%	7,201	8.9%	73,435	90.6%	81,018
Year-to-Date	***3,725***	***0.4%***	***84,334***	***8.7%***	***883,654***	***90.9%***	***971,713***
Dec-01	644	0.7%	7,010	7.9%	80,835	91.4%	88,489
2001	**4,369**	**0.4%**	**91,344**	**8.6%**	**964,489**	**91.0%**	**1,060,202**
2002							
Jan-02	440	0.5%	7,085	7.9%	82,424	91.6%	90,004
Feb-02	384	0.5%	6,993	8.8%	72,144	90.7%	79,569
Mar-02	363	0.4%	7,164	8.6%	75,823	90.9%	83,395
Apr-02	322	0.4%	6,767	8.6%	71,560	90.9%	78,688
May-02	245	0.3%	6,856	8.2%	76,528	91.5%	83,658
Jun-02	225	0.2%	6,796	7.5%	83,565	92.2%	90,613
Jul-02	313	0.3%	6,860	6.9%	92,766	92.8%	99,977
Aug-02	279	0.3%	6,947	7.0%	91,752	92.7%	99,012
Sep-02	200	0.2%	6,936	7.6%	84,144	92.2%	91,305
Oct-02	264	0.3%	7,458	8.4%	80,714	91.2%	88,469
Nov-02	397	0.5%	7,268	8.4%	79,301	91.1%	87,016
Year-to-Date	***3,432***	***0.4%***	***77,130***	***7.9%***	***890,721***	***91.7%***	***971,706***
Dec-02	525	0.6%	7,274	7.7%	86,784	91.7%	94,648
2002	**3,957**	**0.4%**	**84,404**	**7.9%**	**977,505**	**91.7%**	**1,066,354**
2003							
Jan-03	484	0.5%	7,132	7.2%	91,109	92.2%	98,784
Feb-03	405	0.5%	7,135	8.3%	78,838	91.2%	86,428
Mar-03	298	0.3%	7,291	8.4%	78,770	91.2%	86,396
Apr-03	338	0.4%	6,941	8.8%	71,993	90.8%	79,314
May-03	241	0.3%	6,850	8.2%	76,714	91.5%	83,834
Jun-03	212	0.2%	6,959	7.7%	82,659	92.0%	89,856
Jul-03	301	0.3%	7,052	7.0%	93,326	92.7%	100,716
Aug-03	299	0.3%	6,975	6.8%	94,649	92.8%	101,960
Sep-03	192	0.2%	6,998	7.7%	83,695	92.1%	90,908
Oct-03	234	0.3%	7,443	8.4%	80,710	91.3%	88,416
Nov-03	372	0.4%	7,374	8.5%	79,154	91.0%	86,945
Year-to-Date	***3,376***	***0.3%***	***78,150***	***7.9%***	***911,617***	***91.8%***	***993,557***

*In its April 2003 report, the Energy Information Administration revised its presentation of coal consumption by the electric power sector. The category presently comprises electricity-only plants as well as combined heat and power plants. Additionally, beginning in 1989, consumption by independent power producers has also been included.
Sources: Credit Lyonnais Securities, Energy Information Administration.

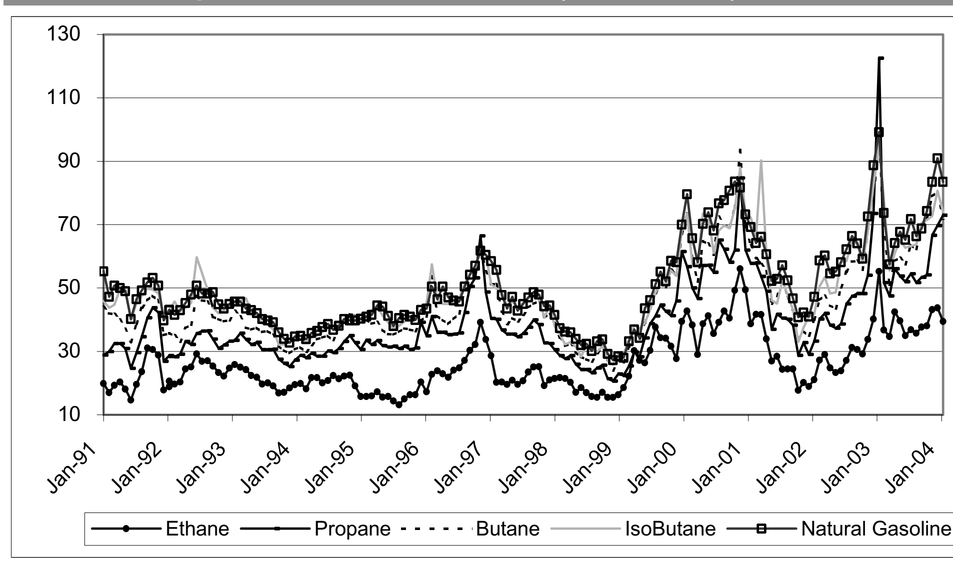
Natural Gas Liquids

Exhibit 72: Liquids Prices at Mont Belvieu (Cents/Gallon)

	Ethane	Propane	Butane	IsoButane	Natural Gasoline
1991	21.8	33.1	41.3	46.3	48.6
1992	23.6	32.1	39.6	46.4	45.7
1993	21.3	31.0	36.2	39.8	40.6
1994	20.8	30.2	35.1	36.9	37.2
1995	16.0	32.3	37.7	40.6	41.4
1996	26.7	43.0	47.5	51.3	51.2
1997	22.0	36.6	43.5	46.2	47.8
1998	18.1	25.5	30.2	31.3	33.6
1999	28.1	34.8	41.6	42.5	43.8
2000	41.1	59.7	68.4	69.5	73.9
2001	**31.0**	**45.0**	**51.0**	**55.7**	**56.5**
Jan-02	19.0	29.0	34.9	41.0	41.0
Feb-02	21.1	33.3	40.0	41.8	47.3
Mar-02	27.3	40.3	46.3	50.5	58.8
Apr-02	29.0	42.0	47.5	53.5	60.3
May-02	24.9	38.3	44.5	48.3	54.6
Jun-02	23.4	37.4	43.5	48.6	55.1
Jul-02	23.9	38.6	50.1	58.3	58.1
Aug-02	27.1	45.0	55.1	58.5	62.3
Sep-02	31.3	47.4	58.3	64.8	66.5
Oct-02	30.6	48.3	58.5	63.8	64.1
Nov-02	29.3	48.3	55.8	58.0	59.3
Dec-02	33.8	54.0	68.8	68.0	72.6
2002	**26.7**	**41.8**	**50.3**	**54.6**	**58.3**
Jan-03	40.3	73.5	79.5	82.5	88.8
Feb-03	55.3	122.5	95.0	95.3	99.3
Mar-03	36.8	51.8	70.5	78.0	73.8
Apr-03	34.8	47.5	51.0	55.5	57.5
May-03	42.5	56.1	58.5	61.0	64.3
Jun-03	39.6	53.8	59.5	65.1	67.8
Jul-03	35.0	52.0	57.4	62.8	65.3
Aug-03	36.9	54.5	63.8	63.3	71.8
Sep-03	35.8	51.8	62.3	63.8	66.4
Oct-03	37.8	53.4	70.0	70.5	68.8
Nov-03	38.1	54.1	72.0	71.5	74.3
Dec-03	43.3	66.6	79.0	72.8	83.5
2003	**39.7**	**61.5**	**68.2**	**70.2**	**73.4**
Jan-04	43.8	69.8	80.3	80.8	91.0
Feb-04	39.5	73.0	72.0	74.0	83.5

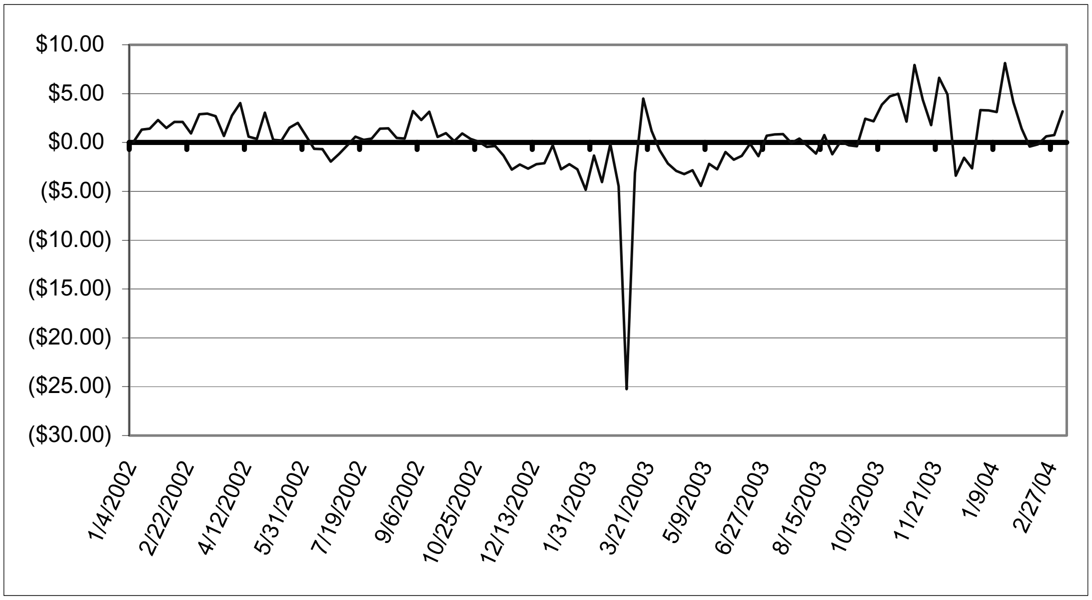
Sources: Credit Lyonnais Securities, Bloomberg.

Exhibit 73: Liquids Prices at Mont Belvieu (Cents/Gallon)



Sources: Credit Lyonnais Securities, Bloomberg.

Exhibit 74: Fractionation Spreads for Full Recovery Ethane at Henry Hub ($/MMBtu)*



The 35% ethane fractionation spreads have not been available on Bloomberg since 5/9/03. We are currently in the process of obtaining access to an accurate and consistent source of information for this important benchmark. In the interim, we have provided data for full recovery ethane.
Sources: Credit Lyonnais Securities, Bloomberg.

Crack Spreads

Exhibit 75: 2:1:1 Crack Spreads ($/Barrel)

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Average
1995	$3.56	$3.24	$3.05	$3.60	$4.08	$4.01	$3.97	$4.01	$3.72	$3.60	$3.92	$4.97	$3.81
1996	$4.40	$4.55	$4.07	$4.87	$3.31	$3.03	$4.15	$3.94	$3.91	$4.15	$5.05	$4.09	$4.13
1997	$4.08	$4.06	$4.29	$4.41	$4.04	$4.93	$4.85	$4.42	$3.90	$4.11	$4.03	$3.01	$4.18
1998	$4.64	$4.44	$4.34	$4.91	$3.99	$4.00	$2.40	$2.59	$2.88	$3.23	$2.69	$2.82	$3.58
1999	$2.32	$2.50	$3.82	$2.48	$1.76	$2.93	$3.62	$3.81	$3.19	$3.52	$4.17	$2.85	$3.08
2000	$9.40	$7.22	$5.49	$5.36	$6.59	$6.16	$6.28	$7.47	$6.39	$5.35	$5.89	$8.51	$6.68
2001	$4.64	$5.74	$7.77	$9.62	$7.74	$4.28	$3.76	$5.55	$4.18	$3.42	$3.34	$3.87	$5.33
2002	$3.74	$4.50	$5.31	$4.32	$3.87	$3.94	$3.97	$3.59	$3.43	$4.36	$4.25	$5.30	$4.21
2003	$6.36	$9.11	$5.24	$5.29	$4.14	$4.64	$4.88	$5.28	$4.22	$4.40	$4.81	$6.28	$5.39
2004	$6.48	$7.25											$6.87

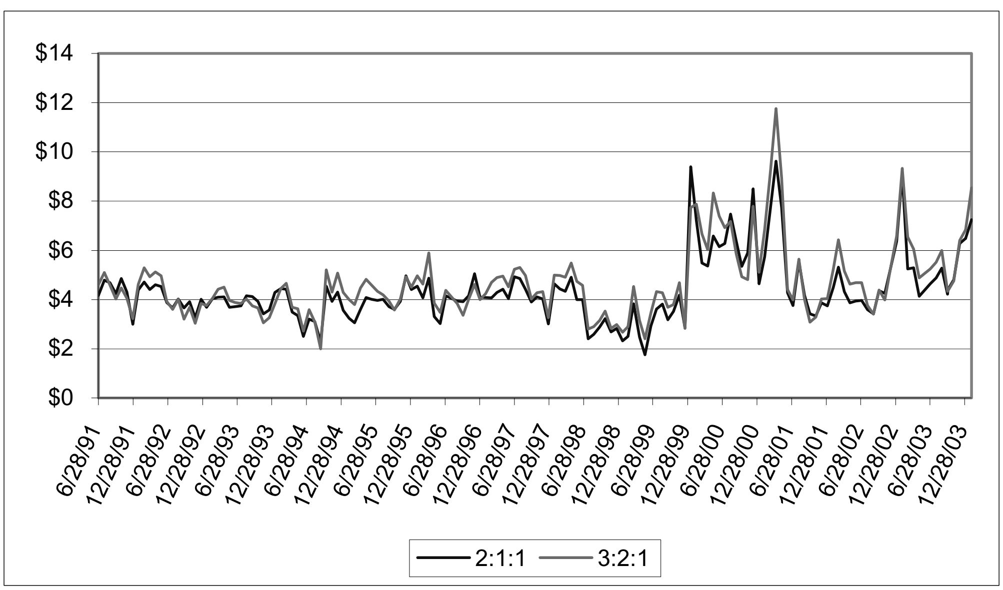
Note: The 2:1:1 crack spread assumes that two barrels of NYMEX oil are cracked into one barrel of gasoline and one barrel of distillate.
Sources: Credit Lyonnais Securities, Bloomberg.

Exhibit 76: 3:2:1 Crack Spreads ($/Barrel)

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Average
1995	$4.29	$3.99	$3.80	$4.48	$4.83	$4.59	$4.34	$4.20	$3.94	$3.58	$4.02	$4.93	$4.25
1996	$4.50	$4.97	$4.63	$5.90	$3.85	$3.47	$4.38	$3.84	$3.36	$4.01	$4.61	$4.00	$4.29
1997	$4.23	$4.70	$4.90	$4.95	$4.52	$5.24	$5.31	$4.98	$4.03	$4.28	$4.32	$3.27	$4.56
1998	$5.00	$4.98	$4.91	$5.49	$4.74	$4.58	$2.80	$2.90	$3.15	$3.53	$2.82	$2.98	$3.99
1999	$2.67	$2.90	$4.53	$3.16	$2.41	$3.47	$4.32	$4.28	$3.68	$3.79	$4.68	$2.84	$3.56
2000	$7.74	$7.88	$6.68	$6.02	$8.33	$7.38	$6.93	$7.18	$5.86	$4.93	$4.82	$7.80	$6.79
2001	$5.11	$6.85	$9.26	$11.77	$8.94	$4.40	$3.99	$5.64	$4.01	$3.08	$3.29	$4.03	$5.86
2002	$4.04	$5.24	$6.43	$5.17	$4.62	$4.68	$4.68	$3.75	$3.41	$4.40	$3.99	$5.31	$4.64
2003	$6.59	$9.34	$6.55	$6.06	$4.88	$5.25	$5.51	$5.99	$4.33	$4.36	$4.75	$6.41	$5.83
2004	$6.84	$8.54											$7.69

Note: the 3:2:1 crack spread assumes that three barrels of NYMEX oil are cracked into two barrels of gasoline and one barrel of distillate.
Sources: Credit Lyonnais Securities, Bloomberg.

Exhibit 77: Crack Spreads ($/Barrel)



Note: The 2:1:1 crack spread assumes that two barrels of NYMEX oil are cracked into one barrel of gasoline and one barrel of distillate, while the 3:2:1 crack spread assumes that three barrels of NYMEX oil are cracked into two barrels of gasoline and one barrel of distillate.
Sources: Credit Lyonnais Securities, Bloomberg.

Weather

Exhibit 78: Heating Degree Days—Weekly

	Heating Degree Days			Pct Change	
Week Ending	2004/2003	Normal	2003/2002	From Normal	From 2003/2002
4-Oct-03	62	37	19	68% Colder	226% Colder
11-Oct-03	32	48	39	33% Warmer	18% Warmer
18-Oct-03	54	61	76	11% Warmer	29% Warmer
25-Oct-03	66	82	104	20% Warmer	37% Warmer
1-Nov-03	73	89	113	18% Warmer	35% Warmer
8-Nov-03	92	103	124	11% Warmer	26% Warmer
15-Nov-03	117	118	92	1% Warmer	27% Colder
22-Nov-03	95	134	129	29% Warmer	26% Warmer
29-Nov-03	144	149	163	3% Warmer	12% Warmer
6-Dec-03	168	163	197	3% Colder	15% Warmer
13-Dec-03	181	176	185	3% Colder	2% Warmer
20-Dec-03	188	188	153	0% Colder	23% Colder
27-Dec-03	163	197	190	17% Warmer	14% Warmer
3-Jan-04	148	204	167	27% Warmer	11% Warmer
10-Jan-04	225	208	175	8% Colder	29% Colder
17-Jan-04	200	209	231	4% Warmer	13% Warmer
24-Jan-04	229	208	250	10% Colder	8% Warmer
31-Jan-04	247	204	209	21% Colder	18% Colder
7-Feb-04	207	198	184	5% Colder	13% Colder
14-Feb-04	201	189	213	6% Colder	6% Warmer
21-Feb-04	180	178	188	1% Colder	4% Warmer
28-Feb-04	163	166	209	2% Warmer	22% Warmer
6-Mar-04	116	170	206	32% Warmer	44% Warmer
13-Mar-04	135	146	155	8% Warmer	13% Warmer

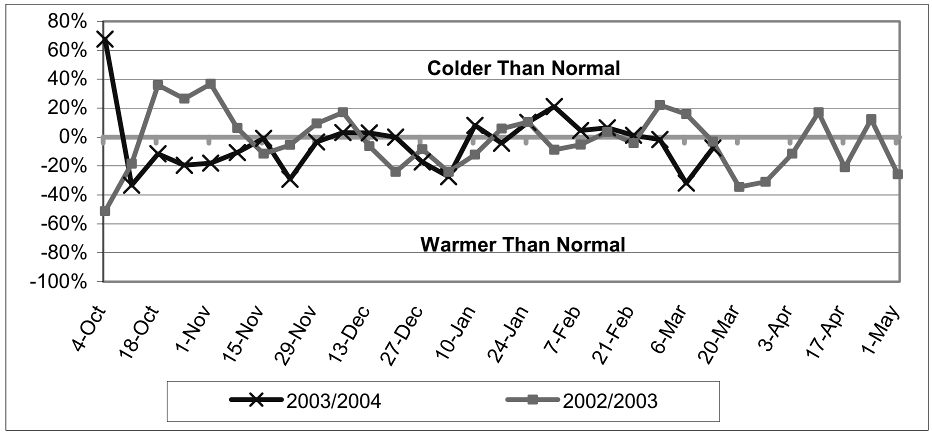
Sources: Credit Lyonnais Securities, National Oceanic and Atmospheric Administration.

Exhibit 79: Heating Degree Days—Cumulative by Region, March 13, 2004*

	Heating Degree Days			Pct Change	
Region	2004/2003	Normal	2003/2002	From Normal	From 2003/2002
New England	5,056	5,047	5,483	Normal	8% Warmer
Mid-Atlantic	4,615	4,644	5,047	1% Warmer	9% Warmer
E N Central	4,889	5,141	5,438	5% Warmer	10% Warmer
W N Central	5,127	5,440	5,569	6% Warmer	8% Warmer
South Atlantic	2,444	2,469	2,643	1% Warmer	8% Warmer
E S Central	2,957	3,073	3,274	4% Warmer	10% Warmer
W S Central	1,847	2,060	2,173	10% Warmer	15% Warmer
Mountain	3,840	4,023	3,716	5% Warmer	3% Colder
Pacific	2,216	2,337	2,113	5% Warmer	5% Colder
Total	**32,991**	**34,234**	**35,456**	**4% Warmer**	**7% Warmer**

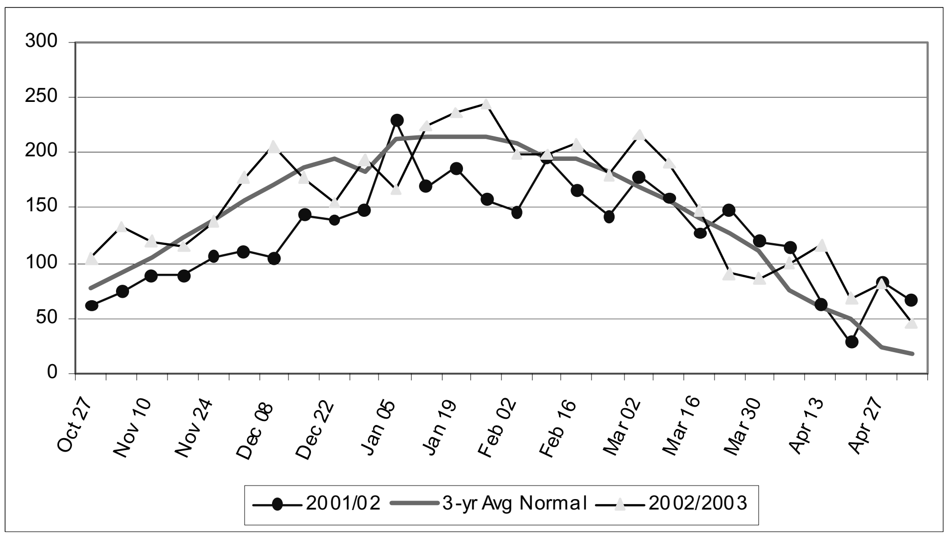
*CLS cumulative averages begin with week ending 10/04/03 data and may differ modestly from National Oceanic and Atmospheric Administration data, which population weights regions in addition to states.
Sources: Credit Lyonnais Securities, National Oceanic and Atmospheric Administration.

Exhibit 80: Heating Degree Days Percent Deviation from Normal, Winter 2003/2004 vs. Winter 2002/2003



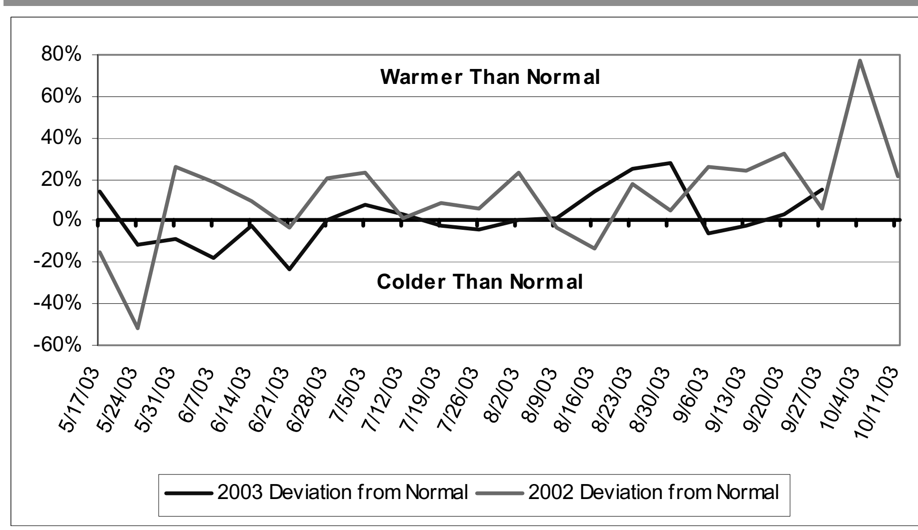
Sources: Credit Lyonnais Securities, National Oceanic and Atmospheric Administration.

Exhibit 81: Heating Degree Days, 1999-2003



Sources: Credit Lyonnais Securities, National Oceanic and Atmospheric Administration.

Exhibit 82: Cooling Degree Days Percent Deviation from Normal, Summer 2003/2002



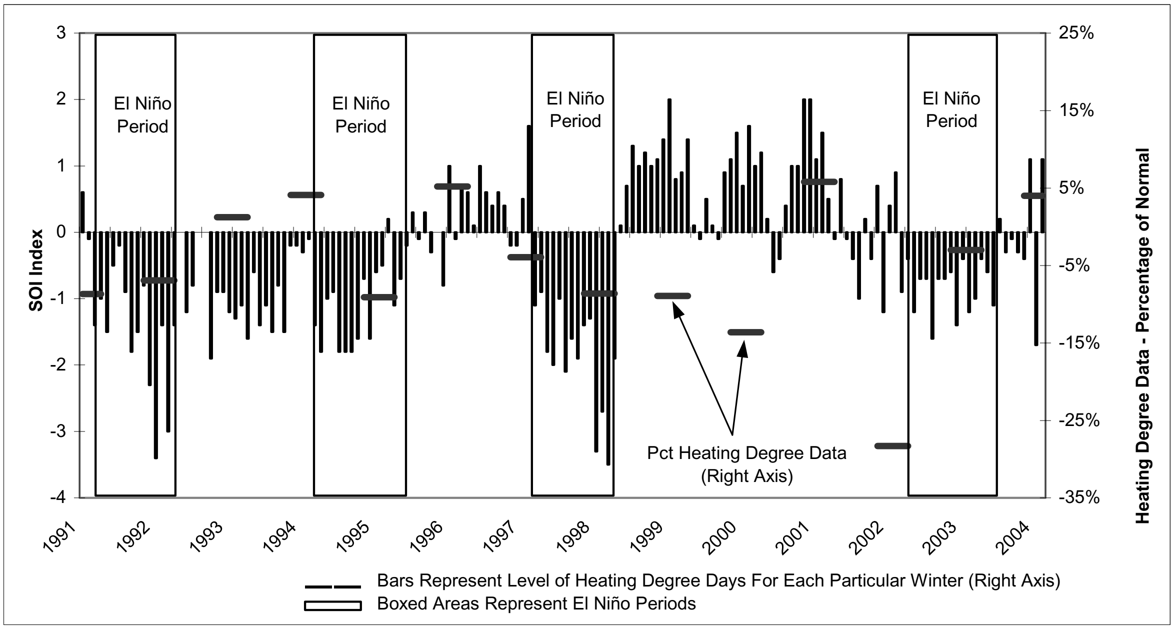
Sources: Credit Lyonnais Securities, National Oceanic and Atmospheric Administration.

Exhibit 83: El Niño Indicator—Southern Oscillation Index

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
1951	1.7	0.6	-0.8	-0.6	-1.0	-0.3	-1.4	-0.7	-1.3	-1.4	-1.4	-1.0
1952	-1.2	-1.1	0.0	-0.5	0.6	0.5	0.4	-0.4	-0.3	0.2	-0.2	-1.6
1953	0.2	-1.0	-0.8	-0.1	-2.2	-0.3	-0.1	-1.9	-1.5	-0.2	-0.4	-0.7
1954	0.6	-0.7	-0.3	0.4	0.3	-0.3	0.3	0.8	0.2	0.1	0.1	1.5
1955	-0.7	1.8	0.1	-0.5	1.1	1.1	1.7	1.2	1.5	1.5	1.3	1.0
1956	1.4	1.5	0.9	0.7	1.3	0.8	1.1	0.9	0.0	1.9	0.1	1.0
1957	0.6	-0.5	-0.4	0.0	-1.0	-0.2	0.1	-1.0	-1.1	-0.2	-1.2	-0.5
1958	-2.3	-1.0	-0.3	0.1	-0.9	-0.2	0.3	0.6	-0.4	-0.2	-0.6	-0.9
1959	-1.2	-2.0	0.9	0.2	0.3	-0.6	-0.5	-0.6	0.0	0.3	1.0	0.8
1960	0.0	-0.3	0.6	0.6	0.3	-0.3	0.4	0.5	0.7	-0.1	0.5	0.8
1961	-0.4	0.7	-2.7	0.7	0.1	-0.3	0.1	-0.2	0.1	-0.7	0.6	1.6
1962	2.2	-0.7	-0.4	0.0	1.0	0.4	-0.1	0.3	0.5	0.9	0.3	0.0
1963	1.1	0.4	0.7	0.6	0.1	-1.0	-0.3	-0.5	-0.7	-1.6	-1.0	-1.6
1964	-0.5	-0.3	0.7	1.0	-0.1	0.4	0.4	1.3	1.4	1.3	0.0	-0.5
1965	-0.6	0.1	0.2	-0.8	-0.1	-1.0	-2.2	-1.2	-1.5	-1.2	-1.8	0.0
1966	-1.7	-0.7	-1.7	-0.5	-0.7	0.0	-0.1	0.3	-0.3	-0.4	-0.1	-0.6
1967	1.9	1.6	0.8	-0.3	-0.3	0.3	0.0	0.5	0.6	-0.2	-0.6	-0.8
1968	0.4	1.1	-0.5	-0.2	1.1	0.9	0.6	-0.1	-0.3	-0.3	-0.5	0.0
1969	-2.0	-1.1	-0.1	-0.6	-0.6	-0.2	-0.7	-0.6	-1.2	-1.3	-0.2	0.3
1970	-1.4	-1.6	0.0	-0.4	0.1	0.7	-0.6	0.2	1.3	1.6	1.7	2.1
1971	0.3	1.9	2.1	1.7	0.7	0.1	0.1	1.3	1.6	1.7	0.5	0.0
1972	0.4	0.8	0.1	-0.4	-2.1	-1.1	-1.9	-1.0	-1.6	-1.2	-0.5	-1.6
1973	-0.5	-2.0	0.2	-0.2	0.2	0.8	0.5	1.1	1.4	0.6	2.9	2.0
1974	2.7	2.0	2.2	0.8	0.9	0.1	1.2	0.5	1.3	0.8	-0.3	0.0
1975	-0.8	0.6	1.2	1.1	0.5	1.1	2.1	1.9	2.4	1.7	1.3	2.3
1976	1.5	1.6	1.3	0.1	0.2	-0.1	-1.2	-1.3	-1.4	0.2	0.7	-0.6
1977	-0.7	1.1	-1.3	-0.8	-0.9	-1.5	-1.5	-1.3	-1.0	-1.4	-1.6	-1.4
1978	-0.4	-3.5	-0.8	-0.6	1.3	0.3	0.4	0.0	0.0	-0.7	-0.1	-0.3
1979	-0.7	0.8	-0.5	-0.4	0.3	0.4	1.3	-0.6	0.1	-0.4	-0.6	-1.0
1980	0.3	0.0	-1.2	-1.0	-0.3	-0.4	-0.2	0.0	-0.6	-0.3	-0.5	-0.3
1981	0.2	-0.6	-2.1	-0.4	0.7	1.0	0.8	0.4	0.4	-0.7	0.1	0.5
1982	1.3	-0.1	0.1	-0.2	-0.7	-1.6	-1.9	-2.5	-2.0	-2.2	-3.2	-2.8
1983	-4.2	-4.6	-3.4	-1.3	0.5	-0.3	-0.8	-0.2	1.0	0.3	-0.2	-0.1
1984	0.1	0.6	-0.9	0.2	0.0	-0.8	0.0	0.0	0.1	-0.6	0.2	-0.4
1985	-0.5	1.0	0.2	1.0	0.2	-0.9	-0.3	0.7	0.0	-0.7	-0.3	0.1
1986	0.9	-1.6	0.0	0.1	-0.5	0.7	0.1	-1.0	-0.6	0.5	-1.5	-1.8
1987	-0.9	-1.9	-2.0	-1.9	-1.7	-1.7	-1.7	-1.5	-1.2	-0.7	-0.1	-0.7
1988	-0.2	-0.9	0.1	-0.1	0.8	-0.2	1.1	1.4	2.1	1.4	1.9	1.3
1989	1.7	1.1	0.6	1.6	1.2	0.5	0.8	-0.8	0.6	0.6	-0.4	-0.7
1990	-0.2	-2.4	-1.2	0.0	1.1	0.0	0.5	-0.6	-0.8	0.1	-0.7	-0.5
1991	0.6	-0.1	-1.4	-1.0	-1.5	-0.5	-0.2	-0.9	-1.8	-1.5	-0.8	-2.3
1992	-3.4	-1.4	-3.0	-1.4	0.0	-1.2	-0.8	0.0	0.0	-1.9	-0.9	-0.9
1993	-1.2	-1.3	-1.1	-1.6	-0.6	-1.4	-1.1	-1.5	-0.8	-1.5	-0.2	-0.2
1994	-0.3	-0.1	-1.4	-1.8	-1.0	-0.9	-1.8	-1.8	-1.8	-1.6	-0.7	-1.6
1995	-0.6	-0.5	0.2	-1.1	-0.7	-0.2	0.3	-0.1	0.3	-0.3	0.0	-0.8
1996	1.0	-0.1	0.7	0.6	0.1	1.0	0.6	0.4	0.6	0.4	-0.2	-0.2
1997	0.5	1.6	-1.1	-0.9	-1.8	-2.0	-1.0	-2.1	-1.6	-1.9	-1.4	-1.3
1998	-3.3	-2.7	-3.5	-1.9	0.1	0.7	1.3	1.0	1.2	1.0	1.1	1.4
1999	2.0	0.8	0.9	1.4	0.1	-0.1	0.5	0.1	-0.1	0.9	1.1	1.5
2000	0.7	1.6	1.0	1.2	0.2	-0.6	-0.4	0.4	1.0	1.0	2.0	2.0
2001	1.1	1.5	0.5	-0.1	0.8	-0.1	-0.4	-1.0	0.2	-0.4	0.7	-1.2
2002	0.4	0.9	-0.9	-0.4	-1.2	-0.7	-0.7	-1.6	-0.7	-0.7	-0.6	-1.4
2003	-0.4	-1.2	-1	-0.4	-0.6	-1.1	0.2	-0.3	-0.1	-0.3	-0.4	1.1
2004	-1.7	1.1										

The Southern Oscillation Index (SOI) is a measure of the large-scale fluctuations in air pressure occurring between the western and eastern tropical Pacific during El Niño and La Niña episodes. Traditionally, this index has been calculated based on the differences in air pressure between Tahiti and Darwin, Australia, and is an indicator of the presence of trade winds. In general, the SOI corresponds very well with changes in ocean temperatures across the eastern tropical Pacific—the presence of trade winds physically pushes sun-warmed ocean-surface waters from east to west, away from the eastern tropical Pacific (i.e., South America). This sun-warmed water is subsequently displaced with cooler, sub-surface ocean waters in the eastern tropical Pacific. The negative phase of the SOI indicates the absence of normal trade winds, and coincides with abnormally warm ocean waters across the eastern tropical Pacific, which is typical of El Niño episodes. Prolonged periods of positive SOI values coincide with abnormally cold ocean waters across the eastern tropical Pacific typical of La Niña episodes.
Sources: Credit Lyonnais Securities, National Oceanic and Atmospheric Administration.

Exhibit 84: Southern Oscillation Index vs. Average Heating Degree Days



Note: This graph displays the relationship between El Niño periods, as measured by the SOI, and temperatures in the United States as measured by Heating Degree data. The horizontal bars on the graph represent the percentage of heating degree days above or below normal on a percentage-of-normal basis (as indicated on the right axis). The SOI is reflected by the vertical lines (as indicated on the left axis). For a description of the SOI, please see Exhibit 89.

Sources: Credit Lyonnais Securities, National Oceanic and Atmospheric Administration.

Hydro Availability Analysis

Exhibit 85: Run-Off Summary for Key Areas in Northwest (Million Acre-Feet)*

	Grand Coulee Dam (near Spokane, WA)	% of Normal	Ice Harbor Dam (near Burbank, WA)	% of Normal	Dalles Dam (Near Portland, OR)	% of Normal	Dworshak Dam (in Orofino, ID)	% of Normal	Average % of Normal
Oct-03	4.0	*146%*	0.9	*54%*	0.3	*147%*	0.1	*79%*	**107%**
Nov-03	6.5	*114%*	1.8	*53%*	0.7	*170%*	0.2	*66%*	**101%**
Dec-03	8.4	*101%*	3.0	*52%*	1.4	*213%*	0.3	*64%*	**108%**
Jan-04	10.3	*94%*	4.4	*54%*	2.1	*233%*	0.4	*60%*	**110%**
Feb-04	12.1	*89%*	6.1	*56%*	2.9	*255%*	0.5	*59%*	**115%**

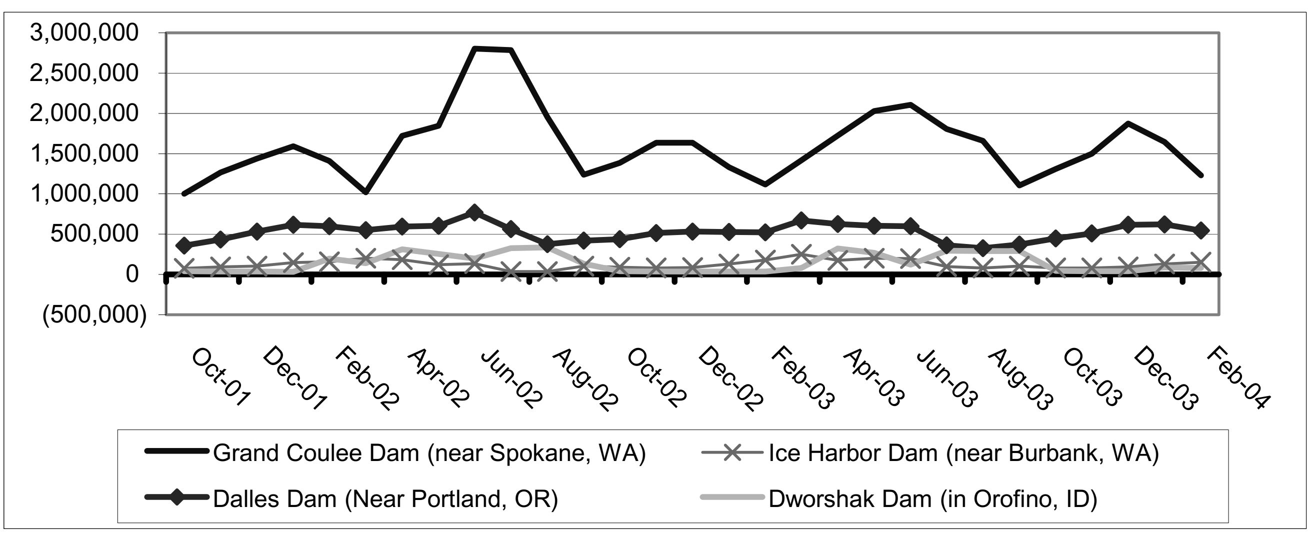
*Data reflect YTD 2004 water year (10/03-9/04). The 2003 water year was based on October 2002 to September 2003. Areas represent a selective sampling of the Columbia River Basin hydro facilities in the Pacific Northwest. Power generated by federal dams in the Northwest is shared over the entire transmission grid maintained by the Bonneville Power Administration (BPA). As such, it is important to examine hydro and production levels throughout the region in order to ascertain the amount of power that will be available for BPA's service area, which includes Oregon, Washington, Idaho, Montana and small portions of Wyoming, Nevada, Utah and California.
Sources: National Weather Service Northwest River Forecast Center and Credit Lyonnais Securities.

Exhibit 86: Selected Net Generation to Bonneville Power Administration (Mwh)*

	Grand Coulee Dam (near Spokane, WA)	% Change vs. 2003	Ice Harbor Dam (near Burbank, WA)	% Change vs. 2003	Dalles Dam (Near Portland, OR)	% Change vs. 2003	Dworshak Dam (in Orofino, ID)	% Change vs. 2003
Oct-03	1,310,782	*-5.3%*	82,034	*-6.6%*	446,936	*2.4%*	44,399	*8.1%*
Nov-03	1,497,568	*-8.4%*	79,667	*-1.3%*	512,096	*-0.8%*	40,164	*9.8%*
Dec-03	1,875,654	*14.5%*	95,953	*13.2%*	619,068	*16.3%*	42,228	*19.3%*
Jan-04	1,647,396	*23.6%*	128,096	*0.0%*	621,027	*17.9%*	87,308	*140.4%*
Feb-04	1,232,116	*10.3%*	151,165	*-15.3%*	545,430	*4.5%*	82,984	*133.0%*

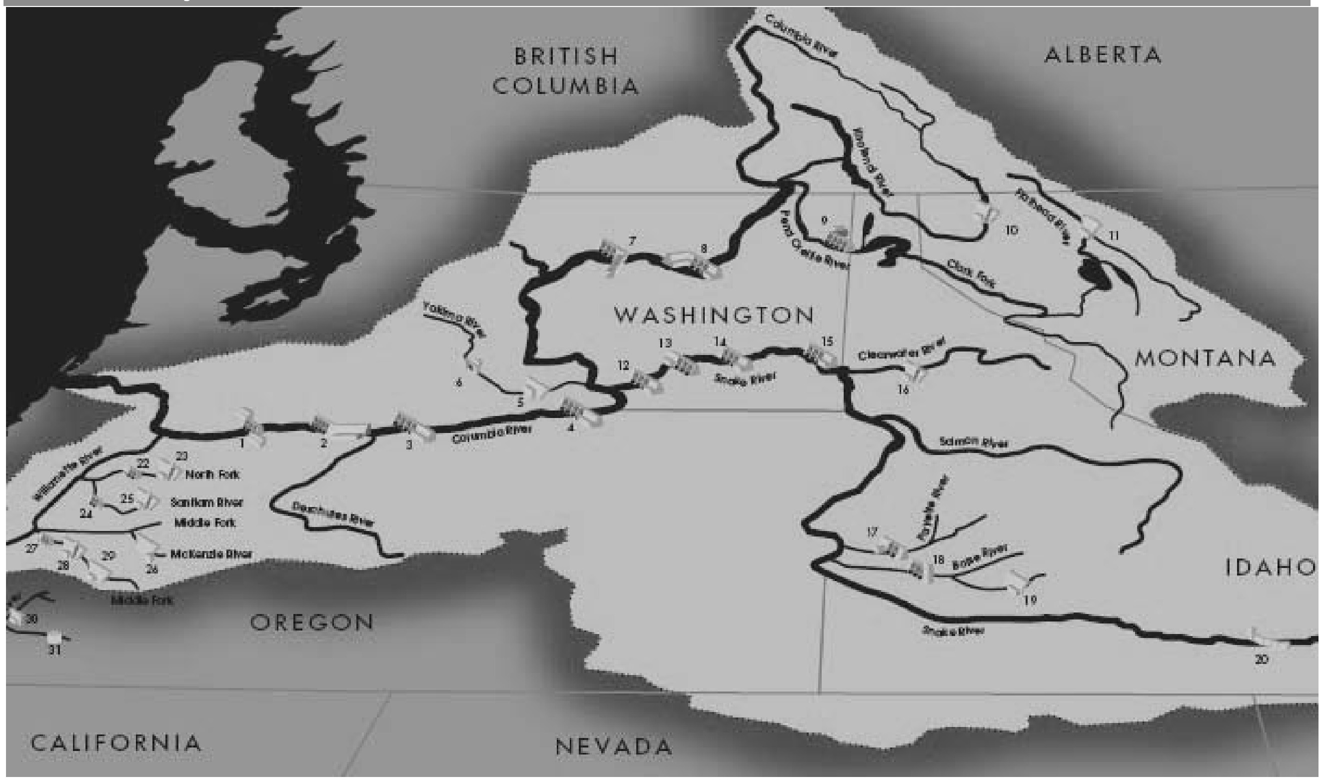
*Please see footnote to Exhibit 42 for explanation of regions selected and description of Northwest hydro. Data reflect YTD 2004 water year (10/03-9/04).
Sources: U.S. Army Corps of Engineers, North Pacific Region Water Management Division and Credit Lyonnais Securities.

Exhibit 87: Selected Net Generation to Bonneville Power Administration (Mwh)*



*Please see footnote to Exhibit 42 for explanation of regions selected and description of Northwest hydro. Data reflect YTD 2004 water year (10/03-9/04).
Sources: U.S. Army Corps of Engineers, North Pacific Region Water Management Division and Credit Lyonnais Securities.

Exhibit 88: Major Northwestern Rivers and Dams



	Plant	Mw		Plant	Mw		Plant	Mw		Plant	MW		Plant	MW
1	Bonneville	1,104	**8**	Grand Coulee	6,809	**15**	Lower Granite	930	**22**	Big Cliff	21	**29**	Hills Creek	34
2	The Dalles	2,080	**9**	Albeni Falls	49	**16**	Dworshak	465	**23**	Detroit	115	**30**	Lost Creek	56
3	John Day	2,480	**10**	Libby	605	**17**	Black Canyon	10	**24**	Foster	23	**31**	Green Springs	18
4	McNary	1,120	**11**	Hungry Horse	428	**18**	Boise River Diversion	2	**25**	Green Peter	92			
5	Chandler	12	**12**	Ice Harbor	693	**19**	Anderson Ranch	40	**26**	Cougar	28			
6	Roza	13	**13**	Lower Monumental	930	**20**	Minidoka	28	**27**	Dexter	17			
7	Chief Joseph	2,614	**14**	Little Goose	930	**21**	Palisades	176	**28**	Lookout Point	138			

Sources: Bonneville Power Association and Credit Lyonnais Securities.

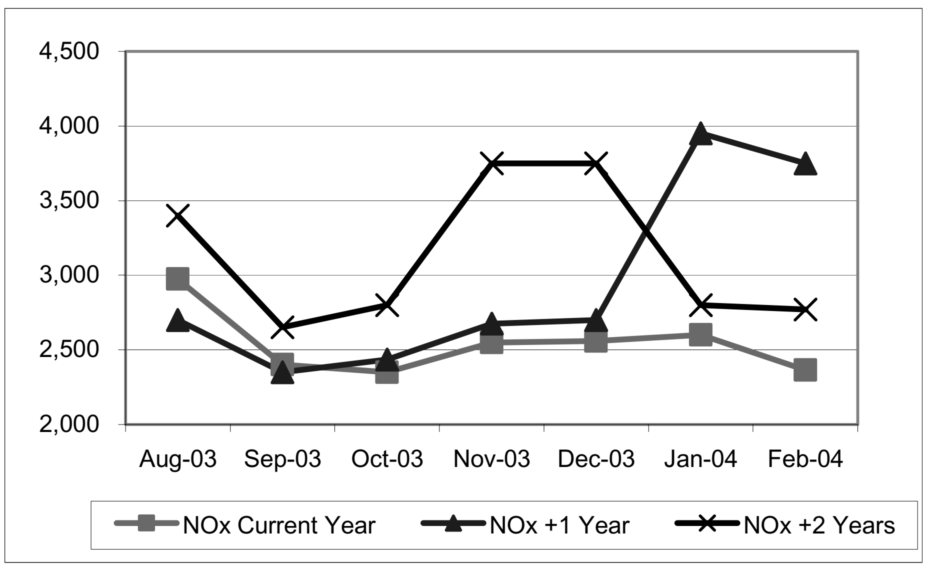
Emission Credits

Exhibit 89: Nitrogen Oxide and Sulfur Dioxide – Current Year ($/Short Ton)

SO_2 Current Year					NOx Current Year				
	Bid	**Ask**	**Index**			**Bid**	**Ask**	**Index**	
Aug-03	181.50	184.00	**182.00**		**Aug-03**	2,800.00	3,150.00	**2,975.00**	*
Sep-03	181.50	184.50	**182.00**		**Sep-03**	2,300.00	2,550.00	**2,400.00**	
Oct-03	184.00	186.50	**185.00**		**Oct-03**	2,320.00	2,490.00	**2,350.00**	
Nov-03	205.50	208.75	**207.00**		**Nov-03**	2,490.00	2,700.00	**2,550.00**	
Dec-03	217.00	220.75	**219.50**	*	**Dec-03**	2,469.00	2,650.00	**2,560.00**	*
Jan-04	250.00	255.40	**254.00**		**Jan-04**	2,490.00	2,700.00	**2,600.00**	
Feb-04	264.50	269.50	**266.50**		**Feb-04**	2,305.00	2,425.00	**2,365.00**	

Note: No asterisk denotes consensus last done trade. Asterisk denotes bid/ask mean for index value.
Data from Platts Monthly Broker Emissions Index, compiled from the mean of confidential submissions from the following emissions brokers: Air Liquid Advisors, Cantor Fitzgerald, Evolution Markets LLC, ICAP Energy (formerly APB Energy), Natsource LLC, United Power Inc.
Sources: Credit Lyonnais Securities, Platts.

Exhibit 90: Nitrogen Oxide – Current Year vs. Future Year Contracts ($/Short Ton)



Data from Platts Monthly Broker Emissions Index, compiled from the mean of confidential submissions from the following emissions brokers: Air Liquid Advisors, Cantor Fitzgerald, Evolution Markets LLC, ICAP Energy (formerly APB Energy), Natsource LLC, United Power Inc.
Sources: Credit Lyonnais Securities, Platts.

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Initiating Coverage

UTILITIES

PUGET ENERGY, INC.

RATING: BUY

PRICE: $21.87	TICKER: PSD
PRICE TARGET: $28	MARKET CAP: $2.2B
S&P 500: 1107	NASDAQ: 1944

SOURCE: FactSet

Initiating Coverage With BUY Rating and $28 Price Target

- **Rate cases raise ROE, EPS, and value:** We project that Puget will be allowed to raise its electric rates 2.4% in 2004 and 4% in 2005. The rate increases contribute to 25% EPS growth in 2004 and 12% EPS growth in 2005
- **Utility investment drives EPS growth:** Puget will spend $1.3 billion through 2013 to add generating capacity. We project that its 11% allowed ROE on its investment results in a 10% EPS CAGR from 2004 through 2009
- **No excess fuel costs raise 2004 EPS:** Puget absorbed $0.25 per share of excess fuel costs in 2003. Future excess fuel costs will be paid by customers, so EPS should rise by $0.25, or about 70% of the 25% 2004 EPS growth
- **Trading at a discount:** Investors should buy the shares because they do not reflect Puget's strong EPS growth and above-average dividend yield; however, our positive view would be tempered if Puget is not allowed to raise its rates

FORECASTS *

DECEMBER YEAR	2003	2004E					2005E
		1Q04E	2Q04E	3Q04E	4Q04E	YEAR	
Revenue (M)	$2,492	$639	$636	$343	$952	$2,570	$2,675
EBITDA (M)	$653	$179	$167	$85	$258	$689	$733
EPS	$1.26	$0.63	$0.27	$0.08	$0.60	$1.58	$1.77
FCF/S	$1.58	$0.96	-$0.07	-$0.05	$0.78	$1.63	-$0.55

** Percentage changes on page 2*

CAPITALIZATION	
Shares Outstanding (M)	99
Total Net Debt-($M) (12/31/03)	$2,203
Enterprise Value ($M)	$4,848
Total Debt/Capitalization	54%

VALUATION	2003	2004E	2005E
P/E	17.3x	13.9x	12.4x
Rel. to S&P 500	0.9x	0.8x	0.7x
EV/EBITDA	7.4x	7.0x	6.6x
FCF MULTIPLE	13.8x	13.5x	n.m.

KEY DRIVERS TO MONITOR

1) Outcome of recent filing for 4.7% rate increase
2) Outcome of general rate case (to be filed 2Q04)
3) Actual power costs versus threshold power costs
4) Balance sheet improvement
5) InfrastruX EPS and strategic direction

BENCHMARKS

ROIC	5.2%
Interest Coverage	2.6x
Book Value P/S (09/30/03)	$16.72
Price/Book	1.4x
Free Cash Flow Yield (2004E)	7.4%
Projected 3-year EPS Growth Rate	14.2%
Institutional Ownership	45.5%

TRADING / DIVIDEND DATA

52-Week Range	$24 - $20
Avg. Daily Trading Volume (000)	281
Dividend/Yield	$1.00 / 4.6%
Share Float/% Sh. Out	99 / 99.8%

FORECAST PERCENT CHANGE (Y/Y)

DECEMBER YEAR	2003	2004E					2005E
		1Q04E	2Q04E	3Q04E	4Q04E	YEAR	
Revenue (M)	+4%	-5%	+14%	-33%	+28%	+3%	+4%
EBITDA (M)	+5%	-2%	+26%	-27%	+36%	+11%	+6%
EPS	+2%	+39%	+23%	-24%	+24%	+25%	+12%
FCF/S	-73%	-28%	+88%	-161%	+8%	+4%	-134%

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TABLE OF EXHIBITS

SUMMARY & RECOMMENDATION

We are initiating coverage of Puget Energy with a BUY rating and a price target of $28. Puget Sound Energy, an electric and gas utility that serves the Puget Sound region of Washington, contributes 98% of Puget's EBIT. Puget also owns InfrastruX, a subsidiary that constructs utility infrastructure. Puget's EPS fell in 2003 because of high power costs, but its regulatory structure now insulates it from power price increases. InfrastruX EPS also fell because of bad weather and lower utility spending. We expect Puget to invest about $1.3 billion in utility capacity additions by 2013 and earn its 11% allowed ROE on its investment. As a result, we project a 10% five-year EPS CAGR after excluding 25% EPS growth in 2004. It has requested an initial 4.7% rate increase, however, we expect it to be allowed to only raise its rates 2.4%. We believe even receiving half of its requested rate increase will be positive for the stock because we believe Puget's share price reflects little or no rate increase. The shares yield 4.6%, which is above the S&P Utilities Index yield of 3.8%. However, we project that its balance sheet improves throughout our forecast period and that it will have capacity to increase its dividend by 2005.

KEY FINDINGS

- **We project that Puget will be allowed to raise rates 2.4% in 1Q04 to partially cover increased power supply costs and a plant acquisition. We project that the rate increase contributes to year-over-year EPS growth of 25%.** Please see page 7.
- **Puget has been earning below its allowed 11% ROE, so it will file a general rate case in 2Q04. We project that it will be allowed to raise rates 4% in 1Q05, which we project will raise its ROE to about 11% and contribute to EPS growth of about 12% in 2005.** Please see page 8.
- **Puget is shifting its strategy to serve its load with owned capacity instead of long-term contracts. We project that Puget will be allowed to earn an 11% ROE on about $1.3 billion it plans to invest in new capacity by 2013, which contributes to a 10% five-year EPS CAGR after excluding 25% EPS growth in 2004.** Please see page 9.
- **Puget operates under a mechanism that shares fuel costs with customers and also caps Puget's maximum fuel costs at $40 million. Puget expects to hit the $40 million cap in 2003, so the cap on future fuel costs also contributes to year-over-year EPS growth of 25%.** Please see page 10.
- **Puget's financial condition deteriorated over the past several years, but it has taken steps to improve its balance sheet. We project that its financial condition improves throughout our forecast period and that it will likely have capacity to begin increasing its dividend in 2005.** Please see page 11.
- **InfrastruX results suffered in 2003 from unfavorable weather and reduced utility spending. We assume a return to normal weather and utility spending in 2004 contribute an additional $0.05 to EPS.** Please see page 12.

POWER COST RATE CASE RESULTS IN STRONG 2004 EPS GROWTH

Puget recently announced that it is acquiring 137 net MW of natural gas fired capacity at the Frederickson plant as an initial step toward its plan to increase its generating capacity. It is paying $80 million for the plant and has petitioned the Washington Utilities and Transportation Commission (WUTC) for a 4.7% electric rate increase to cover the plant acquisition as well as increased fuel costs as a result of rising natural gas prices and contract fuel cost escalation clauses. Puget's requested rate increase would raise its revenue by $64.4 million; however, in the WUTC Staff's (Staff) response to Puget's request for a rate increase it raised an issue that it believes should result in Puget only receiving a rate increase of $7.5 million. The key elements of the Staff response to Puget's filing are as follows:

- **Staff agreed that Frederickson plant acquisition is prudent and should be reflected in rates:** Staff agreed that Puget's acquisition of the Frederickson plant should be reflected in increased rates.
- **Staff believes request for additional power cost recovery should be reduced to adjust for 1997 and 1998 contract buyouts:** Staff indicated that it believed part of Puget's requested rate hike should be amended to reflect its 1997 and 1998 buyouts of two gas supply contracts related to its Tenaska and Encogen projects. Staff contends that Puget originally proposed that it could reduce gas supply costs by buying out the contracts; however, Puget subsequently failed to generate the indicated savings.

We do not believe Puget should be penalized for gas contract buyout

Puget has filed its rebuttal to Staff's testimony, and it contends that its fuel purchases were reasonable and prudent and should not affect its requested rate increase.

It appears to us that Staff is recommending that Puget be penalized based on a backward looking analysis. Essentially, Puget attempted to actively manage its natural gas supply costs to reduce supply expense, but was negatively impacted by rising natural gas prices. Staff contends that Puget should have been able to lock-in fuel purchases or otherwise guarantee its natural gas costs. We believe it is unfair to penalize Puget based on an analysis that has the benefit of hindsight when a backward looking analysis does not take into account the actual options available to Puget when it was securing natural gas supply. For example, although historical price data may show that Puget paid more for natural gas supply than it might have paid under the original contracts, at the time Puget was securing natural gas supply it may have been prohibitively expensive to buy natural gas based on the terms available to Puget at that time.

We assume Puget is allowed 50% of its requested increase

Ultimately, the WUTC commissioners will determine how much Puget is allowed to raise rates. We expect the commission to weigh the arguments put forth by Staff; however, we also expect the commission to weigh the benefits of Puget's improving financial condition as well as its commitment to serve its load by adding resources to its utility system. The WUTC commissioners are expected to rule on Puget's rate case in mid to late March of 2004.

We believe Puget must raise rates to address its financial stability as well as its ability to continue to provide reliable and cost effective utility service to its customers. We also believe that the commission is aware of this and is generally in agreement with Puget's long-term plans. We have assumed that Puget is granted 50% of its requested 4.7% rate increase; however, we believe the commission might allow Puget to raise its rates more than the 2.4% we have assumed in order to continue to help it improve its financial condition.

Higher rate increase raises EPS and value

If Puget is allowed to raise its rates 4.7% as it has requested, our 2004 EPS estimate would increase to $1.74 from $1.58, our 2005 EPS estimate would increase to $1.98 from $1.77, and our estimate of Puget's fair value would increase to$31 from $28.

EXPECT GENERAL RATE CASE TO IMPROVE ROE AND EPS IN 2005

Puget is allowed to earn an 11% ROE at its utility. However, it appears that the utility has not been earning its allowed ROE. We estimate that Puget earned an ROE of only about 6% in 2001 and 2002, and we project that it will earn an ROE of about 7% in 2003. The weak ROE has been driven in part by excess power costs that the company has been forced to absorb; however, Puget is insulated from future power costs increases as we discuss below.

Active efforts to improve regulatory relationships

Puget has taken steps to improve its relationship with the WUTC.

- **Reinvigorated its regulatory department:** Puget has refocused its regulatory efforts on filing and managing the rate case process.
- **Improving financial condition:** Puget promised the WUTC that it would improve its financial condition, and it is targeting a 45% equity ratio by 2005. The company has taken aggressive steps to improve its financial condition, and we estimate that it will achieve its targeted 45% equity ratio in late 2004 or early 2005 versus its current ratio of about 37%.
- **Open dialog with the WUTC:** As part of Puget's efforts to improve its regulatory relationships, it has taken steps to ensure that all parties involved in its regulatory process are well informed of its intentions. Puget meets regularly with the WUTC commissioners and staff, the major intervenors in Puget's territory, and the Office of Public Council and the attorney general, who are responsible for protecting small ratepayers and the public interest, respectively.

We believe Puget's efforts to improve its regulatory environment and relationships should help it receive reasonable, if not favorable, regulatory treatment in the future.

General rate case filing planned in 2Q04

Puget plans to file a general rate case in 2Q04. The review is expected to take about 11 months, and the new regulatory structure should be in place by 1Q05. The general rate case will be a combined gas and electric rate case. Puget plans to request a rate base increase for its gas business and will target a 45% equity ratio and an 11% ROE. The general rate case will not address Puget's Power Cost Adjustment mechanism.

Successful rate case contributes to strong 2005 and 2006 EPS growth

We expect Puget to be allowed to raise its rates so that it earns its allowed ROE of 11%, which we estimate would require about a 4% rate increase. We calculate that Puget's 2005 and 2006 EPS will grow by 12% and 8%, respectively, if it is allowed to increase its rates 4% at the end of 1Q05.

If Puget is allowed to raise its rates 4.7% as it has requested in its recent power cost rate case filing, we project that it will only require a 3% increase as part of its general rate case filing.

SHOULD EARN 11% ROE ON INCREMENTAL RESOURCE INVESTMENTS

Puget supplies almost 75% of its load primarily through long-term power purchase contracts in addition to a small amount of spot market purchases. However, following the California power crisis, Puget and the WUTC decided that it was preferable to have Puget supply more of its load from owned capacity. As a result, Puget has developed a Least Cost Plan (LCP) to meet its energy supply needs through 2023. We estimate that Puget needs to add about 1.7 GW of supply by 2013 to meet its load requirements and expect the supply to come from several sources:

- **New gas fired generation**: Puget recently announced the purchase of a 137 MW natural gas fired plant, and we estimate that it will add about 800 MW of additional natural gas fired generation by 2013.
- **New coal fired generation**: We estimate that Puget will add about 350 MW of coal fired capacity by 2013.
- **Renewable energy**: Puget expects to supply about 10% of its load from renewable energy sources by 2013, the bulk of which it expects to be wind power. Puget has an outstanding Request For Proposal (RFP) for 150 MW of wind capacity, and we project that it will add an additional 100 MW of wind capacity by 2013.
- **Conservation**: Puget expects conservation to contribute about 200 MW to its supply requirements by 2013.

LCP partially funded with equity

We estimate that Puget will spend about $1.3 billion between now and 2013 to meet its LCP. It has indicated that it will fund a portion of its LCP with equity in order to maintain its targeted 45% common equity ratio. As a result, we project that it will issue about $35 million of equity in 2004, or 1.6 million shares at current prices, $150 million of equity in 2005, or 6.4 million shares at current prices, and $20 million of equity in 2007, or almost 1 million shares at current prices. We also project that it will issue an additional $360 million of equity in 2008-2013.

11% return on $1.3 billion investment drives long-term EPS growth

We expect Puget to spend about $1.3 billion between now and 2013 to meet its LCP. As discussed, we expect it to raise its rates 2.4% in 2004 and 4% in 2005. We project that it will be allowed to raise its rates an additional 4% in 2007 to maintain its allowed ROE of 11%. We estimate that the combined impact of Puget earning an 11% ROE on an expanding rate base results in a five-year EPS CAGR of about 15% based on 2003 EPS and about 10% if our projected 25% 2004 EPS growth is excluded from the calculation. Puget achieves this level of EPS growth even after absorbing the dilution from partially funding the LCP with equity.

CUSTOMERS WILL PAY 99% OF FUTURE EXCESS POWER COSTS

Puget has a sharing mechanism in place through June 2006 called the Power Cost Adjustment (PCA) that results in sharing of excess power costs or savings with customers. Under the PCA, actual power costs are compared with PCA threshold power costs, which are based on a power price of about $45 per MWh, and the variance is shared with customers as shown in Exhibit 1. Additionally, the maximum cumulative excess power cost that can be absorbed by Puget is capped at $40 million. Once Puget has absorbed $40 million of excess power costs, 99% of the costs are passed through to customers.

Exhibit 1: Power Cost Adjustment

Annual Power Cost Variance	Customer's Share	Company's Share
+/- $20 million	0%	100%
+/- $20-$40 million	50%	50%
+/- $40-$120 million	90%	10%
+/- $120+ million	95%	5%

Source: Lazard Freres & Co. LLC, company reports

$40 million cap reached in 2003

About 40% of Puget's energy is supplied by hydroelectric generation. Hydroelectric generation production is highly variable depending on the level of precipitation, and when hydroelectric generation is low, Puget must purchase replacement power from the market. 2003 was a dry year in the Pacific Northwest, with river flows into Puget's hydroelectric system about 12%-17% below normal. Therefore, Puget expects to reach the $40 million cumulative PCA threshold because it was forced to buy expensive replacement power from the market. As a result, it is largely insulated from additional power price increases. Although the company must absorb 1% of future excess power costs, we estimate that if Puget incurs $150 million in excess power costs, its EPS would only fall by about $0.01.

No excess power costs in 2004 contributes to strong EPS growth

Puget incurred $5.2 million of excess power costs in 2002. Therefore, in order to reach the $40 million cumulative cap on excess power costs, Puget absorbed $34.8 of excess power costs in 2003, or about $0.25 per share. As a result, the absence of excess power costs in 2004 should contribute about $0.25 in year-over-year EPS improvement.

IMPROVING FINANCIAL CONDITION

Puget's dividend payments and capital spending consistently exceeded its cash flow throughout the 1990s, and it funded the shortfall with debt financing. Additionally, Puget was hurt by high power costs as a result of the California energy crisis. Because of the decline in its financial condition, the company's credit ratings are currently one notch above non investment grade at both Moody's and Standard & Poor's. Puget does not have any obligations that would come due in the event that it loses its investment-grade credit rating. We believe credit rating downgrades are unlikely, however, Puget's liquidity could be negatively affected by a credit rating downgrade because its access to the commercial paper market would be limited.

Steps to address its financial condition

Puget has taken several steps to address its financial condition, and its actions should continue to improve its balance sheet.

- **Cut the dividend**: Puget reduced its annual dividend to $1.00 from $1.84 per share in 2002. The company indicated that it is targeting a dividend payout ratio of 60% of its utility earnings. We estimate that its current payout will be almost 80% of 2003 utility earnings, but we project that it will reach its 60% target in late 2004 or early 2005. We expect it to grow its dividend in line with utility earnings growth thereafter.
- **Equity issuance**: Puget issued $100 million of equity in 2002 and raised an additional $100 million of equity in 2003 through a private sale to Franklin Advisers.
- **PCA mechanism adopted**: Puget and the WUTC agreed to the PCA mechanism in part to help Puget improve its capital structure and ROE by limiting its exposure to rising power costs.

We are concerned about Puget's current financial condition because it is only one notch above non-investment grade; however, we believe that it has taken the necessary steps to improve its balance sheet. Additionally, we expect favorable outcomes from its power cost rate filing and general rate case to further strengthen Puget's balance sheet. We project that its equity ratio will improve to about 45% by late 2004 or early 2005 and that its FFO/interest expense ratio will improve to about 3.5x in 2005 from about 2.1x currently. It appears that the rating agencies may also be evaluating Puget's actions favorably because Standard & Poor's recently changed its outlook on Puget's credit ratings to Positive from Stable, and Moody's recently changed its outlook on Puget's credit ratings to Stable from Negative.

INFRASTRUX RESULTS NEUTRAL AT WORST, LIKELY TO IMPROVE

InfrastruX is an engineering and construction (E&C) company that Puget formed through the acquisition of several regional independent E&C companies over the past several years. The majority of InfrastruX's work is for utilities and primarily focuses on the transmission and distribution (T&D) system. It does not construct power plants. Puget derives only about 2% of its EBIT from InfrastruX, so it is a small part of its earnings stream, but it can contribute to earnings volatility. For example, InfrastruX contributed $0.11 to 2002 EPS, but only contributed $0.02 to 2003 EPS. We also estimate that InfrastruX contributes less than $1 per share to Puget's fair value.

Poor results in 2003

The earnings contribution from InfrastruX suffered in 2003 due to two primary factors as identified by Puget. First, construction in the early part of the year was hampered by unfavorable weather conditions. Second, utility spending was below plan for the remainder of the year, which Puget believes is the result of financial distress in the utility industry. Puget provides limited information about InfrastruX such as the average size of its contracts, the average contract length, or its construction backlog. As a result, it is difficult to forecast results for the business.

2004 results likely neutral at worst

The weather in 2004 could be as severe as in 2003, which would negatively affect InfrastruX results; however, this scenario would result in a flat year-over-year contribution from InfrastruX. If the weather improves in 2004, we would expect to see modest earnings improvement over the prior year. If utility spending does not improve in 2004, this scenario would also result in a flat year-over-year contribution from InfrastruX. However, we believe that utility spending could likely return to normal levels in 2004, which would also result in a modest year-over-year earnings improvement. Utilities must maintain their infrastructure or customer service will ultimately suffer, which damages the utilities' relationships with regulators. Therefore, we believe that utilities may delay their maintenance spending temporarily but are unlikely to delay spending long enough to impair system reliability.

InfrastruX lost $0.04 per share in 1Q03 but contributed $0.03 to EPS in 2Q03, $0.02 to EPS in 3Q03, and $0.01 to EPS in 4Q03. We are assuming a return to normal weather and utility spending and that quarterly EPS remain around $0.01-$0.02. As a result, we are expecting an annual EPS contribution of $0.05 in 2004.

Evaluating strategic options

Puget is evaluating strategic alternatives for InfrastruX and plans to focus on 2004 results as it evaluates its long-term plans. Puget has committed not to invest additional capital in InfrastruX and indicated it would consider divesting the business as one of its strategic alternatives. Although InfrastruX is currently struggling, if Puget decides to divest InfrastruX, it may be exiting the business at the trough of the E&C cycle and may be abandoning a potential source of earnings growth, albeit small. However, InfrastruX is a minor part of Puget, and we do not believe that there is a strategic fit with Puget's utility operations. We ultimately believe that it may be prudent for Puget to divest InfrastruX.

INVESTMENT CASE PREDICATED ON RATE INCREASES

Our investment thesis for Puget's shares is based primarily on it being allowed to increase its rates to recover investment in its utility infrastructure, improve its utility ROE, and continue to improve its balance sheet.

If Puget is not allowed to increase its rates, it will continue to earn a utility ROE that is well below the industry average, and will have difficulty further improving its balance sheet materially. In this case, our outlook for the shares would be much less favorable.

VALUATION

SUMMARY RESULTS

We calculate that Puget has an enterprise value of $5.5 billion and a fair equity value of $2.8 billion, or $28 per share, as shown below.

Exhibit 2: Sum-of-the-Parts Valuation

Component	$ Millions	$ Per Share
Puget Sound Energy	$5,441	$53.82
InfrastruX	88	0.87
Corporate and Other	(52)	(0.51)
Enterprise Value	**$5,477**	**$54.17**
Net Debt	($2,355)	($23.29)
Preferred Share Value	(282)	(2.79)
Minorities	0	0.00
Total Equity Value	**$2,840**	**$28.09**
Current Price		$21.87
Upside/(Downside)		**28%**

Source: Lazard Frères & Co. LLC estimates, company reports

VALUATION METHODOLOGY

Our primary valuation methodology is a discounted cash flow analysis, using the Adjusted Present Value (APV) method. We value each business separately and include the cash flows from businesses and projects that are currently operating or are in development. We value each merchant power plant separately, based on its unique operating characteristics and our forecast of the market prices in the region in which it is located. A full discussion of our valuation methodology can be found in Appendix 1 on page 25.

KEY DRIVERS TO MONITOR

We believe that near-term results will be driven by several factors:

- **Outcome of rate case filings:** We project that Puget is allowed to increase its rates in 2004 and 2005. If it is allowed to raise its rates less than it has requested, or if it is not allowed to raise its rates at all, its earnings and value would be materially reduced.
- **Actual power costs versus threshold power costs:** Puget is insulated from future power cost increases because it has hit the $40 million cap in the PCA mechanism.
- **Balance sheet improvement:** Puget faces a 2% rate reduction penalty if it does not achieve its equity ratio targets. Its credit ratings, financing costs, and access to the capital markets could also be negatively affected if it does not improve its balance sheet.
- **InfrastruX EPS and strategic direction:** Puget's ability to improve InfrastruX's EPS will contribute modestly to EPS growth. Puget's future InfrastruX strategy will also impact the magnitude and volatility of InfrastruX's EPS contribution.

FINANCIAL OVERVIEW

As we have discussed, Puget has taken significant steps to improve its financial condition and Standard & Poor's recently raised its outlook on Puget to Positive from Stable. Moody's also recently raised its outlook on Puget to Stable from Negative. A summary of Puget's credit ratings is shown in Exhibit 3.

Exhibit 3: Credit Ratings

	S&P		Moody's	
	Rating	**Outlook**	**Rating**	**Outlook**
Puget Energy	BBB-	Positive	Baa3	Stable
Puget Sound Energy	BBB-	Positive	Baa3	Stable

SOURCE: Bloomberg

We project that Puget's balance sheet improves throughout our forecast period. We project that its equity ratio improves to 45% from about 37% currently and that it will have the capacity to increase its dividend modestly by late 2004 or early 2005. As a result, we expect its credit ratings to improve. Puget has indicated that it believes its optimal corporate credit rating is BBB+/Baa1 and that it expects its balance sheet will be positioned to support a BBB+/Baa1 rating in 2005.

RECENT RESULTS

Share Price

Puget's shares rose about 8% in 2003, underperforming the S&P Utilities Index, which rose about 16% last year. Puget's shares have fallen 8% since the beginning of 2004, underperforming the S&P Utilities Index, which has risen 2% during the same period.

Earnings

Puget earned $1.26 per share in 2003 versus $1.24 per share in 2002. The principal factors affecting results were as follows:

- **Sales growth:** Utility revenues grew slightly driven by customer volume growth despite warmer than normal weather in 1Q03, which is historically a period of peak heating demand.
- **Excess power costs:** Puget absorbed $34.8 million of excess power costs in 2003, which negatively impacted its EPS.
- **Future power costs capped:** Puget reached its maximum $40 million power cost threshold, so future power cost increases will be paid 99% by customers and 1% by Puget.
- **InfrastruX results:** InfrastruX contributed $0.02 to EPS in 2003 versus contributing $0.10 to EPS in 2002. Low utility spending and poor weather were the primary drivers.

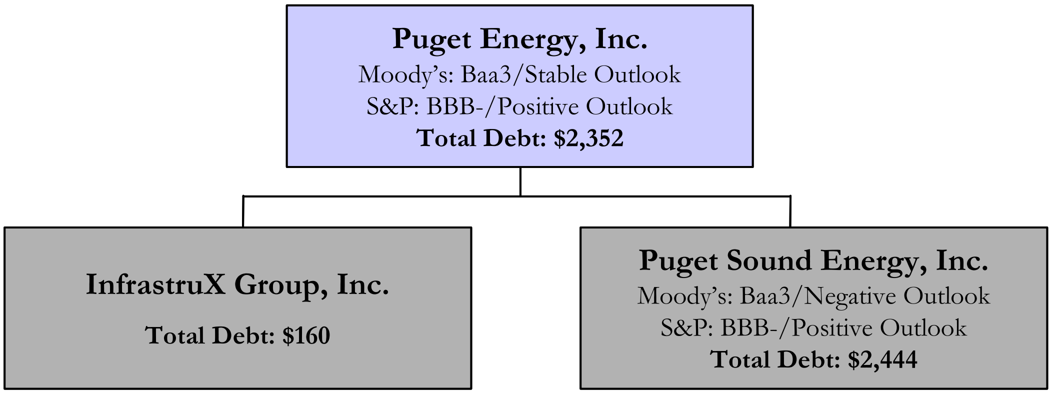
COMPANY HISTORY AND ORGANIZATION

HISTORY

Puget Sound Energy, the predecessor to Puget Energy, was formed from the merger of Puget Sound Power & Light, Washington Energy Company, and Washington Natural Gas Company in 1997. The company reorganized into a holding company with Puget Sound Energy and InfrastruX as subsidiaries in 2001 and changed its name to Puget Energy.

ORGANIZATION

Exhibit 4: Organization Chart



SOURCE: Lazard Frères & Co. LLC estimates, company reports

GENERATION

All of Puget's owned generating assets are part of its integrated utility system. It derives approximately 40% of its energy from hydroelectric generation, 30% of its energy from natural gas fired generation, and about 30% of its energy from coal fired generation. It generates about 1% of its energy from renewable resources. Puget's generating assets are shown in Exhibit 5.

Exhibit 5: Utility Plants

Plant	Location	Type	Fuel	Gross MW	Stake	Net MW
Colstrip 1&2	MT	Steam	Coal	660	50%	330
Colstrip 3&4	MT	Steam	Coal	1480	25%	370
Upper Baker River	WA	Hydro	Hydro	91	100%	91
Lower Baker River	WA	Hydro	Hydro	79	100%	79
White River	WA	Hydro	Hydro	70	100%	70
Snoqualmie Falls 1&2	WA	Hydro	Hydro	44	100%	44
Electron	WA	Hydro	Hydro	26	100%	26
Fredonia 1&2	WA	Combustion Turbine	Gas	210	100%	210
Fredrickson Units 2&3	WA	Combustion Turbine	Gas	150	100%	150
Whitehorn Units 2&3	WA	Combustion Turbine	Gas	150	100%	150
Fredonia 3&4	WA	Combustion Turbine	Gas	108	100%	108
Encogen	WA	Cogeneration	Steam	170	100%	170
Crystal Mountain	WA	Internal Combustion	Diesel	2.8	100%	2.8
Total				**3,241**		**1,801**

Source: Lazard Frères & Co. LLC estimates, company reports

MANAGEMENT

Puget's senior management team consists of the following:

Stephen Reynolds, 55, chief executive officer, president, and director. Mr. Reynolds was appointed CEO in January 2002. Prior to joining Puget, he was the president and CEO of Reynolds Energy from 1998 to 2002 and Pacific Gas & Electric Gas Transmission Texas from 1997 to 1998.

Bertrand Valdman, 41, senior vice president and chief financial officer. Mr. Valdman joined Puget in December 2003. He was previously managing director of investment banking in the Natural Resources Group at J.P. Morgan Securities.

John Durbin, 67, chairman and chief executive office, InfrastruX. Mr. Durbin has been CEO of InfrastruX since 2000. He was an executive director of Emerge Corporation from 1999 to 2000 and an executive director of Olympic Capital partners from 1996 to 1999.

Eric Markell, 52, senior vice president. Mr. Markell has over 20 years of experience in the power industry. He served as vice president and CFO of United American Energy Corp., a private company focused on acquiring and managing power assets. Mr. Markell also served as treasurer and controller for Central Hudson Gas & Electric Corp and as vice president of the Energy Research and Development Authority of New York.

James Eldredge, 52, corporate secretary and chief accounting officer. Mr. Eldridge is also a vice president, corporate secretary, controller, and chief accounting officer of Puget Sound Energy.

Donald Gaines, 46, vice president and treasurer. Mr. Gaines is also the treasurer and the vice president of finance for Puget Sound Energy.

Jennifer O'Connor, 46, vice president and general counsel. Ms. O'Connor joined Puget in January 2003. Prior to joining Puget, she worked in the general counsel's office at Starbucks from 1998 to 2002.

BOARD OF DIRECTORS

Puget has a ten-member board of directors consisting of CEO Stephen Reynolds and eight outside members. These individuals represent a variety of industries including retail, banking, telecommunications, manufacturing, paper, and consulting. The company's Audit Committee consists of five independent members and the Governance and Public Affairs Committee consists of four independent members.

OWNERSHIP

Exhibit 6 details the major insider ownership of Puget Energy.

Exhibit 6: Insider Holdings

Name	Shares	% Outstanding
Stephen Reynolds	80,000	0.1%
William A. Gaines	16,752	0.0%
James Eldredge	16,165	0.0%
P.M Wiegand	16,013	0.0%
Donald E. Gaines	15,547	0.0%
Susan Mclain	12,954	0.0%
Bertrand Valdman	10,000	0.0%
Jerry L. Henry	9,786	0.0%
Charles Bingham	8,247	0.0%
Total Shares	**185,464**	**0.2%**

SOURCE: Lazard Frères & Co. LLC estimates, Bloomberg

OPTIONS COMPENSATION EXPENSE

We estimate that expensing options in 2003 and 2004 would not have a material impact on Puget's earnings, as shown in Exhibit 7. This analysis assumes that Puget would expense all outstanding options over the appropriate service period. The negative impact of expensing options under the FAS 123 method in 2000 and 2002 occurs because Puget's reported earnings include a more conservative estimate of the impact of expensing stock options.

Exhibit 7: Stock Option Expense Impact

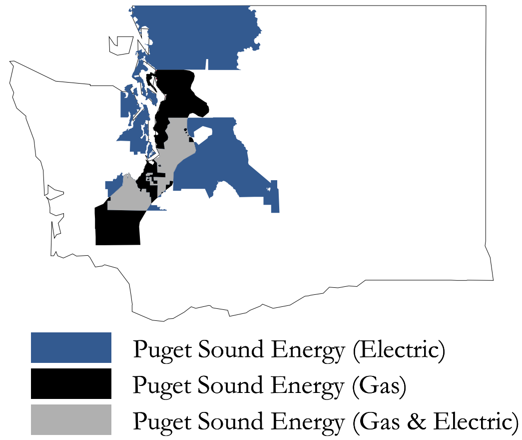
	2000	2001	2002	2003E	2004E
Diluted EPS – Reported	$2.16	$1.14	$1.24	$1.26	$1.58
Diluted EPS - Adjusted for Options Expense	$2.16	$1.12	$1.25	$1.27	$1.59
Difference	$0.00	$0.02	($0.01)	($0.01)	($0.01)
% Difference	**0.0%**	**1.8%**	**-0.8%**	**-0.8%**	**-0.6%**

Source: Lazard Freres & Co. LLC, company reports

UTILITY OPERATIONS

Puget's primary business is its integrated utility subsidiary, Puget Sound Energy, which generates, transmits, and delivers electricity and gas to approximately 1.3 million customers in 11 Washington state counties. A map of Puget's service territories is shown in Exhibit 8 on page 19.

Exhibit 8: Puget Sound Energy's Service Territory



SOURCE: Lazard Frères & Co. LLC estimates, RDI

Winter peaking market

Many U.S. utilities experience peak demand in the summer months, so the third quarter is their most robust. However, because the weather patterns in the Pacific Northwest result in Puget experiencing its peak load in the winter, the fourth and first quarters are its most robust.

REGULATORY OVERVIEW

In return for being allowed to function as a monopoly service provider in its respective territory, Puget is permitted to earn a rate of return on its investment. As we have discussed, it appears that it has been earning well below its allowed ROE. As a result, it has filed a power cost rate case and plans to submit a general rate case in 1Q04.

Overview of the regulatory commission

The WUTC is comprised of three commissioners: Dick Hempstad, Patrick Oshie, and Chairwoman Marilyn Showalter. Commissioners are appointed by the governor for a six-year term but also must be confirmed by the Senate. The commission is required to include at least one Democratic and one Republican representative. Chairwoman Showalter was recently reappointed by the governor but has not received Senate confirmation. We expect her reappointment to be approved by the Senate. Commissioner Oshie's term has about four years remaining, and Commissioner Hempstad's term has about two years remaining. We do not expect a material change in the composition of the WUTC.

Deregulation unlikely

Washington opposes deregulation efforts, primarily due to fallout from the California power crisis. As a result, we assume that Puget's territory remains regulated throughout our forecast period.

Fuel cost recovery

Puget is allowed to fully recover its natural gas costs for its natural gas utility. However, it is not allowed to pass all of its purchased power costs and fuel expenses at its electric utility through to customers. During the California power crisis, Puget purchased electricity from the spot market at extremely high prices, which hurt its EPS and cash flow. As a result, it negotiated a fuel cost sharing mechanism, the PCA, as part of its rate agreement that took effect in July 2002. The PCA shares the variations in expected electricity costs between customers and Puget.

The threshold power price for calculating threshold power costs is about $45 per MWh. The $45 per MWh price is comprised of a variable fuel cost component of about $37 per MWh and a fixed cost component of about $8 per MWh. The variable cost component includes all costs that affect rates including hydroelectric generation, sales from other utilities, and natural gas prices. Puget can request changes to the threshold price through rate case filings, although it does not plan to request a change to the threshold price in its upcoming general rate case.

The PCA is measured over four 12-month periods beginning in July 2002 and ending in June 2006. For a given 12-month period, actual electricity costs are compared to expected costs. Variances between actual and expected costs are shared between customers and Puget according to the proportions shown in Exhibit 1 on page 10. Each July, the sharing mechanism is reset, however, cumulative variances accrue. Puget's cumulative cost exposure is limited to $40 million plus 1% of the excess over the four-year period through June 2006.

Bonneville Exchange Power Credit deferral may affect future rates

The Bonneville Power Administration (BPA) generates electricity to serve part of Puget's load, so Puget's customers receive a credit of approximately $0.01085 per kWh, escalating to $0.02302 per kWh. This credit offsets both revenues and expenses for Puget and therefore does not affect its earnings. However, the BPA is deferring payment of approximately $28 million to customers until late 2006 due to financial difficulties. Although the BPA credit and the deferral do not affect Puget's earnings, customer bills rise when the BPA credit falls or is deferred. As a result, ratepayers could pressure Puget even though the rate increase is out of its control.

Target equity to capital ratio met

As we have discussed, Puget is on track to meet its equity ratio target. If it fails to do so by the end of 2005, however, it faces a 2% rate reduction penalty. This was required by the WUTC in an effort to ensure greater utility stability following the California Energy Crisis.

LONG-TERM RESOURCE PLAN

Puget submitted its LCP to the WUTC in April 2003 to address its expected electric and gas load and supply plans through 2023. Puget determined that it needs approximately 1.7 GW of new electricity supply by 2013 and a total of about 2.4 GW by 2023. It expects to meet these needs through the addition of new capacity to its utility system.

More load to be supplied from internal resources

Puget purchased almost 75% of the 27 GWh of electricity needed to serve its load in 2002. However, as a result of the California energy crisis, it adopted a long-term objective in conjunction with the WUTC to supply more of its own electricity needs instead of relying on the power markets. Puget's power purchase contracts start to expire and its load continues to grow, which will create a supply deficit of about 475 MW by January 2005 and 1.7 GW by 2013. Significant portions of Puget's long-term contracts expire from 2011 to 2014, forcing it to add about 610 MW of supply during that period.

Declining hydroelectric generation

Puget generated about 40% of its energy from hydroelectric plants in 2002. It expects its hydroelectric production to decline in 2003 to about 35% and to decline to about 32% of total supply in 2013. In absolute terms, Puget expects the level of hydroelectric capacity to decline as plants are closed and/or their output is physically and financially constrained as a result of fish protections and other environmental restrictions.

NON-UTILITY BUSINESSES

InfrastruX Group is Puget's non-regulated business that engages in infrastructure construction for electric, gas, and telecommunications utilities primarily in Texas and the northeastern United States. Puget acquired and consolidated 11 independent companies from 2000 to 2002 as shown in Exhibit 9.

Exhibit 9: InfrastruX Acquisitions

Company	Date
Lineal	2000
Utilx	2000
Intercon	2001
Keystone Pipeline Services	2001
Seen Corporation	2001
Skibeck	2001
Texas Electric Utility Construction	2001
Trafford	2001
Chapman	2002
Gill Electric Service	2002
Wire Dynamix	2002
Flowers	2002
B&H Maintenance	2003

Source: Lazard Freres & Co. LLC, company reports

Earnings fell in 2003 – evaluating strategic alternatives

InfrastruX contributed $0.11 to 2002 EPS, but it has struggled in 2003 as a result of unfavorable weather and a decline in utility spending. InfrastruX only earned $0.02

per share in 2003. The company has indicated that it will focus on InfrastruX's current businesses and will not make acquisitions until it has determined the long-term strategic position of InfrastruX within the company. We believe that InfrastruX contributes minimal value and EPS to Puget and does not fit strategically with Puget's utility operations. As a result, we believe that divesting InfrastruX may be prudent.

Fragmented industry

The infrastructure construction and maintenance industry is highly geographically fragmented throughout the United States. Puget acquired these companies believing that there will be growing demand for infrastructure repairs and construction related to the electricity grid and pipelines. It also wanted to be the first-mover in an industry that it believed would begin consolidating.

Total investment not significant

Based on the InfrastruX total assets reported in Puget's financial statements, we estimate that the company paid about $320 million to acquire the businesses that constitute InfrastruX. Total assets do not necessarily reflect market value; however, Puget acquired the bulk of its InfrastruX companies in the past three years. As a result, InfrastruX's total assets should approximate what Puget paid for them. All but one of the companies Puget acquired for InfrastruX was private at the time of the purchase so transaction premiums are difficult to determine.

InfrastruX must deliver growth to justify its acquisition cost

We project that InfrastruX's earnings return to a normalized level in 2004 and assume that its EPS grow at 2.5% thereafter. Accordingly, we project that InfrastruX has an enterprise value of about $200 million. We estimate that InfrastruX would have to grow at 7%-8% per year through 2013 to have an enterprise value of $300-$350 million.

Limited Disclosure

Puget Energy does not report detailed segment information related to InfrastruX. This makes valuing InfrastruX and forecasting its EPS contribution difficult. Additionally, Puget believes about 65% of InfrastruX business is effectively recurring since it is under master order contracts, but 35% of its business is bid-based. The project-oriented nature of a significant portion of InfrastruX's business and the associated uncertain timing of earnings also make forecasting EPS difficult.

MODEL ASSUMPTIONS

We forecast the earnings and cash flows from Puget's businesses using the following principal assumptions:

Puget Sound Energy

- **Sales growth:** We assume a long-term sales growth rate of 2.5% per year, which is consistent with historical results.
- **Regulated rate of return:** We assume that Puget Sound is allowed to raise its electric rates 2.4% on April 1, 2004 and 4% on April 1, 2005. We also project that it is allowed to raise its rates 4% in 2007.
- **Least Cost Plan:** We assume that Puget adds 1.5 GW of generating capacity to its fleet by 2013 at a cost of $1.3 billion. We also project that it funds 45% of the capital spending on its LCP with equity.
- **O&M expense:** We project that O&M expenses will escalate at one half the rate of inflation, which is consistent with O&M expense trends for the utility industry.

InfrastruX

- **Weather and utility spending:** We project that InfrastruX's EPS return to 2002 levels based on a return to normal weather and utility spending.
- **Strategic direction:** We assume that Puget retains its InfrastruX ownership but do not forecast incremental acquisitions.

FINANCIAL STATEMENTS

INCOME STATEMENT

- **EBIT:** EBIT rises in 2004, 2005, and 2006 because we project that Puget is allowed to increase its rates to incorporate a return on its LCP investment and improve its ROE.
- **Interest Expense:** Interest expense falls throughout the forecast period as Puget's capital structure improves.
- **Shares outstanding:** We project that Puget funds a portion of its LCP investment with equity in order to maintain its capital structure, so its shares outstanding increases.

Exhibit 10: Income Statement Forecast ($ Millions)	2002	2003	2004E	2005E	2006E
Sales	**$2,392**	**$2,492**	**$2,570**	**$2,675**	**$2,749**
COGS and SG&A	1,777	1,844	1,887	1,947	1,985
D&A	246	270	276	289	291
Total Operating Expenses	**2,023**	**2,114**	**2,163**	**2,237**	**2,276**
Other income	(9)	6	6	6	6
EBIT	**360**	**383**	**413**	**444**	**478**
EBITDA	**606**	**653**	**689**	**733**	**769**
Equity Income	0	0	0	0	0
Interest Expense, Net	191	190	158	144	144
Income Tax Provision	59	72	96	113	126
Extraordinary Items, Net of Tax	0	0	0	0	0
Net Income	**$110**	**$120**	**$159**	**$188**	**$209**
Basic Shares Outstanding	88	95	100	105	109
Diluted Shares Outstanding	89	95	101	106	109
Basic EPS	$1.25	$1.27	$1.59	$1.78	$1.92
Diluted EPS	**$1.24**	**$1.26**	**$1.58**	**$1.77**	**$1.91**

SOURCE: Lazard Frères & Co. LLC estimates, company reports

BALANCE SHEET

- **Capital structure:** We project that Puget's capital structure improves throughout our forecast period.
- **Cash:** Cash is reduced to zero in our forecast, because we treat cash on hand as a reduction to outstanding debt for future periods.

Exhibit 11: Balance Sheet Forecast ($ Millions)	2002	2003	2004E	2005E	2006E
Cash	$177	$27	$0	$0	$0
Current Assets	496	466	475	487	495
Plant, Property, & Equipment	3,997	4,172	4,262	4,590	4,590
Non-Current Assets	988	1,009	1,009	1,009	1,009
Total Assets	**$5,657**	**$5,675**	**$5,746**	**$6,085**	**$6,094**
Current Liabilities	586	674	585	542	547
Long Term Debt	2,136	1,956	2,006	2,144	2,047
Preferred Stock	403	282	282	282	282
Other Non-Current Liabilities	1,009	1,108	1,108	1,108	1,108
Common Equity	1,524	1,655	1,765	2,010	2,110
Total Liabilities & Equity	**$5,657**	**$5,675**	**$5,746**	**$6,085**	**$6,094**

SOURCE: Lazard Frères & Co. LLC estimates, company reports

CASH FLOW STATEMENT

- **Capital expenditures:** We forecast increased capital expenditures in 2004 and 2005 as Puget implements its LCP.

Exhibit 12: Cash Flow Statement Forecast ($ Millions)

	2002	2003	2004E	2005E	2006E
Net Income	$110	$120	$159	$188	$209
Depreciation and Amortization	229	237	276	289	291
Other Non-Cash Items	180	0	0	0	0
Changes in Working Capital	102	24	(5)	(7)	(4)
Change in Other Assets	103	(58)	0	0	0
Net Operating Cash Flow	**$724**	**$323**	**$430**	**$470**	**$496**
Capital Expenditures and Net Acquisitions	(323)	(289)	(365)	(618)	(291)
Cash From Investing Activities	**($323)**	**($289)**	**($365)**	**($618)**	**($291)**
Net Common Equity Issued/(Repurchased)	120	107	51	162	0
Net Debt Issued/(Repurchased)	(332)	(82)	(43)	90	(97)
Net Preferred Equity Issued/(Repurchased)	(8)	(121)	0	0	0
Dividends Paid	(97)	(87)	(100)	(105)	(109)
Other Financing Activity	0	0	0	0	0
Cash From Financing Activities	**($316)**	**($183)**	**($93)**	**$148**	**($205)**
Increase/(Decrease) in Cash	**$84**	**($149)**	**($27)**	**$0**	**$0**
Cash at Beginning of the Period	92	177	27	0	0
Cash at End of the Period	177	27	0	0	0

SOURCE: Lazard Frères & Co. LLC estimates, company reports

APPENDIX 1: VALUATION METHODOLOGY

The Adjusted Present Value (APV) discounted cash flow analysis is our primary valuation methodology, because we believe that it provides the most straightforward estimate of a company's value when leverage changes over time. We value each business separately and include only the cash flows from businesses and projects that are currently operating or are in development. The following steps comprise our valuation methodology.

- **Step 1: Calculate unlevered enterprise value:** We discount the after-tax, free cash flows from all business units using the unlevered cost of equity to estimate the unlevered enterprise value of each investment.
- **Step 2: Calculate value of tax shields:** We then separately calculate the present value of expected future debt tax shields.
- **Step 3: Determine total enterprise value:** We add the present value of debt tax shields to the unlevered enterprise value to obtain the total enterprise value.
- **Step 4: Calculate equity value:** We then subtract the value of debt, preferred stock, and minority interests and add the value of equity investments to obtain the fair value of equity.

PRINCIPAL VALUATION ASSUMPTIONS

We use the following assumptions in our analysis:

- **Nominal risk-free rate:** 4.98%, based on the 12-month rolling-average 10-year Treasury bond yield.
- **Equity risk premium:** 5% for the U.S. equity market.
- **Equity beta:** For unregulated businesses in the United States and Europe, we use a levered equity beta of 1.25. For regulated business in the United States and Europe, we use a levered equity beta of 0.5.
- **Terminal growth rate:** We project that free cash flow should grow at 2.0% after our forecast period, based on expectations for long-term economic growth.

BUSINESS FORECAST METHODOLOGY

We forecast cash flows separately for each business unit. We forecast the earnings and cash flows from all merchant power plants by examining each generating station independently over a ten-year period. We look at each generating plant's unique cost structure and operating profile, and the market prices for energy and capacity in the regions in which the plants operate.

Generating Unit Costs

We begin by examining the cost structure and efficiency of each generating plant. This is important, because the production cost of the plants will determine the number of hours that the plants operate and the margin they will earn when they generate power. The primary inputs in our analysis are heat rate, fuel cost, and fixed and variable O&M costs.

Market Price of Electricity

We forecast the market price of power over a ten-year period for each region, using our internal power pool price model. We begin with estimates of current market prices and then project prices based on the marginal costs of existing generators and the level of new power plant construction in the various power pools. We forecast both on-peak and off-peak energy prices as well as capacity prices in all power pools. When significant transmission constraints exist within a power pool, we forecast prices for these load pockets separately.

Over the long term, the market price of power in all U.S. power pools should approximate the long-run marginal cost of new gas-fired generating units. The state-of-the-art generation technology for new baseload power is a gas-fired combined-cycle generating unit. New gas-fired combustion turbines represent the state-of-the-art generation technology for peaking power.

Using our power plant cost data and our market price forecasts, we estimate the profit and loss for each power plant and aggregate these results to forecast consolidated earnings.

COVERAGE LIST AND COMPANIES MENTIONED IN THIS REPORT

Exhibit 13: Coverage List

Company	Recommendation	Price	Ticker
American Electric Power	Buy	$33.60	AEP
Constellation Energy Group	Sell	$39.63	CEG
Calpine Corp	Sell	$5.29	CPN
Dominion Resources	Hold	$63.51	D
Duke Energy	Hold	$21.50	DUK
Entergy Corp.	Hold	$57.77	ETR
Exelon Corp.	Hold	$67.26	EXC
FPL Group	Hold	$66.30	FPL
Puget Energy	Buy	$21.91	PSD
Southern Company	Hold	$30.09	SO
TXU Corp.	Hold	$27.31	TXU

Source: Lazard Frères & Co. LLC, Bloomberg, Prices as of March 11, 2004

Exhibit 14: Additional Companies Mentioned in this Report

Company	Recommendation	Price	Ticker
J.P. Morgan Chase & Company	Not Rated	$41.30	JPM
PG&E Corp.	Not Rated	$27.00	PCG
Starbucks	Not Rated	$37.65	SBUX

Source: Lazard Frères & Co. LLC, Bloomberg, Prices as of March 11, 2004

IMPORTANT DISCLOSURES

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RATING	GUIDELINE (return targets may be modified by risk or liquidity issues)
BUY	Expected to produce a total return of **15% or better** in the next 12 months.
HOLD	Fairly valued; total return in the next 12 months expected to be **±10%**.
SELL	Stock is expected to **decline by 10% or more** in the next 12 months.

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DISTRIBUTION OF INVESTMENT RATINGS (AS OF 12/31/03)

OVERALL GLOBAL DISTRIBUTION			BANKING CLIENT GLOBAL DISTRIBUTION*		
BUY	HOLD	SELL	BUY	HOLD	SELL
39%	52%	9%	21%	7%	0%

** Indicates the percentage of each category in the Overall Distribution that were banking clients of Lazard Frères in the previous 12 months.*

They're Back!

Twenty-Six Rate Cases This Year Give Rise to the Regulators

Sector View: 3-NEGATIVE

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We believe the 26 rate cases in view as we head into 2004 will be a key driver of stock performance.

- Our study of stock performance during electric utility rate cases since 1986 shows that in low-interest-rate environments (10-year treasuries less than 5.25%) affected electric utilities underperform the group heading into and in the early discovery phases of a case (down 8%) and outperform it in the 12 months following commission staff / intervenor recommendations (up 8%).
- Electric utilities with rate cases in the preinflection stage in 1H04 include: American Electrical Power (AEP), Duquense Light Holdings (DQE), Consolidated (ED), Northeast Utilities (NU), OGE Energy (OGE), Pepco Holdings (POM), PPL Corp. (PPL), Puget Energy (PSD), and Southern Co. (SO) with 3-Underweight-rated Con Edison and Northeast Utilities most affected.
- The companies trapped between intervenor testimony and final orders that are likely reflecting maximum rate case risk premiums are: Cinergy (CIN), DTE Energy (DTE), Edison International (EIX), FirstEnergy Corp. (FE), and NiSource, Inc. (NI). We are generally intrigued by the discount valuations in this group; however, we currently recommend only FE and NI. Those in the post-inflection sweet spot include 1-Overweight-rated PG&E Corp. and Wisconsin Energy.
- We also found that stocks in more constructive regulatory jurisdictions trade at a price-book premium over time. Specifically, the more business-oriented Midwest (up 10.6%) and Southeast (9.7%) trade at premiums to the consumer and natural resource-oriented Southwest (down 17.6%) and New England (down 13.5%) regions.
- This report provides a detailed analysis of electric utility stock performance in 351 rate cases since 1986, a road map for 29 companies involved in rate cases over the next 24 months, a ranking of state regulatory commissions, a listing of commissioners, and key contacts by state.
- We maintain our 3-Negative rating on electric utilities due to: valuations at the high end of historic ranges, expectations for rising interest rates, continued weakness in gas spark spreads, and regulatory overhang.

Analyst Certification

I, Daniel F. Ford, CFA , hereby certify (1) that the views expressed in this research report accurately reflect my personal views about any or all of the subject securities or issuers referred to in this report and (2) no part of my compensation was, is or will be directly or indirectly related to the specific recommendations or views expressed in this report.

March 5, 2004

http: / / www.lehman.com

This report, "They're Back!" is the follow-on report to "A Blast from the Past" published on June 4, 2003. In this piece, we attempt to provide a reference for the many rate proceedings under way at the state level in the coming years. In this report you will find: 1) a review of the impact of rate cases on utility performance; 2) a review of the trend in allowed returns; 3) a state regulatory ranking; 4) an illustration of the typical rate case; 5) a calendar of rate cases upcoming; and 6) a detailed company-by-company analysis of important proceedings.

We believe the 36 rate cases on the calendar for electric utilities over the next 24 months will be a key driver of stock performance.

We see 36 rate cases on the calendar for electric utilities over the next 24 months. These cases will likely be the drivers of stock performance. Rate case cycles are typically eight to 10 years apart, and we believe the number of cases ahead marks the beginning of another round. A study of stock performance around rate cases we conducted for this piece illustrates that, particularly in low-interest-rate environments, electric utility stocks underperform the group heading into and during the discovery phases of the case and outperform it following a bottom marked around filing of staff and / or intervenor testimony.

Many of this year's cases are in the preinflection stage including those for 3-Underweight-rated Con Edison and Northeast Utilities. Other companies heading into cases include: AEP, DQE, ED, NU, OGE, POM, PPL, PSD, and SO.

The companies trapped between intervenor testimony and final orders that are likely reflecting maximum rate case risk premiums are: CIN, DTE, EIX, FE, NI, PNW, and SRE. We are generally intrigued by the discount valuations in this group; however, we currently recommend only FE and NI. Companies that are in the post-inflection sweet spot include 1-Overweight-rated PG&E Corp. and Wisconsin Energy.

Performance Trend Most Investable When Interest Rates Are Low

Our review of 351 rate cases since 1986 shows that electric utility stocks underperform the group heading into cases and outperform post the commission staff / intervenor recommendations in low-interest-rate environments (rates below 5.25% on the 10-year treasury). According to Lehman Brothers Economist Ethan Harris, the current low rate environment could continue through 2005. His 2004 year-end forecast is 4.75%. For 2005, Harris predicts 5.20%. Overall, we believe rate cases will serve as an overhang for the group in 2004, as 26 cases are in sight as we enter the year.

When interest rates are low, electric utilities in rate cases underperform the group 8.1% heading into staff / intervenor recommendations and outperform by 8.2% in the following 9 months.

Specifically, we found that when 10-year treasuries are below 5.25%, electric utilities underperform the group by -8.1% prior to filing and in the early stages of discovery. This underperformance is reflected from the period seven weeks prior to a rate case filing to the time when staff and intervenors file positions. In this environment, electric utility stocks reach peak relative outperformance of 8.2% about nine months after the staff / intervenor filings. These proposals generally mark the most negative milestone of a rate case because they are made by competing and more consumer-oriented parties. Figure 1 illustrates our findings.

In other interest rate environments the trend is similar, but the relative returns are too small for investors to consistently exploit. The average underperformance in neutral to high interest rate environments is –1.0% heading into and through the discovery phase. The average outperformance after the inflection point is 2.2%.

Figure 1: Electric Utility Stock Performance vs. the UTY During Rate Cases

	Relative Underperformace to Inflection Point		Relative Outperformace from Inflection Point		
Rates	%	Timing	%	Timing	# Cases
below 5.25%	-8.1%	7 weeks before filing	8.2%	37 weeks after	44
5.25-6.50%	-0.4%	6 weeks post filing	1.1%	47 weeks after	107
6.51-7.75%	-1.2%	9 weeks post filing	3.5%	50 weeks after	59
above 7.75%	-1.5%	at rate case filing	1.9%	51 weeks after	98
Average	-2.8%		3.7%		

**The inflection point is defined as the conclusion of the hearing phase marked by staff and intervenor recommendations.*

Source: Regulatory Research Associates, FactSet

As shown in Figure 2, electric utilities also underperform the market in periods leading up to the inflection point. We believe this tendency is quite logical. Rate cases widen the range of financial outcomes. As a result, it appears that the market appropriately assigns an increased equity risk premium to utilities involved in the most uncertain phases of a rate proceeding. Conversely, utilities perform roughly in line with the market post-case as the risk premium subsides and higher forecast certainty resumes.

Figure 2: Electric Utility Stock Performance vs. the S&P 500 During Rate Cases

	Relative Underperformace to Inflection Point		Relative Outperformace from Inflection Point		
Rates	%	Timing	%	Timing	# Cases
below 5.25%	-7.1%	9 weeks before filing	1.8%	36 weeks after	44
5.25-6.50%	-1.4%	8 weeks before filing	0.3%	7 weeks after	107
6.51-7.75%	-5.5%	5 weeks before filing	-0.2%	2 weeks after	64
above 7.75%	-6.8%	12 weeks before filing	0.6%	52 weeks after	136
Average	-5.2%		0.6%		

Source: Regulatory Research Associates, FactSet

Stocks in Constructive Regulatory Regions Trade at Premium

Utilities in more constructive jurisdictions like the more business oriented Midwest and Southwest trade at 10.6% and 9.7% price-book group premiums, respectively.

We looked at price-book valuations over the same period and found that electric utility stocks tied to more constructive regulatory jurisdictions trade at a price / book premium. Overall, it seems as if the more business-oriented Midwest and Southeast trade at the highest valuations on average and the more consumer and natural-resource-oriented New England and Southwest regions traded at discounts. Specifically, the Midwest traded at a 10.6% premium to the average price / book value followed by the Southeast, which was a 9.7% premium. On the down side, the Southwest is a 17.6% discount and New England-based utilities are a 13.5% discount.

Figure 3: Relative Price-Book Valuation of Electric Utilities by Region

Region	Relative P/B Value	Stocks
Midwest	10.6%	AEP, DPL, DQE, EXC
Southeast	9.7%	CNL, DUK, ETR, FPL, PGN, SCG, SO, TE
Plains	4.0%	AEE, EDE, GXP, OGE, WR
Mid-Atlantic	3.6%	AYE, CEG, POM, PEG
Upper Midwest	2.8%	LNT, CMS, DTE, NI, WPS, WEC
West	0.5%	EIX, PCG, PSD, SRE, SRP
New England	-13.5%	ED, EAS, NST, NU, UIL
Southwest	-17.6%	PNM, PNW, TXU, XEL

Source: FactSet

Allowed Returns in Rate Case Decisions in 2003 Down but at High End of Historic Spread to Interest Rates

The average allowed ROE in 1,100 rate cases since 1980 has been 396 basis points above the 10-year treasury with a standard deviation of 162 basis points totaling 558 basis points of flexibility.

In 17 rate cases in 2003, the average allowed ROE was 10.96%, which was 698 basis points above the corresponding yield on the 10-year treasury at the time of the decisions. In our compilation of more than 1,100 rate cases since 1980, the average outcome has been 396 basis points above the 10-year treasury with a standard deviation of 162 basis points totaling 558 basis points of flexibility. The constructive 2003 average allowed ROE seems attributable to an unsustainable low interest rate environment and by a number of outcomes in Wisconsin. Ex-Wisconsin, the average allowed ROE would have been 10.41%, or 645 basis points above treasuries.

Figure 4: 2003 Rate Case Decisions

Date	Company	State	Allowed ROE	Yield on 10 Year Treasury	BP Spread
1/14/2003	SCANA	SC	12.45%	4.08%	837
2/28/2003	Madison Gas & Electric	WI	12.30%	3.69%	861
3/6/2003	Scottish Power	WY	10.75%	3.66%	709
3/7/2003	Rochester Gas & Electric	NY	9.96%	3.64%	632
3/20/2003	WPS Resources	WI	12.00%	3.96%	804
	1st Quarter Averages		**11.49%**	**3.81%**	**769**
4/4/2003	Alliant Energy	WI	12.00%	3.95%	805
4/15/2003	Alliant Energy	IA	11.15%	3.99%	716
6/25/2003	Aquila	CO	10.75%	3.41%	734
6/26/2003	Xcel Energy	CO	10.75%	3.54%	721
	2nd Quarter Averages		**11.16%**	**3.72%**	**744**
7/9/2003	Public Svc Enterprise Group	NJ	9.75%	3.68%	607
7/16/2003	Consolidated Edison	NJ	9.75%	3.92%	583
7/25/2003	FirstEnergy	NJ	9.50%	4.18%	532
8/26/2003	Scottish Power	OR	10.50%	4.48%	602
9/3/2003	Maine Public Service	ME	10.25%	4.60%	565
	3rd Quarter Averages		**9.95%**	**4.17%**	**578**
11/10/2003	Wisconsin Energy	WI	12.70%	4.45%	825
11/14/2003	Alliant Energy	WI	12.00%	4.22%	778
12/19/2003	Northeast Utilities	CT	9.75%	4.14%	561
	4th Quarter Averages		**11.48%**	**4.27%**	**721**
	2003 Average		**10.96%**	**3.98%**	**698**

Source: Regulatory Research Associates, FactSet

In 2003 the average allowed ROE in 17 decisions was 10.96% and 10.41%, ex-Wisconsin. We believe allowed ROEs will be in the 9.5%–11.0% range in 2004.

Since 1980 the average allowed ROE was 13.76% (1,113 decisions), and since 1990 it was 11.73% (367 decisions). Using a regression analysis applied to this quarterly data, we found that taking one-half of the current 10-year treasury rate and adding 870 basis points is an effective means of forecasting allowed ROEs. That predictive accuracy of this relationship produced a 78% R2. Using current interest rate levels, this would imply an allowed ROE of about 10.7% for cases in 1Q04. For the year, we would expect that upcoming decisions will produce average ROEs in the 9.5%–11.0% range.

There are a number of cases in progress that imply that the overall average will come down. Companies affected include Energy East's Rochester G&E in New York, Aquila in Missouri, Northeast Utilities in New Hampshire, and Pepco Holdings in New Jersey.

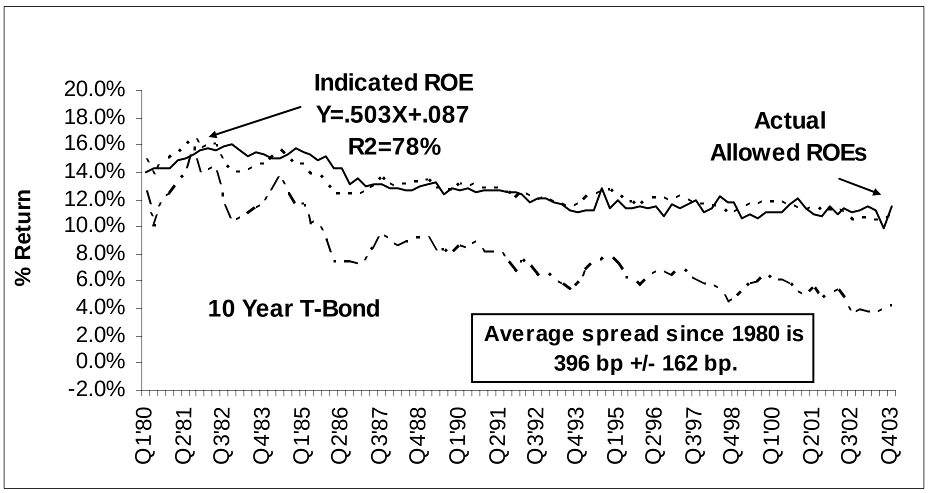
- **Rochester G&E in New York.** In rebuttal testimony, parent EAS indicated that the Staff recommendation implies that rates are set at a 4.0% ROE mainly due to the rate base reduction associated with the sale of the Ginna nuclear plant. The Staff's headline allowed 9.96% ROE is unreachable in their view.

- **Aquila in Missouri.** In December the Missouri Public Service Commission Staff recommended an 8.72%–9.72% ROE range using a 35.3% equity ratio for Aquila, which is indicative of a tough environment.

- **Northeast Utilities in New Hampshire.** The relevant test year for this case is the 12 months ended June 30, 2003. Excluding one-time items, NU believes that the relevant ROE for the case is 15.1%, and that it was 13.3% for the 12 months ended September 30, 2003. Based on the company's outcome in Connecticut and the low indicated range for EAS, we believe a 9.5%–10.5% ROE outcome is more likely. Every 100-basis-point difference in the allowed ROE on the test year equity base is $0.03 per share.

- **Pepco Holdings in New Jersey.** Based on our conversations with staff at the Board of Public Utilities, we expect a recommendation in the 9.5%–10.0% range, which is in line with the 9.50%–9.75% outcomes for FirstEnergy and Public Service Enterprise Group.

Figure 5: Allowed ROEs and Interest Rates



Source: Regulatory Research Associates, FactSet

Another Rate Case Cycle?

The electric utility industry has experienced a lull in rate cases that has lasted for roughly 15 years. However, we think the industry is heading toward into a rate case cycle. The cycle is beginning to mature with 26 rate cases in sight, but we also see three main drivers for increased regulatory proceedings. The anticipated rate cases would address: 1) the end of deregulation transition periods; 2) new capital investment and costs of business that have not been incorporated into rates since the last case, which may have been eight to 10 years ago; and 3) the low-interest-rate environment.

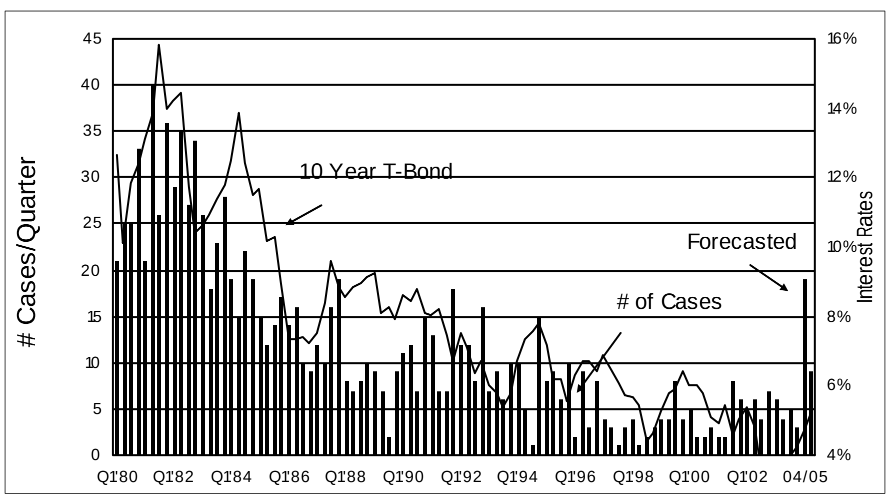
The end of deregulation transition periods: Many state deregulation plans include a developmental period for customer choice. In this period, generation was separated from delivery either functionally or through asset sales. In many cases, part of the enticement to companies for opening up their territory to customer choice was eliminating return caps on distribution service. This allowed for a considerable cost-cutting program and high ROEs at distribution companies during the transition but presents exposure in rate cases at the end of the transition.

Returns on capital investment since the previous rate case: Many companies that we follow have not had rate cases in eight to 10 years, and in the interim the industry has invested billions of dollars into infrastructure. In addition, many costs such as post retirement benefits, pensions, and environmental requirements have changed considerably. While allowed ROEs are attractive in the industry relative to today's interest rate environment, some companies are likely to need to seek recovery of their investment through rate increases (or to offset rate reductions).

Using our coverage universe as a proxy for regulated electric and gas utilities in general, we look for 15–20 rate decisions per quarter in 2004 and around 10 per quarter in 2005.

The low interest rate environment: Utility regulators are enticed to initiate rate cases when interest rates remain at a lower level for a period of time, while companies are motivated to do the exact opposite. Rate case decisions per quarter peaked in the last cycle at 40 in the second quarter of 1981 in the early 1980s and continued to occur at a heightened pace in the mid-1980s as rates were high and a capital spending cycle was coming to an end. This last cycle was clearly to the benefit of the utility. Using our coverage universe of 38 companies as a proxy, which have 26 cases in sight as we enter 2004, industrywide electric and gas rate case decisions per quarter in 2004 should be in the 15–20 range and in 2005 a bit lower at about 10. In Figure 6 we have also included the Lehman Brothers forecast of 10-year treasury interest rates.

Figure 6: Interest Rates and the Rate Case Cycle



Source: Regulatory Research Associates, FactSet

Ranking of State Utility Commissions

In Figure 7 we provide the Lehman Brothers ranking of state utility commissions from an investor perspective. Our rankings are based on six criteria: 1) elected versus appointed commissions; 2) PBR mechanism or not; 3) allowed ROEs; 4) *Settle vs. Litigate;* 5) rate levels; and 6) a subjective investor friendliness rating. The criteria are equal-weighted and receive a value of 1 to 2, with the smaller number representing a better ranking. In our ranking, Ohio is the top-rated commission and also in the top tier are Alabama, Colorado, Indiana, Kentucky, and Wyoming. The bottom tier consists of Arizona, Nevada, New Hampshire, New Mexico, Vermont, and West Virginia.

Figure 7: Normal Distribution Rankings of State Utility Commissions

Tier 1 "Most Shareholder Oriented"				Tier 5 "Most Consumer Oriented"
		Arkansas		
		District of Columbia		
		Idaho		
		Illinois		
		Kansas		
		Maine		
		Maryland		
		Michigan		
		Mississippi		
		New York		
		North Carolina		
		North Dakota		
	Delaware	Oklahoma	California	
	Florida	Oregon	Connecticut	
Alabama	Georgia	Rhode Island	Hawaii	Arizona
Colorado	Iowa	South Carolina	Louisiana	Nevada
Indiana	Massachusetts	South Dakota	Minnesota	New Hampshire
Kentucky	New Jersey	Texas	Missouri	New Mexico
Ohio	Pennsylvania	Virginia	Montana	Vermont
Wyoming	Wisconsin	Washington	Utah	West Virginia

Source: Lehman Brothers

Description of Criteria

1. Elected versus appointed. The elected commissions have a greater tendency to be more consumer-oriented and focused on keeping the companies in check versus appointed commissions.

2. PBR mechanism. Those states that provide incentives for companies to perform and share the benefits with customers get the top rating in this category.

3. Allowed ROEs. A ranking based on the last five rate case outcomes relative to 10-year treasury levels. Included decisions go back roughly 15 years.

4. *Settle vs. Litigate.* Settlement often works out in a better outcome for all parties and consequently earns the state a better rating.

5. Rate levels. The higher the rate, the greater the potential for rate shock from regulators. Lower rates get the better ranking.

6. Subjective investor friendliness rating. A track record for reaching decisions that are outside of consensus expectation, staff reputation and influence, and ability to recognize and address emerging trends are some key considerations.

Please see appendix for state utility commission ranking computations, list of state utility commissioners and commission staff contact List.

Figure 8: Ranking of State Utility Commissions

	Rank	Raw Score
Ohio Public Utilities Commission	1	6.25
Alabama Public Service Commission	2	7.00
Colorado Public Utilities Commission	2	7.00
Wyoming Public Service Commission	2	7.00
Indiana Utility Regulatory Commission	5	7.25
Kentucky Public Service Commission	5	7.25
Florida Public Service Commission	7	7.50
Georgia Public Service Commission	7	7.50
Iowa Utilities Board	7	7.50
Wisconsin Public Service Commission	7	7.50
Delaware Public Service Commission	11	7.75
Massachusetts Dept of Tele and Energy	11	7.75
New Jersey Board of Public Utilities	11	7.75
Arkansas Public Service Commission	14	8.00
North Dakota Public Service Commission	14	8.00
Oklahoma Corporation Commission	14	8.00
Oregon Public Utility Commission	14	8.00
Pennsylvania Public Utility Commission	14	8.00
Texas Public Utility Commission	14	8.00
District of Columbia Public Svc Commission	20	8.25
Illinois Commerce Commission	20	8.25
Maine Public Utilities Commission	20	8.25
Maryland Public Service Commission	20	8.25
Michigan Public Service Commission	20	8.25
North Carolina Utilities Commission	20	8.25
Virginia State Corporation Commission	20	8.25
Idaho Public Utilities Commission	27	8.50
South Carolina Public Service Commission	28	8.75
Kansas Corporation Commission	29	9.00
Mississippi Public Service Commission	29	9.00
New York Public Service Commission	29	9.00
Rhode Island Public Utilities Commission	29	9.00
Washington Utils and Trans Commission	29	9.00
Connecticut Department of Pub Utility Control	34	9.25
Louisiana Public Service Commission	34	9.25
South Dakota Public Utilities Commission	34	9.25
California Public Utilities Commission	37	9.50
Minnesota Public Utilities Commission	37	9.50
Missouri Public Service Commission	37	9.50
Montana Public Service Commission	37	9.50
Utah Public Service Commission	37	9.50
Hawaii Public Utilities Commission	42	10.00
West Virginia Public Service Commission	42	10.00
Vermont Public Service Board	44	10.25
Arizona Corporation Commission	45	10.50
New Hampshire Public Utilities Commission	45	10.50
New Mexico Public Regulation Commission	45	10.50
Nevada Public Utilities Commission	48	10.75

Source: Lehman Brothers

Rate Case Illustration

Traditional rate cases can be triggered in three ways. They are by: 1) the expiration of a previous rate plan; 2) commission action in response to over-earning; and 3) the company proactively seeks relief for spending. There is no difference in the progression of the rate case once it is initiated. However, the type of filing by the company will clearly differ. For instance, a company's conclusion to scenarios #1 and #3 would be a required rate increase (or decrease) based on the test year, which could be the prior year, or done a forward-looking pro forma basis. In scenario #2, which is a "show cause" proceeding, the company would show why it was not over-earning based on current market factors and cost of service.

Rate cases usually last 6 to 15 months. The biggest delays come when deadlines are extended to allow parties time to settle. Settling is almost always a better path for shareholders than a litigated outcome. In Figure 9 we list a potential calendar for a rate case filed in January of a given year.

Figure 9: Typical Rate Case Schedule

	Jan	Feb	March	Apr	May	June	July	Aug	Sep	Oct	Nov	Dec
Company Filing	x											
Intervenor Testimony			x									
Hearings				x								
Reply Briefs					x							
ALJ Decision / Staff Recommendation						x	x					
Final Decision									x			
Appeals											x	

Source: Lehman Brothers

Rate Case Filing: Obviously this kicks off the process. The company makes a proposal, which includes a full year's financials. Key variables are allowed ROE, allowed and projected expenses, projected sales volumes, rate base and capital structure. In some states companies file on a forward test year, and in other states the filing is a based on a historical result. The company's position will be supported in testimony from key company officials and hired witnesses. Usually a third-party witness will submit analysis to formulate the ROE request. Most case filings are at least several hundred pages with dozens of financial schedules.

Intervenor Testimony: This phase is the opportunity for the intervenors to file their positions, and it may follow the company filing by 30–60 days. There can be a wide range of supporting analysis (e.g., hiring of their own expert witnesses) depending on resources and the party's interest level. How persuasive the argument is will be at least somewhat tied to the level of analysis. In this phase, the public service commission staff, the attorney general, and the consumer advocate usually make key filings. The consumer advocate filing and the attorney general's typically have the worst implications for the company's financials and marks the lower bound for the potential range of outcomes. Publicity of this position usually sends the company's stock to the low point in the rate case. However, if jurisdiction is well known to be shareholder unfriendly, the low point could be deeper into the process all the way up to the final outcome.

Figure 10 provides an example of what a rate case filing might look like. In this scenario, the company has reported 2002 results and is filing a case on a forward-looking test year. We also include the company's pro forma capital structure. The pro forma capital structure can be used when a company's equity ratio is inconsistent with that of a normal electric utility where the equity ratio is around 45%.

Figure 10: Rate Case Illustration

Earned Returns		Balance Sheet		
	2002		2002	% Total
Net Income	$500	Equity	$4,000	34.8%
		Debt	$7,000	60.9%
Earned ROE	12.5%	Preferred	$500	4.3%
Earned ROR	9.8%	Total	$11,500	
Known and Quantifiable Additions to Rate Base			$1,000	

Filed Positions and Implications

	Company		Staff		Consumer Advocate	
ROE	11.0%		10.0%		9.5%	
ROR	9.3%		8.3%		8.1%	
Rate Increase or Decrease	$83.3		$0.0		-$120.8	
Pro-forma Balance Sheet						
Equity	$5,000	40.0%	$5,000	40.0%	4500	37.5%
Debt	7000	56.0%	7000	56.0%	7000	58.3%
Preferred	500	4.0%	500	4.0%	500	4.2%
Total Capital	$12,500		$12,500		$12,000	
Allowed Income	$550		$500		$428	

Source: Lehman Brothers

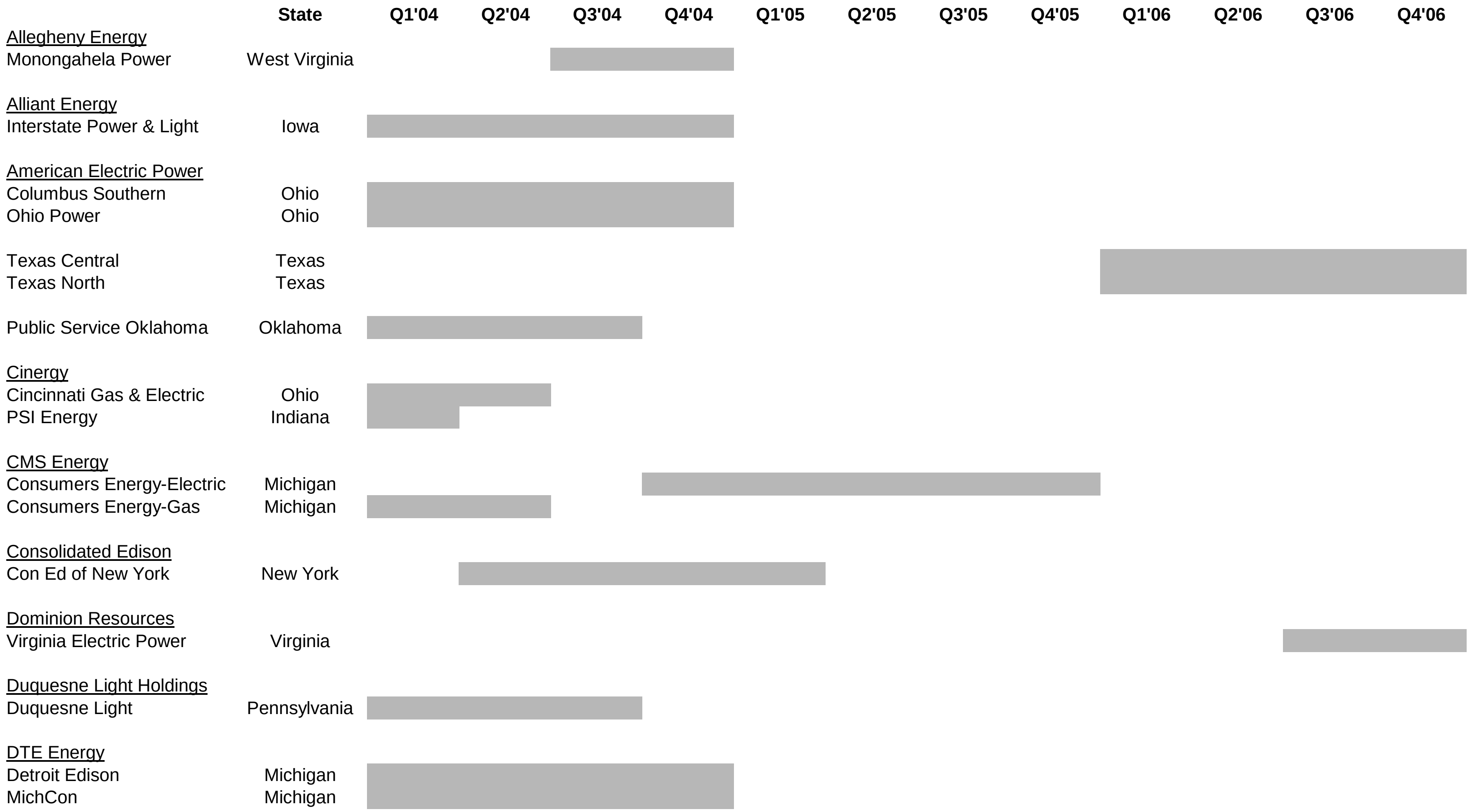
Hearings. Hearings are generally a restatement of the filed position. They involve calling witnesses to support positions on things such as ROEs, operating expenses, rate design, retirement benefits, and decommissioning expenses. The question and answer period is the most important aspect of hearings. A lack of preparation by the company or another party has been known to "turn the tide" in the case. Hearings usually last one to two weeks, though are sometimes longer.

Reply Briefs. This is rarely a material step in the process. Its importance is that it helps to more clearly establish the parties' positions. This is helpful for providing the conditions for a settlement. Parties will comment on other parties' positions, which is helpful for understanding the middle-of-the-road position.

Administrative Law Judge Decision. A law judge is a hearing officer who listens to testimony and recommends a decision to the commission. Some states do not use ALJs, though the Federal Energy Regulatory Commission does. If we have gotten to this stage, settlement is unlikely. The best time for settlement is between the reply briefs and the ALJ decision. The ALJ decision poses uncertainty for all parties that they would probably rather avoid. There can be significant delays at this stage of the rate case. The ALJ may encourage the parties to settle to avoid doing the work on what are increasingly complex rate proceedings these days.

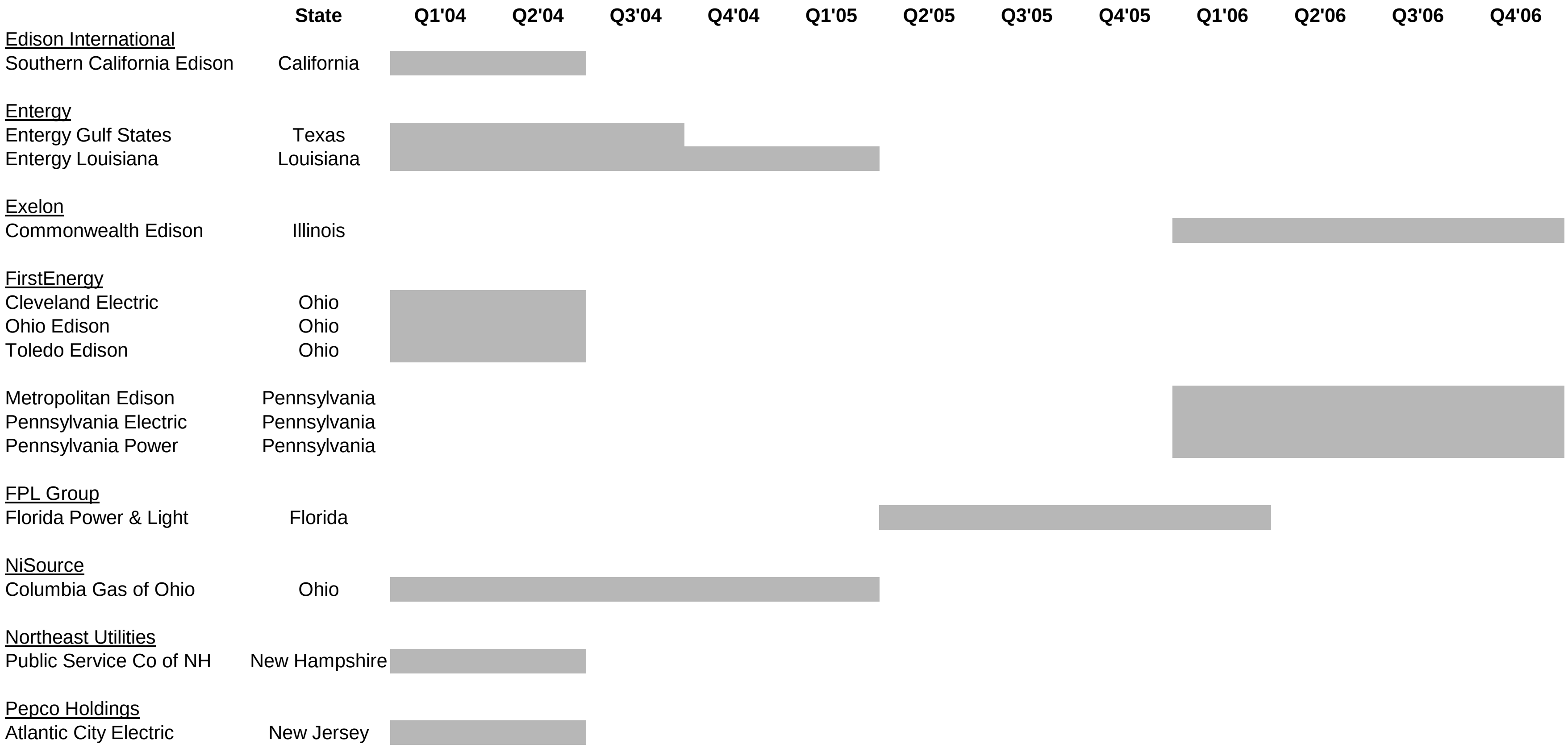
Final Decision. Again, if we have gotten to this stage, it does not bode well for shareholders. Usually, the final outcome is typically most consistent with the ALJ and/or staff. There can be appeals, usually within 30–45 days of the final decision, but they do not often result in a meaningful change. If the appeal to the utility commission is unsuccessful, a party's recourse is generally to the state court system.

Figure 11: Electric Utility Rate Case Timeline



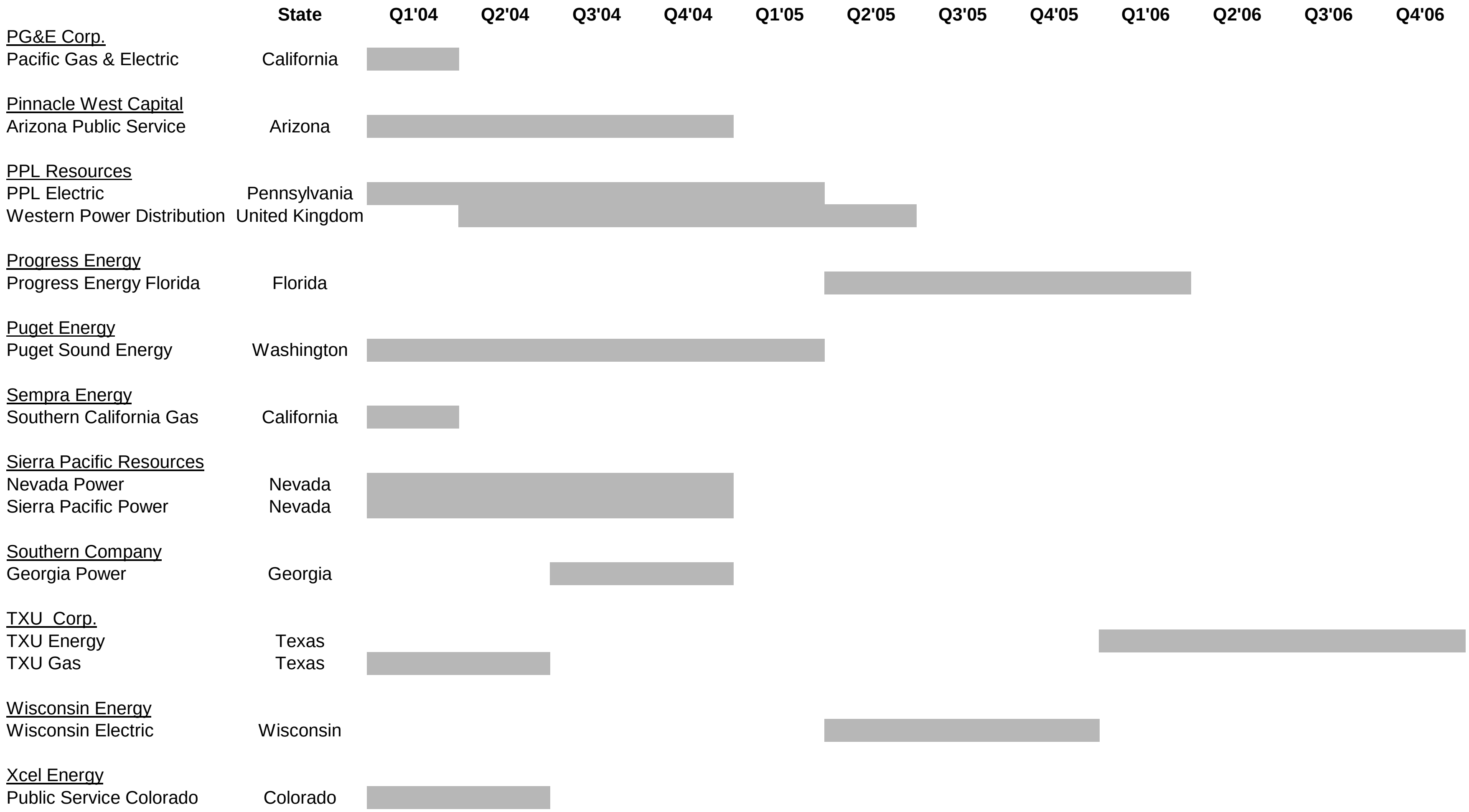
Source: Company reports and Lehman Brothers

Figure 12: Electric Utility Rate Case Timeline



Source: Company reports and Lehman Brothers

Figure 13: Electric Utility Rate Case Timeline



Source: Company reports and Lehman Brothers

Analysis of Upcoming Rate Cases

Allegheny Energy

Figure 14: Allegheny Energy

Allegheny Energy

Subsidiary	State	Rate Case Timeline Filing	Rate Case Timeline Implementation	ROE Last Allowed	When	ROE 2002A	Equity 2002	% Total 2002	EPS 2002A
Monongahela Power	West Virginia	Q2'04	1/05	10.85%-L	11/94	10.6%	$478	24.7%	$0.40

** S-Indicates settled and L-Indicates litigated*

Source: Company reports, Regulatory Research Associates

AYE has two rate issues: a general rate case in West Virginia, which could be effective in early 2005 and a rate plan extension in Ohio.

In West Virginia the company's rate plan ends at December 31, 2004. In 2000, AYE's Monongahela Power subsidiary agreed to reduce rates $10 million in exchange for being allowed to implement retail competition. Unfortunately, West Virginia did not allow retail competition, but left the rate decrease in effect. We would expect AYE to argue for this to be addressed in the rate proceeding. We have assumed no rate relief in our 2005 EPS estimate of $1.06 for AYE. The company is allowed a 10.85% ROE in West Virginia and earned a 10.6% ROE in 2002.

In Ohio, the company's market transition period was scheduled to end on December 31, 2003, according to the company's stipulation with the Ohio Public Utility Commission. This was expected to supercede legislation that stated that it end by 2005. Pursuant to this, the company sent out an RFP to provide service to customers and the lowest bidder was Allegheny Energy Supply, which was willing to serve at significant rate increases of 17%–35%. This amounts to only a few millions annually for AYE because its Ohio operation is very small. The outcome was apparently a wake-up call to the Ohio Public Utility Commission, which subsequently ruled that the market transition period and rates be extended two years through 2005. AYE is currently appealing this decision with the commission, and if unsuccessful may also look to the courts.

Alliant Energy

Figure 15: Alliant Energy

Subsidiary	State	Rate Case Timeline Filing	Rate Case Timeline Implementation	ROE Last Allowed	When	ROE 2002A	Equity 2002	% Total 2002	EPS 2002A
Interstate P&L	Iowa	Q1'04	6/04	11.4%-L	12/95	10.2%	$867	47.2%	$0.96

** S-Indicates settled and L-Indicates litigated*

Source: Company reports, Regulatory Research Associates

LNT will file a rate case in Iowa by the end of 1Q04 mainly to implement the "Power Iowa" initiative, but it is also an integrated rate case. In the "Power Iowa" initiative, the Iowa legislature has granted the company a 12.23% ROE and 50% equity ratio for a 550 MW combined-cycle gas plant. The plant is scheduled to start-up in June 2004 and will add $25 million net income annually, or $0.22 per share. The return is for 27 years as codified in legislation, and the project is expected to cost $400 million. The company does not over-earn its allowed ROE of 11.2% in Iowa, so we do not expect offsetting rate cuts. The company will receive an interim decision with 90 days of filing, which will pave the way for construction of the related power plant and a final decision in 1Q05. In Figure 16 we provide the potential operating data for "Power Iowa".

Figure 16: Power Iowa Initiative

Power Iowa Initiative

500 MW combined cycle plant

Allowed ROE	12.2%
Depreciation	27 years
Start	June '04
Equity ratio	50.0%
Fuel/Mwhr	$37.50
MMwhrs	3.3
Revenue	$213.2
Fuel	$123.2
O&M	$16.4
Depreciation	$14.8
General Taxes	$6.0
Operating Incom	$52.8
Interest	$13.0
Pre-tax income	$39.8
Taxes	$15.3
Net Income	$24.5
EPS	$0.22

Source: Lehman Brothers

American Electric Power

Figure 17: American Electric Power

		Allowed ROE		2002A				Status of:	
Utility Subsidiary	**Jurisdiction**	Allowed	Date	ROE*	Equity	% Cap	EPS	Base Rates	Fuel Clause Rates
Ohio Power Co.	Ohio	12.81%	1995	17.95%	1,233.1	52%	$0.66	Frozen through 2005	None
Columbus Southern	Ohio	12.46%	1992	22.11%	847.7	57%	$0.54	Frozen through 2005	None
Texas Central	Texas	10.02%	1997	21.96%	1,101.1	41%	$0.83	PTB rates until 1/1/07	N/A
Texas North	Texas	11.38%	1995	6.22%	208.6	61%	$0.04	PTB rates until 1/1/07	N/A
Appalachian Power	*Consolidated*			*17.65%*	*1,166.1*	*37%*	*$0.61*		
	Virginia	10.85%	1999					Capped until 7/1/07	Capped until 7/1/07
	West Virginia	10.70%	1999					Fixed	Suspended
Southwestern Power Co.	*Consolidated*			*12.20%*	*661.8*	*45%*	*$0.25*		
	Texas	15.70%	1984					Capped until 6/15/05	Active
	Louisiana	11.10%	1999					Capped until 6/15/05	Active
	Arkansas	10.75%	1999					Capped until 6/15/03	Active
Indiana & Michigan	*Consolidated*			*7.08%*	*1,018.7*	*37%*	*$0.21*		
	Indiana	12.00%	1999					Capped until 1/1/05	Capped until 3/1/04
	Michigan	13.00%	1990					Capped until 1/1/05	Capped until 1/1/04
Public Service Co. of OK	Oklahoma	N/A	N/A	9.23%	399.2	39%	$0.12	Under review	Active
Kentucky Power	Kentucky	16.50%	1984	7.42%	298.0	39%	$0.06	Frozen until 6/15/03	Active
Wheeling Power	West Virginia	N/A	1983	16.04%	27.8	52%	$0.01	Fixed	Suspended
Kingsport Power	Tennessee	12.00%	1992	16.31%	27.8	48%	$0.01	Not capped or frozen	Active

**Unadjusted financial basis*

Source: Company reports and Lehman Brothers

Ohio

In 1999, the governor of Ohio signed the Amended Substitute Senate Bill No. 3 (SB 3). That legislation, among other things, provided for a market development period (MDP)—beginning on January 1, 2004 and ending no later than December 31, 2005—during which retail customers could choose their electric power supplier or receive default service at frozen generation rates from the incumbent utility. At the end of the MDP, generation rates for customers who did not switch (i.e., receive default service) would be at market-based rates or market-based standard service offer (MBSSO) rates. In addition, each incumbent utility is required to offer its customers an option to purchase competitive retail electric supply service at prices determined by competitive bidding process (CBP). In a December 17, 2003 order (Case No. 01-2164-EL-ORD), the PUCO directed utilities to file an application for a MBSSO and a CBP by July 1, 2004. The commission indicated, however, that a utility could submit a stipulation that varied from the proposed rules for the MBSSO and CBP.

On Monday (February 9), Ohio Power Company (OPCo) and Columbus Southern Power Company (CSPCo), the Ohio public utility subsidiaries of AEP, filed an application for the approval of a post-market development period rate stabilization plan with the Public Utilities Commission of Ohio (PUCO). According to AEP's filing, this plan would substitute during the Rate Stabilization Period (January 1, 2006–December 31, 2008) for the companies' MBSSO without the need for a CBP. In Case No. 01-2164-EL-ORD, the commission found that an MBSSO-only application did not relieve a utility from filing an application for a CBP. In our opinion, the filing will accomplishes three primary things: 1) extends the current frozen distribution rates three additional years through December 31, 2008 from December 31, 2005; 2) provides incremental revenue to begin recovering costs for environmental improvements through increased rates for generation service; and 3) allows recovery through additional filings for certain other expenditures, including RTO implementation costs and post 9/11 security costs. The plan also sets a cap on annual increases for generation rates, and customers remain free to switch to a Competitive Retail Electric Service (CRES) provider. The companies expect a decision as early as the 1H04 and before year-end 2004.

Some of the key features of the plan are summarized below:

Distribution Service – Distribution electric rates and charges in effect on December 31, 2005 would be frozen through December 31, 2008. Under the plan, these rates and charges could be adjusted for: 1) an emergency; 2) increased distribution related expenses associated with: a) changes in laws, rules or regulations related to environmental requirements; b) post-9/11 security measures; c) taxes; d) O&M associated with new requirements imposed on OPCo and CSPCo by federal or state legislative or regulatory bodies after January 31, 2004; and e) major storm damage service restoration; 3) regulatory assets to be recorded in 2004 and 2005 plus carrying costs for deferred RTO administration charges as a result of joining PJM; and 4) deferred equity carrying costs on capital expenditures plus a full carrying cost in 2004 and 2005 on in-service capital expenditures since January 1, 2002.

Generation Service – For all nonresidential customers, the plan proposes annual percentage increases for 2006, 2007, and 2008 of 3% per year for OPCo customers and by 7% per year for CSPCo. To make the increases more palatable for residential customers, AEP proposes the termination of the current temporary 5% generation discount on June 30, 2004, such that rates would increase by a net 1.6% per year and 5.7% per year over the respective period. OPCo and CSPCo have not had an increase in base rates since 1995 and 1994, respectively.

OPCo and CSPCo would also have the ability to adjust rates for the same items listed in #2 for distribution service and if customer load switches service to a CRES provider. Under the plan, if the commission fails to issue a final order within 90 days of a filed increase by AEP, the proposed increase will become effective on an interim basis until a final order is issued. Generation rate increases, excluding the effects of the temporary residential discount, would be capped at an average of 11% for OPCo and 7% for CSPCo for the years 2006–08.

RTO Cost Recovery – OPCo and CSPCo would also be able to adjust the transmission components of their standard service offer rates to reflect applicable FERC-approved charges or rates related to open access transmission, net of congestion and ancillary services. Any adjustment would become effective within 30 days of a company's adjustment filing unless the PUCO delays implementation. After 60 days, the rates would become effective unless rejected by the commission for cause.

Accounting Authority – The companies are also seeking regulatory accounting treatment of two items: 1) the deferral on RTO administrative charges related to the stalled integration into PJM through December 31, 2005 plus carrying charges until recovered and 2) the deferral, in 2004 and 2005, of the equity carrying charge on the companies' construction expenditures beginning January 1, 2002, construction work in progress, and a full carrying charge on in-service capital expenditures beginning January 1, 2002. In addition, AEP is seeking relief for "construction and installation of equipment to comply with requirements imposed by statute, rule, regulation or administrative or court order inclusive of environmental, security and other requirements". These deferred costs would be amortized over a three-year period commensurate with recovery beginning in January 2006 through a distribution rider that cannot be bypassed.

As of September 30, 2003, AEP had deferred approximately $24 million of RTO formation and integration costs plus related carrying charges. In a July 2003 order, FERC indicated that it would review the deferred costs at the time they are transferred to a regulatory asset account and scheduled for amortization and recovery in the open access transmission tariff (OATT). In order for AEP to fully recover these amortized costs, the company needs regulatory asset treatment of OPCo's and CSPCo's portion of the OATT and an increase in retail rates.

Perhaps the most important aspect of the filing is the recovery of environmental-related expenditures. The proposed plan would provide the companies with a current equity return in 2004 and 2005 on required capital expenditures not yet in service and a full current year return on such expenditures after they go into service plus carrying costs until the regulatory asset is fully recovered.

According to AEP's 2002 10-K, the estimated environmental compliance costs for OPCo and CSPCo were $93 million and $535 million–$864 million, respectively, of which approximately $387 million and $45 million had been spent as of December 31, 20/02. In 2002, OPCo spent $110.3 million and CSPCo $25.4 million on environmental expenditures. An estimated $53.1 million and $39.3 million, respectively, were planned for 2003. However, these costs do not account for additional capital costs that may be needed to comply with future laws and regulations and pending litigation.

Since 1999 OPCo and CSPCo, as well as a number of other AEP subsidiaries, have been involved in litigation with the Federal EPA regarding plant emissions under the Clean Air Act. Specifically, the EPA alleges that modifications to certain coal-fired plants made over a 20-year period were in violation of the New Source Review rules under the Clean Air Act. If the companies were to lose this litigation, future environmental expenditures could be significantly higher due to requirements for the installation of additional pollution control equipment. Without recovery of these costs, the companies' cash flows and financial condition could be negatively affected.

Texas

2004 True-Up Proceedings: Beginning in January 2004, the Public Utility Commission of Texas (PUCT) will conduct true-up proceedings for each investor-owned utility, its affiliated REP, and affiliated power generation company. The purpose of the true-up proceeding is to (i) quantify and reconcile the amount of stranded costs and generation-related regulatory assets that have not yet been securitized, (ii) conduct a true-up of the PUCT ECOM model for 2002 and 2003 to reflect market prices determined in required capacity auctions, (iii) establish final fuel recovery balances, and (iv) determine the price to beat clawback component. The amount under (i) will be recovered through securitization, while items (ii)-(iv) will increase or decrease the amount recovered via competition transition charges (CTC). The proposed true-up filing dates for AEP Texas North Company (TNC) and AEP Texas Central Company (TCC) are May 28, 2004 and September 3, 2004, respectively.

Figure 18: Texas True-Up Process Timeline

Date	Action
Aug/Nov 2003	Due diligence to be completed by bidders
May 9, 2003	PUCT unanimously approves rule clarifying inclusion of STP to determine stranded costs
December 2003	Final bids due
February 2004	Purchase and Sale Agreement ready to be signed
April 2004	Right of first refusal period ends for Oklaunion co-owners
August 2004	Right of first refusal period ends for STP co-owners
Jun/Sep 2004	Transaction closing
September 2004	True-up filings made with PUCT; 150-day process with possible extension
Feb/Mar 2005	Final PUCT True-up decision, if not extended and if no appeals
Apr/May 2005	Request to reflect stranded costs in CTC surcharge (must be filed w/in 60 days of final order in true-up proceeding
August 2005	PUCT CTC approval (beginning of stranded cost recovery)
September 2005	Request to securitize stranded costs
December 2005	PUCT securitization approval, assuming no appeals
April 2006	Issuance of securitization bonds

Source: Company reports and Lehman Brothers

Generation-Related Stranded Cost Determination: In December 2002, TCC filed a plan of divestiture with the PUCT seeking approval to sell its generation assets (4,241 MW) in order to determine their market value, and, ultimately, the amount of its stranded costs. These assets have a book value of approximately $1.7 billion, the bulk of which is attributable to TCC's 25.2% interest in the South Texas Project nuclear plant (STP). On May 9, 2003, the PUCT granted approval of the sale of STP in the determination of TCC's stranded costs. The co-owners of STP have the right of first refusal to purchase TCC's interest. Divestiture of TCC's interest in STP to a nonaffiliate will also require NRC approval. The difference between the market value of the assets upon sale and their book value (approximately $1.8 billion) will be recovered via securitization.

The 2004 true-up proceeding will also address the remaining generation-related regulatory assets of approximately $193 million originally included in TCC's 1999 securitization request. TNC does not have any recoverable stranded costs or generation-related regulatory assets that can be considered as part of the 2004 true-up process.

ECOM / Capacity Auction: Under Senate Bill 7, any difference between the excess costs over market (ECOM) model market prices and actual market power prices obtained through the generation capacity auctions during the period from January 1, 2002 to December 31, 2003 will be a component of the 2004 true-up proceeding. Auctions to date have generally shown market prices that have been lower than the ECOM estimates, and, therefore, TCC booked about $262 million ($0.50 per share) of noncash earnings in 2002 and recognized another $218 million ($0.37 per share) in 2003. The cash recovery of these earnings, which is subject to a true-up proceeding, will be accomplished over time through a CTC charge.

Fuel Recovery Balance Determination: Any under or over-recovery of fuel costs, plus interest, as of December 31, 2001 will be recovered from or returned to customers as a component of the 2004 true-up proceeding.

TNC's fuel reconciliation requests approval of $293.7 million in fuel costs associated with serving both ERCOT and SPP retail customers from July 1, 2000 through December 31, 2001 and reflects a fuel under-recovery balance, as of December 31, 2001, of $28.2 million, including interest. As a result of a March 2003 ALJ ruling, which reduced the company's under-recovery balance by about $12.5 million, TNC established a $13 million reserve. The PUCT remanded the final fuel reconciliation to the ALJ in order to consider two additional issues: 1) the sharing of off-system sales margins with customers beyond the termination of the fuel factor and 2) the inclusion of January 2002 fuel factor revenues and associated costs in the determination of the fuel factor. These issues could result in an increase in the disallowance.

TCC's fuel reconciliation filing seeks approval for $1.6 billion in fuel expense collected from retail customers from July 1998 through December 2001 and reflects a fuel over-recovery balance, as of December 31, 2001, of $63.5 million, including interest. Due to the March 2003 ALJ ruling in the TNC reconciliation case, TCC established a reserve for potential adverse rulings of $36 million.

Price to Beat (PTB) Clawback: The amount TCC or TNC recovers in the 2004 true-up proceeding could be reduced (or the amount TCC or TNC must refund could be increased) by the PTB clawback component. Although AEP sold its two Retail Electric Provider (REPs) affiliates to Centrica, both AEP and Centrica share responsibility for any PTB clawback amounts that can be up to $150 per customer if less than 40% of the REPs customers switch as of January 1, 2004. AEP took a $50 million reserve for such an assessment in 2002.

Oklahoma

Public Service Company of Oklahoma (PSO) provides retail electric services in Oklahoma at a bundled rate approved by the Oklahoma Corporation Commission (OCC). PSO's rates are set on a cost-of-service basis. Fuel and purchased power costs above the amount included in base rates are recovered by applying a fuel adjustment factor to retail kilowatt-hour sales. The factor is adjusted quarterly and is based upon forecasted fuel and purchased power costs. Over or under collections of fuel costs for prior periods can be recovered when new quarterly factors are established.

Rates were capped through December 31, 2002. In February 2003, the OCC required PSO to file documents necessary for a general rate review. PSO filed testimony on October 17, 2003. A procedural schedule has not been set. In addition, the OCC is conducting a prudence review of PSO's 2001 fuel and purchased power practices. At the end of 2002, PSO had a $44 million under-recovery of fuel costs. (Staff recommended recovery of $42.4 million).

Cinergy Corp.

Figure 19: Cinergy Corp.

Subsidiary	State	Rate Case Timeline: Filing	Rate Case Timeline: Implementation	ROE Last Allowed	When	ROE 2002A	Equity 2002	% Total 2002	EPS 2002A
Cincinnati Gas & Electric	Ohio	1/04	1/1/05	11.4-12.7%-S	1993	14.5%	$1,810	51.4%	$1.56
PSI Energy	Indiana	1/03	4/1/04	11.0%-L	1996	15.1%	$1,401	49.2%	$1.26

** S-Indicates settled and L-Indicates litigated*

Source: Company reports, Regulatory Research Associates

Cinergy has two rate cases on the horizon. There is currently a case under way in Indiana where positions have been filed, and the company has asked for a final outcome effective April 1, 2004. CIN has also filed a rate stabilization plan in Ohio at the request of the Ohio Public Utility Commission. The outcome could extend CIN's market development period three years from January 1, 2006 through 2008, but CIN is requesting a distribution rate case with the outcome (potential increase) to be effective sooner.

PSI Energy-Indiana

The range of outcomes in Indiana is roughly plus or minus $0.10 per share of EPS versus our estimates. The key items in the case are: allowed ROE/rate relief, sharing of wholesale margins with customers, and depreciation schedules. CIN has updated its filing to an 11.2% ROE and a $179 million rate increase, versus 11.5%–12.0% initially and $225 million. This compares with allowed ROEs of 9.15% ($18 million rate relief) from the Office of Consumer Counsel (OCC) and a range of 10.35%–10.55% ($145 million) from the Commission Staff. We have assumed a 10.5% ROE and $145 million of rate relief. While we do not believe PSI Energy has significant wholesale volumes, we assume CIN is allowed to keep half of the margins, while Staff would allow retention of 20%, and the OCC would allow none. Only the OCC calls for a different depreciation schedule than the company's proposed annual base of $219 million.

We think a settlement is very unlikely at this point. Hearings have been completed, which removes a milestone before which settlements sometimes occur and the ROE gap between the company's proposal and the OCC's is too wide. However, we believe

CIN can still receive a reasonable outcome on a litigated basis, though it will take more time. The key milestone now is the mid-March ALJ decision, which could be quickly followed by a final order as CIN has requested an April 1 effective date. We do not believe a delay in the final outcome has a significant impact to EPS. In Figure 20 we highlight a range of outcomes.

Figure 20: Summary of PSI Energy Rate Case ($ Millions)

	Cinergy	Office of Consumer Counsel	Lehman Brothers	Staff	
ROE	**11.20%**	**9.15%**	**10.50%**	**10.45%**	**(a)**
Equity ratio	46.60%	46.60%	45.00%	45.00%	
Equity	$1,628	$1,629	$1,573	$1,573	
Net Income	$182.3	$149.1	$165.2	$164.4	
Difference	$17.2	-$16.1	--	-$0.8	
2004 EPS	**$2.85**	**$2.66**	**$2.75**	**$2.75**	
Off-system sales sharing with customers	50/50	None	50/50	80/20	
Rate Relief	$179	$18	$145	$145	

(a) Reflects the mid-point of proposed 10.35-10.55% range.

Source: Lehman Brothers, company reports

Cincinnati Gas & Electric-Ohio

The company's transition period in Ohio expires at year-end 2005. Like FirstEnergy's Ohio subsidiary, CIN's proposed a rate stabilization plan as an alternative to a competitive bid. CIN had been pushing to end the transition period, but the request was not addressed last year. In 2000, the OPUC gave CIN the exclusive right to end the market development period and charge competitive rates to all nonresidential customer classes that achieved 20% or more customer migration to competitive suppliers. All of CG&E's related nonresidential customer classes achieved the required 20% by January 1, 2003. In 2003, CG&E asked to end the market development, but the request was not addressed.

Key elements of CIN's request filed January 25 include: 1) a T&D rate case effective by 2005; 2) tracking mechanisms for distribution reliability and transmission upgrades; 3) recovery of costs up to 10% of "little g" to maintain reliable generation supply; and 4) extension of 5% residential-only generation rate cut through 2008. Regarding the distribution case, CIN believes it is under-earning and can request a $60 million–$70 million of rate increase, or about 5% using an 11% ROE and current capital structure. Our 2005 EPS estimate of $2.70 assumes no increase, but the requested increase could raise our EPS outlook to $3.00.

The upcoming schedule includes:

Figure 21: CG&E Rate Case Schedule

Date	Action
March 25	CG&E's testimony due
April 1	PUCO Staff's testimony due
April 8	Intervenor testimony due
April 19	Hearing
July 1	Requested final outcome

Source: Ohio Public Utility Commission

Like FirstEnergys' Ohio subsidiaries requested, Cinergy's CG&E has provided customers two options: a market-based option and a rate stabilization option. Under the market-based option, CIN would end the market development for customer classes with 20% or more customer migration no later than December 31, 2004. CIN would act as the provider of last resort but would charge a variable "market price tracker adjustment," "POLR adjustment," and "true-up adjustment". Another option of the market-based approach would be a bidding process for alternative generation suppliers as originally contemplated under the legislation. Under these options, CG&E would still defer costs associated with its transmission and distribution systems during the market development period for recovery in the next rate case, including the Transmission Cost Rider and Capital Investment Reliability Rider. Commission staff would review costs. Last, CG&E would have no obligation to transfer its generation facilities to another unregulated subsidiary.

The alternative rate stabilization plan would essentially extend the rate plan through 2008. Under this plan, the market development period would end for all customers December 31, 2004. Those customers that have not switched to alternative suppliers would maintain their prices to compare through 2005. CIN would reduce its current generation rates by the current stranded cost recovery "RTC" mechanism. Instead a similar "little g" charge would act as an adder, which would continue through 2008. CIN would be able to recover up to an additional 10% of "little g" to maintain reliable generation supply costs and fulfill the POLR obligation including fuel, environmental costs, purchased power, homeland security, and other costs. If CIN does not increase "little g" by 10% in a given year, it could still implement any unused increases, though this would be subject to review by PUCO Staff.

CMS Energy

Figure 22: CMS Energy

Utility Subsidiary	State	Allowed ROE Last	Allowed ROE Year	2002A ROE*	2002A Equity	2002A % Cap	2002A EPS
Consumers Energy	*Consolidated*			*15.45%*	*1,889*	*33%*	*$2.11*
Electric**	Michigan	12.25%	1996	17.50%	1,400	31%	$1.76
Gas	Michigan	11.40%	2002	14.26%	340	36%	$0.35

**Financial basis*
***Excludes MCV related earnings*
Source: Company reports and Lehman Brothers

Gas Rate Case (U-13730)

On March 14, 2003, Consumers filed for a $156 million increase in gas delivery and transportation rates based on a 2004 test year and for immediate rate relief of a like amount. The filing also included a 13.50% authorized ROE (versus 11.40% currently) and a higher equity component of about 47% (versus 39%). The original filing was subsequently amended in September 2003 to reduce the requested annual increase to $139 million. That same month, the MPSC staff recommended $80.5 million of interim rate relief based on an 11.40% ROE and 39% equity ratio, both of which are consistent with current rates. By December, Consumers had further revised its interim rate relief amount to $33 million.

Interim Rate Relief with a Catch

On December 18, 2003, the commission granted Consumers a $19.3 million interim gas rate increase. Using the staff's recommended amount of $80.5 million as a starting point, the MPSC's primary adjustments were a $34.0 million adjustment for depreciation expense, which the company had proposed in a December 2003 filing, and a $29.8 million reduction in other O&M expenses (the company had derived its estimate using a 2004 test year). However, the increase was contingent on the company's acceptance of a $190 million cap on dividends to the parent. The company accepted the dividend limitation on the 18th, and rates become effective as of that date. Although the order dictates that the dividend cap remains in place as long as interim rates are in effect, we believe it will likely remain a component of the final order. A proposed final order was scheduled for January 23, 2004. As of the date of this report, the commission had yet to issue a decision.

Securitization (U-13715)

On March 4, 2003, Consumers filed for approval to issue approximately $1.084 billion of securitization bonds. The Michigan Public Service Commission (MPSC) determined, on June 3, 2003, that Consumers had $644 million of qualified costs for securitization (Figure 22), but only authorized the securitization of up to $544 million. In addition, the commission conditioned its approval with the stipulation that the securitization proceeds were to be used to reduce debt or equity only at Consumers and not at CMS Energy.

Figure 23: Filed vs. Authorized Securitization Costs

Dollars in Thousands	(a)	(b)		(b) / (a)
	Filed	**Authorized**	**$**	**%**
Cost	**Amount**	**Amount**	**Difference**	**Authorize**
Clean Air Act Costs	$587,106	$544,429	($42,677)	93%
Electric Pension Costs	226,595	0	-226,595	0%
Unsecuritized Palisades Capital Costs	113,279	0	-113,279	0%
Retail Open Access Implementation Costs	96,791	64,108	-32,683	66%
Issuance Costs, including Liquidity Subaccount	60,316	35,853	-24,463	59%
Total Qualified Costs to be Securitized	**$1,084,087**	**$644,390**	**($439,697)**	**59%**

Source: Company Reports and Lehman Brothers

Although the MPSC disallowed a number of Consumers' costs, including the post-2000 Palisades costs and pension costs, it approved recovery of the bulk of the Clean Air Act costs sought by the company. Overall, we viewed the commission's treatment of Consumers as fairly supportive.

Other Securitization Related Issues

In July, Consumers filed for rehearing and clarification of certain issues related to the securitization order of June 2, 2003. Although the commission found that it erred in excluding approximately $14.4 million of additional carrying costs for 2001–03, the MPSC did not alter the securitization amount because the company has already agreed to securitize the capped amount of $544.3 million. In addition, the commission held fast to its dividend restriction to the parent. The company wanted a firm definition of "earnings" to be "retained earnings." The MPSC rejected this notion, making it clear that it wanted to safeguard the securitization savings at the utility.

Two issues were remanded for rehearing and clarification starting January 13, 2004. The more significant issue is the determination of the cost responsibility for securitization charges among full service customers and retail open access (ROA) customers. The current mechanism allows ROA customers to bypass these costs and put the onus on full service customers, which could result in the company recovering less than 100% of its securitized costs. This could have a negative impact on the pricing and marketability of the bonds. The second issue involves the potential "double charging" of ROA customers for Clean Air Act compliance costs. On January 13, the ALJ in the case established a schedule for additional hearings (Figure 24).

Figure 24: Additional Securitization Hearing Schedule

Date	Scheduled Filing
February 13	Consumers Energy Testimony
March 12	Staff & Intervenor Testimony
March 22	Rebuttal Testimony
April 9	Briefs
April 19	Reply Briefs
No date set	Proposal for Decision

Source: Company reports and Lehman Brothers

Based on the schedule set by the ALJ, it appears that the issuance of securitization bonds would not likely occur until 3Q04/4Q03 or in early 2005.

Stranded Cost Recovery

In conjunction with its March 4, 2003 securitization filing, Consumers filed for approval of net stranded costs incurred in 2002 and for a stranded cost recovery charge. The amount of stranded costs filed by Consumers will depend on the outcome of its securitization filing. If the company's proposal to securitize Clean Air Act expenditures and post-2000 Palisades related costs are approved then the amount will be approximately $35 million. If these costs are not approved, the amount will be about $103 million.

Two Strikes on the Recovery of Net Stranded Costs for 2000 and 2001

On December 18, the MPSC denied Consumers' application for rehearing on the recovery of net stranded costs for 2000 and 2001. The commission maintained its view, which was set forth in its December 2002 order, that Consumers had negative stranded costs in 2000 and 2001, and, therefore, has a zero transition charge. It is not clear if the company has additional recourse or if it even intends to pursue the matter since the dollar amount is relatively small ($11 million).

Electric Rate Case

Consumers Energy's retail electric base rates are frozen through December 31, 2003. Rates remain capped for small commercial and industrial customers through December 31, 2004 and through December 31, 2005 for residential customers. We expect Consumers to file a rate case in 4Q04 with the hope of having new rates in effect by the start of the 2006 calendar year. Given parties such as ABATE and the state attorney general's office, which have been historically vocal, and a relatively inexperienced staff, we would not expect a settlement prior to the average 11- to 12-month regulatory process. In our opinion, regulatory relief would provide a needed boost to regulated earnings and the utility's ability to delever. It is unclear whether the parent would benefit, as the commission would likely continue to restrict the amount of dividends that can be upstreamed to the parent.

Consolidated Edison

Figure 25: Consolidated Edison

Subsidiary	State	Rate Case Timeline Filing	Rate Case Timeline Implementation	ROE Last Allowed	When	ROE 2002A	Equity 2002	% Total 2002	EPS 2002A
Con Ed of New York-E, G, S	New York	5/04	3/05	11.75%-S	4/02	12.4%	$4,890	41.9%	$2.94

** S-Indicates settled and L-Indicates litigated*

Source: Company reports, Regulatory Research Associates

ED will have a rate case to address as a result of the expiration of its rate plan in March 2005 for Con Ed of New York. We look for the company to make a filing in early May 2004 and for the process to take six to nine months. We believe that the range of outcomes from the case include an ROE from 9.75% to 11.0%. The range is bounded at the low-end by the initial outcome of the Rochester Gas & Electric rate case from early 2003. This ROE covered a one-year period. The higher-end reflects the 50–100 basis point premium that ED has enjoyed over other utilities in New York historically. Multiyear deals in New York have also received a 50 basis point premium or more over one-year deals. We believe ED will likely file for a three-year rate plan, and we have assumed a 10.25% ROE.

In this case, rate relief is the key since the company needs cash. Our 10.25% ROE assumes that the company receives $450 million of cumulative rate relief, which reflects staged-in rate relief of $75 million in 2005, $150 million in 2006, and $225 million in 2007. We believe this can be justified by considering the level of net regulatory deferrals the company has on their balance sheet, which is $716 million. The rate relief reflects 63% recovery of those deferrals. Even with this level of recovery, we project that after asset sales and World Trade Center spending recovery, ED needs to finance between $350 million and $400 million in 2005.

Dominion Resources

Figure 26: Dominion Resources

Utility Subsidiary	State	Allowed ROE Last	Allowed ROE Year	2002A ROE*	2002A Equity	2002A % Cap	2002A EPS
Virginia Electric & Power	*Consolidated*			*18.33%*	*4,331*	*45%*	*$2.66*
Virginia Power	Virginia	11.40%	1994				
North Carolina Power	North Carolina	11.80%	1993				

**Financial basis*

Source: Company Reports and Lehman Brothers

Virginia

Under the Virginia Restructuring Act, Virginia Power's base rates (excluding fuel costs and certain other allowable expenses) are capped until July 2007. Fuel is recovered through a fuel factor in rates. The current fuel factor of 1.163 cents/Kwh is effective through December 31, 2003.

Tentative Fuel Clause Settlement

On October 9, Virginia Power reached a tentative settlement with the Virginia Attorney General's Office of Consumer Counsel and the State Corporation Commission regarding its 2004 fuel factor application to increase power rates to recover costs attributable to nuclear plant outages for reactor vessel head replacements, increased fuel costs, and an unusually cold winter. Under the settlement, the total amount of the proposed increase will be $386 million, or about $56 million lower than the amount requested by Dominion of $441.7 million. The adjustments included a $46 million decrease in projected fuel costs, a $4 million increase in unrecovered fuel costs, and a $14 million decrease in the balance of deferred fuel costs, which the company wrote off during the quarter.

In its original request, the company offered a two-year recovery period to lessen the impact of the proposed increase. The recovery period in the tentative settlement is three-and-one-half years, ending July 1, 2007, or the end of the transition period for electric utility restructuring. About $171.1 million of the $386 million increase will be recovered in 2004, $85 million in 2005, $87 million in 2006, and $43 million for the first six months in 2007.

Proposed Rate Cap Extension

On October 14, the offices of the governor and the attorney general recommended to the Commission on Electric Utility Restructuring, a special legislative panel of the Virginia General Assembly, that the existing cap on base electric rates be extended by three years to July, 1 2010 from July 1, 2007 and that the wires charge be phased out or eliminated. The proposal has drawn mixed support from lawmakers, including some that would seek to investigate Virginia Power's earnings under capped rates, and opposition from various consumer groups. The state's second largest utility, American Electric Power, is also opposed to the extension due to increases in its environmental, reliability, security, and pension costs.

Rate Extension Bill Sails Through Virginia Senate

A draft of the rate cap extension bill (SB 651) was submitted to the Senate Commerce and Labor Committee on Friday, January 23 and unanimously passed (15-Y; 0-N) on Monday, January 26. The Senate passed the bill in a majority vote (29-Y; 10-N; 1-A) and forwarded it to the House on Friday, January 30. Three competing House bills (HB264, HB1268, and HB1437) were tabled in favor of SB651, which is currently in the House Commerce and Labor Committee.

Key features of SB651 include:

- An extension of the rate cap until December 31, 2010, unless terminated sooner by the State Corporation Commission ("SCC") upon a finding of an effectively competitive market for generation services in the service territory of an incumbent utility.

- The continuation of the fuel costs recovery tariff provisions in effect on January 1, 2004, for any electric utility that purchases fuel for the generation of electricity and that was, as of July 1, 1999, bound by a rate case settlement adopted by the SCC that extended in its application beyond January 1, 2002. The fuel factors remain in effect until the earlier of (i) July 1, 2007; (ii) the termination of capped rates; or (iii) the establishment of tariff provisions as directed by the SCC.

- A requirement that each incumbent electric utility with transmission capacity, owned or controlled, join or establish a regional transmission entity. If passed, this would supersede the SCC's current position against Virginia utilities' participation in RTOs. The SCC's delay of Virginia Power's move to PJM is expected to cost the company $15 million–$20 million after-tax ($0.05–$0.06 per share) in 2004.

- Switching by industrial and commercial customers to a competitive service provider without paying a wires charge if they agree to pay market-based prices if they ever return to the incumbent electric utility. Customers who make this commitment and obtain power from suppliers without paying wires charges are not entitled to obtain power from their incumbent utility at its capped rates.

- The ability to recover and earn a return on the costs of constructing coal-fired generation in the state and that uses Virginia coal by designated default service providers.

What's Next in the Process

Upon leaving the House C&L committee, the bill will be put to the House floor for debate and eventual vote. If the House amends a Senate bill, or the Senate amends a House bill, and the house of origin disagrees with the amendment, a conference committee, usually consisting of three members from each legislative body, may be formed to resolve differences. Once passed by both houses of the General Assembly, the bill is printed as an enrolled bill, examined, and signed by the presiding officer of each chamber. The bill is then sent to the governor for his approval.

When a bill passes the House and Senate and is sent to the governor, he / she has 30 days to approve or veto the bill (if the session has adjourned). If the House and Senate are in Session (prior to March 13), the governor would have seven days to approve or veto the bill. If the governor does not act on a bill, it becomes law without his / her signature. Bills that become law at a regular session (or the reconvened session that follows) are effective the first day of July following adjournment of the regular session unless otherwise specified. The 2004 Virginia legislative session ends on March 13, 2004.

North Carolina

In connection with its acquisition of CNG in 2000, Dominion agreed not to request an increase in North Carolina retail electric base rates until 2006. Fuel rates are subject to change under fuel cost the annual fuel cost adjustment proceedings.

DTE Energy

Figure 27: DTE Energy

Subsidiary	State	Rate Case Timeline Filing	Rate Case Timeline Implementation	ROE Last Allowed	When	ROE 2002A	Equity 2002	% Total 2002	EPS 2002A
Detroit Edison	Michigan	5/03	Q2'04	11.0%-L	1/94	16.8%	$2,122	37.2%	$2.11

** S-Indicates settled and L-Indicates litigated*

Source: Company reports, Regulatory Research Associates

DTE is involved in both electric and gas rate cases in Michigan, which are both headed toward final decisions late in the year. On the electric side, the company recently received an expectedly weak interim relief order. The company received $278 million of rate relief, including $71 million deferred and a $4 million transition charge worth $30 million. This was just below our $281 million and staff's $289 million recommendation. The commission also incorporated Staff's Customer Choice lost margin assumption for 2004 of $162 million, versus our $190 million, which reflects the year-end run rate. We look toward Staff and Intervenor testimony on March 5 for better clarity on the outcome in the full case. However, we may have to wait for the proposed decision on June 30.

Detroit Edison – Electric Case

The key issues in the electric rate case are: 1) Allowed returns; 2) Customer Choice margin recovery; and 3) PSCR reinstatement.

Allowed Returns. The company has requested an 11.5% equity ratio which is reflective of a 7.37% rate of return after-tax and 9.88% pretax on $7.4 billion of rate base. Our forecast assumes a 10.5% ROE for 2005. The company proposed a $3.265 billion equity, including a $600 million contribution. The Staff recommended a $2.8 billion equity base that is reflective of a 45% equity / capital structure for Detroit Edison at year-end 2003 in practice, assuming no incremental capital contributions beyond the $170 million contributed in 2Q03. Of note, the $2.8 billion of equity is 38% of the $7.4 billion rate base, however, Michigan rate base includes "no cost" elements, which mean it will not be consistent with the sum of GAAP equity and debt.

Customer Choice / Stranded Costs. This issue was not addressed in the interim order. In the company's view, the Customer Choice market is the most important regulatory issue to be addressed. DTE is following a parallel path of seeking relief from the legislature and at the Michigan Public Service Commission. At its February 6 analyst meeting, DTE noted that Customer Choice has been on the rise. DTE now projects $240 million lost margin in 2004 from a $190 million year-end run rate and $140 million–$200 million previous forecast. In our 2004 estimate, we have assumed the company's year-end run rate.

In Michigan there has been an annual stranded cost "true-up" process in which DTE has requested recovery for the last few years and received none. This includes recovery of costs related to "Customer Choice" migration to competitive retail marketers and other stranded costs. DTE previously filed for $30 million in costs in 2003 that relates to a charge of four mills on 7.6 MMwhrs of customer choice volumes. At the meeting, the company indicated that it would require a charge of at least 10 mills.

Management is also working with the Michigan legislature to address Customer Choice. To date, the effort has focused on educating legislative leadership on the key issues, and the company believes that it has support, though there has been no action. If anything, this is likely to be a fallback strategy if the rate case outcome is unacceptable. DTE believes that for deregulation in Michigan to be successful, it has to be fully competitive. Some issues it is focused on are eliminating the right of Choice customers to switch back for service with no penalty, providing certainty on stranded cost recovery, and requiring marketers to post reserve margins.

PSCR Mechanism. This relates to a fuel recovery under which DTE has been earning a $126 million pretax margin annually under a fixed cost recovery level. In the interim order, the MPSC called for DTE to reinstate the PSCR fuel recovery mechanism and refund recoveries since January 1, 2004. The company had not complied with the commission's December 18, 2003 order to reinstate it, as it was anticipating a mitigation adjustment in the order for interim relief. On an annualized basis, this is a $126 million reduction, and the Commission also fined DTE $15,300 (the $300 maximum per day) for overcharging customers.

Interim Electric Rate Order

On February 20, DTE received interim relief of $278 million as aforementioned. The rate relief seems closely tied to consumer spending. In other words, the Michigan Public Service Commission (MPSC) mostly allowed for recovery *of* and not *on* spending. The $248 million increase includes: $108 million for pension, $48 million for Clean Air costs, $40 million for low-income assistance funding, and $51 million related to a host of other items. The company's request for recovery of $84 ,million related to the merger with MichCon was deferred to the final proceeding. There was also no discussion of allowed returns as this proceeding is geared toward providing DTE emergency relief for cost items.

We viewed this outcome as an expectedly difficult result that appears to be slightly in favor of the consumer. We believe this illustrates the fact that it is difficult for electric utilities to get significant rate relief in low-interest-rate environments. As reminder, DTE requested interim rate relief of $504 million. With that in mind, we lowered our 2004 EPS estimate $0.10 to $3.25 and our 2005 EPS estimate $0.15 to $3.35 to adopt a more conservative outlook for the full case. Our 2005 estimate reflects about $320 million of net income and $1.90 of EPS. Regarding cash flow, we believe the interim order implies that DTE would need to externally finance $50 million–$100 million of the $350 million dividend.

MichCon – Gas Rate Case

In the gas rate proceeding, the company filed for a $193.6 million increase in base rates on September 30 and a prehearing conference was held in mid-December to set a schedule. Key milestones included a staff and intervenor interim recommendation on May 3, final recommendation on July 26, rebuttal testimony on August 6, hearings August 23–September 3, and a final outcome in November 2004. We have assumed an allowed ROE of 10.5% on a pro forma 45% equity ratio, or about $760 million of equity. This produces $80 million of net income.

Duquesne Light Holdings

Figure 28: Duquesne Light Holdings

		Rate Case Timeline		ROE				%	
				Last		ROE	Equity	Total	EPS
Subsidiary	State	Filing	Implementation	Allowed	When	2002A	2002	2002	2002A
Duquesne Light	Pennsylvania	Q4'03	1/1/05	12.87%-L	1988	13.8%	$521	30.6%	$1.04

** S-Indicates settled and L-Indicates litigated*

Source: Company reports, Regulatory Research Associates

DQE is involved in a rate case to extend the company's rate plan through the decade. The proposal is roughly in line with expectations. It gives smaller customers the security of fixed rates and larger customers the option of variable pricing or annual fixed rates. DQE does request rate relief for serving smaller customers but argues that rates in 2008 will still be 10% less than what they were in 1990. Larger customers would get options of fixed or variable rates, and much of that load could go to competitive suppliers. However, most of this load was a pass-through, so its migration to other suppliers would not be a material impact to margins.

Competing parties have filed a range of opinions. The Office of Consumer Advocate (OCA) was generally supportive of DQE's fixed rate proposal but at different levels. On the other hand, the Office of Trial Staff (OTS) rejected DQE's proposal in favor of a competitive auction. OTS had four specific issues with DQE's proposal: 1) There are indications that the cost of power could decrease; 2) The presence of sub-Duquesne Power to sell to the disco creates an unnecessary layer of margin; 3) Customers have no way of sharing the benefits of declining power prices; and 4) Use of a 3% inflation rate is too high. Other key parties are industrial customers and the retail marketers.

We believe there are solid arguments in favor of both a fixed rate plan and for a competitive auction. The competitive auction would expose the smaller customer to the risk of price spikes and could lead to higher rates in an environment of rising commodity prices. The security of annual fixed (albeit increasing) rates alternatively puts a cap on smaller customers' power costs. As the process moves forward, this case should gain increased interest from investors. However, the company has been able to work with Pennsylvania regulators to forge reasonable solutions in the past which is a positive. From here, key milestones in the case are hearings March 29–April 1, an ALJ recommendation the week of May 24, and a final outcome by July 8.

Details of DQE's Rate Filing

Smaller Customers. These customers would have a "glide path" where rates would be fixed, except for an 11.5% generation rate increase in January 2005 and a 9.3% generation rate increase in January 2008. This reflects an average total increase of 7% in January 2005 and 5.9% in January 2008. The average residential generation rate would be 6.17 cents/kwh starting on January 1, 2005 and 6.79 cents/kwh starting on January 1, 2008. The average small commercial and industrial generation rate would be 6.38 cents/kwh starting on January 1, 2005 and 6.90 cents/kwh starting on January 1, 2008. Output from the 436 MW Sunbury plant would be targeted to serve these customers. The company's Duquesne Power subsidiary would supplement the generation output with power purchases. Transmission and distribution rates would be adjusted to reflect the roll-in of the Pennsylvania gross receipts tax at a level of 5.9% as opposed to the current 4.4% level.

Large Commercial and Industrial Customers. The company offers two options: an "Hourly Price Service" (HPS) and a "Fixed Price Default Service" (FPDS) to customers who demand 300 kw or larger. This is 850 customers, or 45% of the total load. Both services will reflect the results of a competitive auction administered by DQE for which the company proposes a 5 mill/kwh adder. The FPDS would serve as the default option for customers, so no one would end up in a variable pricing structure involuntarily. In the HPS auction, participants would submit a fixed demand charge in dollars per KW month, and in the FPDS bidders would submit a price in fixed dollar per kwhr.

Duquesne will also join PJM West at the end of the POLR II period, which has been supported by the Office of the Consumer Advocate and Duquesne Industrial Intervenors.

Implied EPS of Competing Proposals

We believe the company's POLR III filing covering 2005–10 supports EPS of at least $1.30 in 2005 at the low-end of the range and potentially $1.50–$1.60. The second proposed rate increase effective in 2008 would essentially offset the expiration of section 29 credits, which is a loss per share of $0.35. A key assumption is similar small customer load loss to competitive suppliers. The EPS upside comes from: 1) the 12% generation rate increase in 2005; 2) lower power supply costs; and 3) the $5.00/MWhr procurement fee on large customers that are mainly transitioning from POLR I service. Assuming no additional customer switching, the rate increase adds roughly $32 million, though higher gross receipts taxes are an offset. The company should realize savings on the power procurement costs. The company has been purchasing power at $55/Mwhr but would replace that with Sunbury (variable cost in mid-$20s/Mwhr) and blocks of power purchases that could be in the $45–$50/MWhr range. Last, the $5.00/MWhr procurement fee applied to larger customers would be worth $29 million ($5.00/MWhr x 5.8 MMwhrs).

Within the POLR III rate proposal is an $8 million RTO fee to cover capacity and ancillary services charges. The company notes that this is about an $8 million deficit to the market cost. This includes $11 million, or 0.16 cents/kwhr for capacity based on monthly contracts traded from October 2002 through September 2003 and $5 million for ancillary services, or 0.07 cents/kwh. DQE already has in FERC transmission rates $6 million to of ancillary services associated with small customer load. The RTO adder request of $8 million is below the $30 million of capacity and ancillary services charges on an annual basis in the POLR II contract with Reliant Resources subsidiary Orion Power to serve POLR II customers.

The OCA proposal is incomplete and only refers to a few items but recommends smaller customers pay $57/Mwhr for three years, versus the company's $61.70/Mwhr proposal. The rate for the next three years would be somewhere between $57/MWhr and the company's $67/MWhr proposal, depending on market prices. We calculate the $4.70/MWhr difference to be a loss per share of $0.21 to the company's proposal. The OCA also proposes that $9 million ($0.07 per share) related to joining PJM should be able to be bypassed, which provides some exposure. On the plus side, the OCA is supportive of DQE's purchase of Sunbury.

At the low end, we believe DQE could earn in the $1.10–$1.20 range on the OTS proposal, as we would expect the company to earn a fee for conducting the auction, which is the norm in some other states such as Connecticut and Maryland. The fee would help replace the $5.00/Mwhr margin that DQE projects will contribute $21 million–$22 million of net income this year, or about $0.28 per share. We estimate that a $4.00–$5.00/MWhr fee on all of DQE's current generation customers would be necessary to offset the lost margin. While DQE earns the $5.00/MWhr margin on POLR II customers, both POLR I and II customers would likely participate in auctions. While the fee could help maintain earnings power now, $0.35 per share of tax credit related earnings falls off in at year-end 2007, which brings the sustainability of the $1.00 dividend into question.

Edison International

Figure 29: Edison International

	Rate Case Timeline			ROE		ROE	Equity	%	EPS
Subsidiary	State	Filing	Implementation	Last Allowed	When	2002A	2002	Total 2002	2002A
Southern California Edison	Calif	Q403	May-03	11.60%	2002	11.6%+	$ 4,384	48%	$ 1.80

Source: Company reports and Lehman Brothers

The primary regulatory focus for EIX is the 2003 General Rate Case (GRC) at Southern California Edison (SCE), which has dragged on considerably longer than originally anticipated. The California Energy crisis has returned CA IOU's to vertically integrated cost of service regulation, and therefore the company is seeking rate relief in all portions of the business. SCE has requested an adjusted $251 million electric rate increase (more than currently authorized levels) based on an 11.6% ROE. The Office of Ratepayer Advocate (ORA) has filed its GRC testimony to reduce SCE's base rates by $172 million. The company recently received an ALJ decision calling for a $15 million increase. We would expect an alternate decision on the path to a final CPUC decision during 2Q04. Our estimates reflect the company earning an 11.6% ROE in 2003 and 2004 through a combination of rate increase and cost reductions. Roughly 65%–70% of the request is related to depreciation-related items that could reduce cash flow but not necessarily result in dollar-for-dollar reduced regulatory earnings profile as depreciation schedules, pension and O&M could be adjusted.

SCE's 2004 revenue requirements request is an increase of $137 million over the 2003 GRC request; however, it results in an overall nonfuel revenue reduction of $54 million, primarily due to the expiration of the eight-year San Onofre Nuclear Generating Station (San Onofre) incremental cost incentive pricing mechanism and the return of its incremental costs to conventional cost-of-service rate-making on January 1, 2004. SCE's GRC filing also requests an $85 million increase in revenue in 2005. The company will make a filing for the 2006 GRC during August 2004.

SCE has already received a cost of capital decision for 2003 (11.6%) and was granted an extension through 2004. Therefore, cost recovery will be the major consideration in the current GRC, and ROE will not be revisited until at least 2005. As the company will need to file the 2005 cost of capital during May 2004, every 100-basis-point swing in the allowed ROE is worth approximately $0.14 per share to EIX.

A longer-term but very important issue to monitor is SCE's procurement strategy and the direction of direct access in California. While the legislature (AB 57) and the CPUC have maintained constructive positions since late 2001, the management of energy procurement and cost recovery remains an important issue for CA IOU's, as the net open position grows with the passage of time. We will continue to monitor the CPUC's approach to long-term procurement and prudent cost recovery principles to ensure the utilities are returned and remain investment grade credits. The status of direct access will be an important determinant of the short side of the company's portfolio, and several bills are currently lingering in the state legislature.

On a separate but related issue to direct access and the short position, the construction of utility generation in California is moving ahead in policy and perhaps shortly in practice. In late December, the CPUC approved the Mountain View project ($684million / 1054MW project), which will be owned by a subsidiary of SCE with a bilateral contract to the utility. Although this contract will be FERC regulated, it is possible with the passage of enabling California legislation the plant could become CPUC jurisdiction ratebase. The California legislature is currently contemplating several bills that would address long-term generation planning and regulatory recovery for the California IOUs potential generation investment. While the California legislature is notoriously slow, SCE will be retiring the Mojave plant in 2005, load growth continues, and the DWR contracts wind down by the end of the decade.

Entergy

Figure 30: Entergy Corp.

Subsidiary	State	Rate Case/Plan Status	Allowed ROE	% non-fuel retail revenues	Fuel Recovery
E Arkansas	Arkansas	No case rate pending; mid 2005 would be filing related to steam generator replacement at ANO	11%	25%	Annual reset
E Gulf States*	Texas, Louisiana	Texas – base rate freeze until open access (not expected to occur until 1Q2005) – see below. Louisiana – see below	TX: 10.95% LA: 11.1%	28%	TX: Semi-annual reset LA: Monthly reset with 60 day lag
E Louisiana	Louisiana	Filing made January 2004 – see below	11.30%	26%	Monthly reset with 60 day lag
E Mississippi	Mississippi	Settlement for rate increase for $48.2mm effective 1/2003. Annual formula rate plan; earnings above band shared 50%/50%; next filing 3/2004	10.64% - 12.86%	14%	Quarterly reset
E New Orleans	Louisiana	June 2003, a $30.2mm rate increase under a 2 year formula rate plan was approved.	10.25% - 12.25% (1% adder to ROE band due to generation performance)	7%	Monthly reset with 60 day lag

* Approximately 45% Texas, 55% Louisiana

Source: Company reports, Lehman Brothers

This year we would anticipate most of the regulatory activity will be concentrated in Louisiana. Our estimates do not reflect any impact for Louisiana. **Entergy Louisiana** currently has a settlement that effectively allows it to earn 11.3%. On January 9, Entergy Louisiana filed with the Louisiana Public Service Commission to approve a $167 million increase in its base rates, which uses a 2002 test year and assumes a 11.4% return on equity. In its filing, the company indicated that this increase would be largely offset by a $147 million savings from reduced fuel costs. This filing contemplates recovery of its acquisition of a new 750MW gas-fired combined cycle unit in Perryville, Louisiana from CLECO. A Procedural Schedule was approved by ALJ on March 2, 2004.

June 16, 2004	Staff / Intervenor file Direct Testimony
July 16, 2004	Staff / Intervenor file Cross-Answering Testimony
August 17, 2004	ELI file Rebuttal Testimony
August 31, 2004	Staff / Intervenor file Surrebuttal Testimony
September 14, 2004	ELI file Rejoinder Testimony
Sept. 27 through Oct. 5, 2004	Hearings
November 24, 2004	ALJ targeted Decision date
January 2005	LPSC Decision (Monthly Meeting TBD)

Source: LPSC

Furthermore, **Entergy Gulf States, Louisiana** is in the process of completing its ninth post-Gulf States rate case review (2002). With respect to the ninth review, the company's initial filing included an $11.5 million refund (implemented June 2002), and subsequently late 2003 requested a prospective rate increase of $23 million. The staff in its testimony filed January 2004, recommended a $30 million refund and a prospective rate reduction of $50 million. The company plans to propose a $32 million pro forma adjustment to include revenue requirements related to the Perryville power purchase agreement. Additional testimony is due 1Q04. Hearings related to this proceeding are set for May 2004.

Entergy Gulf States Texas, on January 24, 2003, filed a proposal with the PUC of Texas to open retail competition. With recent approval by the FERC and PUC of Texas of the market protocols for retail access, the company is on track for retail competition by late 1Q05. Hearings at the Texas Commission on transmission independence are set for June 3–4, 2004. Entergy is hoping to get a decision by the PUCT soon after the conclusion of the hearings. If the PUCT approves the transmission independence structure, EGSI-TX can begin its pilot program. After the completion of the pilot program there will be a readiness proceeding to review the pilot to determine when EGSI-TX moves to competition. This timing depends on the pilot program. In addition, the company has filed for state and federal approval of its business separation plan. We give credit for approximately $40 million net benefit from moving to competition in our 2005 EPS estimate of $4.80.

FERC: The company currently has two outstanding cases of importance. One is related to eight contracts that are under review due to affiliate transaction concerns. Hearings are set for June 2004, with an initial decision expected 4Q04. The second was related to cost shifting between Arkansas and Louisiana. On February 6, a FERC ALJ ruled that ETR should reallocate electricity costs among its five subsidiaries in a move that could shift millions of dollars from ratepayers in Arkansas to Louisiana customers. This shift approximates nearly $150 million, pretax. Two rounds of briefs are anticipated by 1Q04. A FERC final decision is not anticipated until year-end. Even with an unfavorable ruling, it is likely that this matter will continue to be tied up in the courts with appeals and counter appeals.

Exelon

Figure 31: Exelon

		Rate Case Timeline		ROE			Equity	% Total	EPS
Subsidiary	State	Filing	Implementation	Last Allowed	When	2002A	2002	2002	2002A
Commonwealth Edison	Illinois	Q1/06	1/1/07	10 yr + 800 bp-L	8/98	13.7%	$5,758	57.1%	$2.43
* S-Indicates settled and L-Indicates litigated									
PECO Energy	Pennsylvania	Q1/10	1/1/11	12.8%	1990	19.0%	$2,519	59.5%	$1.47

Source: Company reports, Regulatory Research Associates

Exelon's distribution rate plan in Illinois ends in June 2006, and regulatory transition charges and shopping credits also expire at utility sub Commonwealth Edison in 2007. Average rates are currently almost $78/MWhr comprised of $26/MWhr for transmission and distribution and the rest covering CTC recovery, a charge that tracks wholesale prices, and an adder. The law calls for a competitive generation auction in Illinois effective for 2007. Whether EXC's earnings from Com-ed decline in 2007 depends on the outcome of the rate case and the competitive auction.

On the distribution side, the company's last allowed ROE as a result of its dereg transition plan was a mechanism tracking the 10-year treasury plus 850 basis points, or about 12.5%–13.0% based on projected 2004 interest rates. We believe that the company will earn around this range for the remainder of the rate plan. This assumes that Com-ed writes-off half of the $4.7 billion of goodwill on its books from the merger with Peco Energy over the 2005–07 time frame. How much of the remaining goodwill is included in rate base will be a topic for this distribution case. The company believes that it can justify a 25% distribution rate increase of $5.00/MWhr, or about $463 million, which will reflect about $5 billion of capital investment since the 1998 rate case. Our work below shows that the increase could produce an ROE of 12% in 2007 using a 50% equity ratio, or $6.1 billion, which is similar to current levels. However, this would mean a reduction in the dividends paid to the parent. In 2003, Com-ed paid just over $400 million to Exelon, which our scenario below shows could be repeated in 2004 but would cease thereafter. For the next several years, the company would accumulate retained earnings. We believe the company has a good argument on the regulated side as it has made significant investment in the system and have the highest service quality in the state. The capital investment could offset the exclusion of goodwill from the rate base. However, every 100 basis points on the ROE is $0.19 per share.

The retail service rate realized through a competitive auction would have to replace the remaining $47/MWhr to maintain earnings power. The Illinois Commerce Commission may opt against the competitive auction and extend EXC's rate plan through a litigated or negotiated process. EXC tried to advance this approach with its offer for Illinois Power but failed. A 1.5x average multiplier of wholesale prices is a rough approximation of retail rates. The company sees relevant around the clock prices of $28.50/Mwhr in 2007, which would translate to $43/MWhr. This compares with the 2004 forward price in MAIN of $26.50 / Mwhr. In this scenario with $43 / MWhr versus $52 / MWhr for the other elements of rates, the net decline would be about $150 million, or a loss per share of $0.30. The Illinois Commerce Commission will begin hosting a related workshop for parties this spring, and we believe a resolution could be discussed late in the year or in 2005.

Figure 32: Commonwealth Edison Summary

($ in Millions)

	2004		2005		2006		2007	
EBIT	1,704		1,725		1,727		1,673	
Interest Expense	401		403		423		468	
Taxes	508		515		509		470	
Net Income	795		806		796		735	
Average Rates								
Wires	$26.00		$26.00		$26.00		$31.00	
Other	$51.80		$51.80		$51.80		$43.00	
Total	$77.80		$77.80		$77.80		$74.00	
Bundled Mwhrs	66,003		67,133		68,284		69,457	
Retail Delivery Mwhrs	87,838		89,383		90,957		92,560	
Operating Cash Flow	$1,220		$1,240		$1,211		$1,132	
Cap-ex	-$700		-$700		-$700		-$700	
Dividends	-$450		$0		$0		$0	
Maturities	-$579		-$806		-$770		-$400	
Other Change in Debt	$500		$1,000		$1,000		$1,000	
Total	-$9		$734		$741		$1,032	
Goodwill	4,711	% Total	3,891	% Total	3,071	% Total	2,251	% Total
Equity	6,236	55.1%	6,222	54.1%	6,198	52.9%	6,112	50.0%
Debt	5,089	44.9%	5,283	45.9%	5,513	47.1%	6,113	50.0%
ROE	12.8%		13.0%		12.8%		12.0%	

Source: Lehman Brothers

FirstEnergy

Figure 33: FirstEnergy

		Rate Case Timeline		ROE				%	
Subsidiary	State	Filing	Implementation	Last Allowed	When	2002A	Equity 2002	Total 2002	EPS 2002A
Cleveland Electric	Ohio	Q3'03	12/05	12.6%	1995	11.3%	$1,226	30.2%	$0.47
Ohio Edison	Ohio	Q3'03	12/05	13.2%	1989	12.5%	$2,840	57.2%	$1.20
Toledo Edison	Ohio	Q3'03	12/05	12.6%	1995	0.3%	$713	40.6%	$0.01
Metropolitan Edison	Pennsylvania	Q1'06	12/07	11.3%	1993	4.8%	$1,315	62.8%	$0.21
Pennsylvania Electric	Pennsylvania	Q1'06	12/07	15.8%	1986	3.8%	$1,353	67.4%	$0.17
Pennsylvania Power	Pennsylvania	Q1'06	12/07	12.9%	1987	19.2%	$229	42.9%	$0.15

Source: Company reports, Regulatory Research Associates

FirstEnergy filed a request to extend its rates in Ohio from 2005 to 2008. FE's proposed a status quo option called the "rate stabilization" plan versus the current law that mandates a competitive generation service auction à la New Jersey's BGS effective January 1, 2006. Key topics of the debate shaping up are the potential for some rate cuts to secure approval, the removal of the distribution rate cap that currently extends through 2007, and recovery of environmental spending. We believe FE can earn in the $3.50 area in 2006 based on the revised proposal. The plan would also be $0.16 per share accretive in 2004 and $0.20 per share in 2005 as a result of changes in the amortization schedule and recovery of carrying charges. If the plan were approved, we would raise our EPS estimates accordingly to $2.81 and $3.05 for 2004 and 2005, respectively.

The key competing parties in the case are the Office of Consumer's Counsel, NOPEC (Northeast Ohio Public Energy Council), industrial customers, and retail marketers. Of note, the OCC and NOPEC filed negative competing positions criticizing FE's proposed Rate Stabilization Charge, which reflects about $900 million in annual revenue at lease initially.

Since FE's initial proposal, the company incorporated some of the parties' comments and issued a revised proposal. Our sense is that this was constructive to the process. Hearings are now completed, and briefs should follow in the second half of March and reply briefs in early April. It is possible that the OPUC could issue a final decision in the case in April.

Rate Stabilization Proposal: A Status Quo Approach

For the most part, the rate stabilization proposal takes the current conditions in Ohio that would have been in place through 2005 and extends that framework through 2008. The law currently calls for a competitive auction to serve customers effective January 1, 2006. While FE's proposal requests that the OPUC choose that option or its rate stabilization plan, the majority of parties are in favor of protecting customers from potential volatility in prices that could come from an auction.

The rate structure would be similar for the most part. It currently includes five components: 1) Distribution; 2) Transmission; 3) Generation Transition Charge (GTC); 4) Regulatory Transition Charge (RTC); and 5) Generation adder or little "g." Under FE's proposal, distribution rates would be frozen through 2007 as they are now, though the rate would include costs of complying with changes in laws or regulations and importantly environmental compliance. Transmission rates would continue to be frozen through 2005, and beginning January 1, 2006 they would be adjustable for FERC-approved rates or charges. Residential customers will get an extension of the 5% generation only rate cut, which is $57 million annually through the stranded cost recovery period which ends in 2010. It had been scheduled to expire at year-end 2005. A monthly residential customer rate credit (dating back to the Ohio Edison / Centerior merger) that amounts to about $70 million also continues through the stranded cost recovery period, as it would have under the current law. FE's proposal calls for these two rate credits to be applied to the RTC.

Generation Transition Charge or GTC. On average, the GTC is worth $15 / Mwhr, or about $920 million per year to FE. FE's proposal eliminates the GTC, but in effect replaces it with a Rate Stabilization Charge at the same level for customers who stay with the company for generation service. Both the GTC and RSC are elements of rates that can be bypassed.

Regulatory Transition Charge or RTC. The RTC will remain in place until kwh sales targets are reached, or when a specific date is reached by the companies. Under the current law, the RTC ends no later than 2010, or full recovery of related costs. By company, it would expire December 31, 2007 for Ohio Edison, December 31, 2008 for Toledo Edison, and December 31, 2009 for Cleveland Electric Illuminating. The charge would be reduced about $130 million annually for the residential credits mentioned above.

Little "g." This is a generation adder under the current law that cannot be bypassed. As it stands through 2005, if a customer chooses a competitive supplier, the customer pays FE little "g," but gets a larger shopping credit. This difference is deferred from an EPS standpoint and the cash is recovered under the RTC though the time value of money is lost. However, FE has earnings exposure currently if the company resells power at a lower rate than "g." FE's proposal calls for "g" to be adjustable starting January 1, 2006 for costs of supply such as fuel, emission allowances, nuclear security, etc. However, there would be caps as described below.

It is also worth noting that the PUCO has the option of terminating FE's rate stabilization plan if an annual test followed by a hearing produces a determination that it is in the customers' best interests to move to a competitive auction. The PUCO would have to give one year's notice prior to termination.

Key Differences Under the Rate Stabilization Approach

Differences include incentives to sign one- to three-year contracts with retail marketers, capping / levelizing of shopping credits, lower stranded cost recovery revenue, and changes to transition cost amortizations.

More deals offered to customers for competitive generation service. In FE's original proposal, the company provided commercial and industrial customers the option to sign a three-year contract from 2006 to 2008, which would have allowed them to bypass 65% of the RSC (Rate Stabilization Charge, or $17 / Mwhr on average). In other words, their shopping credit would be the relevant generation charge (little "g") plus 65% of the RSC. Under FE's proposal, commercial and industrial customers could sign on for one to three years depending on the time remaining in the market development period. The level of RSC that can be bypassed would increase each year from 65% in 2006, 75% in 2007, and 85% in 2008. Foregone RSC rises to 100% if customers are willing to refuse all safety backstops. Conceptually, the RSC is the price that the customer pays for being able to return to FE for service at the standard offer following a six-month market price period. Without it, customers would be fully subjected to market prices if their aggregator defaulted.

Shopping credits capped. The maximum credit varies by customer class. It is $50–$52 / Mwhr for residential, $45.47 / Mwhr for commercial customers, and $34.55 / Mwhr for industrial customers. The company proposed these maximum credits to address inequities in the rate structure across customer classes and the company's three Ohio subsidiaries. Across FE's system, the average we estimate the maximum credit is in the mid-$40 / Mwhr area and a bit lower overall.

Potential to Receive Lower RSC / Stranded Cost Recovery. The increased flexibility for customers to sign contracts means that there would be greater customer migration to competitive suppliers over time. For FE, that means a reduction in RSC and more exposure to reselling power at market prices. As it stands, FE has achieved more than 20% "Customer Choice" in part due to providing retail marketers access to its generation. In fact, if FE's proposal were adopted, the company would have to provide generation access to competitive suppliers in any customer class that did not achieve the 20% shopping benchmark. To some extent, we think customers (smaller customers especially) will still remain sticky. However, every 20% of customers that choose competitive suppliers is roughly $260 million of foregone RSC, or about $0.50 per share of NPV. For illustration, if 60% of customers remained with FE for service and 40% went to competition and elected no emergency backstop, the NPV of RSC would be about $3.80 per share. Under FE's proposal, we think it is reasonable to assume that RSC would still provide $3.00–$4.00 / MWhr of NPV over 2006–08.

FE's revised proposal also includes a smaller window for RSC recovery. Specifically, it reduces the level of 5.1 MMwhrs for Cleveland Electric Illuminating and 6.5 MMwhrs for Toledo Edison. This reduces cumulative stranded cost recovery by $125 million on a net present value basis. This adopts Commission Staff's proposal to adjust stranded cost recovery levels.

Revised Amortization Schedule. We do not include the benefits of FE's amortization schedule changes in our EPS estimates. We would include the benefits with a final order. The proposed changes would be EPS neutral over their life and are more accretive in 2004 and 2005 and noticeably dilutive in 2007.

Figure 34: Rate Stabilization Amortization Schedule ($ Millions)

		Ohio Rate Proposal		After-Tax	EPS
Year	**Current**	**Initial**	**Revised**	**Change**	**Change**
2004	$786	$705	$729	$35	$0.11
2005	$913	$813	$833	$50	$0.15
2006	$378	$365	$381	-$2	-$0.01
2007	$213	$300	$314	-$63	-$0.19
2008	$162	$193	$154	$5	$0.02
2009	$44	$120	$85	-$25	-$0.08

Source: FirstEnergy

Commission Staff's Exceptions to FE's Proposal

It is worth mentioning the key elements of Staff's proposal, as we believe FE's revised proposal addressed a number of these items.

Elimination of FE's proposal for early termination of the plan if 250 MW is removed from service due to environmental regulations. The Staff disagrees and wants the company to bear this risk.

Potential reduction of the 35% of the "RSC" paid by those who choose alternate power suppliers by December 31, 2004. Staff believes that customers have the option to reduce or eliminate their RSC charges by foregoing some or all of their rights to return to the utility for service.

A Cap on Deferral of Expenses. FE proposes that rates be adjustable through the little "g" portion by up to 15% for cost increases such as fuel, emission allowances, and nuclear security. FE also asks for amounts in excess of 15% to be eligible for deferral and recovery. Staff's proposal would cap the recovery at 15% of "g."

End to the Distribution Rate Freeze January 1, 2006. This is two years early, though the proposal may be driven more by rate design rather than a concern about excessive earnings. Staff has concerns about tracking the company's level of expense deferrals based on rates that were set 16 years ago. Staff would be more open to deferrals if it had a better sense of what expenditures are in rates. FE believes that the company is under-earning on a distribution basis. Our discussions with Staff indicate that it does not have the opinion that FE is over-earning. In fact, it would not be surprised if the company is under-earning. However, it is early to consider what would qualify for rate relief versus deferral treatment.

Maintain Status Quo on Deferrals Related to Customer Migration to Other Suppliers. FE proposes to defer and recover a larger margin that is the difference between the shopping credit and "g." FE currently defers the difference between the shopping credit and the market support price.

Earnings Outlook

We believe FE can earn in the $3.50 per share level in 2006 on the company's revised proposal. The key drivers to 2006 EPS are the year-over-year reduction in amortization as well as schedule changes and earned RSC revenue as it replaces foregone GTC revenue. These items are offset by continuation of the residential rate cuts and potential customer migration to competitive suppliers.

FPL Group

Figure 35: FPL Group

Subsidiary	State	Rate Case/Plan Status	Allowed ROE	Fuel Recovery
Florida P&L	Florida	Revenue sharing rate plan that extends through December 2005 – see below	Not applicable	Annual reset

Source: Company reports and Lehman Brothers

Mid-2005, **Florida Power & Light** is prepared to file both a traditional rate case and incentive based rate plan. Historically, the Florida Commission has encouraged negotiated settlements, and the company has been successful in achieving settlements with the Staff, OPC, and other significant intervenors. In a settlement, the company may seek a similar tenor of three or more years and a plan with self-correcting mechanisms (i.e., to adjust for inflation, pensions, health etc) together with mechanisms to enable sharing of higher revenues with customers instead of self-regulation of over-earnings. We would anticipate that timing of such a rate case / settlement would also likely address the mid-2005 operation of two power plants (Martin and Manatee) totaling 1900MW (approximately $1.1 billion of capital investment).

Just for reference, the last rate case called for:

base rate reduction of $250 million annually;

revenue sharing mechanism (one-third to shareholders / two-thirds to customers if exceed certain revenue threshold amounts for calendar year 2003, 2004, and 2005 of $3,680 million, $3780 million, and $3,880 million, respectively).

Annual depreciation credit of $125 million.

NiSource Inc.

Figure 36: NiSource, Inc.

Subsidiary	State	Rate Case Timeline Filing	Implementation	ROE Last Allowed	When	ROE 2002A	Equity 2002	% Total 2002	EPS 2002A
Columbia Gas of Ohio	Ohio	Late 2003 / Early 2004	2005	No Cap	1999	25%	$ 437	49%	$ 1.82

Source: Company Reports and Lehman Brothers

In October 2004, Columbia Gas of Ohio comes off the base rate freeze and Customer Choice program that was agreed in December 1999. While NI is seeking to extend the Customer Choice program and the rate moratorium, we believe this jurisdiction bears watching as it is the largest in EPS and ROE earned. We expect the stipulation filed with the PUCO in late 2003 will undergo change when it likely sees a final vote during March 2004. We expect the changes to include the following: 1) shortening the duration from 2010 to 2007 and 2008; 2) lowering the pipeline capacity contracting to 80%-plus from the company's proposal of 100% in 2005 and 95% thereafter, and 3) disallowing the deferral of post in service operating expenses.

In 2002, Columbia Gas of Ohio earned a 24.6% ROE on a 49% equity ratio and therefore strikes us as vulnerable to regulatory process regardless of the success of the Customer Choice program (we estimate every 100 basis points of adjustment is worth approximately $0.02 per share). Beyond Ohio, Columbia Gas of Pennsylvania strikes us as the only other long-term exposure where the company earned an 18.5% ROE in 2002. We are not aware of any regulatory process to interfere with returns in Pennsylvania, but note that every 100 basis points of adjustment is worth approximately $0.01 per share. In conclusion, rightsizing the Ohio and Pennsylvania ROE levels toward the current interest rate environment (11% ROE), we see total EPS exposure in 2005 of approximately $0.30 per share.

Beyond the state regulatory issues, we are monitoring the pipeline firm service contract process during 2003 and 2004. Specifically, the majority of NI's gas transmission pipelines are undergoing recontracting on capacity re-subscription with gas local distribution companies during 2004. As the vast majority of NI's gas transmission pipes are already receiving maximum tariffs and approximately two-thirds of the capacity is sold to NI LDCs, we do not see any potential upside. That said, we will continue to monitor the risk presented by state regulators evaluating the cost recovery of pipeline capacity costs in general rate case proceedings.

Northeast Utilities

Figure 37: Northeast Utilities

Subsidiary	State	Rate Case Timeline Filing	Rate Case Timeline Implementation	ROE Last Allowed	When	ROE 2002A	Equity 2002	% Total 2002	EPS 2002A
Public Service Co of NH	New Hampshire	1/04	Q4/04	15.0%-L	1987	20.9%	$322	44.2%	$0.52

** S-Indicates settled and L-Indicates litigated*

Source: Company reports, Regulatory Research Associates

NU has been involved in two rate cases: one in New Hampshire which was filed in late December and one in Connecticut where there was a decision on December 18.

New Hampshire. NU filed its New Hampshire rate case, which requested a $21 million (2.6%) distribution rate increase and an 11.2% ROE. The rate filing is generally in line with expectations. NU's request assumes an increase in capital and makes adjustments for one-time items in the test year, which is the 12 months ended June 30, 2003. Regarding the capital structure, the PSNH rate request assumes $400 million of pro forma equity, which is 47.8% equity/capital (45% on a rating agency basis). The equity total assumes the NU parent made a $30 million contribution to PSNH in

December 2003 and makes another $30 million in 2Q04. PSNH also assumes a $50 million debt issuance in 2004. NU argues that this will maintain the BBB+ credit rating.

The relevant financials for the test year are $57.8 million of net income, or a 17.0% ROE and $50.9 million at 14.4% for the 12 months ended September 30, 2003. Excluding one-time items, which NU argues contributed $7.9 million and $6.1 million, respectively, the relevant ROEs are 15.1% and 13.3%. The one-timers include regulatory assets and storm reserves. Including NU's pro forma adjustments, the rate request implies $45 million of net income. Our outlook assumes an 11% ROE on the $337 million actual equity, which produces $37 million of net income. The deficit to NU's request is a loss per share of $0.06. Based on other, recent rate case outcomes in the Northeast, a 9.5%–10.5% ROE outcome is more likely. Every 100 basis points difference in the allowed ROE on the test year equity base is $0.03 per share.

Overall, NU identifies a $27 million revenue deficiency. Of this total, $6 million relates to distribution assets currently recovered in FERC transmission rates for which NU does not seek recovery. PSNH breaks down its rate request into four main categories: increased depreciation expense ($6 million), transmission and reliability expenses ($6 million), pension expense ($4 million), and several other adjustments ($5 million) including regulatory assets.

NU also requested relief from two rate case filing requirements. The first includes filing of financial reports as the company already makes the filings, segmentation of data on a business unit basis, a detailed list of charitable contributions, and payments in excess of $50,000 for individuals and corporations for contractual purposes. The company also requests that tax filing requirements be met through FERC Form 1 filings, versus a separate filing with the New Hampshire Commission.

Highlights of the schedule include intervenor testimony due May 28 and hearings from August 2–6. There are also scheduled settlement discussions May 12–13, June 29–30, and July 20. There is also a tentative date for filing a settlement on July 27. However, we have no reason to believe at this early stage that this process is more likely settled than litigated.

Connecticut. The company received a decision in Connecticut on December 18, which was in line with expectations and included a 9.85% allowed ROE. The allowed ROE of 9.85% compares with our 10.25% forecast and the company's 10.75% request. The company also received an earnings sharing mechanism. Earnings in excess of its allowed ROE would be shared evenly (50 / 50) with customers. In addition, the company essentially received its requested capital structure, which included a 47.22% equity ratio. This was more constructive than our 41% forecast.

The company received a distribution rate reduction of -$1.9 million for 2004 and increases of $23 million in 2005, $35 million in 2006, and $42 million in 2007. The company will also get to use $130 million of over-recoveries to supplement the relief, with roughly offsetting depreciation adjustments. On the transmission side, the company received $28.4 million of rate relief up-front that includes a potential transfer of $10.5 million of Hydro Quebec costs, however, the company did not receive the requested "transmission tracker" for new projects. The Connecticut DPUC decided that the charges for the transmission intertie linking New England with Quebec, Canada should be recovered in the retail transmission rate. This should be recoverable in the end but would be through a different proceeding. The company's transmission rate relief compares with the proposed level of $16.9 million in 2004, another $19.9 million in 2005, $14 million in 2006, and a reduction of -$3.4 million in 2007.

Overall, the outcome seems mixed. While the DPUC granted an ROE sharing mechanism and a fair capital structure, the allowed ROE was weak, there was no transmission tracker, and the outcome is a bit better from an earnings than cash perspective. Our $1.25 2004 EPS estimate would assume the company can earn its allowed ROE. Last, it is also worth remembering that the company receives a 0.5–0.75 mill adder for power procurement, or $0.06–$0.09 per share that is not a part of this proceeding.

OGE Energy

Figure 38: OGE Energy

Subsidiary	State	Rate Case/Plan Status	Allowed ROE	Fuel Recovery
Oklahoma Gas and Electric	Oklahoma	Rate case settlement approved November 2002; Follow on prudency review upon mid-year announcement of plant acquisition – see below	11.55%; equity of 56%	No more than quarterly reset

Source: Company reports and Lehman Brothers

The company late last year in its settlement with the Commission agreed to the following main features:

Immediate base rate reduction of $25 million;

Phase-in of at least $75 million additional rate reductions (annualized $25 million) through fuel savings over a 36-month period (by December 31, 2006);

Upon prudency review, rate basing of 400+MW generation to serve retail load and replace purchased power contract expiration(s).

Oklahoma Gas and Electric, last year announced its acquisition of NRG's 400MW single unit plant. The equity tranche for the plant came in August 2004. The debt was to be financed upon approval from the Oklahoma Commission to rate base the plant. The company had filed for approximately $90mm rate increase to account for rate basing this acquisition and other rising costs. However, in a surprise decision, the Federal Energy Regulatory Commission, which has authority over wholesale asset sales, postponed approval of the acquisition due to market power concerns. As it stands, the company has a FERC hearing scheduled for August 3, 2004, regarding its proposed acquisition of McClain. The company filed a petition on January 20 with the FERC for reconsideration of a newly submitted mitigation plan. Should that be denied, the company does not anticipate a settlement with the intervenors, which would cause the case to go its full course with likely ruling by year-end. On January 15, OGE also filed with the OCC to withdraw its retail rate increase until there is final resolution or order from the FERC on its acquisition of the plant. The OCC approved this request at the end of January.

Meantime, as a result of this FERC delay, the company now has a related proceeding in front of the Oklahoma Commission. On January 8, the company filed to seek technical clarity from the Oklahoma Commission that the company is in compliance with its 2002 Rate Stipulation to deliver prescribed savings ($2.1 million per month). In other words, the company wants confirmation that savings coming from a purchased power contract with McClain is equally acceptable to delivering the savings from an outright acquisition of McClain, which they wereit was unable to close by year-end 2003. Hearings are scheduled April 19. Both the OCC Staff and Attorney General's office testimony implied that the company is in compliance with its Stipulation to deliver customer savings regardless of not having outright ownership of McClain by 2003. A final order could be received in 2Q.

Another proceeding exists in front of the OCC related to a filing by Smith Cogeneration requesting the Ccommission to extend a110MW purchased power contract with Oklahoma Gas, which is scheduled to expire in August 2004. Finally, the company also anticipates filing in April a cost of service rate case with the Ccommission for its Enogex gas transportation contract with anticipated completion by 3Q.

Pepco Holdings

Figure 39: Pepco Holdings

Subsidiary	State	Rate Case Timeline: Filing	Rate Case Timeline: Implementation	ROE Last Allowed	When	ROE 2002A	Equity 2002	% Total 2002	EPS 2002A
Atlantic City Electric	New Jersey	9/02	Q4'03	12.5%-L	7/91	9.5%	$619	34.1%	$0.36

** S-Indicates settled and L-Indicates litigated*

Source: Company reports, Regulatory Research Associates

The company has a New Jersey rate case. POM originally filed for a $68 million rate increase, which reflected a 12.5% ROE and 45% equity ratio. Of this request, $63 million related to distribution rates and $5 million for recovery of regulatory assets. As a result of the discovery process, the company has updated its request to $73 million, including about $37 million for distribution rates, which appears to reflect an 11.0% ROE. The balance of the rate request relates to cash and not earnings items. We had been assuming a 10.25% ROE in our $1.45 2004 EPS estimate, although the 9.75% and 9.5% allowed ROEs that PEG and FE received are probably not a bad gauge for what POM will get. This makes sense since the company was able to earn a 9.7% ROE on a GAAP basis in 2002. The next step ahead is hearings in March, and we expect a final outcome midyear that would be retroactive to January 1, 2004.

PG&E Corp.

Figure 40: PG&E Corp.

Subsidiary	State	Rate Case Timeline Filing	Implementation	ROE Last Allowed	When	ROE 2002A	Equity 2002	% Total 2002	EPS 2002A
Pacific Gas & Elec	Calif	Q103	Jan-03	11.22%	2002	11.22%+	$ 3,821	48%	$ 1.91

Source: Company reports and Lehman Brothers

The primary regulatory focus for PG&E Corp is the 2003 General Rate Case (GRC) at Pacific Gas & Electric. The California Energy crisis has returned CA IOU's to vertically integrated cost of service regulation, and therefore the company is seeking rate relief in all portions of the business (electric & gas distribution and utility retained generation).

Pacific Gas & Electric has entered a comprehensive settlement with the major intervening parties and is awaiting an ALJ PD (anytime) and thereafter a final PUC decision. The settlement includes: 1) a $236 million electric distribution increase and $52 million gas distribution increase and a $38 million electric generation increase; 2) no rate review until the 2007 test year; 3) attrition revenues would be authorized for 2004–06; 4) a future cost of capital decision could have an impact on rates (but is not eligible for adjustment until A credit ratings are achieved per the Chapter 11 settlement).

A longer-term but very important issue to monitor is the utility's procurement strategy and the direction of direct access in California. While the legislature (AB 57) and the CPUC have maintained constructive positions since late 2001, the management of energy procurement and cost recovery remains an important issue for CA IOU's as the net open position grows with the passage of time. We will continue to monitor the CPUC's approach to long-term procurement and prudent cost recovery principles to ensure the utilities are returned and remain investment-grade credits. The status of direct access will be an important determinant of the short side of the company's portfolio, and several bills (SB 888 and AB428) are currently lingering in the state legislature.

Pinnacle West Capital

Figure 41: Pinnacle West Capital

	Rate Case Timeline			ROE Last				% Total	
Subsidiary	State	Filing	Implementation	Allowed	When	ROE 2002A	Equity 2002	2002	EPS 2002A
Arizona Public Service	Arizona	Jun-03	Late 2004 / Early 2005	No Cap	1999	11.22%+	$ 2,159	45%	$ 3.56

Source: Company reports and Lehman Brothers

The primary regulatory focus for Pinnacle West continues to be the 2004 General Rate Case (GRC) at Arizona Public Service (APS). APS is seeking a $175 million rate increase and a final decision is not expected until late 2004 or early 2005, absent a settlement. The ACC staff recently filed a position advocating a $142 million rate decrease that included a 9% ROE, 45% equity ratio, zero ratebaseing of PWEC plants, and no fuel clause.

We expect the GRC to begin in a fully litigated fashion and the prospect of a settlement will only develop after the hearings are under way. Given the company's history of ratepayer / shareholder friendly settlements and the complex nature of this case, we believe a settlement is the most likely outcome to this GRC. That said, we believe the wide gap between ACC staff and the company position has downward shifted the bid-ask spread of a settlement.

At issue in the GRC will be the following major elements: 1) rate base determination including recovery of prior competition costs and write-offs; 2) potential ratebasing of PWEC assets (Redhawk 1&2, West Phoenix 4&5 and Saguaro); 3) cost of capital and 4) reestablishment of a fuel clause.

The traditional distribution and generation APS rate base of $3.3 billion (including the recovery of prior period charges) will be subject to the ROE / equity ratio determination where we see $0.08 per share of EPS sensitivity for every 100 basis points.

In addition to the historical vertically integrated utility asset base, PNW will seek to ratebase portions of the PWEC merchant assets (approximately $895 million of ratebase potentially). The PWEC assets were built in merchant form and outside APS due to the 1999 regulatory settlement, and the competition rules although they were intended to serve the APS retail base and secondarily dispatch wholesale. In order to move the PWEC assets into ratebase, APS will likely need to justify that the PWEC assets offer the lowest cost and most reliable source of power to serve APS customers. We believe the West Phoenix assets are an obvious inclusion in ratebase, while the Red Hawk units could be more easily debated. The ratebasing of PWEC has important EPS implications, as the range is flat to $0.55 per share.

In both the 1996 and 1999 regulatory settlement's, APS managed to avoid a cap on ROE by offering customers rate stability and gradual rate reductions on an annual basis.

We would suspect APS will seek to preserve the same flexibility through a settlement, as the current interest rate environment could set up for a fairly low ROE outcome.

The current schedule (which keeps changing) is as follows: 1) APS rebuttal testimony due March 30, 2004; 2) ACC staff and intervenor surrebuttal testimony due on April 30, 2004; 3) APS rejoinder testimony due May 14, 2004; and 4) hearings begin May 25, 2004.

PPL Resources

Figure 42: PPL Resources

		Rate Case Timeline		ROE Last		ROE	Equity	% Total	EPS
Subsidiary	Location	Filing	Implementation	Allowed	When	2002A	2002	2002	2002A
PPL Electric	PA	Q104	01/01/05	11.50%	1995	6.1%	$ 1,147	45%	$ 3.54
Western Power Distribution	United Kingdom	6/30/2004	4/1/2005	8.6% pretax	1999	17%	$ 300	8%	$ 3.54

Source: Company reports and Lehman Brothers

PPL is facing two major regulatory cases during 2004 with new rates to be effective for 2005. Pennsylvania Power and Light (PP&L) will be filing in PA/FERC for distribution/transmission increases, while the WPD property in the United Kingdom will be going through the five-year U.K. rate review process beginning in March 2004.

PP&L's $2.2 billion of regulated ratebase is currently operating under a T&D rate freeze ($17.40/mwhr) that expires on January 1, 2005. As a result of the freeze and rising cost pressures, PP&L is earning a 4%–5% ROE on the regulated utility business. We expect PP&L will likely seek $50million-plus of cost recovery at the FERC for transmission expenses and could request an equal amount at the PA level (we will watch this filing closely as the ultimate number is likely capped by local politics). We are projecting $60 million of combined rate relief, which should raise the utility EPS by approximately $0.20 annually. We expect an initial company filing at the end of 1Q and a final PAPUC determination during late 2004 as new rates become effective January 1, 2005.

In the U.K. process, the operative question is how much of an EPS hit will be sustained in the regulatory review. The upcoming review will set rate structures beginning April 1, 2005 and likely extend for another five years. While reliability and therefore capital adequacy have gained regulatory attention in the United Kingdom, we suspect the regulatory review will nonetheless extract some flesh up front and allow the companies to earn it back through capital and operational efficiencies in the ensuing five years. If we assume WPD's $2.2 billion RAV is allowed a 7.5% pretax return, we see approximately $0.20 of EPS downside annually from WPD.

The initial look at cost of capital ranges, etc., will be the week of March 22, when OFGEM makes an initial release on the electricity review. Initial company proposals will follow in June 2004 with a final outcome in November 2004. New rates will become effective April 1, 2005 assuming no referral to the Competition Commission.

Progress Energy

Figure 43: Progress Energy

Subsidiary	State	Rate Case/Plan Status	Allowed ROE	Fuel Recovery
Progress Energy Florida	Florida	Revenue sharing rate plan that extends through December 2005 – see below.	Not applicable unless falls below 10%	Annual reset
Progress Energy Carolinas*	North and South Carolina	NC: Base retail rate freeze through December 31, 2007 related to NC Clean Air Act (reduce NOx and SOx levels). 70% of capital costs (~$570mm) is to be amortized by end of freeze period, with an annual maximum of $174mm.	Not applicable in NC; 12.75% ROE in SC	NC: Annual reset SC: Annual reset
		SC: Base retail rate cap through December 2005 – see below.		

*15% South Carolina; 85% North Carolina

Source: Company reports and Lehman Brothers

Progress Energy Florida's settlement followed on the heels of Florida Power and Light and consequently had many of the same features. The settlement called for:

Annual base retail rate reduction of $125 million

Revenue sharing mechanism (one-third shareholders, two-thirds customers); the threshold amounts for 2003, 2004, and 2005 are $1,333 million, $1,370 million, and $1,407 million, respectively.

Annual depreciation credit of $62.5 million.

We would anticipate that a settlement rather than a full-blown rate case would be the ultimate outcome when the current plan expires. We would anticipate the company would simultaneously address the addition to rate base of approximately 1,200 MW of capacity in Florida by 2005 (approximately $420 million total capital investment). We believe that while Progress Energy Florida has different issues from Florida Power and Light (subsidiary of FPL Group), it is likely that an incentive-based mechanism would be applied similarly for both entities in Florida, and we would recommend watching an outcome from Florida Power and Light. Progress Energy management has also indicated an interest in announcing an incremental plant acquisition in Florida to add to rate base to meet growing retail load needs. It is too early to determine if timing would be simultaneous with the expiration of the current Florida plan.

Progress Energy South Carolina currently has no statutory date by which either it or intervenors would file for a rate review and / or plan. Meantime, by 2005, the company will have added approximately 300MW (160 MW of a peaking capacity at its

Richmond plant and approximately 140 MW of nuclear uprates at its Robinson nuclear plant) to its South Carolina rate base. Again, we would expect if a rate proceeding was initiated, this incremental capacity would likely be addressed in a final outcome.

Puget Energy

Figure 44: Puget Energy

		Allowed ROE		2003A			
Utility Subsidiary	**State**	Last	Year	ROE*	Equity	% Cap	EPS
Puget Sound Energy	Washington	11.00%	2002	7.98%	1,559	40%	$1.25

**Financial basis*

Source: Company reports and Lehman Brothers

In June 2002, the WUTC granted final regulatory approval of a comprehensive electric and gas rate settlement with Puget Sound Energy (PSE), the electric and gas subsidiary of Puget Energy. The settlement provided for an 8.76% overall return on capital, an authorized return on common equity of 11.00%, and a pro forma capital structure that assumed a 40% equity component (compared with an equity ratio of 30% at December 31, 2001). As part of this settlement, PSE agreed to achieve minimum equity targets of 34%, 36%, and 39% at year-end 2003, 2004, and 2005, respectively. PSE must maintain, at least, a 39% equity ratio until the conclusion of its next general rate case. If the company fails to achieve a target threshold, the WUTC will reduce PSE's overall general electric and gas rates by 2% for a one-year period. The settlement also approved the adoption of an electric power cost-adjustment mechanism.

General Rate Case Expected in 2004

PSE plans to file a general rate case (GRC) in 1Q04 to increase its electric and gas rates, which will include a request for a pro forma common equity ratio of 45% and an ROE of 11.00% or more. The company's October 2003 $100 million equity transaction with Franklin Advisers Inc. may help in obtaining the 45% equity capital structure. A fully litigated rate case would take 11 months to complete, with rates not effective until 1Q05. Thus, the company likely would seek to settle the case, as it did in the 2002 rate case, sometime during 2004.

Power Cost Only Rate Case

Under the 2002 GRC settlement, PSE can initiate a power cost only rate proceeding to add new generation to the Power Cost Rate (PCR). Upon filing with the commission, hearings would be set to review the appropriateness of adding the new resource costs to the PCR. These hearings will consider only power supply costs included within the Power Cost Rate, and will be completed within four months. The WUTC will issue an order within 30 days following the hearings. The objective of the accelerated process is to have the new Power Cost Rate in effect before the new resource goes into service. This single-issue rate case would not address GRC items, such as the distribution rate base, ROE, or equity structure. Thus, the new resource would presumably go into the rate base with the same 11% ROE and 40% pro forma equity component as outlined in the June 2002 settlement.

On October 22, 2003, PSE announced the acquisition of a 49.9% interest in the Frederickson 1 power plant, a 249 MW combined-cycle, natural gas-fired facility that is in the process of expanding to 275 MW, for $80 million (or $584/Kw). The plant is relatively new, having begun operations in August 2002, and is strategically located in Pierce County, which is central to the company's service territory. PSE filed a power-cost only rate case (UE-031725) on October 24, 2003 for a $64.4 million rate increase.

Staff Recommendation

On January 30, 2004, the WUTC staff filed testimony in PSE's Power Only Rate Case. Although the staff found that the acquisition of the interest in the Frederickson 1 plant was prudent and appropriate to include in rates, it recommended: 1) an increase in rates of $7.5 million based on fuel cost disallowances related to the company's Tenaska and Encogen power projects and 2) the elimination of an "out" clause in the purchase contract for Frederickson 1, which allows PSE to terminate the contract if it does not receive WUTC approvals.

The differential between the staff's recommendation and the company's proposal was primarily due to $33 million of fuel disallowances related to the Tenaska and Encogen power plants and a $12 million prudence review adjustment for the Tenaska acquisition. Staff contends that when PSE bought out the fuel supply contracts for Tenaska in 1997 and Encogen in 1999 that the company committed to reduce the cost of these projects to ratepayers through lower gas costs. Instead, staff believes that, the company's fuel procurement actions have resulted in an increase in the cost of these resources. With respect to the prudence review adjustment, staff appears to have imposed a fixed cap on future recoverable costs for the Tenaska purchase versus a calculation based on a percentage factor methodology.

PSE filed rebuttal testimony on February 13 and the WUTC held hearings during the week of February 23. The remaining procedural schedule in the case is summarized in Figure 45.

Figure 45: PCORC – Remaining Procedural Schedule

Event	Date	Interval
Simultaneous Initial Briefs	March 12, 2004	14 days
Simultaneous Reply Briefs	March 19, 2004	7 days

Source: Company reports and Lehman Brothers

The company expects a final order by mid-April, assuming no delays. If the transaction closes during this time and was to be approved as filed, the company expects the acquisition to be accretive to 2004 earnings by about $0.02 per share.

PSE filed a '203' request with the FERC on January 14 and asked for a decision on or before March 25, 2004. According to the company, the application is on track to meet this deadline. We do not expect to see a repeat of the OGE/McClain issues as the Bonneville Power Administration owns most of the transmission and generation in the region and Frederickson is not interconnected to PSE's transmission system.

Sempra Energy

Figure 46: Sempra Energy

Subsidiary	Location	Rate Case Timeline Filing	Rate Case Timeline Implementation	ROE Last Allowed	When	ROE 2002A	Equity 2002
SDG&E	CA	2003	01/01/04	10.82%	2003	6.1%	$ 1,150
So Cal Gas	CA	2003	01/01/04	10.90%	2003	17%	$ 1,350

Source: Company reports and Lehman Brothers

Both San Diego Gas & Electric (SDG&E) and Southern California Gas (SCG) are undergoing a general rate case process during 2004. During December 2003, both subsidiaries announced settlements that would reduce rates by $17.8 million and $33 million from current rate levels, respectively. The settlement will likely have a four- to five-year duration and allow the company to harvest operational and capital cost savings throughout the settlement period. A lack of hard ROE caps as the company operates on a floating cost of capital mechanism should allow the subsidiaries to earn outsized ROE's as historically has been the case. The settlements have been proposed to the CPUC and the company is awaiting a proposed decision (PD) by April and hopefully a final decision by June. While the settlements could be adjusted, we expect the strong consumer group support (all major groups except UCAN) should translate into no material alternation.

The aforementioned settlements do not cover the subsidiaries' long-standing performance-based ratemaking mechanisms or attrition revenue adjustments. The PBR's and attrition adjustments have been separated into a different docket (Phase II) and will likely be addressed during 2H04 by the CPUC. We would expect the mechanisms to continue in the future, but the benchmarks are likely to be tightened and therefore reduce the potential shareholder benefits in the near years. As for historical PBR awards, the company continues to await decision on approximately $48 million of prior year awards. Finally, the duration of the settlement will be decided during Phase II and could limit the ability of the utilities to announce cost savings as Phase II will likely not be decided until late 2004.

SRE has filed to expand ratebase generation at SDG&E through the Palomar project. Palomar will be built at Sempra Resources and sold to SDG&E upon completion. The 500 MW Palomar project and associated transmission facilities will approximate $475 million of total capital expenditures. The project will likely receive AFUDC treatment and begin adding to EPS in late 2004 with full annualized contribution of approximately $0.12 per share in 2006. We would expect approval by the CPUC during 2004 to facilitate construction.

Sierra Pacific Resources

Figure 47: Sierra Pacific Resources

Subsidiary	State	Rate Case Timeline Filing	Implementation	ROE Last Allowed	When	ROE 2002A	Equity 2002	% Total 2002	EPS 2002A
Nevada Power	Nevada	Early 10/03	180 Days Post	10.10%	2002	-20%	$ 1,149	36%	$ (3.00)
Sierra Pacific Power	Nevada	Dec-03	180 Days Post	10.17%	2002	-3%	639	37%	$ (3.00)

Source: Company reports and Lehman Brothers

The Nevada regulatory environment continues to improve, but the company's structural short position, historical test year regulation, rapidly growing service territory, and rising operating costs make for ongoing challenges. We believe the replacement of Commisioner McIntyre with Commisioner Linvill will enhance the improving regulatory trend, but it appears the Nevada utility subs are likely to experience a slow heal as opposed to a quick regulatory fix.

As usual, SRP has a deferred energy and general rate case ongoing at both Nevada Power (NVP) and Sierra Pacific Power (SPPC). The company continues to underearn the allowed ROE due to rising cost pressures and deferred energy is a practical reality with the company's structural short position in one of the nations most volatile commodity markets.

At NVP, the company filed for a staggered $133.5 million GRC rate increase. NVP sought $50 million effective April 1, 2004 and the balance plus carrying cost effective January 1, 2005 in order to avoid customer rate shock. The PUCN staff supplied testimony only supporting a $17 million increase with depreciation schedules, goodwill disallowance, lower ROE and redirection to FERC on transmission rate base as the primary differences. Given the historical PUCN pattern, we would expect the revenue requirements to land closer to PUCN staff than the company's request. On deferred energy, NVP filed for a $93 million increase to be effective April 1, 2004. The PUCN staff filed testimony supporting a $79 million increase, and again we would expect a final decision closely mirroring PUCN staff testimony. The final decision on the GRC and deferred energy cases will be March 24 with a draft order on March 23.

At SPPC, the company filed for a $95 million GRC rate increase and no incremental deferred energy hike. Staff and intervenor testimony is due on ROE (March 11) and revenue requirements (March 12–25), and we would expect the same levels of ROE and revenue requirements adjustments to present in that testimony. The hearings are scheduled for April with a final decision in May or June.

The pursuit of Performance Based Ratemaking (PBR) is certainly a positive step for Nevada and one that would become all the more worthwhile if the utility subs could start by earning the allowed ROEs. Based on a history of earning at least the allowed ROE, we believe PBR would present a reasonable opportunity at SPPC. While a PBR may ultimately make sense at NVP, we think the company should just focus on turning what appears to be a liability into an asset (the rapid growth) by mitigating the regulatory lag that has seemingly lead to a history of underearning.

Southern Company

Figure 48: Southern Company

Subsidiary	State	Rate Case/Plan Status	Allowed ROE	% utility revenues	Fuel Recovery
Georgia Power	Georgia	3 year retail rate order through December 31, 2004; filing due 7/1/04 – see below	10% -12.95%; sharing above the band	46%	At its discretion, company can file for fuel reset on as needed basis
Alabama Power	Alabama	Rate Stabilization Equalization Plan in place which allows for annual adjustments up to 3% p.a. to adjust for earnings below band; Certified New Plant (CNP) Plan that allows for rate base increases for new plant and purchase power agreements in services	13% - 14.5%	35%	At its discretion, company can file for fuel reset on as needed basis
Mississippi Power	Mississippi	Annual Performance Evaluation Plan (PEP) in place; various performance criteria allows earning potential above the band. $11mm net base rate increase 1/2002 for plant addition	10.75% - 12.75%	8%	Annual reset
Gulf Power	Florida	No rate case pending; $53mm base rate increase 6/2002 related to new plant	10.75%-12.75%	8%	Annual reset, with potential for mid-course revision due to 10% variance at discretion of company
Savannah Electric	Georgia	No rate case pending; $8mm base rate increase 6/2002	12%	3%	At its discretion, company can file for fuel reset on as needed basis

Source: Company reports and Lehman Brothers

Georgia Power is required to file for a new retail plan July 1, 2004. The rate case / settlement will be completed within six months of that filing. The company under the current plan was required to provide: 1) retail base rate decrease of $118 million; 2) ROE range of 10%.0–12.95%; and 3) any overearnings over the band would be shared one-third for shareholders and two-thirds for customers.

This three-year plan is the third extension. Since it has been 14 years from last rate increase, the company will attempt to request rate relief due to increased overall costs, including transmission costs. We would anticipate that since there is no looming effort to deregulate the retail market, that the company, after staff and intervenor testimony is filed and hearings are held, could negotiate a settlement plan. This plan could sustain another rate cut to make staff happy but would continue to allow for a band around the allowed ROE with potential incentive mechanisms, either around the ROE or revenues.

FERC: On the federal front, Southern Power's two purchased power contracts set to begin mid-2005 with its Georgia Power and Savannah Electric affiliates are currently under investigation by the Federal Energy Regulatory Commission. At issue is whether Southern Company gave its affiliates unfair advantages in a power solicitation. Most recently, due to potential settlement efforts between Southern and intervenors (staff, Calpine, Williams), the FERC Trial Staff proposed hearings be postponed until March 29.

TXU Corp.

Figure 49: TXU Corp.

Subsidiary	State	Rate Case/Plan Status	Allowed ROE	Fuel Recovery
TXU Energy	Texas	Price To Beat (PTB) ceiling until 2007; PTB floor until 2005 unless 40% residential customers lost; currently PTB is approximately $10.01/mwh, with the gas component at $5.36/mmbtu.	Not applicable	Semi- Annual adjustments to PTB (2 were approved in 2003, none have been requested in 2004)
TXU Gas	Texas	Filing made late May; Final order anticipated 2Q04 – see below. CapEx tracker approved by 2003 legislature allows annual cap ex inclusion in rates with full rate case every 5 years (subject to rules implementation at RRC)	11.50%	Automatic pass-thru; Reconciliation of gas cost made annually; Prudency of gas acquired made every 3 years
TXU Delivery	Texas	No scheduled rate cases; file earnings monitoring report annually in 1Q following year; Allows one rate adjustment per year for transmission cap ex and twice per year for TCRF	11.25% (60% debt/40% equity)	Not applicable
TXU Australia	Victoria	Rate case every 5 years – electricity rate case in 2005 with rate reset in 2006; gas rate case in 2007 with rate reset in 2008	12% ROE (40% equity cap)	Not applicable

Source: Company reports and Lehman Brothers

TXU Gas filed in May 2003 a bundled gas rate case for approximately $70 million rate increase with the Railroad Commission in Texas (RRC). In the past, the pipeline business was primarily regulated by the Railroad Commission of Texas and the distribution by multiple cities (roughly 430 incorporated cities). However, due to regulatory lags and constant disallowances between the pipeline and distribution affiliates, the business has had dismal returns, or well below that of the allowed ROE of 11.5% (returns have been closer to 5%). To consolidate the process, reduce the regulatory lag, and affiliate cost disallowances, management filed a bundled rate case for both the distribution and pipeline business with the Railroad Commission simultaneous with the cities. Hearings were completed on February 20.

On an annual basis, this case could add as much as $0.10 to EPS. However we expect that an actual outcome could carry a lower ROE in keeping with the current rate environment resulting in lower EPS contribution. Our 2005 estimate reflects approximately $50 million annualized. The company's 2004 EPS guidance of $2.15 reflects the full rate request adjusted for partial year implementation. A final order is anticipated in May 2004.

Wisconsin Energy

Figure 50: Wisconsin Energy

Subsidiary	State	Rate Case Timeline: Filing	Rate Case Timeline: Implementation	ROE Last Allowed	When	ROE 2002A	Equity 2002	% Total 2002	EPS 2002A
Wisconsin Electric	Wisconsin	Q1'05	1/06	12.2%-L	7/00	12.6%	$2,050	95.8%	$2.06
						10.5%	(a)		

** S-Indicates settled and L-Indicates litigated*
(a) Applies regulatory treatment for Wicor merger benefits.

Source: Company reports, Regulatory Research Associates

The company has a general rate case in May 2005. The 2005 rate case is the result of the completion of the company's transition plan. As it stands, the company is allowed a 12.2% ROE though merger savings ($70 million pretax) are excluded from the calculation. The company is currently earning around the allowed range. We expect that WEC will request a rate increase, though elimination of the merger synergy carve-out would be negative.

Xcel Energy

Figure 51: Xcel Energy

Subsidiary	Location	Rate Case Timeline: Filing	Rate Case Timeline: Implementation	ROE Last Allowed	When	ROE 2002A	Equity 2002
PSCO	Colorado	2003	06/30/04	10.85%	2003	10.7%	$ 1,980

Source: Company reports and Lehman Brothers

With the costly NRG divorce nearly behind XEL, the company has largely become a plain–vanilla, vertically integrated utility once again. While XEL has operating subsidiaries in many jurisdictions, Minnesota and Colorado dominate the EPS mix, and therefore regulation in those states remains the primary driver.

In Colorado, XEL's utility subsidiary (PSCO) is seeking to recover generation capacity costs that are not automatically passed through to the end user. As a result of PSCO's reliance on purchased power and growing system demand, the company has been bearing incremental generation capacity costs of approximately $31.5 million. PSCO has sought approval of $31.5 million of revenue to cover the rising capacity costs from third-party suppliers such as Calpine. As part of the request to Colorado regulators, PSCO has agreed to an ROE cap of 10.75% whereby any earnings above that level would be passed through to customers. The schedule currently stands as follows: 1) intervenor testimony due March 15; 2) PSCO rebuttal testimony due March 26; 3) hearings scheduled for April 14–16; and 4) position statements due April 23 and a final decision shortly thereafter. The company is looking for recovery beginning in June 2004, which would bring $20 million of additional revenue in 2004. The capacity rider program would last through 2006 and then be subject to some form of renewal through base rates.

XEL is considering adding generation rate base in Colorado as part of its long-term resource planning process. Specifically, PSCO is considering construction of a 500–750MW coal plant ($1 billion potential capex) for operation in the 2009 and 2010 period. The new construction reflects customer growth that will require approximately 1,600 megawatts (MW) of new electricity generating capacity by 2013 and more than 3,100 MW overall, according to Xcel Energy's projections. PSCO will present additional information on April 30, 2004 regarding long-term resource planning and likely provide more clarity around any specific plans. The company has conducted preliminary evaluations of two potential locations for expansion of existing coal facilities in Colorado: the Comanche Station in Pueblo or the Pawnee Station in Brush. Comanche currently has two units: 325 MW and 335 MW (total 660 MW). Pawnee currently has one 500 MW unit.

As part of the 2003 Colorado rate settlement, the Colorado PUC has the ability to conduct a proceeding to determine whether energy trading should be continued in it present form. We will watch this potential proceeding, as XEL still derives modest M&T margin in part from excess generation sales and financial trading in Colorado.

In the Upper Midwest, Xcel Energy has proposed investing approximately $164 million in generating capacity in Minnesota and South Dakota to ensure adequate supply for its Upper Midwest customers during peak demand periods. Specifically, XEL intends to seek authorization for a $100 million project to add two combustion turbines at its Blue Lake peaking plant in Shakopee, Minnesota, and for a $64 million project to add one turbine at its Angus Anson peaking plant in Sioux Falls, South Dakota. Each of the three new turbines would be fired by natural gas and would have a summer capacity of approximately 160 megawatts. The Blue Lake plant currently has four units fired by oil and a capacity of 225 megawatts; the Angus Anson plant has two units that can be fired by either natural gas or oil and a capacity of 223 megawatts.

Figure 52: State Utility Commission Ranking Factors

	Elected	Appointed	PBR?	Settlement	Litigated	Average ROE	Average BP Spread 10-Year	Average Rates	Investor Friendly? (1-5, 1-Best)
Alabama Public Service Commission	x		ROE	x		13.75%	754	$5.57	1
Arizona Corporation Commission	x		Price		x	10.97%	451	$8.02	3
Arkansas Public Service Commission		x	Price	x		10.88%	507	$6.72	3
California Public Utilities Commission		x	ROE		x	11.02%	530	$13.93	5
Colorado Public Utilities Commission		x	ROE, Fuel	x		11.25%	530	$5.93	2
Connecticut Department of Pub Utility Control		x	ROE		x	10.72%	566	$9.99	5
Delaware Public Service Commission		x	Price	x		12.00%	534	$6.68	3
District of Columbia Public Svc Commission		x	Price	x		11.86%	475	$6.30	4
Florida Public Service Commission		x	ROE, Price	x		11.86%	543	$7.73	2
Georgia Public Service Commission	x		ROE	x		12.00%	628	$5.81	2
Hawaii Public Utilities Commission		x	--		x	11.34%	545	$12.13	3
Idaho Public Utilities Commission		x	--	x		10.88%	434	$4.99	3
Illinois Commerce Commission		x	ROE		x	10.89%	627	$6.26	4
Indiana Utility Regulatory Commission		x	ROE	x		11.45%	450	$5.26	2
Iowa Utilities Board		x	ROE	x		10.75%	608	$6.06	3
Kansas Corporation Commission		x	--		x	10.94%	564	$5.79	3
Kentucky Public Service Commission		x	ROE	x		12.13%	509	$4.14	3
Louisiana Public Service Commission	x		ROE	x		11.15%	504	$6.61	4
Maine Public Utilities Commission		x	ROE, Price		x	11.28%	551	$6.38	3
Maryland Public Service Commission		x	Price		x	11.84%	550	$6.21	3
Massachusetts Dept of Tele and Energy		x	Price	x		11.45%	518	$12.18	1
Michigan Public Service Commission		x	Price		x	11.53%	612	$7.15	3
Minnesota Public Utilities Commission		x	--		x	11.41%	467	$5.87	2
Mississippi Public Service Commission	x		--	x		11.70%	561	$6.24	2
Missouri Public Service Commission		x	--		x	11.32%	529	$5.92	4
Montana Public Service Commission	x		ROE		x	11.21%	449	$5.15	3
Nevada Public Utilities Commission		x	--		x	11.19%	517	$8.20	5
New Hampshire Public Utilities Commission		x	--		x	13.25%	502	$10.82	4
New Jersey Board of Public Utilities		x	Price	x		10.64%	573	$9.16	2
New Mexico Public Regulation Commission	x		--		x	11.22%	562	$7.30	3
New York Public Service Commission		x	ROE, Fuel		x	10.83%	578	$11.50	4
North Carolina Utilities Commission		x	--	x		12.08%	534	$6.06	2
North Dakota Public Service Commission	x		ROE	x		11.53%	547	$5.81	3
Ohio Public Utilities Commission		x	Price	x		12.53%	606	$5.82	1
Oklahoma Corporation Commission	x		Fuel	x		11.78%	650	$5.69	4
Oregon Public Utility Commission		x	--	x		11.17%	549	$5.06	4
Pennsylvania Public Utility Commission		x	Price	x		11.61%	429	$6.58	2
Rhode Island Public Utilities Commission		x	ROE, Price		x	11.75%	483	$6.90	3
South Carolina Public Service Commission	x		--	x		11.92%	590	$5.79	2
South Dakota Public Utilities Commission	x		Price	x		11.63%	425	$6.80	3
Texas Public Utility Commission		x	Price	x		11.34%	528	$7.99	4
Utah Public Service Commission		x	--		x	11.15%	503	$4.80	4
Vermont Public Service Board		x	--		x	11.15%	527	$10.96	3
Virginia State Corporation Commission	x		ROE, Price	x		11.44%	459	$5.07	2
Washington Utils and Trans Commission		x	--		x	11.41%	634	$6.15	3
West Virginia Public Service Commission		x	--		x	11.54%	422	$4.67	5
Wisconsin Public Service Commission		x	Fuel		x	12.36%	798	$6.00	1
Wyoming Public Service Commission		x	Price	x		11.17%	540	$4.80	3

Source: Regulatory Research Associates, Lehman Brothers

Figure 53: State Utility Ranking Tally

	Score Tally							
	Elected / Appointed	PBR	Settle / Litigate	ROE	Rates	Investor Friendly?	Raw Score	Rank
Alabama Public Service Commission	2	1	1	1.00	1.00	1.00	7.00	**2**
Arizona Corporation Commission	2	1	2	2.00	2.00	1.50	10.50	**45**
Arkansas Public Service Commission	1	1	1	1.75	1.75	1.50	8.00	**14**
California Public Utilities Commission	1	1	2	1.50	2.00	2.00	9.50	**37**
Colorado Public Utilities Commission	1	1	1	1.50	1.25	1.25	7.00	**2**
Connecticut Department of Pub Utility Control	1	1	2	1.25	2.00	2.00	9.25	**34**
Delaware Public Service Commission	1	1	1	1.50	1.75	1.50	7.75	**11**
District of Columbia Public Svc Commission	1	1	1	2.00	1.50	1.75	8.25	**20**
Florida Public Service Commission	1	1	1	1.50	1.75	1.25	7.50	**7**
Georgia Public Service Commission	2	1	1	1.00	1.25	1.25	7.50	**7**
Hawaii Public Utilities Commission	1	2	2	1.50	2.00	1.50	10.00	**42**
Idaho Public Utilities Commission	1	2	1	2.00	1.00	1.50	8.50	**27**
Illinois Commerce Commission	1	1	2	1.00	1.50	1.75	8.25	**20**
Indiana Utility Regulatory Commission	1	1	1	2.00	1.00	1.25	7.25	**5**
Iowa Utilities Board	1	1	1	1.50	1.50	1.50	7.50	**7**
Kansas Corporation Commission	1	2	2	1.25	1.25	1.50	9.00	**29**
Kentucky Public Service Commission	1	1	1	1.75	1.00	1.50	7.25	**5**
Louisiana Public Service Commission	2	1	1	1.75	1.75	1.75	9.25	**34**
Maine Public Utilities Commission	1	1	2	1.25	1.50	1.50	8.25	**20**
Maryland Public Service Commission	1	1	2	1.25	1.50	1.50	8.25	**20**
Massachusetts Dept of Tele and Energy	1	1	1	1.75	2.00	1.00	7.75	**11**
Michigan Public Service Commission	1	1	2	1.00	1.75	1.50	8.25	**20**
Minnesota Public Utilities Commission	1	2	2	2.00	1.25	1.25	9.50	**37**
Mississippi Public Service Commission	2	2	1	1.25	1.50	1.25	9.00	**29**
Missouri Public Service Commission	1	2	2	1.50	1.25	1.75	9.50	**37**
Montana Public Service Commission	2	1	2	2.00	1.00	1.50	9.50	**37**
Nevada Public Utilities Commission	1	2	2	1.75	2.00	2.00	10.75	**48**
New Hampshire Public Utilities Commission	1	2	2	1.75	2.00	1.75	10.50	**45**
New Jersey Board of Public Utilities	1	1	1	1.25	2.00	1.50	7.75	**11**
New Mexico Public Regulation Commission	2	2	2	1.25	1.75	1.50	10.50	**45**
New York Public Service Commission	1	1	2	1.25	2.00	1.75	9.00	**29**
North Carolina Utilities Commission	1	2	1	1.50	1.50	1.25	8.25	**20**
North Dakota Public Service Commission	2	1	1	1.25	1.25	1.50	8.00	**14**
Ohio Public Utilities Commission	1	1	1	1.00	1.25	1.00	6.25	**1**
Oklahoma Corporation Commission	2	1	1	1.00	1.25	1.75	8.00	**14**
Oregon Public Utility Commission	1	2	1	1.25	1.00	1.75	8.00	**14**
Pennsylvania Public Utility Commission	1	1	1	2.00	1.75	1.25	8.00	**14**
Rhode Island Public Utilities Commission	1	1	2	1.75	1.75	1.50	9.00	**29**
South Carolina Public Service Commission	2	2	1	1.00	1.25	1.50	8.75	**28**
South Dakota Public Utilities Commission	2	1	1	2.00	1.75	1.50	9.25	**34**
Texas Public Utility Commission	1	1	1	1.50	1.75	1.75	8.00	**14**
Utah Public Service Commission	1	2	2	1.75	1.00	1.75	9.50	**37**
Vermont Public Service Board	1	2	2	1.75	2.00	1.50	10.25	**44**
Virginia State Corporation Commission	2	1	1	2.00	1.00	1.25	8.25	**20**
Washington Utils and Trans Commission	1	2	2	1.00	1.50	1.50	9.00	**29**
West Virginia Public Service Commission	1	2	2	2.00	1.00	2.00	10.00	**42**
Wisconsin Public Service Commission	1	1	2	1.00	1.50	1.00	7.50	**7**
Wyoming Public Service Commission	1	1	1	1.50	1.00	1.50	7.00	**2**

Source: Lehman Brothers

Figure 54: State Commissioners

		Party	Age	Began Service	Term Ends	Background
Alabama	James Sullivan (President)	R	53	2/83	11/04	President of Sullivan Furniture
	Jan Cook	D	44	11/90	11/06	Alabama State Auditor for 8 years
	George Wallace, Jr.	R	48	11/98	11/06	State Treasurer; University Administrator
Arizona	Marc Spitzer (Chair)	R	44	11/00	1/07	Tax attorney; former state legislator
	William Mundell	R	49	6/99	1/05	Attorney, former state legislator
	James Irvin	R	50	1/97	1/07	Businessman, President of family-owned security firm
	Jeff Hatch-Miller	R	--	1/03	1/05	State legislator
	Mike Gleason	R	--	1/03	1/05	State legislator
Arkansas	Sandra Hochstetter (Chair)	R	--	7/00	1/05	Attorney; PSC Staff Director; Governor's Liaison
	Daryl Bassett	R	--	9/02	1/09	Investment broker; Various positions with Governor
	Randy Bynum	R	--	1/03	1/07	Attorney, CPA, business owner
California	Michael Peevey (President)	D	--	3/02	1/09	Pres. Southern California Edison
	Loretta Lynch	D	38	12/99	1/05	Advisor to Governor Davis, CPUC Chair
	Susan Kennedy	D	--	1/03	1/09	Cabinet Secretary to Gov. Davis
	Carl Wood	D	52	6/99	1/05	Utility Workers Union of America representative
	Geoffrey Brown	D	--	1/01	1/07	CEO of a public law firm
Colorado	Gregory Sopkin (Chairman)	R	--	1/03	1/07	Attorney
	Polly Page	R	--	1/00	1/08	County Commissioner
	Jim Dyer	D	--	5/01	6/04	State Senator; U.S. Navy and Marine Corps
Connecticut	Donald Downes (Chair)	R	51	7/97	6/05	Attorney, Dep Scty of State Office of Policy & Mgmt
	Jack Goldberg (Vice Chair)	R	48	7/95	6/07	Private attorney, newspaper reporter
	John Betkoski	D	48	7/97	6/05	State legislator
	Linda Kelly Arnold	D	51	9/97	6/07	Attorney, SVP & General Counsel of Shawmut Bank Connecticut
	Anne George	R	--	7/03	6/07	Counsel to Gov. Rowland
Delaware	Arnetta McRae (Chair)	D	54	6/96	5/06	Attorney, Trademark & copyright counsel to DuPont
	Donald Puglisi (Vice Chairman)	I	54	7/97	2/09	Prof Business & Finance of U of Delaware
	Joshua Twilley (Vice Chairman)	D	73	2/75	5/04	Attorney, County Commissioner
	Jaymes Lester	R	--	7/01	5/06	Manager, Richland Farms
	Joann Conway	D	--	7/01	5/06	Realtor
District of Columbia	Agnes Yates (Chair)	D	45	1/93	6/04	Deputy Director D.C. Office Labor Relations and Coll. Bargaining
	Anthony Rachal III	D	--	7/02	6/06	Attorney; Long-time government employee.
	Richard Morgan	D	--	7/03	6/07	Energy analyst, U.S. EPA
Florida	Lila Jaber (Chair)	R	35	2/00	1/05	Attorney, various positions at PSC.
	Terry Deason	D	46	2/91	1/07	Chief Reg Analyst for FL Office of Public Counsel
	Braulio Baez	R	37	9/00	1/06	Attorney, Exec Asst to former PSC Commissioner
	Charles "Chuck" Davidson	R	50	1/03	1/07	Florida Office of Tourism
	"Rudy" Bradley	R	55	1/02	1/06	Businessman; FL House of Reps; FL Dept of Education
Georgia	Doug Everett (Chairman)	R	--	1/03	12/08	State legislator
	Angela Speir (Vice Chair)	R	--	1/03	12/08	Headhunter
	Robert "Bobby" Baker	R	45	1/93	12/04	Attorney, Gwinnett County Planning Commissioner
	Stancil "Stan" Wise	R	50	1/95	12/06	Owner of an insurance business
	David Burgess	D	43	4/99	12/06	Dir. PSC's Telecomm Unit, Rates, and Tariffs Section
Hawaii	Carlito Caliboso (Chairman)	R	--	4/03	6/04	Attorney, private practice
	Janet Kawelo	D	--	1/02	6/06	Deputy Dir. Of Dept of Land & Natural Resources
	Wayne Kimura	D	--	12/01	6/08	Long-time government employee.
Idaho	Paul Kjellander (Chairman)	R	--	2/99	1/05	State legislator
	Marsha Smith	D	--	1/91	1/09	Idaho Deputy Attorney General
	Dennis Hansen	R	--	2/95	1/07	State Senator; Accountant
Illinois	Edward Hurley (Chairman)	D	46	2/99	1/09	Attorney, General Manager-family-owned business
	Mary Frances Squires	R	67	3/00	1/05	Long-time government employee.
	Kevin Wright	D	--	--	1/07	Gov. Ryan staffer
	Lula Ford	D	--	1/03	1/08	Long-time government employee.
	Erin O'Connell-Diaz	D	--	4/03	1/08	ALJ, assistant Attorney General
Indiana	William McCarty (Chairman)	D	57	6/97	4/05	Attorney, State Senator
	David Ziegner	D	47	8/90	4/07	Attorney, IURC General Counsel
	Larry Landis	R	--	12/02	1/04*	President-marketing & communications company
	Judith Ripley	R	58	9/98	4/06	Attorney, Indiana legislative assistant
	David Hadley	D	50	2/00	1/06	Exec, Indiana AFL-CIO ; Business Dev. Specialist
Iowa	Diane Munns (Chair)	D	48	6/99	4/09	IUB General Counsel
	Mark Lambert	D	40	8/01	4/05	Attorney; Exec. Dir. Iowa Environmental Council
	Elliott Smith	R	--	2/02	4/07	Attorney; President Iowa Taxpayers Association
Kansas	Brian Moline (Chairman)	D	61	12/98	3/07	General Counsel for KCC, Kansas Insurance Dept.
	John Wine	R	48	3/96	3/04	Attorney; Kansas Securities Commissioner
	Robert Krehbiel	D	--	3/03	3/07	Attorney, private practice

Source: Regulatory Research Associates, utility commission web sites.

Figure 55: State Commissioners

		Party	Age	Began Service	Term Ends	Background
Kentucky	Mark Goss			2/04	2/08	
	Gary Gillis (Vice Chairman)	D	55	11/97	7/05	CPA; Business Owner; Long-time govt. employee
	Martin Huelsmann	D	59	8/00	7/04	Attorney; Exec. Director of PSC
Louisiana	Jack "Jay" Blossom, Jr. (Chairman)	R	37	1/97	12/08	Attorney, member of civic organizations
	Irma Muse Dixon (Vice Chair)	D	49	1/93	12/04	State legislator; long-time government employee
	C. Dale Sittig	D	61	1/96	12/04	State legislator
	James M. Field	R	62	11/96	12/06	Attorney; NFL agent
	Foster Campbell, Jr.	D	--	1/03	12/08	State legislator, farmer
Maine	Thomas Welch (Chairman)	D	--	5/93	3/05	Chief Deputy Attorney General for antitrust in Pennsylvania
	Stephen Diamond	--	--	10/98	3/07	U.S. Senator Aide; Securities Administrator
	Sharon Reishus	D	--	7/03	3/09	Energy consultant, PUC staff analyst
Maryland	Kenneth Schisler	R	--	7/03	6/08	Attorney, member House of Delegates
	Harold Williams	D	--	9/02	6/08	Retired from Baltimore Gas & Electric
	J. Joseph Curran, III	D	36	8/99	6/05	Attroney in private practice
	Gail McDonald	D	57	3/01	6/04	Long-time government employee.
	Ronald Guns	D	--	7/01	6/06	House of Delegates, Positiosns at Verizon Maryland
Massachusetts	Paul Alfonso (Chairman)	R	--	8/03	12/05	DTE General Counsel, attorney in private practice
	James Connelly	R	--	11/97	12/05	General Counsel to DTE and Office of Consumer Affairs
	Robert Keating	R	--	2/98	12/014	Mgr. Government relations Tenneco
	Eugene Sullivan, Jr.	D	--	7/98	12/04	Commissioner of Wakefield Gas & Light Dept.
	Deirdre Manning	D	--	4/00	12/03*	Senior health analyst, Div of Insurance Investigator
Michigan	J. Peter Lark (Chairman)	D	--	8/03	7/09	Attorney, assitant Attorney General
	Laura Chappelle	R	--	1/01	7/07	Gov. Engler's Deputy Legal Counsel
	Robert Nelson	I	54	5/99	7/05	Pres MI Electric & Gas; Dir PSC Office Reg & Consumer Affairs
Minnesota	J. Leroy Koppendrayer (Chairman)	R	59	1/98	1/010	Dairy farmer; senior state legislator
	Gregory Scott	I	43	8/97	1/05	Attroney in private practice
	Kenneth Nickolai	I		1/04	1/09	ALJ, Deputy Commissioner-Office of Human Rights, EPA
	R. Marshall Johnson	I	67	8/93	1/08	Consultant, business executive
	Phyllis Reha	D	54	5/01	1/07	Administrative Law Judge
Mississippi	Dorlos "Bo" Robinson (Chair)	D	--	1/04	1/08	Mississippi House of Representatives
	Nielsen Cochran (Vice Chair)	R	--	1/04	1/08	City of Jackson Commissioner; baseball player
	Michael Callahan	D	--	1/04	1/08	Assistant District Attorney; PSC Staff
Missouri	Steven Gaw (Chairman)	D	43	4/01	1/07	State House of Representatives, City Prosecutor
	Connie Murray	R	58	5/97	4/09	Attorney, State House of Representatives
	Robert Clayton III	D	--	5/03	4/09	Attorney, State House of Representatives
	Vacancy					
	Vacancy					
Montana	Bob Rowe (Chairman)	D	--	1/93	1/05	Attorney; Represented Human Resource Counsel for PSC
	Tom Schneider (Vice Chairman)	D	--	1/03	1/07	Former PSC Commissioner
	Jay Stovall	R	61	1/01	1/05	State legislator; rancher
	Greg Jergeson	D	--	1/03	1/07	State legislator
	Matt Brainard	R	53	1/01	1/05	State legislator
Nevada	Donald Soderberg (Chairman)	R	--	12/98	9/04	PUC Commissioner ('95-'97)
	Carl Linvill	I	--	10/03	10/07	Energy and Economic Advisor to Gov. Guinn
	Adriana Escobar-Chanos	R	--	2/01	9/05	Attorney; Member of Nevada Taxicab Authority
New Hampshire	Thomas Getz (Chairman)	D	48	10/01	6/07	Attorney, PUC Executive Director; Councel for utility
	Susan Geiger	R	46	1/94	7/05	Chief of Staff at NH Department of Justice
	Graham Morrison	R		7/03	7/09	VP Marketing at Novilit 1996-2001
New Jersey	Jeanne Fox (President)	D	--	3/02	3/08	Attorney, EPA Administrator
	Frederick Butler	D	--	3/99	3/09	Exec Dir, Democratic Office NJ Assembly
	Carol Murphy	R	--	2/01	3/07	NJ Assembly
	Connie Hughes	R	--	7/01	10/07	Long-time government employee.
	Jack Alter	D	--	10/02	10/08	Mayor-Fort Lee, insurance businessman
New Mexico	Lynda Lovejoy (Chair)	D	--	1/99	12/06	Served for 5 terms as state representative
	David King (Vice Chair)	R	--	1/03	12/06	CFO New Mexico State University
	Herbert Hughes	R	--	1/99	12/04	Albuquerque City Councilor
	Jerome Block	D	--	1/99	12/04	Former State Corporation Commission Chairman
	E. Shirley Baca	D	--	1/03	12/06	Attorney, State legisalator
New York	William Flynn (Chair)	R	--	2/03	2/09	Deputy Attorney General, Pres. NY Energy R&D
	Thomas Dunleavy	D	--	6/96	2/01 *	Deputy Comm. NYC Dept of Info Tech & Telecomm
	James Bennett	R	--	3/98	2/03*	Private attorney, LIPA Trustee
	Leonard Weiss	D	--	3/99	2/04	Presiding Judge, Appellate Div. State Supreme Court
	Neal Galvin	R	--	6/99	2/05	Former CEO of stone & asphalt producer

Source: Regulatory Research Associates, utility commission web sites.

Figure 56: State Commissioners

		Party	Age	Began Service	Term Ends	Background
North Carolina	Jo Anne Sanford (Chair)	D	--	7/95	6/09	Attorney, N.C. Department of Justice
	Richard Conder	D	--	7/97	6/05	State Senator, Bank VP
	Robert "Bobby" Owens, Jr.	D	--	8/97	6/05	Director of Governor's Eastern Office
	Samuel Ervin, IV	D	--	7/99	6/07	Attorney
	Lorinzo Little Joyner	D	--	1/01	6/09	Govt Attorney, Staff Attorney for utility Commission
	James Kerr, II	D	--	7/01	6/09	Attorney in private practice
	Michael "Mike" Wilkins	D	--	1/02	6/09	Chief of Staff and Liaison to House Speaker
North Dakota	Anthony Clark (President)	R	--	1/01	12/06	State Labor Commissioner; State legislator
	Susan Wefald	R	--	1/93	12/08	President of the Bismarck School Board
	Leo Reinbold	R	--	1/81	12/04	Dir. Of Valley City Municipal Utilities
Ohio	Alan Schriber (Chairman)	I	56	4/99	4/04	Radio station owner, PUC Commissioner ('83-'89)
	Ronda Fergus	R	46	4/95	4/05	Attorney, PUC Chief of Telecomm
	Judith Jones	R	66	4/97	4/07	Toledo City Council, Ohio School Boards Assoc.
	Donald Mason	R	45	2/98	4/08	Major Zanesville, State Dept of Nat Resources
	Clarence Rogers	I	63	2/01	4/06	Attorney, Transportation Administrator
Oklahoma	Denise Bode (Chair)	R	--	6/97	1/05	President, Independent Petroleum Assoc. of America
	Bob Anthony (Vice Chair)	R	--	1/89	1/07	President/Chairman of C.R. Anthony, clothing retailer
	Jeff Cloud	R	--	1/03	1/09	Attorney; Long-time government employee.
Oregon	Lee Beyer (Chairman)	D	--	9/01	3/04	State Senator
	Raymond Baum	R	--	9/03	3/07	Oregon Liquor Control Commission, legislator
	John Savage	D	--	9/03	3/05	Director of PUC Utility Program
Pennsylvania	Terrance Fitzpatrick (Chairman)	R	47	11/99	4/04	State positions utilities/environment
	Robert Bloom (Vice Chairman)	R	75	5/95	4/05	Cabinet Gov. Thornburgh; PUC Comm ('71-'79)
	Wendell Holland	--	--	4/03	4/08	Retired Judge, VP of American Water Works
	Glenn Thomas	R	32	6/01	4/06	Attorney, member of Gov. Tom Ridge's staff.
	Kim Pizzingrilli	R	--	1/02	4/07	Long-time government employee.
Rhode Island	Elia Germani (Chair)	R	--	5/00	3/07	Attorney for Rhode Island utility
	Kate Racine	D	--	3/93	3/05	State liquor control administrator
	Robert Holbrook	R	--	5/03	3/09	CFO Meeting Street Center, Town Councilman
South Carolina	Mignon Clyburn (Chairman)	D	40	7/02	--	Newspaper owner
	Randy Mitchell (Vice Chairman)	--	51	7/02	--	Owner and manager of poultry farm/rental business
	William Saunders	D	67	7/02	--	Radio station owner
	Clay Curruth, Jr.	--	53	7/02	--	State Senate staffer and PSC Counsel
	Robert Moseley	R	61	7/02	--	Insurance agency owner
	James Blake Atkins	D	47	7/02	--	Research professor; scientist S.C. Dept of Health/Env Control
	Nick Theodore	D	73	7/02	--	Insurance business; Lt. Governor
South Dakota	Robert Sahr (Chairman)	R	--	12/01	1/07	Attorney; Counsel for Bureau of Personnel
	Gary Hanson (Vice Chair)	R	--	1/03	1/09	Real estate broker, PUC Commissioner
	James Burg	D	--	1/87	1/05	State legislator
Tennessee	Sarah Kyle (Chair)	D	48	1/95	6/08	Memphis City Court Judge
	Deborah Taylor Tate	R	--	7/02	6/08	Attorney; Asst to Governor
	Patrick Miller	D	--	7/02	6/08	Attorney; Speaker of Senate; Gov. Chief of Staff
	Ronald Jones		--	7/02	6/08	Accountant; Financial Analyst
Texas	Paul Hudson (Chairman)	R	--	8/03	8/09	Policy Director to Gov. Perry
	Julie Caruthers Parsley	R	--	11/02	8/05	Attorney, Solicitor General
	Vacancy					
Utah	Richard Campbell (Chairman)	R	39	4/01	2/07	Accountant, Economist
	Constance White	I	45	3/95	2/05	Attorney; Exec. Dir. Of Utah Dept. of Commerce
	Ted Boyer	R	--	6/03	2/09	Long-time government employee.
Vermont	Michael Dworkin (Chairman)	I	--	3/99	2/05	SVP & General Counsel of engineering & consulting firm
	David Coen	I	--	6/95	2/07	Dept store president
	John Burke	--	--	1/01	2/09	Attorney in private practice, professor
Virginia	Theodore Morrison, Jr. (Chairman)	--	--	2/89	2/08	Attorney, member of Virginia House of Delegates
	Hullihen Williams Moore	--	--	2/92	2006	Attorney in private practice
	I. Clinton Miller	--	--	2/96	2/06	Attorney, member of Virginia House of Delegates
Washington	Marilyn Showalter (Chair)	D	50	1/99	1/09	Senior advisor on energy and telecomm to the Gov.
	Richard Hemstad	R	66	6/93	1/05	Aide to former Gov. Dan Evans
	Patrick Oshie	D	48	6/01	1/07	Attorney, private practice
West Virginia	James Williams (Chairman)	D	--	8/01	6/07	President, Bank of St. Albans (WV)
	Michael Shaw	--	--	6/03	6/07	Attorney, State Senator
	Martha Walker	D	--	12/00	6/05	West Virginia House of Delegates (Senate)
Wisconsin	Burneatta Bridge (Chair)	D	--	2/03	3/09	Attorney; Deputy Attorney General
	Ave Bie	R	--	8/98	3/05	Deputy Secretary, Wisconsin Dept. of Corrections
	Robert Garvin	R	--	3/01	3/07	Attorney, Exec. Asst to PSC Chairperson
Wyoming	Steve Ellenbecker (Chairman)	R	52	3/91	3/09	Chief rate and accounting analyst for PSC
	Kristin Lee (Deputy Chair)	D	42	3/96	3/05	Senior Assistant to Attorney General for Wyoming
	Steve Furtney	R	49	11/97	3/07	Economist for Wyoming Dept of Administration and Information

** Continuing to serve pending replacement.*

Source: Regulatory Research Associates, utility commission Web sites

Figure 57: State Utility Commission Staff Contacts

State	Name	Position	Phone
Alabama	Judy McLean	Director of Advisory Staff	334-242-5025
	Clark Bruner	Public Information Officer	334-242-5025
Arizona	Heather Murphy	Information Office	602-542-0844
Arkansas	John Bethel	Executive Director-General Staff	501-682-1794
California	Wesley Franklin	Executive Director	415-703-3808
	Lynn Carew	Chief, ALJ Division	415-703-2027
	Paul Clanon	Director, Energy Division	415-703-2237
	Regina Birdsell	Director, ORA	415-703-2544
Colorado	Geri Santos-Rach	Chief of Fixed Utilities	303-894-2533
	Barbara Fernandez	Chief of Staff	303-894-2012
Connecticut	Beryl Lyons	Media Relations	860-827-2670
	Steve Cadwallader	Chief of Regulation (elec/gas)	860-827-2629
Delaware	Connie McDowell	Chief of Technical Services	302-739-4247
	Karen Nickerson	Support Services Administrator	302-739-4247
D.C.	Timothy Robinson	General Counsel	202-626-5140
	Phylicia Fauntleroy Bowman	Dir, Office of Technical & Reg Analysis	202-626-9176
Florida	Mary Andrews Bane	Executive Director	850-413-6055
	Richard Tudor	Director, Office of Public Information	850-413-6482
Georgia	Tom Bond	Dir., Utilities Division	404-656-0977
	Bill Edge	Public Information Officer	404-656-2316
Hawaii	Paul Shigenaga	Administrative Director	808-586-2028
	Joan Yamaguchi	Chief Legal Counsel	808-586-2044
Idaho	Randy Lobb	Administrator of Utilities Division	208-334-0350
	Gene Fadness	Public Information Officer	208-334-0339
Illinois	Robert Bishop	Director, Financial Analysis Div.	217-782-7281
	David Farrell	Director, Public Affairs	217-524-5046
Indiana	Mary Beth Fisher	Public Information	317-232-2297
Iowa	Judi Cooper	Executive Secretary	515-281-5386
Kansas	Rosemary Foreman	Director-Public Affairs	785-271-3275
	Joe White	Director-Utilities Division	785-271-3221
Kentucky	Tom Dorman	Executive Director	502-564-3940
Louisiana	Lawrence C. St. Blanc	Secretary	225-342-4427
Maine	Richard Kivela	Utility Analyst	207-287-1562
	Dennis Keschl	Administrative Director	207-287-1353
Maryland	Gregory Carmean	Executive Director	410-767-8010
	Chrys Wilson	Manager External Relations	410-767-8028
Massachusetts	Timothy Shevlin	Executive Director	617-305-3691
	Mary Cottrell	Department Secretary	617-305-3600
Michigan	Gary Kitts	Chief Administrative Officer	517-241-6190
	Mary Jo Kunkle	Public Information Officer	517-241-3323
Minnesota	Janet Gonzalez	Supervisor, Energy	651-296-1336
	Burl Haar	Executive Secretary	651-296-7526
Mississippi	Brian Ray	PSC Staff	601-961-5434
	Tad Campbell	General Counsel	601-961-5469
Missouri	Bob Schallenberg	PSC Staff	573-751-7162
	Kevin Kelly	Public Information Administrator	573-751-9300

Source: Regulatory Research Associates, utility commission Web sites

Figure 58: State Utility Commission Staff Contacts

State	Name	Position	Phone
Montana	David Hoffman	Administrator-Utility Division	406-444-6187
New Hampshire	Debra Howland	Executive Director	603-271-2431
New Jersey	Lance Miller	Chief of Staff	973-648-3175
	Fred Grygiel	Chief Economist	973-648-3860
New Mexico	Vince Martinez	Chief of Staff	505-827-6942
	John Curl	Director Utility Division	505-827-6960
Nevada	Cynthia Messina	Public Information Officer	702-486-7299
	Neill Dimmick	Director of Regulatory Operations	775-687-6005
New York	David Flanagan	Public Information	518-474-7080
	Frank Herbert	Dir. Competition Transition Office	518-474-2530
North Carolina	Robert Bennink, Jr.	Dir. Adm. Division and General Counsel	919-733-0833
	Debbie Holder	Fiscal Management Division	919-733-0832
North Dakota	Illona Jeffcoat	Director of Public Utilities Division	701-328-2407
Ohio	Ed Hess	PSC Staff	614-466-7627
	Shana Gerber	Media Chief/Public Affairs	614-466-7750
Oklahoma	Joyce Davidson	Dir. Public Utility Division	405-522-1155
Oregon	Bill Warren	Director of Utility Program	503-378-6053
	Rick Willis	Executive Director	503-373-1303
Pennsylvania	Robert Rosenthal	Dir. Bureau of Fixed Utility Services	717-783-5242
	Robert Christianson	Chief ALJ	717-787-1191
Rhode Island	Luly Massaro	Commission Clerk	401-941-4500, x10
	Thomas Massaro	Chief Financial Analyst	401-941-4500, x10
South Carolina	Gary Walsh	Executive Director/Secretary	803-896-5133
	Randy Watts	Chief-Electric Utilities Department	803-896-5137
South Dakota	Greg Rislov	Commission Advisor	605-773-3201
Tennessee	K. David Waddell	Executive Secretary	615-741-2776, x14
	Greg Mitchell	Information Officer	615-741-2776, x13
Texas	Martha Hinkle	Dir. Financial Review Division	512-936-7425
	Jess Totten	Dir. Electric Division	512-936-7235
Utah	Julie Orchard	Commission Secretary, PSC	801-530-6713
	Lowell Alt	Director, Division of Public Utilities	801-530-6675
Vermont	Susan Hudson	Clerk of the Board	802-828-2358
	Ennis Gidney	Economist	802-828-2358
Virginia	Ronald Gibson	Dir., Div. Of Public Utility Accounting	804-371-9708
	Kenneth Schrad	Dir. Information Resources	804-371-9141
Washington	Dixie Linnenbrink	Regulatory Services Director	360-664-1296
	Marilyn Meehan	Public Information Officer	360-664-1116
West Virginia	David Ellis	Director, Utilities Division	304-340-0426
	Sandra Squire	Executive Secretary	304-340-0347
Wisconsin	Robert Norcross	Administrator, Electric Division	608-266-0699
	Annemarie Newman	Public Information Officer	608-266-9600
Wyoming	David Mosier	Administrator	307-777-7427
	Denise Parrish	Rates and Pricing Supervisor	307-777-7427

Source: Regulatory Research Associates, utility commission Web sites

Figure 59: Utility and Power Rankings

Investment Opinion	Ticker	Company	Current Price 03/02/04	Indicated Annual Dividend	Current Yield	12 Month Price Target (1)	12 Month % Change	12 Mo. Total Return Potential	Earnings per Share 2003E	Earnings per Share 2004E	Earnings per Share 2005E	5 Year Est. EPS Growth	2004E Price/ Earnings	2005E Price/ Earnings
1-OW	TXU	TXU Corp	$28.29	$0.50	1.8%	$36	28%	30%	$2.03	$2.15	$2.35	0%	13.2x	12.0x
1-OW	EXC	Exelon	$67.18	$2.20	3.3%	$84	25%	28%	$5.22	$5.71	$6.05	7%	11.8x	11.1x
1-OW	ETR	Entergy Corp	$59.40	$1.80	3.0%	$74	25%	28%	$4.25	$4.23	$4.80	6%	14.0x	12.4x
1-OW	NI	NiSource Inc	$21.87	$0.92	4.2%	$26	21%	25%	$1.63	$1.70	$1.75	4%	12.9x	12.5x
1-OW	WEC	Wisconsin Energy Corp	$32.52	$0.84	2.6%	$37	14%	16%	$2.31	$2.21	$2.33	8%	14.7x	14.0x
2-EW	FPL	FPL Group Inc	$66.25	$2.40	3.6%	$74	12%	15%	$4.89	$5.02	$4.80	3%	13.2x	13.8x
1-OW	PPL	PPL Corporation	$46.48	$1.44	3.1%	$52	12%	15%	$3.54	$3.70	$3.80	4%	12.6x	12.2x
1-OW	PCG	PG&E Corp	$28.62	$0.00	0.0%	$33	15%	15%	$1.48	$2.25	$2.30	6%	12.7x	12.4x
2-EW	PEG	Public Service Entrp Group Inc	$47.33	$2.20	4.6%	$51	8%	13%	$3.72	$3.75	$3.80	4%	12.6x	12.5x
2-EW	SO	Southern Co	$30.42	$1.40	4.6%	$33	8%	12%	$1.97	$1.96	$1.96	2%	15.5x	15.5x
2-EW	DTE	DTE Energy Co	$40.43	$2.06	5.1%	$43	7%	12%	$2.99	$3.25	$3.35	0%	12.4x	12.1x
2-EW	DPL	DPL Inc	$20.10	$0.96	4.8%	$22	7%	12%	$1.42	$1.25	$1.30	2%	16.1x	15.5x
2-EW	LNT	Alliant Energy	$25.86	$1.00	3.9%	$28	7%	10%	$1.76	$1.85	$1.95	4%	14.0x	13.3x
1-OW	FE	FirstEnergy Corp	$38.63	$1.50	3.9%	$41	6%	10%	$1.86	$2.65	$2.85	2%	14.6x	13.6x
2-EW	EIX	Edison International	$23.65	$0.80	3.4%	$25	7%	10%	$2.20	$1.65	$1.75	0%	14.3x	13.5x
2-EW	PNW	Pinnacle West Capital	$39.27	$1.80	4.6%	$41	5%	9%	$2.70	$2.50	$3.00	2%	15.7x	13.1x
2-EW	D	Dominion Resources Inc	$63.19	$2.58	4.1%	$66	4%	8%	$4.55	$4.89	$5.05	5%	12.9x	12.5x
2-EW	CEG	Constellation Energy Corp	$40.16	$1.04	2.6%	$42	4%	6%	$2.76	$3.07	$3.10	6%	13.1x	13.0x
2-EW	AES	AES Corporation	$8.99	$0.00	0.0%	$10	6%	6%	$0.50	$0.65	$0.70	15%	13.8x	12.8x
2-EW	PGN	Progress Energy	$46.74	$2.30	4.9%	$47	0%	5%	$3.56	$3.57	$3.62	0%	13.1x	12.9x
2-EW	XEL	Xcel Energy	$17.95	$0.75	4.2%	$18	0%	5%	$1.20	$1.25	$1.25	3%	14.4x	14.4x
2-EW	CIN	Cinergy Corp	$39.87	$1.88	4.7%	$39	-1%	4%	$2.54	$2.75	$2.70	3%	14.5x	14.8x
2-EW	AEE	Ameren Corp.	$47.88	$2.54	5.3%	$46	-5%	0%	$2.95	$2.83	$2.87	0%	16.9x	16.7x
2-EW	SRP	Sierra Pacific Resources	$8.00	$0.00	0.0%	$8	0%	0%	$0.55	$0.35	$0.45	1%	22.9x	17.8x
2-EW	PSD	Puget Energy	$22.77	$1.00	4.4%	$22	-5%	0%	$1.26	$1.55	$1.87	5%	14.7x	12.2x
3-UW	ED	Consolidated Edison	$44.47	$2.26	5.1%	$42	-6%	-1%	$2.83	$2.70	$2.72	0%	16.5x	16.3x
2-EW	POM	Pepco Holdings	$21.24	$1.00	4.7%	$20	-6%	-1%	$1.24	$1.45	$1.50	5%	14.6x	14.2x
2-EW	SRE	Sempra Energy	$32.38	$1.00	3.1%	$31	-4%	-1%	$2.87	$2.75	$2.85	6%	11.8x	11.4x
2-EW	EDE	Empire District Electric	$22.95	$1.28	5.6%	$21	-7%	-1%	$1.29	$1.29	$1.38	1%	17.8x	16.6x
2-EW	OGE	OGE Energy Corp	$25.82	$1.33	5.2%	$24	-7%	-1%	$1.50	$1.45	$1.52	1%	17.8x	17.0x
3-UW	NU	Northeast Utilities	$19.20	$0.60	3.1%	$18	-5%	-2%	$0.92	$1.25	$1.35	4%	15.4x	14.2x
2-EW	AYE	Allegheny Energy Inc	$13.40	$0.00	0.0%	$13	-3%	-3%	($1.73)	$0.56	$1.06	NA	23.9x	12.6x
2-EW	AEP	American Electric Power	$34.98	$1.40	4.0%	$32	-9%	-5%	$2.21	$2.25	$2.30	3%	15.5x	15.2x
2-EW	TE	TECO Energy Inc	$15.10	$0.76	5.0%	$14	-10%	-5%	$0.92	$1.00	$1.15	0%	15.1x	13.1x
2-EW	DQE	Duquesne Light Holdings	$20.34	$1.00	4.9%	$18	-11%	-6%	$1.15	$1.10	$1.30	4%	18.5x	15.6x
2-EW	CMS	CMS Energy Corp	$9.34	$0.00	0.0%	$9	-8%	-8%	$0.80	$0.70	$0.70	1%	13.3x	13.3x
3-UW	GXP	Great Plains Energy	$35.00	$1.66	4.7%	$30	-15%	-11%	$2.08	$2.20	$2.20	3%	15.9x	15.9x
2-EW	HE	Hawaiian Electric Inds	$53.64	$2.48	4.6%	$45	-16%	-11%	$2.95	$2.95	$3.00	1%	18.2x	17.9x
3-UW	DUK	Duke Energy Corp	$22.14	$1.10	5.0%	$18	-17%	-12%	$1.28	$1.15	$1.10	-1%	19.3x	20.1x
3-UW	DYN	Dynegy Inc	$4.30	$0.00	0.0%	$4	-19%	-19%	($0.02)	($0.05)	($0.16)	NA	NM	NM
3-UW	CPN	Calpine Corp	$5.35	$0.00	0.0%	$3	-44%	-44%	($0.08)	($0.17)	($0.13)	NA	NM	NM
Averages:														
Utility			$31.70	$1.30	3.9%	$32	1%	5%	$2.10	$2.16	$2.24	2.7%	15.2x	14.4x
IPP			$4.83	$0.00	0.0%	$3	-31%	(31%)	($0.05)	($0.11)	($0.15)	NA	13.8x	12.8x
Integrated			$39.12	$1.36	3.3%	$43	5%	9%	$2.52	$2.88	$3.08	3.4%	15.1x	13.5x
Coverage Universe			$32.22	$1.25	3.5%	$33	0%	4%	$2.10	$2.23	$2.33	2.9%	15.2x	14.2x
S&P 500 Index			$1,155.96	$16.72	1.4%	$1,225	6%	7%	$55.15	$61.75	$66.00	7.0%	18.7x	17.5x

(1) Price target methodologies are mainly based on forward P/E multiples, but also consider EV/EBITDA and cash flow. Price targets are also adjusted weekly to reflect interest rate changes.
(2) We co-cover DYN with Lehman natural gas analyst, Rick Gross.

Source: FactSet, Lehman Brothers

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Estimate Change ☑

Puget Energy, Inc. (PSD)

HOLD (2)
High Risk (H)

PSD: Strategy To Strengthen Financial Position & Add Energy Resources Remains

Mkt Cap: $2,149 mil.

United States

March 2, 2004

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SUMMARY

We are reducing our 2004 EPS estimate to $1.55 from $1.85 due to: recent negative regulatory recommendations could offset positive impact of adding generating resources to rate base; January ice storm caused $5 MM of costs, almost entire annual storm cost budget; higher operating costs; & flat performance of $0.02 from InfrastruX, down from previous $0.10 projection.

Our estimate may prove conservative, but PSD had to make continuous downward adjustments to its guidance throughout 2003.

We project 2005 EPS to increase to $1.65 which is based on normal weather, modest economic improvement & resolution of pending Power Cost Only Rate Case which should add about $0.01. We have not included any impact from electric & natural gas rate cases that are expected to be filed shortly.

Additional energy resources expected to be added in 2004 & 2005 & expect further balance sheet strengthening & dividend payout ratio improvement.

FUNDAMENTALS

P/E (12/03A)	18.1x
P/E (12/04E)	14.7x
TEV/EBITDA (12/03A)	6.2x
TEV/EBITDA (12/04E)	5.8x
Book Value/Share (12/03A)	$16.97
Price/Book Value	1.3x
Revenue (12/03A)	$2,491.5 mil.
Proj. Long-Term EPS Growth	4%
ROE (12/03A)	10.0%
Long-Term Debt to Capital(a)	55.6%

PSD is in the S&P 400® Index.

(a) Data as of most recent quarter

SHARE DATA

Price (3/1/04)	$22.77
52-Week Range	$24.09-$20.05
Shares Outstanding(a)	94.4 mil.
Div(E) (Cur/Prev)	**$1.00**/$1.00

RECOMMENDATION

Rating (Cur/Prev)	**2H**/2H
Target Price (Cur/Prev)	**$24.00**/$24.00
Expected Share Price Return	5.4%
Expected Dividend Yield	4.4%
Expected Total Return	9.8%

EARNINGS PER SHARE

FY ends		1Q	2Q	3Q	4Q	Full Year
12/02A	**Actual**	**$0.28A**	**$0.34A**	**$0.07A**	**$0.55A**	**$1.24A**
12/03A	**Current**	**$0.45A**	**$0.22A**	**$0.10A**	**$0.48A**	**$1.26A**
	Previou	$0.45A	$0.22A	$0.10A	$0.63E	$1.40E
12/04E	**Current**	**$0.58E**	**$0.26E**	**$0.12E**	**$0.59E**	**$1.55E**
	Previou	$0.56E	$0.42E	$0.14E	$0.73E	$1.85E
12/05E	**Current**	**$0.60E**	**$0.27E**	**$0.13E**	**$0.65E**	**$1.65E**
	Previou					

First Call Consensus EPS: 12/03A $1.34; 12/04E $1.61; 12/05E $1.74

OPINION

Weather & Unrecovered High Power Costs Cause 2003 Earnings Disappointment

Although Puget's 2003 earnings of $120.2 million or $1.26 per share were up from $110.1 million or $1.24 per share in the prior year, they were a bit disappointing. Abnormal weather conditions reduced earnings by about $0.10, while underrecovery under the Power Cost Adjustments lowered earnings by $0.25 last year. Fourth quarter earnings dropped to $47.0 million or $0.48 per share from $49.6 million or $0.55 per share for the same period in 2002. The fourth quarter shortfall was primarily the result of: higher income taxes -$0.04; higher operating expenses -$0.04; and lower other income -$0.01, offset by improved electric and natural gas margins +$0.04 and lower interest charges +$0.04.

Puget faced several challenges throughout most of 2003 that put pressure on earnings. Warm weather, poor hydro conditions, higher power costs not recovered through utility rates, and weak economic conditions were the most prevalent. However, the company was able to strengthen its balance sheet and add energy resources that will support the growing needs of the next generation of Pacific Northwest customers. This should produce more price stability for Puget's utility customers while also providing a higher earnings base for shareholders. Puget continues to support the growth in its service territory growth by upgrading its energy delivery systems and acquiring energy resources and at the same time is working in collaboration with its regulators to achieve both its strategic and financial objectives. Both Moody's Investor Services and Standard and Poors revised their outlook on Puget Energy and PSE upward to "stable" and "positive," respectively, late last year.

Because we believe Puget Energy will face similar challenges this year, we are reducing our 2004 earnings estimate to $1.55 per share from $1.85. This may prove a bit conservative, but the company had to make continuous downward adjustments to its guidance throughout 2003. Also, the recent negative regulatory recommendations could offset the positive impact of adding the Frederickson generating plant to rate base. Therefore, we believe it is prudent to be conservative at this time. A January 2004 ice storm caused $5 million of storm costs, almost the entire storm cost budget for the year. In its upcoming rate case filings, Puget will most likely request clarification of the definition of catastrophic damage and revisit the deferral mechanism associated with this type of expense. Puget Sound Energy will account for almost 99% of Puget Energy's consolidated earnings this year and its profitability is tied to the outcome of the pending Power Cost Only Rate Case and weather conditions. Puget has indicated that it expects the Power Cost Only Rate Case to contribute about $0.01 per share to 2004 earnings assuming it is granted full relief as filed or $64.4 million. We expect InfrastruX to make a minor contribution to Puget Energy's 2004 earnings -- $0.02 per share, about flat with last year. But management continues to evaluate strategic options and we would not be surprised if Puget decides to sell the business.

Our 2005 estimate of $1.65 per share is based on normal weather and resolution of the Power Cost Only Rate Case. We have not included any impact from the yet-to-be filed electric and natural gas rate cases.

UTILITY OPERATIONS—IMPROVEMENT ON THE WAY, BUT LOWER THAN INITIALLY ANTICIPATED

Quick 2003 Review

Higher earnings of $118.7 million or $1.25 per share were reported by Puget Sound Energy (PS) in 2003 compared with $101.1 million or $1.14 per share, but fourth quarter earnings fell to $46.3 million or $0.48 per share from $47.8 million or $0.53 per share in the same quarter in 2002. Heating degree-days in the fourth quarter of 2003 were 2% below normal, but 5% above the level in the year-earlier period. The operating decline combined with an increase of Puget Energy shares outstanding due to the November 2003 sale of $100 million of common stock resulted in a $0.05 decline in fourth quarter earnings per share. Proceeds were invested in PSE and used to redeem approximately $94 million of high-cost preferred stock. PSE's 2003 financial performance was also impacted by increased depreciation and property tax expenses resulting primarily from new utility plant investment, higher federal income tax expenses, and a $1.5-million after-tax impact of a rate case settlement agreement during the fourth quarter. As a result of the steps Puget has taken to reduce debt and refinance higher cost securities, interest expense and preferred dividends declined by $3.7 million or $0.04 per share in the fourth quarter of 2003.

PSE's common equity ratio was 40% at year-end 2003 compared with 36.1% a year earlier. The utility is more than well ahead of the requirement specified in its July 2002 rate settlement to rebuild its common equity ratio to 39% by 2005, and has established a longer-term common equity ratio goal of 45%.

Regulatory Update

In October 2003, PSE took its first step towards its plan of having a balanced, diversified mix of energy resources by acquiring a 49.85% interest in Frederickson Power LP's 249-MW generation facility near Tacoma, Washington. Subject to Washington Utilities and Transportation Commission (WUTC) approval, PSE filed a Power Cost Only Rate Case to include the $80-million cost in its electric rates and to update the utility's other power supply costs to current projections. The Power Cost Only Rate Case process was established as part of the WUTC's approval of a Power Cost Adjustment Mechanism (PCA), which became effective July 1, 2002. WUTC Staff and other parties, including the group Industrial Customers of Northwest Utilities (ICNU), filed testimony seeking downward adjustments to PSE's proposed electric rate increase. In addition to several other items, they proposed that a significant amount of the utility's future fuel costs associated with electric generating facilities be disallowed for recovery in electric rates based upon their interpretation of a 1994 WUTC order and a contention that PSE should have secured fixed price fuel supply options that were available in late 1997. After factoring in such proposed fuel supply disallowances and some lower estimates for future power costs which are trued-up to incurred actuals through the PCA, the WUTC Staff recommended a $7.5 million net rate increase compared with PSE's requested $64.4 million. If the WUTC were to adopt Staff's or ICNU's recommendations, the proposed fuel cost disallowances would adversely impact PSE's future financial performance. PSE believes that the proposed fuel cost disallowances proposed by the WUTC Staff are legally and factually deficient and has filed a rebuttal case. PSE does not perceive the issues raised by the WUTC Staff as a negative reflection on its strong and collaborative relationship with the WUTC and continues to believe the power cost only rate case is a very effective process to obtain an expedited decision on power costs. The WUTC is expected to render a decision in the PSE Power Cost Only Rate Case by April 30, 2004. With the expected rate base treatment, the Frederickson acquisition is expected to add between $0.02 and $0.03 per share to 2004 earnings.

To meet its customers' electricity demand, PSE estimates it will need about 475 average megawatts (aMW) of additional power by January 2005. If not addressed, its projected supply deficit grows to 1,700 aMW by 2013, and to 2,400 aMW by 2023.

PSE's Least Cost Plan filed with the WUTC in April 2003 outlined its strategy for a balanced, diversified mix of energy resources to limit customers' financial risks and provide stable rates over the long-term. In addition to the Frederickson plant, the utility's energy supply strategy includes: 1) expanding its energy-conservation program to help residential and commercial customers save more than 20 aMW of electricity annually during the next 10 years (276 aMW total over 20 years); 2) acquiring 10% of customers' total electricity supply or 270 aMW by 2013 from renewable energy sources such as wind power. PSE will solicit proposals to provide 50 aMW of new wind-power resources in the Northwest and could enter into agreements by September 2004; 3) ongoing exploration of other potential power resource acquisitions to further reduce the gap between its secure energy supply and customers' growing power demand. PSE's objective is to ultimately secure almost all of its power supply under long-term arrangements which is in concert with the Washington State Energy Strategy to provide stable-priced, affordable energy for customers.

Under its PCA mechanism, for the period July 2002 through June 2006, PSE is required to submit a Compliance Filing for its power costs to the WUTC for each 12-month period ending June 30. In a December 2003 agreement with the WUTC staff to settle its compliance filing for the PCA mechanism period covering July 1, 2002 through June 30, 2003, PSE agreed to reduce the amount of future recovery related to two regulatory assets in its current electric tariff rates. This one-time adjustment was the primary reason for a $1.3 million or a $0.01 per share reduction in other income in the fourth quarter of 2003.

INFRASTRUX GROUP...STRATEGIC OPTIONS BEING DISCUSSED

Poor weather conditions in the Northeast and a general slow-down in utility construction work and capital spending were responsible for InfrastruX's disappointing year. Income, net of minority interest, dropped to $1.6 million, or $0.02 per share from $9.5 million or $0.10 per share in 2002. We project InfrastruX's earnings to be flat in 2004, which is a reduction from our earlier projection of $0.10 per share. InfrastruX is well-positioned to take advantage of infrastructure spending when it begins to recover. Puget will not contribute additional equity to InfrastruX in 2004 and continues to evaluate strategic options.

VALUATION

Our target price on Puget Energy is $24 per share. We have changed our projected P/E multiple to roughly 14x 2005 expectations from our earlier valuation of 13x 2004 expectations. As a result of Puget Energy's improving financial position and credit profile, we believe the shares should trade in line with their traditional natural gas distribution peers, with an average 2005 P/E multiple of about 14x. Puget Energy has steadily made progress on its goal to rebuild its common equity ratio to 45%, which approximated 40% at the end of 2003. The company is considerably ahead of the targets specified in its comprehensive rate settlement. We expect as earnings continue to pick up, Puget's common equity ratio will continue to improve to more healthy levels as well. We also value Puget on its book value multiple. The company's shares are currently trading at 1.3x book, below the average gas distribution group multiple of 1.9x. If the shares were to trade at the peer group multiple, Puget's stock price would approximate $32 per share. However, our $24 target price is based on a 1.4 book value multiple which we believe is reasonable due to the regulatory challenges, albeit which have improved, that the company still faces.

RISKS

We rate Puget Energy a High risk due to the company's historical lack of earnings growth, dividend reduction, high debt to equity ratio of approximately 60%, low interest coverage, and weak (although improving) credit ratings. Weather affects the company's electric and natural gas deliveries and earnings. Hydro conditions in the Northwest part of the country and economic conditions impact electric and gas deliveries especially to commercial and industrial customers affect Puget's earnings. One of Puget Energy's objectives has been to achieve higher earnings growth through its InfrastruX business. However, abnormal weather conditions and cutbacks in utility infrastructure spending levels has hurt the profitability of the company and Puget Energy is exploring strategic options for this business. If cold winter weather or hot summer temperatures prevail, Puget Energy's earnings could improve significantly, and the shares could exceed our target price. If a turn around at InfrastruX does not occur or Puget Energy announces a generation acquisition that would not be added to rate base or result in earnings dilution, the shares may fail to meet our target price.

INVESTMENT THESIS

We rate the shares of Puget Energy Hold/High Risk (2H) with a target price of $24 per share. We believe the company s relatively new management team was instrumental in achieving the four-year comprehensive rate settlement agreement that should help steadily restore the utility s financial health. In our view, the improving working relationship between Puget Sound Energy, the Washington Utilities and Transportation Commission as well as other constituencies is an important factor in the company s future profitability. A power cost tracker (a mechanism that raises or lowers rates based on electric commodity price changes) and electric and gas rate increases, combined with above-average customer growth in its service territory, should provide Puget Energy with a stable and growing future earnings base, while maintaining competitive low rates for its customers. Puget Energy s strength has been its core electric and gas distribution business, a business we believe it does well and on which it will continue to concentrate. Overall, Puget Energy s story is one of recovering stable utility earnings enhanced by modest diversified results contributed by its non-regulated InfrastruX Group. In our view, Puget Energy shares will perform better as earnings stabilize and grow. However, 2003 earnings were negatively impacted by poor hydro conditions in the Pacific Northwest (thanks to El Nino), which has resulted in additional purchase power costs. The company s Power Cost Adjustment mechanism caps cumulative variable excess costs at $40 million and this cap was met by the end of 2003. The cap will largely protect against excess variable costs till mid-2006 and should lead to positive year-over-year comparisons in 2004. The first step has been announced on Puget s plan to acquire generating resources and the Frederickson investment could be part of the company s rate base in 2004. Puget will look for additional generating facilities to fulfill its customers needs in future years. In March 2002, Puget Energy reduced its annual dividend rate by 45.6% to the current $1.00 per share rate from $1.84. The settlement agreement underscores the sustainability of the company s targeted dividend payout ratio of 60%-65%, based on utility earnings. However, we do not project a dividend increase until 2005, when we believe earnings will be more sustainable and the dividend payout ratio will be closer to its targeted range.

COMPANY DESCRIPTION

Puget Energy, headquartered in Bellevue, WA, was established as the first sizeable merger between an electric utility (PSE) & a natural gas utility (Washington Energy) that was completed in 1997. On January 1, 2001, Puget Energy was established as a holding company for two subsidiaries PSE & InfrastruX Group. PSE delivers electricity, gas, & innovative energy solutions to more than 1.2 million customers throughout WA, primarily in the Puget Sound region. The utility serves approximately 940,600 electric customers & 606,000 gas customers of which 298,600 customers purchase both forms of energy from PSE. InfrastruX Group is a holding company for Puget s non-regulated businesses that provide design, construction, engineering, & other infrastructure services to the utility industry.

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Equity Research

SECTOR REVIEW

26 February 2004
Americas/United States
Electric Utilities
Utilities
UNDERWEIGHT

Away from Basics

Positioning in Utilities for 2004

- **Looking out into 2004, we believe a number of variables/trends warrant increased attention and will be important in forming an effective utility investment framework:**

  Expectations trending toward sustainable levels. The utilities lowered 2004 expectations and long-term growth rates during Q403 earnings calls, as highlighted in our report *Lowering the Bar* (January 27, 2004), without much penalty owing to the strong equity market backdrop.

  Interest rates. We would not dare attempt to predict interest rate movements, but we do believe rates are more likely to rise than fall from current levels. Although we believe structural changes in the Utility sector have softened the relationship between interest rates and dividend yields, we would still recommend investing in utilities that look less like fixed income surrogates.

  Rate cases. Interest rates have fallen meaningfully since the 1990s while allowed ROEs have eased only modestly, creating an ever-greater *equity premium* (spread between ROEs and interest rates) even as back-to-basics is widely embraced. Several recent recommendations/ decisions have been surprisingly negative, possibly signaling a change in commission tone.

  Flight to lower quality. The winning investment strategy in 2003 was to buy depressed/ oversold utilities and ride the recovery to more normal valuation levels—a trend we continue to see in 2004. We are concerned that the market is getting ahead of the recovery play prospects, bidding up stocks before fundamentals justify a recovery.

  November 2004 elections. The leading Democratic candidates have promised to repeal Bush's tax incentives for the "rich," including dividend tax relief. We estimate the Utilities have benefited from a 1.0-1.5 times P/E multiple increase with the dividend tax cut—look for the increase to evaporate if/when confidence shifts toward a Democratic victory. Congressional elections have the potential to affect the Energy Bill and the next wave of environmental legislation.

  New Income funds. Many mutual funds are rolling out new income-oriented investment products, finding good interest in the wake of strong broader market performance and tax law changes, etc. Although growth in this investment class may provide the Utility sector support over the near term as new capital is deployed, the breadth of investment options and new equity coming from secondary offerings will likely offset some of the new money impact.

  Valuations offer limited upside. With estimates down and the stocks holding near recent highs, the group is trading above historical ranges and on par with traditional relative multiples.

- **We maintain our Underweight view for the Electric Utility sector. Considering the issues outlined above, we would focus on electric utilities with above-average earnings growth prospects (the market rewards for value creation) and a bias to competitive businesses (to limit rate case risk and likelihood of comparisons to fixed income securities).**

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Executive Summary

As we get past Q403 earnings and move into 2004, we thought this would be a useful time to look at the major issues that will likely affect utility investments over the coming year. We continue to focus on the role of commodity prices for shaping near-term earnings prospects and guiding long-term investment decisions, but want to highlight other issues that affect the attractiveness of utility investments. We categorize the themes into positive, neutral, and negative when assessing how each factor affects the investment proposition. They are specifically broken down as follows:

Positive

- Earnings expectations are approaching more realistic and sustainable levels.
- The focus on, and start of, many new income-oriented mutual funds is bringing new investment dollars into the group.

Neutral

- Flight to lower-quality stocks creates an opportunity in some oversold companies, but we remain concerned the market is giving too much credit now for stocks that will take years to turn around (hard to justify paying current group multiples for earnings several years off).

Negative

- Interest rates appear more likely to increase from here (versus down), which should put pressure on the group even if the relationship between dividend yield and interest rates is not as significant as in past periods.
- The dividend tax cut appears to be in significant jeopardy if a Democratic candidate wins the election, wiping away the 1.0-1.5 times P/E multiple increase priced into the utilities since the summer.
- Recent rate cases suggest state commissions could be clamping down on allowed ROEs to reflect the low interest rate environment; at a minimum, we believe it will be a challenge to see ROE increases in a rising rate environment (except in unique circumstances with a constructive regulatory environment).
- Utility valuations appear to be pressing the upper end of traditional trading ranges, and are consistent relative to the S&P Industrials—both suggest the group is running out of room for valuation expansion.

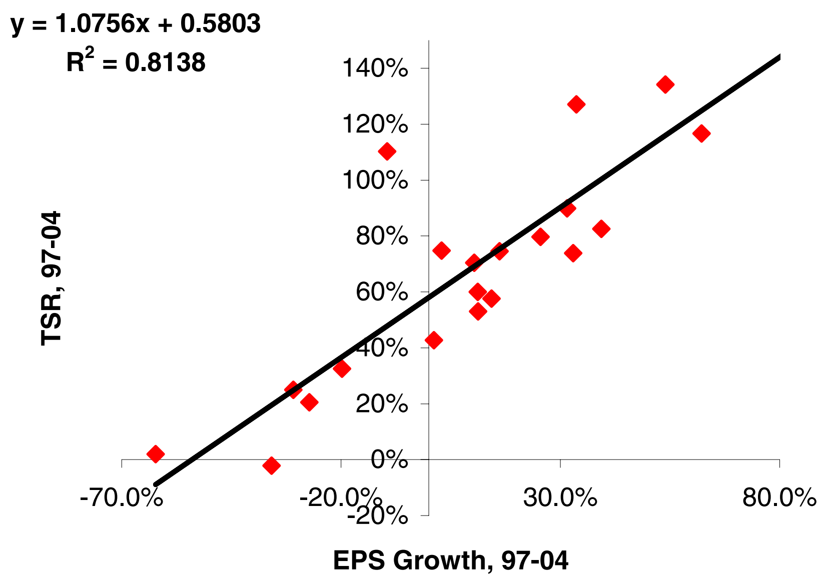
So Where Does That Put Us for 2004?

Remain Underweight the utilities; prefer companies with less regulated exposure

We remain Underweight the Electric Utility sector, as we believe the negatives facing the group outweigh the positives. Although the utilities appear to have overcome downward revision risk, we still see a number of challenges still to face. From an investment positioning perspective, we prefer companies with less regulated market exposure than the fully regulated and back-to-basics companies.

The less regulated stocks help to reduce some of the negatives facing the group, namely the risk of negative/disappointing rate case outcomes and less pressure if rates rise, since these companies look less like fixed-income surrogates. Within the less regulated camp, we are drawn to companies that can deliver better than group EPS growth, since these stocks have historically been the best-performing investments within the sector. (See Exhibit 1 and refer to our report *Penny Wise, Pound Foolish* from January 14, 2004.)

Exhibit 1: EPS Growth versus Total Shareholder Return, 1997–2004



Source: Company data, CSFB estimates.

Earnings Expectations Approaching Sustainable Levels

Earnings expectations for 2004 have broadly come down in recent months

One of our concerns about the group is that expectations for 2004 earnings and longer-term growth rates are too high. To this end we have seen the utilities systematically lower expectations, bringing the consensus down to what we view as more sustainable levels. Exhibit 2 highlights the shift in 2004 consensus expectations from July 2003 to current levels, showing the downward movements for much of our coverage universe.

Exhibit 2: **Earnings Deviations from July 2003 Consensus Expectations**

	2004 Consensus (Current)	2004 Consensus as of July 15, 2003	Consensus Change
AEP	$2.29	$2.29	0.0%
CEG	$3.09	$2.92	5.8%
D	$4.94	$5.06	(2.4)%
DUK	$1.17	$1.41	(16.5)%
EIX	$1.60	$1.47	8.5%
FE	$2.77	$3.51	(21.0)%
PCG	$2.06	$2.07	(0.5)%
PEG	$3.73	$3.82	(2.3)%
PNW	$2.73	$3.18	(14.0)%
SO	$1.97	$1.94	1.6%
TXU	$2.15	$2.06	4.2%

Source: CSFB Equity Research, First Call.

Longer-term growth rates have also been trending lower, with what was the seemingly standard 5-7% annual growth target being lowered to sub-5% growth. We discussed this topic in more detail in our January 27, 2004, note titled *Lowering the Bar*.

We do not see much risk of further downward earnings revisions

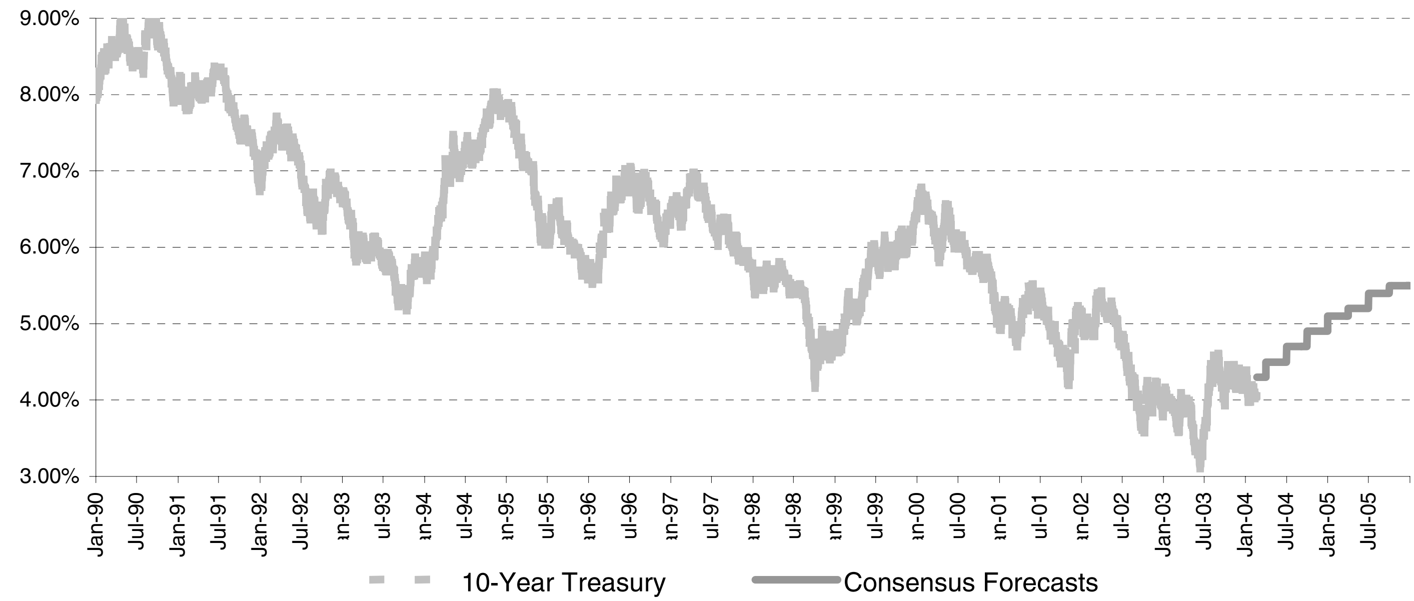
By bringing earnings expectations to more attainable levels—and remarkably doing so without meaningfully affecting the group—the likelihood of negative earnings revisions has declined. We view this as a positive because it eliminates a risk, but would caution that we do not believe many of the stocks are equipped to surprise to the upside in light of the current challenging market backdrop.

Interest rates appear more prone to rise than fall from current levels

Interest Rate Risk

We are not daring (dumb) enough to attempt to predict interest rates, but we do buy into expectations that rates are more likely to rise than fall at this time—market expectations for interest rates are now pointing upward. (See Exhibit 3.) From the current record lows, we believe it hard to imagine further meaningful declines in interest rates.

Exhibit 3: 10-Year Treasury Including Consensus Forecasts



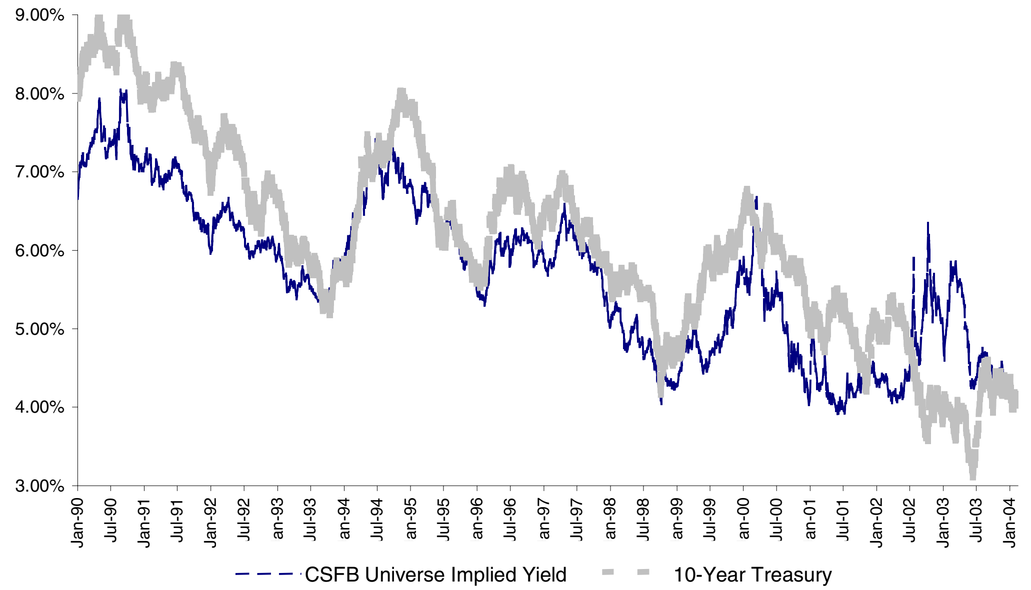
Source: CSFB Equity Research, Bloomberg.

Interest rates are important to utilities for two reasons:

1. the relationship to allowed ROEs (which we discuss in the following section)
2. the market's relationship between rates and dividend yield

Historically there was a strong relationship between utility dividend yield and the 10-year treasury, highlighting the market's view that utilities represented an equity market proxy for a fixed income investment. For a group of highly regulated utilities, the relationship was significant during the 1990s, only to fall apart with the group's troubles in the early 2000s. (See Exhibit 4.)

Exhibit 4: **CSFB Utility Universe Yield versus 10-Year Treasury**



Source: CSFB Equity Research, Company Data, Bloomberg.

Increased exposure to competitive wholesale markets and the reduced relationship between allowed ROEs and interest rates make utilities less "fixed income like" than in the past

We believe that two distinct structural changes have occurred in the electric utility sector that makes the companies much less like equity market surrogates for fixed income investments:

1. More competitive market exposure. With the development of competitive wholesale markets and utilities selling between 5-15% of generation into this market, the earnings stream composition is not as stable as in the past.
2. ROEs and rates (we discuss in greater detail in the section on Rate Case Exposure). Over the past decade or so, utilities had rate case hearings much less frequently and, in turn, allowed returns remained high despite declining interest rates. The reduced relationship between interest rate movements and utility earnings responsiveness makes the group even less like a fixed income security, further softening the yield and interest rate relationship.

The broader market expectation is that with the widely embraced back-to-basics themes and focus on regulated operations, the relationship between rates and yields should reorganize. With rates appearing more likely to rise than not, the implication would be stock price pressure at the utilities if yields are to track interest rates since the capacity for raising dividends appears limited. That said, we are not convinced the relationship will return to the same significance as in the past owing to the structural changes in the utility sector even as companies focus more on back-to-basics strategies.

Position in less regulated utilities to reduce potential interest rate drag

To help reduce the drag from rising rates, we would look to position in utilities with a less regulated business mix/exposure, reducing the similarities to fixed income securities and the associated stock price pressure move likely at the regulated utilities.

Utility earnings streams historically supported the view of utilities as fixed income surrogates…

…but structural changes and reduced rate case activity have softened this relationship

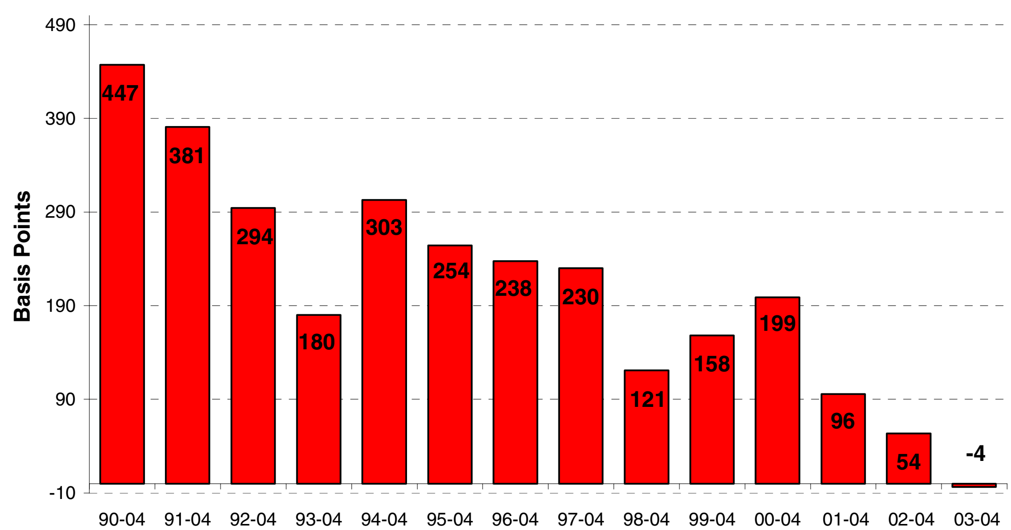
Rate Case Exposure

Several recent rate cases (or at least staff filings) suggest the split between interest rate movements and allowed ROEs may be over or, at a minimum, are not going to widen.

Utilities historically would have a rate case hearing every couple years, with the state commissions adjusting allowed ROEs with movements in interest rates to maintain a discernible equity risk premium (over owning bonds). The old model worked because utilities were regulated monopolies—about as close to a bond as could be found in the equity market.

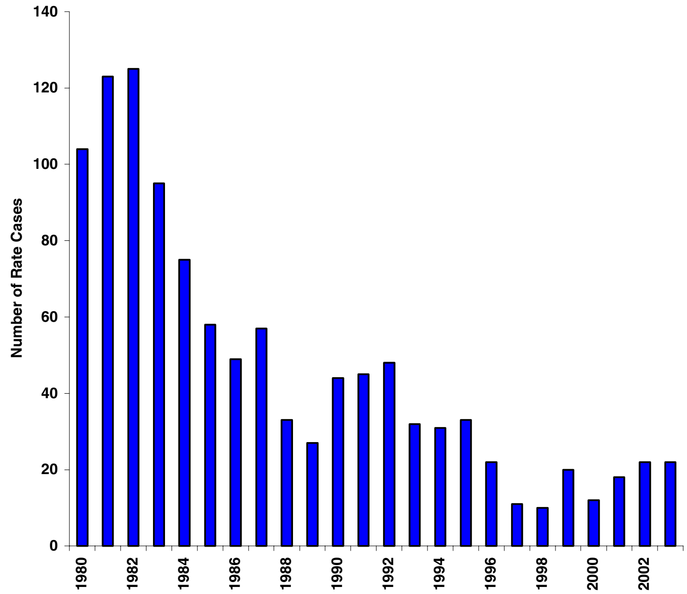
With the introduction of competitive wholesale markets, expansion into businesses outside of regulated utility functions, and deregulation, the frequency of rate cases slowed with the most recent rate cases for many utilities dating back to the mid-1990s. Since these rate cases, interest rates have fallen considerably, and in turn the equity risk premium for utilities has widened. (Exhibit 5 shows the cumulative interest rate changes.) In recent years the number of rate cases has declined (Exhibit 6) while ROE adjustments have been much less dramatic than interest rate movements. (See Exhibit 7.)

Exhibit 5: 10-Year Treasury—Cumulative Interest Rate Change Since 1990



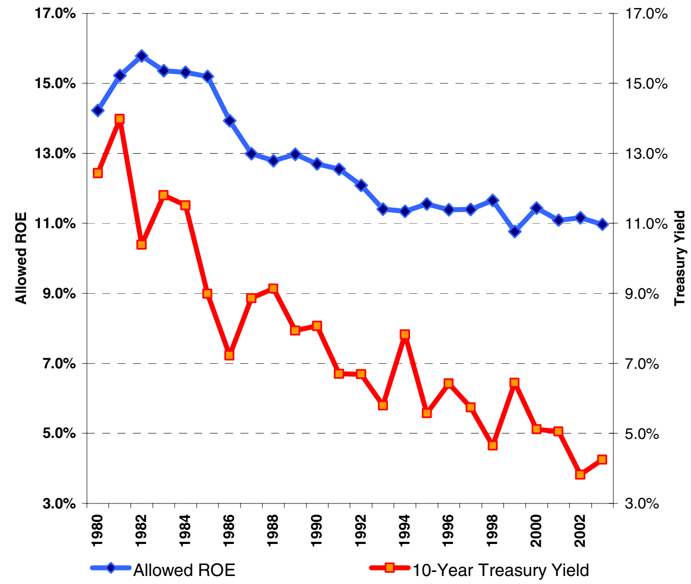
Source: CSFB Equity Research, Bloomberg.

Exhibit 6: Number of Rate Cases Per Year



Source: CSFB Equity Research, Regulatory Research Associates.

Exhibit 7: Allowed ROE Adjustments versus 10-Year Treasury Yields



Source: CSFB Equity Research, Regulatory Research Associates.

An uptick in rate case activity and commission focus on returns could translate into pressure on allowed ROEs

We are now seeing the tide start to shift, with more companies currently facing rate cases, or with them at least on the horizon. Several recent cases had reductions in allowed ROEs with additional negative staff recommendations in other pending cases. While these events partly reflect state-specific issues (some are still supporting high/higher ROEs), commissions appear more interested in the ROE/interest rate spreads and the rates being charged to customers as rate bases grow.

We are not going as far as to predict that future rate cases will automatically yield lower allowed ROEs, but we do see increased risk that returns could come under greater scrutiny with future cases. Pressure on allowed returns in a rising interest rate environment would be a double whammy for the earnings power of regulated utilities.

November Elections

An interesting dynamic to consider will be the November 2004 elections, as the implications for utility companies and investors could be greater than it appears on the surface.

Dividend tax relief, and the group's 1.0-1.5 times P/E multiple increase, will be at risk with a Democratic presidential victory

On the presidential side, the primary consideration will be tax policy—more specifically, dividend tax policy. President Bush's agenda includes making the tax cuts implemented during his first administration permanent (versus the current staggered expiration dates). All of the Democratic contenders plan to push legislation repealing the tax cuts that are viewed to benefit the rich, including the dividend tax cut.

Based on the after-tax return improvement for utility investors with the tax cut, we believe the group has correctly benefited from a 1.0-1.5 times P/E multiple increase to recognize the financial benefit. (See Exhibit 8.) Depending on poll results during the fall and ultimately the final election outcome, utility stocks face potential risk based on the election leader and ultimate winner.

Exhibit 8: **Dividend Tax Cut Impact**

	Old Tax	New Tax
Dividend Yield	5.0%	5.0%
Tax Rate	35.0%	15.0%
After-tax Yield	3.3%	4.3%
After-tax Return Pick-up	**1.0%**	

Source: CSFB Equity Research.

Congressional elections will impact the look of the Energy Bill and environmental legislation

Congressional elections will also play a part in utility prospects, specifically related to the Energy Bill and future environmental legislation. The Republicans were only one vote short in the Senate last fall from passing the Energy Bill, so potentially a one-vote shift in their favor would get the legislation passed. Gains by the Democrats would likely end the prospects of passing the Energy Bill, or at least one that excludes the ban on MTBE litigation. (See our report *Regulation through Legislation*, September 3, 2003, for more Energy Bill thoughts.)

Environmental legislation remains a sticking point and will likely be a striking point for the Democrats following Bush's easing of New Source Review (NSR) rules. We think NSR is a short-term issue that will be resolved with a more significant, organized, and comprehensive set of environmental requirements. Although many of the ultimate environmental goals are consistent, the magnitude of the reductions and the reasonableness of the timeframe will be important differences between the two parties. Another wave of environmental legislation is needed and will probably result in structural changes (which will lead to the permanent decommissioning of inefficient older assets). The actual implementation of this legislation will be key for assessing the economic impact on the utilities.

Flight to Lower Quality

Buying struggling utilities was an effective strategy in 2003 that is being pursued again in 2004

An effective investment strategy in 2003 (and the key to keeping up with the index) was buying struggling utilities under the premise that they would recover, or at least move away from the brink. Moving into 2004, we are seeing considerable interest in buying any of the still depressed utilities under the thesis that they too will turn the corner. We don't disagree with the motivation—we highlighted buying depressed names as an effective strategy for investment outperformance in *Penny Wise, Pound Foolish* (January 14, 2004)—we simply caution that the purchase price needs to compensate for taking on the incremental risk.

We only caution not to overpay for the sought after recovery plays

In pursuit of depressed names, the market has willingly bid up companies on still slippery footing to levels equal to, and at times greater, than valuations afforded higher-quality utilities that are executing. The solution to this situation is relatively straight forward: don't steer away from the depressed names, but don't overpay for them either. Uncovering the troubled names will likely only get harder from here.

New Income Funds

Seeing an increase in income focused investment funds, bringing new capital into the group

In the wake of the dividend tax cut and a market searching for segments that have yet to make major moves, we are seeing a rise in new dedicated income oriented investment funds. Covering utilities, we are always pleased to see new capital being directed into the group and would agree that some of the marginal buying support has come from these new funds. A quick, informal survey of our institutional sales force came up with over $4.0 billion of new income oriented funds within the past 12 months and potentially more to come (our apologies to those we overlooked).

But would note that not every new dollar will go to supporting the existing utility equity base

While the size of the new funds illustrate the potential flow of new capital into the group, we should note the following:

- Income funds have a breadth of industries to invest in—not all of this capital is going to flow into the utility sector.
- New equity issuances will absorb some of the capital from these funds. We have recently seen a decent amount of new equity issuance (Exhibit 9) with more likely to come. Additionally, the extensive use of DRIPs (dividend reinvestment plans) inserts more new equity into the market, which eventually looks for a home.
- The total market capitalization for the largest utilities is over $250 billion—the new funds can have an impact at the margin but probably not enough to see a sustainable step function change in valuations.

We are not trying to minimize the positive impact from new capital coming into the group, but we want to highlight that the impact may not be as meaningful as some suggest. That said, the effort to put new capital to work could provide some near-term valuation support.

Exhibit 9: Equity Issuance, 2003

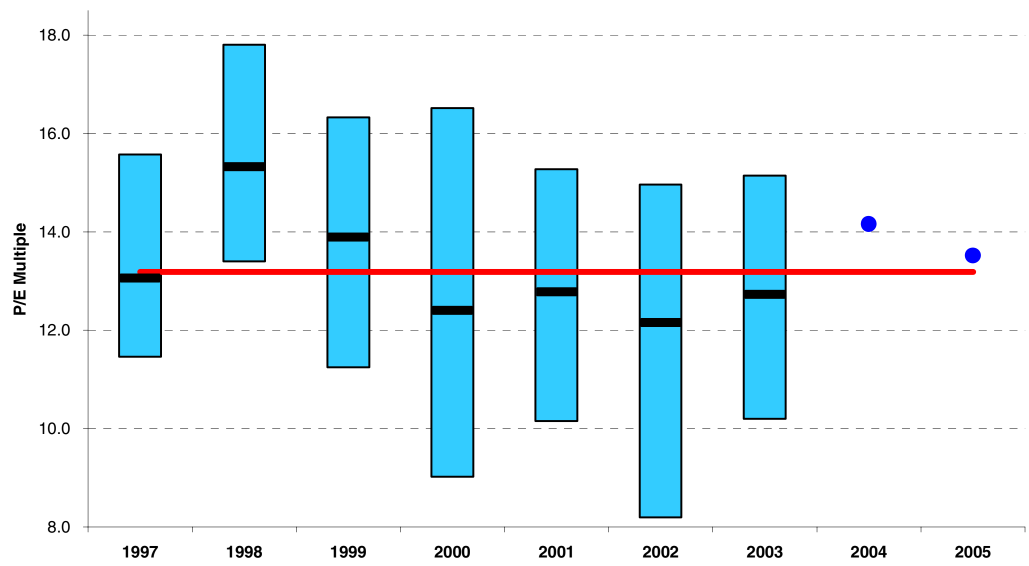
Filing Date	Issuer	Total Amount Offered ($MM)
02/27/03	American Electric Power Co Inc	$1,177
09/11/03	FirstEnergy Corp	$966
05/01/03	Duke Energy Corp	$770
05/20/03	Dominion Resources Inc	$684
11/06/03	Calpine Corp	$600
05/13/03	Centerpoint Energy Inc	$575
07/09/03	TXU Corp	$526
01/13/03	KeySpan Corp	$480
10/08/03	Sempra Energy	$420
01/22/03	Oneok Inc	$403
05/15/03	PPL Corp	$400
05/19/03	Consolidated Edison Co of New York	$381
10/01/03	Public Service Enterprise Group Inc - PSEG	$367
06/17/03	AES Corp	$346
07/01/03	Alliant Energy Corp	$332
05/20/03	Williams Companies Inc	$300
02/11/03	Sierra Pacific Resources	$300
05/15/03	PPL Corp	$270
12/01/03	CMS Energy Corp	$250
01/22/03	Oneok Inc	$237
12/11/03	Centerpoint Energy Inc	$225
06/18/03	Reliant Resources Inc	$225
01/14/03	Ameren Corp	$223
12/03/03	Dominion Resources Inc	$200
08/05/03	Oneok Inc	$181
01/31/03	Cinergy Corp	$177
07/31/03	Dynegy Inc	$175
06/05/03	Southern Union Co	$175
11/19/03	WPS Resources Corp	$173
07/09/03	CMS Energy Corp	$150
08/07/03	Vectren Corp	$148
02/11/03	AGL Resources Inc	$142
06/05/03	Southern Union Co	$125
04/24/03	Black Hills Corp	$124
08/21/03	OGE Energy Corp	$115
06/18/03	Atmos Energy Corp	$101
12/23/03	El Paso Corp	$69
11/11/03	Plug Power Inc	$59
11/19/03	El Paso Corp	$52
12/11/03	Empire District Electric Co	$42
		$12,663

Source: Company data, CSFB estimates.

Healthy Valuation

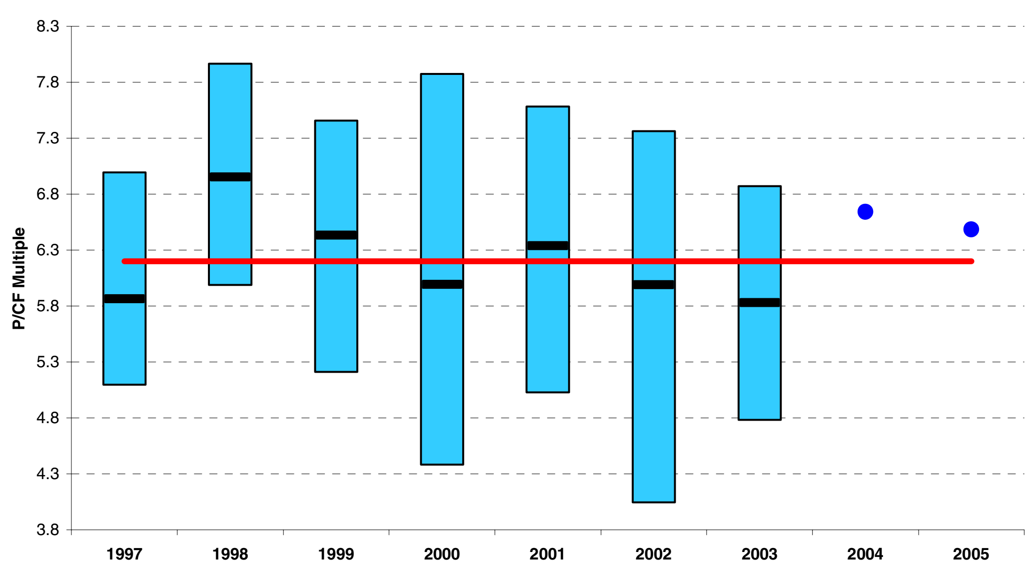
The electric utilities currently trade above historical averages and are trending toward the upper end, suggesting that the group may be nearing the end of the road for multiple expansion. (See Exhibit 10 and Exhibit 11.)

Exhibit 10: Price to Earnings Trading Bands



Source: CSFB Equity Research, company data.

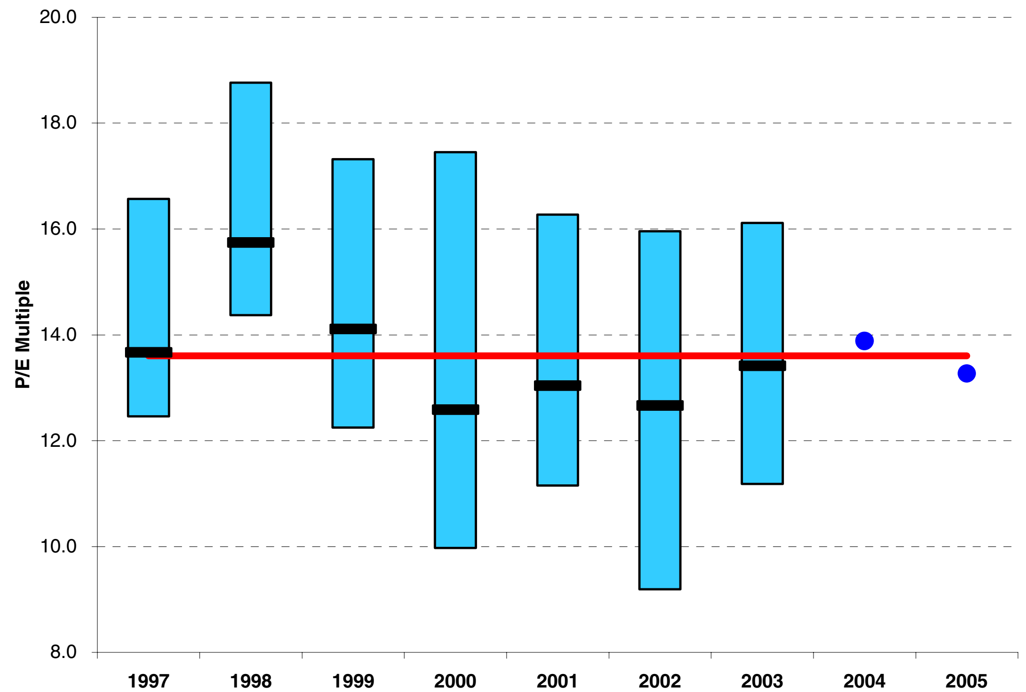
Exhibit 11: Price to Cash Flow Trading Bands



Source: CSFB Equity Research, company data.

We recognize that changes in the dividend tax law justify higher multiples to reflect the roughly 1% after-tax increase in returns associated with the dividend tax cut. (See Exhibit 8.) Incorporating this consideration in our look at historical valuation, we see the group is still on par with historical levels despite the challenges ahead. (See Exhibit 12.)

Exhibit 12: Price to Earnings Trading Bands, Adjusted for the Dividend Tax Cut

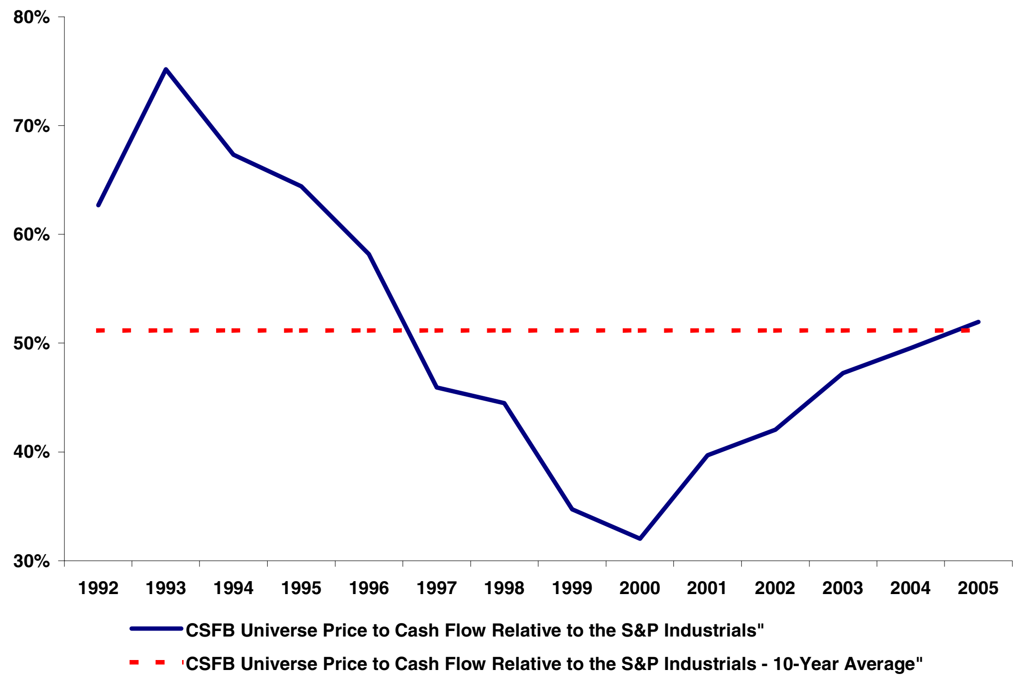


Source: Company data, CSFB estimates.

The group is approaching historical market multiple parity despite very different earnings outlooks

Relative to the broader market, the electric utilities are approaching fair valuation (Exhibit 13:). Considering the significantly higher growth expectations for the S&P Industrials (up 14% in 2004 and 2005) versus the Utilities in the sub-5% growth range, we believe the discount to absolute parity and current closeness to historical levels is fair. Additionally, the S&P Industrials yield approximately 1.3%, reducing the after-tax relative returns pick-up from the dividend tax law change and the argument for a higher relative valuation.

Exhibit 13: Price to Cash Flow Multiple Relative to the S&P Industrials



Source: CSFB Equity Research, company data.

Companies Mentioned *(Price as of 20 Feb 04)*

American Electric Power Co., Inc. (AEP, $33.54, NEUTRAL, TP $29.00, UNDERWEIGHT)
Constellation Energy Group Inc. (CEG, $39.62, OUTPERFORM, TP $41.00, UNDERWEIGHT)
Dominion Resources (D, $62.80, OUTPERFORM, TP $69.00, UNDERWEIGHT)
Duke Energy (DUK, $21.52, NEUTRAL, TP $20.00, UNDERWEIGHT)
Edison International (EIX, $22.13, RESTRICTED, UNDERWEIGHT)
FirstEnergy (FE, $37.92, OUTPERFORM, TP $40.00, UNDERWEIGHT)
PG&E Corporation (PCG, $27.31, NEUTRAL, TP $28.00, UNDERWEIGHT)
Pinnacle West Capital Corp. (PNW, $37.91, NEUTRAL, TP $39.00, UNDERWEIGHT)
Public Svc Ent (PEG, $45.91, NEUTRAL, TP $45.00, UNDERWEIGHT)
Southern Company (SO, $29.83, UNDERPERFORM, TP $28.00, UNDERWEIGHT)
TXU Corporation (TXU, $24.83, NEUTRAL, TP $25.00, UNDERWEIGHT)

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Earnings Release

ChevronTexaco Corp. (NYSE-CVX-$87.57) **Price Target: $90.00**

Jonathan S. Geurkink (206) 386-4709 Value Recommended List—Appreciation: HOLD

- ChevronTexaco announced Wednesday it had regained access to one of its oilfields in southern Nigeria after an 11-month absence due to local uprisings and violence.
- The Company hopes to restore 140,000 barrels per day of production in the region within the next 18-months. The move is significant as shut-in Nigerian operations have hampered the Company's otherwise strong results during the past year. Total production for 2003 averaged approximately 2.9 million barrels of oil equivalent per day.
- Our price target for ChevronTexaco is $90, based on a 13x multiple to peak earnings, which we estimate to be in the range of $6.50–$7.00 per share. There is not a lot of trading history for ChevronTexaco since its merger just over two years ago, but Chevron, on a stand-alone basis, historically traded at a price-to-earnings multiple in the mid-to-high teens range on average.
- We believe the primary risk to the stock achieving our price target includes worldwide economic decline, which would depress oil and gas prices from current levels.

Earnings Release

Puget Energy, Inc. (NYSE-PSD-$23.30) **Price Target: $27**

Greg M. Stevenson (206) 464-5951 Value Recommended List – Appreciation/Income: HOLD/HOLD

- Puget Energy reported 4Q03 earnings of $0.48, down 12.7% from 4Q02 and $0.09 below consensus expectations. Earnings in the quarter were adversely affected by increased property tax and depreciation expense, higher federal income taxes and a $1.5M hit to earnings from a rate-case settlement. For 2003, the Company reported earnings of $1.26, up 1.6% from a disappointing year in 2002.
- Customers growth in 4Q03 year-over-tear was 3.6% on the gas side of the business while the electrical business grew 2.1%.
- Company expects to file for a general rate case increase in 2Q04 and is still awaiting results from a power rate case filed in 2003 which is expected to have a decision made in March or April.
- Management guided earnings expectations for 2004 to the range of $1.50-$1.60, below current consensus of $1.80. Most of the increase in earnings expected in 2004 is directly due to the company having already reached the limit on excess power costs when the Power Cost Adjustment mechanism kicks in. It should also be noted that current guidance reflects management's position on the pending power rate case while the staff of the regulator has initially recommended a lower power rate increase is appropriate.
- Capex is expected to increase to $450M in 2004, of which $375M is for maintenance. Given the sizable increase over 2002 and 2003 ($224M and $270M respectively) and its effect on cash flow, we will be following up with management on their capex funding plans for this year. (Management indicated on the call that the maintenance capex figure in 2004 will contain several one-time items.)
- Trading at approximately 15x the low end of the guided range for 2004 earnings and with earnings likely to grow faster than the industry over the next two years, the stock appears fairly valued near term and the $1/share (4.3%) annual dividend appears secure. Our price target is $27, which is based on a price-to-earnings multiple of 14.0x our estimate of Puget's normalized earnings power ($1.80 to $2.00). Historically, Puget's stock has traded at an average multiple of 13.5x earnings. Maintain HOLD on Value Recommended List – Appreciation/Income
- We believe the primary risk to Puget Energy's stock achieving our price target include economic deterioration in its service territory and unfavorable regulatory action. Puget's earnings are dependent, among other things, on weather and hydro conditions in the Pacific Northwest.

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BUY Immediate purchase is recommended; the stock is expected to outperform the general market over the next 12-18 months.

HOLD Holding the stock is recommended. The stock has moved out of our preferred buying range, but there is further upside to the share price; or stated objectives at the time of purchase have changed and share appreciation may take another 6-12 months.

SELL The stock has reached the stated price objective and appreciation has been achieved; or certain company fundamentals have changed which warrant investors selling the stock to avoid price decline.

Notes
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Rating	% of covered companies with this rating	% for which IB Services have been provided
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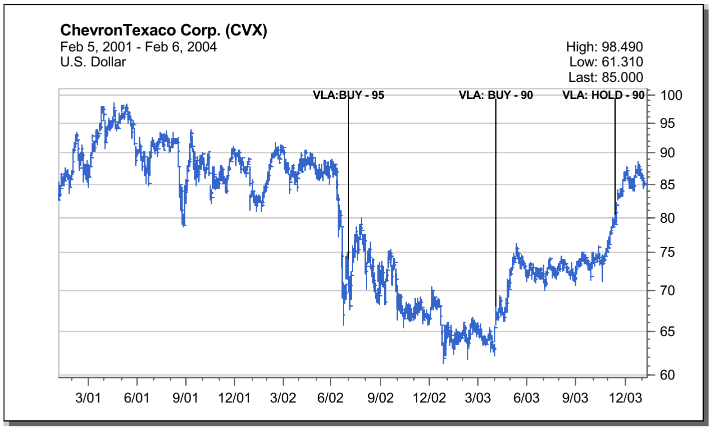
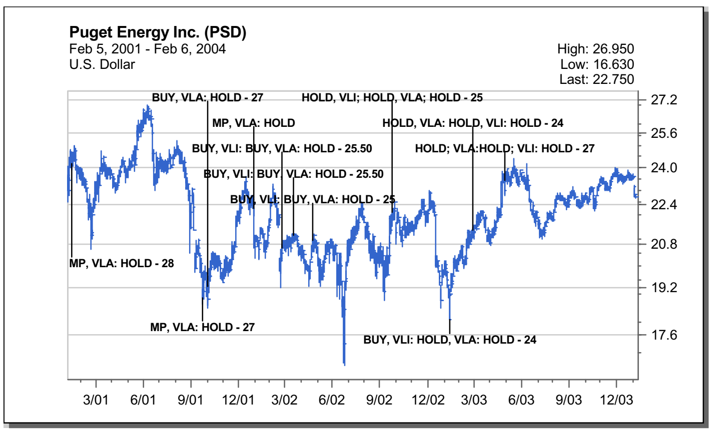
HOLD	75%	5%
SELL	5%	0%
Value Recommended List—Appreciation		
BUY	14%	0%
HOLD	68%	0%
SELL	18%	0%
Value Recommended List—Income		
BUY	25%	0%
HOLD	75%	0%
SELL	0%	0%
Growth Recommended List		
BUY	60%	0%
HOLD	40%	0%
SELL	0%	0%

Updated on 1/19/2004

Annotated Price History Charts for all subject companies are located on the following page.

Price History Graphs





February 12, 2004

United States
Energy & Power
Power & Utilities

Puget Energy (PSD - $22.51) 2-Equal weight

Earnings Review

2003 Results and 2004 Outlook Disappoint

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Investment conclusion

- We believe PSD is a solid total return story with modest utility growth plus a dividend yield of 4%+.

Summary

- Puget reported 4Q03 EPS of $0.48 versus $0.55 in 4Q02. The results fell short of our and street estimates of $0.57 per share. For the year, the company reported EPS of $1.26 which was below the guidance range of $1.30-$1.40.
- The significant decline in quarter over quarter results was primarily driven by higher income taxes and operating expenses. The lower 4Q03 results were also the primary driver of the year-end EPS miss.
- The company provided EPS guidance for 2004 of $1.50-$1.60. This is $0.20-$0.30 below our estimate and the street average of $1.80.
- We believe the company provided a conservative EPS range that it can confidently achieve. We are lowering our 2004 EPS estimate to $1.55 from $1.80.
- As a result of our new 2004 EPS estimate, we are also lowering our price target.

Stock Rating:	
New:	2-Equal weight
Old:	2-Equal weight

Target:	
New:	22.00
Old:	24.00

Sector View: 3-Negative

EPS (FY Dec)

	2002	2003			2004			% Change	
	Actual	Old	New	St. Est	Old	New	St. Est	2003	2004
1Q	0.28	0.45A	0.45A	0.45A	NA	NA	0.63E	61	NA
2Q	0.34	0.22A	0.22A	0.22A	NA	NA	0.39E	(35)	NA
3Q	0.07	0.10A	0.10A	0.10A	NA	NA	0.12E	43	NA
4Q	0.55	0.57E	0.48A	0.57E	NA	NA	0.72E	(13)	NA
Year	1.24	1.34E	1.26A	1.34E	1.80E	1.55E	1.80E	2	23
P/E			17.9			14.5			

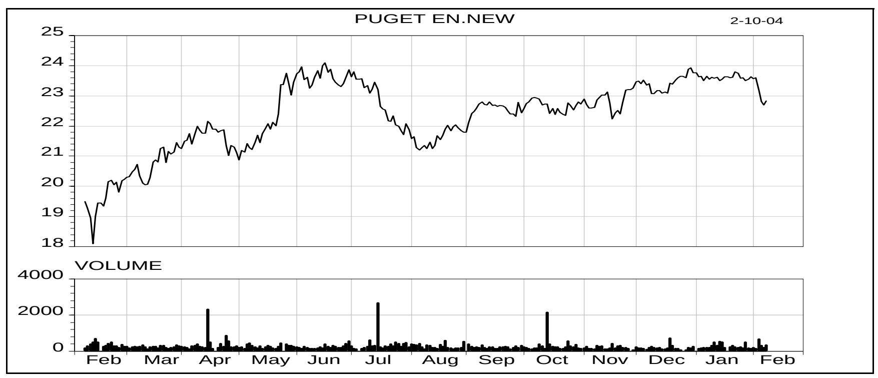
Market Data

Market Cap	2120.4M
Shares Outstanding (Mil)	94.2
Float	93
Dividend Yield	4.40
Convertible	No
52 wk Range	24.40 - 18.10

Financial Summary

Revenue FY03	NA
Five-Year EPS CAGR	4.00
Return on Equity	NA
Current BVPS	16.08
Debt To Capital	59.4

Stock Overview



4Q03 and Yr-end Results Disappoint

Yesterday, Puget reported 4Q03 earnings of $0.48 per share versus $0.55 per share last year. The results were below our and the street estimate of $0.57 per share. As a result of the lower than expected fourth quarter earnings, the year-end 2003 results of $1.26 per share fell below the company's guidance for the year of $1.30-$1.40 per share and our estimate of $1.34.

The lower than expected 4Q03 results were primarily driven by higher income taxes (-$0.04), higher O&M expenses (-$0.04), and lower other income (-$0.01). On a quarter over quarter basis, the major negative variances were for higher income taxes (-$0.10), higher D&A (-$0.01), higher property taxes (-$0.01), and lower other income ($0.01). On the positive side, improved margins on electric and gas sales added $0.04 per share and lower interest expenses contributed another $0.04 per share.

Fourth Quarter Highlights

On a segment basis, the **Regulated Utility Operations** earned $0.45 per share compared to $0.49 last year. The lower results were mainly attributable to the higher operating expenses and income taxes outlined above. In addition, the utility was negatively affected by increases in other O&M expenses, including $0.02 per share for unplanned maintenance expenditures resulting from weather-related

PLEASE SEE ANALYST(S) CERTIFICATION(S) ON PAGE 3 AND IMPORTANT DISCLOSURES BEGINNING ON PAGE 4

damage to PSE's electric distribution system and an equipment failure at one of the utility's hydro facilities and $0.01 per share of incremental costs associated with its energy resources initiatives.

Partially offsetting the higher operating expenses was a $5.5 million increase in electric and gas margins to $258.7 million. The improved margins were primarily driven by a $7.2 million increase in gas margins to $82.8 million, which benefited from weather that was 4.5% colder than last year and a 3.6% increase in customers. Electric margins were down $1.6 million to $175.9 million as a result of incurring $2.6 million of excess power costs under the PCA mechanism versus last year.

InfrastruX's earnings slipped to $0.01 per share compared to $0.02 per share in 4Q02 due to the continued slow-down in utility construction work. Results for the **Other** segment were flat at $0.02 per share.

Company Puts a Hole in 2004 Guidance

Puget provided 2004 EPS guidance of $1.50-$1.60, which is $0.20-$0.30 below our estimate and the average street estimate of $1.80 per share, but would not provide specific earnings guidance by segment. Management did, however, comment that it expects InfrastruX's earnings contribution to exceed the 2003 level of $0.02 per share but would not provide guidance beyond that statement. If we assume that InfrastruX earns $0.02 per share this year, the implication is that PSE will earn between $1.48 and $1.58 per share. The upper and lower bands of the range will likely be dependent upon the outcome and timing of the Power Cost Only Rate Case (PCORC) and the combined gas and electric general rate gas (GRC) that the utility plans to file in early 2Q04. The company guidance does not reflect the outcome of the GRC but does include about $0.01 per share from PCORC. (This assumes about 8 months of benefit ($0.02 per share for full year) and that the company gets full relief as filed ($64.4 million increase).

Making Sense of it All

In our opinion, the company has given the street a conservative EPS range that it is confident can be achieved. Keep in mind that, during 2003, Puget took down guidance three times—once in February by $0.25 per share for higher power costs, again in April for mild 1Q03 weather (-$0.10), and finally in October to adjust InfrastruX's outlook (-$0.10)—and the company still missed the number. Given this backdrop and the uncertain outcome of the regulatory proceedings for the PCORC and the GRC, we can understand why the company would err on the conservative side.

We would also note that management highlighted that it continues to evaluate strategic options for InfrastruX and that InfrastruX's management was conspicuously absent on the earnings conference call.

How the Math Works

At the high end of the range, the utility is expected to earn about $1.58 per share. The company arrives at this figure by starting with the actual 2003 results for PSE of $1.25 and then adds back the following items: $0.25 per share for power cost underrecovery under the PCA mechanism, $0.10 per share for normal weather, and $0.01 per share for the PCORC. This calculation yields $1.61 per share, implying a negative offset of $0.03 per share. We believe this is to account for unrecoverable storm costs above its budgeted amount. According to the company, a January 2004 ice storm resulted in $5 million of storm costs, which is equivalent to its entire storm cost budget for the year. Because this storm occurred in a rural part of its service territory and did not affect more than 25% of its customers, the company was not able to defer these costs for future recovery. Thus, in the event of a similar storm(s), additional expenses would be incurred and reduce net income. (In the planned 2Q04 GRC filing, the company plans to address this issue by asking for a clarification of the definition of catastrophic damage and fine tuning the deferral mechanism associated with these types of expenses.) Presumably the low end of the range takes into account a higher level of storm costs and possibly the impact of unfavorable weather conditions.

On a normalized basis, PSE appears to be earning about $1.60 per share (excluding the PCORC benefit). This implies a financial ROE of about 10.3% using the average common equity for 2002 and 2003. Assuming the $1.48 to $1.58 range is correct for PSE, the guidance appears to assume an ROE in the range of 9.8% to 10.2%. PSE's approved ROE is 11.00%.

Lowering 2004 EPS Estimate

Given management's conservative outlook and the potential regulatory pitfalls in 2004, we are lowering our 2004 EPS estimate to $1.55 from $1.80. We have assumed that InfrastruX earns about $0.02 per share (down from our prior estimate of $0.09 per share) and that PSE earns about $1.53 per share (vs. $1.71 per share previously).

Due to the lack of visibility around PSE's earnings post 2004, we are maintaining our 2005-2007 EPS estimates. The resolution of the pending PCORC, the planned GRC, and the potential filing of two new PCORCs before year-end should provide a much better picture of the utility's go forward earnings power.

Regulatory Update

Power Cost Only Rate Case

Table 1: PCORC - Remaining Procedural Schedule

Event	Date	Interval
PSE Rebuttal Testimony	February 13, 2004	14 days
Evidentiary Hearing	February 23-27, 2004	10 days
Simultaneous Initial Briefs	March 12, 2004	14 days
Simultaneous Reply Briefs	March 19, 2004	7 days

Source: WUTC and Lehman Brothers

As seen in Table 1, the company is expected to file its rebuttal testimony in the PCORC for the Frederickson 1 plant acquisition this Friday (2/13). Although the staff of the WUTC found that the acquisition of the interest in the Frederickson 1 plant was prudent and appropriate to include in rates, it only recommended an increase in rates of $7.5 million (versus the company's proposal of $64.4 million) primarily due to $33 million of fuel disallowances related to the Tenaska and Encogen power plants and a $12 million prudence review adjustment for the Tenaska acquisition.

We would expect PSE to respond to both of these issues in its rebuttal testimony. While the staff's position on the fuel disallowances has the appearance of a 20/20 look back, we believe that staff would like to get justification of the company's actions and is not necessarily seeking to condemn its prior actions. When we met with staff last week, they appeared to be open to dialogue but, depending on the rebuttal filing, may seek a delay in the process in order to process any new data/testimony. The company expects a final order by mid-April, which does not assume any delays.

PSE filed a '203' request with the FERC on January 14 and asked for a decision on or before March 25, 2004. According to the company, the application is on track to meet this deadline. We do not expect to see a repeat of the OGE/McClain issues as the Bonneville Power Administration owns most of the transmission and generation in the region and Frederickson is not interconnected to PSE's transmission system.

GRC

PSE plans to file a straightforward ratecase that will recover its investments in gas and electric infrastructure. The company will also seek a 45% pro forma equity structure that it will achieve over time, similar to the 2002 GRC settlement. Other components include rate design and, as previously mentioned, a clarification of the catastrophic damages definition. The company does not expect the case to take the full statutory 11 months. Given the historical treatment by the commission and comments made by WUTC staff and commissioners, we would expect a settlement to be reached prior to the 11 months.

Valuation—Lower Price Target to $22

Due to PSD's improving balance sheet and credit profile, we believe PSD should trade in line with the average 2005 P/E multiple of its peer group or about 13.9x. Applying this multiple to our new 2004 EPS estimate of $1.55 results in a 12-month price target of $22 per share. Our previous price target of $24 per share reflected a EPS estimate of $1.80.

To develop a comparable peer group P/E multiple, we screened our current coverage universe for companies with a market capitalization between $1 billion and $4 billion. We further refined this group by eliminating those companies that were either distressed, did not pay a common dividend, or had a dividend yield in excess of 5.5%.

Analyst Certification:

I, Daniel Ford, hereby certify (1) that the views expressed in this research note accurately reflect my personal views about any or all of the subject securities or issuers referred to in this note and (2) no part of my compensation was, is or will be directly or indirectly related to the specific recommendations or views expressed in this note.

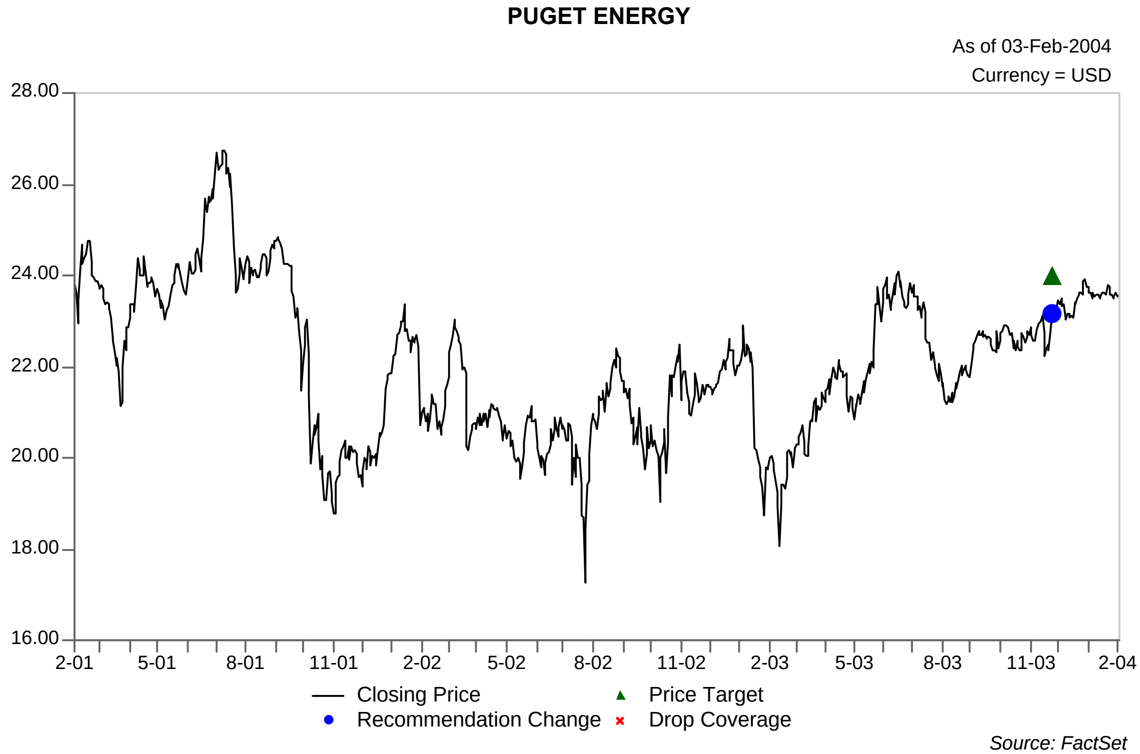
Company Description:

Puget Energy, Inc. is a public utility holding company with two primary subsidiaries: Puget Sound Energy, an electric and gas utility, and InfrastruX Group, a utility infrastructure contractor.

Company Name:	Disclosures	Ticker	Price (2/11)	Rating
Puget Energy	F	PSD	22.51	2-Equal weight

Important Disclosures

Rating and Price Target Chart: PSD



Date	Closing Price	Rating	Price Target
25-Nov-03	$23.19		$24.00

Date	Closing Price	Rating	Price Target
25-Nov-03	$23.19	2-Equal weight	

FOR EXPLANATION OF RATINGS PLEASE REFER TO THE STOCK RATING KEYS LOCATED AT THE END OF THIS DOCUMENT

Important Disclosures:
The analysts responsible for preparing this report have received compensation based upon various factors including the Firm's total revenues, a portion of which is generated by investment banking activities.

F - Lehman Brothers Inc. and/or an affiliate beneficially own 1% or more of any class of common equity securities of the subject company.

Risks Which May Impede the Achievement of the Price Target:
PSD: Puget's operations are primarily subject to federal and state regulatory risk, interest rate risk, exposure to the wholesale commodity markets, hydro conditions, and general economic conditions.

Key to Investment Opinions:

Stock Rating
1-Overweight - The stock is expected to outperform the unweighted expected total return of the industry sector over a 12-month investment horizon.
2-Equal weight - The stock is expected to perform in line with the unweighted expected total return of the industry sector over a 12-month investment horizon.
3-Underweight - The stock is expected to underperform the unweighted expected total return of the industry sector over a 12-month investment horizon.
RS-Rating Suspended - The rating and target price have been suspended temporarily to comply with applicable regulations and/or firm policies in certain circumstances including when Lehman Brothers is acting in an advisory capacity on a merger or strategic transaction involving the company.

Sector View
1-Positive - sector fundamentals/valuations are improving.
2-Neutral - sector fundamentals/valuations are steady, neither improving nor deteriorating.
3-Negative - sector fundamentals/valuations are deteriorating.

Stock Ratings From February 2001 to August 5, 2002 (sector view did not exist):
This is a guide to expected total return (price performance plus dividend) relative to the total return of the stock's local market over the next 12 months.
1-Strong Buy - expected to outperform the market by 15 or more percentage points.
2-Buy - expected to outperform the market by 5-15 percentage points.
3-Market Perform - expected to perform in line with the market, plus or minus 5 percentage points.
4-Market Underperform - expected to underperform the market by 5-15 percentage points.
5-Sell - expected to underperform the market by 15 or more percentage points.

Stock Ratings Prior to February 2001 (sector view did not exist):
1-Buy - expected to outperform the market by 15 or more percentage points.
2-Outperform - expected to outperform the market by 5-15 percentage points.
3-Neutral - expected to perform in line with the market, plus or minus 5 percentage points.
4-Underperform - expected to underperform the market by 5-15 percentage points.
5-Sell - expected to underperform the market by 15 or more percentage points.
V-Venture – return over multiyear timeframe consistent with venture capital; should only be held in a well diversified portfolio.

Distribution of Ratings:
Lehman Brothers Equity Research has 1619 companies under coverage.
40% have been assigned a 1-Overweight rating which, for purposes of mandatory regulatory disclosures, is classified as a Buy rating, 39% of companies with this rating are investment banking clients of the Firm.
40% have been assigned a 2-Equal weight rating which, for purposes of mandatory regulatory disclosures, is classified as a Hold rating, 10% of companies with this rating are investment banking clients of the Firm.
20% have been assigned a 3-Underweight rating which, for purposes of mandatory regulatory disclosures, is classified as a Sell rating, 65% of companies with this rating are investment banking clients of the Firm.

February 12, 2004
Rated: NEUTRAL

PUGET ENERGY, INC.

PSD – NYSE – $22.51
(Price: 2/11/04)

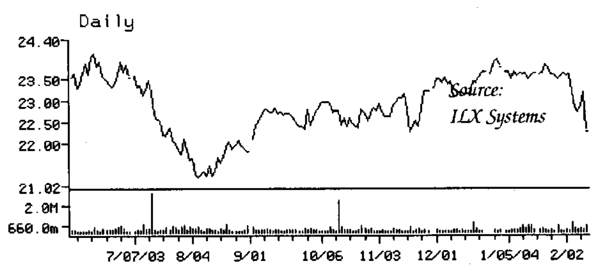
FY: DEC	2003A	3/31/04E	6/30/04E	9/30/04E	12/31/04E	2004E	2005E
Revenue ($M)	$2,491.5	*$781.7*	*$620.7*	*$535.9*	*$756.5*	$2,694.7	$2,835.5
Year-over-year revenue growth	4%	*16%*	*11%*	*4%*	*2%*	8%	5%
Price/Revenue ratio	.9x					.8x	.8x
EPS Revised	**$1.26**	***$0.65***	***$0.25***	***$0.04***	***$0.62***	**$1.56**	**$1.74**
EPS Previous	$1.35	-	-	-	-	$1.76	-
Price/EPS ratio	17.9x					14.4x	12.9x
EBITDA ($M)	$619.9	*$210.3*	*$147.4*	*$115.3*	*$207.3*	$680.2	$718.8
EV/EBITDA ratio	7.6x					6.9x	6.6x

Valuation Data

Long-term growth rate	5%
Debt/Cap	59.6%
Book value per share (12/31/03)	$16.81
Dividend (yield)	$1.00 (4.4%)
12-18 month Target Price	$22
5-year Target Price	$30
Return on Equity	8%

Trading Data

Shares outstanding (M)	99.6
Market Capitalization ($M)	$2,243
52-week low	$18.10
52-week high	$24.40
Average daily volume (3 mos.)	222,000
Float	100%
Index Membership	S&P400 MidCap
Industry	Electric/Gas Utility



Company Description
Bellevue, WA -- Puget Energy, Inc., through its wholly owned utility subsidiary, Puget Sound Energy, provides electric and gas services to more than 1.2 million customers, principally located in the Puget Sound region of Washington State. The firm has been focusing on low-risk energy distribution services, but has said it was seeking to return to a vertically integrated model. It is also developing a non-regulated utility services business called InfrastruX.

Utility Misses Quarter. Retaining NEUTRAL Rating in Wake of Lowered 2004 Estimate.

- Puget Energy reported disappointing 4Q'03 diluted EPS of $0.48, compared to $0.55 for 4Q'02. We were forecasting $0.57.
- Regulated EPS of $0.45 compared to $0.50 and our projection of $0.55. Regulated utility results were significantly below our forecast, as higher expenses for income taxes, power costs, depreciation, property taxes, and a regulatory settlement charge overwhelmed improved gas margins and lower interest expenses.
- We are lowering our 2004 EPS estimate by $0.20 per share to $1.56. However, our new estimate is $0.30 higher than Puget's 2003 EPS of $1.26, based on the fact the company has reached a $40 million cumulative cap on power costs and 1Q'04 is displaying a return to normal weather. As shown in our earnings model, we are also initiating quarterly estimates for 2004, as well as a 2005 EPS forecast of $1.74.
- Disappointed by reduced 2004 expectations for the utility, we are maintaining our 12-18 month target price of $22, or 13.3x the average of our revised 2004 earnings estimate and initiated 2005 forecast. We are maintaining our **NEUTRAL** rating.

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Please refer to page two of this report for detailed disclosure and certification information.

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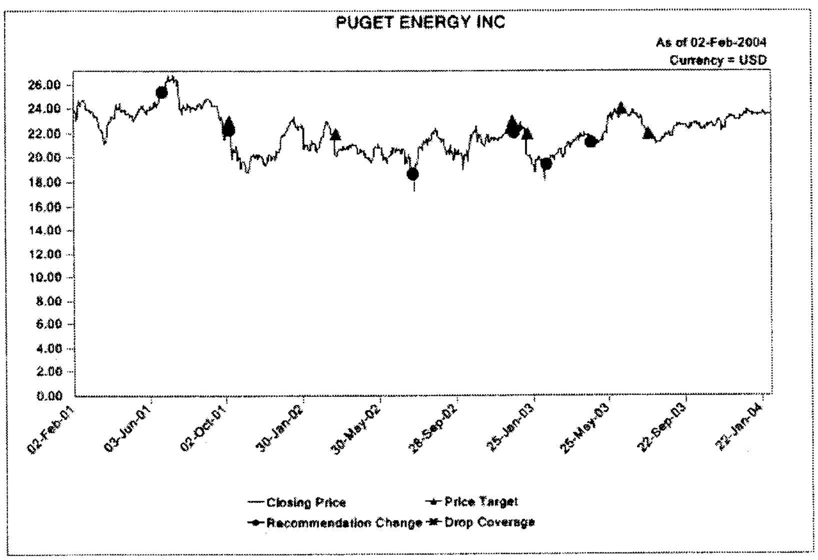
D.A. Davidson & Co. Ratings	Buy	Neutral	Underperform
Risk adjusted return potential	Over 15% total return expected on a risk adjusted basis over next 12-18 months	>0-15% return potential on a risk adjusted basis over next 12-18 months	Likely to remain flat or lose value on a risk adjusted basis over next 12-18 months

Distribution of Ratings (as of 12/31/03)	Buy	Hold	Sell
Corresponding Institutional Research Rating	Buy	Neutral	Underperform
Distribution of Institutional Research Ratings	41%	48%	11%
Corresponding Retail Research Rating	Buy, Core/Buy	Hold, Core/Hold	Avoid
Distribution of Retail Research Ratings	85%	15%	0%
Distribution of combined ratings	52%	40%	8%
Distribution of companies from whom D.A. Davidson & Co. has received compensation for investment banking services in last 12 mos	4%	8%	15%



D.A. Davidson & Co. has made two changes to its institutional ratings scale. The first occurred on June 18, 2001 and the second occurred on July 9, 2002. The corresponding scales are reproduced below.

D.A. Davidson & Co. Institutional Research Rating Scale (beginning 7/9/02)
Buy, Neutral, Underperform

D.A. Davidson & Co. Institutional Research Rating Scale (6/18/01 – 7/9/02)
Strong Buy, Buy, Neutral, Underperform

D.A. Davidson & Co. Institutional Research Rating Scale (6/1/99 – 6/18/01)
Buy, Outperform, Neutral, Underperform, Sell

PUGET ENERGY INC

Currency = USD

Date	Closing Price	Recommendation Change	Date	Closing Price	Price Target
24-Apr-2003	21.35	NEUTRAL	24-Jul-2003	22.05	22.00
14-Feb-2003	19.44	BUY	12-Jun-2003	23.84	24.00
26-Dec-2002	22.10	NEUTRAL	16-Jan-2003	20.24	22.00
22-Jul-2002	18.73	BUY	26-Dec-2002	22.10	23.00
05-Oct-2001	22.28	NEUTRAL	21-Mar-2002	20.29	22.00
21-Jun-2001	25.39	OUTPERFORM/BUY	05-Oct-2001	22.28	23.00

Target prices are our Institutional Research Department's evaluation of price potential over the next 12-18 months and 5 years based upon our assessment of future earnings and cash flow, comparable company valuations, growth prospects and other financial criteria. Certain risks may impede achievement of these price targets including, but not limited to, broader market and macroeconomic fluctuations and unforeseen changes in the subject company's fundamentals or business trends. Information contained herein has been obtained by sources we consider reliable, but is not guaranteed and we are not soliciting any action based upon it. Any opinions expressed are based on our interpretation of data available to us at the time of the original publication of the report. These opinions are subject to change at any time without notice. Investors must bear in mind that inherent in investments are the risks of fluctuating prices and the uncertainties of dividends, rates of return and yield. Investors should also remember that past performance is not necessarily an indicator of future performance and D.A. Davidson & Co. makes no guarantee, express or implied, as to future performance. Investors should note this report was prepared by D.A. Davidson & Co.'s Institutional Research Department for distribution to D.A. Davidson & Co.'s institutional investor clients and assumes a certain level of investment sophistication on the part of the recipient. Readers, who are not institutional investors or other market professionals, should seek the advice of their individual investment advisor for an explanation of this report's contents, and should always seek such advisor's advice before making any investment decisions. Further information and elaboration will be furnished upon request.

EPS Below Forecast

Puget Energy reported 4Q'03 diluted EPS of $0.48, compared to $0.55 for 4Q'02. We were forecasting $0.57. Utility results were significantly below our forecast, as higher expenses for income taxes, power costs, depreciation, property taxes, and a regulatory settlement charge overwhelmed improved gas margins and lower interest payments.

Regulated EPS of $0.45 compared to $0.50 and our projection of $0.55. Non-regulated EPS of $0.03 compared to $0.05 and our estimate of $0.02. Note that we separate earnings between regulated and non-regulated activities to more clearly keep tabs of the electric and gas business, having found over time that the timing of the utility's non-regulated activities is not predictable. This means we remove the earnings from the non-regulated activities of the company's utility, Puget Sound Energy, from the regulated activities and combine them with the results of InfrastruX, calling them "non-regulated" earnings.

Consolidated 4Q'03 revenues of $742 million rose $88 million, or 13%, primarily because gas revenues were sharply higher. The increase in gas revenues was primarily the result of rate increases to pass through the higher costs of purchased gas to ratepayers.

For 2003, Puget Energy reported revenues of $2.5 billion, net income available for common stock of $120 million, and EPS of $1.26. In comparison, in 2002, revenues were $2.4 billion, net income was $110 million, and EPS was $1.24.

Utility Experienced Cost Pressures

Quarterly electric revenues of $401 million rose $14 million, or 14%. This increase was due primarily to a $19 million increase in retail sales, which were partially offset by an $8 million decline in wholesale sales. Retail sales rose because retail and transportation volumes were 5% higher, due to 2% customer growth and 4% colder temperatures than a year earlier. After deducting from electric revenues the costs of generating and purchasing electric energy, Puget Sound Energy had electric margins of $176 million during 4Q'03. These electric margins were down $2 million, or 1%, as a result of the utility absorbing $6 million of excess power costs under the Power Cost Adjustment (PCA) mechanism compared to $3 million a year earlier.

Quarterly gas revenues of $252 million rose $79 million, or 46%, primarily due to higher tariffs under the current Purchased Gas Adjustment (PGA) mechanism to recover higher purchased gas costs. Gas revenues also rose due to a 10% increase in retail and transportation volumes stemming from colder temperatures, 3% customer growth, and an improved economy in the company's service territory in Washington. After deducting from gas revenues the costs of gas sales to retail and transportation customers, gas margins were $83 million in 4Q'03, which were up $7 million, or 9%, from 4Q'02.

The net impact of gas and electric margins combined provided a $0.04 EPS benefit to the recent quarter. Lower amounts for interest and preferred dividends payments, due to the retirement of more than $160 million of debt and preferred stock over the past year, added another $0.04 EPS benefit. These benefits were more than offset by several items, including: a $0.10 per share upward swing in income taxes, a $0.02 per share jump in higher power costs, a $0.01 per share rise in property taxes, a $0.01 per share increase in depreciation expenses, and a $0.01 per share charge for a regulatory settlement.

InfrastruX Results Disappoint

Revenues at InfrastruX of $86 million dropped $5 million, or 5%, due to difficult weather in the East that slowed construction and softness in infrastructure spending by utility customers. Earnings from InfrastruX on a standalone basis were $0.01 compared to $0.02.

Dropping 2004 EPS Estimate

We are lowering our 2004 EPS estimate by $0.20 per share to $1.56. Our regulated forecast is being reduced from $1.65 to $1.49. (For 2003, regulated results were $1.19 compared to $1.08 in 2002.) Helping 2004 regulated results should be the fact the company has now absorbed $40 million of power costs since the 2002 rate settlement agreement. Going forwarded, 99% of any higher power costs above the established regulatory level will be deferred and absorbed by ratepayers, with the company only required to absorb 1% of higher costs. We are also assuming a return to normal temperature in 2004. In 1Q'03, mild temperatures reduced results by approximately $0.10 per share. (January 2004 was 28% colder than January 2003, as measured by heating degree-days at the Seattle/Tacoma airport.) Our forecast of non-regulated earnings, which is principally InfrastruX, is being lowered from $0.11 per share to $0.07. (For 2003, InfrastruX contributed $0.02 per share compared to $0.10 in 2002.)

As shown in our earnings model, we are also initiating quarterly estimates for 2004, as well as a 2005 EPS forecast by $1.74, based on the benefits of assumed higher electric and gas rates.

Pending Rate Cases Important to 2005 Forecast

Sometime in 2Q'04, Puget Sound Energy plans to file a general electric and gas rate increase request. The Washington Utilities and Transportation Commission (WUTC) would be expected to take eleven months to review the request. The yet-to-be-specified rate increase, if granted, could help bolster 2005 results.

Puget has filed a "Power Cost Only Rate Review" request with the WUTC, to increase rates by $64.4 million to recover the company's planned investment to acquire a minority interest in the 249-megawatt gas-fired Fredrickson Power plant near Tacoma, Washington. If all goes as planned, the Fredrickson acquisition would be consummated in early April, with electric rates expected to rise by a low single digit percentage increase, and augmenting 2004 EPS by $0.02, which we will incorporate into our earnings forecast once regulatory approval is granted.

If approved by the WUTC, Puget will pay approximately $80 million to EPCOR Power Development Corporation for a 49.85% interest in Fredrickson, which is currently being upgraded to 275 megawatts. The price of Puget's 137-megawatt share of the expanded plant is approximately $590 per kilowatt of electric capacity, which we believe is a relatively attractive long-term price.

The company has not divulged how it might finance the Fredrickson transaction, but we suspect the company will use internally generated funds and draw on its bridge loan authority. Ultimately, we expect permanent financing for this plant, as well as for other resources we expect the company will acquire to satisfy a total need of 487 megawatts by the first of 2005. We also expect this financing to be in the form of equity and debt offerings under the company's remaining shelf registration of about $250 million.

After likely announcements later in 2004 for about 150 megawatts of wind-power capacity (providing an average 50 megawatts) and 300 megawatts of additional thermal resources, we would expect the utility to file "power cost only" rate applications to recover any investment incurred.

Maintaining Target Price and Rating

Disappointed by reduced 2004 expectations for the utility, we are maintaining our 12-18 month target price of $22, or 13.3x the average of our revised 2004 earnings estimate and initiated 2005 forecast. Despite a secure $1.00 per share dividend that provides a 4.4% yield, we believe shares of Puget offer investors little near term upside price potential. We are maintaining our **NEUTRAL** rating.

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PUGET SOUND ENERGY, INC.
BALANCE SHEET

($000's; years end 12/31)	2000	2001	9/30/2002	2002	9/30/2003	2003
Assets						
Utility Plant:						
Electric plant	$4,054,551	$4,167,920	$4,216,391	$4,229,352	$4,254,837	
Gas plant	1,459,488	1,551,439	1,613,009	1,645,865	1,714,071	
Common plant	351,051	362,670	376,943	378,844	389,073	
Less: Accumulated depreciation and amortization	(2,026,681)	(2,194,048)	(2,309,062)	(2,337,832)	(2,406,507)	
Net utility plant	3,838,409	3,887,981	3,897,281	3,916,229	3,951,474	
Other Property and Investments:						
Investment in Bonneville Exchange Power Contract	58,189	54,663		51,136		
Goodwill, net	45,655	102,151	130,635	125,555	134,692	
Intangibles, net		16,059	19,517	18,652	17,813	
Non-utility property and equipment, net		48,369	74,992	80,855	91,432	
Other	188,453	96,007	157,307	101,932	161,297	
Total other property and investments	292,297	317,249	382,451	378,130	405,234	
Current Assets:						
Cash	36,383	92,356	117,431	176,669	28,086	
Restricted cash				18,871	3,811	
Accounts receivable, net						
Less: Allowance for doubtful accounts						
Total accounts receivable	343,108	279,321	232,116	279,623	238,465	
Unbilled revenues	211,784	147,008	71,586	112,115	69,459	
Materials and supplies, at average cost	99,001	90,333	70,788	70,402	91,070	
Purchased gas receivable	96,050	37,228				
Current portion of FAS-133 unrealized gain (net of tax)		3,315	1,678	3,741	3,957	
Taxes receivable			2,675			
Prepayments and other	11,607	11,277	13,824	11,323	25,076	
Total current assets	797,933	660,838	510,098	672,744	459,924	
Long-Term Assets:						
Regulatory asset for deferred income taxes	207,350	193,016	180,744	167,058	158,655	
PURPA buyout costs	243,071	244,635	243,854	243,584	233,558	
FAS-133 unrealized gain (net of tax)		3,317	12,951	9,870	8,910	
Power cost adjustment mechanism					4,129	
Other	177,609	239,941	279,131	269,876	309,547	
Total Long-term assets	628,030	680,909	716,680	690,388	714,799	
Total Assets	$5,556,669	$5,546,977	$5,506,510	$5,657,491	$5,531,431	$5,657,491
Capitalization and Liabilities						
Capitalization:						
Common stock	$859,038	$870	$877	$936	$942	
Additional paid-in capital	470,179	1,358,946	1,365,622	1,484,615	1,496,872	
Earnings reinvested in the business	92,673	32,229	8,737	36,396	38,435	
Accumulated other comprehensive income	4,750	(29,321)	3,965	1,840	6,089	
Total common equity	$1,426,640	$1,362,724	$1,379,201	$1,523,787	$1,542,338	$1,675,000
Preferred stock not subject to mandatory redemption	60,000	60,000	60,000	60,000	60,000	
Preferred stock subject to mandatory redemption	58,162	50,662	43,162	43,162	1,889	
Corporation obligated, mandatorily redeemable preferred securities of subsidiary trust holding solely junior subordinated debentures of the corporation	100,000	300,000	300,000	300,000	280,250	280,250
Long-term debt	2,170,797	2,127,054	2,162,841	2,149,733	2,006,889	2,194,894
Total capitalization	3,815,599	3,900,440	3,945,204	4,076,682	3,891,366	4,150,144
Minority interest in equity of a consolidated subsidiary			10,338	10,629	11,616	
Current Liabilities:						
Accounts payable	410,619	167,426	151,985	205,619	162,188	
Short-term debt	378,316	348,577	138,331	47,295	26,513	0
Current maturities of long-term debt	19,000	119,523	88,092	73,206	247,278	
Purchased gas liability	0	0	98,584	83,811	6,777	
Accrued expenses:						
Taxes	103,996	70,708		62,562	43,712	
Salaries and wages	17,445	14,746	12,148	11,441	11,751	
Interest	43,955	42,505	46,051	37,942	43,110	
Current portion of FAS-133 unrealized losss		35,145	7,095	2,410		
Other	26,685	46,178	47,191	47,761	50,172	
Total current liabilites	1,000,016	844,808	589,477	572,047	591,501	
Deferred Income Taxes	608,185	605,315	695,117	730,675	767,611	
Other Deferred Credits	132,869	196,339	266,014	267,458	269,337	
Commitments and Contingencies	0	0	0	0	0	
Unrealized Loss on derivative instruments		75	0	0	0	
Total Capitalization and Liabilities	$5,556,669	$5,546,977	$5,506,150	$5,657,491	$5,531,431	$5,657,491
% of Capitalization						
Long-term debt and other obligations	59.5%	62.2%	62.4%	60.1%	58.8%	59.6%
Preferred stock	3.1%	2.8%	2.6%	2.5%	1.6%	0.0%
Common stock	37.4%	34.9%	35.0%	37.4%	39.6%	40.4%
	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%
Shares outstanding (000's)	85,904	87,023	87,693	93,643	94,221	99,644
Book value per share	$16.61	$15.66	$15.73	$16.27	$16.37	$16.81

PUGET SOUND ENERGY, INC. - CONSOLIDATED STATEMENTS OF INCOME*

000's, except per share; years end 12/31)	4Q02	2002	1Q03	2Q03	3Q03	4Q03	2003	1Q04E	2Q04E	3Q04E	4Q04E	2004E	2005E
OPERATING REVENUES:													
Electric	$387,071	$1,365,885	$416,997	$348,196	$343,470	$400,800	$1,509,463	$436,496	$377,357	$341,183	$392,872	$1,547,907	$1,649,302
Gas	172,492	697,155	187,788	116,747	78,171	251,524	634,230	265,161	145,336	94,739	268,599	773,834	791,209
Other	94,404	329,282	71,176	92,913	93,926	89,815	347,830	80,000	98,000	100,000	95,000	373,000	395,000
Total operating revenues	653,967	2,392,322	675,961	557,856	515,567	742,139	2,491,523	781,656	620,693	535,922	756,471	2,694,742	2,835,511
OPERATING EXPENSES:													
Energy costs:													
Purchased electricity	202,640	645,371	240,436	191,600	174,937	216,217	823,189	238,763	205,660	171,956	200,365	816,743	870,831
Purchased gas	80,572	405,016	86,954	57,372	35,469	147,337	327,132	153,258	81,153	50,129	154,526	439,066	455,257
Electric generation fuel	16,822	113,538	15,074	11,088	21,252	17,584	64,999	14,841	11,698	20,471	16,108	63,118	67,621
Residential Exchange	(49,832)	(149,970)	(52,679)	(36,977)	(32,894)	(51,289)	(173,840)	(54,998)	(37,736)	(32,412)	(50,288)	(175,434)	(175,000)
Unrealized (gain)/loss on derivative instruments	472	(11,612)	(477)	(44)	905	(278)	106	0	0	0	0	0	0
Utility operations and maintenance	77,715	286,220	70,055	73,895	67,682	78,070	289,702	80,000	75,000	72,000	77,000	304,000	310,000
Other operations and maintenance	80,132	273,157	70,521	77,117	81,435	74,900	303,972	72,000	80,000	84,000	81,000	317,000	327,000
Depreciation and amortization	58,248	228,743	57,944	59,321	59,159	60,442	236,866	60,750	62,000	62,250	62,500	247,500	252,000
Merger and related costs/conservation amort.	7,516	17,501	7,722	6,295	9,897	9,544	33,458	9,500	9,500	9,500	9,500	38,000	38,000
Taxes other than federal income taxes	55,586	214,984	57,660	46,950	43,176	60,608	208,395	59,000	49,000	46,000	62,000	216,000	227,000
Federal income taxes	24,928	59,705	31,366	4,832	160	36,010	72,369	38,591	14,374	2,180	35,719	90,864	102,501
Total operating expenses	554,799	2,082,653	584,576	491,449	461,178	649,145	2,186,348	671,705	550,649	486,074	648,430	2,356,858	2,475,211
OPERATING INCOME	99,168	309,669	91,385	66,407	54,389	92,994	305,175	109,951	70,044	49,848	108,040	337,884	360,300
OTHER INCOME	1,403	5,458	704	2,247	2,663	(90)	5,524	1,000	1,000	1,000	1,000	4,000	4,000
INCOME BEFORE INTEREST CHARGES	100,571	315,127	92,089	68,654	57,052	92,904	310,699	110,951	71,044	50,848	109,040	341,884	364,300
INTEREST CHARGES, net of AFUDC	48,858	196,377	47,665	45,980	44,845	45,483	183,973	46,048	46,048	46,548	46,548	185,192	187,000
Mandatorily redeemable securities interest					1,048	24	1,072						
Minority interest	188	867	(332)	282	156	71	177	200	200	200	200	800	1,000
Discontinued Operations:													
NET INCOME before effect of acct. change	51,525	117,883	44,756	22,392	11,003	47,326	125,477	64,703	24,796	4,100	62,292	155,892	176,300
FAS-133 transition adjustment loss (net of tax)			169				169					0	
Less: Preferred stock dividends/ redemptions	1,940	7,831	1,867	1,794	1,118	373	5,152	118	118	118	118	472	500
INCOME FOR COMMON STOCK	$49,585	$110,052	$42,720	$20,598	$9,885	$46,953	$120,156	$64,585	$24,678	$3,982	$62,174	$155,420	$175,800
DILUTED COMMON SHARES OUT. --WEIGHTEI	91,069	88,777	94,172	94,440	94,635	97,228	95,309	99,174	99,474	99,774	100,074	99,624	100,824
INCOME FOR COMMON STOCK													
Utility before accounting change	$45,489	$96,213	$45,945	$15,768	$8,278	$43,833	$113,824	$64,585	$22,678	$1,232	$59,574	$148,070	$165,800
Cumulative effect of accounting change			169				169						
Non-utility	4,096	13,839	(3,394)	4,830	1,607	3,120	6,163	0	2,000	2,750	2,600	7,350	10,000
Total	$49,585	$110,052	$42,720	$20,598	$9,885	$46,953	$120,156	$64,585	$24,678	$3,982	$62,174	$155,420	$175,800
EARNINGS PER COMMON SHARE													
Utility	$0.50	$1.08	$0.49	$0.17	$0.09	$0.45	$1.19	$0.65	$0.23	$0.01	$0.60	$1.49	$1.64
Cumulative effect of accounting change			$0.00				$0.00						
Non-utility	0.05	0.16	(0.04)	0.05	0.02	0.03	0.06	0.00	0.02	0.03	0.03	0.07	0.10
DILUTED EARNINGS PER SHARE	$0.55	$1.24	$0.45	$0.22	$0.10	$0.48	$1.26	$0.65	$0.25	$0.04	$0.62	$1.56	$1.74

4 February 2004

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Puget Energy Inc.

Stepping Aside — **NEUTRAL**

Reason for Report: Moving to Neutral on bad Staff Rec and less conviction on numbers.

Volatility Risk: MEDIUM

Company

PSD; $23.60; B-1-7 to B-2-7

EPS (Dec): 2002A $1.24; 2003E $1.30; 2004E $1.75
P/E (Dec): 2002A 19.0x; 2003E 18.2x; 2004E 13.5x

GAAP EPS (Dec): 2002A $1.24; 2003E $1.30; 2004E $1.75
GAAP P/E (Dec): 2002A 19.0x; 2003E 18.2x; 2004E 13.5x

Event

Washington Utilities and Transportation Commission (WUTC) Staff has recommended a $7.5M increase in Puget Energy's electric rates, well short of the $64.4M the company had requested. Staff agreed that the purchase of the Fredrickson power plant was prudent, it penalized the company for its prior buyout of fuel supply contracts at other facilities, offsetting the increase that would result from inclusion of Fredrickson.

Analysis

Importantly, this is not a final order, just a Staff recommendation. However, in our view, Staff's actions here send a chilling message that runs counter to one of the fundamental premises we've had for recommending the stock—that Washington regulators are supportive of the company's efforts to improve its financial health and to beef up its power portfolio.

The Staff recommendation, in our view, is on shaky ground, especially in its attempt at "woulda, coulda, shoulda" ratemaking with respect to prior fuel contract buyouts.

Fredrickson was only expected to have a modest positive impact on earnings; the potential impact of the recommended changes to treatment of fuel costs is not yet known; we plan to address that in discussions with the company today. Since those buyouts were likely subject to prior Commission approval, it would appear unlikely that Staff's recommendations here would ultimately be accepted.

The paltry recommendation here also raises questions about the atmosphere for the company's general rate case, due to be heard and adjudicated later this year.

Recommendation

We lowered our 2004 estimate on Puget last week, but decided at that time to "hang in there" on expectations for an uptick in earnings next year. However, our conviction level ahead of next week's earnings--and release of the 2004 outlook--has been softening.

We fully recognize that today's news is only a weakly premised Staff recommendation. However, coupled with the potential for a weaker current year earnings outlook, it could render the shares dead money, particularly as this and the general rate case await action this year. As such we are moving to a Neutral rating.

Refer to important disclosures on page 3.
Analyst Certification on page 2.

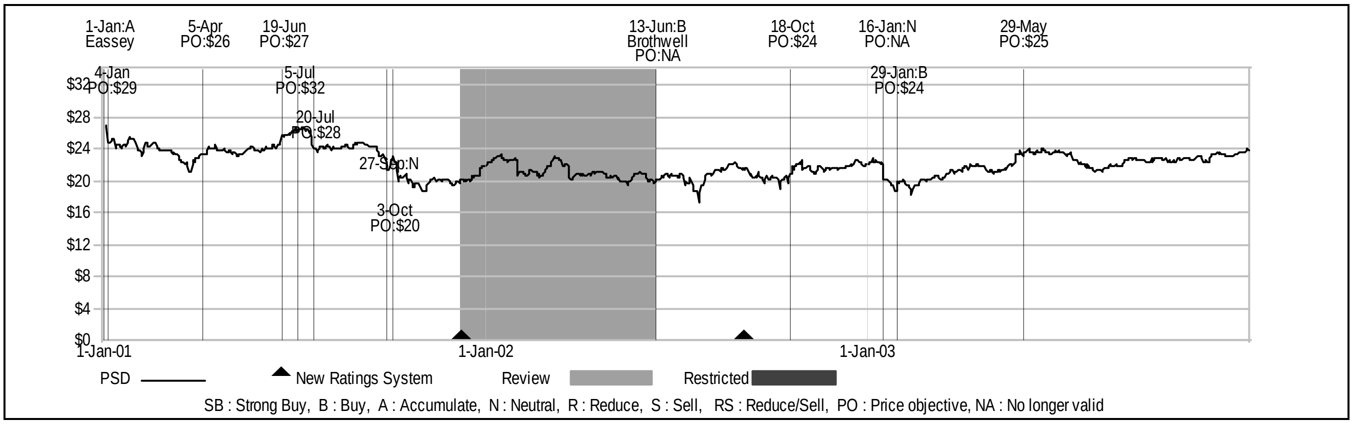
Merrill Lynch Global Securities Research & Economics Group
Global Fundamental Equity Research Department

Analyst Certification

I, Sam Brothwell, hereby certify that the views expressed in this research report accurately reflect my personal views about the subject securities and issuers. I also certify that no part of my compensation was, is, or will be, directly or indirectly, related to the specific recommendations or view expressed in this research report.

Important Disclosures

PSD Price Chart



Prior to 8 Dec. 2001, the Investment Opinion System included: Buy, Accumulate, Neutral, Reduce and Sell. From 8 Dec. 2001 to 6 Sep. 2002, the Investment Opinion System included: Strong Buy, Buy, Neutral, and Reduce/Sell. On 8 Dec. 2001 Buy ratings became Strong Buy, Accumulate became Buy, and Reduce and Sell became Reduce/Sell. On 6 Sep. 2002, Strong Buy and Buy ratings became Buy, and Reduce/Sell became Sell. Any exceptions to these rating revisions are reflected in the chart. All price objectives for Neutral and Sell rated securities established before 6 Sep. 2002 were eliminated as of that date. The current Investment Opinion System is contained at the end of the report. Dark Grey shading indicates security is restricted with the opinion suspended. Light Grey shading indicates security is under review with the opinion withdrawn.

Investment Rating Distribution: Energy Group (as of 31 December 2003)

Coverage Universe	Count	Percent	Inv. Banking Relationships*	Count	Percent
Buy	70	49.30%	Buy	27	38.57%
Neutral	62	43.66%	Neutral	17	27.42%
Sell	10	7.04%	Sell	1	10.00%

Investment Rating Distribution: Global Group (as of 31 December 2003)

Coverage Universe	Count	Percent	Inv. Banking Relationships*	Count	Percent
Buy	1050	42.53%	Buy	352	33.52%
Neutral	1236	50.06%	Neutral	309	25.00%
Sell	183	7.41%	Sell	31	16.94%

* Companies in respect of which MLPF&S or an affiliate has received compensation for investment banking services within the past 12 months.

OPINION KEY: Opinions include a Volatility Risk Rating, an Investment Rating and an Income Rating. VOLATILITY RISK RATINGS, indicators of potential price fluctuation, are: A - Low, B - Medium, and C - High. INVESTMENT RATINGS, indicators of expected total return (price appreciation plus yield) within the 12-month period from the date of the initial rating, are: 1 - Buy (10% or more for Low and Medium Volatility Risk Securities - 20% or more for High Volatility Risk securities); 2 - Neutral (0-10% for Low and Medium Volatility Risk securities - 0-20% for High Volatility Risk securities); 3 - Sell (negative return); and 6 - No Rating. INCOME RATINGS, indicators of potential cash dividends, are: 7 - same/higher (dividend considered to be secure); 8 - same/lower (dividend not considered to be secure); and 9 - pays no cash dividend.

MLPF&S or one or more of its affiliates acts as a market maker for the recommended securities to the extent that MLPF&S or such affiliate is willing to buy and sell such securities for its own account on a regular and continuous basis: Puget Energy.

MLPF&S or an affiliate expects to receive or intends to seek compensation for investment banking services from this company within the next three months: Puget Energy.

MLPF&S or one of its affiliates is willing to sell to, or buy from, clients the common equity of the company on a principal basis: Puget Energy.

The analyst(s) responsible for covering the securities in this report receive compensation based upon, among other factors, the overall profitability of Merrill Lynch, including profits derived from investment banking revenues: Puget Energy.

Additional information pursuant to Section 34b of the German Securities Trading Act: Merrill Lynch and/or its affiliates was an underwriter in an offering of securities of the issuer in the last five years: Puget Energy.

Neither the information nor any opinion expressed constitutes an offer, or an invitation to make an offer, to buy or sell any securities or any options, futures or other derivatives related to such securities ("related investments"). Officers of MLPF&S or one of its affiliates may have a financial interest in securities of the issuer(s) or in related investments.

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Foreign currency rates of exchange may adversely affect the value, price or income of any security or related investment mentioned in this report. In addition, investors in securities such as ADRs, whose values are influenced by the currency of the underlying security, effectively assume currency risk.

11 February 2004

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Puget Energy Inc.

Longer and Harder **NEUTRAL**

Reason for Report: 2003 1.26; 2004E $1.55; What's Going On Here?

Volatility Risk: MEDIUM

Company

PSD; $22.83; B-2-7

EPS (Dec): 2003A $1.26; 2004E $1.55
P/E (Dec): 2003A 18.1x; 2004E 14.7x

GAAP EPS (Dec): 2003A $1.26; 2004E $1.55
GAAP P/E (Dec): 2003A 18.1x; 2004E 14.7x

Event

2003 earnings were weak as expected, but the 2004 view was cut to a range of $1.50 to $1.60, without much detail on why at this point. We had previously cut our 2004E to $1.75 and moved to Neutral from Buy; things are obviously worse than we thought. What's going on?

Analysis

Keep in mind two key facts: one, PSD has a new chief financial officer, and two, the company had to make several downward adjustments to its earnings outlook last year. As such, we think that at this point, it's probably prudent to err on the conservative side—we detect a subtle bias in that direction.

As noted previously, this has been a tough winter, including an unusual ice storm that paralyzed the Seattle area last month. Ice storms are very hard on electric utilities. While not yet quantified, this will have a negative impact on current year results. And it adds to the list of costs that the company must ultimately seek to recover from customers.

At a higher level, that raises another key issue…what if the incremental capital and O&M costs of keeping pace with service area growth--compounded by the slow but steady demise of the region's inherent hydro-power subsidy--puts PSD on a steeper regulatory treadmill? One that requires steady and frequent rate filings to keep pace with a steadily rising cost base to provide reliable electric service?

We noted last week that the WA Commission Staff has proposed some negative adjustments that would offset the positive impact of adding the Fredrickson power plant to rate base. Our conversations with Staff lead us to believe that the regulatory relationship remains healthy, and that they are supportive of PSD's plans to add generation resources. *But, while they remain mindful that utility financial health is very important, regulators also have to look out for consumers.* PSD is on solid ground in keeping up with customer growth and addressing the region's resource needs head-on. But the regulatory process may not prove as smooth or as expedited as the company may have hoped.

Recommendation

Remain Neutral. 2003 actual/2004 outlook are collectively a big miss; expectations have been cut beyond what we and a lot of other folks were thinking. Look for a contentious conference call later today. We continue to believe PSD is on the right track and that the company is taking a harder and more realistic view of its financial outlook. But that outlook has broken a bit from what we had been thinking.

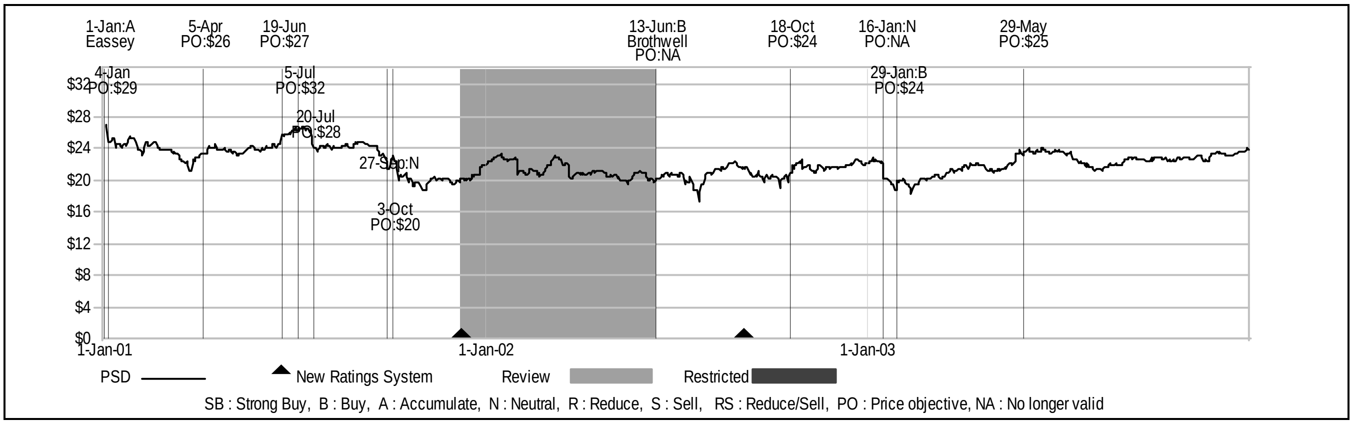
Refer to important disclosures on page 3.
Analyst Certification on page 2.

Analyst Certification

I, Sam Brothwell, hereby certify that the views expressed in this research report accurately reflect my personal views about the subject securities and issuers. I also certify that no part of my compensation was, is, or will be, directly or indirectly, related to the specific recommendations or view expressed in this research report.

Important Disclosures

PSD Price Chart



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Neutral	1236	50.06%	Neutral	309	25.00%
Sell	183	7.41%	Sell	31	16.94%

* Companies in respect of which MLPF&S or an affiliate has received compensation for investment banking services within the past 12 months.

OPINION KEY: Opinions include a Volatility Risk Rating, an Investment Rating and an Income Rating. VOLATILITY RISK RATINGS, indicators of potential price fluctuation, are: A - Low, B - Medium, and C - High. INVESTMENT RATINGS, indicators of expected total return (price appreciation plus yield) within the 12-month period from the date of the initial rating, are: 1 - Buy (10% or more for Low and Medium Volatility Risk Securities - 20% or more for High Volatility Risk securities); 2 - Neutral (0-10% for Low and Medium Volatility Risk securities - 0-20% for High Volatility Risk securities); 3 - Sell (negative return); and 6 - No Rating. INCOME RATINGS, indicators of potential cash dividends, are: 7 - same/higher (dividend considered to be secure); 8 - same/lower (dividend not considered to be secure); and 9 - pays no cash dividend.

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RESEARCH NOTE

February 4, 2004

(Price 2/4/04)

Puget Energy, Inc.
James L. Bellessa, Jr., CFA
PSD – NEUTRAL – $22.98

Testimony Seeks to Limit Utility's Rate Request on Frederickson Plant.

Recent testimony filed in what we thought was a "power cost only rate review" has the potential of adversely impacting Puget Energy. While we believe the new testimony, which appears to go beyond the scope of the current case, may be rejected by the Washington Utilities and Transportation Commission (WUTC), or overcome by the utility's rebuttal, we believe the regulatory risks faced by Puget Energy have risen. Notwithstanding these risks, we reaffirm our **NEUTRAL** rating and $22 target price on the stock of PSD.

The WUTC staff has recently filed testimony recommending that the costs incurred by Puget Sound Energy (PSE), to acquire a 49.85% interest in the Frederickson power plant, be included in the utility's costs and recovered through an electricity rate increase. However, WUTC staff's net recommendation is to allow a $7.5 million increase in rates to recover the costs of the plant, compared to the company's request for a $64.4 million increase.

While WUTC staff concludes that the acquisition of Fredrickson is prudent and appropriate to include in rates, it recommends downward adjustments in another area of the company's power cost portfolio. The difference between the company's request and the staff's recommendation is primarily due to fuel costs associated with the company's Tenaska and Encogen power projects. WUTC staff contends that when PSE bought out fuel supply contracts for Tenaska in 1998 and Encogen in 2000, the company claimed it would reduce the cost of power from these two projects. The WUTC staff does not believe the company has achieved that claim and is attempting to bring those issues into the current "power cost only" case on the proposed purchase of the Frederickson plant.

In an 8-K filing with the SEC, the company states the WUTC staff's rate proposal would hurt the utility's financial performance. Furthermore, the utility says the WUTC staff's proposal is "legally and factually deficient and PSE will file a rebuttal case by February 13, 2004." We expect the company will submit sufficient evidence about the reasonableness of its fuel costs to dissuade the Commission from fully accepting the WUTC staff's testimony. The Commission is handling the "power cost only" proceeding on an expedited schedule at PSE's request, with evidentiary hearings scheduled to commence on February 23.

If the ultimate rate order is insufficient from the current "power cost only" case, the company has the option to cancel its planned purchase of the 49.85% interest in the Frederickson power plant. In October 2003, PSE announced plans to acquire a minority interest in the 249-megawatt gas-fired facility near Tacoma, Washington, for $80 million, subject to appropriate regulatory approvals. With a planned upgrade, the Frederickson plant capacity would be expanded to 275 megawatts. PSE's share would be 137 megawatts, or about 30% of the total new resource requirement the company states it needs to secure by the first of 2005. If adequately rate based, we believe the Frederickson plant has the potential of adding $0.05 per share to the company's annual earnings.

Please refer to the end of this report for detailed disclosures and certification information

D.A. Davidson & Co.
Two Centerpointe Drive, Suite 400 • Lake Oswego, Oregon 97035 • (503) 603-3000 • (800) 755-7848 • www.dadavidson.com

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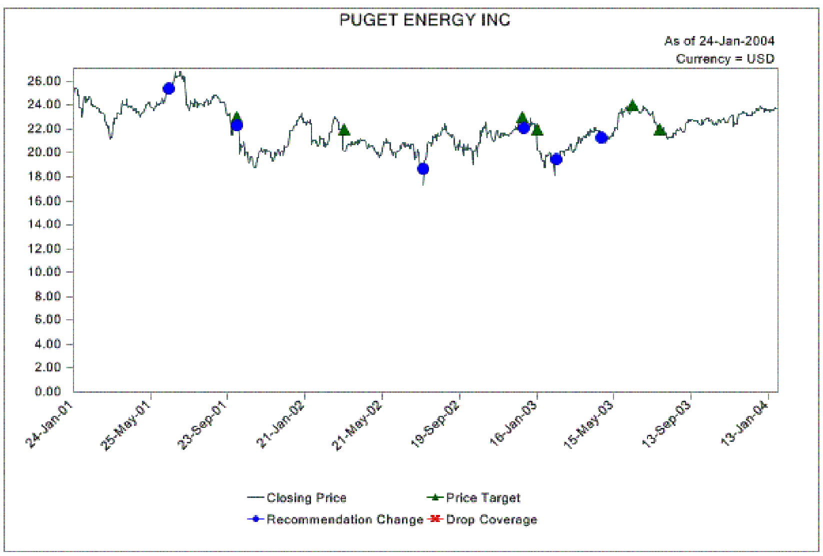
D.A. Davidson & Co. Ratings	**Buy**	**Neutral**	**Underperform**
Risk adjusted return potential	Over 15% total return expected on a risk adjusted basis over next 12-18 months	>0-15% return potential on a risk adjusted basis over next 12-18 months	Likely to remain flat or lose value on a risk adjusted basis over next 12-18 months

Distribution of Ratings (as of 12/31/03)	**Buy**	**Hold**	**Sell**
Corresponding Institutional Research Rating	Buy	Neutral	Underperform
Distribution of Institutional Research Ratings	41%	48%	11%
Corresponding Retail Research Rating	Buy, Core/Buy	Hold, Core/Hold	Avoid
Distribution of Retail Research Ratings	85%	15%	0%
Distribution of combined ratings	52%	40%	8%
Distribution of companies from whom D.A. Davidson & Co. has received compensation for investment banking services in last 12 mos	4%	8%	15%



D.A. Davidson & Co. has made two changes to its institutional ratings scale. The first occurred on June 18, 2001 and the second occurred on July 9, 2002. The corresponding scales are reproduced below.
D.A. Davidson & Co. Institutional Research Rating Scale (beginning 7/9/02)
Buy, Neutral, Underperform
D.A. Davidson & Co. Institutional Research Rating Scale (6/18/01 – 7/9/02)
Strong Buy, Buy, Neutral, Underperform
D.A. Davidson & Co. Institutional Research Rating Scale (6/1/99 – 6/18/01)
Buy, Outperform, Neutral, Underperform, Sell

PUGET ENERGY INC

Currency = USD

Date	**Closing Price**	**Recommendation Change**	**Date**	**Closing Price**	**Price Target**
24-Apr-2003	21.35	NEUTRAL	24-Jul-2003	22.05	22.00
14-Feb-2003	19.44	BUY	12-Jun-2003	23.84	24.00
26-Dec-2002	22.10	NEUTRAL	16-Jan-2003	20.24	22.00
22-Jul-2002	18.73	BUY	26-Dec-2002	22.10	23.00
05-Oct-2001	22.28	NEUTRAL	21-Mar-2002	20.29	22.00
21-Jun-2001	25.39	OUTPERFORM/BUY	05-Oct-2001	22.28	23.00

Target prices are our Institutional Research Department's evaluation of price potential over the next 12-18 months and 5 years based upon our assessment of future earnings and cash flow, comparable company valuations, growth prospects and other financial criteria. Certain risks may impede achievement of these price targets including, but not limited to, broader market and macroeconomic fluctuations and unforeseen changes in the subject company's fundamentals or business trends. Information contained herein has been obtained by sources we consider reliable, but is not guaranteed and we are not soliciting any action based upon it. Any opinions expressed are based on our interpretation of data available to us at the time of the original publication of the report. These opinions are subject to change at any time without notice. Investors must bear in mind that inherent in investments are the risks of fluctuating prices and the uncertainties of dividends, rates of return and yield. Investors should also remember that past performance is not necessarily an indicator of future performance and D.A. Davidson & Co. makes no guarantee, express or implied, as to future performance. Investors should note this report was prepared by D.A. Davidson & Co.'s Institutional Research Department for distribution to D.A. Davidson & Co.'s institutional investor clients and assumes a certain level of investment sophistication on the part of the recipient. Readers, who are not institutional investors or other market professionals, should seek the advice of their individual investment advisor for an explanation of this report's contents, and should always seek such advisor's advice before making any investment decisions. Further information and elaboration will be furnished upon request.

January 05, 2004

United States of America
Energy & Power
Power & Utilities

Power & Utilities

Recommendation Change

Back to Boring

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Sector View:

New: 3-Negative

Old: 2-Neutral

Investment conclusion

- We are lowering our sector rating to 3-Negative from 2-Neutral. We believe that underperformance for utilities could start immediately as investors reset their portfolios for 2004.

Summary

- Expectations for rising interest rates in 2004 suggest underperformance for the utility sector, while valuation measures (both relative and absolute) are at the high end of historical ranges.
- Utility growth rates will be challenged by regulatory proceedings, continued pressure on spark spreads, incremental equity and cost pressures (healthcare and pension) through 2005. We are releasing below consensus 2005E EPS estimates for the group as a result.
- We suggest a general underweight position in the group, but are particularly concerned about valuation levels at 3-Underweight rated CPN, DUK, ED, GXP, and NU.
- Equities that we believe have a chance to buck the underperformance trend in 2004 couple relative rate certainty, strong cash flow and attractive valuation. Our favorites are EXC, FE, NI, PPL, PCG, and WEC.

In 2003, the utility group regained its historical position in the marketplace. A stabilization of the group balance sheets through several equity offerings, asset sales, debt refinancings, and a couple of bankruptcies released valuations from the power market debacle of 2001 and 2002. By several measures, utilities are now trading at the middle to high end of their historical valuation ranges both in absolute terms and relative to the S&P 500. However, from here we see more challenges than opportunities for the group. As a result, we are lowering our sector view to 3 – Negative from 2 – Neutral.

The challenges that we foresee include both macro issues as well as industry specific trends. On the macro front, Lehman Brothers' economics and strategy teams forecast continued economic expansion and rising interest rates through 2004 and into 2005. The traditionally defensive and interest sensitive utility sector should suffer in this environment. Additionally, in non-recessionary markets, utility performance exhibits significant seasonality. The worst performance comes in the first quarter, which contributes to the timing of this sector rating change.

Industry trends are also challenging and result in slower than consensus growth that we forecast over the next few years. The large number of rate cases that face the group in 2004 and 2005 will likely reduce allowed returns on regulated capital given today's low absolute interest rates. The soft market for gas fired generation output should continue through 2004 before improving the second half of this decade due to excess reserve margins. Pressures from pension obligations and rising healthcare costs should mute cost saving opportunities. And finally, the costs associated with balance sheet repair in the last 12 to 24 months are showing up in incremental equity dilution. In this report we include a complete list of our 2005 EPS estimates and compare them to consensus numbers.

While we have a negative view on group performance, we don't believe that any smoking-gun issue exists that will lead to a sharp correction. Nonetheless, December's outperformance (UTY +5.4% versus S&P 500 +3.9%) presents an opportunity for Investors to lighten on the group and in the following 3-Underweight rated names in particular at or close to 52 week highs – Calpine (CPN; $4.97; 3-UW), Duke Energy (DUK; $20.35; 3-UW), Consolidated Edison (ED; $42.98; 3-UW), Great Plains Energy (GXP; $31.85; 3-UW), and Northeast Utilities (NU; $20.10; 3-UW).

PLEASE SEE ANALYST(S) CERTIFICATION(S) ON PAGE 8 AND IMPORTANT DISCLOSURES BEGINNING ON PAGE 10

For those that must be involved in utility stocks, individual stock selection will be key to keep up with the market in 2004. Our overweight recommendations focus on companies with intriguing relative valuation coupled with comparative forecast certainty. These stocks are either emerging from major regulatory proceedings like Wisconsin Energy (WEC; $33.45; 1-OW), or PG&E Corp. (PCG; $27.23; 1-OW), are recovering from credit stress such as NiSource (NI; $21.66; 1-OW) and First Energy (FE; $35.34; 1-OW) due to superior cash flows, or have positive exposure to natural gas prices through non-gas generation where Exelon (EXC; $66.00; 1-OW) and PPL Corporation (PPL; $43.75; 1-OW) fit the bill.

Valuation Normal to Expensive

After a good performance from the October 2002 lows (up 49% absolute and 7% relative to the market), the group now stands at normal to expensive valuation levels on both relative and absolute measures.

Relative Measures

- *P/E ratio relative to S&P 500.* Utilities currently stand at 89% of the forward S&P 500 multiple. The historical range is 65%–75%.
- *Utility current yield to 10-year Treasury yield.* Utilities trade at 86% of the 10-year note. The historical range is 75%–85%.

Absolute Measures

- *EV/EBITDA.* The group is at 7.8x. The historical range is 6x-8x.
- *P/BV.* Utilities are at 1.69x. The historical range is 1.25x–1.75x.

Wrong Group/Wrong Season

Utilities do not perform well in rising interest rate environments. According to work done by our equity strategist, Chip Dickson, in the 12 months prior to Federal Reserve rate hikes; utilities underperform the market by 11.4%. A snapshot of Lehman Brothers' and the consensus interest rate forecasts are presented below.

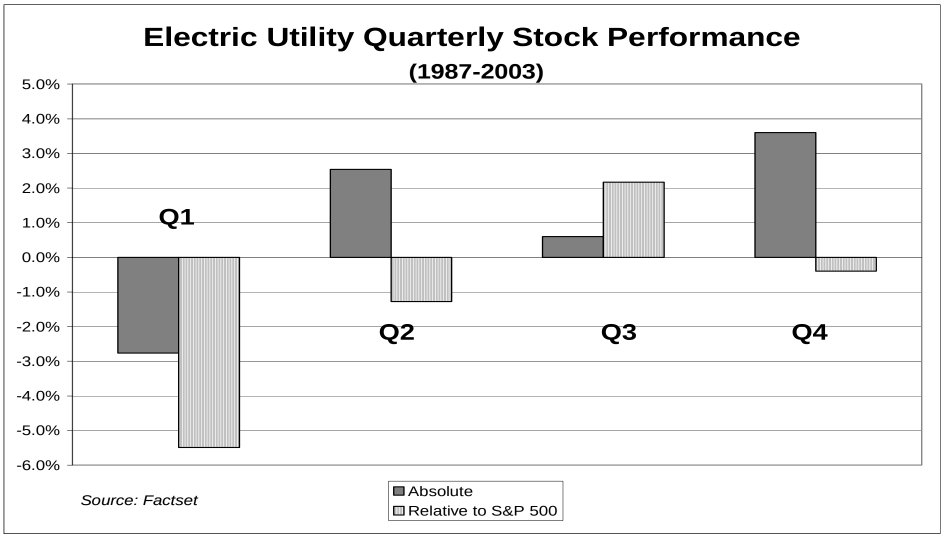
Table 1: Lehman and Consensus Interest Rate Forecasts

		1 Month Forward		3 Months Forward		12 Months Forward	
%	Current Rate	Market	Lehman	Market	Lehman	Market	Lehman
Fed Funds Rate	1.00	1.01	1.00	1.03	1.00	1.70	1.00
10-Year Bond Yield	4.37	4.32	4.35	4.41	4.40	4.84	5.00

Forecasted data as of December 18, 2003
source: Lehman Economics

Seasonally, Electric utilities underperform in the first quarter. Intuitively speaking, "safe haven" utilities are of more interest in the second half as investors try to lock-in returns for the year, and less interesting as they adopt a more aggressive outlook in the first quarter. Since 1987 electric utilities have averaged upside of 3.6% absolute and -0.4% relative to the S&P 500 in Q4, but declined 2.8% and underperformed -5.5% in Q1. First Quarter relative underperformance was observed in 13 of the 16 years reviewed while absolute price declines happened in 10 of these years.

Figure 1: Historic Seasonality of Utility Returns

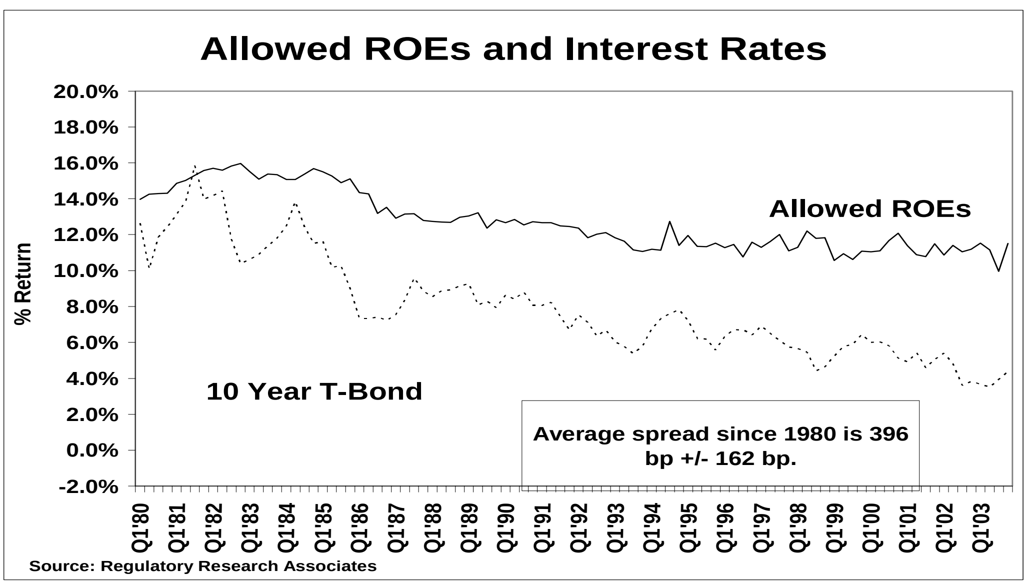


Rate Rulings, Excess Plant, Cost Pressures and Balance Sheet Repair to Stunt Growth

Rate Rulings: We foresee a significant ramp in rate activity in 2004 and 2005. We count 34 rate cases affecting 25 companies in our coverage universe of 38 electric utilities over this period. As allowed return levels are benchmarked against market interest rates it seems inevitable that lower utility earnings can be expected. In 18 cases in 2003, allowed returns averaged 11.0% with a range from 9.5% to 12.7%. These returns do not compare well to allowed returns between 12% and 13% which most of the industry enjoys. For specific rate case schedules and information refer to our report "A Blast From the Past," published 6/4/03.

Two of our 3-UW rated stocks have significant rate activity in 2004 contributing to our opinion. Northeast Utilities has a rate-case in New Hampshire and Consolidated Edison will be filing a gas and electric general rate cases in New York this Spring. On the positive front, 1-OW Wisconsin Energy and PG&E Corp. are in periods of relative rate certainty following 2003 regulatory activity.

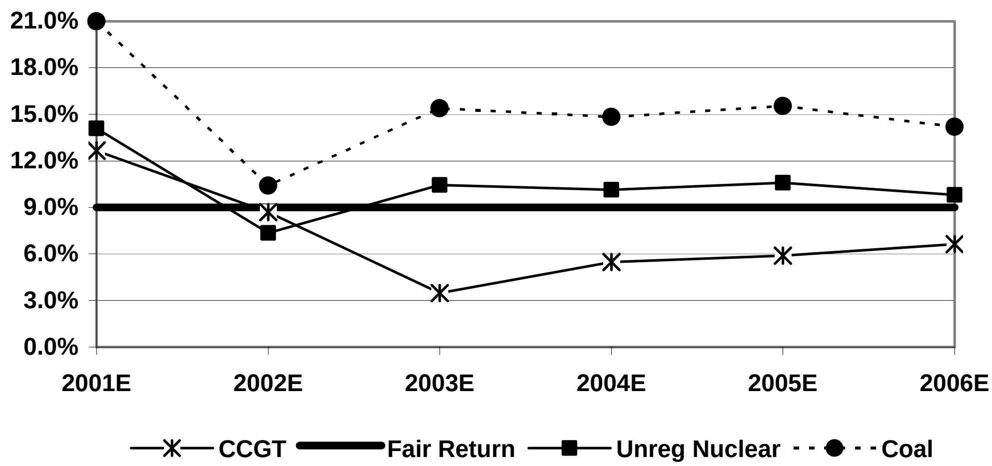
Figure 2: Historical Relationship Between Regulated Returns on Equity and Interest Rates



Excess Plant: Incorporating our best estimate of plant construction, we believe that additions will outstrip electricity demand growth again in 2004. We look for an additional 32K MW of supply in 04 vs. a demand growth of 17.5K MW to 22.5K MW (see "Cross Over to the Dark Side" 5/6/03 for detail). As a result, we forecast that reserve margins will rise yet again in 2004 to just over 30% nationwide before subsiding as construction falls off in the back half of the decade. Fortunately for the industry, high natural gas prices are supporting margins for non-gas fired power plant, however, pressure on spark spreads (gas fired gross margins) remain and will continue to produce sub-standard return on invested capital in the intermediate term.

Our Negative views on Calpine and Duke Energy are in part the result of our continued dim view of Spark spreads. With significant spark exposure, we believe that margins will continue to disappoint at these two companies, stressing valuations and credit. On the flip side, 1-OW Exelon and PPL Corporation have leverage to higher nuclear and coal based generation profitability leading to a positive earnings surprise bias, which we believe will lead to out-performance. The chart below indicates our forecast for return on invested capital by generation output for un-contracted electricity sales.

Figure 3: Spot Generation ROIC Forecast



Cost Pressures: Rising health care costs and under funded pension plans will continue to place a ceiling over efficiency opportunities. While it is hard to be specific around pension expenses due to the flexibility involved in accounting for individual plans, the industry continues to be significantly under-funded with fairly aggressive return and discount rate assumptions. The following table outlines where the companies we follow stand.

Table 2: Utility Group Pension Funding Status

Pension Funding Status
($ in millions)
Based on Year-end 2002 data

	Pension Benefits									
	Discount Rate	Expected Return	Difference	Value Assets	Funded Status	Funded % Mkt Cap	Service Cost (1)	Interest Cost (2)	Annual Return (3)	Annual Deficit (3)-(2)-(1)
AES Corporation (a)	6.50%	8.90%	2.40%	$474.0	-$317.0	-6.3%	$7.0	$50.0	$42.2	-$14.8
Allegheny Energy Inc	6.50%	9.00%	2.50%	$702.8	-$294.3	-22.0%	$20.2	$59.3	$63.3	-$16.2
Alliant Energy	6.75%	9.00%	2.25%	$466.7	-$141.8	-6.2%	$12.9	$39.7	$42.0	-$10.6
Ameren Corp.	6.75%	8.50%	1.75%	$1,059.0	-$528.0	-7.3%	$33.0	$103.0	$90.0	-$46.0
American Electric Power (b)	6.75%	9.00%	2.25%	$2,795.0	-$788.0	-7.0%	$72.0	$241.0	$251.6	-$61.5
Calpine Corp	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
Cinergy Corp	6.75%	9.00%	2.25%	$756.5	-$558.4	-8.5%	$27.3	$79.2	$68.1	-$38.4
CMS Energy Corp	6.50%	8.75%	2.25%	$607.0	-$650.0	-58.1%	$40.0	$84.0	$53.1	-$70.9
Consolidated Edison	6.75%	9.20%	2.45%	$5,759.7	-$673.9	-7.3%	$92.2	$440.1	$529.9	-$2.4
Constellation Energy	6.75%	9.00%	2.25%	$767.7	-$479.8	-7.5%	$29.6	$82.2	$69.1	-$42.7
Dominion Resources Inc	6.75%	9.50%	2.75%	$3,074.0	$273.0	1.4%	$77.0	$177.0	$292.0	$38.0
DPL Inc	6.75%	8.75%	2.00%	$268.6	$1.7	0.1%	$3.7	$19.2	$23.5	$0.6
DQE Inc	6.75%	7.50%	0.75%	$596.4	-$28.5	-2.1%	$5.9	$40.7	$44.7	-$1.9
DTE Energy Co	6.75%	9.00%	2.25%	$1,845.0	-$654.0	-10.4%	$43.0	$162.0	$166.1	-$39.0
Duke Energy Corp	6.75%	9.25%	2.50%	$2,120.0	-$551.0	-3.3%	$69.0	$177.0	$196.1	-$49.9
Dynegy Inc	6.50%	9.00%	2.50%	$501.0	-$125.0	-8.4%	$19.0	$38.0	$45.1	-$11.9
Edison International	6.50%	8.50%	2.00%	$2,322.0	-$372.0	-5.4%	$86.0	$165.0	$197.4	-$53.6
Empire District Electric	6.75%	9.00%	2.25%	$78.2	-$32.3	-6.7%	$2.2	$5.6	$7.0	-$0.8
Entergy Corp	6.75%	8.75%	2.00%	$1,451.8	-$540.5	-4.3%	$56.9	$128.4	$127.0	-$58.3
Exelon	6.75%	9.50%	2.75%	$5,395.0	-$2,459.0	-11.9%	$95.0	$525.0	$512.5	-$107.5
FirstEnergy Corp	6.75%	9.00%	2.25%	$2,889.0	-$977.4	-9.3%	$58.8	$249.3	$260.0	-$48.1
FPL Group Inc	6.00%	7.75%	1.75%	$2,388.0	$983.0	8.3%	$52.0	$84.0	$185.1	$49.1
Great Plains Energy	6.75%	9.00%	2.25%	$324.2	-$126.6	-5.8%	$13.4	$30.3	$29.2	-$14.5
Hawaiian Electric Inds	6.75%	9.00%	2.25%	$552.0	-$110.3	-6.4%	$17.0	$41.9	$49.7	-$9.2
NiSource Inc	7.00%	9.00%	2.00%	$1,651.1	-$297.2	-5.4%	$39.5	$125.8	$148.6	-$16.7
Northeast Utilities	7.25%	9.25%	2.00%	$1,632.3	-$157.5	-6.3%	$37.2	$119.8	$151.0	-$6.0
OGE Energy Corp	6.75%	9.00%	2.25%	$286.3	-$156.7	-8.1%	$13.3	$28.7	$25.8	-$16.2
PG&E Corp	7.25%	8.10%	0.85%	$6,189.0	-$592.0	-6.0%	$140.0	$438.0	$501.3	-$76.7
Pinnacle West Capital	6.75%	9.00%	2.25%	$720.8	-$347.8	-9.8%	$30.3	$71.2	$64.9	-$36.6
Pepco Holdings	6.75%	9.00%	2.25%	$1,240.6	-$158.3	-5.0%	$16.0	$54.1	$111.7	$41.6
PPL Corp.	6.75%	7.80%	1.05%	$1,376.0	-$182.0	-2.6%	$40.0	$99.0	$107.3	-$31.7
Progress Energy	6.60%	9.25%	2.65%	$1,363.9	-$329.6	-3.1%	$45.4	$105.6	$126.2	-$24.8
Public Service Entrp Group	6.75%	9.00%	2.25%	$2,131.0	-$447.7	-4.8%	$69.0	$188.0	$191.8	-$65.2
Puget Energy	6.75%	8.25%	1.50%	$344.0	-$25.7	-1.2%	$8.5	$25.9	$28.4	-$6.0
Sempra Energy	6.50%	8.00%	1.50%	$1,984.0	-$306.0	-4.6%	$57.0	$149.0	$158.7	-$47.3
Southern Co	6.50%	8.50%	2.00%	$4,600.0	$506.0	2.3%	$109.0	$277.0	$391.0	$5.0
Sierra Pacific Resources	6.75%	8.50%	1.75%	$238.8	-$190.1	-23.8%	$11.9	$27.7	$20.3	-$19.3
TECO Energy Inc	6.75%	9.00%	2.25%	$371.9	-$83.2	-3.6%	$11.8	$28.7	$33.5	-$7.0
TXU Corp	6.75%	8.50%	1.75%	$1,595.0	-$338.0	-4.7%	$45.0	$128.0	$135.6	-$37.4
Wisconsin Energy Corp	6.75%	9.00%	2.25%	$861.2	-$218.1	-5.7%	$23.6	$73.0	$77.5	-$19.1
Xcel Energy	6.75%	9.50%	2.75%	$2,640.0	-$183.0	-2.7%	$65.6	$172.3	$250.8	$12.9

(a) Also, international plan has $830M assets (-$1.1B underfunded).
(b) Also, international plan has $723M assets (-$1.1B underfunded).
Source: Company reports.

Costs of the Balance Sheet: Asset sales and equity and convertible offerings were commonplace in 2002 and 2003 as utilities struggled to improve their credit standings. The annualization of these dilutive activities will extend through 2005. The table below outlines the additional average shares in 2004 and 2005 that we expect from mandatory convertible expirations, dividend reinvestment programs, new issuance and annualization of offerings in 2003.

Table 3: 2004E and 2005E Average Share Additions

	Average 2003E Shares	2004E Mandatory	2004E Drip/ ESOP/Options	2004E Other Issuance	2005E Mandatory	2005E Drip/ ESOP/Options	2005E Other Issuance	% Change Shares*
AES Corporation	595.5							0%
Alliant Energy	98.3							0%
Allegheny Energy Inc	126.7						20.0	16%
Ameren Corp.	160.1							0%
American Electric Power	385.9			9.6	2.8			3%
Calpine Corp	440.0		6.0			1.0		2%
Cinergy Corp	175.2		2.4		10.4			7%
CMS Energy Corp	165.0							0%
Consolidated Edison	220.2						6.3	3%
Constellation Energy Corp	166.0		0.8			0.8		1%
Dominion Resources Inc	318.2		1.0	21.3		2.0		8%
DPL Inc	124.8							0%
Duquesne Light Holdings	74.8		0.8			0.8		2%
DTE Energy Co	167.9	1.5			1.5			2%
Duke Energy Corp	904.0	14.7	5.0		26.4	5.0		6%
Edison International	329.0		1.0			1.0		1%
Empire District Electric	22.7							0%
Entergy Corp	230.0		2.0			2.0	-4.8	0%
Exelon	325.3		0.9			0.9		1%
FirstEnergy Corp	308.1							0%
FPL Group Inc	178.0		1.5		8.8	1.5		7%
Great Plains Energy	69.2							0%
Hawaiian Electric Inds	37.3		0.2			0.2		1%
NiSource Inc	264.0		0.0			0.0		0%
Northeast Utilities	127.1		1.0			1.0		2%
OGE Energy Corp	82.5			4.0				5%
PG&E Corp	425.0		2.5			2.5	-16.7	-3%
Pinnacle West Capital	91.3		0.0			0.0		0%
Pepco Holdings	170.7							0%
PPL Corporation	180.0	5.5	1.9		3.9	1.9		7%
Progress Energy	246.0							0%
Public Service Entrp Group Inc	94.0				2.1			2%
Puget Energy	96.3		1.0	2.8		1.0		5%
Sempra Energy	222.0		0.0		11.6	0.0		5%
Southern Co	730.1		7.0			7.0		2%
Sierra Pacific Resources	113.8		0.0			0.0		0%
TECO Energy Inc	180.1		0.6	6.9	17.1	0.6		14%
TXU Corp	379.0	1.4	0.5		11.0	0.5		4%
Wisconsin Energy Corp	116.9		1.5			1.4		3%
Xcel Energy	425.0		2.9			2.9		1%
Average								3%

*share change not necessarily indicative of dilution as use of proceeds not reflected
Source: Bloomberg

Releasing Below-Consensus 2005 EPS Outlook

We forecast 3.0% EPS growth for the group in 2005 versus the 4.6% First Call consensus. The largest downside surprises we forecast vs. consensus are for CPN, CMS, DUK, FPL, and ED. The biggest upsides we forecast are for TE, POM, AES, EIX, SRE, and EXC.

Table 4: Lehman EPS Estimates and Consensus

	EPS				First Call Consensus EPS			% From Consensus
	2002A	2003E	2004E	2005E	2003E	2004E	2005E	2005E
AES Corporation	$0.78	$0.50	$0.65	$0.70	$0.48	$0.61	$0.65	8%
Allegheny Energy Inc	-$5.02	-$1.40	$0.81	$1.06	$0.72	$0.80	$1.09	-3%
Alliant Energy	$1.33	$1.55	$1.75	$1.85	$1.58	$1.68	NA	NA
Ameren Corp.	$3.01	$2.90	$2.95	$3.00	$2.96	$3.01	$3.03	-1%
American Electric Power	$2.89	$2.22	$2.15	$2.30	$2.21	$2.21	$2.39	-4%
Calpine Corp	$0.75	$0.10	$0.11	$0.10	$0.20	$0.02	$0.16	-38%
Cinergy Corp	$2.68	$2.58	$2.65	$2.70	$2.61	$2.76	$2.86	-6%
CMS Energy Corp	$1.50	$0.80	$0.70	$0.70	$0.78	$0.84	$0.85	-18%
Consolidated Edison	$3.12	$2.80	$2.80	$2.77	$2.81	$2.86	$2.98	-7%
Constellation Energy Corp	$2.52	$2.75	$3.07	$3.10	$2.79	$3.04	$3.10	0%
Dominion Resources Inc	$4.83	$4.67	$4.89	$5.05	$4.68	$4.99	$5.19	-3%
DPL Inc	$0.87	$1.25	$1.37	$1.45	$1.33	$1.32	$1.43	1%
DQE Inc	$1.19	$1.13	$1.10	$1.30	$1.12	$1.13	NA	NA
DTE Energy Co	$3.83	$3.00	$3.50	$3.50	$3.14	$3.49	$3.68	-5%
Duke Energy Corp	$1.88	$1.20	$1.15	$1.10	$1.20	$1.20	$1.25	-12%
Edison International	$1.80	$1.50	$1.65	$1.70	$2.09	$1.60	$1.61	6%
Empire District Electric	$1.19	$1.40	$1.43	$1.38	$1.36	$1.41	$1.40	-1%
Entergy Corp	$3.81	$4.20	$4.20	$4.58	$4.21	$4.22	$4.53	1%
Exelon	$4.83	$5.15	$5.61	$5.95	$5.13	$5.46	$5.69	5%
FirstEnergy Corp	$2.69	$2.19	$2.75	$2.85	$2.10	$2.85	$3.11	-8%
FPL Group Inc	$4.80	$4.88	$5.02	$4.80	$4.88	$5.10	$5.10	-6%
Great Plains Energy	$2.04	$2.00	$1.95	$2.05	$2.05	$2.07	$2.19	-6%
Hawaiian Electric Inds	$3.26	$2.95	$2.95	$3.00	$2.91	$3.07	NA	NA
NiSource Inc	$1.82	$1.60	$1.70	$1.75	$1.64	$1.71	$1.75	0%
Northeast Utilities	$1.08	$0.95	$1.25	$1.35	$1.19	$1.25	$1.35	0%
OGE Energy Corp	$1.55	$1.50	$1.45	$1.52	$1.51	$1.51	NA	NA
PG&E Corp	$1.85	$1.80	$2.25	$2.30	$1.87	$2.06	$2.21	4%
Pinnacle West Capital	$3.50	$2.70	$3.25	$3.35	$2.60	$2.93	$3.22	4%
Pepco Holdings	$1.74	$1.45	$1.55	$1.60	$1.47	$1.47	$1.46	10%
PPL Corporation	$3.54	$3.55	$3.60	$3.70	$3.59	$3.66	$3.85	-4%
Progress Energy	$3.81	$3.55	$3.70	$3.76	$3.53	$3.73	$3.88	-3%
Public Service Entrp Group Inc	$3.76	$3.67	$3.75	$3.85	$3.70	$3.71	$3.83	1%
Puget Energy	$1.25	$1.34	$1.80	$1.87	$1.35	$1.82	NA	NA
Sempra Energy	$2.68	$2.65	$2.65	$2.75	$2.72	$2.68	$2.60	6%
Southern Co	$1.78	$1.90	$1.96	$1.96	$1.91	$1.96	$2.00	-2%
Sierra Pacific Resources	$1.05	$0.55	$0.35	$0.45	$0.25	$0.40	NA	NA
TECO Energy Inc	$2.28	$0.70	$1.10	$1.25	$0.89	$0.82	$0.86	45%
TXU Corp	$2.90	$2.00	$2.10	$2.03	$1.99	$2.07	$2.16	-6%
Wisconsin Energy Corp	$2.23	$2.25	$2.35	$2.46	$2.30	$2.37	$2.50	-2%
Xcel Energy	$1.43	$1.20	$1.25	$1.25	$1.19	$1.23	$1.29	-3%
% Change (a)		-6.7%	5.9%	3.0%		4.6%	4.6%	

Source: First Call
(a) Excludes extraordinary comps.

Table 5: Utility and Power Rankings

Investment Opinion	Ticker	Company	Current Price 01/03/04	Indicated Annual Dividend	Current Yield	12 Month Price Target (1)	12 Month % Change	12 Mo. Total Return Potential	Earnings per Share 2003E	Earnings per Share 2004E	Earnings per Share 2005E	5 Year Est. EPS Growth	2003E Price/ Earnings	2004E Price/ Earnings	2005E Price/ Earnings
1-OW	EXC	Exelon	$66.00	$2.00	3.0%	$80	21%	24%	$5.15	$5.61	$5.95	7%	12.8x	11.8x	11.1x
1-OW	PCG	PG&E Corp	$27.23	$0.00	0.0%	$33	21%	21%	$1.80	$2.25	$2.30	6%	15.1x	12.1x	11.8x
1-OW	NI	NiSource Inc	$21.66	$0.92	4.2%	$25	16%	20%	$1.60	$1.70	$1.75	4%	13.5x	12.7x	12.4x
2-EW	PEG	Public Service Entrp Group Inc	$43.80	$2.16	4.9%	$49	12%	17%	$3.67	$3.75	$3.85	5%	11.9x	11.7x	11.4x
1-OW	PPL	PPL Corporation	$43.75	$1.44	3.3%	$49	13%	16%	$3.55	$3.60	$3.70	4%	12.3x	12.2x	11.8x
2-EW	ETR	Entergy Corp	$57.25	$1.80	3.1%	$64	12%	15%	$4.20	$4.20	$4.58	5%	13.6x	13.6x	12.5x
2-EW	D	Dominion Resources Inc	$64.01	$2.58	4.0%	$71	10%	15%	$4.67	$4.89	$5.05	5%	13.7x	13.1x	12.7x
1-OW	FE	FirstEnergy Corp	$35.34	$1.50	4.2%	$39	10%	14%	$2.19	$2.75	$2.85	3%	16.1x	12.9x	12.4x
1-OW	WEC	Wisconsin Energy Corp	$33.45	$0.80	2.4%	$37	10%	13%	$2.25	$2.30	$2.46	8%	14.9x	14.5x	13.6x
2-EW	PNW	Pinnacle West Capital	$40.29	$1.80	4.5%	$43	8%	12%	$2.70	$3.25	$3.35	4%	14.9x	12.4x	12.0x
2-EW	PSD	Puget Energy	$23.64	$1.00	4.2%	$26	8%	12%	$1.34	$1.80	$1.87	5%	17.6x	13.2x	12.6x
2-EW	FPL	FPL Group Inc	$65.03	$2.40	3.7%	$70	8%	12%	$4.88	$5.02	$4.80	3%	13.3x	13.0x	13.5x
2-EW	TXU	TXU Corp	$23.79	$0.50	2.1%	$26	9%	11%	$2.00	$2.10	$2.03	0%	11.9x	11.3x	11.7x
2-EW	EIX	Edison International	$21.93	$0.80	3.6%	$23	6%	10%	$1.50	$1.65	$1.70	5%	14.6x	13.3x	12.9x
2-EW	PGN	Progress Energy	$45.50	$2.30	5.1%	$47	4%	9%	$3.55	$3.70	$3.76	0%	12.8x	12.3x	12.1x
2-EW	SO	Southern Co	$30.06	$1.40	4.7%	$31	3%	8%	$1.90	$1.96	$1.96	3%	15.8x	15.3x	15.3x
2-EW	SRP	Sierra Pacific Resources	$7.42	$0.00	0.0%	$8	8%	8%	$0.55	$0.35	$0.45	1%	13.5x	21.2x	16.5x
2-EW	SRE	Sempra Energy	$30.20	$1.00	3.3%	$32	4%	8%	$2.65	$2.65	$2.75	6%	11.4x	11.4x	11.0x
2-EW	DPL	DPL Inc	$20.69	$0.96	4.6%	$21	1%	6%	$1.25	$1.37	$1.45	6%	16.6x	15.1x	14.3x
2-EW	TE	TECO Energy Inc	$14.39	$0.76	5.3%	$15	1%	6%	$0.70	$1.10	$1.25	0%	20.6x	13.1x	11.5x
2-EW	DTE	DTE Energy Co	$39.49	$2.06	5.2%	$40	1%	6%	$3.00	$3.50	$3.50	0%	13.2x	11.3x	11.3x
2-EW	XEL	Xcel Energy	$16.97	$0.75	4.4%	$17	1%	5%	$1.20	$1.25	$1.25	3%	14.1x	13.6x	13.6x
2-EW	POM	Pepco Holdings	$19.79	$1.00	5.1%	$20	-1%	4%	$1.45	$1.55	$1.60	4%	13.6x	12.8x	12.4x
2-EW	AEE	Ameren Corp.	$45.80	$2.54	5.5%	$45	-2%	4%	$2.90	$2.95	$3.00	2%	15.8x	15.5x	15.3x
2-EW	EDE	Empire District Electric	$21.92	$1.28	5.8%	$21	-3%	3%	$1.40	$1.43	$1.38	0%	15.7x	15.3x	15.9x
2-EW	CEG	Constellation Energy Corp	$39.30	$1.04	2.6%	$39	0%	3%	$2.75	$3.07	$3.10	7%	14.3x	12.8x	12.7x
2-EW	CIN	Cinergy Corp	$38.77	$1.84	4.7%	$37	-3%	1%	$2.58	$2.75	$2.70	3%	15.0x	14.1x	14.4x
2-EW	OGE	OGE Energy Corp	$24.05	$1.33	5.5%	$23	-5%	0%	$1.50	$1.45	$1.52	1%	16.0x	16.6x	15.8x
2-EW	AES	AES Corporation	$9.48	$0.00	0.0%	$10	0%	0%	$0.50	$0.65	$0.70	15%	19.0x	14.6x	13.5x
2-EW	AEP	American Electric Power	$30.76	$1.40	4.6%	$29	-5%	0%	$2.22	$2.15	$2.30	3%	13.9x	14.3x	13.4x
3-UW	ED	Consolidated Edison	$42.98	$2.24	5.2%	$40	-6%	-1%	$2.80	$2.80	$2.77	1%	15.4x	15.4x	15.5x
2-EW	LNT	Alliant Energy	$24.82	$1.00	4.0%	$24	-5%	-1%	$1.55	$1.75	$1.85	5%	16.0x	14.2x	13.4x
2-EW	DQE	Duquesne Light Holdings	$18.05	$1.00	5.5%	$17	-8%	-2%	$1.13	$1.10	$1.30	4%	16.0x	16.4x	13.9x
2-EW	AYE	Allegheny Energy Inc	$12.61	$0.00	0.0%	$12	-2%	-2%	($1.40)	$0.81	$1.06	NA	-9.0x	15.6x	11.9x
3-UW	GXP	Great Plains Energy	$31.85	$1.66	5.2%	$29	-10%	-5%	$2.00	$1.95	$2.05	2%	15.9x	16.3x	15.5x
2-EW	CMS	CMS Energy Corp	$8.59	$0.00	0.0%	$8	-5%	-5%	$0.80	$0.70	$0.70	1%	10.7x	12.3x	12.3x
2-EW	HE	Hawaiian Electric Inds	$47.40	$2.48	5.2%	$41	-13%	-8%	$2.95	$2.95	$3.00	1%	16.1x	16.1x	15.8x
3-UW	NU	Northeast Utilities	$20.10	$0.60	3.0%	$17	-14%	-11%	$0.95	$1.25	$1.35	4%	21.2x	16.1x	14.9x
3-UW	DYN	Dynegy Inc	$4.55	$0.00	0.0%	$4	-12%	-12%	($0.02)	($0.05)	($0.05)	NA	NM	NM	NM
3-UW	DUK	Duke Energy Corp	$20.35	$1.10	5.4%	$14	-31%	-26%	$1.20	$1.15	$1.10	0%	17.0x	17.7x	18.5x
3-UW	CPN	Calpine Corp	$4.97	$0.00	0.0%	$3	-40%	-40%	$0.10	$0.11	$0.10	NA	49.7x	45.2x	49.7x
Averages:															
Utility			$30.44	$1.30	4.0%	$31	2%	6%	$2.09	$2.22	$2.27	3.1%	14.9x	14.2x	13.7x
IPP			$4.76	$0.00	0.0%	$4	-26%	(26%)	$0.04	$0.03	$0.03	NA	34.3x	29.9x	31.6x
Integrated			$37.23	$1.33	3.5%	$40	3%	6%	$2.52	$2.88	$3.03	3.5%	12.1x	13.5x	12.7x
Coverage Universe			$31.35	$1.27	3.8%	$32	1%	5%	$2.18	$2.32	$2.38	3.2%	15.0x	14.8x	14.4x
S&P 500 Index			$996.79	$16.72	1.7%	$1,150	15%	17%	$54.75	$60.00	$64.20	7.0%	18.2x	16.6x	15.5x

(1) Price target methodologies are mainly based on forward P/E multiples, but also consider EV/EBITDA and cash flow. Price targets are also adjusted weekly to reflect interest rate changes.
(2) We co-cover DYN with Lehman natural gas analyst, Rick Gross.

Analyst Certification:

I, Daniel Ford, hereby certify (1) that the views expressed in this research note accurately reflect my personal views about any or all of the subject securities or issuers referred to in this note and (2) no part of my compensation was, is or will be directly or indirectly related to the specific recommendations or views expressed in this note.

Related Stocks:	Ticker	Price ()	Rating
AES Corp	AES	8.75	2-Equal weight
CMS Energy	CMS	8.20	2-Equal weight
Calpine Corp	CPN	4.59	3-Underweight
Duke Energy	DUK	19.82	3-Underweight
Consolidated Edison	ED	42.38	3-Underweight
Edison International	EIX	21.30	2-Equal weight
Exelon Corp	EXC	64.20	1-Overweight
FirstEnergy Corp	FE	34.92	1-Overweight
FPL Group	FPL	64.30	2-Equal weight
Great Plains Energy	GXP	32.25	3-Underweight
NiSource, Inc	NI	21.03	1-Overweight
Northeast Utilities	NU	19.45	3-Underweight
PG&E Corp	PCG	27.24	1-Overweight
Pepco Holdings	POM	18.92	2-Equal weight
PPL Corporation	PPL	42.73	1-Overweight
Sempra Energy	SRE	29.03	2-Equal weight
TECO Energy	TE	14.19	2-Equal weight
Wisconsin Energy	WEC	32.70	1-Overweight

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The analysts responsible for preparing this report have received compensation based upon various factors including the Firm's total revenues, a portion of which is generated by investment banking activities.

Key to Investment Opinions:

Stock Rating
1-Overweight - The stock is expected to outperform the unweighted expected total return of the industry sector over a 12-month investment horizon.
2-Equal weight - The stock is expected to perform in line with the unweighted expected total return of the industry sector over a 12-month investment horizon.
3-Underweight - The stock is expected to underperform the unweighted expected total return of the industry sector over a 12-month investment horizon.
RS-Rating Suspended - The rating and target price have been suspended temporarily to comply with applicable regulations and/or firm policies in certain circumstances including when Lehman Brothers is acting in an advisory capacity on a merger or strategic transaction involving the company.

Sector View
1-Positive - sector fundamentals/valuations are improving.
2-Neutral - sector fundamentals/valuations are steady, neither improving nor deteriorating.
3-Negative - sector fundamentals/valuations are deteriorating.

Stock Ratings From February 2001 to August 5, 2002 (sector view did not exist):
This is a guide to expected total return (price performance plus dividend) relative to the total return of the stock's local market over the next 12 months.
1-Strong Buy - expected to outperform the market by 15 or more percentage points.
2-Buy - expected to outperform the market by 5-15 percentage points.
3-Market Perform - expected to perform in line with the market, plus or minus 5 percentage points.
4-Market Underperform - expected to underperform the market by 5-15 percentage points.
5-Sell - expected to underperform the market by 15 or more percentage points.

Stock Ratings Prior to February 2001 (sector view did not exist):
1-Buy - expected to outperform the market by 15 or more percentage points.
2-Outperform - expected to outperform the market by 5-15 percentage points.
3-Neutral - expected to perform in line with the market, plus or minus 5 percentage points.
4-Underperform - expected to underperform the market by 5-15 percentage points.
5-Sell - expected to underperform the market by 15 or more percentage points.
V-Venture – return over multiyear timeframe consistent with venture capital; should only be held in a well diversified portfolio.

Distribution of Ratings:
Lehman Brothers Equity Research has 1618 companies under coverage.
38% have been assigned a 1-Overweight rating which, for purposes of mandatory regulatory disclosures, is classified as a Buy rating, 38% of companies with this rating are investment banking clients of the Firm.
41% have been assigned a 2-Equal weight rating which, for purposes of mandatory regulatory disclosures, is classified as a Hold rating, 9% of companies with this rating are investment banking clients of the Firm.
21% have been assigned a 3-Underweight rating which, for purposes of mandatory regulatory disclosures, is classified as a Sell rating, 66% of companies with this rating are investment banking clients of the Firm.

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Initiation of Coverage

Puget Energy Inc.

A Small-Cap Name with a Solid Total Return Story

Stock Rating:	2-EQUAL WEIGHT
Sector View:	2-NEUTRAL
Ticker:	PSD
Price (11/24/03):	$ 22.77
Price Target:	$24
Exchange:	NYSE
S&P 600	262.87

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We have initiated coverage of Puget Energy with a 2-Equal weight rating and a $24 price target.

- In our opinion, PSD is a solid total return story for investors seeking a small capitalization utility. Our $24 price target represents potential upside of 8% from current levels, which, when combined with the dividend yield of 4.4%, provides a potential total return of 12%.
- The implementation of the Power Cost Adjustment mechanism should provide earnings stability for the electric utility operations, while the Power Cost Only rate proceeding should allow rate base expansion and potential incremental earnings in 2004 and beyond.
- The company has limited nonregulated exposure, representing less than 5% of earnings, through its utility infrastructure business. Furthermore, management has stated that it would not commit additional capital for acquisitions.
- Although Puget Sound Energy's credit is weak (Baa3/BBB-), the company has right-sized the dividend, issued equity, and reduced short-term debt. A more stable electric utility operation, the planned addition of new generation resources to rate base, the recent issuance of 4.55 million common shares, and the filing of a general rate case in 1Q04 to increase rates could improve this credit picture.

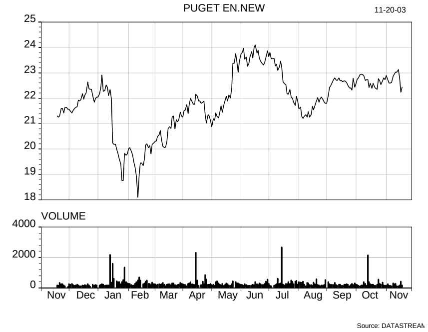
Analyst Certification

I, Daniel F. Ford, CFA, hereby certify (1) that the views expressed in this research report accurately reflect my personal views about any or all of the subject securities or issuers referred to in this report and (2) no part of my compensation was, is or will be directly or indirectly related to the specific recommendations or views expressed in this report.

Market Data	
52-Week Range	24 - 18
Market Cap.	2.1 Bil.
Shares Outstanding (Mil.)	94.0
Float	93.1
Dividend Yield	4.4
Convertible	No

Financial	
Revenues FY 2003	2.5 Bil.
5-Year EPS CAGR (%)	4
ROE (%)	8.5
Current BVPS	16.54
Debt-To-Capital (%)	53

EPS (FY DEC)	2002	2003	2004
1Q	0.28	0.45 A	NA
2Q	0.34	0.22 A	NA
3Q	0.07	0.10 A	NA
4Q	0.55	0.57 E	NA
Year	1.24	1.34 E	1.80 E
P/E		16.7	12.5



November 26, 2003

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Puget Energy Inc. (PSD)

NOVEMBER 26, 2003

ENERGY & POWER

EXECUTIVE SUMMARY

Investment Conclusion

In our opinion, Puget Energy is a solid total return story for investors looking for exposure to a small-capitalization utility with a stable regulated earnings base and an average dividend yield.

More than 90% of the company's earnings and nearly all of its cash flow comes from its electric and gas utility operations. A 2002 general rate case settlement provided an 11% ROE on a 40% pro forma equity base, authorized the use of a Power Cost Adjustment (PCA) mechanism to insulate earnings from purchased power costs, and created a Power Cost Only rate case, an accelerated process to add new generation to the rate base. The addition of a power plant(s) would increase the electric rate base, and could be incremental to earnings. A planned general rate case filing in 1Q04 to increase electric and gas rates could further bolster utility earnings.

In March of 2002, the company was forced to reduce its annual dividend from $1.84 to $1.00 a share and to adopt a dividend policy with a targeted payout ratio of 60% of normalized utility earnings. In our opinion, the current dividend is sustainable, and likely will remain at the current level to achieve the utility's 45% common equity goal by 2005. The current dividend yield of 4.4% is comparable to that of its peer group.

Although PSD has a nonregulated utility infrastructure business, it is relatively small, representing less than 5% of earnings, and management has stated that it would not commit additional capital for acquisitions.

The company recently issued 4.55 million common shares, which should raise its common equity ratio above 40% by year-end 2003, much in advance of a mandated regulatory target of 39% by 2005.

Given Puget Energy's stable utility earnings base and potential for rate base expansion, limited nonregulated exposure, strengthening balance sheet, and modest total return potential, we initiated coverage of PSD with a 2-Equal weight rating.

Valuation

Our $24 price target represents upside of 8% from current levels, which, when combined with the dividend yield of 4.4%, provides a potential total return of 12%. We arrive at our price target by taking a 5% discount (for a weaker credit profile) to the average 2004 small cap utility P/E multiple of 14.4x, and applying it to our 2004 EPS multiple of $1.80.

Earnings Forecast

We estimate earnings of $1.34 per share and $1.80 per share for 2003 and 2004, respectively. The growth in 2004 reflects the positive effect of implementing the PCA mechanism and reaching the cumulative $40 million cap in 2003. We have not assumed any incremental earnings from the acquisition of the Frederickson 1 power plant or the planned filing of a general rate case in 1Q04.

Long-Term Risk

In the near term, the main risk factor is likely to be headline risk-related to lingering issues, with the Western power crisis of 2000–01. Longer term, the key risks are the company's credit rating and unexpected changes in state and/or federal regulation.

Puget Energy, Inc.
Consolidated Income Statement
Dollars in Millions, except per share data

PUGET ENERGY

For the Year Ended December 31,	**2000**	**2001**	**2002**	**2003E**	**2004E**	**2005E**	**2006E**	**2007E**
Operating Revenues								
Electric	$ 2,632.3	$ 1,865.2	$ 1,365.9	$ 1,524.2	$ 1,417.2	$ 1,458.8	$ 1,571.2	$ 1,684.7
Gas	612.3	815.1	697.2	574.0	616.0	630.0	645.2	661.0
Other	57.7	206.3	329.3	353.6	392.2	399.9	407.7	415.6
Total Operating Revenues	3,302.3	2,886.6	2,392.3	2,451.7	2,425.4	2,488.7	2,624.1	2,761.3
Energy Costs								
Purchased Electricity	1,627.2	918.7	645.4	840.9	651.5	668.1	684.7	654.0
Residential/Farm Exchange Credit	(41.0)	(75.9)	(150.0)	(170.6)	(177.0)	(180.1)	(126.2)	0.0
Purchased Gas	332.9	537.4	405.0	265.6	285.8	291.9	298.7	305.6
Electric Generation Fuel	183.0	281.4	113.5	60.5	70.6	68.4	66.3	66.3
Unrealized (Gain) Loss on Derivatives	0.0	(11.2)	(11.6)	0.4	0.0	0.0	0.0	0.0
Total Energy Costs	2,102.2	1,650.5	1,002.3	996.9	830.9	848.4	923.5	1,026.0
Gross Margin	1,200.1	1,236.1	1,390.0	1,454.8	1,594.6	1,640.3	1,700.5	1,735.3
Gross Margin %	36.3%	42.8%	58.1%	59.3%	65.7%	65.9%	64.8%	62.8%
Expenses								
Utility O&M	237.7	262.9	279.2	289.2	302.3	313.7	325.5	337.6
Other O&M	60.6	156.7	273.2	310.6	327.4	331.7	337.5	344.0
Depreciation & Amortization	196.5	217.5	228.7	237.5	248.6	259.1	268.4	277.1
Conservation Amortization	6.8	6.5	17.5	29.7	25.9	26.4	26.9	27.4
Taxes Other than Income Taxes	202.4	212.6	210.2	202.2	209.1	214.7	223.3	240.8
Total Operating Expenses	704.0	856.2	1,008.9	1,069.2	1,113.2	1,145.6	1,181.5	1,226.8
Operating Income	496.1	379.9	381.1	385.7	481.4	494.7	519.0	508.5
Other Income	13.3	2.2	5.5	6.6	4.4	4.3	4.2	4.1
Earnings Before Interest and Taxes	509.5	382.1	386.6	392.3	485.8	499.0	523.2	512.6
Interest Charges	175.1	190.1	196.4	185.0	172.2	170.1	164.5	150.4
Minority Interest	0.0	0.0	0.9	0.1	0.8	0.8	0.8	0.8
Earnings Before Taxes	334.4	192.0	189.3	207.2	312.8	328.1	357.9	361.4
Effective Tax Rate	39.9%	39.9%	37.1%	35.3%	42.5%	42.5%	42.5%	42.5%
Income Taxes	133.5	76.5	70.3	73.1	133.0	139.5	152.2	153.7
Net Income	200.8	115.5	119.1	134.1	179.8	188.6	205.7	207.7
Preferred Stock Dividends	9.0	8.4	7.8	5.1	0.0	0.0	0.0	0.0
Net Income to Common	**$ 191.8**	**$ 107.1**	**$ 111.3**	**$ 129.0**	**$ 179.8**	**$ 188.6**	**$ 205.7**	**$ 207.7**
Avg. Diluted Shares Outstanding	85.7	86.7	88.8	96.3	100.1	101.1	102.1	103.1
Earnings Per Share	**$2.24**	**$1.23**	**$1.25**	**$1.34**	**$1.80**	**$1.87**	**$2.02**	**$2.02**
Dividend per share	$1.84	$1.84	$1.00	$1.00	$1.00	$1.00	$1.00	$1.00
Payout Ratio	82%	149%	80%	75%	56%	54%	50%	50%

Earnings Contribution by Segment	**2000**	**2001**	**2002**	**2003E**	**2004E**	**2005E**	**2006E**	**2007E**
Earnings per Share								
Utility	$2.28	$1.02	$1.10	$1.29	$1.67	$1.74	$1.89	$1.89
InfrastruX	($0.01)	$0.03	$0.11	$0.01	$0.09	$0.08	$0.09	$0.09
Other	($0.04)	$0.19	$0.05	$0.04	$0.04	$0.04	$0.04	$0.04
Consolidated	**$2.24**	**$1.23**	**$1.25**	**$1.34**	**$1.80**	**$1.87**	**$2.02**	**$2.02**
Percent of Total								
Utility	102%	83%	88%	96%	93%	93%	94%	94%
InfrastruX	0%	2%	8%	0%	5%	5%	4%	5%
Other	-2%	15%	4%	3%	2%	2%	2%	2%
Consolidated	100%	100%	100%	100%	100%	100%	100%	100%

Investment Thesis

PSD has a stable utility earnings base with the potential for rate base expansion, limited nonregulated exposure, a weak but improving credit profile, and modest total return potential.

We initiated coverage of Puget Energy with a 2-Equal weight rating and a price target of $24 per share. In our opinion, PSD is a solid total return story for investors looking for exposure to a small-capitalization utility. The company has a stable utility earnings base with the potential for rate base expansion, limited nonregulated exposure, an improving credit profile, and modest total return potential.

More than 90% of Puget's earnings and nearly all of its cash flow comes from its electric and gas utility subsidiary, Puget Sound Energy (PSE). In 2002, a general rate case settlement provided for an 11% ROE on a pro forma equity base of 40%, authorized the use of a Power Cost Adjustment (PCA) mechanism to insulate earnings from purchased power costs, and created a Power Cost Only rate case (PCORC), an accelerated process to add new generation to the rate base. The company recently announced the acquisition of a 49.9% interest in a 275 megawatt, combined-cycle, gas-fired power plant and the filing of a PCORC. If approved, we estimate the addition of the plant to rates would be $0.03 per share accretive to 2004 earnings. PSE also plans to file a general rate case in 1Q04 to increase electric and gas rates.

In March of 2002, the company was forced to reduce its annual dividend to $1.00 a share from $1.84 and adopt a dividend policy with a targeted payout ratio of 60% of normalized utility earnings. In our opinion, the current dividend is sustainable and likely would remain at the current level to achieve the utility's common equity goal of 45% by 2005. The current dividend yield of 4.4% is comparable to that of its peer group.

Although Puget Energy has a nonregulated utility infrastructure business, it is relatively small, representing less than 5% of earnings, and management has stated that it would not commit additional capital for acquisitions.

Puget Sound Energy is currently rated Baa3/BBB- because of high leverage and weak coverage ratios created by its merger with Washington Natural Gas, a power contract restructuring, and the prior under-recovery of power costs. Last year's dividend cut, the issuance of 5.75 million common shares, reduction in short term debt, and general rate case settlement helped to stabilize the company's credit profile. The recently completed $100 million equity issuance, the expansion of the electric rate base through plant acquisitions, and the potential increase in electric and gas rates could improve PSE's credit picture going forward, though this could be muted by the credit agencies' treatment of PPAs as imputed debt and interest.

Our $24 price target represents upside of 8% from current levels, which, when combined with the dividend yield of 4.4%, provides a potential total return of 12%. Near-term potential catalysts for the stock include the addition of the recent generation acquisition to rate base in 1Q04, and the filing and potential settlement of a general rate case in 2H04.

Investment Risks

Unforeseen Regulatory Actions

Unexpected changes that alter the company's allowed rates of return, financing ability, recovery of capital investments, and mechanisms for power and gas cost recovery could negatively affect PSE's earnings and financial condition.

Credit Ratings

Puget Energy's and PSE's credit ratings are one notch above junk. Although neither company has any rating downgrade triggers that would accelerate the maturity dates of outstanding debt, a downgrade to junk could have a negative impact on liquidity because of increased financing costs, cash prepayments, letter of credit or collateral postings, etc. Furthermore, a reduction in the company's commercial paper (CP) ratings (currently A-3 / P-2) could preclude PSE's ability to issue CP, which it uses to fund working capital and as bridge financing for utility capital expenditures.

Lingering Issues from the Western Power Crisis

PSE is a party to several unresolved issues regarding the Western energy crisis of 2000–01. While these issues may not ultimately have a material effect on PSE's financial condition, they could cast a pall on the stock.

CAISO Receivable and California Refund Proceeding

PSE has booked a gross receivable of $65.6 million due from the California Independent System Operator (CAISO). Against this amount, the company has a bad debt reserve and a transaction fee reserve totaling $41.5 million for a net receivable amount of $24.1 million. On October 17, 2003, PSE sent a demand letter to the CAISO seeking payment of the total gross revenues associated with the transactions of $26.0 million.

"Gaming" Show Cause Order

On June 25, 2003, the FERC directed PSE, along with 43 other energy companies, to "show cause" that they did not engage in illegal market manipulation during the California energy crisis. On August 28, 2003, the FERC trial staff and PSE filed an agreement that would end all accusations by FERC regarding PSE's participation in market manipulation during the crisis. Under the terms of the agreement, the FERC trial staff cleared PSE of all allegations involving so called "ricochet" transactions and paper trading activities. In return, PSE agreed to pay $17,092 in connection with two missed deliveries of power contracted for by the CAISO without admitting any wrongdoing. The agreement must be approved by a FERC administrative law judge and the FERC Commission before becoming effective. If the commission approves the settlement, Moody's may reconsider changing its negative outlook to stable.

Valuation

P/E Multiple

To develop a comparable peer group P/E multiple, we screened our current coverage universe for companies with a market capitalization between $1 billion and $4 billion. We further refined this group by eliminating those companies that were either distressed, did not pay a common dividend, or had a dividend yield in excess of 5.5%. The results are summarized in Figure 1.

Given its weaker credit profile, we believe PSD should trade at a 5% discount to the average 2004 P/E multiple of its peer group or about 13.6x. Applying this multiple to our 2004 EPS estimate of $1.80 results in a 12-month price target of $24 per share.

Figure 1: P/E Valuation Peer Group

				Market	P/E Multiple			Credit Ratin	
Company	**Rating**	**Ticker**	**Price**	**Cap ($ B)**	2003E	2004E	**Yield %**	Moody's	S&
Alliant Energy	2-EW	LNT	$24.00	$2.6	15.5x	14.5x	4.2%		BE
DPL Inc	2-EW	DPL	$19.30	$2.4	15.4x	14.1x	4.9%	Ba1	BE
Great Plains Energy	3-UW	GXP	$32.06	$2.2	16.0x	16.4x	5.2%		BE
Northeast Utilities	3-UW	NU	$19.28	$2.4	20.3x	15.4x	3.1%	Baa1	BE
Pinnacle West Capital	2-EW	PNW	$39.14	$3.5	14.5x	12.0x	4.6%	Baa2	BE
Wisconsin Energy Corp	1-OW	WEC	$31.95	$3.7	14.2x	13.9x	2.5%	A3	BE
Group Average					**16.0x**	**14.4x**	**4.1%**		
Puget Energy	**2-EW**	**PSD**	**$22.77**	**$2.1**	**17.0x**	**12.7x**	**4.4%**	**Baa3**	**BE**

Source: Lehman Brothers

EV/EBITDA

On an EV/EBITDA analysis, we arrive at a valuation of $24 per share comprised of $23 from the utility and $1 from InfrastruX (see Figures 2 and 3). We have applied a conservative 6.5x multiple to our projected 2004 utility EBITDA of $692.2 million. For InfrastruX, we applied a 5.5x EV/EBITDA multiple, which is equivalent to the historical trough multiple for the Engineering & Construction group as identified by Lehman Brothers Analyst Thomas Ford.

Figure 2: Utility Breakup Valuation

EBITDA	$693.6
EBITDA multiple	6.5x
Implied EV	$4,508.6
Plus: Cash	7.5
Less: Debt	1,959.7
Less: Preferred Stock	0.0
Less: Preferred Securities	280.3
Equity Value	$2,276.2
Value per Share	**$23**

Source: Lehman Brothers

Figure 3: InfrastruX Breakup Valuation

EBITDA	$40.8
EBITDA multiple	5.5x
Implied EV	$224.3
Plus: Cash	3.2
Less: Debt	153.1
Equity Value	$74.4
Value per Share	**$1**

Source: Lehman Brothers

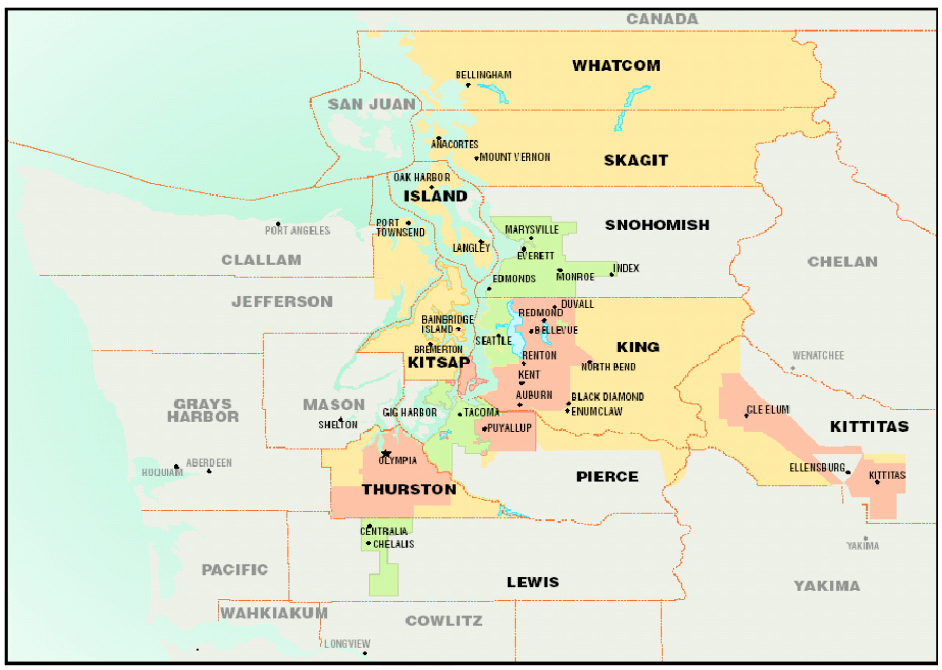
Business Overview

Puget Energy Inc. is a public utility holding company with two primary subsidiaries; Puget Sound Energy Inc., a wholly owned, regulated electric and gas utility that principally serves western Washington state, and InfrastruX Group, Inc., a provider of specialized contracting services primarily to the electric and natural gas industries.

Puget Sound Energy Inc. (PSE)

PSE became an integrated utility in 1997 through the merger of Puget Sound Power & Light, an electric utility, Washington Natural Gas (WNG), a natural gas local distribution company, and Washington Energy Co., the parent company of WNG. On January 1, 2001, Puget Sound Energy Inc. reorganized into a holding company structure, creating Puget Energy Inc.

Figure 4: Map of PSE Service Territory



Combined electric and natural gas service
Electric service
Natural gas service

Puget Sound Energy's service territories:
Electric Service: Island, Jefferson, parts of King (not Seattle), Kitsap, Kittitas, Pierce (not Tacoma), Thurston, Skagit and Whatcom counties. (Public utility districts also serve parts of some counties.)
Natural Gas Service: King, Lewis, Pierce, Snohomish, Thurston and parts of Kittitas counties.

Puget Sound Energy is Washington state's largest energy utility, providing electric and natural gas service to more than 1.2 million customers, primarily in Washington state's Puget Sound region.

PSE PUGET SOUND ENERGY

Source: Company reports

Today, PSE is the largest vertically integrated utility based in the state of Washington, with a service territory covering more than 6,000 square miles, more than 968,000 electric customers, and more than 633,000 gas customers.

Service Territory – A Slowing Economy and Population Growth

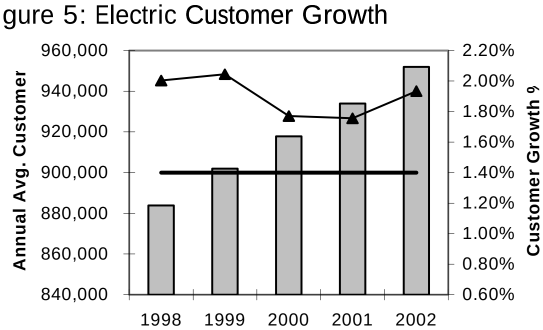
PSE continues to experience customer growth rates that are above the industry averages.

PSE's service territory encompasses some of the largest counties in the state of Washington, including King County and Pierce County (see Figure 4). Although the electric utility does not service Seattle and Tacoma, the largest cities in King and Pierce counties, respectively, its service territory does include Bellevue (the fifth-most-populated city in the state) and Olympia, the state capital. The company's gas service territory includes Seattle and Tacoma.

The majority of growth in the state remains concentrated in the central Puget Sound region, which includes the counties of King, Kitsap, Pierce, and Snohomish. Population growth in this region, however, has been steadily declining, from more than 3% in the early 1990s, to 2% percent in 1995, and to 0.93% in 2003—the lowest since 1983. The slowdown in population growth mainly reflects the plight of the region's economy, and its links to the aerospace and high-technology sectors.

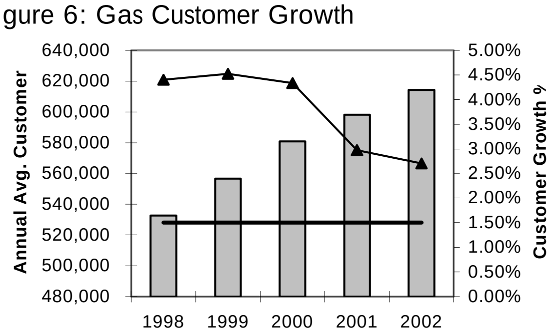
The aerospace industry has long been a foundation of the region's economy. Boeing Co. is the largest aerospace company in the region, accounting for 76,000 of the region's nearly 88,000 aerospace jobs in 2001. In September 2001, Boeing moved its company headquarters to Chicago (but maintained its Commercial Airplanes unit in Renton). In addition, the September 11 terrorist attack on the World Trade Center negatively affected the aerospace industry. Following September 11, Boeing announced that it would cut 30,000 jobs by March 2002, more than half of which were located in the central Puget Sound region. 2001 was also the year of the "dot-com bust," resulting in numerous layoffs and high-technology company bankruptcies. The regional economy has not markedly improved since then. Estimates predict that the central Puget Sound region could experience very slow job growth in 2003, and may not fully recover to prerecession growth rates until 2005. Similarly, the slowdown in population growth is expected to last through 2004 and into 2005. Thus, population growth is not expected to rebound until the region's economy recovers, which could pose a challenge to the company's projected near-term customer growth targets of 1.7% for electric customers and 2.9% for gas. To date, though, the company continues to experience strong customer growth of 2.2% and 3.5% in the electric and gas businesses, respectively.

Figure 5: Electric Customer Growth



Source: Company reports and Lehman Brothers

Figure 6: Gas Customer Growth



Source: Company reports and Lehman Brothers

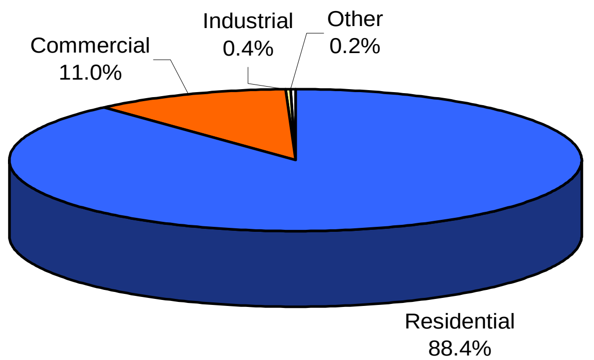
Although PSE's customer growth rate has slowed in the last five years, particularly in the gas business, the average annual electric and gas customer growth rate continues to outpace the industry averages (see Figures 5 and 6).

Favorable Customer Mix and Balanced Customer Revenues

The bulk of PSE's customers are higher-margin, residential and commercial customers.

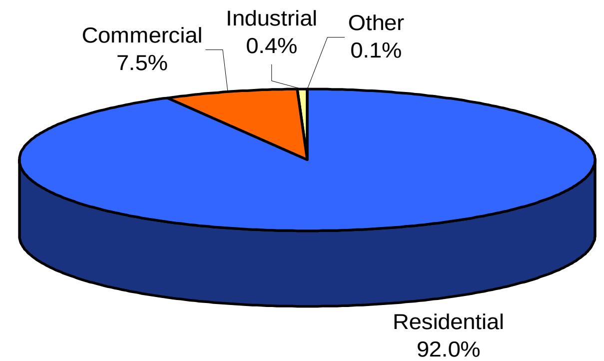
The bulk of PSE's customers are higher margin, residential and commercial customers (about 99% for both the electric and gas businesses; see Figures 7 and 8). Industrial customers accounted for less than 0.5% of all retail customers and less than 10% of retail revenues at the end of 2002 (Figures 9 and 10). Prior to 2002, electric industrial customers provided about 20% of electric retail revenues. Customer revenue concentration shifted following an April 2001 regulatory decision to allow large industrial customers, whose rates were linked to a market index, to choose an alternative supplier or to self-generate. The company's top 10 customers now account for only about 7% of total electric revenues. The electric utility's largest customer only accounts for 1.5% of electric revenues. Thus, the company's earnings are not overly exposed to a single customer or group of customers.

Figure 7: 2002 Electric Customers by Customer Class



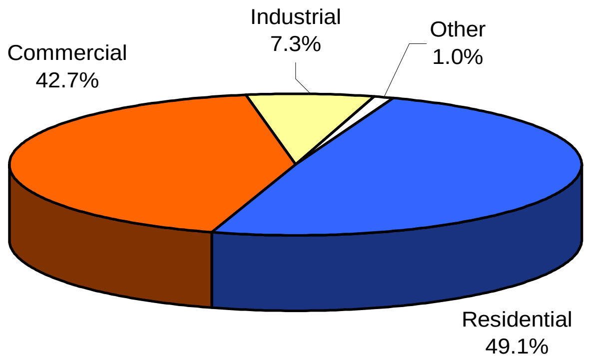
Source: Company reports and Lehman Brothers

Figure 8: 2002 Gas Customers by Customer Class



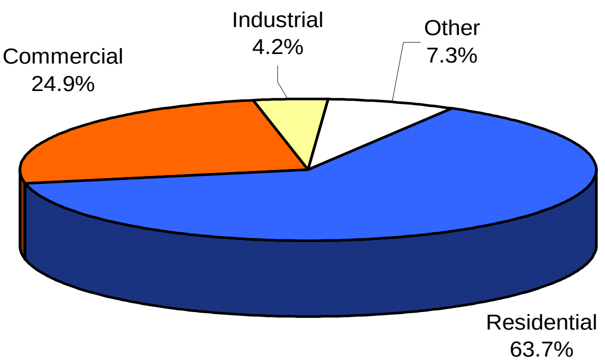
Source: Company reports and Lehman Brothers

Figure 9: 2002 Electric Retail Revs by Customer Type



Source: Company reports and Lehman Brothers

Figure 10: 2002 Gas Retail Revs by Customer Type



Source: Company reports and Lehman Brothers

State Regulatory Overview

Deregulation – An Unlikely Event

The state of Washington does not plan to open its electric and gas markets to retail competition. The state's legislature has not passed any bills mandating retail access, nor has it established time lines for implementing direct access for all customers. Because of the impact of the Western power crisis of 2000–01, deregulation appears to be a moot issue in the state. Furthermore, the state regulatory agency, the Washington Utilities and Transportation Commission (WUTC), clearly favors the traditional cost of service model, and is staunchly opposed to federal intervention to create a competitive market in the state. The WUTC is a three-member board (Marilyn Showalter, chairwoman, Dick Hemstad, and Patrick Oshie) that is appointed by the governor and confirmed by the state senate to six-year terms. Unlike other state utility commissions, the WUTC does not have "show cause" authority or the ability to force a utility to justify its rates.

Although the regulatory environment in Washington is fairly conservative, the WUTC has been supportive of the utilities that it regulates.

Although the regulatory environment in Washington is fairly conservative, the WUTC has been supportive of the utilities that it regulates. For example, the commission authorized utilities to recover from customers the extraordinary power costs they incurred during the power crisis, it permits the use of purchased gas adjustments and recently, a power cost adjustment mechanism, and created an expedited rate review process for certain new generation investments.

Improving Regulatory Relations

Relations between the WUTC and Puget Energy's prior management could be characterized as contentious. As a result of closer interaction during and after the power crisis, and under the leadership of Steve Reynolds as CEO (appointed in January 2002), a more constructive relationship appears to have been formed.

For example, in June 2002, the WUTC granted final regulatory approval of a comprehensive electric and gas rate settlement with PSE. The settlement provided an 8.76% overall return on capital, an authorized return on common equity of 11.00%, and a pro forma capital structure that assumed a 40% equity component (compared to an equity ratio of 30% at Dec. 31, 2001). As part of this settlement, PSE agreed to achieve minimum equity targets of 34%, 36%, and 39% at year-end 2003, 2004, and 2005, respectively. PSE must maintain, at least, a 39% equity ratio until the conclusion of its next general rate case. If the company fails to achieve a target threshold, the WUTC will reduce PSE's overall general electric and gas rates by 2% for a one-year period. The settlement also approved the adoption of an electric power cost-adjustment mechanism.

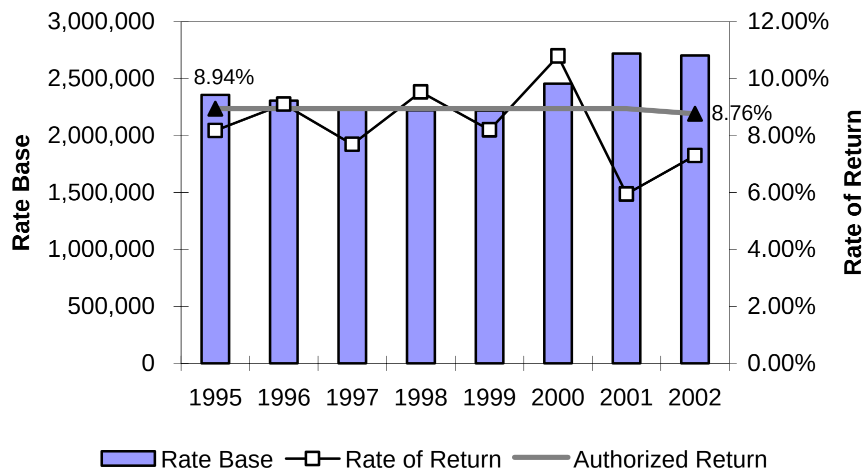
General Rate Case Expected in 2004

PSE plans to file a general rate case in 1Q04 to increase its electric and gas rates, and will include a request for a pro forma common equity ratio of 45% and an ROE of 11.00% or more. (Additional details are expected to be disclosed on the company's year-end conference call in February 2004). The company's recent equity transaction with Franklin Advisers Inc. may help in obtaining the 45% equity capital structure. A fully litigated rate case would take approximately 11 months to complete, with rates not effective until 1Q05. Thus, the company likely would seek to settle the case, as it did in 2002, sometime during 2004.

Electric

Until 2000, the electric business earned close to or more than its authorized rate of return (see Figure 11). Since then, returns have been negatively affected by increasing purchase power costs, Federal Energy Regulatory Commission (FERC)-imposed price controls on wholesale electricity in the Western states, and by industrial and commercial customers switching to transportation rate tariffs from market index rates.

Figure 11: Electric Rate Base versus Earned Rate of Return



Source: WUTC and Lehman Brothers

Power Supply Risk

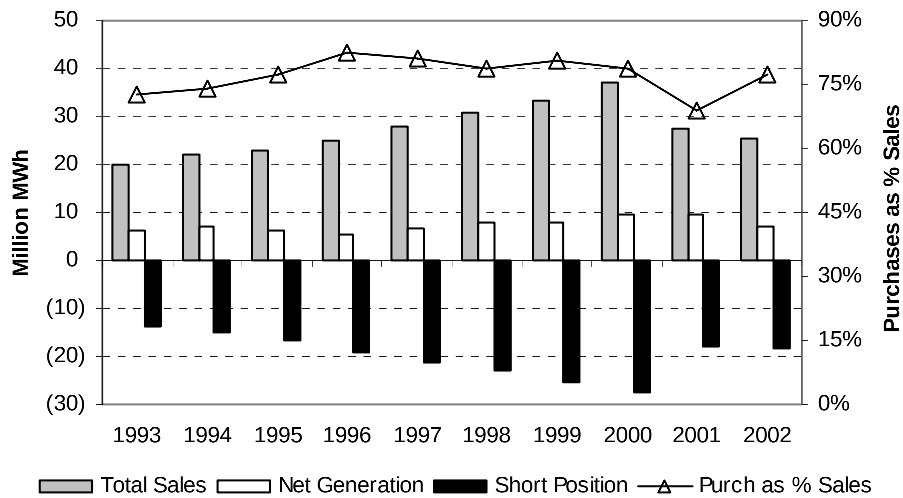
The Pacific Northwest is home to the largest coordinated hydroelectric system in the country. More than a third of the region's total hydroelectric capacity is owned and operated by the U.S. Army Corps of Engineers. (The bulk of this capacity is located in the Columbia River Basin, which runs along the Oregon / Washington border). The Bonneville Power Administration (BPA), a self-funding federal power agency, is the designated marketer for this power, which accounts for about 45% of the electric power used in the region. Additionally, the BPA owns about three-quarters of the region's electric transmission system.

Under average hydro conditions, hydro resources (including owned and contracted) account for about 40% of PSE's electric supply needs. This dependence creates volatility, because the amount and timing of hydroelectric shortfalls or surpluses can greatly affect the costs incurred for replacement power. For example, in a low hydro year, the company would be forced to replace very low-cost hydro supply with much more expensive natural gas or oil resources, as was the case in 2000 and 2001, during the Western energy crisis.

PSE is short on power, and must purchase about 75% of its electric supply needs.

Further compounding this exposure is the fact that the company is short on power, and must purchase about 75% of its electric supply needs (see Figure 12). PSE purchases approximately 60% of its purchase power needs through long term contracts (see Figure 23) with several Washington Public Utility Districts (PUD), Non-Utility Generators (NUGs), and other long-term purchase and exchange contracts, including contracts with Qualifying Facilities (QFs).

Figure 12: PSE Electric Short Position



Source: FERC Form 1 filings and Lehman Brothers

The hydro-based contracts represent about 60% of the company's total purchased resources and the NUG contracts provide more than 50% of the nonhydro energy supply. On the positive side, most of the NUG contracts and long-term contracts do not expire until the 2011–12 period (see Figure 24). The downside is the high expense of the NUG supply, because of its PURPA-regulated contracts and the exposure to low hydro supply conditions, which, for the Columbia River PUD contracts, means not only obtaining replacement power, but also cost-of-service payments. (According to cost-of-service payment arrangements, PSE pays its proportional share of the annual debt service and operating and maintenance costs of each project, regardless of the availability or operational status).

From October 1991 to September 1996, earnings were not significantly influenced by sales of surplus electricity, by variations in weather, hydro conditions, or nonfirm regional electric energy prices, because of a Periodic Rate Adjustment Mechanism (PRAM). The PRAM allowed PSE to request annual rate adjustments, on a prospective basis, to reflect changes in certain costs, principally those affected by hydro and weather conditions. Because of the stipulated settlement that authorized the merger with Washington Natural

Gas in September 1996, the PRAM was eliminated, and rates were frozen for a five-year period ending 2001.

Consequently, from 1997 to 2000, PSE was able to use sales of excess power to offset its cost of purchased power. (PSE has a winter peaking load, which means it has excess capacity in the summer months to export to other territories). This arrangement allowed the electric operation to earn near or more than its authorized rate of return (ROR), as was evident in 2000, during the Western energy crisis (see Figure 11). Then, in the latter half of 2001, FERC instituted price controls on wholesale electricity for the entire Western region, which materially diminished the value of PSE's excess capacity and negatively affected financial results.

Power Cost Adjustment to Mitigate Supply Risk

The PCA limits shareholder exposure to $40 million, plus 1% of the excess costs.

Beginning in July 2002, a Power Cost Adjustment (PCA) mechanism became effective. The PCA was designed to provide stability after the end of the five-year rate period by tracking the difference between PSE's modified actual power costs and a power cost baseline. The baseline accounts for all significant variable supply cost drivers, including hydro generation variability, market price variability for purchased power and surplus power sales, natural gas and coal fuel price variability, generation unit forced outage risk, and wheeling cost variability.

Under the PCA, ratepayers and shareholders share in deviations from the baseline through a series of annualized sharing bands (see Figure 13).

Figure 13: PCA Sharing Bands

Annual Power Cost Variability	Ratepayer's Share	Company's Share
+ / - $20 million	0%	100%
+ / - $20-$40 million	50%	50%
+ / - $40-$120 million	90%	10%
+ / - $120+ million	95%	5%

Source: Company reports

Other important features of the PCA include:

- Applicable for a four-year period ending June 30, 2006, with sharing amounts calculated for 12-month periods beginning on July 1 of each year.
- During the four-year period, PSE's pretax earnings exposure is capped at +/- $40 million. Once the cap is exceeded, the company's exposure is 1% of the excess costs or benefit.
- When the cap is removed on June 30, 2006, any deferred balances associated with the cap are set for refund or collection at that time.

- Interest is accrued on any deferred balance.
- PSE can request a PCA rate surcharge if, for any 12-month period, the actual or projected deferred power costs exceed $30 million.
- PCA does not recover variations in margin resulting from temperature fluctuations.

Actual power costs may be modified for two factors; the availability of Colstrip and new resources. The first adjustment allows for the removal of a portion of PSE's fixed cost associated with its Colstrip generation facility, if the equivalent availability factor falls to less than 70%. The second adjustment is for new resources with a term of less than or equal to two years, and for new resources with a term longer than two years. Short-term new resources will be included in allowable PCA costs, with prudence determined in the WUTC's annual review of PSE's PCA. New long-term resources will be reviewed in a Power Cost Only Rate Case (PCORC) or General Rate Case (GRC).

PSE anticipates reaching the $40 million cumulative cap by 4Q03.

The PCA limits shareholder exposure to $40 million plus 1% of costs in excess of that amount through June 30, 2005, and therefore, helps to reduce earnings volatility and to insulate equity. PSE anticipates reaching the $40 million cumulative cap by 4Q03. On the flip side, if power prices were to decline, any amounts accrued that were less than the tracker and more than the $40 million cap would be refunded to customers through the aforementioned sharing bands. Thus, PSE would receive only partial benefits from lower power costs.

Plans to Add Generation Resources

The power cost rate proceeding provides an accelerated regulatory review process to add new electric resources to the rate base.

By statute, PSE is required to file a Least Cost Plan (LCP) on a biennial basis. The LCP describes the mix of generating resources and efficiency improvements that would meet current and future demand at the lowest cost to the utility and its ratepayers. The WUTC uses the LCP to evaluate the performance of the state's utilities in rate proceedings, including the review of avoided cost determinations.

Based on its LCP analyses, PSE determined a need for new electric resources because of the growing load in its service territory, the loss of existing resources in the next 10 years, reduced hydro and combustion turbine generation, and the expiration of power purchase and NUG contracts. The company concluded that it should pursue a diversified resource strategy that includes conservation (19 aMW per year), wind, and other renewables, with a goal of serving 10% of its load by 2013, conventional thermal generation (combined-cycle gas-fired turbine generation and coal-fired generation), and seasonal exchanges or other shaping transactions, as needed.

Under the 2002 GRC settlement, PSE can initiate a power cost only rate proceeding to add new generation to the Power Cost Rate (PCR). Upon filing with the commission, hearings would be set to review the appropriateness of adding the new resource costs to the PCR. These hearings will consider only power supply costs included within the Power

Cost Rate, and will be completed within four months. The WUTC will issue an order within 30 days following the hearings. The objective of the accelerated process is to have the new Power Cost Rate in effect *before* the new resource goes into service. This single-issue rate case would not address GRC items, such as the distribution rate base, ROE, or equity structure. Thus, the new resource would presumably go into the rate base with the same 11% ROE and 40% pro forma equity component as outlined in the June 2002 settlement.

PSE recently announced the acquisition of a 49.9% interest in the Frederickson 1 power plant, a 249 MW combined-cycle, natural gas-fired facility that is in the process of expanding to 275 MW, for $80 million (or $584/Kw). The plant is relatively new, having begun operations in August 2002, and is strategically located in Pierce County, which is central to the company's service territory. PSE filed its power-only rate case on October 24, 2003, which means that the plant could be in rates by the end of 1Q04. If this timing is correct, we estimate that the transaction could be accretive to 2004 earnings by $0.03 per share.

The company still needs to add approximately 350 MW of new resources in 2005, and plans to issue multiple RFPs in the next year or two that would allow it to review different types of generation opportunities. PSE already commented that it would like to add another 250 MW–300 MW of gas-fired generation and 50 MW of wind generation in 2005.

Figure 14: Resource Acquisition Program Schedule

Date	Milestone
Sept. 9, 2003	Wind Power Resource RFP (Round 1)
Fall 2003	Completion of the competitive solicitations that PSE issued in August 2002 (assets) and November 2002 (power purchase agreements)
Fall 2003/2004	All resource RFPs, including seasonal shaping

Source: Company reports-

On Sept 9, 2003, PSE issued a draft RFP to acquire approximately 150 megawatts of capacity from wind power (or about 50 average MW) through purchased-power agreements and/or ownership arrangements. The WUTC granted approval of the RFP on November 13, 2003. This approval allows PSE to begin evaluating long-term purchase power agreements or ownership of wind power projects. The company expects the RFP process to result in the addition of one or more projects by the end of 2005.

Competitive Rates

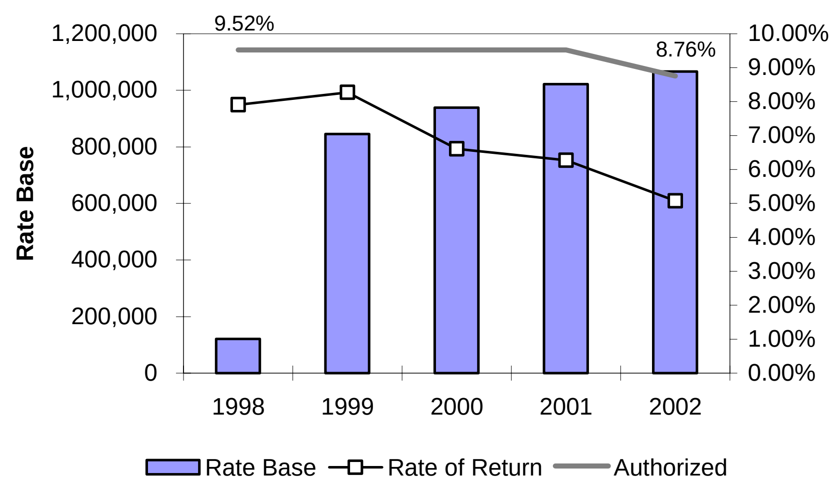
PSE's primary competitors are the public power utilities, Seattle City and Light and Tacoma Power & Light. (The two other investor-owned utilities operate in different parts of the state). Despite a 4.6% increase in electric rates from the 2002 general rate case settlement, PSE's rates remain competitive. As seen in Figure 25, the residential rates of the public power utilities are the highest among the state's electric utilities, primarily because of rate increases during the Western power crisis.

Gas

The planned general rate case in 2004 may help to narrow the gap between the earned and authorized ROR.

As seen in Figure 15, the rate base in the gas business has grown significantly in the last five years, primarily because of an increasing number of customers. Earned returns, however, have not kept pace with this growth. The planned general rate case may help to narrow this gap. In the interim, PSE will continue to focus on organic and targeted growth to achieve its authorized ROR. This means targeting customers with the highest margins and the lowest customer addition costs: for example, marketing to residential customers that are on or near existing mains and coordinating marketing with new home construction planning. (New construction accounts for about 70% of the company's new gas customer additions).

Figure 15: Gas Rate Base versus Earned Rate of Return



Source: WUTC and Lehman Brothers

Long-Term Gas Supplies and PGA

The company's gas supply needs are met through a combination of long-term and winter peaking agreements and purchased and owned storage capacity. The current firm, long-term gas supply portfolio consists of arrangements with 17 producers and marketers, with no single supplier representing more than 11% of expected peak day requirements. Most of these supply contracts purchase gas at prevailing market prices and contain market sensitive pricing provisions based on gas indices. Under a Purchased Gas Adjustment (PGA) mechanism, PSE can fully recover the costs of gas procurement from its gas customers.

The PGA allows PSE to pass through to its customers, on a dollar-for-dollar basis, the actual costs of gas supply and upstream-of-the-city-gate gas transmission and storage resource costs. At least once every 15 months, the company estimates the cost of gas supply and related transmission and storage costs for the ensuing 12 months, and then seeks WUTC approval to establish PGA unit rates to recover those projected costs. Subsequently, each month, the company compares the actual gas supply and related costs to the amounts recovered from customers under the PGA rates. Any difference is deferred to a regulatory asset or liability account for future recovery or refund to customers. The change in PGA rates does not affect PSE's gas margin and net income.

Main Remediation Program

Because of a 1992 WUTC order, PSE must replace or line all of its cast-iron pipes by 2007. The company has 10,798 miles of main in its service territory, of which 10,516 miles is either plastic or wrapped steel. The remaining 282 miles of the system consists of 76 miles of cast iron and 206 miles of bare steel, and will be addressed through an ongoing remediation program.

InfrastruX Group Inc.

InfrastruX is a provider of specialty infrastructure contracting services to the electric, natural gas, telecommunications, and cable industries (see Figure 16). The company was incorporated in June of 2000 as a nonregulated growth vehicle for Puget Sound Energy. At the end of 2002, Puget Energy owned approximately 91.2% of the outstanding shares of InfrastruX. The officers of InfrastruX hold the remaining outstanding shares.

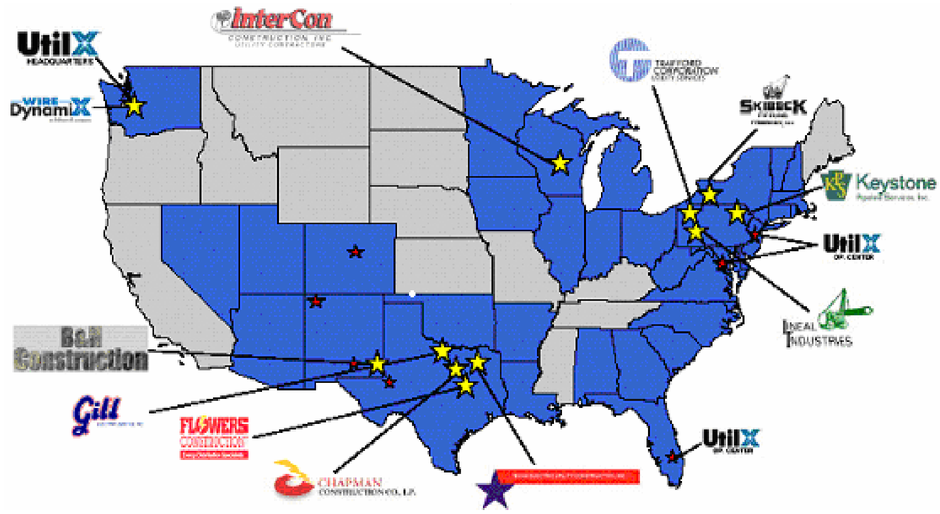
Figure 16: Outline of InfrastruX Services

Electrical	• Overhead and underground power line construction, installation, and maintenance including high-voltage transmission and distribution lines • Duct installation • Revitalization and damage prevention for underground power lines • Substation construction • Other specialty services for new and existing infrastructures
Gas	• Large diameter pipeline installation and maintenance • Service lines and meters • Conventional river crossings and bridge maintenance • Cathodic protection • Power station fabrication and installation • Vacuum excavation • Hydrostatic testing • Internal pipeline inspection • Product pipelines • Other specialty services for distribution and transmission pipeline systems
Directional Drilling	Horizontal directional drilling for underground conduits, pipelines, power lines, and cables
Cable Restoration	Restoration of electric and telecommunication cables using patented treatment called CableCURE®
Telecommunications	Aerial and underground installation, and maintenance of copper, fiber optic cables, conduit systems and wireless infrastructure, and revitalization of underground cables
Water and Sewer	• Mainline and distribution construction, installation, and maintenance • Construction of lift stations, wet wells, pump stations, and retention ponds • Other specialty services for new and existing infrastructures
Engineering and Design	Engineering, design, surveying, right-of-way acquisition, permitting, and environmental requirements
Outsourcing	Turnkey outsourced solutions for the entire service and support lifecycle, including design and engineering, logistics, materials management, construction, installation, ongoing maintenance, and emergency restoration.

Source: Company reports and Lehman Brothers

InfrastruX operates in three primary regions—along the Eastern seaboard, in Texas / South Central United States, and the Upper Midwest United States—that provide the company with a national reach (see Figure 17).

Figure 17: InfrastruX Geographic Footprint



Source: Company presentation

Utility Customer Base

InfrastruX's business is closely linked to the capital expenditure cycles of the utilities that it serves.

Most of InfrastruX's work is done almost exclusively for electric and natural gas utilities (accounting for 90% of its revenues in 2002). According to management, InfrastruX's anchor customers are "market leading" utilities with which it has either a long-term relationship, alliance agreement, or master service agreement. The company's largest customers account for about 20% of total revenues. Thus, the company's business is closely linked to the capital expenditure cycles of the utilities that it serves. InfrastruX also sees utility outsourcing opportunities as a significant growth market. An estimated 60%–65% of utility infrastructure construction and maintenance work, totaling an estimated $40 billion–$50 billion, is still performed in-house.

Growth Via Roll-Up Strategy

The business model for InfrastruX was based on a "roll up" strategy of established, mid-sized infrastructure service companies to achieve scale and synergies that would position the company for long-term organic growth opportunities. In the last three years, InfrastruX has acquired 12 companies with a normalized annual revenue run rate of more than $350 million. Initial plans projected revenues of more than $1 billion and a 20% earnings contribution to consolidated earnings by 2004.

Probationary Period

Puget Energy will not to commit additional capital to the business for acquisitions.

Puget Energy's current management decided not to commit additional capital to the business for acquisitions. Based on internal growth, management expects InfrastruX to contribute 1%–2% annual growth to Puget Energy's earnings and an ROE more than the regulated business or in the mid-teens. In 2002, the company accounted for about 8% of consolidated net income, had a debt-to-capital ratio of 57%, and an ROE of about 9%.

Unfortunately, InfrastruX's 2003 operations have been negatively affected by severe weather conditions and by the reduction in and/or deferral of utility maintenance budgets because of weaker balance sheets, lower credit ratings, and a more challenging operating environment. As a result, we estimate that InfrastruX may only earn $0.01 per share in 2003, versus about $0.10 per share last year.

Initially, Puget's management set 2003 as the "make or break" year for InfrastruX. Due to the unusual weather conditions during the year, the company was given a reprieve until year-end 2004.

The Jury Is Still Out on InfrastruX

Because InfrastruX is in its nascent stage, it is difficult to accurately assess the business' true potential. From the results to date, though, it is clear that the company's earnings are volatile. A big reason for this volatility is the fact that about two-thirds of the company's business is done on so-called alliance contracts, versus long-term fixed contracts with the remaining work done on a bid basis. Thus, the company is at the whim of the utilities that it serves. The business is also highly susceptible to seasonal weather conditions, because most of the work is done outdoors.

Further complicating matters is the fact that limited information exists regarding its contracts (i.e., type and tenure), margins, cost structure, etc. We have seen utilities chase low-margin businesses that require critical mass (nee appliance services and retail marketing) with little success and even smaller returns. Thus, we view InfrastruX with a healthy degree of skepticism, although current management's "wait and see" attitude and capital discipline are encouraging.

Financial Condition

Profitability and Cash Flow

Earnings Profile and Forecast

Puget Energy reports three business segments: Regulated Utility, InfrastruX, and Other. The Other segment consists of the nonregulated subsidiaries of Puget Sound Energy and miscellaneous holding company expenses. The principal nonregulated subsidiary of PSE is Puget Western Inc., a real estate investment and development company. The company's guidance, on a normalized basis, is $1.75–$1.85 per share, consisting of $1.60–$1.70 per share for utility operations, and $0.15 per share for InfrastruX.

In 2002, earnings from the Regulated Utility operations accounted for 88% of Puget Energy's consolidated earnings and nearly all of its cash flow from operations. We project that this trend could continue, albeit with a higher utility earnings contribution of more than 90%. Utility results should mostly reflect continued customer growth in the electric and gas utilities of about 2% and 3%, respectively, and limited exposure to purchase power costs of 1% in excess of the $40 million cap. Upside in utility results could come from the proposed addition of new generating resources to the electric rate base in 1Q04, a planned generation acquisition in 2005, and the filing of a general rate case in 1Q04.

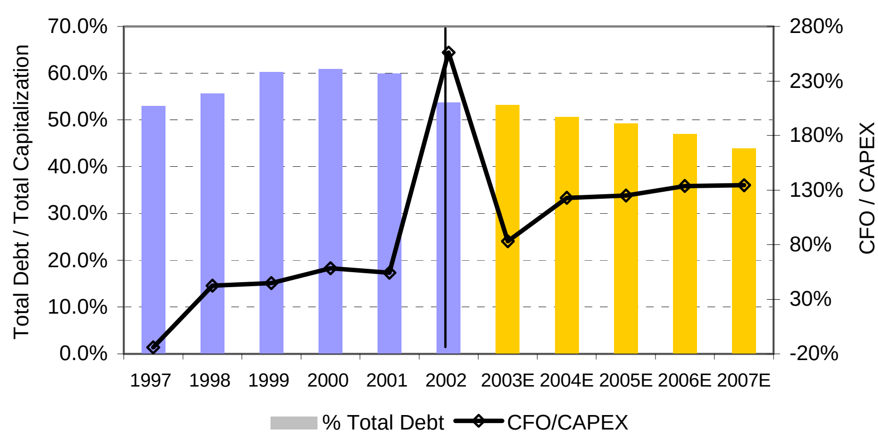
For 2003, we estimate earnings of $1.34 per share, versus the company's guidance for normalized results of $1.75–$1.85. The below-guidance estimate primarily reflects the negative effects on utility results of higher power supply costs, not hitting the $40 million cap according to the PCA until the end of 2003, and a significantly lower contribution from InfrastruX, mostly because of poor weather during 1H03 and weak overall business conditions.

In 2004, we forecast significant improvement in utility results to $1.76 per share from $1.29 in 2003. The increased earnings are primarily driven by the electric operations, which should benefit from the power cost tracker's being above the $40 million cap. We project a more "normal" year for InfrastruX, versus the weak 2003 results, and therefore, an $0.08 per share increase in earnings to $0.09 per share. Our consolidated estimate of $1.80 per share does not assume any earnings from the planned addition of a power plant to the electric rate base or the potentially favorable outcome from the general rate case that is expected to be filed in 1Q04.

Puget Energy's effective tax rate is expected to be higher than in previous years, because of a shift in state income tax expense from the "Taxes Other than Income Tax" line to "Income Tax Expense." The move reflects the growth in earnings and related taxes at InfrastruX.

Improving Internally Generated Cash Flow

Figure 18: Internally Generated CF versus % Debt



Note: Total Debt excludes approximately $280 million of trust preferred securities
Source: Company reports and Lehman Brothers estimates

Internal cash flow available to fund capital expenditures should improve, primarily because of the reduction in the annual common dividend in 2002. Prior to the reduction and following the merger (i.e., 1997–2001), internally generated cash, net of dividends, covered, on average, about 40% of PSE's total capital expenditures (net of AFUDC). Going forward, we estimate that internally generated funds will average about 120% of capital expenditures, which should help to reduce PSE's dependence on external debt financing and further enhance its chances of achieving its 45% common equity target by 2005.

Dividend Policy

We would not expect a change in the dividend prior to 2005.

On March 20, 2002, Puget Energy's board of directors decided to lower the annual common stock dividend from $1.84 to $1.00 per share, and to adopt a dividend policy with a target payout ratio set at 60% of normalized utility earnings. We would not expect a change in the dividend before 2005 because of the significant amount of capital expenditures needed to maintain and upgrade the company's distribution system. The current dividend yield of about 4.4% is comparable to the average yield of the small-cap utility peer group of 4.1%.

Capital Structure and Financial Flexibility

Following the merger with WNG, PSE's total debt-to-total capitalization (D/C) ratio grew to a high of 61% in 2000. This increase was primarily due to the debt assumed in the merger, the Tenaska purchase power contract buyout in 1997, and the acquisition of the Encogen power plant in 1999. The high leverage also reflects the company's reliance on external financing to fund capital expenditures related to growth and maintenance of its electric and gas distribution systems. In 2002, the D/C ratio fell to 54% because of the aforementioned dividend reduction, a 5.75-million-share common stock offering, and the paydown of more than $300 million of short-term debt.

We estimate PSE's 2003 equity ratio will be about 40%, which will exceed the 2005 regulatory target of 39%.

In the next five years, we estimate that PSE's D/C ratio should continue to decline (see Figure 20). On October 31, Puget Energy sold 4.55 million shares of common stock directly to funds managed by Franklin Advisers Inc. at a price of $22.00 a share. Net proceeds from the sale of approximately $100 million were invested in PSE to permanently fund the redemption of $93.75 million of high-cost preferred stock and for general corporate purposes. At year-end 2003, we estimate PSE's equity ratio could be about 40%, which would exceed the 2005 regulatory target of 39% set forth in the 2002 general rate case settlement. This ratio could have positive repercussions for the company's expected general rate case filing in 1Q04, which includes a request for a pro forma equity capital structure of 45%, and for its credit ratings. The company has targeted a common equity ratio of 45% by 2005. By our estimates, PSE's equity ratio could be more than 43% by 2005, and depending on the outcome of the planned general rate case and the expected acquisition of another thermal generation asset, could be close to or at the 45% level.

Equity may be further supplemented through the company's "Dribble Out" program. In July 2003, Puget Energy entered into equity distribution agreements with Banc One Capital Markets Inc. and Cantor Fitzgerald & Co. to sell up to 3.5 million shares of common stock each. Puget Energy has approximately $128.5 million of room left on its shelf registration to issue new common stock, trust preferred securities, and / or debt.

Credit Ratings Key to Financial Plan

PSE is currently rated BBB- / Baa3 by Standard and Poors' (S&P) and Moody's, respectively. The goal of the company's current financial plan is to restore its credit ratings to healthier levels. In the near term, this rating appears to be BBB / Baa2, and for the long term, BBB+ / Baa1 or higher. The company made significant progress toward achieving these goals in 2002 with the reduction in the annual common dividend and the issuance of 5.75 million shares of common stock. In addition, the 2002 rate case settlement provided permanent rate increases and the approval of the PCA mechanism, which should result in a better matching of revenues and expenses. The recent direct equity offering to Franklin Advisors Inc. and the planned filing to increase electric and gas rates could further help to bolster the company's bid for improved credit ratings. Standard & Poor's recently raised its ratings outlook to positive from stable to reflect the company's compliance with the 40% equity ratio target, ongoing debt reduction, and strong prospects for financial recovery

One area that may slow the company's path to higher ratings is the agencies' treatment of purchase power agreements (PPAs) as imputed debt (plus imputed interest expense) in the calculation of various credit ratios, including FFO interest coverage and FFO to debt. The recent equity offering, addition of new generation to the electric rate base in 1Q04 and planned addition in 2005, and potentially positive impacts of a 2004 general rate case could help to mute this impact.

Ample Liquidity

Puget Energy and its subsidiaries appear to have sufficient liquidity, provided by several short-term borrowing facilities totaling $594.8 million, to support its operations.

- PSE has a $250 million unsecured 364-day credit agreement and a $150 million three-year receivables securitization program that it uses to provide working capital for its utility construction program. These facilities provide back-up liquidity for the company's commercial paper program.

- InfrastruX has a three-year credit agreement for up to $150 million, and its subsidiaries have an additional $29.8 million in credit lines that were established to fund the company's acquisitions and working capital requirements. Puget Energy is the guarantor of the $150 million credit line.

- Puget Energy has a $15 million line of credit which it uses for general corporate purposes.

Figure 19: Puget Energy Consolidated Balance Sheet

Dollars in Millions *For the Year Ended December 31,*	2000	2001	2002	2003E	2004E	2005E	2006E	2007E
Current assets:								
Cash	$ 36.4	$ 92.4	$ 176.7	$ 86.1	$ 11.2	$ 56.3	$ 65.1	$ 9.3
Restricted cash	0.0	0.0	18.9	0.0	0.0	0.0	0.0	0.0
Accounts receivable, net	343.1	279.3	279.6	240.9	245.0	251.0	262.2	273.7
Unbilled revenues	211.8	147.0	112.1	64.8	65.3	67.3	70.7	78.4
Purchased gas receivable	96.1	37.2	0.0	0.0	0.0	0.0	0.0	0.0
Materials and supplies	99.0	90.3	70.4	91.2	71.7	73.6	77.8	82.0
Unrealized gain on derivatives	0.0	3.3	3.7	3.3	3.3	3.3	3.3	3.3
Prepayments and other	11.6	11.3	11.3	10.8	10.8	10.8	10.8	10.8
Total current assets	797.9	660.8	672.7	497.2	407.4	462.3	490.0	457.5
Net utility plant	3,838.4	3,888.0	3,916.2	3,967.0	4,002.8	4,031.1	4,051.7	4,064.5
Total other property and investments	292.3	317.2	378.1	383.6	379.9	375.0	361.0	340.1
Total other long-term assets	628.0	680.9	690.4	692.9	686.4	676.3	663.1	649.9
Total Assets	**$ 5,556.7**	**$ 5,547.0**	**$ 5,657.5**	**$ 5,540.7**	**$ 5,476.6**	**$ 5,544.8**	**$ 5,565.8**	**$ 5,511.9**
Current liabilities:								
Accounts payable	$ 410.6	$ 167.4	$ 205.6	$ 134.0	$ 130.6	$ 133.0	$ 140.6	$ 148.3
Purchased gas liability	0.0	0.0	83.8	0.0	0.0	0.0	0.0	0.0
Accrued expenses:								
Taxes	104.0	70.7	62.6	65.0	63.0	64.8	68.7	72.7
Salaries and wages	17.4	14.7	11.4	11.5	11.2	11.5	12.2	12.9
Interest	44.0	42.5	37.9	31.5	30.5	31.3	33.2	35.2
Unrealized gain on derivatives	0.0	35.1	2.4	2.4	2.4	2.4	2.4	2.4
Other	26.7	46.2	47.8	47.8	47.8	47.8	47.8	47.8
Total current liabilities	602.7	376.7	451.5	292.3	285.5	290.7	304.9	319.3
Total long-term liabilities	741.1	801.7	998.1	1,044.6	1,051.5	1,056.7	1,059.8	1,060.7
Pfd stk not subj. to mandatory redemption	60.0	60.0	60.0	0.0	0.0	0.0	0.0	0.0
Pfd stk subject to mandatory redemption	58.2	50.7	43.2	0.0	0.0	0.0	0.0	0.0
Corp oblig., mandatorily redeem. pfds	100.0	300.0	300.0	280.3	280.3	280.3	280.3	280.3
Total Debt	2,568.1	2,595.2	2,270.2	2,251.2	2,112.7	2,081.7	1,990.7	1,835.7
Minority interest in equity of consolidated sub.	0.0	0.0	10.6	10.7	11.4	12.2	13.0	13.8
Common Equity:								
Common stock	859.0	0.9	0.9	0.9	0.9	0.9	0.9	0.9
Additional paid-in capital	470.2	1,358.9	1,484.6	1,584.7	1,584.7	1,584.7	1,584.7	1,584.7
Earnings reinvested in the business	92.7	32.2	36.4	67.4	147.5	235.5	329.5	414.6
Accum. other compreh. inc. (loss), net	4.8	(29.3)	1.8	8.6	2.0	2.0	2.0	2.0
Total shareholders' equity	1,426.6	1,362.7	1,523.8	1,661.7	1,735.2	1,823.1	1,917.2	2,002.2
Total Liabilities and Shareholders' Equity	**$ 5,556.7**	**$ 5,547.0**	**$ 5,657.5**	**$ 5,540.7**	**$ 5,476.6**	**$ 5,544.8**	**$ 5,565.8**	**$ 5,511.9**

Source: Lehman Brothers

Figure 20: Puget Sound Energy Balance Sheet

Dollars in Millions *For the Year Ended December 31,*	2001	2002	2003E	2004E	2005E	2006E	2007E
Current assets:							
Cash	$ 82.7	$ 161.5	$ 83.1	$ 7.5	$ 44.9	$ 56.5	$ 16.5
Restricted cash		18.9	0.0	0.0	0.0	0.0	0.0
Accounts receivable, net	235.3	208.7	152.3	147.6	151.7	160.9	170.3
Unbilled revenues	147.0	112.1	64.8	65.3	67.3	70.7	78.4
Purchased gas receivable	37.2	0.0	0.0	0.0	0.0	0.0	0.0
Materials and supplies	85.3	63.6	83.9	64.0	65.8	69.8	73.9
Unrealized gain on derivatives	3.3	3.7	3.3	3.3	3.3	3.3	3.3
Prepayments and other	7.4	8.9	8.9	8.9	8.9	8.9	8.9
Total current assets	598.3	577.4	396.5	296.7	341.9	370.2	351.4
Net utility plant	3,888.0	3,916.2	3,967.0	4,002.8	4,031.1	4,051.7	4,064.5
Total other property and investments	150.5	154.8	151.2	147.7	144.2	140.6	137.1
Total other long-term assets	680.9	690.4	692.9	686.4	676.3	663.1	649.9
Total Assets	**$ 5,317.8**	**$ 5,338.7**	**$ 5,207.6**	**$ 5,133.7**	**$ 5,193.5**	**$ 5,225.7**	**$ 5,202.9**
Current liabilities:							
Accounts payable	$ 154.6	$ 193.6	$ 120.7	$ 117.0	$ 120.2	$ 127.5	$ 135.0
Purchased gas liability	0.0	83.8	0.0	0.0	0.0	0.0	0.0
Accrued expenses:							
Taxes	70.2	64.4	65.0	63.0	64.8	68.7	72.7
Salaries and wages	14.7	11.4	11.5	11.2	11.5	12.2	12.9
Interest	42.5	37.9	31.5	30.5	31.3	33.2	35.2
Unrealized gain on derivatives	35.1	2.4	2.4	2.4	2.4	2.4	2.4
Other	25.2	25.5	25.5	25.5	25.5	25.5	25.5
Total current liabilities	342.4	419.1	256.6	249.6	255.6	269.5	283.6
Total long-term liabilities	788.1	966.2	1,007.3	1,014.2	1,019.5	1,023.5	1,025.9
Pfd stk not subj. to mandatory redemption	60.0	60.0					
Pfd stk subject to mandatory redemption	50.7	43.2					
Corp oblig., mandatorily redeem. pfds	300.0	300.0	280.3	280.3	280.3	280.3	280.3
Total Debt	2,509.0	2,124.2	2,098.2	1,959.7	1,928.7	1,847.7	1,712.7
Minority interest in equity of consolidated sub.							
Common Equity:							
Common stock	859.0	859.0	859.0	859.0	859.0	859.0	859.0
Additional paid-in capital	382.6	498.3	598.4	598.4	598.4	598.4	598.4
Earnings reinvested in the business	55.3	67.0	99.1	170.6	249.9	345.3	440.9
Accum. other compreh. inc. (loss), net	(29.3)	1.8	8.6	2.0	2.0	2.0	2.0
Total shareholders' equity	1,267.7	1,426.1	1,565.2	1,630.1	1,709.4	1,804.7	1,900.4
Total Liabilities and Shareholders' Equity	**$ 5,317.8**	**$ 5,338.7**	**$ 5,207.6**	**$ 5,133.7**	**$ 5,193.5**	**$ 5,225.7**	**$ 5,202.9**

SELECTED METRICS	**2001**	**2002**	**2003E**	**2004E**	**2005E**	**2006E**	**2007E**
Capitalization							
	Regulatory Target:		*34.0%*	*36.0%*	*39.0%*		
Common Equity	30.3%	36.1%	39.7%	42.1%	43.6%	45.9%	48.8%
Preferred Stock	2.6%	2.6%	0.0%	0.0%	0.0%	0.0%	0.0%
Trust Preferred Securities	7.2%	7.6%	7.1%	7.2%	7.2%	7.1%	7.2%
Short-term Debt	8.1%	0.8%	0.2%	0.2%	0.2%	0.2%	0.2%
Long-term Debt	51.8%	53.0%	53.0%	50.4%	49.0%	46.7%	43.8%
Total Capitalization	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%

Source: Lehman Brothers

Figure 21: : Puget Energy Statement of Cash Flows

Dollars in Millions *For the Year Ended December 31,*	2000	2001	2002	2003E	2004E	2005E	2006E	2007E
Net income	**$ 193.8**	**$ 106.8**	**$ 117.9**	**$ 134.1**	**$ 179.8**	**$ 188.6**	**$ 205.7**	**$ 207.7**
Adjustments to reconcile net income:								
Depreciation and amortization	196.5	217.5	228.7	237.5	248.6	259.1	268.4	277.1
Deferred income taxes and tax credits	(7.4)	11.5	151.3	46.4	6.8	5.3	3.0	0.9
Gain from sale of securities	(6.5)	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Net unrealized (gains) losses on derivs	0.0	3.6	(11.6)	0.4	0.0	0.0	0.0	0.0
Other (incl. conservation amortization)	(7.3)	(4.5)	10.9	17.0	20.8	24.4	27.5	27.6
Cash collateral received from energy supplier	0.0	0.0	21.4	0.0	0.0	0.0	0.0	0.0
Interest Expense	175.1	190.1	196.4	185.0	172.2	170.1	164.5	150.4
Subtotal	350.4	418.2	597.1	486.3	448.5	458.9	463.5	456.0
Cash flow before working capital, interest	**544.2**	**525.0**	**715.0**	**620.5**	**628.3**	**647.5**	**669.3**	**663.7**
Cash flow effects of working capital								
Accts receivable and unbilled revenue	(220.6)	147.6	46.9	86.0	(4.6)	(8.0)	(14.6)	(19.2)
Materials and supplies	(29.8)	10.6	22.1	(20.8)	19.5	(1.9)	(4.2)	(4.2)
Prepayments and other	(1.7)	0.9	0.1	0.5	0.0	0.0	0.0	0.0
Purchased gas receivable/liability	(62.4)	58.8	121.0	(83.8)	0.0	0.0	0.0	0.0
Accounts payable	232.4	(254.9)	34.4	(71.6)	(3.4)	2.4	7.6	7.7
Taxes payable	31.3	(33.3)	(18.3)	2.5	(2.0)	1.7	4.0	4.0
Accrued expenses and other	1.8	33.6	(1.0)	0.5	(7.9)	1.1	2.6	2.7
Subtotal	(48.9)	(36.7)	205.2	(86.8)	1.5	(4.6)	(4.6)	(9.0)
Cash flow before interest	**495.4**	**488.3**	**920.3**	**533.7**	**629.8**	**642.9**	**664.7**	**654.7**
Interest expense, net	(175.1)	(190.1)	(196.4)	(185.0)	(172.2)	(170.1)	(164.5)	(150.4)
Cash flow from operations	**320.3**	**298.3**	**723.9**	**348.8**	**457.5**	**472.7**	**500.1**	**504.3**
Cash flow effects of long-term assets								
Construction expenditures excl. AFUDCE	(296.5)	(247.4)	(224.2)	(271.9)	(265.3)	(265.0)	(265.0)	(265.0)
Additions to other PP&E	0.0	(5.2)	(11.6)	(16.6)	(19.0)	(21.0)	(13.6)	(7.5)
Energy conservation expenditures	(6.9)	(15.6)	(11.4)	(16.0)	(10.0)	(10.0)	(10.0)	(10.0)
Restricted cash	0.0	0.0	(18.9)	18.9	0.0	0.0	0.0	0.0
Proceeds from sale of invst in Cabot pfd stk	51.5	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Proceeds from sale of Centralia plant	37.4	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Proceeds from sale of securities	6.8	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Investments by InfrastruX	(85.5)	(75.6)	(41.6)	(10.5)	0.0	0.0	0.0	0.0
Repayment from (loans to) Schlumberger	(20.9)	51.9	0.0	0.0	0.0	0.0	0.0	0.0
Other	(14.1)	(16.4)	(15.8)	0.0	0.0	0.0	0.0	0.0
Subtotal	(328.3)	(308.3)	(323.4)	(296.1)	(294.3)	(296.0)	(288.6)	(282.5)
Free cash flow	**(8.0)**	**(10.0)**	**400.5**	**52.7**	**163.2**	**176.7**	**211.6**	**221.8**
Dividends paid (cmn and pfd)	(142.9)	(141.7)	(97.3)	(101.4)	(99.7)	(100.7)	(101.7)	(102.7)
Free cash flow after dividends	**(150.9)**	**(151.7)**	**303.2**	**(48.7)**	**63.6**	**76.1**	**109.9**	**119.1**
Cash flow effects of financing								
Increase (decrease) in short-term debt - net	(226.4)	(32.4)	(301.3)	(14.0)	0.0	0.0	(10.0)	(20.0)
Issuance of common stock	0.0	0.0	120.2	100.1				
Issuance of trust preferred stock	0.0	200.0	0.0	(19.8)	0.0	0.0	0.0	0.0
Redemption of preferred stock	(7.5)	(7.5)	(7.5)	(103.2)	0.0	0.0	0.0	0.0
Issuance of bonds and long-term debt	510.0	70.3	40.0	311.9	0.0	0.0	0.0	0.0
Redemption of bonds and notes	(151.0)	(19.0)	(65.9)	(316.9)	(138.5)	(31.0)	(91.0)	(155.0)
Other	(3.6)	(3.6)	(4.4)					
Subtotal	121.5	207.7	(218.9)	(41.8)	(138.5)	(31.0)	(101.0)	(175.0)
Increase (decrease) in cash	**$ (29.3)**	**$ 56.0**	**$ 84.3**	**$ (90.5)**	**$ (74.9)**	**$ 45.1**	**$ 8.9**	**$ (55.9)**
Cash at beginning of year	65.7	36.4	92.4	176.7	86.1	11.2	56.3	65.1
Cash at end of year	**$ 36.4**	**$ 92.4**	**$ 176.7**	**$ 86.1**	**$ 11.2**	**$ 56.3**	**$ 65.1**	**$ 9.3**

Source: Lehman Brothers

Appendix

Figure 22: Puget Sound Energy Generation Portfolio

Plant Name	Fuel Type	Owner's Share of Plant (%)			Operating Capacity (MW)			Net Generation (MWh)			Capacity Factor (%)			Plant Heat Rate (Btu/KWh)		
		2000	2001	2002	2000	2001	2002	2000	2001	2002	2000	2001	2002	2000	2001	2002
Colstrip	**Coal**	**32.1**	**32.4**	**33.4**	**680**	**700**	**700**	**4,702,592**	**5,001,418**	**4,482,635**	**79%**	**82%**	**73%**	**10,941**	**10,532**	**10,544**
Encogen	Gas	100	100	100	160	170	160	1,366,434	1,402,653	941,557	97%	94%	67%	9,589	9,488	8,935
Frederickson	Gas/Oil	100	100	100	178	150	150	277,130	569,950	3,654	18%	43%	0%	12,736	12,892	13,281
Fredonia	Gas/Oil	100	100	100	247	210	318	956,603	951,297	56,904	44%	52%	2%	12,004	11,905	11,114
Whitehorn 2&3	Gas/Oil	100	100	100	178	150	150	670,885	596,174	14,614	43%	45%	1%	10,314	12,618	12,812
Crystal Mountain	Oil	100	100	100	3	3	3	230	49	18	1%	0%	0%	0	0	0
Total Natural Gas/Oil		**100**	**100**	**100**	**766**	**683**	**781**	**3,271,282**	**3,520,123**	**1,016,747**	**49%**	**59%**	**15%**	**10,710**	**11,222**	**9,128**
Black Creek	Hydro	100	100	100	4	4	4	9,023	6,634	8,370	28%	20%	26%	0	0	0
Electron	Hydro	100	100	100	26	26	26	133,429	126,112	117,392	58%	55%	52%	0	0	0
Lower Baker	Hydro	100	100	100	71	71	79	349,677	233,138	400,861	56%	37%	58%	0	0	0
Snoqualmie Falls 1	Hydro	100	100	100	13	13	13	17,752	26,040	59,184	16%	23%	52%	0	0	0
Snoqualmie Falls 2	Hydro	100	100	100	31	31	36	219,119	215,513	192,768	80%	79%	61%	0	0	0
Upper Baker	Hydro	100	100	100	103	103	108	330,346	296,812	353,106	37%	33%	37%	0	0	0
White River	Hydro	100	100	100	70	70	70	248,082	203,727	228,229	40%	33%	37%	0	0	0
Total Hydro		**100**	**100**	**100**	**318**	**318**	**336**	**1,307,428**	**1,107,976**	**1,359,910**	**47%**	**40%**	**46%**	**0**	**0**	**0**
Summary																
	Coal	32	32	33	680	700	700	4,702,592	5,001,418	4,482,635	79%	82%	73%	10,941	10,532	10,544
	Gas/Oil	100	100	100	766	683	781	3,271,282	3,520,123	1,016,747	49%	59%	15%	10,710	11,222	9,128
	Hydro	100	100	100	318	318	336	1,307,428	1,107,976	1,359,910	47%	40%	46%	0	0	0
Total Portfolio		**74**	**74**	**74**	**1,763**	**1,700**	**1,816**	**9,281,302**	**9,629,517**	**6,859,292**	**60%**	**65%**	**43%**	**9,318**	**9,573**	**8,244**

Plant Name	Fuel Type	Owner's Share of Plant (%)			(A) Fuel Expense ($/MWh)			(B) Non Fuel Operating Expenses ($/MWh)			(C) Maintenance Expenses ($/MWh)			= (A) + (B) + (C) Total Production Expenses ($/MWh)		
		2000	2001	2002	2000	2001	2002	2000	2001	2002	2000	2001	2002	2000	2001	2002
Colstrip	**Coal**	**32.1**	**32.4**	**33.4**	**$5.79**	**$6.22**	**$6.50**	**$2.08**	**$1.57**	**$2.85**	**$3.64**	**$2.54**	**$3.02**	**$7.87**	**$7.80**	**$9.34**
Encogen	Gas	100	100	100	$26.65	$37.82	$31.67	$1.25	$0.70	$1.10	$1.10	$3.36	$2.40	$27.90	$38.52	$32.77
Frederickson	Gas/Oil	100	100	100	$65.28	$80.18	$43.90	$1.55	$1.08	$73.78	$1.23	$0.63	$49.99	$66.83	$81.26	$117.67
Fredonia	Gas/Oil	100	100	100	$56.54	$96.01	$896.72	$0.42	$0.78	$98.71	$0.53	$3.47	$20.87	$56.96	$96.79	$995.43
Whitehorn 2&3	Gas/Oil	100	100	100	$63.67	$93.76	$59.97	$6.48	$7.79	$303.50	$0.45	$3.30	$71.42	$70.16	$101.55	$363.47
Crystal Mountain	Oil	100	100	100	$109.87	$75.33	$404.67	$99.81	$407.59	$2,048.39	$170.79	$1,048.33	$351.00	$209.68	$482.92	$2,453.06
Total Natural Gas/Oil		**100**	**100**	**100**	**$46.26**	**$69.88**	**$80.54**	**$2.11**	**$1.99**	**$11.21**	**$0.82**	**$2.95**	**$4.61**	**$48.37**	**$71.87**	**$91.75**
Black Creek	Hydro	100	100	100	$0.00	$0.00	$0.00	$0.00	$3.12	$4.67	$2.23	$5.68	$1.37	$0.00	$3.12	$4.67
Electron	Hydro	100	100	100	$0.00	$1.46	$0.00	$6.52	$9.00	$7.99	$6.09	$5.25	$7.14	$6.52	$10.46	$7.99
Lower Baker	Hydro	100	100	100	$0.00	$0.00	$0.00	$2.48	$3.99	$2.24	$2.09	$1.21	$1.10	$2.48	$3.99	$2.24
Snoqualmie Falls 1	Hydro	100	100	100	$0.00	$0.00	$0.00	$15.11	$9.84	$3.32	$35.51	$40.70	$7.21	$15.11	$9.84	$3.32
Snoqualmie Falls 2	Hydro	100	100	100	$0.00	$0.00	$0.00	$0.67	$0.71	$0.84	$0.77	$0.85	$1.43	$0.67	$0.71	$0.84
Upper Baker	Hydro	100	100	100	$0.00	$0.00	$0.00	$3.88	$2.85	$2.29	$1.86	$1.37	$1.56	$3.88	$2.85	$2.29
White River	Hydro	100	100	100	$0.00	$0.00	$0.00	$3.81	$4.55	$3.82	$7.51	$5.07	$4.31	$3.81	$4.55	$3.82
Total Hydro		**100**	**100**	**100**	**$0.00**	**$0.12**	**$0.00**	**$3.35**	**$3.85**	**$2.88**	**$3.70**	**$3.31**	**$2.60**	**$3.35**	**$3.97**	**$2.88**
Summary																
	Coal	32.1	32.4	33.4	$5.79	$6.22	$6.50	$2.08	$1.57	$2.85	$3.64	$2.54	$3.02	$7.87	$7.80	$9.34
	Gas/Oil	100	100	100	$46.26	$69.88	$80.54	$2.11	$1.99	$11.21	$0.82	$2.95	$4.61	$48.37	$71.87	$91.75
	Hydro	100	100	100	$0.00	$0.12	$0.00	$3.35	$3.85	$2.88	$3.70	$3.31	$2.60	$3.35	$3.97	$2.88
Total Portfolio		**74**	**74**	**74**	**$19.24**	**$28.78**	**$16.19**	**$2.27**	**$1.99**	**$4.09**	**$2.65**	**$2.78**	**$3.17**	**$24.16**	**$33.54**	**$23.44**

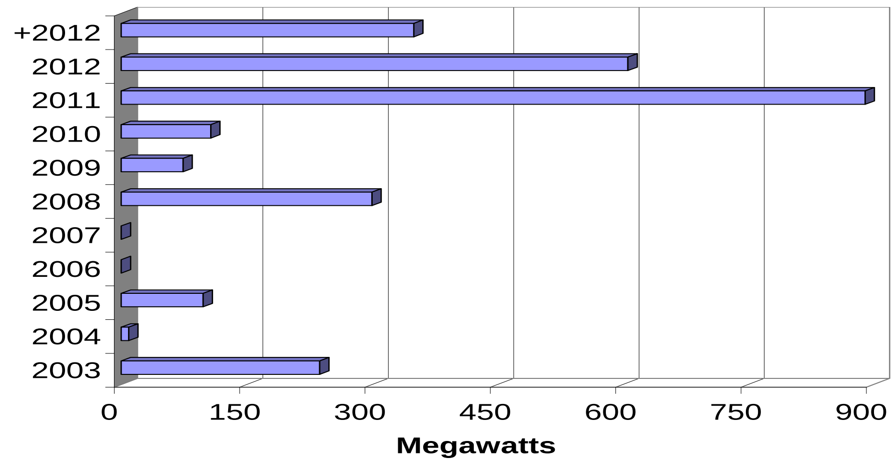
Source: FERC Form 1 filings and Lehman Brothers

Figure 23: PSE Long-term Purchase Power Contracts

Resource	Fuel Type	Capacity MW	TOP / TAP	Contract Expiration
Columbia River PUD Contracts				
Wanapum	Hydro	98	TOP	2005
Priest Rapids	Hydro	72	TOP	2009
Rocky Reach	Hydro	505	TOP	2011
Rock Island I & II	Hydro	455	TOP	2012
Wells	Hydro	261	TOP	2018
Total		**1,391**		
Other Hydro				
Port Townsend Paper	Hydro	0	TAP	2003
CSPE	Hydro	20	TAP	2003
Supplemental & Entitlement Capacity	Hydro	10	TAP	2003
Baker Replacement	Hydro	7	TAP	2003
Hutchinson Creek	Hydro	1	TAP	2004
Powerex/Pt. Roberts	Hydro	8	TAP	2004
Snohomish PUD Conservation Contract	Hydro	10	TAP	2010
North Wasco	Hydro	5	TAP	2012
Kingdom Energy-Sygitowicz	Hydro	0	TAP	2014
Weeks Falls	Hydro	5	TAP	2022
Twin Falls	Hydro	20	TAP	2025
Canadian EA	Hydro	0	TAP	2025
Koma Kulshan	Hydro	14	TAP	2037
Total		**100**		
Other Producers				
PacifiCorp	Thermal	200	TAP	2003
PG&E Seasonal Exchange	Thermal	300	TAP	2008
Puyallup Energy Recovery Co.	Biomass	2	TAP	2009
Northwestern Energy	Coal	97	TAP	2010
March Point I	Gas	80	TAP	2011
March Point II	Gas	60	TAP	2011
Tenaska	Gas	245	TAP	2011
Sumas	Gas	123	TAP	2012
Spokane Municipal Solid Waste	Biomass	23	TAP	2012
BPA - WNP-3 Exchange	Various	50	TAP	2017
Total		**1,180**		
Summary				
Columbia River PUD Contracts		1,391	TOP	
Other Hydro		100	TAP	
Other Producers		1,180	TAP	
Total Purchased Resources		**2,672**		

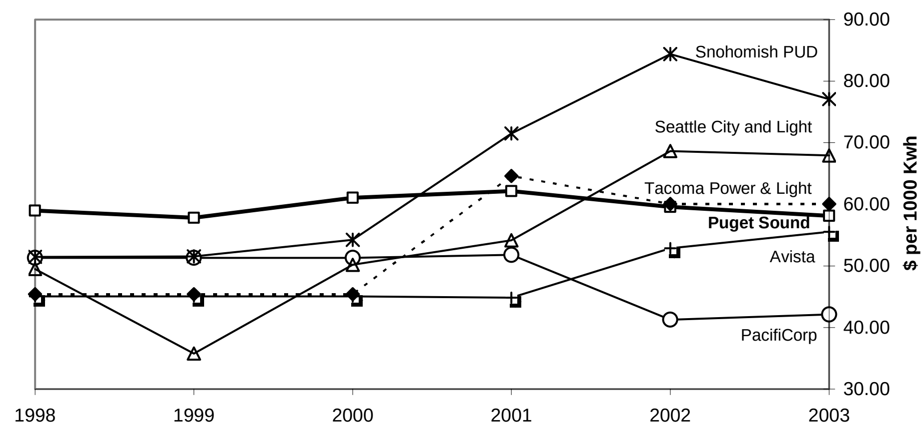
TOP = Take or Pay, TAP = Take and Pay
Source: April 2003 Least Cost Plan, Ch. VIII

Figure 24: Long-term Contract Expiration Schedule



Source: April 2003 Least Cost Plan, Ch. VI, and Lehman Brothers

Figure 25: Average Monthly Residential Electric Rate Comparison



As of January 1,	**1998**	**1999**	**2000**	**2001**	**2002**	**2003**
Puget Sound Energy	58.99	57.81	61.06	62.13	59.57	58.13
Avista	45.05	45.05	45.05	44.83	52.89	55.51
PacifiCorp	51.30	51.30	51.30	51.81	41.28	42.13
Seattle City Light	49.51	35.76	50.18	54.18	68.64	67.94
Tacoma Power & Light	45.40	45.40	45.40	64.60	60.07	60.07
Snohomish PUD	51.46	51.55	54.24	71.50	84.37	77.06

Source: Washington Utilities and Transportation Commission and Lehman Brothers

Important Disclosures

Rating and Price Target Chart: PSD

CHART IS NOT APPLICABLE

Date	Closing Price	Rating	Price Target

Date	Closing Price	Rating	Price Target

Company Description: Puget Energy, Inc. is a public utility holding company with two primary subsidiaries: Puget Sound Energy, an electric and gas utility, and InfrastruX Group, a utility infrastructure contractor.

Stock Ratings From February 2001 to August 5, 2002 (sector view did not exist):

This is a guide to expected total return (price performance plus dividend) relative to the total return of the stock's local market over the next 12 months.

1-Strong Buy - expected to outperform the market by 15 or more percentage points.

2-Buy - expected to outperform the market by 5-15 percentage points.

3-Market Perform - expected to perform in line with the market, plus or minus 5 percentage points.

4-Market Underperform - expected to underperform the market by 5-15 percentage points.

5-Sell - expected to underperform the market by 15 or more percentage points.

Stock Ratings Prior to February 2001 (sector view did not exist):

1-Buy - expected to outperform the market by 15 or more percentage points.

2-Outperform - expected to outperform the market by 5-15 percentage points.

3-Neutral - expected to perform in line with the market, plus or minus 5 percentage points.

4-Underperform - expected to underperform the market by 5-15 percentage points.

5-Sell - expected to underperform the market by 15 or more percentage points.

V-Venture - return over multiyear timeframe consistent with venture capital; should only be held in a well diversified portfolio.

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Risks Which May Impede the Achievement of the Price Target: PSD: Risks include lingering issues related to the Western power crisis of 2000–01, further credit rating downgrades, and unforeseen regulatory changes (state and federal).

Key to Investment Opinions:

Stock Ratings:

1-Overweight - the stock is expected to outperform the unweighted expected total return of the industry sector over a 12-month investment horizon.

2-Equal weight - the stock is expected to perform in line with the unweighted expected total return of the industry sector over a 12-month investment horizon.

3-Underweight - the stock is expected to underperform the unweighted expected total return of the industry sector over a 12-month investment horizon.

RS-Rating Suspended - The rating and target price have been suspended temporarily to comply with applicable regulations and/or firm policies in certain circumstances including when Lehman Brothers is acting in an advisory capacity in a merger or strategic transaction involving the company.

Sector View:

1-Positive - sector fundamentals/valuations are improving.

2-Neutral - sector fundamentals/valuations are steady, neither improving nor deteriorating.

3-Negative - sector fundamentals/valuations are deteriorating.

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United States of America
Energy & Power
Electric Utilities

Electric Utilities

Industry Update

Back to School

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Sector View:

New: 2-Neutral

Old: 2-Neutral

Investment conclusion

- We believe key factors driving utility performance for the balance of the year are: 1) Ability to make consensus earnings forecasts; 2) Energy legislation; and 3) The direction of spark spreads. We are more confident that a few names will differentiate themselves from the pack than we are in a clear group move, namely 1-Overweight rated EXC, TXU, PCG and WEC.

Summary

- We believe 2003 consensus EPS forecasts are largely un-biased. 2H Midwest/Northeast weather comps are tough, but a cushion exists from 1H.
- Forward spark spreads haven't changed much this Summer, but year/year changes in Dark and Spark spreads are converging.
- We are raising 2003 EPS estimates for CEG and GXP and lowering estimates for AES, ED, CIN, DTE, FE, PGN.
- The Power Outage of 2003 is likely to help spurn energy legislation this Fall with PUHCA repeal the biggest near-term impact. This could spark Fall performance for perceived mid-cap take-out candidates: AYE, CEG, CIN, CMS, DPL, DQE, GXP, NI, NU, and PPL.
- Clearest picks to underperform are 3-Underweight rated DUK and TE where 3Q EPS results could be catalysts.

As we head into the Fall conference season, we thought it was worthwhile to provide our outlook for electric utility stocks for the balance of the year. Overall, we are more confident that a few names will differentiate themselves from the pack than we are in a clear group move out of the trading range in which it has labored. The key factors driving performance for the balance of the year should be: 1) Ability to make consensus earnings forecasts; 2) Energy legislation; and 3) The direction of spark spreads. We think there is little bias to 2003 consensus EPS forecasts. Important drivers are weather comps, which are tough in 2H and gas spark spreads which remain weak. While year/year changes in Dark/Gas Spark spreads have converged recently, if gas prices remain high by historical standards Dark Spreads will continue to have an advantage. Names that should break from the pack in our opinion are: 1-Overweight rated Exelon (EXC; $58.44), TXU Corp. (TXU, $21.84), PG&E Corp. (PCG, $21.96) and Wisconsin Energy (WEC, $28.25). Our clearest picks to underperform are 3-Underweight rated Duke Energy (DUK, $16.95) and Teco Energy (TE, $11.80) where quarterly results could drive stock moves in these weaker fundamental stories.

We believe the Power Outage of 2003 could accelerate passage of energy legislation, which already looked likely to occur. We expect key provisions will be incentives for infrastructure spending, environmental regulation and repeal of the Public Utility Holding Company Act (PUHCA). We also expect debate over changes to grid management but think the urgency to quickly pass a bill probably rules out meaningful change. Passage of PUHCA repeal could spark performance of perceived mid-cap take-out candidates. Mid-caps that could benefit are Allegheny Energy (AYE; 2-Equal weight; $8.68), Constellation Energy (CEG; 2-Equal weight; 34.96); Cinergy (CIN; 2-Equal weight; $33.86), CMS Energy (CMS; 2-Equal weight; $6.38), DPL Inc. (DPL; 2-Equal weight; $15.35), DQE (DQE; 2-Equal weight; $14.49), Great Plains Energy (GXP; 3-Underweight; $28.89), NiSource (NI, 2-Equal weight; $19.00), Northeast Utilities (NU; 3-Underweight; $17.11), and PPL Resources (PPL; 1-Overweight; $39.16). Perceived big-cap buyers could also be impacted negatively unless they have sworn-off M&A like Exelon and Southern Company.

Lastly, state regulatory proceedings are expected to have an impact though more cases seem to be in their earlier stages, which is generally worse for the stocks. Names where regulatory proceedings could be negative catalysts are DTE Energy (DTE; 2-Equal weight; $34.76), Northeast Utilities, and Pepco Holdings (POM; 2-Equal weight; $17.50). We see a neutral case for Cinergy, given recent underperformance. On the positive side, Wisconsin Energy could receive a reasonable outcome in its “Power the Future” proceeding on November 10. At the federal level, we do not expect much progress from the IRS on the syn-fuel investigations. While we could see news on Progress Energy since their review is at the front of the queue, it may be Q1’04 before we get news on other companies. In general, we don’t believe the related names have adequately discounted this issue.

PLEASE SEE ANALYST(S) CERTIFICATION(S) ON PAGE 6 AND IMPORTANT DISCLOSURES BEGINNING ON PAGE 7

2003 Consensus EPS Un-biased

Our review of trailing 12 month EPS and upcoming performance leads us to believe 2003 EPS estimates are largely un-biased. One of our biggest concerns is difficult weather comps for the balance of the year. The toughest comps are in the Mid-Atlantic, Midwest, and Northeast and comps in the all-important July/August timeframe are both the toughest and in the rear-view-mirror. These conditions have led some companies with particularly strong trailing 12 month EPS to hold earnings guidance after the 2nd quarter.

Weather Conditions

	July '03		Aug 1-Aug 16, 2003		Aug '02	Sept '02	Q4'02
	Vs. Norm	Vs. 2002	Vs. Norm	Vs. 2002	Vs. Norm	Vs. Norm	Vs. Norm
New England	12.6%	-16.4%	43.7%	-6.7%	33.3%	-35.9%	6.5%
Mid-Atlantic	1.2%	-19.2%	21.9%	-5.4%	25.4%	-23.6%	12.0%
EN Central	-9.1%	-33.8%	-0.9%	-9.1%	13.7%	-3.7%	3.4%
WN Central	8.7%	-10.7%	2.2%	7.6%	-2.0%	5.2%	1.5%
South Atlantic	-5.4%	-10.9%	-3.8%	-6.8%	6.7%	11.1%	8.8%
ES Central	-8.7%	-14.0%	-9.9%	-15.0%	13.0%	25.4%	8.7%
WS Central	0.6%	4.4%	1.6%	3.3%	5.3%	9.3%	9.8%
Mountain	27.0%	6.1%	28.3%	15.4%	8.6%	4.1%	-8.3%
Pacific	14.2%	15.8%	-6.8%	-8.6%	-17.7%	-6.1%	-14.3%
Average	**3.5%**	**-8.5%**	**6.1%**	**-2.4%**	**8.3%**	**1.4%**	**3.1%**

Source: NOAA

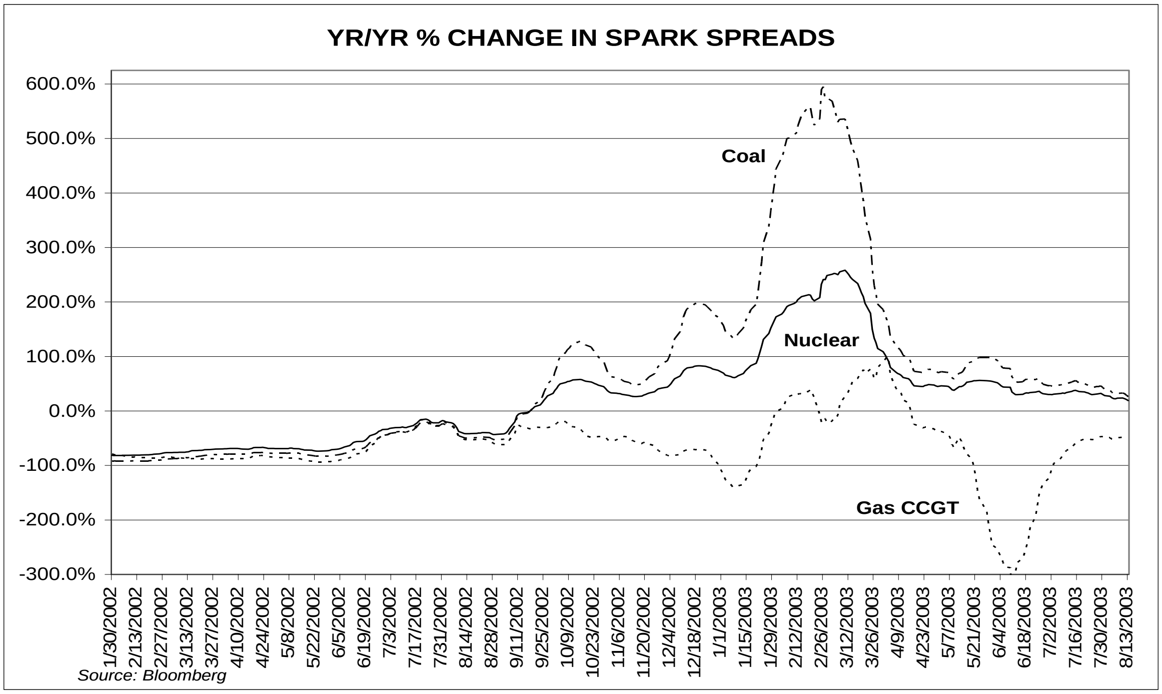
Forward spark spreads don't seem to have changed much either over the last few months. Spreads are still generally negative for gas peakers and returns on combined cycle gas plants are not enough to justify new investment most everywhere. Unfortunately, market liquidity and related price reporting have made tracking these trends more difficult. While the credit profile of leading market participants has improved, the liquidity trends make it riskier for retail marketers to aggregate load in markets without assets. Risks may be the greatest in the New England market longer-term as so much of the generation is operated by companies in bankruptcy and gas prices are particularly volatile.

Spark Spread Comparisons

	SPARK SPREADS-2003 FORWARDS						SPARK SPREADS-TRAILING ACTUALS					
NATIONAL AVG		**Gas**						**Gas**				
$/MWhr	**Coal**	**Peaker**	**CCGT**	**Nuclear**	**Hydro**	**Weighted**	**Coal**	**Peaker**	**CCGT**	**Nuclear**	**Hydro**	**Weighted**
July/Aug	$43.20	$4.83	$20.60	$52.20	$59.20	$33.75	$19.80	$5.36	$14.19	$28.80	$35.80	$18.10
Q3'03 vs. Q3'02	$36.07	-$3.37	$12.71	$45.07	$52.07	$26.48	$18.35	$2.42	$11.68	$27.35	$34.35	$16.32
Q4	$26.06	-$15.50	$1.19	$35.06	$42.06	$16.14	$17.85	-$8.53	$3.76	$26.85	$33.85	$12.69
Year	$30.07	-$5.00	$9.23	$37.94	$44.07	$21.60	$15.75	-$0.39	$8.35	$23.63	$29.76	$13.39
Jan/Feb	$34.17	-$4.56	$11.31	$43.17	$50.17	$23.10	$46.93	-$22.17	$2.51	$55.93	$62.93	$24.20
Mar/Apr	$31.40	-$4.47	$10.58	$40.40	$47.40	$18.95	$44.11	-$5.97	$13.19	$53.11	$60.11	$25.48
July/Aug	$39.08	$4.37	$19.08	$48.08	$55.08	$29.21	$34.01	-$3.20	$12.23	$43.01	$50.01	$23.48
WESTERN AVG		**Gas**						**Gas**				
	Coal	**Peaker**	**CCGT**	**Nuclear**	**Hydro**	**Weighted**	**Coal**	**Peaker**	**CCGT**	**Nuclear**	**Hydro**	**Weighted**
Q3'03 vs. Q3'02	$40.00	$0.56	$16.64	$49.00	$56.00	$30.99	$13.02	-$3.96	$5.61	$22.02	$29.02	$12.67
Q4'03 vs. Q4'02	$33.08	-$8.61	$8.12	$42.08	$49.08	$23.70	$21.61	-$2.90	$8.85	$30.61	$37.61	$18.38
Year	$34.89	-$6.12	$10.41	$43.89	$50.89	$25.64	$14.81	-$4.39	$5.82	$23.81	$30.81	$13.65
NON-WESTERN AVG		**Gas**						**Gas**				
	Coal	**Peaker**	**CCGT**	**Nuclear**	**Hydro**	**Weighted**	**Coal**	**Peaker**	**CCGT**	**Nuclear**	**Hydro**	**Weighted**
July/Aug	$44.28	$6.26	$21.93	$53.28	$60.28	$34.67	$22.06	$8.48	$17.06	$31.06	$38.06	$19.92
Sep	$25.22	-$15.64	$0.85	$34.22	$41.22	$15.28	$18.19	$0.63	$10.36	$27.19	$34.19	$15.16
Q4	$23.71	-$17.81	-$1.13	$32.71	$39.71	$13.61	$16.59	-$10.41	$2.06	$25.59	$32.59	$10.79
2004	$23.67	-$7.79	$4.94	$30.67	$36.11	$15.93	$14.49	-$1.17	$6.98	$21.49	$26.93	$11.47
Jan/Feb	$34.17	-$4.56	$11.31	$43.17	$50.17	$23.10	$46.93	-$22.17	$2.51	$55.93	$62.93	$24.20
Mar/Apr	$31.40	-$4.47	$10.58	$40.40	$47.40	$18.95	$44.11	-$5.97	$13.19	$53.11	$60.11	$25.48
July/Aug	$39.08	$4.37	$19.08	$48.08	$55.08	$29.21	$34.01	-$3.20	$12.23	$43.01	$50.01	$23.48

Source: Bloomberg

On a year/year basis, changes in Dark Spreads (the gross margin on coal and nuclear electric sales) and gas spark spreads (the gross margins on efficient gas electric sales) have been converging. This is a switch from the wide divergence earlier in the year. Early in the year, gas price spikes to the high single digit $/Mcf levels in the Northeast and Midwest created particularly favorable conditions for coal and nuclear generators. In June, gas spark spreads remained weak versus unfavorable margins last year, Dark spreads remained improved. While the convergence of % change in spreads takes away some of the relative upside from the coal and nuclear generators, if gas prices remain high, Dark Spreads will be relatively attractive. Our Oil and Gas E&P analyst Tom Driscoll maintains the position that gas prices will remain in the $4.50/Mcf range in the coming years though we expect volatility in the $4.00-$5.00/Mcf range.



Trailing 12 Month EPS

Of the 37 stocks we cover, 27 have trailing month EPS 5% or more above our 2003 forecast. This is reflective of the need to discount results for a number of factors including weather, pensions/OPEB expenses, equity dilution; and other expenses in the second half of 2003. The following table compares the trailing 12 month results.

Trailing 12 Month EPS Check

	Quarterly Results				Lehman Brothers		First Call			
	Q1'03	Q2'03	Q3'02	Q4'02	Old 2003E	Revised 2003E	2003E	Trailing 12 Months	Upside to Estimate	Revision Potential
Calpine Corp	-$0.03	-$0.09	$0.29	$0.09	$0.15		$0.28	$0.26	$0.11	73.3%
Allegheny Energy Inc	**$0.25**	TBD	$0.94	**$0.16**	$0.80		$0.85	$1.35	$0.55	68.8%
TECO Energy Inc	**$0.21**	$0.31	$0.76	$0.37	$1.15		$1.15	$1.65	$0.50	43.5%
Northeast Utilities	$0.47	$0.21	$0.27	$0.36	$0.95		$1.06	$1.31	$0.36	37.9%
CMS Energy Corp	$0.50	$0.01	$0.42	$0.11	$0.80		$0.82	$1.04	$0.24	30.0%
FirstEnergy Corp	$0.47	$0.52	$1.19	$0.51	$2.30	$2.22	$2.27	$2.69	$0.47	21.2%
American Electric Power	$0.61	$0.44	$1.21	$0.52	$2.30		$2.28	$2.78	$0.48	20.9%
AES Corporation	$0.16	$0.12	$0.17	$0.03	$0.50	$0.40	$0.44	$0.48	$0.08	20.0%
OGE Energy Corp	$0.00	$0.41	$1.27	$0.00	$1.45		$1.43	$1.68	$0.23	15.9%
Cinergy Corp	$0.81	$0.46	$0.79	$0.78	$2.60	$2.50	$2.65	$2.84	$0.34	13.6%
Great Plains Energy	$0.28	$0.47	$1.11	$0.41	$1.90	$2.00	$1.95	$2.27	$0.27	13.5%
Duke Energy Corp	$0.43	$0.28	$0.51	$0.32	$1.38		$1.36	$1.54	$0.16	11.6%
Public Service Entrp Group Inc	$1.42	$0.66	$1.00	$1.16	$3.82		$3.83	$4.24	$0.42	11.0%
NiSource Inc	$0.87	$0.15	$0.02	$0.66	$1.55		$1.62	$1.70	$0.15	9.7%
DQE Inc	$0.30	$0.28	$0.41	$0.24	$1.13		$1.12	$1.23	$0.10	8.8%
Exelon	$1.22	$1.23	$1.70	$1.22	$5.00		$4.99	$5.37	$0.37	7.4%
Xcel Energy	$0.33	$0.16	$0.44	$0.30	$1.15		$1.17	$1.23	$0.08	7.0%
DTE Energy Co	$1.00	$0.23	$0.96	$1.21	$3.30	$3.18	$3.21	$3.40	$0.22	6.9%
DPL Inc	$0.30	$0.28	$0.54	$0.21	$1.25		$1.23	$1.33	$0.08	6.4%
Dominion Resources Inc	$1.52	$0.84	$1.54	$1.13	$4.75		$4.77	$5.03	$0.28	5.9%
Southern Co	$0.41	$0.49	$0.84	$0.23	$1.87		$1.86	$1.97	$0.10	5.3%
PG&E Corp	$0.45	$0.31	$0.64	$0.48	$1.80		$1.86	$1.88	$0.08	4.4%
Wisconsin Energy Corp	$0.79	$0.42	$0.50	$0.63	$2.25		$2.30	$2.34	$0.09	4.0%
Ameren Corp.	$0.52	$0.68	$1.63	$0.18	$2.90		$2.89	$3.01	$0.11	3.8%
Consolidated Edison	$0.72	$0.29	$1.31	$0.53	$2.90	$2.75	$2.86	$2.85	$0.10	3.6%
Progress Energy	$0.79	$0.67	$1.53	$0.71	$3.66	$3.60	$3.65	$3.70	$0.10	2.8%
Hawaiian Electric Inds	$0.66	$0.69	$0.90	$0.72	$2.95		$2.93	$2.97	$0.02	0.7%
Entergy Corp	$1.12	$1.23	$1.50	$0.32	$4.20		$4.16	$4.17	-$0.03	-0.7%
PPL Corporation	$1.06	$0.67	$0.95	$0.82	$3.55		$3.61	$3.50	-$0.05	-1.4%
FPL Group Inc	$0.97	$1.34	$1.79	$0.75	$4.93		$4.91	$4.85	-$0.08	-1.6%
Empire District Electric	$0.27	$0.13	$0.82	$0.16	$1.43		$1.47	$1.38	-$0.05	-3.5%
Pinnacle West Capital	$0.28	$0.61	$1.38	$0.26	$2.70		$2.66	$2.53	-$0.17	-6.3%
Edison International	$0.20	$0.54	$1.09	$0.18	$2.20		$1.84	$2.01	-$0.19	-8.6%
Pepco Holdings	$0.04	$0.31	$0.80	$0.24	$1.55		$1.62	$1.39	-$0.16	-10.3%
Constellation Energy Corp	$0.36	$0.58	$1.00	$0.41	$2.65	$2.75	$2.74	$2.35	-$0.40	-14.5%
TXU Corp	$0.30	$0.49	$0.92	-$0.24	$2.04		$2.00	$1.47	-$0.57	-27.9%
Sierra Pacific Resources	-$0.15	-$1.48	$0.78	-$0.39	$0.55		$0.49	-$1.24	-$1.79	-325.5%

Boldface numbers are estimates.
Source: First Call

Raising 2003E

Constellation Energy. We are raising our 2003E $0.10/share to $2.75 which is in the middle of the company's $2.65-$2.85 EPS guidance. We have stayed at the conservative end of guidance as we watched the progress at Competitive Supply from new origination and NewEnergy. Of the targeted $364M of gross margin for the year, CEG generated $88.5M in the first half versus $129.2M in 1H'02. However, new and renewal margin already in place for the second half of the year brings the total to $317M. We believe CEG can close the gap in the remainder of the year. On the flip side, the company lost 3 traders last week including its head trader who reported directly to Tom Brooks, President of Constellation Power Source, which if nothing else is a personnel hurdle. Weather and a possible Nine Mile Point outage are potential offsets, though we believe we have conservatively included them.

Great Plains Energy. We are raising our 2003E $0.10/share to $2.00 which is at the top end of the company's $1.90-$2.00 EPS guidance. Similarly, we have remained cautious while waiting for retail marketing subsidiary Strategic Energy to grow its backlog of business for the year. In the first half of 2003 the company generated $0.32 of the forecasted $0.50 total. The company was on track to deliver 15.8 MMWhrs based on the backlog at mid-year which was the middle of the 15-17/MWhr range necessary to hit the total. We believe this gets the company most of the way toward hitting the target as overhead has increased as well, but closing the gap looks doable. Hurdles are the impacts of a Wolf Creek outage on wholesale sales, weather, and share dilution, but trailing 12 month EPS of $2.27 and lower interest and cost cuts are offsets.

Worth Buying For Potential Earnings Upside

TXU Corp. The trailing 12 months of $1.47 would suggest that TXU would be stretching to reach its EPS guidance for 2003 of $2.00-$2.10. For the first half the company posted EPS of $0.79 and gave guidance of $0.90 for the 3rd quarter. We believe that management was being cautious on the quarter considering that this is essentially the first year by which the company sets its base earnings power. The company should deliver at least second half EPS results of $1.25, driven by the following factors: 1) significant cost cutting benefits (approximately net $150mm pretax), 2) enhanced margins from higher price to beat (approximately $180mm pretax); 3) lower customer attrition than guidance of net 5%, 4) discontinued telecommunication operations (approximately $20mm aftertax); 5) better hedging capability in 4Q03 than 4Q02 for both revenues and cost of goods sold due to stabilized company profile; and 6) increased terawatt hour sales to C&I customers than budgeted. The offsets to further upside may be pretax impacts for Comanche outage (approx $20mm pretax), gas plant starts in excess of budget ($25mm pretax) and cost shifting ($20mm pretax). We continue to recommend Buying TXU. TXU has valuation upside nearing 20% benefits and favorable potential catalysts including the announcement of a successor for CEO Erle Nye in 2003 and possible dividend growth in 2004.

Lowering 2003E

AES Corp. We are lowering our 2003 EPS estimate $0.10/share to $0.40 to reflect Drax accounting treatment for the first half of 2003. We had expected that Drax losses would be reversed out of operations as a result of AES' walking away in Q3, but the auditors came up with a different outcome. Drax had a -$0.10/share impact on AES in 1H'03.

Cinergy. We are lowering our 2003E $0.10/share to $2.50 which compares to the company's $2.55-$2.70 range. The main driver is a difficult weather comp. Despite trailing 12 month EPS of $2.84, weather was $0.13/share above normal in 2H'02 and looks to be a drag of $0.15/share or more based on the quarter to date. We also look for gas marketing margins to be impacted with Apache's decision to bring the operations in house.

Consolidated Edison. We are lowering our 2003E $0.15/share to $2.75 which compares to the company's $2.82-$2.97 range. Trailing 12 month EPS is $2.85 and weather was strong positive in 2H'02. While there was no notable damage to the ED's system in the outage, the company missed about 1 ½ days of electric sales. Other incremental factors include share dilution and pension/OPEB expenses, somewhat offset by some cost cuts and rate relief.

DTE Energy. The company has quantified the impact of the outage to be $20-$50M including lost sales and other expenses. It also took several days for the company's Fermi nuclear plant to return to service. With that in mind, we are lowering our 2003 EPS estimate -$0.12/share to $3.18 which essentially represents the middle of the range.

FirstEnergy. We are lowering our 2003E $0.08/share to $2.22 to reflect costs related to the power outage. Specifically, the 1,320 MW Perry plant did not return until the end of this week following the outage. In addition, FE like other affected utilities lost sales opportunities as well.

Progress Energy. The trailing 12 months of $3.70 is by our estimates the top end of what the company could deliver this year without slowing clean air accelerated depreciation ($100mm/annual and $54mm ytd). At this point we believe that management would not go off its target for the year. However, given the milder weather than normal and vs last year ($0.13 up vs normal in 2H02) through mid-August, we are lowering our EPS estimate for 2003 to $3.60 from $3.66. We maintain our 2004 EPS estimate at $3.77. PGN shares will continue to be plagued by the uncertainty surrounding the audit and validation of its syn-fuel operations and tax credits. It is anticipated that the IRS could opine in September. Just as a reminder, the ongoing EPS impact from syn-fuel is approximately $0.70/ps.

Worth Shedding for Possible Downside

Teco Energy. The trailing 12 months reflects $1.74. Due to year on year negative impacts from share dilution, higher interest costs, and merchant plant operational losses, we maintain our estimate $1.15 and $0.80 estimate for 2003 and 2004, respectively.

Blackout Hearings and Energy Legislation a Priority

When members return in September, priorities will be hearings on the power outages in Rep. Tauzin's Energy & Commerce Committee which are set for September 3-4 and appointment of conferees for the energy legislation. The first day's blackout hearings will start at 10 AM and will consist of Energy Secretary Richard Abraham who is running the investigation and at least a number of officials from affected areas. Invited parties include FERC Chairman Pat Wood, NERC President Michehl R. Gent, Gov. Pataki of New York and Mayor Bloomberg of New York City among others. The second day's hearings will start at 9:30 AM and will include a CEO panel with CEO Pete Burg of FirstEnergy and others. The hearings will be webcast from the House Energy and Commerce website at http://energycommerce.house.gov. We expect that these hearings will accelerate the process of assigning culpability for the outage.

Regarding energy legislation we expect many of the conferees will be the same though leadership from the Senate is now with Republicans led by Sen. Pete Domenici (R-NM). Leading the way from the House side will be Rep. Bill Tauzin (R-LA) who is also playing a key role on Medicare. We look for passage in the Fall and as mentioned we expect key provisions will be incentives for infrastructure spending and repeal of the Public Utility Holding Company Act (PUHCA). Ways to stimulate infrastructure spending are through project incentives and potentially by classifying standalone transmission companies as MLPs. Stocks that would be impacted are those of big transmission owners such as Exelon, Entergy, FirstEnergy, and American Electric Power.

On the topic of PUHCA repeal, we believe it would lead to a rally in mid-cap stocks perceived as take-out candidates and conversely big-cap buyers would likely trade-off as the state approvals process is still lengthy even without PUHCA. Mid-caps that could benefit are AYE, CEG, CIN, CMS, DPL, DQE, GXP, NI, NU, and PPL.

Blast from the Past

We believe rate cases will impact group performance since so many of our companies are involved in meaningful proceedings, 12 in total. Since most of the companies are at the front-end of proceedings, we expect stocks of related companies to be suffering. This is likely at least until Staff and Intervenor testimony is filed. Companies that still face key filings from Commission Staff and/or Intervenors are: Cinergy, CMS Energy, DTE Energy, DQE, Northeast Utilities, Pinnacle West, and Sierra Pacific Resources. DQE and Northeast Utilities still face initial filings in Pennsylvania and New Hampshire respectively by early fourth quarter. Out of this group, we believe the stock that is most likely to benefit from getting a rate case outcome behind them is Cinergy, though this is more of a fourth quarter item. On the plus side, we believe Wisconsin Energy could benefit from a reasonable outcome in its "Power the Future" plan. WEC's proposal would call for 3 x 600 MW coal plants to come on-line in 2007, 2009, and 2011. In the final ruling currently scheduled for November 10, 2 of the proposed coal plants should be approved, but a third plant is less likely. In this scenario we believe average EPS growth can be 7-8% from 2003-2009 which is still quite attractive. For more details on rate case proceedings upcoming please see our June 4 publication "A Blast from the Past".

Analyst Certification:

I, Daniel Ford, hereby certify (1) that the views expressed in this research note accurately reflect my personal views about any or all of the subject securities or issuers referred to in this note and (2) no part of my compensation was, is or will be directly or indirectly related to the specific recommendations or views expressed in this note.

Related Stocks:	**Ticker**	**Price (08/25)**	**Rating**
Allegheny Energy	AYE	8.68	2-Equal weight
Constellation Energy	CEG	35.01	2-Equal weight
Cinergy Corp	CIN	33.72	2-Equal weight
CMS Energy	CMS	6.35	2-Equal weight
DPL Inc	DPL	15.20	2-Equal weight
DQE Inc	DQE	14.43	2-Equal weight
DTE Energy	DTE	34.63	2-Equal weight
Duke Energy	DUK	17.00	3-Underweight
Consolidated Edison	ED	39.54	3-Underweight
Exelon Corp	EXC	57.61	1-Overweight
Great Plains Energy	GXP	28.96	3-Underweight
NiSource, Inc	NI	19.06	2-Equal weight
Northeast Utilities	NU	17.10	3-Underweight
PG&E Corp	PCG	21.90	1-Overweight
Public Service Enterprise Gp	PEG	42.16	1-Overweight
Pepco Holdings	POM	17.40	2-Equal weight
PPL Corporation	PPL	38.87	1-Overweight
TECO Energy	TE	11.72	3-Underweight
TXU Corp	TXU	21.70	1-Overweight
Wisconsin Energy	WEC	28.15	1-Overweight

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Stock Rating
1-Overweight - The stock is expected to outperform the unweighted expected total return of the industry sector over a 12-month investment horizon.
2-Equal weight - The stock is expected to perform in line with the unweighted expected total return of the industry sector over a 12-month investment horizon.
3-Underweight - The stock is expected to underperform the unweighted expected total return of the industry sector over a 12-month investment horizon.
RS-Rating Suspended - The rating and target price have been suspended temporarily to comply with applicable regulations and/or firm policies in certain circumstances including when Lehman Brothers is acting in an advisory capacity on a merger or strategic transaction involving the company.

Sector View
1-Positive - sector fundamentals/valuations are improving.
2-Neutral - sector fundamentals/valuations are steady, neither improving nor deteriorating.
3-Negative - sector fundamentals/valuations are deteriorating.

Stock Ratings From February 2001 to August 5, 2002 (sector view did not exist):
This is a guide to expected total return (price performance plus dividend) relative to the total return of the stock's local market over the next 12 months.
1-Strong Buy - expected to outperform the market by 15 or more percentage points.
2-Buy - expected to outperform the market by 5-15 percentage points.
3-Market Perform - expected to perform in line with the market, plus or minus 5 percentage points.
4-Market Underperform - expected to underperform the market by 5-15 percentage points.
5-Sell - expected to underperform the market by 15 or more percentage points.

Stock Ratings Prior to February 2001 (sector view did not exist):
1-Buy - expected to outperform the market by 15 or more percentage points.
2-Outperform - expected to outperform the market by 5-15 percentage points.
3-Neutral - expected to perform in line with the market, plus or minus 5 percentage points.
4-Underperform - expected to underperform the market by 5-15 percentage points.
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