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BEFORE THE IDAHO PUBLIC UTILITIES COMMISSION

IN THE MATTER OF THE APPLICATION	)	CASE NO. AVU-E-04-01
OF AVISTA CORPORATION FOR THE	)	
AUTHORITY TO INCREASE ITS RATES	)	
AND CHARGES FOR ELECTRIC AND	)	
NATURAL GAS SERVICE TO ELECTRIC AND	)	EXHIBIT NO. 7
NATURAL GAS CUSTOMERS IN THE STATE	)	
OF IDAHO	)	ROBERT J. LAFFERTY
	)	

FOR AVISTA CORPORTATION

(ELECTRIC ONLY)

(SCHEDULES 16, 21 & 31 OF THIS EXHIBIT ARE CONFIDENTIAL)

CASE NO. AVU-E-04-01

EXHIBIT NO. 7
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CONFIDENTIAL

Natural Gas Purchase & Hedge Transactions - Graph

THIS PAGE CONTAINS CONFIDENTIAL MATERIALS AND IS SEPARATELY FILED

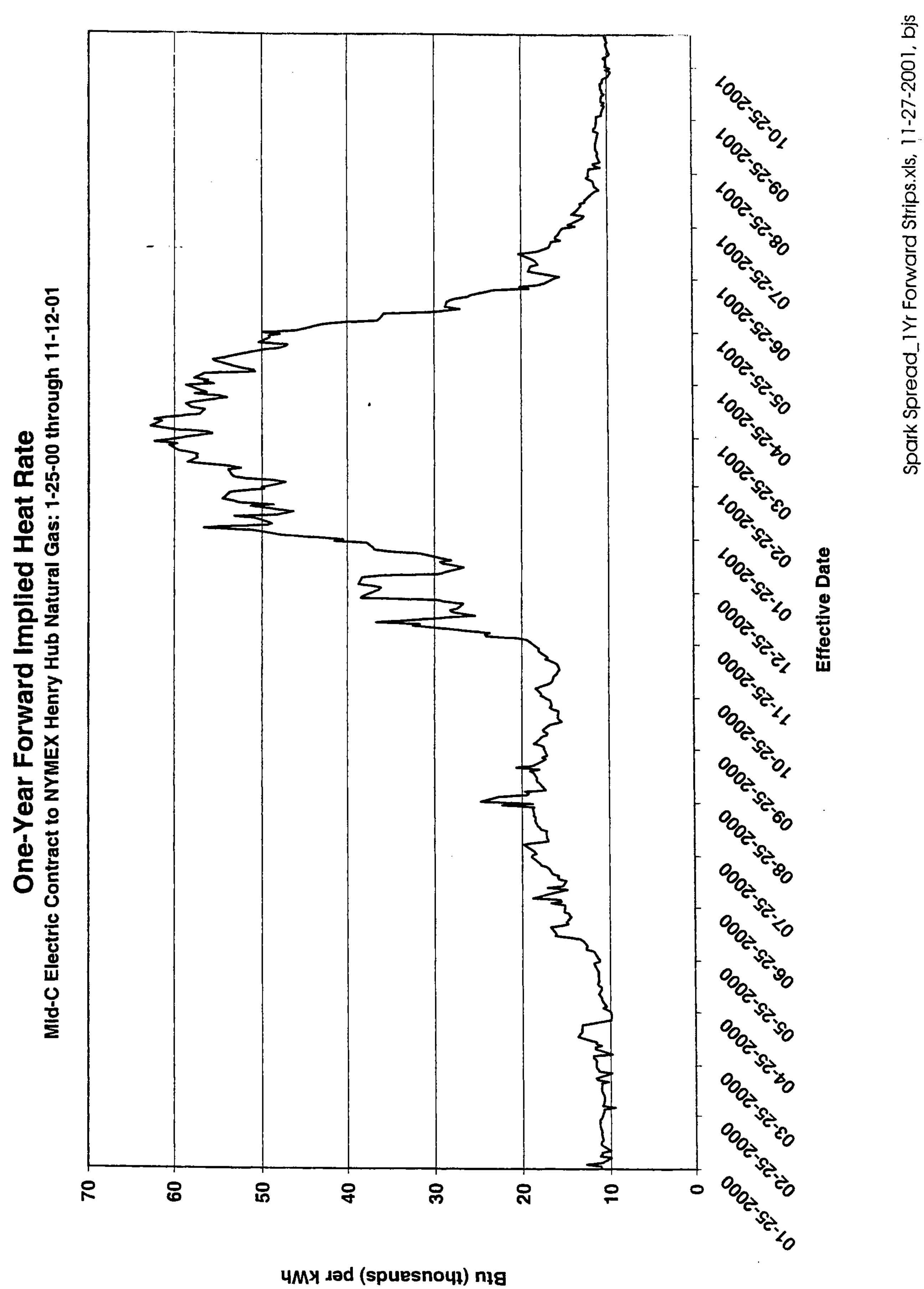
Avista Corporation

3-21-01 L&R With Natural Gas-Fired Generation Adjusted To The Amount Of Generation Hedged

Requirements and Resources
figures in MW (critical water)

Line No.		2002 Pk	2002 Avg	2002 Adj. Fuel*	2003 Pk	2003 Avg	2003 Adj. Fuel*	2004 Pk	2004 Avg	2004 Adj. Fuel*
	REQUIREMENTS									
1	System Load	1,554	974	974	1,605	1,006	1,006	1,662	1,046	1,046
2	PacifiCorp Exchange	-	3	3	-	3	3	-	-	-
3	Puget #2	33	25	25	-	-	-	-	-	-
4	PacifiCorp 1994	-	9	9	-	9	9	-	-	-
5	PGE #1	150	-	-	150	-	-	150	-	-
6	Nichols Pumping	4	4	4	4	3	3	1	1	1
7	Reserves	245	-	-	251	-	-	256	-	-
8	TOTAL REQUIREMENTS	1,986	1,015	1,015	2,010	1,021	1,021	2,069	1,047	1,047
	RESOURCES									
9	System Hydro	946	316	316	946	316	316	946	316	316
10	Contract Hydro	195	74	74	195	74	74	195	74	74
11	Can Ent Return	(8)	(4)	(4)	(8)	(5)	(5)	(11)	(6)	(6)
12	Small Power	12	11	11	12	11	11	12	11	11
13	Northeast CTs	69	5	-	69	5	-	69	5	-
14	Rathdrum CTs	176	62	29	176	62	-	176	62	-
15	PacifiCorp Exchange	50	3	3	50	3	3	50	3	3
16	Entitle. & Supple.	4	-	-	4	-	-	-	-	-
17	BPA Res. Exchange	47	47	47	47	47	47	47	47	47
18	BPA-WNP #3	82	10	10	82	10	10	82	10	10
19	CSPE	9	5	5	8	1	1	-	-	-
20	SEMPRA	-	7	7	-	-	-	-	-	-
21	TransAlta-Centralia	200	143	143	200	143	143	-	-	-
22	Thermal-Kettle Falls	49	45	45	49	45	45	49	45	45
23	Colstrip	222	191	191	222	191	191	222	191	191
24	CS II CCCT	-	101	141	280	241	220	280	241	100
25	TOTAL RESOURCES	2,053	1,016	1,017	2,332	1,144	1,056	2,117	999	791
26	SURPLUS (DEFICIT)	67	1	2	323	123	35	48	(48)	(256)

Notes:
* Adj. Fuel - Includes only that natural gas-fired generation with fixed priced fuel purchased.



One-Year Forward Implied Heat Rate
Mid-C Electric Contract to NYMEX Henry Hub Natural Gas: 1-25-00 through 11-12-01
Btu (thousands) per kWh
70
60
50
40
30
20
10
0
01-25-2000
02-25-2000
03-25-2000
04-25-2000
05-25-2000
06-25-2000
07-25-2000
08-25-2000
09-25-2000
10-25-2000
11-25-2000
12-25-2000
01-25-2001
02-25-2001
03-25-2001
04-25-2001
05-25-2001
06-25-2001
07-25-2001
08-25-2001
09-25-2001
10-25-2001
Effective Date
Spark Spread_1Yr Forward Strips.xls, 11-27-2001, bjs

Avista Utilities

Summary of Forward Monthly Natural Gas Fixed Priced Purchases Compared to Electric Market Prices

April 2000 through December 2001

Transaction Date	Delivery Period	Transaction Volume Dth/day	Gas Fixed Price ($/Dth)	Plant	Variable Generation Cost ($/MWh)	Mid-C HLH Price ($/MWh)	Mid-C LLH Price ($/MWh)	HLH (Benefit/ MWh)	LLH (Benefit/ MWh)
4/12/2000	Aug-00	5,000	$2.82	Rathdrum	$33.45	$50.25		$16.80	
5/1/2000	Aug-00	5,000	$3.03	Rathdrum	$35.87	$56.13		$20.27	
5/1/2000	Sep-00	5,000	$3.10	Rathdrum	$36.67	$56.13		$19.46	
5/5/2000	Sep-00	5,000	$2.885	Rathdrum	$34.20	$57.00		$22.80	
5/10/2000	Jun-00	5,000	$2.81	Rathdrum	$33.34	$37.30		$3.97	
5/17/2000	Jun-00	5,000	$3.10	Rathdrum	$36.67	$49.00		$12.33	
6/1/2000	Jul-00	10,000	$3.85	Rathdrum	$45.30	$75.08		$29.79	
6/1/2000	Jul-00	4,500	$3.77	Rathdrum	$44.38	$75.08		$30.71	
6/12/2000	Oct-00	5,000	$4.10	Rathdrum	$48.17	$81.00		$32.83	
6/13/2000	Aug-00	10,000	$3.80	Rathdrum	$44.72	$139.50		$94.78	
6/23/2000	Oct-00	5,000	$4.50	Rathdrum	$52.77	$73.30		$20.53	
6/23/2000	Nov-00	5,000	$4.50	Rathdrum	$52.77	$73.30		$20.53	
6/23/2000	Dec-00	5,000	$4.50	Rathdrum	$52.77	$73.30		$20.53	
6/30/2000	Nov-00	5,000	$4.45	Rathdrum	$52.20	$82.00		$29.81	
6/30/2000	Dec-00	5,000	$4.45	Rathdrum	$52.20	$83.00		$30.81	
6/30/2000	Jan-01	5,000	$4.45	Rathdrum	$52.20	$57.00		$4.80	
6/30/2000	Feb-01	5,000	$4.45	Rathdrum	$52.20	$54.00		$1.80	
6/30/2000	Mar-01	5,000	$4.45	Rathdrum	$52.20	$54.00		$1.80	
7/18/2000	Jan-01	5,000	$4.05	Rathdrum	$47.60	$58.00		$10.41	
7/18/2000	Feb-01	5,000	$4.05	Rathdrum	$47.60	$58.00		$10.41	
7/18/2000	Mar-01	5,000	$4.05	Rathdrum	$47.60	$58.00		$10.41	
8/29/2000	Sep-00	25,000	$4.03	Rathdrum	$47.37	$134.00	$80.00	$86.64	$32.64
8/29/2000	Oct-00	25,000	$4.03	Rathdrum	$47.37	$136.25	$80.00	$88.89	$32.64
8/30/2000	Nov-00	5,000	$5.04	Rathdrum	$58.98	$96.00		$37.02	
8/30/2000	Dec-00	10,000	$5.22	Rathdrum	$61.05	$96.00		$34.95	
8/30/2000	Jan-01	10,000	$5.12	Rathdrum	$59.90	$90.00		$30.10	
8/30/2000	Jul-01	5,000	$4.09	Rathdrum	$48.06	$140.00		$91.95	
8/30/2000	Aug-01	5,000	$4.09	Rathdrum	$48.06	$150.00		$101.95	
8/30/2000	Sep-01	5,000	$4.09	Rathdrum	$48.06	$144.00		$95.95	

Note: LLH Margin is shown when enough natural gas is purchased to run some LLH in addition to all HLH.

Avista Utilities

Summary of Forward Monthly Natural Gas Fixed Priced Purchases Compared to Electric Market Prices

April 2000 through December 2001

Transaction Date	Delivery Period	Transaction Volume Dth/day	Gas Fixed Price ($/Dth)	Plant	Variable Generation Cost ($/MWh)	Mid-C HLH Price ($/MWh)	Mid-C LLH Price ($/MWh)	HLH (Benefit/ MWh)	LLH (Benefit/ MWh)
9/12/2000	Nov-00	5,000	$5.45	Rathdrum	$63.70	$118.00		$54.31	
9/12/2000	Dec-00	5,000	$5.45	Rathdrum	$63.70	$122.00	$65.00	$58.31	$1.30
9/12/2000	Jan-01	5,000	$5.45	Rathdrum	$63.70	$109.00	$60.00	$45.31	($3.70)
9/12/2000	Feb-01	5,000	$5.45	Rathdrum	$63.70	$100.00		$36.31	
9/15/2000	Nov-00	10,000	$5.37	Rathdrum	$62.78	$118.00	$70.00	$55.23	$7.22
9/15/2000	Dec-00	10,000	$5.37	Rathdrum	$62.78	$120.00	$65.00	$57.23	$2.22
9/15/2000	Jan-01	10,000	$5.37	Rathdrum	$62.78	$108.00	$60.00	$45.23	($2.78)
9/15/2000	Feb-01	10,000	$5.37	Rathdrum	$62.78	$94.00	$60.00	$31.23	($2.78)
9/15/2000	Mar-01	10,000	$5.37	Rathdrum	$62.78	$92.00	$60.00	$29.23	($2.78)
9/15/2000	Apr-01	10,000	$5.37	Rathdrum	$62.78	$66.00		$3.22	
9/15/2000	Oct-00	5,000	$5.66	Rathdrum	$66.11	$137.25	$80.00	$71.14	$13.89
9/15/2000	Nov-00	5,000	$5.66	Rathdrum	$66.11	$118.00	$70.00	$51.89	$3.89
9/15/2000	Nov-00	5,000	$5.63	Rathdrum	$65.77	$118.00	$70.00	$52.24	$4.24
9/15/2000	Dec-00	5,000	$5.63	Rathdrum	$65.77	$120.00	$65.00	$54.24	($0.77)
9/15/2000	Jan-01	5,000	$5.63	Rathdrum	$65.77	$108.00	$60.00	$42.24	($5.77)
9/15/2000	Jun-01	10,000	$4.63	Rathdrum	$54.27	$88.00		$33.74	
9/15/2000	Jul-01	10,000	$4.63	Rathdrum	$54.27	$152.00		$97.74	
9/15/2000	Aug-01	10,000	$4.63	Rathdrum	$54.27	$162.00		$107.74	
9/15/2000	Sep-01	10,000	$4.63	Rathdrum	$54.27	$157.00		$102.74	
9/15/2000	Oct-01	10,000	$4.63	Rathdrum	$54.27	$90.00		$35.74	
9/15/2000	Nov-01	10,000	$4.63	Rathdrum	$54.27	$80.00		$25.74	
9/15/2000	Dec-01	10,000	$4.63	Rathdrum	$54.27	$80.00		$25.74	
9/15/2000	Jul-01	30,000	$4.64	Rathdrum	$54.38	$152.00	$50.00	$97.62	($4.38)
9/15/2000	Aug-01	30,000	$4.64	Rathdrum	$54.38	$162.00	$50.00	$107.62	($4.38)
9/15/2000	Sep-01	30,000	$4.64	Rathdrum	$54.38	$157.00	$50.00	$102.62	($4.38)
9/15/2000	Oct-01	30,000	$4.64	Rathdrum	$54.38	$90.00	$50.00	$35.62	($4.38)
9/15/2000	Nov-01	30,000	$4.64	Rathdrum	$54.38	$80.00	$50.00	$25.62	($4.38)
9/15/2000	Dec-01	30,000	$4.64	Rathdrum	$54.38	$80.00	$50.00	$25.62	($4.38)
11/29/2000	Dec-00	4,000	$15.50	Rathdrum	$187.02		$215.00		$27.98
12/28/2000	Jan-01	4,000	$12.75	Rathdrum	$154.02		$500.00		$345.98
1/26/2001	Apr-01	10,000	$6.33	Rathdrum	$76.98	$377.50		$300.52	
1/29/2001	Apr-01	5,000	$5.90	Rathdrum	$71.82	$377.50	$150.00	$305.68	$78.18
2/9/2001	Aug-01	5,000	$6.07	NECT	$83.91	$345.00	$278.00	$261.09	
2/9/2001	Sep-01	5,000	$6.07	NECT	$83.91	$333.00	$266.00	$249.09	
2/9/2001	Oct-01	5,000	$6.07	NECT	$83.91	$353.00	$298.00	$269.09	

Note: LLH Margin is shown when enough natural gas is purchased to run some LLH in addition to all HLH.

Avista Utilities

Summary of Forward Monthly Natural Gas Fixed Priced Purchases Compared to Electric Market Prices

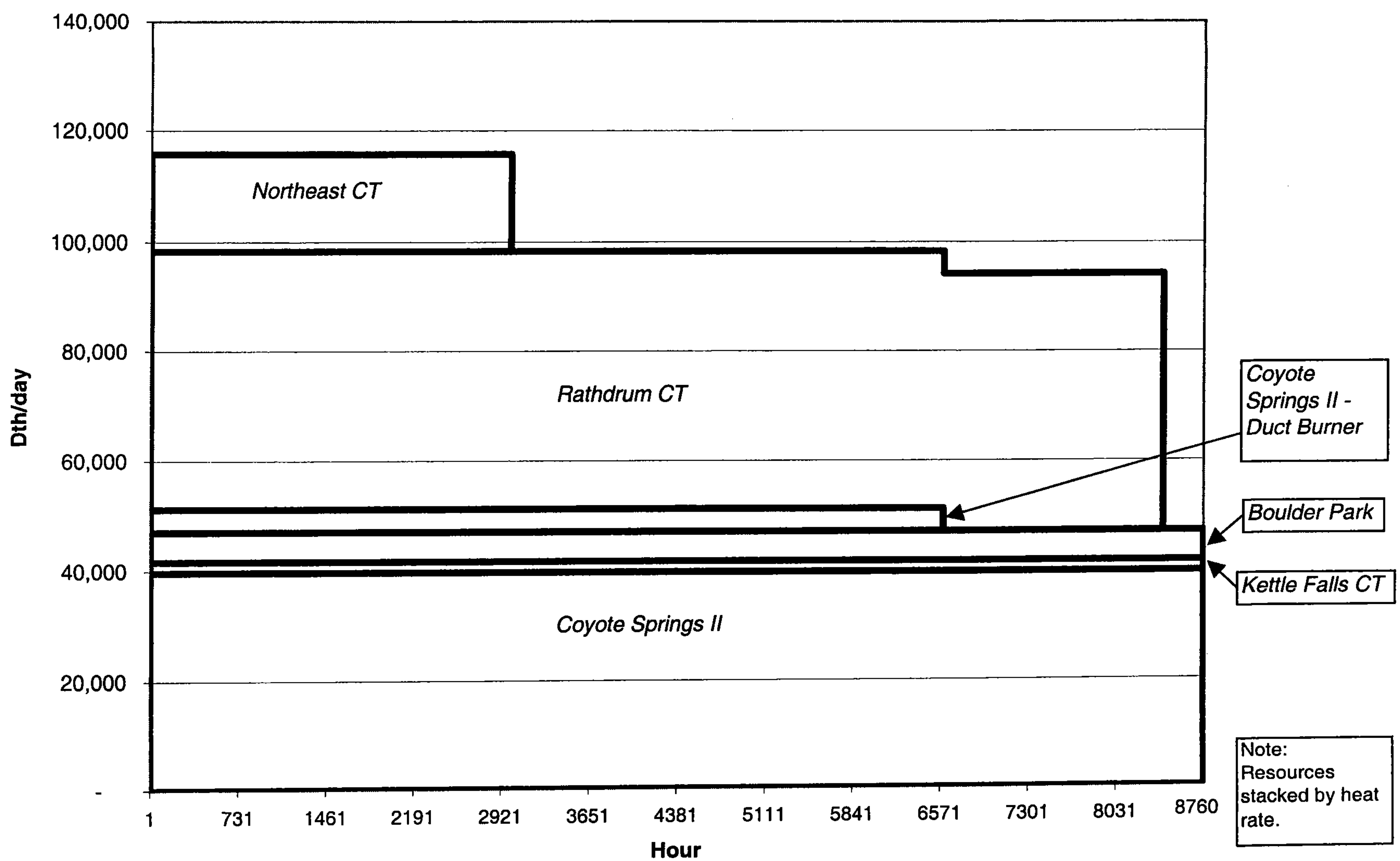
April 2000 through December 2001

Transaction Date	Delivery Period	Transaction Volume Dth/day	Gas Fixed Price ($/Dth)	Plant	Variable Generation Cost ($/MWh)	Mid-C HLH Price ($/MWh)	Mid-C LLH Price ($/MWh)	HLH (Benefit/ MWh)	LLH (Benefit/ MWh)
2/12/2001	Aug-01	10,000	$5.97	NECT	$82.61	$408.00	$341.00	$325.39	$258.39
2/12/2001	Sep-01	10,000	$5.97	NECT	$82.61	$394.00	$327.00	$311.39	$244.39
2/12/2001	Oct-01	10,000	$5.97	NECT	$82.61	$372.00	$317.00	$289.39	$234.39
2/12/2001	Nov-01	10,000	$8.97	NECT	$121.61	$304.00	$249.00	$182.39	
2/12/2001	Dec-01	10,000	$8.97	NECT	$121.61	$359.00	$304.00	$237.39	
2/26/2001	Mar-01	5,000	$5.49	NECT	$76.37	$227.50	$200.20	$151.13	
2/26/2001	Apr-01	5,000	$5.49	NECT	$76.37	$235.00	$206.80	$158.63	
3/1/2001	Mar-01	10,000	$5.60	NECT	$77.80	$300.00	$264.00	$222.20	
3/1/2001	Apr-01	10,000	$5.45	NECT	$75.85	$291.00	$256.08	$215.15	
3/1/2001	May-01	10,000	$5.45	NECT	$75.85	$272.50	$239.80	$196.65	
3/8/2001	Apr-01	10,000	$5.40	Rathdrum	$65.82	$290.50	$255.64	$224.68	$189.82
3/8/2001	May-01	15,000	$5.44	Rathdrum	$66.24	$288.00	$253.44	$221.76	$187.20
3/8/2001	Jun-01	15,000	$5.46	Rathdrum	$66.54	$284.00	$249.92	$217.46	$183.38
3/12/2001	Apr-01	10,000	$5.28	Rathdrum	$64.38	$282.00	$248.16	$217.62	$183.78
3/12/2001	May-01	10,000	$5.28	Rathdrum	$64.38	$273.00	$240.24	$208.62	$175.86
3/12/2001	Jun-01	10,000	$5.28	Rathdrum	$64.38	$292.50	$257.40	$228.12	$193.02
4/10/2001	June-02 - Oct-03	10,000	$6.56	CSII	$46.06	$ 126.75	$ 105.38	$80.70	$59.33
4/11/2001	Nov-01 - Dec-01	10,000	$6.90	NECT	$94.73	$ 309.00	$ 271.92	$214.27	$177.19
4/11/2001	Nov-01 - May-02	10,000	$6.90	Rathdrum	$83.85	$ 230.86	$ 212.53	$161.78	$140.51
4/11/2001	Jan-02 - May-02	10,000	$6.90	Boulder Pk	$67.64	$ 199.60	$ 188.78	$131.96	$121.14
4/11/2001	June-02 - Oct-04	10,000	$6.90	CSII	$48.44	$ 108.89	$ 85.08	$60.45	$36.64
5/2/2001	Nov-01 - May-02	10,000	$6.00	NECT	$83.00	$ 254.00	$ 223.52	$171.00	$140.52
5/2/2001	Nov-01 - May-02	10,000	$6.00	Rathdrum	$73.02	$ 187.86	$ 147.45	$104.98	$66.84
5/2/2001	Jan-02 - May-02	10,000	$6.00	Boulder Pk	$59.45	$ 161.40	$ 117.02	$101.95	$57.57
5/2/2001	June-02 - Oct-04	10,000	$6.00	CSII	$42.16	$ 84.78	$ 61.46	$42.62	$19.30
5/10/2001	June-02 - Oct-03	10,000	$5.41	CSII	$38.06	$ 100.99	$ 79.27	$62.93	$41.21

Note: 5,000Dth/day purchase from Enron on 10/25/01 for Aug-Sept-02 at $3.07/Dth with Enron was terminated in conjunction with the Enron bankruptcy.

Note: LLH Margin is shown when enough natural gas is purchased to run some LLH in addition to all HLH.

Average Maximum Daily Natural Gas Consumption By Generation Project For A One Year Period



1-26-04

Avista Corporation
Natural Gas for Thermal Generation

Maximum Daily Natural Gas Consumption

	NECT (dth/day)	Rathdrum (dth/day)	Boulder Park (dth/day)	KFCT (dth/day)	CSII (dth/day)	CSII Duct (dth/day)	Total (dth/day)
Jan	17,360	44,225	5,328	1,995	43,817	4,915	117,640
Feb	17,175	43,708	5,328	1,995	43,551	4,965	116,723
Mar	16,806	43,020	5,328	1,995	43,451	5,066	115,666
April	16,437	42,217	5,328	1,995	43,218	5,116	114,311
May	16,129	41,471	5,328	1,995	42,853	5,166	112,942
June	15,821	40,783	5,328	1,995	42,188	5,216	111,331
July	15,452	40,037	5,328	1,995	41,523	5,216	109,551
Aug	15,513	40,152	5,328	1,995	41,523	5,216	109,727
Sept	15,944	41,070	5,328	1,995	42,653	5,216	112,206
Oct	16,437	42,160	5,328	1,995	43,218	5,166	114,304
Nov	16,991	43,307	5,328	1,995	43,551	5,066	116,237
Dec	17,237	43,995	5,328	1,995	43,817	4,965	117,337
Annual Ave. Max. Daily Nat. Gas Consumption	16,442	42,179	5,328	1,995	42,947	5,107	113,998
Annual Ave. Max. Daily Nat. Gas Consumption based on Air Permit Operating Hours	5,631	40,561	5,328	1,995	42,947	3,848	100,310

	Annual Ave. Daily Natural Gas Requirement (dth/day)	% Of Nat. Gas Hedged for Period 11-1-01 through 12-31-01	% Of Nat. Gas Hedged for Period 1-1-01 through 5-31-02	% Of Nat. Gas Hedged for Period 6-1-02 through 10-31-03	% Of Nat. Gas Hedged for Period 11-1-03 through 10-31-04
Coyote Springs II	46,795	N.A.	N.A.	85%	43%
Rathdrum	40,561	49%	36%	N.A.	N.A.
Boulder Park	5,328	N.A.	100%	N.A.	N.A.

Notes: 1) Period 11-1-01 through 12-31-01; 20,000 Dth/day hedged
2) Period 1-1-02 through 5-31-02; 20,000 Dth/day hedged
3) Period 6-1-02 through 10-31-03; 40,000 Dth/day hedged
4) Period 11-1-03 through 10-31-04; 20,000 Dth/day hedged
5) N.A. means that the plant either is not available or it is not the most economic plant available to use the nat. gas

CONFIDENTIAL

Natural Gas Transaction Records for Medium-Term Purchases

THIS PAGE CONTAINS CONFIDENTIAL MATERIALS AND IS SEPARATELY FILED

Megawatt Daily's **MarketReport**

FT Financial Times Energy

Monday, December 11, 2000

Indexes and Transaction Record for 12/11/00

Explanations

Index — Volume-weighted average of all trades reported.
Absolute Low — Lowest trade reported.
Absolute High — Highest trade reported.
Trading Volume Reported — Volume of trades per hour for each of 16 peak hours. This figure is a total of all trading volume reported to MWD for each delivery site; because every effort is made to capture both sides of every deal reported, MWD recognizes that this figure includes duplicate volumes, and the figure should be used as a trend indicator not necessarily as an indicator for transmitted volumes.
Total Peak Volume — Volume for all peak hours, found by multiplying the trading volume by 16.
Number of Trades — This figure is calculated by dividing the trading volume reported by 50 MW/h for all Central and East listings; numbers of trades for delivery points in the West are calculated by dividing by 25 MW/h.

Methodology

The prices displayed in the table to the right are for power, in $/MWh, traded at the delivery points and regions listed. Peak hours are 0600-2200 hrs.; PJM and New York peak hours are 0700-2300. Off-peak hours generally start at 2200 hrs. on the date before the delivery date and end at 0600 on the delivery date. Not included are 24-hour deals categorized in some NERC regions as off-peak hours over Saturdays and Sundays. Transactions at the hubs listed in the separate table at the top of this page are financially firm. Deals at other locations may be unit-firm or system-contingent, and may include capacity reservation charges. Transactional data is gathered from utilities, marketers, co-ops, brokers, municipals and government power agencies. Deals done in the West are excluded if done after 1015 hrs. PT; deals done in the East and Central areas are excluded if done after 1100 hrs. CT. The middle column is the volume-weighted average of all deals reported and should be used for indexing purposes. The common range represents pricing for most of the trading volume; the absolute range represents lowest and highest prices reported. Copyright 2000 by Financial Times Energy.

Trades for Standard 16-Hour Daily Products; *all prices and volumes in $MWh*

Delivery Point	Weighted Average Index	Absolute Low	Absolute High	Trading Volume Reported	All Peak Hours Volume	Number of Trades Reported
West						
COB	$3,000.00	$3,000.00	$3,000.00	25	400	1
Four C	—	—	—	0	0	0
Mead, Nev.	—	—	—	0	0	0
Mid-Columbia	$4,175.00	$3,000.00	$5,000.00	100	1,600	4
NP15	—	—	—	0	0	0
Palo Verde	$395.00	$360.00	$425.00	75	1,200	3
SP15	$350.00	$350.00	$350.00	25	400	1
Central						
ERCOT-B	$65.59	$60.00	$75.00	850	13,600	17
Ameren	—	—	—	0	0	0
Com Ed, into	$44.39	$40.00	$52.00	900	14,400	18
MAIN North	$63.33	$58.00	$120.00	300	4,800	6
MAIN South	—	—	—	0	0	0
MAPP North	$60.94	$50.00	$75.00	160	2,560	3
MAPP South	—	—	—	0	0	0
Entergy, into	$67.40	$50.00	$76.00	2,000	32,000	40
SPP	$65.90	$58.00	$75.00	500	8,000	10
East						
Cinergy	$48.47	$44.00	$53.00	6,550	104,800	131
North ECAR	$51.52	$45.00	$55.00	1,405	22,480	28
PJM-West	$49.01	$46.00	$54.00	2,800	44,800	56
Nepool	$74.00	$72.00	$80.00	500	8,000	10
NY Zone G	$67.50	$67.50	$67.50	200	3,200	4
NY Zone A	$57.85	$57.00	$59.00	600	9,600	12
NY Zone J	$81.00	$81.00	$81.00	50	800	1
VaCar	$46.00	$46.00	$46.00	150	2,400	3
Southern	$45.00	$45.00	$45.00	50	800	1
TVA, into	$43.92	$43.00	$47.00	1,200	19,200	24
Fla.-Ga.	$42.50	$40.00	$45.00	100	1,600	2
Fla. in-state	—	—	—	0	0	0

Trades for Standard Forward Products *(all prices in $/MWh)*

Delivery Point	Next Week 12/18 to 12/22 Low	Next Week High	Balance of Month 12/12 to 12/31 Low	Balance of Month High	Prompt Month 01/01 Low	Prompt Month High	Index	All pk. hrs. vol.	No. of Trades
West									
COB	—	—	—	—	—	—	—	0	0
Mid-Columbia	—	—	—	2,000.00	575.00	800.00	675.00	1,200	3
NP15	—	—	—	—	—	320.00	320.00	400	1
Palo Verde	—	—	—	—	250.00	375.00	300.00	1,200	3
SP15	—	—	—	—	—	—	—	0	0
Central									
Com Ed, into	—	75.00	—	68.00	—	—	—	0	0
Entergy, into	—	—	—	—	—	—	—	0	0
East									
Cinergy, into	72.00	85.00	—	70.00	—	—	—	0	0
PJM-West	—	—	—	61.00	—	—	—	0	0
NEPOOL	82.00	90.00	82.00	85.00	—	—	—	0	0
NY Zone G	—	—	—	—	—	—	—	0	0
NY Zone A	60.00	60.50	—	—	—	—	—	0	0
NY Zone J	—	—	—	—	—	—	—	0	0
TVA, into	—	66.00	—	—	—	—	—	0	0

Ranges and Indexes of Trades for Standard Off-Peak Products

Delivery Date: 12/11/00

	Wtd. Av. Index	Absolute Low	Absolute High	Trading Vol. Reported
West				
COB	—	—	—	0
Four C	$275.00	$275.00	$275.00	25
Mead, Nev.	—	—	—	0
Mid-C	$2,016.67	$1,550.00	$2,500.00	75
NP15	—	—	—	0
Palo Verde	$275.00	$275.00	$275.00	25
SP15	—	—	—	0
Central				
ERCOT-8	—	—	—	0
Ameren	—	—	—	0
Com Ed, into	$19.00	$19.00	$19.00	300
MAIN North	—	—	—	0
MAIN South	—	—	—	0
MAPP North	$21.00	$21.00	$21.00	125
MAPP South	$20.00	$20.00	$20.00	100
Entergy, into	—	—	—	0
SPP	$17.04	$13.00	$23.50	260
East				
Cinergy	—	—	—	0
North ECAR	$19.50	$19.00	$19.55	1,157
PJM-West	—	—	—	0
Nepool	—	—	—	0
NY Zone G	—	—	—	0
NY Zone A	—	—	—	0
NY Zone J	—	—	—	0
VaCar	—	—	—	0
Southern	—	—	—	0
TVA, into	—	—	—	0
Fla.-Ga.	$25.00	$25.00	$25.00	50
Fla. in-state	—	—	—	0

MGE, Alliant propose plant for university

A proposal between Madison Gas & Electric (MGE), Alliant Energy, the University of Wisconsin-Madison and Wisconsin's Department of Administration may result in a $170 million, 90-to 100-MW, natural gas-fired power plant on school ground that could solve a long-term energy crunch facing both the university and the city, the parties said last week.

If the plant gets all approvals necessary, the two utilities will jointly plan and oversee construction of the facility, which is anticipated to start in summer 2002. Plant operation is expected to begin in late 2003 or spring 2004.

Once construction is complete, MGE would own the facility with a third-party investor but would retain full operational control. Alliant will act as project manager. Although not a specified owner, Alliant will be paid for its services, company representative Chris Schoenherr said.

The proposed site at the university has the necessary infrastructure in place to support the facility, including electric transmission lines, a power substation and natural gas lines. MCM

Dailies scream to $5,000 at Mid-C, $3,000 at COB

The relentless upswing in next-day prices prevailed, with dailies trading to $5,000 at Mid-Columbia and $3,000 at COB.

"This is history," one source said. "Someone who buys power at that price [$5,000] is walking wounded. Actually, they're not even walking."

Western Markets

Overall, next-day volume was sparse. Deals arranged for today's delivery traded up to $425 at Palo Verde and near $350 at SP15.

In the bilateral market, off-peak for today traded near $275 at Palo Verde and at Four Corners.

The extreme pressure on prices carried over into the term markets, where balance-of-the-month sold for $2,000 at Mid-C and January there sold for $800 for a third consecutive day.

Crippled by idled power plants and tight energy imports, the state's power grid strained to meet the load going into the weekend. The danger of blackouts, caused by cold weather and an unprecedented drop in the energy supply, was expected to grow severely today, as an Arctic front blows down the West Coast from Canada.

Going into the weekend, California Power Exchange prices for Saturday peak were $251.23, with off-peak $256.79 and the 24-hour weighted average at $252.79. A day earlier, prices were fractions of a cent above $250.

The Bonneville Power Administration had no surplus power to sell at least through Saturday.

Friday began with a Stage 2 declaration by the California Independent System Operator — the fifth such declaration in as many days and the ninth in three weeks.

Also firming up power prices was the cost of natural gas, which reached as high as $63 at COB/Malin, Ore., $61 at the Pacific Gas & Electric Citygate and $55 at the Southern California Border.

At Palo Verde, January ranged $250-$375 and near $320 at NP15.

Second-quarter 2001 traded as high as $215 at Mid-C and in a tight range to $190 at Palo Verde.

Third-quarter 2001 sold at or above $290 at Palo Verde. KW/NM

Transmission problems force Entergy to mid $70s

Entergy dailies opened at $50, about $23 lower than the previous day's trades. However, they soon regained ground, passing the high from the day before.

By the end of the day deals were done at $76, a net gain of $1. Traders were not certain what was driving prices up, but suspected transmission constraints.

Central Markets

In MAIN, ComEd dailies fell even further, about $16 to the low $50s. Off-peak sold near $19.

Weekend trades moved in the low $30s and off-peak sold in the low $20s.

After undergoing a hot shutdown last week, ComEd's 828-MW nuke unit, Quad Cities 1, began powering back up after repairs.

Northern MAIN dailies moved around the low $60s. However, the same unfortunate player who all last week caught the high deals paid around $120 for a much-needed package. Weekend peak sold in the upper $20s.

Ameren reported weekend off-peak deals near $20.

Light weekend demand helped push northern MAPP dailies down about $20, to $75.

Central Generation Outage Report for December 11

Information from the Nuclear Regulatory Commission is sometimes outdated, and not all utilities respond to requests for verification of unit status. Copyright 2000 by FT Energy

Unit Name, Operator	MW	NERC Region	Unit Status	Scheduled restart or outage date
LaSalle 2 ComEd	828	MAIN	Nuclear; operating at 100% following Oct. 8 refueling outage	Full power Dec. 8
Quad Cities 1 ComEd	828	MAIN	Nuclear; operating at 1% after hot shutdown Dec. 6	Start up on Dec. 7

San Francisco Chronicle
SUNDAY, MAY 6, 2001

Count up the losses of each wasted week

IN APRIL, California spent an average of $458 million per week to buy electricity. The figure will only climb as hot weather drives up energy use.

This summer, more than 30 days of rolling blackouts are expected in Northern California. The region's major utility is in bankruptcy court. Southern California may get 44 days of interrupted electricity while its power provider fends off creditors.

The power market is broken. It's a dangerous and unpredictable disaster with the potential to darken stoplights and close factories.

A colossal gamble on quasi-deregulation has failed. The state has ended up with ill-conceived rules and a market dominated by powerful energy traders.

The power crisis continues to build to seemingly unsolvable heights. But there are significant steps that can tame the problem in the short run.

Some actions already taken should pay off. After Gov. Gray Davis grudgingly gave in, rates will begin rising 30 percent. This change should boost conservation from thrifty users and bring monthly power bills into the real world, not the artificially low levels set by a deregulation law passed in 1996.

The higher bills should also stop the bleeding for major utilities. These firms were obliged to buy power at rising rates while limited to 1996 levels in selling to customers.

A huge financial burden remains. The Legislature should approve a $12.5 billion bond measure, the largest in state history. The bond proceeds will refund the state for past and future power buys it must make on behalf of credit-weakened utilities. The borrowing will be paid back on future power bills. The Assembly is due to vote on the bond package tomorrow.

The bond measure will be a financial bulwark against future damage. But it addresses only part of the problem.

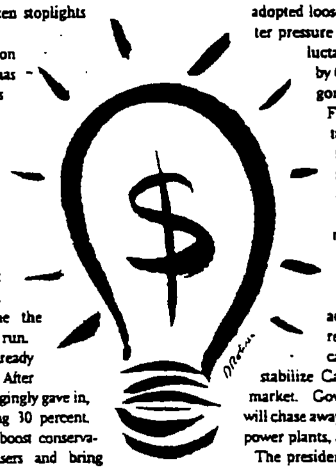
Under deregulation, the so-called spot market for daily power purchases was designed as a way to introduce competition that would hold down energy costs. But this strategy has back-fired: soaring demand driven by population and economic growth has driven up the cost tenfold or more.

Generators can withhold needed power until peak prices are reached. The cost of producing power has nothing to do with its sale price. Several investigations are under way to determine whether California is getting rolled by this buccaneer behavior.

When a handful of companies have a stranglehold on a vital commodity, a windfall profits tax makes sense. A malfunctioning marketplace serves only the suppliers, not buyers with few alternatives. A windfall profits levy acts as a restraint against market manipulation.

Another answer to runaway prices is temporary caps on wholesale electricity costs. Under this plan generators would be limited in what they can charge California. The Federal Energy Regulatory Commission has adopted loose-fit maximums after pressure was put on the reluctant federal agency by California and Oregon politicians. The FERC restraints, tame and limited as they are, are a first step that should be expanded.

The FERC move may be as much as California can expect from Washington. The Bush administration has repeatedly rejected calls to intervene or stabilize California's lop-sided market. Government controls will chase away investment in new power plants, according to Bush.



MARGARET SCOTT/Special to The Chronicle

The president is right in saying that more supply — power plants and efficient transmission lines to transport electricity — is needed. But it will take years to achieve this balance in the form of new plants.

After a decade of no construction, California is already on a crash course to build power plants. Nine plants are under way with enough output to light 6 million homes. However, the start dates of these generating facilities are stretched over the next two years, with the first batch not expected to begin until late summer, when the rolling blackouts have long since crested.

The mantra of more supply and free-market balance can't work in today's chaos. California needs safeguards against the abuses of the energy market. Sacramento should pursue a windfall profits tax. FERC must use its authority to put reasonable caps on prices.

Until Sacramento and Washington move more forcefully to stop the gouging, California will continue to squander tens of millions of dollars each day to subsidize electricity purchases.

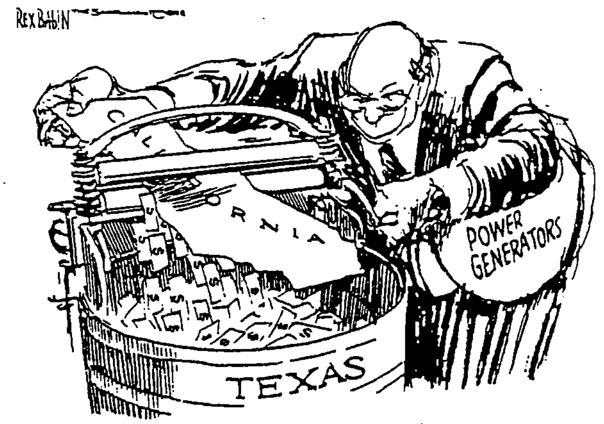
There must be a million better ways to spend the money than to stuff the pockets of the generators and middlemen who are showing no shame in exploiting a crisis.

Consider the alternatives

Want a perspective on the amount state government is spending on electricity subsidies each week? Consider 10 other things that $458 million could buy:

1. A new University of California campus. (A 10th campus planned for Merced has an initial price tag of $380 million.)
2. Mental health care for the estimated 20,000 homeless living on the streets statewide, plus health coverage for 174,000 low-income adults, and 250,000 nursing home patients on state aid.
3. One power plant with enough juice to supply 880,000 homes.
4. An extra lane on a new Bay Bridge for bicyclists, walkers and service vehicles.
5. Pollution clean-up for Lake Tahoe, coastal beaches and buyouts of 5,000 smog-spewing diesel engines used on farms.
6. 217 miles of repaved freeway.
7. Operation of San Francisco Airport for a year.
8. The yearly salaries of 8,400 police officers and 10,500 teachers, plus construction of 85 elementary schools.
9. 19,742 California Highway Patrol cars.
10. A new baseball stadium in downtown Oakland, with about $100 million left over.

The Sacramento Bee • Thursday, April 26, 2001



The San Diego Union-Tribune • Sunday, April 29, 2001

End market power

Sue to block energy price gouging

Private energy companies gouging billions of dollars from California are seeking reauthorization from the Federal Energy Regulatory Commission to continue charging as much as they can for electricity.

And FERC will give it to them — unless California's leaders stop them, both through filing objections with FERC and through the federal courts.

Under FERC regulations, private energy companies are allowed to sell wholesale power at unregulated rates in California as long as they can prove they don't engage in "market power," raising prices above competitive levels for a significant period of time.

Energy crisis

Each of these companies is supposed to file an analysis this spring showing that it hasn't been exercising market power. If FERC accepts these analyses, the companies will be allowed to continue gouging California. But if FERC finds that these companies were in fact gaming the market, then it would supposedly order them to begin selling at a cost-based rate, not a market rate. Cost-based rates would be much lower than market rates, perhaps 90 percent lower.

These reauthorizations haven't gotten much attention, and FERC is expected to approve them without much scrutiny. Some companies, such as Dynegy Corp., which owns the Encina power plant in Carlsbad, have asked for long extensions of FERC's reauthorization of their market-based rate authority. Dynegy requested an extension until next year, so it can continue gouging California without having to justify itself.

Several California entities have filed motions to try to block FERC from renewing these companies' market-based rate authority. Southern California Edison, Pacific Gas & Electric, California Independent System Operator (which runs the state power grid and knows market power when it sees it), the California Public Utilities Commission and the City and County of San Francisco have all filed documents urging FERC to reject the companies' requests. Rep. Bob Filner, D-San Diego, sent a letter requesting that FERC revoke market-based rate authority for 18 companies.

Each of these filings specifies how these companies possess market power in violation of FERC rules. Several of them demand that FERC suspend the entire reauthorization process and set a hearing to re-examine the matter.

The state, via Gov. Davis and Attorney General Bill Lockyer, should also file motions opposing FERC's reauthorization of these companies that are draining billions from our economy. Similar filings should be made by each member of California's congressional delegation, plus every major city and county government.

If FERC grants any of these market-based rate reauthorizations, every opposing party should be ready to appeal to federal court. The state of California should bring this matter before a federal judge.

A few good lawyers should be able to prove what most Californians already know — that private power generators are dominating the market. But the window of opportunity here is very short. California's state and local leaders must not miss this chance.

The e his depth from utili Asked Southern Bonbright proposal

Regulation Status

[13] Real-Time Pricing Crucial, Says Tiered-Rate-Design Witness *(from [2])*

Severin Borenstein, director of the University of California Energy Institute, told the California Public Utilities Commission on April 25 that real-time pricing this summer would help the state to avoid dire economic straits. Borenstein offered testimony as one of three expert witnesses in the CPUC's rate design hearings *[A00-11-038 et al.]*.

Without aggressive conservation efforts, Borenstein warned, the state will face a summer of rolling blackouts and power payments that could top $1 billion per week. Payments of that magnitude would erase the state's budget in a week and "burn through" funding necessary to maintain class-size reduction programs for grades K through 3, calculated Borenstein.

"The good news is that it is still possible, albeit with great effort and with some sacrifice, to avoid dire consequences. But I believe this is only possible now only if we recognize the emergency situation and treat it as such. Many months have been wasted bickering over who will shoulder more of the burden. If we don't all start shouldering the burden, the losses to all of California will dwarf the sums that are being discussed in this rate-design proceeding," said the economist.

'Many months have been wasted bickering.'

Rate design must both achieve aggressive conservation and raise enough revenue to cover the costs of buying and producing power, asserted Borenstein.

The economist's proposal for large industrial and commercial customers would give each customer a baseline consumption profile based on past usage. For consumption above baseline in a given hour, customers would be charged the real-time wholesale price, while for any conservation below baseline, customers would be rebated the real-time wholesale price.

While the proposal suggested that real-time pricing be voluntary, Borenstein recommended that it be implemented on a default basis. All customers with real-time meters, which by July should be all customers above 200 KW peak demand, would be on the program but could opt out by signing contracts with private energy brokers. If real-time pricing is implemented on a voluntary basis, Borenstein suggested that customers choose either real-time pricing or the interruptible program.

For large customers without meters, Borenstein said that a whirlwind effort could be made to install meters, using the $35 million allotted in ABx1-29 for meter purchase, installation and related equipment.

In addition, Borenstein recommended a conservation plan for residential and small customers.

Because these customers do not have real-time meters, the plan would use baseline and time-of-use tiers instead of hour-by-hour consumption.

The economist stressed that conservation will help minimize rolling blackouts and will lower wholesale energy costs by reducing both quantities purchased and the price in the market. Analyzing data from June 2000, he noted that during peak demand, around 44,000 MW, the wholesale price was about $700/MW. At those times, a 1 MW increase in demand was associated with a wholesale price increase of more than $0.20/MWh. Since the net short of the utilities was more than 15,000 MW during peak, this meant that buying one more megawatt cost not $700 but that plus another $3,000 (15,000 multiplied by $0.20/MWh) for a total cost of over $3,700/MWh.

"When we consider the economics of conservation, this is the magnitude of costs that can really be saved," said Borenstein.

The previous day, expert witness George Sterzinger, consultant for EER Consulting/Advanced Renewables, also pushed real-time pricing. Sterzinger recommended modifying Enron Energy Service's proposal, which would measure consumption against a benchmark of up to 87 percent of last year's consumption. For consumption above benchmark, Enron proposed charging market rates, while customers consuming below the benchmark would be refunded at market price. Sterzinger recommended that customers consuming less than the benchmark be paid savings over a ten-year period.

Another expert witness, Vermont-based energy and regulatory adviser Peter Bradford, acknowledged that his weekend review of close to 20 rate-design proposals left him little time to analyze them in detail.

"Even if I could master the facts, the charts, the acronyms, I would not possess the sensitivity to the ongoing interactions between the public, the stakeholders and the regulators that is critical to wise and sensitive regulation," said Bradford.

The former Maine Public Utilities Commission chair said the regulation crisis following the Three Mile Island nuclear accident offered important signposts for the current crisis, including the need to review time-tested rate-design principles.

Bradford offered for consideration eight rate-design principles laid down in the 1960s by economist James Bonbright. Two of the three top principles—fairness and encouraging efficient use—mesh with rate-design goals stated in the assigned commissioner's ruling, said Bradford. The third, assurance of recovering rates, is "difficult to implement in the absence of a revenue requirement," said Bradford.

The Sacramento Bee • Friday, April 20, 2001

State might balk on power

But refusing to pay 'ridiculous' prices could add to crisis.

By Dale Kasler
BEE STAFF WRITER

Adding to the risk of summertime blackouts, the state water department said Thursday it might not pay "ridiculous" prices for electricity even if that leaves California short of power.

The Department of Water Resources, which has been buying electricity for the state's two beleaguered utilities since mid-January, wouldn't spell out what it considers ridiculous. But if prices get too high, the state might be better off ordering blackouts or implementing proposed new conservation programs designed at cutting usage on short notice, said Raymond Hart, the department's deputy director in charge of power purchases.

Gov. Gray Davis took a different view, saying: "We will continue to keep the lights on. When you're fighting a forest fire, you don't say, 'Let me see, how much is this going to cost me? Maybe I can't write the check, maybe I can't put the fire out.' You put the fire out and then worry about the cost later."

But Davis' spokesman, Steve Maviglio, said the Governor's Office indeed is contemplating whether to refuse to buy power at any cost. "At what point does the state say, 'Enough is enough'? Those scenarios are certainly under discussion," Maviglio said.

The water department until recently resisted buying all the power Southern California Edison and Pacific Gas and Electric Co. needed, refusing to purchase electricity it deemed too costly. But lately it's had to relax that stance because of an order by the Federal Energy Regulatory Commission, Hart said.

That April 6 order said power generators can no longer be forced to sell electricity to uncreditworthy entities such as the Independent System Operator, which manages the state's power grid. Because the ISO – which gets its money from the utilities – can no longer buy the power, the water department is now buying all the electricity required by the utilities, Hart said. But he said the department could back off if prices get out of hand.

"If the prices just get ridiculous altogether, there's a policy call to be made, and we'll cross that bridge when we get there," Hart said.

The ISO has predicted that severe shortages could bring 34 days of rolling blackouts this summer. The potential refusal of the water department to buy ultra-expensive power could further strain the grid.

"On a daily basis we're dealt a set of cards," said ISO spokesman Patrick Dorinson. "It sounds like ... we're going to be handed another set of cards, and we're going to have to try to maintain the reliability of the grid as best we can."

Hart's comments came amid an increasingly rancorous debate between Davis and PG&E over the water department's power expenditures. State spending shot up following PG&E's April 6 filing for bankruptcy protection.

Davis said generators began demanding a "credit penalty" from the water department because of the PG&E bankruptcy proceedings. As a result, the state's daily costs shot up last week to $73.2 million from $57.4 million in the week before PG&E went bankrupt, the governor's office said.

Hart agreed, saying several generators raised their prices. "Every time there's a major hiccup in the market, such as PG&E bankruptcy or a staged alert by the ISO, there's a price run-up," Hart said.

But prices have settled down this week. After peaking at $345 a megawatt hour April 12, prices for north state power were at $243 on Thursday, just below what they were prior to the bankruptcy filing, according to the Enerfax news service.

PG&E, however, said its bankruptcy filing had nothing to do with the state's increased spending.

"This claim is simply not accurate," the utility said in a memo to reporters.

Rather, the increased spending is due solely to the fact that the water department is buying more units of electricity in the wake of the FERC order, PG&E said.

Regardless of the cause, the increased spending by the water department could further strain the state's budget – and complicate Davis' plan to finance the power purchases through a bond offering.

The state has committed $5.2 billion from its general fund for power purchases since January. Those mounting purchases, along with PG&E's bankruptcy filing and other energy crisis uncertainties, prompted a third Wall Street credit rating agency, Fitch, to place the state on a "ratings watch" this week, meaning the rating might be downgraded.

A downgrade could raise California's borrowing costs. All three of the leading Wall Street credit agencies now have California on a ratings watch.

Meanwhile, the state Public Utilities Commission on Thursday ordered an investigation of why hundreds of cogenerators and other alternative energy providers haven't resumed production even though they've begun receiving payments again from Edison and PG&E.

These generators, under contract to the utilities, provide more than 20 percent of the state's energy supply. Hundreds shut down, worsening California's power situation, because they'd received little or no money from the utilities since November.

The PUC ordered Edison and PG&E to resume payments, starting this week, for new power deliveries.

But the generators say the payments aren't enough to get them back online.

So PUC President Loretta Lynch said the commission will investigate whether to order Edison and PG&E to begin repaying them the hundreds of millions owed for past deliveries.

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The Bee's Dale Kasler can be reached at (916) 321-1066 or dkasler@sacbee.com. Emily Bazar of The Bee's Capitol Bureau contributed to this report.

San Francisco Chronicle
FRIDAY, MAY 4, 2001

The San Diego Union-Tribune • Wednesday, May 2, 2001

GOP explores alternatives to Davis plan

One would see customers get break on covering energy tab

By Ed Mendel
and Karen Kucher
STAFF WRITERS

SACRAMENTO — Assembly Republicans are looking at alternatives to Gov. Gray Davis' solution to the electricity crisis, including an option in which ratepayers would not have to repay the state general fund for $5 billion spent on power purchases so far.

The Republicans are suggesting that letting the state surplus absorb much of the power cost would sharply reduce the size of the $12.5 billion ratepayer bond proposed by Davis, lowering monthly power bills in the decades ahead.

"There are some members of our caucus who believe we ought not to burden the ratepayers with a certain amount of that contribution," said Assembly GOP leader Dave Cox of Fair Oaks.

Davis wants swift approval of a bond of up to $12.5 billion that would be paid off by ratepayers over 15 years. The money would repay the general fund for power purchases and finance long-term power contracts.

But after Assembly and Senate Republicans met yesterday, Cox said the Republicans want to carefully study the numbers and assumptions in a detailed plan for ending the electricity crisis prepared by the governor's consultants.

"We are not going to be stampeded into making a bad business transaction," he said.

The GOP leader said the size of the bond may become a state budget issue as the governor prepares on May 14 to issue a revision of the spending plan he proposed in January for the fiscal year beginning July 1.

Cox also said Assembly Republicans see no need for a $4.1 billion short-term loan sought by state Treasurer Phil Angelides. The "bridge" loan would repay the general fund until the big bond is issued next month or later.

If the state needs cash before the big bond is issued, Cox said, the treasurer's own reports show that the state has up to $12 billion available that can be borrowed from internal sources.

The governor's finance director, Tim Gage, said Monday that a bridge loan would send a signal to Wall Street of a strong financial commitment by the state and help pave the way for the big bond.

"If you forgive the $5 billion, you don't need the bridge loan," Cox said. "You don't need to float a $13 billion bond."

In another development, San Diego Gas & Electric Co. has sued a power generator that shut down three power plants last month that typically produce about 102 megawatts.

The lawsuit, filed Monday, says Sithe Energies refused to operate natural-gas-fueled plants at North Island Naval Air Station, the Marine Corps Recruit Depot and the San Diego Naval Station at 32nd Street because of a regulatory change in the way small generators are paid.

Yesterday, Sithe began to operate the plants again, but SDG&E President Debra Reed said the utility will pursue an injunction to ensure reliable supplies in the summer. Sithe is under contract until 2019.

"Even if they are operating today, we don't have much confidence that they will continue to operate," Reed said.

Sithe spokeswoman Kristin Vellandi said the company was forced to shut down because its fuel costs exceeded what it was paid for power. She said the company is seeking a long-term solution in talks with regulators and SDG&E.

In March, the state Public Utilities Commission cut the price paid for small generators' power. The commission switched the payment benchmark from the price of gas at the Arizona border to the price of gas at the Oregon border, which is significantly lower.

The new formula left many Southern California generators operating at a loss, said Jan Smutney-Jones, executive director of the Independent Energy Producers Association.

San Francisco Chronicle

California municipal bonds are suddenly out of favor

Utility, Internet crises take a toll, but investors are seeing better yields

By Elizabeth Stanton
BLOOMBERG NEWS

BOSTON — Mutual funds that invest solely in municipal bonds issued in California, winners last year as state finances improved and dot-com millionaires diversified, are losers this year because of the state's power crisis and the evaporation of Internet wealth.

In the first quarter, 17 of the 25 worst-performing municipal bond funds were California funds, investing solely in bonds issued in the state, according to Lipper Inc. Last year, 10 of the 25 best-performing muni funds were from California.

California municipal bonds have been hurt by the utility crisis as the state's finances and economic outlook have deteriorated and officials have made plans to issue as much as $14 billion of new muni debt. And while many investors have snapped up bonds this year seeking refuge from a shaky stock market, demand for California municipals from freshly minted Silicon Valley millionaires has evaporated.

"Last year, there was a tremendous amount of demand for (California) munis chasing very limited supply," said Steve Krupa, who manages about $1 billion of California bonds for Nuveen Investments. "This year, there's a tremendous amount of supply with demand leveling off as dot-commers are not worth what they once were," he said.

Municipal bonds, issued by state and local governments to finance public works, are exempt from federal income taxes. Many investors favor bonds issued in their home state because in most cases they are exempt from state income tax as well.

Last year, the average California municipal bond fund gained 13 percent, more than any other single-state fund and more than the 11 percent return on the average multistate fund.

California bonds fared better, in part, because of the state's improving credit ratings.

Moody's Investors Service and Standard & Poor's both upgraded California in September, citing its strong economy and sound finances. "The economy was doing well and they had been budgeting conservatively," said David Hitchcock, director of S&P's state and local government group.

At the same time, the supply of new California bonds declined, falling 14 percent to $22.9 billion, according to Thomson Financial Securities Data Co. The decline in new issues was a nationwide trend led by fewer refinancings.

Muni buyers, many seeking to preserve gains on their stock portfolios, were plentiful.

"Last year at this time, we were hearing about inquiries that John Dot-Com wanted a laddered portfolio of $100 million bonds for his own account and was relatively price-insensitive," Nuveen's Krupa said.

Now, rating agencies are rethinking those September upgrades, supply is threatening to jump, and the $100 million buyers aren't coming around anymore.

Standard & Poor's and Moody's have slapped negative outlooks on their rating of the state. "The power crisis has increased the risks to the state's current fiscal and economic condition," said Ray Murphy, a vice president at Moody's.

California has authorized its Department of Water Resources to issue as much as $14 billion of municipal bonds to fund power purchases. The prospect of so much fresh supply has hurt prices of existing bonds, Nuveen's Krupa said.

Yields on California general obligation bonds, which were 0.3 percentage point below those on generic AAA-rated bonds late last year, are now 0.1 percentage point above. California muni bond funds gained an average of 1.4 percent in the first quarter, the poorest performance of any single-state category.

Among the worst, Dreyfus California Tax-Exempt Bond, which last year gained 15 percent, making it one of the best-performing municipal bond funds, lost 0.29 percent during the first quarter.

Some funds suffered the additional injury of holding California muni bonds backed by the troubled utilities. For example, Franklin California Tax-Free Income Fund, the largest municipal bond fund with $13.8 billion, holds a revenue bond issued by the Oroville Wyandotte Irrigation District that is an obligation of Pacific Gas and Electric Co. The company has not defaulted on the bonds, which account for less than one-tenth of 1 percent of the Franklin fund, but they have fallen in price.

The relatively poor performance of California bonds this year represents an opportunity in Krupa's view. The power crisis "is going to work itself out," he said. In the meantime, investors can buy California bonds and bond mutual funds at higher yields than they could four months ago.

"We still see California as a very sound investment," Krupa said.

San Francisco Chronicle SUNDAY, APRIL 22, 2001

Blackouts alone could cost billions

State's economy will take big hit, business group says

By Sam Zuckerman
CHRONICLE ECONOMICS WRITER

Blackouts could wallop California's economy to the tune of $16 billion this summer, far worse than the hit from higher power prices, a new study of the energy crisis contends.

The report, released yesterday by the government- and business-funded Bay Area Economic Forum, is one of the first attempts to put a price tag on power interruptions as distinct from the effects of electricity price increases.

For the Bay Area alone, the study forecasts that blackouts could reduce the annual output of goods and services by as much as $5 billion and trim economic growth by as much as 1 percent as factories, offices and laboratories are temporarily idled. That dwarfs the $500 million loss to the area economy the report estimates would result from a 50 percent jump in commercial energy rates.

THE ENERGY CRUNCH

"Although higher prices present a significant risk to the Bay Area economy, the lack of a reliable power supply is a much more serious threat," the report concludes.

Energy experts predict that the state will face at least 34 days of rolling blackouts this summer, when demand will rise as air conditioners are cranked up in homes, schools and workplaces.

The report concludes that consumers and businesses must pay higher prices to encourage conservation and ensure that electricity supplies are adequate. "While revising electricity rates is a politically charged issue, it is apparent that significant increases will be necessary to make up for the shortfall of the past year and accurately reflect the higher cost of energy," the report argues.

"It is clear ... that the Bay Area economy and the state can absorb significant rate increases if allocated equitably," the study adds.

The Forum's report reflects the views of big businesses in the Bay Area, especially Silicon Valley's technology community, which need dependable electricity supplies to power sensitive operations.

"Steady, reliable power is absolutely essential," said Don McIntosh, facilities director for Sunnyvale chipmaker Advanced Micro Devices, about the report's findings. "The cost of energy is much less important to us than reliability of energy."

AMD's main production facilities are located outside the Bay Area, but it does operate a design center and an experimental chip-making facility here.

Potential disaster

"A one-hour loss of power would be disastrous for us," said McIntosh. "You have the potential for ruining an entire batch of (silicon) wafers. In addition, it could take up up to three days to recalibrate all the tools."

To guarantee its electrical supply, AMD built a power substation drawing directly from Pacific Gas and Electric Co. transmission lines about 10 years ago.

Until now, that substation was exempt from blackouts. But under emergency rules set to take effect, the station will lose its exemption. AMD is currently looking at other ways to deliver uninterrupted power to its chip facility this summer.

While stressing the dire effects on businesses, the report concedes that most residential users aren't as vulnerable. For them, "blackouts are largely a matter of inconvenience."

The Bay Area Economic Forum and its partners are using the shock value of the report's big blackout cost projections to press their argument that supply is more important than price.

"Reliability is paramount. The economic numbers say so," said Justin Bradley, director of energy programs for the Silicon Valley Manufacturing Group, which helped produce the study.

Estimates questioned

But several economists said they are skeptical about the report's blackout cost estimate. They say it's wrong to assume that there is a 1-to-1 relationship between economic activity and energy use. In many case, business lost during blackouts could be regained later, they point out.

The report's blackout calculation "is pretty crude," said Mark Bernstein, an energy specialist with Rand, the Southern California research group.

Still, experts agreed with the report's overall conclusion that an unreliable electricity supply is a greater economic threat than higher prices. "I certainly think ... that the reliability issue is more serious," said Tom Lieser, an economic forecaster at the business school of the University of California at Los Angeles. But consumer groups are suspicious of claims that rate increases are needed to guarantee electricity supply. Higher prices, they contend, will simply support price-gouging by power producers and will not significantly add to supply.

"They are giving us the choice of darkness or higher rates," said Nettie Hoge, director of The Utility Reform Network in San Francisco. "In fact, we're going to get both."

How estimates were calculated

To calculate the effect of blackouts, the report's authors, a team from the consulting firm McKinsey & Co., measured the relationship between electricity consumption and economic growth.

They found that for every $16,000 increase in output of goods and services in California, an additional megawatt hour of electricity is consumed. Hence, they said, a blackout that deprived users of 5,000 megawatts of power would reduce output by roughly $75 million to $100 million.

Depending on the frequency and severity of blackouts this summer, the total loss to the California economy could range from $2 billion to $16 billion, the study concluded.

The study focused on the Bay Area and did not calculate the statewide effect of rate increases for businesses. Locally, the $500 million loss it projects represents less than 1 percent of the region's $350 billion annual output of goods and services. That translates into a loss of about 15,000 area jobs over the next three years.

A 30 percent higher residential rate combined with the increases for businesses would trim the disposable income of area households by $750 million to $1.2 billion, a drop of one-third of a percentage point, the report estimates.

Such a small hit suggests "there may be some room for residents to pay higher rates," the study claims.

E-mail Sam Zuckerman at szuckerman@sfchronicle.com.

CEM

FT
FINANCIAL TIMES Energy

.nursday, May 31, 2001

MegawattDaily

From the publisher of Gas Daily® and Coal Outlook

Massey calls for inquiry into market power methodology

FERC Commissioner William Massey, dissenting from two orders yesterday, strongly called for the commission to give up its current method of market power analysis.

"Our current standard is just plain outdated, inadequate and unreliable," Massey said.

Massey has previously attacked the "hub-and-spoke" method of market power analysis, which presumes market power if any single market participant holds a 20% market share.

In April, Pacific Gas & Electric and Southern California Edison made a similar argument in asking FERC to deny renewal of market-based rate authority to Williams Energy Marketing and Trading *(MWD 4/4)*. The two utilities argued that while Williams controls less than 20% of the generation resources in the state, it is still able to exercise market power. To renew its market-based rate authority, Williams should perform an analysis of market power using other means, the utilities said.

Massey said the events of the California wholesale power market — where no single generator or power seller holds close to 20% market share — during the past year indicate that market power can be exercised by any player holding a much smaller piece. The "20-percent share threshold is too simplistic," he said.

In one decision issued yesterday in draft form, the commission granted market-based rate authority to Sierra Southwest Cooperative

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INSIDE THE MARKET REPORT

WESTERN MARKETS:

❑ Dailies rise to upper $100s

Drop in imports forces California into emergency 4

CENTRAL MARKETS:

❑ Dailies sink to teens, $20s

Entergy lands at $25 4

EASTERN MARKETS:

❑ Cinergy takes a beating

TVA barely moves in the teens 5

Key Hub Trades for Standard 16-Hour Daily Products

Weighted average index prices (in $/MWh) and volumes are shown for selected major hubs. More detailed price information is available on page X.

Delivery Point	Weighted Average Index	Trading Volume Reported
COB	180.20	125
Mid-Columbia	176.67	1,425
⁻alo Verde	175.64	1,375
?COT-B	35.12	1,500
⌣om Ed	16.57	350
Entergy	27.24	5,150
Cinergy	17.22	9,620
PJM	24.25	5,600
TVA	17.74	1,450

Bush, Davis agree to disagree on price caps

President Bush and California Gov. Gray Davis have a "fundamental disagreement over whether or not California is entitled to price relief," Davis said after the two met privately in Los Angeles on Tuesday to discuss the state's energy crisis.

Despite intensified arguments that continuing high wholesale power prices will hurt California and the larger U.S. economy, Davis was unable to persuade Bush to support temporary price controls in the state.

Bush again declined Davis' requests for caps on power prices. But California is legally "entitled" to price caps, Davis argued during a press briefing following his meeting with Bush.

"The president did not create this problem," Davis said of the power crisis. "Like me, he inherited a mess." Davis has lately stuck to his message that California is doing all it can to bring new power plants online and to reduce consumption.

The governor, who acknowledged the president's efforts in other areas to help California, said he and Bush have a "fundamental disagreement" over the issue of price caps. Davis said caps are necessary for California, which is short generation and could pay $50 billion to $70 billion this year for its

(Continued on page 7)

State regulators add views to Bush energy plan

Utility regulators from 13 states this week issued a set of national electricity policy recommendations directed at both state and federal lawmakers and officials.

"We feel timing is critical," Montana Public Service Commissioner Bob Anderson, leader of the effort, said. "President Bush issued his energy policy recommendations recently, and we commend him for it. Our recommendations will complement his and enrich the policy debate."

The report identifies seven principal policy areas. "These comprehensive policies present a balance between supply and demand, while recognizing the important role of energy efficiency, as well as environmental and consumer protection," Anderson said.

Policy-makers should improve existing generation technologies to increase efficiency and minimize environmental impact, the report says. Policies also should promote fuel diversity including "green" power sources.

To ensure reliability, transmission and distribution, companies should provide "adequate and efficient generation," the report says. Delivery companies also should provide a certain minimum level of reliability to all customers "as a part of basic electric service."

Because 95% of customer outages re-

(Continued on page 2)

Davis ready to take his case to court ... *(from page 1)*

wer purchases. Davis told Bush he would "pursue every recourse available" to "ensure that markets are functional and rates are just and reasonable."

Davis also said he hoped Bush would communicate to the two new FERC members "that California is entitled to price relief."

So far, federal regulators have taken steps to ensure a competitive power market in the long term, but they have refused to implement short-term caps.

In a meeting that Davis described as "cordial," the governor said he informed the president that he would do all he could to fight for Californians against high power prices charged by generators that Davis accuses of market manipulation.

Davis indicated that action would include lodging a lawsuit against the regulators at FERC. The agency's legal mandate is to ensure that power prices are "just and reasonable," and FERC ruled in a December order that the market was not competitive.

In that order and in subsequent actions, FERC implemented a series of measures aimed ironing out faults in California's market .ucture and at limiting wholesale prices during power emergencies.

Davis and other state officials claim those actions have failed to limit price spikes and will not help the state avoid blackouts and high costs for power this summer. Three state agencies and the state Assembly have filed petitions within the last few days requesting a rehearing of the agency's latest order on price mitigation measures during power emergencies.

Speaking after his meeting with Bush, Davis indicated those filings are the first step in a legal process that could result in lawsuits against FERC. The state must first exhaust all legal and procedural remedies with FERC before turning to the courts, he said.

A lawsuit filed last week in federal court by senior Democrats in the state Senate and Assembly was dismissed Tuesday because those legislators had not first gone through all appeals channels directly available with FERC, Davis said. A three-judge panel at the Ninth Circuit Court of appeals dismissed the .tion, saying only that the "petitioners have not demonstrated that this case warrants the intervention of this court."

FERC Chairman Curt Hebert seemed unfazed at the prospect of Davis' threatened legal action.

"I think the Ninth Circuit made it clear, FERC is doing our job appropriately," Hebert said at yesterday's commission meeting.

In addition to legal remedies to force federal regulators to act, Davis also pointed to Senate Democrats, who will take control of that body early next month, as potential partners who could help California by approving price cap legislation. California's Democratic senators, Dianne Feinstein and Barbara Boxer, have both introduced bills that would impose price caps in Western markets.

"I'm looking forward to working with the newly constituted United States Senate to make sure that the problems of California and the West ... get a full airing," Davis said.

Davis attempted to sway Bush in favor of price caps by arguing that a crisis-damaged California economy will hurt the nation and that the federal government is required by law to ensure reasonable rates.

But Bush, who has been steadfastly against price caps, explained his opposition to the caps in a speech at the World Affairs Council in Los Angeles. He also noted that the Clinton administration did not call for the imposition of price caps.

"We will not take any action that makes California's problems worse, and that's why I oppose price caps," Bush said. "Price caps do nothing to reduce demand, and they do nothing to increase supply. This is not only my administration's position, this was the position of the prior administration."

The president said his administration would help California by expanding the state's main north-south transmission line, Path 15; requiring federal facilities in the state to reduce demand 10%; and providing additional funding to low-income consumers to help offset rising electricity and gas prices.

The president also told Davis that he would dispatch newly installed FERC Commissioner Pat Wood, the former head of the Public Utility Commission of Texas, to California to investigate why natural gas prices are higher in the state than in other parts of the country.

Davis called Bush's offer "good news" and said the president agreed with him that it "made little sense for California to receive Texas natural gas at roughly $15 per British thermal unit, when New York is receiving the same gas at roughly $5.95 per British thermal unit."

The president wants Wood "to see if there is market manipulation" in the California natural gas market and "to review the wisdom of the Federal Energy Regulatory Commission's decision two years ago," when, Davis said, FERC suspended a tariff that controlled the transportation prices of natural gas when it flows from Texas to other parts of the country. MS/ADP

Energy economists to testify on market manipulation

California legislators will hear testimony later today from two prominent energy economists on allegations that power generators have colluded to drive up prices in the state's wholesale power markets.

Severin Borenstein and Alfred Kahn are scheduled to testify before the state Senate's Select Committee to Investigate Price Manipulation of the Wholesale Energy Market. Kahn may address issues of physical withholding of power supplies by generators, while Borenstein would likely brief senators on economic models exhibiting generators' ability to exercise market power to raise prices, a representative of committee Chairman Joseph Dunn indicated.

The select committee has taken testimony in three earlier hearings from state energy officials on plant outages and their effect on prices. Within the next several weeks, the committee also plans to hear from generators, according to the representative.

The "big five" out-of-state generators — Duke, Dynegy, Reliant, Williams/AES and Mirant — will be invited to give their side of the story, as will energy marketer Enron, he said. Those companies have been repeatedly accused by state officials of gouging consumers and engaging in illegal activity.

Borenstein, Kahn and eight other economists last week co-signed a letter to President Bush arguing for the imposition of short-term price caps on wholesale markets. The economists asserted that the failure of deregulation in California could harm the development of competitive electricity markets across the nation. ADP

FT
FINANCIAL TIMES Energy

Thursday, June 14, 2001

MegawattDaily

From the publisher of Gas Daily® and Coal Outlook

Calif. inks deal with QFs, will release details on long-term contracts

California officials have reached agreements with two groups of small generators that will return the full amount of power contracted by those facilities back to the market, adding between 100 MW and 300 MW of additional power to the state's grid this summer, Gov. Gray Davis said yesterday.

Contracts signed with two groups of qualifying facilities establish new prices for the power they will supply to the second largest investor-owned utility in the state, Southern California Edison, Davis said.

The deals also provide for marginal payment of back debts owed by the utility to the generators, provided the individual facilities produce additional energy at their facilities.

But the effective date of the agreed-to prices is linked to approval by the state Legislature of an agreement between SoCalEd's parent company and the state. The memorandum of understanding between Davis and Edison International would pave the way for the state's purchase of the utility's power lines.

Negotiations between the state and the QFs have resulted in bringing 95% of the power produced by those generators back onto the market, Davis said. Numerous QFs had been withholding their output from the market in protest over nonpayment of past bills by California's largest utilities.

The output of QFs serves up to one-third of California's total

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INSIDE THE MARKET REPORT

WESTERN MARKETS:

❑ Prices hold

Good supply, weather avert increases 4

CENTRAL MARKETS:

❑ Dailies fall back

Weather cools 4

EASTERN MARKETS:

❑ Dailies soften

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Key Hub Trades for Standard 16-Hour Daily Products 06/14/01

Weighted average index prices (in $/MWh) and volumes are shown for selected major hubs. More detailed price information is available on page 3.

Delivery Point	Weighted Average Index	Trading Volume Reported
COB	57.33	75
Mid-Columbia	56.20	2,100
Palo Verde	62.59	2,025
ERCOT-B	41.17	1,950
ComEd	49.10	2,050
Entergy	51.98	5,900
Cinergy	53.44	11,000
PJM	55.26	8,750
TVA	52.28	2,000

Cheney, Hebert hold firm on energy policy

Vice President Dick Cheney and FERC Chairman Curt Hebert both pledged yesterday to stay the course when it comes to energy policy. But while both men faced a friendly audience at the Energy Efficiency Forum yesterday at the National Press Club in Washington, their remarks seemed aimed more at winning over a skeptical audience in California.

Cheney and Hebert emphasized the importance of market remedies — and reaffirmed their opposition to price controls. Hebert, for one, was adamant that recent FERC measures would suffice to create a better-functioning market out West.

"California does not mean an end to competition," he said.

Cheney repeated the main selling points of the administration's recently introduced national energy policy. And while he warned of the possible economic impact of the current supply situation, the vice president said that the nation's energy problems could be fixed with a dose of "resolve, ingenuity and clarity of purpose."

The remedies that Cheney listed include the construction of a new gas pipeline that would run from Alaska's North Slope, a proposal that Cheney called "relatively non-

(Continued on page 7)

FERC clears National Grid purchase of NiMo

With a specific provision on accounting procedures, FERC yesterday approved New York-based Niagara Mohawk Holdings' proposed acquisition by National Grid USA, the U.S. branch of the British transmission utility.

National Grid USA, which operates two transmission and distribution utilities in New England, offered to buy NiMo last September in a $3 billion cash and stock transaction that includes assumption of $5.9 billion in NiMo debt *(MWD 9/6/00)*. NiMo serves 1.5 million electricity and 540,000 natural gas customers in upstate New York.

The combined company, which would be a new holding company registered in the United Kingdom under the name National Grid Group (the same name as the existing overall company), would serve 3.3 million electricity customers in the United States, placing it among the top 10 in terms of customers served.

NiMo will continue as the local utility and will remain under the regulations of New York state.

Both companies have sold substantially all of their generation assets — NiMo's major remaining asset, its interests in the Nine Mile Point nuclear plants, has been committed to Constellation Energy Group — so FERC found no competitive market issues there.

(Continued on page 2)

Avista Corporation
2001 Load and Estimated Variability

	Avg (aMW)	Jan (aMW)	Feb (aMW)	Mar (aMW)	Apr (aMW)	May (aMW)	Jun (aMW)	Jul (aMW)	Aug (aMW)	Sep (aMW)	Oct (aMW)	Nov (aMW)	Dec (aMW)
Average Load (1)	965.1	1,147.0	1,108.9	975.4	906.6	861.9	867.7	911.1	956.5	864.0	910.4	1,001.0	1,078.0
80% CI (2)	43.5	86.9	67.6	40.4	36.1	12.3	35.5	39.0	45.7	20.6	33.2	49.0	56.5
95% CI (2)	67.3	134.5	104.7	62.5	55.8	19.0	54.9	60.4	70.8	31.9	51.5	75.8	87.4

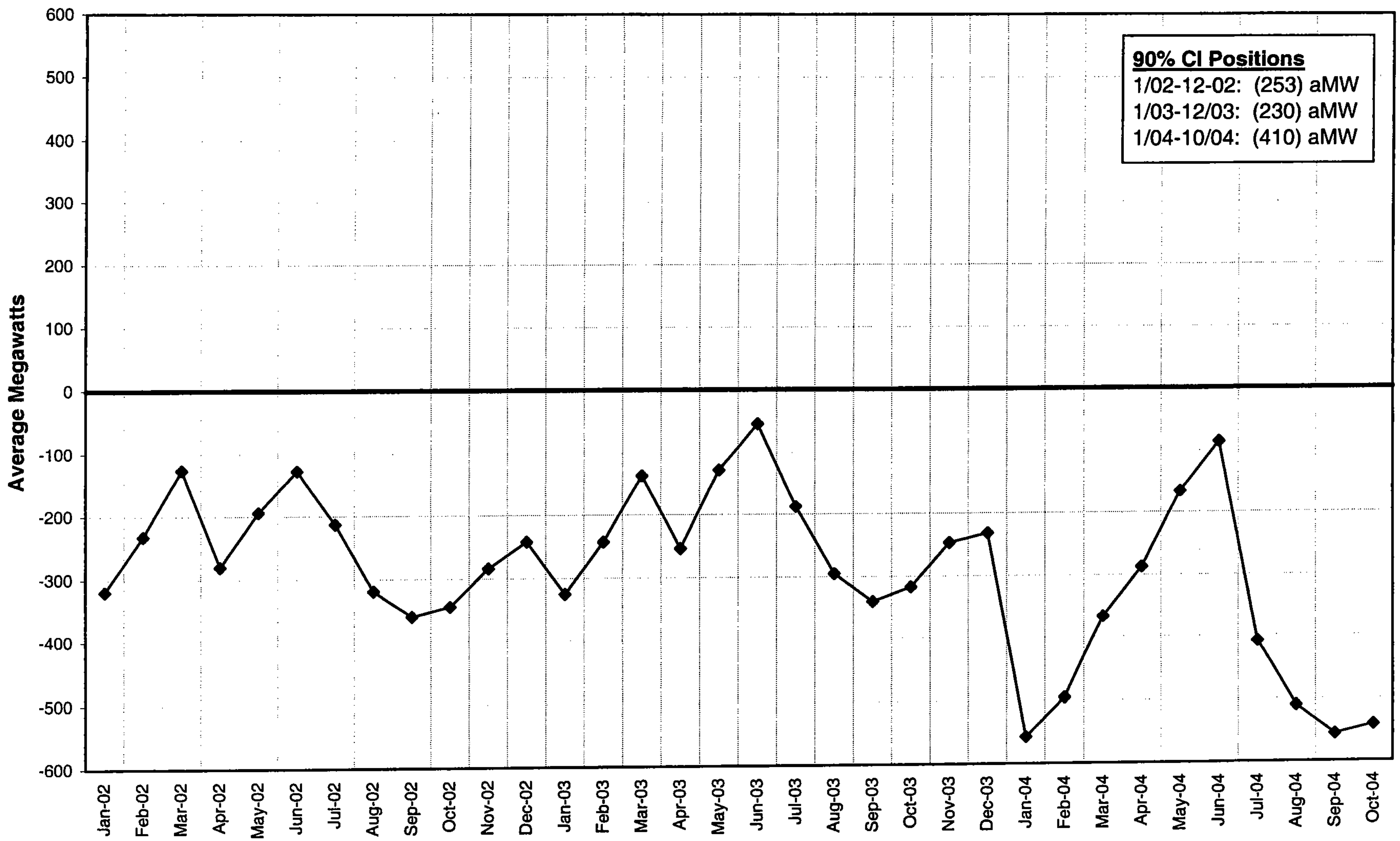
(1) Jan-Oct actuals including full Potlatch load, Nov-Dec values are estimated with 93 aMW of Potlatch lad

(2) average of weekly weekly confidence interval values

Load & Resource Position Summary - Excluding Un-Hedged Natural Gas-Fired Generation

90% Confidence Interval (Load & Hydro Variability)

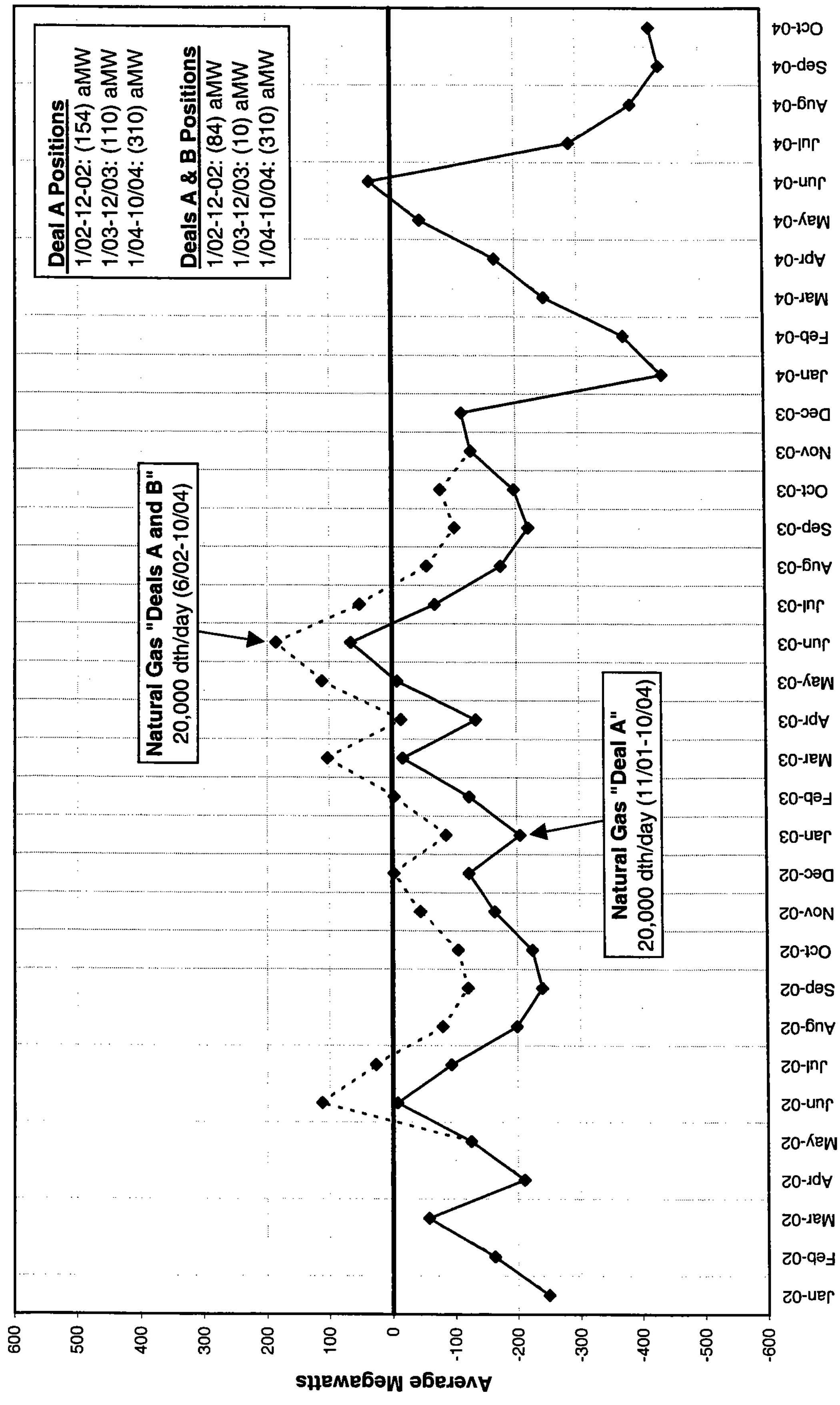
As of 3/30/01



Load & Resource Position Summary - Including Hedged Gas-Fired Generation

90% Confidence Interval (Load & Hydro Variability)

Including Deals A & B Fixed Price Fueled Turbines, as of 3/30/01



Comparison of Hedge Price vs. Forward Curve

Delivery Period	NYMEX ($/Dth)	Malin ($/Dth)	Gas Hedge Transaction @ Malin ($/Dth)
6/1/2002	4.70	7.20	6.50
7/1/2002	4.73	7.23	6.50
8/1/2002	4.74	7.24	6.50
9/1/2002	4.71	7.21	6.50
10/1/2002	4.71	7.21	6.50
11/1/2002	4.83	7.11	6.50
12/1/2002	4.93	7.21	6.50
1/1/2003	4.96	7.24	6.50
2/1/2003	4.79	7.07	6.50
3/1/2003	4.55	6.83	6.50
4/1/2003	4.25	4.70	6.50
5/1/2003	4.19	4.64	6.50
6/1/2003	4.21	4.66	6.50
7/1/2003	4.23	4.68	6.50
8/1/2003	4.26	4.71	6.50
9/1/2003	4.25	4.70	6.50
10/1/2003	4.25	4.70	6.50
	Averages:	6.14	6.50

Comparison of Hedge Price vs. Forward Curve

Delivery Period	NYMEX ($/Dth)	Malin ($/Dth)	Gas Hedge Transaction @ Malin ($/Dth)
11/1/2001	5.65	9.15	6.75
12/1/2001	5.77	12.27	6.75
1/1/2002	5.81	13.11	6.75
2/1/2002	5.63	11.38	6.75
3/1/2002	5.29	9.29	6.75
4/1/2002	4.73	7.13	6.75
5/1/2002	4.59	6.99	6.75
6/1/2002	4.60	7.00	6.75
7/1/2002	4.64	7.04	6.75
8/1/2002	4.64	7.04	6.75
9/1/2002	4.62	7.02	6.75
10/1/2002	4.62	7.02	6.75
11/1/2002	4.74	7.02	6.75
12/1/2002	4.85	7.13	6.75
1/1/2003	4.88	7.16	6.75
2/1/2003	4.70	6.98	6.75
3/1/2003	4.46	6.74	6.75
4/1/2003	4.17	4.72	6.75
5/1/2003	4.11	4.66	6.75
6/1/2003	4.12	4.67	6.75
7/1/2003	4.15	4.70	6.75
8/1/2003	4.17	4.72	6.75
9/1/2003	4.16	4.71	6.75
10/1/2003	4.16	4.71	6.75
11/1/2003	4.27	4.67	6.75
12/1/2003	4.39	4.79	6.75
1/1/2004	4.43	4.83	6.75
2/1/2004	4.31	4.71	6.75
3/1/2004	4.17	4.57	6.75
4/1/2004	4.03	4.43	6.75
5/1/2004	4.07	4.47	6.75
6/1/2004	4.08	4.48	6.75
7/1/2004	4.11	4.51	6.75
8/1/2004	4.13	4.53	6.75
9/1/2004	4.12	4.52	6.75
10/1/2004	4.12	4.52	6.75
	Averages:	6.32	6.75

Comparison of Hedge Price vs. Forward Curve

Delivery Period	NYMEX ($/Dth)	Malin ($/Dth)	Gas Hedge Transaction @ Malin ($/Dth)
11/1/2001	4.88	7.38	5.85
12/1/2001	5.05	11.55	5.85
1/1/2002	5.12	11.62	5.85
2/1/2002	5.00	7.00	5.85
3/1/2002	4.79	5.79	5.85
4/1/2002	4.44	5.64	5.85
5/1/2002	4.37	5.57	5.85
6/1/2002	4.41	5.61	5.85
7/1/2002	4.46	5.66	5.85
8/1/2002	4.50	5.70	5.85
9/1/2002	4.50	5.70	5.85
10/1/2002	4.51	5.71	5.85
11/1/2002	4.65	5.90	5.85
12/1/2002	4.78	6.03	5.85
1/1/2003	4.83	6.08	5.85
2/1/2003	4.67	5.92	5.85
3/1/2003	4.46	5.71	5.85
4/1/2003	4.17	4.67	5.85
5/1/2003	4.12	4.62	5.85
6/1/2003	4.15	4.65	5.85
7/1/2003	4.19	4.69	5.85
8/1/2003	4.22	4.72	5.85
9/1/2003	4.22	4.72	5.85
10/1/2003	4.23	4.73	5.85
11/1/2003	4.34	4.94	5.85
12/1/2003	4.48	5.08	5.85
1/1/2004	4.54	5.14	5.85
2/1/2004	4.42	5.02	5.85
3/1/2004	4.28	4.88	5.85
4/1/2004	4.11	4.51	5.85
5/1/2004	4.08	4.48	5.85
6/1/2004	4.11	4.51	5.85
7/1/2004	4.15	4.55	5.85
8/1/2004	4.18	4.58	5.85
9/1/2004	4.18	4.58	5.85
10/1/2004	4.19	4.59	5.85
	Averages:	5.62	5.85

Comparison of Hedge Price vs. Forward Curve

Delivery Period	NYMEX ($/Dth)	Malin ($/Dth)	Gas Hedge Transaction @ Malin ($/Dth)
6/1/2002	4.19	5.44	5.35
7/1/2002	4.24	5.49	5.35
8/1/2002	4.25	5.50	5.35
9/1/2002	4.26	5.51	5.35
10/1/2002	4.28	5.53	5.35
11/1/2002	4.42	5.42	5.35
12/1/2002	4.55	5.55	5.35
1/1/2003	4.60	5.60	5.35
2/1/2003	4.45	5.45	5.35
3/1/2003	4.26	5.26	5.35
4/1/2003	3.96	4.51	5.35
5/1/2003	3.93	4.48	5.35
6/1/2003	3.97	4.52	5.35
7/1/2003	4.02	4.57	5.35
8/1/2003	4.07	4.62	5.35
9/1/2003	4.09	4.64	5.35
10/1/2003	4.10	4.65	5.35
	Averages:	5.10	5.35

Avista Utilities
2001-2002 Medium-Term Electric Power Purchases

Value of Medium-term Purchases in Idaho Authorized Rates

Delivery Month	HLH	LLH	DJ Index Mid C HLH $/MWh	DJ Index Mid C LLH $/MWh	Mid C Flat $/MWh	Deal #1 Flat MW	Deal #1 Flat $/MWh	Deal #2 Flat MW	Deal #2 Flat $/MWh	Deal #3 On-Peak MW	Deal #3 On-Peak $/MWh	Deal #4 On-Peak MW	Deal #4 On-Peak $/MWh
Jul-00	400	344	$126.55	$65.94	$98.53	50	$14.65	50	$24.65			25	$17.25
Aug-00	432	312	$206.47	$92.62	$158.73	50	$14.65	50	$24.65	50	$20.61	25	$17.25
Sep-00	400	320	$129.50	$86.47	$110.38	50	$14.65	50	$24.65	50	$20.61	25	$17.25
Oct-00	416	329	$103.51	$84.50	$95.11	50	$14.65	50	$24.65	50	$20.61	25	$17.25
Nov-00	400	320	$172.07	$143.41	$159.33	50	$14.65	50	$24.65	50	$20.61	25	$17.25
Dec-00	400	344	$565.46	$441.74	$508.26	50	$14.65	50	$24.65	50	$20.61	25	$17.25
Jan-01	416	328	$273.28	$237.14	$257.35	50	$14.65	50	$24.65	50	$20.61	25	$17.25
Feb-01	384	288	$283.82	$256.53	$272.12	50	$14.65	50	$24.65	50	$20.61	25	$17.25
Mar-01	432	312	$279.80	$225.55	$257.05	50	$14.65	50	$24.65	50	$20.61	25	$17.25
Apr-01	400	319	$310.77	$250.36	$283.97	50	$14.65	50	$24.65			25	$17.25
May-01	416	328	$262.02	$152.74	$213.84	50	$14.65	50	$24.65			25	$17.25
Jun-01	416	304	$69.98	$48.39	$60.86	50	$14.65	50	$24.65			25	$17.25

	Deal #1		Deal #2		Deal #3		Deal #4
Term:	4 years	Term:	2 years	Term:	5 years	Term:	3 years
Start Date:	7/1/1997	Start Date:	7/1/1999	Start Date:	8/1/1997	Start Date:	1/1/1999
End Date:	6/30/2001	End Date:	6/30/2001	End Date:	3/31/2002	End Date:	12/31/2001

Delivery Month	Value Deal #1 Flat	Value Deal #2 Flat	Value Deal #3 On-Peak	Value Deal #4 On-Peak	Value Total
Jul-00	$3,120,188	$2,748,188	$0	$1,093,000	$6,961,376
Aug-00	$5,359,644	$4,987,644	$4,014,576	$2,043,576	$16,405,440
Sep-00	$3,446,120	$3,086,120	$2,177,800	$1,122,500	$9,832,540
Oct-00	$2,997,321	$2,624,821	$1,724,320	$897,104	$8,243,565
Nov-00	$5,208,560	$4,848,560	$3,029,200	$1,548,200	$14,634,520
Dec-00	$18,362,148	$17,990,148	$10,897,000	$5,482,100	$52,731,396
Jan-01	$9,028,340	$8,656,340	$5,255,536	$2,662,712	$25,602,928
Feb-01	$8,651,136	$8,315,136	$5,053,632	$2,559,072	$24,578,976
Mar-01	$9,017,280	$8,645,280	$5,598,504	$2,835,540	$26,096,604
Apr-01	$9,681,975	$9,322,475	$0	$2,935,200	$21,939,649
May-01	$7,409,972	$7,037,972	$0	$2,545,608	$16,993,552
Jun-01	$1,663,712	$1,303,712	$0	$548,392	$3,515,816
Total	$83,946,395	$79,566,395	$37,750,568	$26,273,004	**$227,536,362**

Delivery Month	HLH	LLH	DJ Index Mid C HLH $/MWh	DJ Index Mid C LLH $/MWh	Mid C Flat $/MWh	Deal #5 Flat MW	Deal #5 Flat $/MWh	Net Benefit $/MWh	Net Benefit
Jul-00	400	344	$126.55	$65.94	$98.53	190	$29.40	$69.13	$9,771,654
Aug-00	432	312	$206.47	$92.62	$158.73	190	$29.40	$129.33	$18,281,587
Sep-00	400	320	$129.50	$86.47	$110.38	190	$29.40	$80.98	$11,077,456
Oct-00	416	329	$103.51	$84.50	$95.11	190	$29.40	$65.71	$9,301,955
Nov-00	400	320	$172.07	$143.41	$159.33	190	$29.40	$129.93	$17,774,728
Dec-00	400	344	$565.46	$441.74	$508.26	190	$29.40	$478.86	$67,691,102
Jan-01	416	328	$273.28	$237.14	$257.35	190	$29.40	$227.95	$32,222,632
Feb-01	384	288	$283.82	$256.53	$272.12	190	$29.40	$242.72	$30,991,037
Mar-01	432	312	$279.80	$225.55	$257.05	190	$29.40	$227.65	$32,180,604
Apr-01	400	319	$310.77	$250.36	$283.97	0			
May-01	416	328	$262.02	$152.74	$213.84	0			
Jun-01	416	304	$69.98	$48.39	$60.86	0			
Jul-01	400	344	$60.61	$39.90	$51.03	190	$29.40	$21.63	$3,058,240
Aug-01	432	312	$45.49	$29.58	$38.82	190	$29.40	$9.42	$1,331,338
Sep-01	384	336	$24.11	$20.26	$22.31	190	$29.40	-$7.09	-$969,456
Oct-01	432	313	$26.00	$21.17	$23.97	190	$29.40	-$5.43	-$768,510
Nov-01	400	320	$23.44	$20.01	$21.92	190	$29.40	-$7.48	-$1,023,872
Dec-01	400	344	$25.76	$21.23	$23.67	190	$29.40	-$5.73	-$810,631
Jan-02	416	328	$19.53	$17.04	$18.43	190	$29.40	-$10.97	-$1,550,400
Feb-02	384	288	$20.80	$19.22	$20.12	190	$29.40	-$9.28	-$1,184,506
Mar-02	416	328	$35.51	$31.92	$33.93	190	$29.40	$4.53	$639,981
Apr-02	416	303	$21.04	$16.20	$19.00	0			
May-02	416	328	$21.13	$15.00	$18.43	0			
Jun-02	400	320	$9.37	$4.18	$7.06	0			
Jul-02	416	328	$10.82	$7.82	$9.50	190	$29.40	-$19.90	-$2,813,429
Aug-02	432	312	$18.11	$16.59	$17.47	190	$29.40	-$11.93	-$1,686,060
Sep-02	384	336	$25.58	$22.74	$24.25	190	$29.40	-$5.15	-$703,882
Oct-02	432	313	$30.51	$24.43	$27.96	190	$29.40	-$1.44	-$204,457
Nov-02	400	320	$31.61	$28.09	$30.05	190	$29.40	$0.65	$88,312
Dec-02	400	344	$40.08	$32.00	$36.34	190	$29.40	$6.94	$981,616
Jan-03	416	328	$38.14	$32.36	$35.59	190	$29.40	$6.19	$875,277
Feb-03	384	288	$52.22	$44.93	$49.10	190	$29.40	$19.70	$2,514,749
Mar-03	416	328	$47.43	$42.23	$45.14	190	$29.40	$15.74	$2,224,657
Apr-03	416	303	$32.66	$29.66	$31.40	0			
May-03	416	328	$32.56	$21.83	$27.83	0			
Jun-03	400	320	$35.52	$24.79	$30.75	0			
Jul-03	416	328	$47.15	$39.66	$43.85	190	$29.40	$14.45	$2,042,363
Aug-03	416	328	$41.97	$36.05	$39.36	190	$29.40	$9.96	$1,407,961
Sep-03	400	320	$42.19	$33.39	$38.28	190	$29.40	$8.88	$1,214,632
Oct-03	432	313	$37.41	$30.23	$34.39	190	$29.40	$4.99	$706,821
Nov-03	384	336	$37.02	$32.07	$34.71	190	$29.40	$5.31	$726,408
Dec-03	416	328	$40.61	$36.52	$38.81	190	$29.40	$9.41	$1,329,757
Total									$236,719,664

Avista Utilities
2001-2002 Medium-Term Electric Power Purchases

Quantity	Delivery	Price	Term	Start Date	End Date
25	Flat	$30.50	3 years	01/01/04	12/31/06
25	Flat	$28.00	3 years	01/01/04	12/31/06
25	Flat	$28.00	3 years	01/01/04	12/31/06
25	Flat	$31.75	3 years	01/01/04	12/31/06
25	Flat	$31.00	4 years	01/01/07	12/31/10
25	Flat	$30.80	4 years	01/01/07	12/31/10
25	Flat	$30.40	4 years	01/01/07	12/31/10
25	Flat	$34.50	4 years	01/01/07	12/31/10

	Hours	Hours	Forward Market, Mid C			Grand Total 2004-2010 Purchases	2004 - 2006 Purchases					2007 - 2010 Purchases				
Month	HLH	LLH	HLH	LLH	Flat		$30.50	$28.00	$28.00	$31.75	Total	$31.00	$30.80	$30.40	$34.50	Total
Total						$46,267,712	$4,497,908	$6,141,908	$6,141,908	$3,675,908	$20,457,633	$7,044,225	$7,219,545	$7,570,185	$3,976,125	$25,810,079
Present Value						$34,672,873	$3,922,360	$5,374,845	$5,374,845	$3,196,117	$17,868,167	$5,874,337	$6,023,299	$6,321,224	$3,267,498	$21,486,357
Jan-04	416	328	$48.25	$42.00	$45.49	$1,185,350	$278,900	$325,400	$325,400	$255,650	$1,185,350					
Feb-04	384	312	$45.25	$38.08	$42.03	$868,080	$200,707	$244,207	$244,207	$178,957	$868,080					
Mar-04	432	312	$40.25	$35.77	$38.37	$655,254	$146,376	$192,876	$192,876	$123,126	$655,254					
Apr-04	416	303	$34.75	$26.86	$31.43	$133,967	$16,640	$61,578	$61,578	-$5,828	$133,967					
May-04	400	344	$25.75	$18.39	$22.35	-$536,723	-$151,618	-$105,118	-$105,118	-$174,868	-$536,723					
Jun-04	416	304	$22.75	$16.25	$20.01	-$688,090	-$188,898	-$143,898	-$143,898	-$211,398	-$688,090					
Jul-04	416	328	$36.58	$29.71	$33.55	$296,655	$56,726	$103,226	$103,226	$33,476	$296,655					
Aug-04	416	328	$45.08	$36.61	$41.35	$876,669	$201,730	$248,230	$248,230	$178,480	$876,669					
Sep-04	400	320	$42.08	$34.17	$38.57	$648,241	$145,185	$190,185	$190,185	$122,685	$648,241					
Oct-04	416	329	$41.17	$34.41	$38.18	$642,216	$143,093	$189,655	$189,655	$119,812	$642,216					
Nov-04	400	320	$43.42	$36.29	$40.25	$769,455	$175,489	$220,489	$220,489	$152,989	$769,455					
Dec-04	416	328	$45.92	$38.38	$42.59	$969,533	$224,946	$271,446	$271,446	$201,696	$969,533					
Jan-05	400	344	$41.42	$36.24	$39.03	$704,092	$158,586	$205,086	$205,086	$135,336	$704,092					
Feb-05	384	288	$43.67	$38.21	$41.33	$790,812	$181,953	$223,953	$223,953	$160,953	$790,812					
Mar-05	432	312	$46.17	$40.40	$43.75	$1,055,535	$246,446	$292,946	$292,946	$223,196	$1,055,535					
Apr-05	416	303	$37.15	$28.72	$33.59	$289,874	$55,617	$100,554	$100,554	$33,148	$289,874					
May-05	400	344	$27.53	$19.66	$23.89	-$421,995	-$122,936	-$76,436	-$76,436	-$146,186	-$421,995					
Jun-05	416	304	$24.32	$17.37	$21.39	-$588,702	-$164,050	-$119,050	-$119,050	-$186,550	-$588,702					
Jul-05	400	344	$39.10	$31.76	$35.71	$457,130	$96,845	$143,345	$143,345	$73,595	$457,130					
Aug-05	432	312	$48.19	$39.14	$44.39	$1,103,409	$258,415	$304,915	$304,915	$235,165	$1,103,409					
Sep-05	400	320	$44.98	$36.53	$41.23	$839,837	$193,084	$238,084	$238,084	$170,584	$839,837					
Oct-05	416	329	$44.01	$36.78	$40.82	$838,494	$192,163	$238,725	$238,725	$168,881	$838,494					
Nov-05	400	320	$46.42	$38.79	$43.03	$969,414	$225,478	$270,478	$270,478	$202,978	$969,414					
Dec-05	416	328	$49.09	$41.02	$45.53	$1,188,193	$279,611	$326,111	$326,111	$256,361	$1,188,193					
Jan-06	400	344	$41.67	$36.46	$39.26	$721,513	$162,941	$209,441	$209,441	$139,691	$721,513					
Feb-06	384	288	$43.93	$38.44	$41.58	$807,476	$186,119	$228,119	$228,119	$165,119	$807,476					
Mar-06	432	312	$46.45	$40.64	$44.01	$1,075,065	$251,329	$297,829	$297,829	$228,079	$1,075,065					
Apr-06	400	319	$37.37	$28.89	$33.61	$290,793	$55,847	$100,784	$100,784	$33,378	$290,793					
May-06	416	328	$27.69	$19.78	$24.20	-$398,672	-$117,105	-$70,605	-$70,605	-$140,355	-$398,672					
Jun-06	416	304	$24.47	$17.48	$21.51	-$579,463	-$161,741	-$116,741	-$116,741	-$184,241	-$579,463					
Jul-06	400	344	$39.34	$31.95	$35.92	$473,070	$100,830	$147,330	$147,330	$77,580	$473,070					
Aug-06	432	312	$48.48	$39.37	$44.66	$1,123,226	$263,369	$309,869	$309,869	$240,119	$1,123,226					

Avista Utilities
2001-2002 Medium-Term Electric Power Purchases

Quantity	Delivery	Price	Term	Start Date	End Date
25	Flat	$30.50	3 years	01/01/04	12/31/06
25	Flat	$28.00	3 years	01/01/04	12/31/06
25	Flat	$28.00	3 years	01/01/04	12/31/06
25	Flat	$31.75	3 years	01/01/04	12/31/06
25	Flat	$31.00	4 years	01/01/07	12/31/10
25	Flat	$30.80	4 years	01/01/07	12/31/10
25	Flat	$30.40	4 years	01/01/07	12/31/10
25	Flat	$34.50	4 years	01/01/07	12/31/10

	Hours	Hours	Forward Market, Mid C			Grand Total 2004-2010 Purchases	2004 - 2006 Purchases					2007 - 2010 Purchases				
							$30.50	$28.00	$28.00	$31.75	Total	$31.00	$30.80	$30.40	$34.50	Total
Total						$46,267,712	$4,497,908	$6,141,908	$6,141,908	$3,675,908	$20,457,633	$7,044,225	$7,219,545	$7,570,185	$3,976,125	$25,810,079
Present Value						$34,672,873	$3,922,360	$5,374,845	$5,374,845	$3,196,117	$17,868,167	$5,874,337	$6,023,299	$6,321,224	$3,267,498	$21,486,357
Sep-06	400	320	$45.25	$36.75	$41.47	$857,647	$197,537	$242,537	$242,537	$175,037	$857,647					
Oct-06	416	329	$44.27	$37.00	$41.06	$856,740	$196,724	$243,287	$243,287	$173,443	$856,740					
Nov-06	400	320	$46.69	$39.02	$43.28	$988,001	$230,125	$275,125	$275,125	$207,625	$988,001					
Dec-06	400	344	$49.38	$41.27	$45.63	$1,195,537	$281,447	$327,947	$327,947	$258,197	$1,195,537					
Jan-07	416	328	$41.67	$36.46	$39.38	$572,970						$155,797	$159,517	$166,957	$90,697	$572,970
Feb-07	384	288	$43.94	$38.44	$41.58	$665,796						$177,789	$181,149	$187,869	$118,989	$665,796
Mar-07	432	312	$46.45	$40.65	$44.02	$918,222						$242,111	$245,831	$253,271	$177,011	$918,222
Apr-07	400	319	$37.37	$28.89	$33.61	$139,146						$46,920	$50,515	$57,705	-$15,993	$139,146
May-07	416	328	$27.69	$19.78	$24.21	-$555,662						-$126,360	-$122,640	-$115,200	-$191,460	-$555,662
Jun-07	416	304	$24.47	$17.48	$21.52	-$731,408						-$170,702	-$167,102	-$159,902	-$233,702	-$731,408
Jul-07	400	344	$39.34	$31.95	$35.92	$316,167						$91,597	$95,317	$102,757	$26,497	$316,167
Aug-07	432	312	$48.48	$39.37	$44.66	$966,388						$254,152	$257,872	$265,312	$189,052	$966,388
Sep-07	384	336	$45.26	$36.75	$41.29	$692,239						$185,210	$188,810	$196,010	$122,210	$692,239
Oct-07	432	313	$44.28	$37.00	$41.22	$711,305						$190,398	$194,123	$201,573	$125,211	$711,305
Nov-07	400	320	$46.70	$39.03	$43.29	$836,213						$221,203	$224,803	$232,003	$158,203	$836,213
Dec-07	400	344	$49.39	$41.27	$45.64	$1,038,707						$272,232	$275,952	$283,392	$207,132	$1,038,707
Jan-08	416	328	$41.67	$36.46	$39.38	$572,970						$155,797	$159,517	$166,957	$90,697	$572,970
Feb-08	400	296	$43.94	$38.44	$41.60	$690,830						$184,452	$187,932	$194,892	$123,552	$690,830
Mar-08	416	328	$46.45	$40.65	$43.89	$908,932						$239,788	$243,508	$250,948	$174,688	$908,932
Apr-08	416	303	$37.37	$28.89	$33.80	$152,720						$50,313	$53,908	$61,098	-$12,599	$152,720
May-08	416	328	$27.69	$19.78	$24.21	-$555,662						-$126,360	-$122,640	-$115,200	-$191,460	-$555,662
Jun-08	400	320	$24.47	$17.48	$21.36	-$742,593						-$173,498	-$169,898	-$162,698	-$236,498	-$742,593
Jul-08	416	328	$39.34	$31.95	$36.08	$327,995						$94,554	$98,274	$105,714	$29,454	$327,995
Aug-08	416	328	$48.48	$39.37	$44.47	$951,812						$250,508	$254,228	$261,668	$185,408	$951,812
Sep-08	400	320	$45.26	$36.75	$41.48	$705,845						$188,611	$192,211	$199,411	$125,611	$705,845
Oct-08	432	313	$44.28	$37.00	$41.22	$711,305						$190,398	$194,123	$201,573	$125,211	$711,305
Nov-08	384	336	$46.70	$39.03	$43.12	$823,937						$218,134	$221,734	$228,934	$155,134	$823,937
Dec-08	416	328	$49.39	$41.27	$45.81	$1,051,690						$275,477	$279,197	$286,637	$210,377	$1,051,690
Jan-09	416	328	$42.84	$37.78	$40.61	$664,566						$178,697	$182,417	$189,857	$113,597	$664,566
Feb-09	384	288	$45.17	$39.83	$42.88	$752,895						$199,564	$202,924	$209,644	$140,764	$752,895
Mar-09	416	328	$47.75	$42.11	$45.26	$1,011,033						$265,313	$269,033	$276,473	$200,213	$1,011,033
Apr-09	416	303	$38.42	$29.93	$34.84	$227,768						$69,075	$72,670	$79,860	$6,163	$227,768
May-09	400	344	$28.47	$20.49	$24.78	-$512,805						-$115,646	-$111,926	-$104,486	-$180,746	-$512,805

Avista Utilities
2001-2002 Medium-Term Electric Power Purchases

Quantity	Delivery	Price	Term	Start Date	End Date
25	Flat	$30.50	3 years	01/01/04	12/31/06
25	Flat	$28.00	3 years	01/01/04	12/31/06
25	Flat	$28.00	3 years	01/01/04	12/31/06
25	Flat	$31.75	3 years	01/01/04	12/31/06
25	Flat	$31.00	4 years	01/01/07	12/31/10
25	Flat	$30.80	4 years	01/01/07	12/31/10
25	Flat	$30.40	4 years	01/01/07	12/31/10
25	Flat	$34.50	4 years	01/01/07	12/31/10

	Hours	Hours	Forward Market, Mid C			Grand Total 2004-2010 Purchases	2004 - 2006 Purchases					2007 - 2010 Purchases				
							$30.50	$28.00	$28.00	$31.75	Total	$31.00	$30.80	$30.40	$34.50	Total
Total						$46,267,712	$4,497,908	$6,141,908	$6,141,908	$3,675,908	$20,457,633	$7,044,225	$7,219,545	$7,570,185	$3,976,125	$25,810,079
Present Value						$34,672,873	$3,922,360	$5,374,845	$5,374,845	$3,196,117	$17,868,167	$5,874,337	$6,023,299	$6,321,224	$3,267,498	$21,486,357
Jun-09	416	304	$25.15	$18.11	$22.18	-$683,780						-$158,795	-$155,195	-$147,995	-$221,795	-$683,780
Jul-09	416	328	$40.44	$33.10	$37.21	$411,548						$115,442	$119,162	$126,602	$50,342	$411,548
Aug-09	416	328	$49.84	$40.79	$45.85	$1,054,780						$276,250	$279,970	$287,410	$211,150	$1,054,780
Sep-09	400	320	$46.53	$38.08	$42.77	$798,875						$211,869	$215,469	$222,669	$148,869	$798,875
Oct-09	432	313	$45.52	$38.34	$42.50	$806,561						$214,212	$217,937	$225,387	$149,025	$806,561
Nov-09	384	336	$48.01	$40.43	$44.47	$921,354						$242,489	$246,089	$253,289	$179,489	$921,354
Dec-09	416	328	$50.77	$42.76	$47.24	$1,157,953						$302,043	$305,763	$313,203	$236,943	$1,157,953
Jan-10	400	344	$44.72	$39.17	$42.16	$779,945						$207,541	$211,261	$218,701	$142,441	$779,945
Feb-10	384	288	$47.15	$41.30	$44.65	$871,650						$229,253	$232,613	$239,333	$170,453	$871,650
Mar-10	432	312	$49.85	$43.67	$47.26	$1,159,441						$302,415	$306,135	$313,575	$237,315	$1,159,441
Apr-10	416	303	$40.11	$31.04	$36.29	$331,648						$95,045	$98,640	$105,830	$32,133	$331,648
May-10	400	344	$29.72	$21.25	$25.81	-$436,612						-$96,598	-$92,878	-$85,438	-$161,698	-$436,612
Jun-10	416	304	$26.26	$18.78	$23.10	-$617,373						-$142,193	-$138,593	-$131,393	-$205,193	-$617,373
Jul-10	416	328	$42.22	$34.33	$38.74	$525,747						$143,992	$147,712	$155,152	$78,892	$525,747
Aug-10	416	328	$52.04	$42.30	$47.74	$1,195,515						$311,434	$315,154	$322,594	$246,334	$1,195,515
Sep-10	400	320	$48.57	$39.49	$44.53	$925,842						$243,611	$247,211	$254,411	$180,611	$925,842
Oct-10	416	329	$47.52	$39.75	$44.09	$925,053						$243,835	$247,560	$255,010	$178,648	$925,053
Nov-10	400	320	$50.12	$41.93	$46.48	$1,065,837						$278,609	$282,209	$289,409	$215,609	$1,065,837
Dec-10	416	328	$53.00	$44.34	$49.19	$1,302,776						$338,249	$341,969	$349,409	$273,149	$1,302,776

Holiday reminder

Gas Daily will not publish April 13 in obser-ance of Good Friday. The next issue will ap-pear April 16. The Daily Price Survey published in the April 16 issue will cover transactions con-ducted April 12 for gas flow April 13-16.

NYMEX will be closed April 13. NYMEX Access will be closed April 12 and is scheduled to reopen the evening of April 15.

Gas Daily reader survey

Gas Daily's new 2001 subscriber survey — your chance to win a $200 Golfdiscount.com gift certificate. Visit www.ftenergyusa.com/gasdaily/gdsurvey.asp.

FUTURES
NYMEX @ Henry Hub

Results from Tuesday

	Settlement	High	Low	Change	Volume
May., 2001	5.559	5.620	5.520	8.2	22,204
June	5.611	5.660	5.540	7.5	7,965
July	5.657	5.700	5.630	7.2	1,311
August	5.692	5.740	5.675	7.2	2,473
September	5.672	5.710	5.660	7.2	873
October	5.682	5.720	5.675	7.2	2,029
November	5.807	5.850	5.780	7.2	517
December	5.920	5.970	5.890	7.2	1,358
Jan., 2002	5.957	6.005	5.945	7.2	938
February	5.767	5.820	5.760	6.7	1,272
March	5.422	5.480	5.410	6.7	667
April	4.832	4.860	4.830	4.2	770
May	4.687	4.750	4.680	3.2	309
June	4.698	4.750	4.660	3.8	335
ly	4.728	—	—	3.8	40
gust	4.735	4.750	4.720	3.8	479
ptember	4.712	4.750	4.720	3.5	622
October	4.712	4.700	4.670	3.5	96
November	4.827	4.890	4.810	3.5	24
December	4.932	4.950	4.935	3.5	24
Jan., 2003	4.962	5.030	4.980	3.5	298
February	4.789	4.810	4.810	3.5	37
March	4.549	4.610	4.560	3.5	72
April	4.254	4.270	4.250	1.0	231
May	4.192	—	—	0.3	280
June	4.205	—	—	0.3	130
July	4.230	—	—	0.3	30
August	4.255	4.280	4.280	0.3	31
September	4.245	—	—	0.3	30
October	4.245	—	—	0.3	30
November	4.355	—	—	0.3	30
December	4.475	4.472	4.472	0.3	35
Jan., 2004	4.515	4.550	4.512	0.3	106
February	4.395	4.380	4.380	0.3	1
March	4.255	4.250	4.240	0.3	22
April	4.113	—	—	0.3	0

Volume of contracts (unofficial) 45,669

Front-months open interest Monday:
May, 41,900; June, 21,783; July, 17,326

Total open interest Monday: 372,720

Weighted average of x number of trades in the last two minutes of trading. Change is from previous settlement price.

OPTIONS
NYMEX@Henry Hub

Results from Tuesday

Strike Price	Calls-Settle May.	Jun.	Jul.	Puts-Settle May.	Jun.	Jul.
5.40	—	—	—	14.2¢	28.9¢	40.0¢
5.45	—	—	—	16.2¢	31.1¢	42.3¢
5.50	—	—	—	18.4¢	33.4¢	44.7¢
5.55	—	—	—	20.8¢	35.8¢	47.2¢
5.60	19.2¢	39.4¢	57.0¢	—	38.3¢	49.7¢
5.65	17.2¢	37.2¢	53.4¢	—	—	52.4¢
5.70	15.4¢	35.1¢	51.2¢	—	—	—
[illegible]	13.7¢	33.1¢	49.1¢	—	—	—
[illegible]	—	—	—	—	—	—

Estimated Volume: Calls: n/a Puts: n/a

Total open interest Monday Calls: 149,832 Puts: 206,259

Not all strike and settlement prices listed.

Implied Volatility for at-the-money strike price
Calls: n/a Puts: n/a Source: Bloomberg

Talisman spins plan to acquire Petromet

Talisman Energy will acquire Calgary-based Petromet Resources in a cash offer at a price of C$13.20/share, representing a 26% premium over the closing price of the Petromet shares on April 9.

"This is a good marriage of assets, infrastructure and upside poten ... la," said Talisman President and CEO Jim Buckee. "We intend to consolidat ... omet's Canadian assets into a partnership following completion of ...

"Petromet's assets tie nicely into our rapidly gr ... een building on our existing land base near the Ta ... st year with the acquisition of midstream as ... tion of properties acquired from P ...

A Talisman spokesman ... June 1, is expected to ...

With this a ... than 850 ... 2002. P ... aid it ex ...

w ... il and liquids ... ights to more than ... drilling locations.

... pools is approximately C$638 ... and C$1.12/mcfe (C$6.72/boe) proved ... rate more than C$250 million of cash flow in

... production for the remainder of 2001 at approximately 110 m ... bbl/d of liquids. More than 90% of the asset value is concentrated in two properties — Bigstone and Wild River. Petromet's average working interest in its production is 85%.

The company said it expects to mail its offer to Petromet shareholders and debenture holders on or about April 20. The offer will be conditional upon not less than two-thirds of the Petromet shares and 90% of the Petromet debentures being tendered.

Petromet's board of directors has unanimously voted to recommend acceptance of the offer by the Petromet shareholders and debenture holders. JM

Questar signs deal for portion of Southern Trails

Questar Pipeline said it has concluded a contract with Duke Energy covering all of the capacity for the 80,000 dth/d east zone of its $155 million Southern Trails Pipeline project, a project that involves converting a crude oil pipeline to natural gas. The 705-mile pipeline runs from the Four Corners areas near Blanco, N.M., to Long Beach, Calif., and is divided into east and west zones.

The east zone can transport gas from multiple receipt points in the San Juan Basin to multiple delivery points near the California border. "This contract moves us one very large step closer to making the Southern Trails Pipeline a reality," Questar Pipeline President and CEO D.N. Rose said.

The company also is soliciting interest from customers for Southern Trails' west zone, which runs from the California state line to Long Beach. The west zone will have a capacity of 120,000 dth/d. Questar began work on the east zone last year after receiving FERC approval for the entire project last July.

The west zone is encountering regulatory and utility tariff barriers in California, similar to resistance confronted by other interstate pipelines that have tried to supply gas service into the state's market areas. Questar is proceeding with the east portion as if it were a separate project, Questar spokesman Chad Jones said. The project has received interest in the west zone from potential shippers, contingent on SoCal Gas changing its tariff to make it economically feasible to take gas from a competitive pipeline.

Questar pointed to a Residual Load Service fee imposed by SoCal Gas that "deters existing customers from using alternate natural gas suppliers if they elect to switch part of their transportation to a competing pipeline in Southern California Gas' service area."

Options that SoCal Gas has proposed in response to California Public Utilities Com-

Exh. 7 / Schedule 29 Page 1 of 11
R. Lafferty
Avista Corporation

Michigan clicks on choice

According to the Michigan Public Service ommission, gas customers in the state are showing more interest in the state's customer choice program. As evidence, the PSC pointed to the number of times that the program information Web page has been accessed in recent months.

During March, the PSC's choice comparison of suppliers and prices page received nearly 12,000 hits. Moreover, seven other choice program-related pages were viewed an additional 16,000 times.

The increased consumer interest "will encourage expanded participation by natural gas marketers in Michigan's customer choice programs," said PSC Chairwoman Laura Chappelle. VK

FUTURES
NYMEX @ Henry Hub

Results from Wednesday

	Settlement	High	Low	Change	Volume
Jun., 2001	4.202	4.315	4.145	-7.7	0
July	4.273	4.385	4.220	-8.0	0
August	4.343	4.450	4.290	-8.2	0
September	4.369	4.465	4.330	-8.6	0
October	4.400	4.500	4.360	-9.3	0
November	4.574	4.674	4.550	-9.9	0
December	4.748	4.855	4.710	-10.5	0
Jan., 2002	4.813	4.925	4.775	-11.0	0
February	4.693	4.820	4.650	-11.0	0
March	4.510	4.679	4.490	-10.3	0
April	4.200	4.300	4.190	-9.3	0
May	4.131	4.230	4.130	-9.2	0
June	4.173	4.265	4.170	-9.2	0
July	4.223	4.315	4.200	-9.2	0
August	4.242	4.340	4.230	-9.8	0
September	4.247	4.345	4.270	-9.8	0
October	4.267	4.305	4.285	-9.8	0
November	4.407	4.505	4.420	-9.8	0
December	4.537	4.635	4.550	-9.8	0
Jan., 2003	4.587	4.685	4.600	-9.8	0
February	4.442	4.535	4.475	-9.3	0
March	4.255	4.295	4.287	-9.2	0
April	3.970	4.055	3.995	-8.5	0
May	3.935	3.960	3.930	-8.5	0
June	3.975	3.975	3.975	-8.5	0
July	4.025	4.160	4.160	-8.5	0
August	4.070	4.070	4.070	-7.8	0
September	4.087	4.087	4.087	-7.3	0
October	4.102	4.102	4.102	-6.8	0
November	4.214	4.240	4.230	-6.6	0
December	4.349	4.349	4.349	-6.6	0
Jan., 2004	4.407	4.407	4.407	-6.6	0
February	4.287	4.287	4.287	-6.6	0
March	4.148	4.148	4.148	-6.6	0
April	3.978	3.978	3.978	-6.6	0
May	3.948	3.948	3.948	-6.6	0
Volume of contracts (unofficial)					0

Front-months open interest Tuesday:
June, 44,175; July, 24,183; August, 28,813
Total open interest Tuesday: 409,385
Weighted average of x number of trades in the last two minutes of trading. Change is from previous settlement price.

OPTIONS
NYMEX@Henry Hub

Results from Wednesday

Strike Price	Calls-Settle Jun.	Calls-Settle Jul.	Calls-Settle Aug.	Puts-Settle Jun.	Puts-Settle Jul.	Puts-Settle Aug.
4.05	—	—	—	11.5¢	22.4¢	—
4.10	—	41.5¢	—	13.6¢	—	30.6¢
4.15	—	—	—	15.8¢	26.7¢	—
4.20	17.5¢	—	—	18.2¢	29.0¢	35.2¢
4.25	16.3¢	33.5¢	—	18.5¢	31.5¢	37.5¢
4.30	14.2¢	31.1¢	47.5¢	—	—	40.0¢
4.35	12.4¢	28.9¢	41.5¢	—	—	42.5¢
4.40	10.7¢	—	39.2¢	27.0¢	—	—
4.45	—	—	—	—	—	—

Estimated Volume: Calls: n/a Puts: n/a
Total open interest Tuesday Calls: n/a Puts: n/a
Not all strike and settlement prices listed.
Implied Volatility for at-the-money strike price
Calls: 55.39% Puts: 51.32% Source: Bloomberg

SoCal Ed presses FERC to ma' ...'y public

Firing off another round in the paper war over Califo- ... uthern Califor- nia Edison on Tuesday asked FERC for permi- ... power study that it says proves that El Paso and its affili- ... o drive up prices in the state. And the *New York Time-* ... ry, publishing an article that focused on the uti- ... ies.

As reported in *Gas Daily*, SoC- ... are blaming El Paso for alleged mar- ... s and capacity manipulation. F- ... dismissed the CPUC's c- ... of pipeline capacity in ...

Now SoCal ... sachusetts-based consu- ... oned the study, the repo- ... withholding capacity ... ed to the lack of suffi- ci- ... ffect of raising both natural ... said SoCal Ed.

... ate market manipulation by El Paso ... SoCal Ed reckoned that its electricity ... esult of El Paso's anticompetitive practices. ... ase are concerned about the protection of sensi- ... contained in case proceedings as well as in The ... FERC Chief Administrative Law Judge Curtis Wagner ... ge of materials in the case.

... FERC to reconsider the protected status of study. According to th- ... s right to know outweighs any possible confidentiality concern over material which is mere historical data, which is not contract or customer specific and which is the product of a study performed on behalf of [SoCal Ed]."

The conclusions of The Brattle Group study, however, are already circulating in public. Most recently, the *Times* ran an article that gave considerable play to The Brattle Group's findings.

El Paso has forwarded its own version of the California gas price controversy. According to a study conducted by Lukens Consulting Group and commissioned by El Paso, broader market forces were at work in driving up the price of gas in the Golden State (*GD 4/25*).

Joan Dreskin of the Interstate Natural Gas Association of America, which represents the pipeline industry, said that there should be no rush to judgement in the capacity case. "Neither the press nor the public should jump to conclusions that there was any wrongdoing by either El Paso or its marketing affiliates," she said. "There's a hearing at FERC that will review their conduct ... without having all the facts, the allegations should not be decided by the press," she said. NH

GAO prepares to investigate high gas prices

Even as gas prices fall toward the $4 mark, the investigations continue. The U.S. Congress got in on the act this week, launching a probe into the cause of high natural gas prices.

In response to several requests by members of Congress, the General Accounting Office — the investigative arm of Congress — said it would begin a search into why gas prices have risen over the past couple of years and what caused the record-high costs this past winter.

In a March 30 letter, six House representatives sent a letter to GAO Comptroller General David Walker, questioning why gas prices have risen so dramatically. The letter was signed by Reps. John Spratt, D-S.C., Jan Schakowsky, D-Ill., Bud Cramer, D-Ala., Bob Etheridge, D-N.C., Ed Markey, D-Mass., and Mike Thompson, D-Calif.

"We are alarmed at this spike in the cost of natural gas and the impact on our constituents," the letter stated.

The letter requests that the GAO investigate gas supply availability from domestic and imported production during the recent period of high prices; changes in gas demand by customer class; and the impact of increased demand for electric generation on gas prices.

In addition, the legislators asked that the GAO look into the role of trading futures on the NYMEX, gas forward contracts, and any over-the-counter derivative contracts involving gas

Table 4. U. S. Energy Prices

(Nominal Dollars)

	2000				2001				2002				Year		
	1st	2nd	3rd	4th	1st	2nd	3rd	4th	1st	2nd	3rd	4th	2000	2001	2002
Crude Oil Prices															
Imported Average[a]	**26.84**	**26.55**	**29.11**	*28.27*	*24.57*	*24.50*	*26.00*	*27.00*	*26.33*	*26.00*	*26.50*	*26.83*	*27.72*	*25.52*	*26.41*
WTI[b] Spot Average	**28.82**	**28.78**	**31.61**	*31.96*	*28.82*	*27.67*	*29.04*	*30.01*	*29.34*	*29.00*	*29.50*	*29.83*	*30.29*	*28.88*	*29.42*
Natural Gas Wellhead (dollars per thousand cubic feet)	**2.26**	**3.06**	**3.87**	*5.22*	*6.27*	*4.50*	*4.55*	*5.40*	*5.32*	*4.42*	*4.32*	*5.18*	*3.62*	*5.18*	*4.82*
Petroleum Products															
Gasoline Retail [c] (dollars per gallon)															
All Grades	**1.44**	**1.57**	**1.56**	*1.54*	*1.47*	*1.52*	*1.53*	*1.47*	*1.46*	*1.49*	*1.49*	*1.46*	*1.53*	*1.50*	*1.47*
Regular Unleaded	**1.40**	**1.53**	**1.52**	*1.50*	*1.43*	*1.49*	*1.50*	*1.43*	*1.42*	*1.46*	*1.45*	*1.42*	*1.49*	*1.46*	*1.44*
No. 2 Diesel Oil, Retail (dollars per gallon)	**1.42**	**1.41**	**1.50**	*1.58*	*1.47*	*1.41*	*1.42*	*1.46*	*1.43*	*1.42*	*1.42*	*1.45*	*1.48*	*1.44*	*1.43*
No. 2 Heating Oil, Wholesale (dollars per gallon)	**0.85**	**0.78**	**0.91**	*0.97*	*0.84*	*0.74*	*0.77*	*0.86*	*0.83*	*0.76*	*0.77*	*0.85*	*0.88*	*0.81*	*0.81*
No. 2 Heating Oil, Retail (dollars per gallon)	**1.31**	**1.17**	**1.23**	*1.40*	*1.34*	*1.18*	*1.12*	*1.27*	*1.28*	*1.17*	*1.12*	*1.26*	*1.31*	*1.28*	*1.24*
No. 6 Residual Fuel Oil, Retail [d] (dollars per barrel)	**23.64**	**24.55**	**25.10**	*27.40*	*24.52*	*23.35*	*23.79*	*25.53*	*25.02*	*23.38*	*23.61*	*24.62*	*25.34*	*24.30*	*24.14*
Electric Utility Fuels															
Coal (dollars per million Btu)	**1.21**	**1.21**	**1.18**	*1.20*	*1.21*	*1.22*	*1.20*	*1.20*	*1.20*	*1.21*	*1.19*	*1.18*	*1.20*	*1.21*	*1.20*
Heavy Fuel Oil [e] (dollars per million Btu)	**3.74**	**4.18**	**4.34**	*4.46*	*3.82*	*3.83*	*3.97*	*4.07*	*3.88*	*3.84*	*3.94*	*3.95*	*4.25*	*3.90*	*3.90*
Natural Gas (dollars per million Btu)	**2.85**	**3.78**	**4.46**	*5.91*	*6.91*	*5.15*	*5.16*	*6.02*	*6.02*	*5.03*	*4.92*	*5.79*	*4.25*	*5.61*	*5.27*
Other Residential															
Natural Gas (dollars per thousand cubic feet)	**6.53**	**7.77**	**10.09**	*8.68*	*9.91*	*10.58*	*11.04*	*9.12*	*9.47*	*10.12*	*11.02*	*9.35*	*7.69*	*9.88*	*9.65*
Electricity (cents per kilowatthour)	**7.78**	**8.37**	**8.59**	*8.21*	*7.97*	*8.56*	*8.81*	*8.35*	*7.98*	*8.54*	*8.81*	*8.33*	*8.25*	*8.44*	*8.43*

[a] Refiner acquisition cost (RAC) of imported crude oil.

[b] West Texas Intermediate.

[c] Average self-service cash prices.

[d] Average for all sulfur contents.

[e] Includes fuel oils No. 4, No. 5, and No. 6 and topped crude fuel oil prices.

Notes: Data are estimated for the fourth quarter of 2000. Prices exclude taxes, except prices for gasoline, residential natural gas, and diesel. The forecasts were generated by simulation of the Short-Term Integrated Forecasting System.

Sources: Historical data: Energy Information Administration: latest data available from EIA databases supporting the following reports: *Petroleum Marketing Monthly*, DOE/EIA-0380; *Natural Gas Monthly*, DOE/EIA-0130; *Monthly Energy Review*, DOE/EIA-0035; *Electric Power Monthly*, DOE/EIA-0226.

Table 4. U. S. Energy Prices

(Nominal Dollars)

	2000				2001				2002				Year		
	1st	2nd	3rd	4th	1st	2nd	3rd	4th	1st	2nd	3rd	4th	2000	2001	2002
Crude Oil Prices															
Imported Average[a]	26.84	26.55	29.12	28.25	24.57	25.00	27.00	27.00	26.33	26.00	26.50	26.83	27.72	25.91	26.41
WTI[b] Spot Average	28.82	28.78	31.61	31.96	28.82	28.44	30.14	30.04	29.34	29.00	29.50	29.83	30.29	29.36	29.42
Natural Gas Wellhead															
(dollars per thousand cubic feet)	2.26	3.06	3.87	5.22	6.27	4.57	4.73	5.52	5.38	4.48	4.36	5.19	3.62	5.27	4.86
Petroleum Products															
Gasoline Retail[c] (dollars per gallon)															
All Grades	1.44	1.57	1.56	1.54	1.47	1.66	1.61	1.53	1.48	1.51	1.50	1.47	1.53	1.57	1.49
Regular Unleaded	1.40	1.53	1.52	1.50	1.43	1.62	1.58	1.50	1.44	1.48	1.47	1.44	1.49	1.53	1.46
No. 2 Diesel Oil, Retail (dollars per gallon)	1.42	1.41	1.50	1.58	1.47	1.47	1.48	1.49	1.45	1.43	1.43	1.46	1.48	1.48	1.44
No. 2 Heating Oil, Wholesale (dollars per gallon)	0.85	0.78	0.91	0.97	0.83	0.75	0.80	0.86	0.84	0.76	0.77	0.85	0.88	0.82	0.81
No. 2 Heating Oil, Retail (dollars per gallon)	1.31	1.17	1.23	1.40	1.35	1.19	1.15	1.28	1.29	1.18	1.12	1.26	1.31	1.28	1.25
No. 6 Residual Fuel Oil, Retail[d] (dollars per barrel)	23.62	24.57	25.10	27.41	24.99	24.52	25.22	26.27	25.57	23.83	23.90	25.24	25.34	25.26	24.64
Electric Utility Fuels															
Coal (dollars per million Btu)	1.21	1.21	1.18	1.20	1.21	1.23	1.21	1.20	1.21	1.22	1.19	1.18	1.20	1.21	1.20
Heavy Fuel Oil[e] (dollars per million Btu)	3.74	4.18	4.34	4.52	3.90	4.02	4.20	4.18	3.97	3.91	3.98	4.03	4.27	4.05	3.97
Natural Gas (dollars per million Btu)	2.85	3.78	4.46	6.33	7.61	5.62	5.56	6.24	6.14	5.11	4.97	5.81	4.33	6.03	5.33
Other Residential															
Natural Gas (dollars per thousand cubic feet)	6.53	7.77	10.09	8.68	9.91	10.59	11.12	9.26	9.58	10.20	11.08	9.39	7.69	9.93	9.73
Electricity (cents per kilowatthour)	7.76	8.35	8.57	8.26	8.10	8.79	9.00	8.50	8.11	8.63	8.87	8.38	8.25	8.61	8.51

[a] Refiner acquisition cost (RAC) of imported crude oil.

[b] West Texas Intermediate.

[c] Average self-service cash prices.

[d] Average for all sulfur contents.

[e] Includes fuel oils No. 4, No. 5, and No. 6 and topped crude fuel oil prices.

Notes: Data are estimated for the fourth quarter of 2000. Prices exclude taxes, except prices for gasoline, residential natural gas, and diesel. The forecasts were generated by simulation of the Short-Term Integrated Forecasting System.

Sources: Historical data: Energy Information Administration: latest data available from EIA databases supporting the following reports: *Petroleum Marketing Monthly*, DOE/EIA-0380; *Natural Gas Monthly*, DOE/EIA-0130; *Monthly Energy Review*, DOE/EIA-0035; *Electric Power Monthly*, DOE/EIA-0226.

Non-OPEC production is expected to increase by another 0.6 million barrels per day in 2001, with much of this increase coming from Russia. Although the Caspian Pipeline Consortium has begun filling its new pipeline to transport oil from Kazakhstan to world markets, this is not expected to support greater Caspian production levels until end-2001.

International Oil Demand. World oil demand remains expected to grow, despite concerns over a gradual economic slowdown in the industrialized countries. EIA projects world oil demand growth of 1.4 million barrels per day in 2001 (higher than the IEA's 1.3 million barrels per day prediction), with slightly higher demand growth expected for 2002. Besides the OECD, non-OECD Asia is still expected to be the leading region for oil demand growth over the next two years, although this growth now appears to be weaker than previously assumed.

World Oil Inventories. EIA does not attempt to estimate oil inventory levels on a global basis. However, the direction in which global oil inventories are headed is discerned from EIA's world oil supply and demand estimates. Stocks are currently below "normal" levels, although not by so wide a margin as EIA previously believed, and these low inventory levels are expected to put upward pressure on prices. U.S. crude oil stocks, for example, are expected to remain below normal levels for most of 2001 and to improve in 2002 but only into the lower end of the normal range (Figure 9).

U. S. Energy Prices

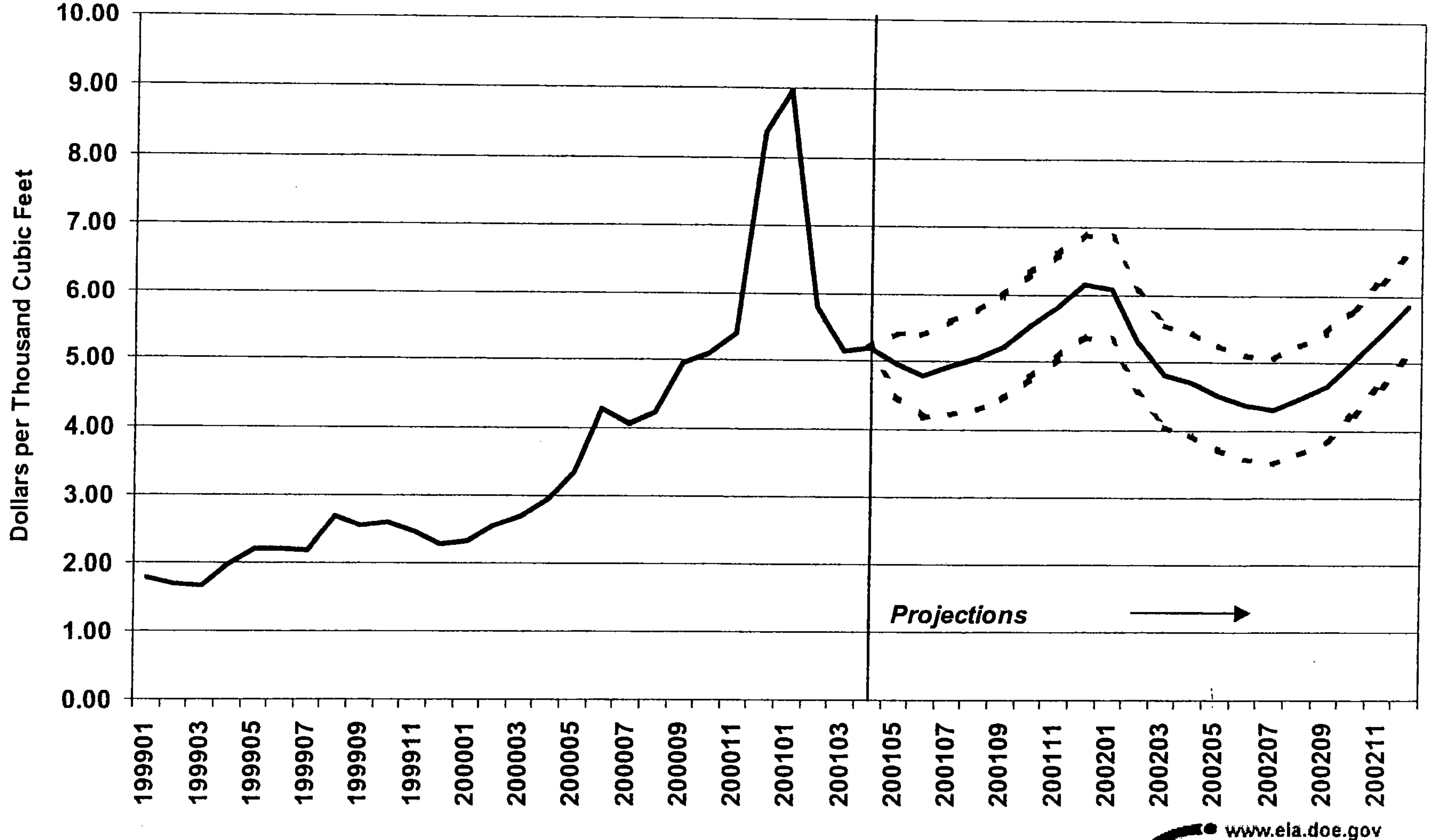
Motor Gasoline. As noted above, pump prices have been soaring due to high demand and low inventories. The tightening of motor gasoline stocks, which are less plentiful now than they were this time last year and have helped push prices into new territories.

As a result, we project that the average monthly pump price for regular gasoline will range between $1.50 and $1.75 per gallon, perhaps more, during the peak months of the driving season. Last year, the high national average prices were skewed by exceedingly high pump prices in the Midwest (over $2.00 per gallon at times), which, in turn, were the result of critical regional supply problems. Although in our base case we do not necessarily project a repeat of last year, the current situation of relatively low inventories for gasoline sets the stage for potential regional imbalances in supply that could bring about significant price volatility in the U.S. gasoline market.

Distillate Fuel Oil (Diesel and Heating Oil). The recent surge in motor gasoline prices may impact the retail price of diesel fuel oil. Since there is currently a supply deficit for motor gasoline, refiners will need to emphasize gasoline production at the expense of distillate. Even though inventories of distillate fuel are adequate, supplies of this fuel may become tighter during the summer as distillate production lags, resulting in a premium for its price. As a result, retail diesel prices are expected to remain fairly high in historical terms, averaging close to $1.50 per gallon during the driving season. Moreover, consumption of distillate fuel in place of natural gas for power generation could put additional pressure on the diesel fuel market, although such a development is rather unlikely unless electricity demand surges sharply in key gas-consuming regions.

Natural Gas. Last winter (October 2000-March 2001) natural gas prices at the wellhead averaged $5.74 per thousand cubic feet, more than double the previous winter's price. Natural gas prices (Figure 10) began climbing last summer primarily in response to low levels of underground gas storage. Compared to this time last year, storage levels are still low. As a result, spot prices are currently averaging about $5.00 per thousand cubic feet. We continue to believe that, given the current state of the natural gas market, it will be a while before prices at the wellhead return to the low level of $2.00 per thousand cubic feet experienced just one year ago. About 90 percent of the planned additions to electric generating capacity over the next few years are designed to primarily use natural gas as a fuel source. For the spring and summer, average

Figure 10. Natural Gas Spot Prices
(Base Case and 95% Confidence Interval)



Sources: History: Natural Gas Week; Projections: Short-Term Energy Outlook, May 2001.

wellhead prices are projected to decline only modestly, averaging an unseasonably strong $4.65 per thousand cubic feet. One factor that should keep prices relatively high is the need for unusually large refill volumes for underground storage. The gas supply situation this injection season bears close monitoring. If the spring and summer weather is particularly hot in regions that consume large quantities of gas-fired electricity, (California and Texas for example), then injections into underground storage for the next winter would again be strained, resulting once more in sharply rising prices from already robust current levels. In 2001, the annual average wellhead price is projected to average over $5.00 per thousand cubic feet. Next year, we expect the storage situation to improve somewhat and with that, we expect a dip in the average annual wellhead price. Increases in production and imports of natural gas needed to keep pace with the rapidly growing demand for natural gas will be accompanied, for the time being, by relatively expensive supplies for gas due to rising production costs and capacity constraints on the pipelines.

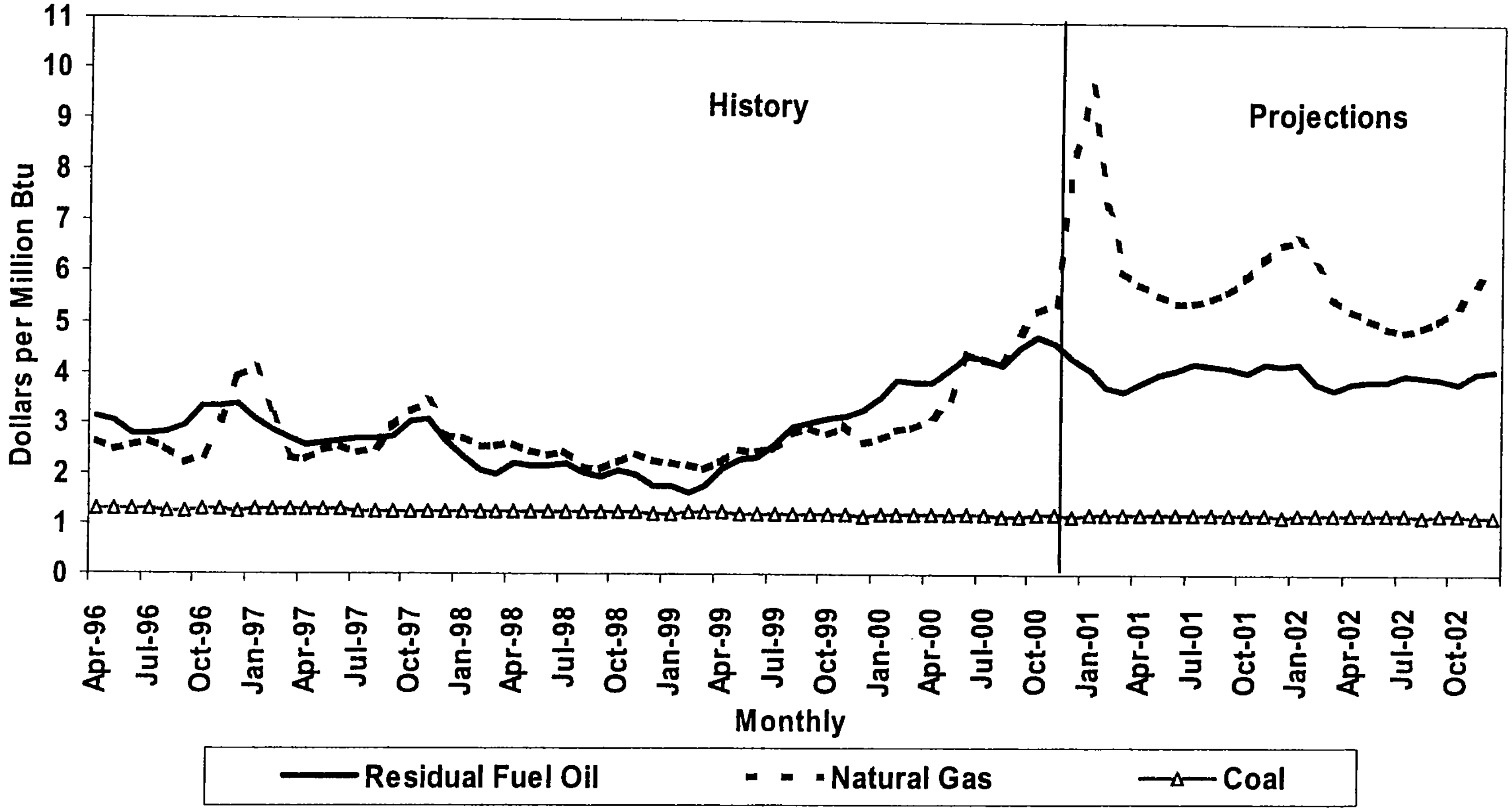
Electric Utility Fuels. The rapid rise in gas prices last summer and fall has pulled delivered gas prices above heavy fuel oil prices on a cost per Btu basis (Figure 11). As this situation is likely to persist, we anticipate some recovery in the amount of heavy fuel oil used for power generation over the very low levels seen since late 1999. In 2001, the cost of coal to electric utilities is projected to increase slightly, after years of slow but continual decline, as coal, like oil, is being used more intensively for electricity generation in lieu of expensive or unavailable natural gas. On an inflation-adjusted basis, however, coal prices should still show a decline this year.

U.S. Oil Demand

Petroleum demand data for 2000 have been revised. (The more detailed view of the revisions is provided in EIA's latest *Petroleum Supply Monthly*). Compared to previous Short-Term Energy Outlook, these revisions, brought about primarily by revisions to imports data, result in an overall 0.9-percent increase in total estimated demand in 2000 compared to the preliminary figures. As a result, total demand increased from 19.52 million barrels per day in 1999 to 19.68 million barrels per day in 2000, an increase of 0.8 percent. This contrasts with a 0.1-percent decline based on the original data. The demand revisions involved upward adjustments in most major product categories. In contrast to the 0.6-percent decline based on the original data, motor gasoline demand now exhibits a 0.5-percent growth rate from the 1999 level, a revision of 1.1 percent. The year-to-year increase in jet-fuel demand has been revised from 2.0 percent to 3.2 percent. In addition, distillate fuel and residual fuel oil demands registered increases of 3.4 and 9.4 percent, up from 3.2 and 1.8 percent based on the preliminary data. The liquefied petroleum products group also underwent an increase but the year-to-year change was still slightly negative. Other minor petroleum products generally registered downward revisions. In general, these revisions reduce the responsiveness to price change that one may reasonably attribute to the petroleum demand weakness witnessed in 2000. As it turns out, the numbers now line up somewhat better, on balance, with the sorts of results one would expect using the short-run price elasticities embedded in the model used for the Short-Term Energy Outlook. However, these elasticities have always been small in absolute value, so the change is not one that is particularly worrisome from the standpoint of consistency with accumulated experience.

Total petroleum products demand is projected to climb an average 250,000 barrels per day, or 1.3 percent, in 2001. Data for the first quarter of this year indicate a sizable year-to-year 510,000 barrels-per day, or 2.6-percent, increase in total petroleum demand. But much of that increase stems from special factors. The most important is the weather, which, although only moderately colder than normal, was more than 11 percent colder in terms of heating degree-days than during the mild winter quarter of 2000. Weather contributed to the 11-percent growth distillate fuel oil demand compared to the same quarter last year. An additional factor was the change in relative prices brought about by the unprecedented spike in natural gas prices, which, in combination with the cold weather, helped boost residual fuel oil demand by 25 percent. Another factor was the concern about the possible impact of Y2K, which boosted deliveries in December, 1999, but depressed shipments in January, 2000.

Figure 11. Fossil Fuel Prices to Electric Utilities



Sources: History: EIA; Projections: Short-Term Energy Outlook, May 2001.

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U.S. natural gas demand is expected to grow at about a 1.9-percent rate this year, following the strong 4.9-percent performance in 2000 (Figure 14). A slowing economy and less rapid demand growth in the industrial and commercial sectors are the reasons. Growth in 2002 is expected to heat up to about 3.4 percent as the economy picks up again and as new gas-fired power generation requirements continue to mount.

Domestic gas production for 2001 and 2002 is expected to rise as production responds to the high rates of drilling experienced over the past year. Production is estimated to have risen by 3.7 percent in 2000 and it is forecast to continue to increase by 2.7 percent rate in 2001 and 2.5 percent in 2002.

Based on EIA survey data and recent information from the American Gas Association on early-season storage additions, we estimate that, on an EIA survey basis, working gas in storage at the end of April was 932 billion cubic feet (bcf) (Figure 15). It is a measure of the sensitivity of the gas market to developments this year concerning the progress of storage additions that recent spot prices and near futures have slipped to below $5.00 per thousand cubic feet (mcf) from recent peaks as high as $5.73 per mcf at the Henry Hub on April 11. <u>The very large storage injections still expected for the summer may yet play a role in strengthening gas prices over the next few months, particularly if very hot temperatures and above-normal cooling demand appear in regions that use large amounts of gas for power generation and heightens the competition for gas between current and future demand sources.</u>

Net imports of natural gas are projected to rise by about 13 percent in 2001 and by another 4 percent in 2002. For this summer, we project that natural gas imports will be 17 percent above last summer's as demand for storage refill is expected to be high.

Electricity Demand and Supply

Total annual electricity demand growth (retail sales plus industrial generation for own use) is projected at about 2.3 percent in 2001 and 2.1 percent in 2002. This is compared with estimated demand in 2000 that was 3.6 percent higher than the previous year's level. Electricity demand growth is expected to be slower in the forecast years than it was in 2000 partly because economic growth is also slowing from its higher 2000 level.

This summer's overall cooling degree-days (CDD) are projected to be normal, or about 1.0 percent below last summer's CDD total. Summer electricity demand is expected to be 2.6 percent higher than last summer based mainly on economic factors, i.e., rising GDP, albeit less rapid than last year, higher housing stocks and employment (Figure 16 and Table 10).

Hydropower generation in the crucial Pacific Northwest is expected to be down by 7.5 percent from last summer, due mainly to lower water levels. According to the National Oceanic and Atmospheric Association (NOAA), this winter was the second driest winter on record, after the 1976/77 winter. In addition, the crisis in California this winter has further drained reservoirs, depriving the region of generation resources for this spring and summer. Nuclear generation is also expected to be 5.6 percent lower than last summer mainly due to scheduled maintenance outages.

A total of 23,558 megawatts of new total electricity generating capacity was added in 2000. Based on accumulated public announcements (including wire reports, news articles and company press releases) over the past year, an estimated 40,000 to 50,000 megawatts of new capacity is planned for installation annually in 2001 and 2002. EIA's power plant surveys suggest that closer to 25,000 megawatts of new capacity will be installed annually in 2001 and in 2002. The table below shows the regional distribution of these capacity increases.

(Energy Information Administration/Short-Term Energy Outlook – May 2001)

PRICE HEDGING REPORT

A Weekly Supplement to *Gas Daily*

Longs dispelled by shorts

The bears were on the prowl last week as the May contract neared expiration. Short positions dramatically increased, creating the reality of a deteriorating market. As summer begins to heat things up, though, prices could follow suit, sources say.

Short positions overtook long positions at an unusually large margin of more than three to one in the Commodity Futures Trading Commission's latest Commitments of Traders Report for the week ending April 24.

Short positions increased considerably last week, jumping to 14,524, compared to the prior week's report of 10,481. Long positions remained virtually unchanged coming in at 4,430 from last week's 4,137.

Spreading positions also increased slightly with the current report, showing 13,771, compared to the previous report of 13,630. Overall open interest increased to 388,716 from 385,794.

As the May contract approached expiration, a daily erosion of the screen began to take shape, sending prices below key support levels on Thursday and ultimately resulting in the May contract settling at $4.891 upon expiration.

The reason for the slump in prices appeared fundamentally based, as mild weather forecasts persist. In addition, a moderately bearish American Gas Association injection estimate also happened to coincide with the usual pre-expiration liquidations, adding fuel to the sell-off.

Even though the week ended with prices trending downward into the $4.80s, some traders believe that gas prices have possibly hit bottom for the rest of the year.

"A little over a week ago, $5 was considered an attractive buy, so now that we are below $5, we should begin to see a flurry of activity as the June contract begins to actively trade," a futures trader said.

"Summer heat is just around the corner, hurricane season begins in just a month from now, and to top it all off, we will be seeing a substantial increase in the number of gas-fired power generation plants coming online. It all adds up to the likelihood of higher prices to come, from what I can see," the trader said. AL

Commitments of Traders

This table shows long, short and spread positions of non-commercials, as reported weekly to the CFTC.

Rpt. Date	Long	Short	Spreading
24-Apr	4,430	14,524	13,771
17-Apr	4,137	10,471	13,630
10-Apr	5,908	7,693	11,911

Traders fear winter price repeat at Sumas

With traders coughing up more than $40/mmBtu for gas at Sumas, Wash., last December, players find themselves this spring attempting to hedge off any repeats of those bad memories.

One source said trying to determine what Sumas prices will do next winter is very difficult. "Weather and demand are big factors. And then there's the uncertainty of when Northwest Pipeline will call an operational flow order at Kemmerer, Wyo.," the source said.

He said constraints on northbound gas out of Wyoming on Northwest forced traders to buy Sumas gas last winter, helping drive the price up there. "That forced a lot of people to buy Sumas gas when they normally wouldn't buy there. If people try to shove gas through the constrained points like they did last year, we'll definitely see expensive gas again."

Because temperatures plunged so early last winter, there were strong storage draws in the Pacific Northwest and Rockies that led to storage worries for the rest of the season, another trader said. And California's power woes started around the same time.

"All of that combining is why we saw $40 gas," the source said. "If all that happens again, we'll see a return of $40 gas."

California's energy crisis will once again have an impact on Sumas price direction next winter, another source said. "If Southern California Gas goes to $40, Malin and Sumas will go there too. It's not just a point-by-point problem. It's a western region problem. A lot of these markets are connected."

To hedge themselves against that kind of volatility for the upcoming winter, most traders are working the November-to-March strip. "Sumas is trading at a small discount to Malin right now," one trader said. "Anywhere from 40¢ to $1.10 over the last few months."

Even though there is a certain spread, there is a big premium to the physical molecule in the wintertime. People trade financially to lock in positions, but if they want to convert to a physical position they pay big dollars, he added. "Physical molecules will create the Btus, not the financial paper," he explained.

Utilities have to make sure they are covered against the big price spikes too, no matter what factors enter the picture, a source said. "As a utility, we probably do more hedging than a marketer. We typically do it every year and not because of what happened last year at Sumas," the utility source said. SS

N. American rig count stable

After two weeks of big drops, the Canadian rig count stayed relatively flat last week at 188. The number of rigs exploring for oil and gas in Canada had dropped a total of 80 in the previous two reports released by Baker Hughes.

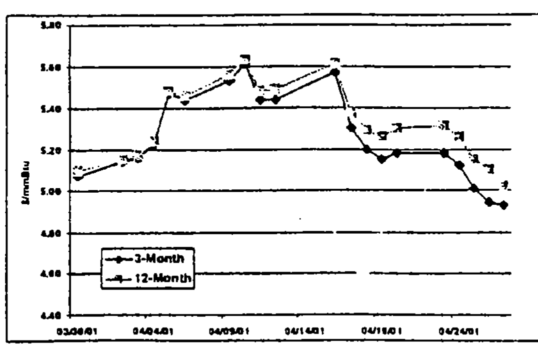
The U.S. rig count remained about the same, as well. The number of rigs exploring for oil and gas stood at 1,212 last week, down one from the previous count.

For all of North America, the oil and gas rig count dropped one to 1,400. RW

Henry Hub Futures and Strips

This table shows selected NYMEX Henry Hub contract settlement prices from the past week and calculates the 3-, 6-, 9-, and 12-month spreads. The chart to the right of the table data shows strip movement over the past 20 trading days. A dash indicates no data; an H indicates a holiday.

	04/23 Mon	04/24 Tue	04/25 Wed	04/26 Thu	04/27 Fri
May-01	5.125	5.078	4.981	4.891	-
Jun-01	5.175	5.114	4.994	4.940	4.867
Jul-01	5.240	5.177	5.057	5.002	4.935
Aug-01	5.298	5.232	5.110	5.055	4.990
Sep-01	5.310	5.245	5.125	5.070	5.010
Oct-01	5.338	5.275	5.155	5.102	5.045
Nov-01	5.482	5.420	5.300	5.252	5.198
Dec-01	5.618	5.562	5.450	5.402	5.354
Jan-02	5.672	5.617	5.507	5.462	5.415
Feb-02	5.512	5.462	5.357	5.317	5.275
Mar-02	5.242	5.205	5.115	5.086	5.050
Apr-02	4.792	4.749	4.665	4.646	4.620
3/strip	5.180	5.123	5.011	4.944	4.930
6/strip	5.248	5.187	5.070	5.010	5.007
9/strip	5.362	5.302	5.187	5.131	5.121
12/strip	5.317	5.261	5.151	5.102	5.022



Daily Price Survey continued

Trans. date	5/9	5/9	5/9
Flow date(s)	5/10	5/10	5/10
	Midpoint	Absolute	Common
New Mexico-San Juan Basin			
El Paso, Bondad	3.615	3.50-68	3.57-66
El Paso, non-Bondad	3.630	3.50-75	3.57-69
TW (Ignacio, pts south)	—	—	—
TW SJ (Blanco)	—	—	—
Rockies			
CIG (N. syst)	3.470	3.16-65	3.35-59
Kern River/Opal plant	3.610	3.38-74	3.52-70
NW, Stanfield	4.170	4.05-25	4.12-22
Questar	3.570	3.40-72	3.49-65
Cheyenne Hub	3.700	3.38-82	3.59-81
NW, Wyoming Pool	3.570	3.50-69	3.52-62
NW, south of Green River	3.465	3.15-65	3.34-59
Canadian Gas			
Iroquois	4.400	4.37-41	4.39-41
Niagara (NFG, Tenn)	4.395	4.37-43	4.38-41
NW Sumas	4.060	3.96-4.12	4.02-10
NOVA (AECO-C, NIT)*	C5.665	C5.62-69	C5.65-68
NOVA (same-day)*****	C5.635	5.58-68	5.61-66
Emerson (Viking/GL)	4.100	4.05-17	4.07-13
Dawn, Ont.	4.405	4.38-44	4.39-42
PG&E-GTNW (Kingsgate)	4.000	3.99-4.01	3.99-4.01
Westcoast, St. 2*	C5.745	C5.67-77	C5.72-77
Appalachia			
Dominion North Point	4.380	4.36-40	4.37-39
Dominion South Point	4.395	4.34-51	4.35-44
Columbia, App	4.345	4.29-43	4.31-38
Mississippi-Alabama			
FGT, Mobile Bay	4.025	4.00-05	4.01-04
Gulf South, Mobile Bay	3.990	3.95-4.03	3.97-4.01
Texas E., M-1 (Kosi)	4.235	4.20-27	4.22-25
Transco, St. 85	4.150	4.12-20	4.13-17
Others			
Algonquin	4.470	4.46-48	4.46-48
SoCal gas, large pkgs***	12.430	12.00-95	12.19-67
PG&E, large pkgs***	8.305	7.50-8.85	7.97-8.64
Kern River Station	—	—	—
Malin	4.605	4.25-95	4.43-78
Alliance (into Interstates)	4.205	4.18-24	4.19-22
ANR ML7 (entire zone)	4.405	4.36-49	4.37-44
NGPL Amarillo receipt	4.065	4.02-12	4.04-09
NGPL Iowa-Ill. receipt	4.095	4.03-16	4.06-13
Northern (Mid 13)	3.790	3.77-81	3.77-81
Northern (Ventura)	4.055	4.01-15	4.02-09
Northern (demarc)	4.050	4.00-15	4.01-09
Dracut (into TN)	4.335	4.30-44	4.30-37
Citygates			
Chicago-LDCs, large e-us	4.230	4.14-30	4.19-27
Mich.-Consum. Energy**	4.355	4.32-42	4.33-38
Mich.-Mich Con**	4.345	4.30-41	4.32-37
PSCo citygate	3.515	3.33-67	3.43-60
PG&E citygate	8.295	7.40-9.10	7.87-8.72
Northwest (all gates)	4.160	4.15-22	4.15-17
Florida gates via FGT	4.465	4.40-51	4.44-49
Algonquin citygates	4.505	4.42-56	4.47-54
Dominion (delivered)	4.580	4.57-59	4.57-59
Columbia Gas (delivered)	4.550	4.54-56	4.54-56
Tenn. zone 5	4.450	4.42-46	4.44-46
Tenn. zone 6 (delivered)	4.440	4.41-49	4.42-46
Iroquois, Zone 2	4.465	4.45-48	4.46-47
Texas E., M-3	4.490	4.41-60	4.44-54
Transco Z6 (non-NY)	4.480	4.41-60	4.43-53
Transco Z6 (NY)	4.515	4.45-62	4.47-56

***NOTE: Price in C$ per gj; C$1=US$0.64918 (Canadian currency settlement from one business day prior EST.) **Large end-user prices. ***Deliveries into SoCal at Topock, Blythe, Needles, Ehrenburg; deliveries into PG&E at Topock and Daggett. ****Volume-weighted for all points except AECO-C and Westcoast St. 2. *****The NOVA (same-day) midpoint and ranges are for flow on the transaction date.**

willingness to absorb both positive and negative financial performance."

In first quarter 2001, TransCanada's gas marketing operation took a major hit supplying gas under a contract with a Midwest utility that calls for lower than market prices. The effects of that contract and the costs of exiting the retail gas business caused the unit to record a C$6 million loss for the quarter. In the 2000 first quarter, the marketing unit reported C$10 million in earnings.

Gas marketing revenues grew by some C$4.5 billion in the first quarter compared to last year, mostly due to higher gas prices.

TransCanada said it had considered other options for the business, such as refocusing and downsizing, but decided it would be more valuable if it was divested as a going concern to "a more appropriate owner."

"We recognize our employees bring the most value to the gas marketing business, so we will negotiate with prospective buyers to maximize opportunities for these employees," Kvisle said. "We will work with all affected employees to ease their transition through the process." SGS

Low storage levels to keep gas prices high

Due to the low level of underground gas storage and strong demand for natural gas to fuel electricity generation, the Energy Information Administration expects gas prices to remain high until at least next year.

For this spring and summer, gas prices are projected to decline modestly. In 2001, annual gas prices will average more than $5, EIA stated in its Short-Term Energy Outlook. If the spring and summer are hot in regions that consume large quantities of gas, the injections into underground storage would again be strained, resulting in a rise in prices again next winter.

The outlook "reaffirm[s] the need to develop additional sources of energy while building and maintaining the necessary infrastructure to more those supplier to the market," said Energy Secretary Spencer Abraham. "Until we take steps to address these problems, we will continue to experience volatility in energy markets and higher prices passed on to consumers at the gas pump."

Domestic gas production for 2001 and 2002 is expected to rise as production responds to the high rates of drilling over the past year, EIA said. The growth rates are projected to be 2.7% in 2001 and 2.5% in 2002, compared to 3.7% in 2000.

Very large storage injections are still expected for this summer. The storage situation, said EIA, is expected to improve next year, however, driving prices down.

A slowing economy and less rapid demand growth in the industrial and commercial sectors would decrease the gas demand in 2001 to about 1.9%, as compared to the high growth rate of 4.9% seen in 2000. Growth in 2002 is expected to be about 3.4% as the economy picks up again.

Net imports for gas are projected to rise about 13% in 2001 and another 4% in 2002. For the coming summer season, EIA projected that gas imports will be 17% above last summer's as demand for storage refill is likely to be high. VK

BP chooses Tampa as site for LNG terminal

The city of Tampa, Fla., has the potential to become one of the great energy hubs in North America as the result of Gulfstream Natural Gas System coming onshore in the area as well as BP's plans to build a $200 million import terminal in the Port of Tampa, BP North America Gas and Power President Tony Fountain said yesterday at GasMart/Power in Tampa.

Crude oil and coal already have a strong presence in Tampa because of its major port. "As for us, we're very keen that this is going to become one of the great [liquefied natural gas] hubs.

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FINANCIAL TIMES Energy

Supply & Demand

[13] Snohomish Public Utility District Contemplates Rate Relief ■ *from [5]*

The PUD with the highest rates in Washington is considering ways to bring electric prices down. At its meeting last week, the Snohomish County PUD board of directors discussed options to lower the utility's average 8.3 cents/KWh price.

"It's absolutely the first priority of this district," said Commissioner Cynthia First. Her own two-month electric bill was $800 "and I don't live in an electrically heated house," she said. The bill equals "another house payment."

Snohomish is BPA's largest customer. It takes 75 percent of its power from the agency, First said. BPA's 46-percent wholesale price increase last October was mostly passed on to ratepayers.

"We are going to be very aggressive, looking at BPA and asking them to cut the cost," she said. "Our customers are biting the bullet and I don't see BPA biting the bullet."

First said she wants the PUD to consider adding generation, possibly a gas-fired plant. It already has one hydro project and has made some headway on renewables. "We need something that gives us control," she said. "Gas is a perfect balance for hydro."

'We are going to be very aggressive, looking at BPA and asking them to cut the cost.'

First said aluminum workers have gotten a lot of attention and money from BPA that her ratepayers are subsidizing, but it's harder to identify the economic damage in the north Puget Sound area.

"Boeing laid off 5,000 people in our service area," she said, noting it is not clear how significant the price of electricity was as a factor in the company's decision to make those staff reductions.

Besides BPA's prices, Snohomish thinks it got screwed on three long-term 25-MW contracts signed last winter, one each with Enron, AEP and Morgan Stanley. The Everett *Herald* reported that if Snohomish can get out of the contracts, it could lead to a 9 percent rate reduction.

The PUD has cancelled an 8-year contract with Enron for 25 MW calculated at $109/MWh and is waiting to see if the bankruptcy court imposes a penalty. This week negotiations are scheduled on changing the terms of a 5-year deal with AEP for 25 MW calculated to cost $150/MWh. And last week the PUD filed with FERC to get out of an 8-year contract with Morgan Stanley for 25 MW at $105/MWh (CU No. 1018 [4/13]). "Our position with Morgan Stanley is that's just out of the ballpark," First said.

PUD spokesman Neil Neroutsos said Snohomish is holding off, for now, on renegotiating a 5-year contract with PacifiCorp for 25 MW. That contract's price was reported at $78/MWh.

Commissioners have cautioned the public that rates may go back up if Bonneville raises its price.

Staff recommendations for reducing rates are on the discussion list for the commission's Feb. 26 meeting. A public hearing on the subject is scheduled for March 5 *[Cindy Simmons]*.

[14] Kaiser Files for Bankruptcy; CFAC Resumes Production ■ *from [7]*

Kaiser Aluminum Corporation blamed asbestos-related lawsuits and falling profits for its decision to seek bankruptcy court protection last week. The company said plant expansions and falling demand, along with the lawsuits, left the company with $700 million in bond debt. It acknowledged that it would not be able to make debt payments of $200 million this month.

Kaiser shut down all of its potlines at primary smelters near Spokane and Tacoma in 2000. It announced last fall that it had no plans to restart either plant.

The bankruptcy filing will have minimal effect on BPA, according to spokesman Bill Murlin. BPA currently supplies Kaiser with less than 29 MW and Murlin said the company "has not told us to stop delivering."

Bonneville also expects Kaiser's long-term take-or-pay agreement to remain in effect. Last year BPA agreed to eliminate the take-or-pay obligation until next October, in return for interruption rights on a portion of the company's federal load. But Murlin said that once the interim agreement expires in October, "they are back on the hook for the amount of power they would normally have taken, which is about 290 MW."

Murlin said Kaiser has made no attempt to renegotiate its contract since the bankruptcy filing. "We have a contract through 2006 and there's been no effort to change that," he said.

Kaiser president and CEO Jack Hockema said the Chapter 11 filing "will provide Kaiser with the opportunity to reorganize its financial structure and implement a strategic plan to return to sustained profitability." Shortly after the filing, the company received a $300-million loan from the Bank of America.

Kaiser was circumspect on whether it plans to sell any of its facilities, but analysts said that companies such as Alcoa Aluminum might be interested in purchasing the Trentwood rolling mill near Spokane. Kaiser spokesman Scott Lamb would only say that the company has "no current plans to sell any of its facilities."

While Kaiser was embroiled in bankruptcy court, another aluminum plant in Washington, Columbia Falls, was making plants to restart one of its five potlines. Idled for more than a year, Columbia Falls will reactivate the potline next month.

"The price and the conditions of service from Enron were ridiculously overpriced and way out of line with what should have been demanded," said Gianunzio. "The prices we were paying at the time were the result of a lot of market manipulation. Hopefully, we can get some relief from [the Federal Energy Regulatory Commission] or renegotiate the contract."

Snohomish is also attempting to renegotiate contracts with American Electric Power and Morgan Stanley. The average price of three contracts, which were signed with Enron, AEP and Morgan Stanley in January 2001, was $110/MWh and the terms were for five to seven years.

FERC deemed that $75/MWh was the ceiling on "just and reasonable" at that time in the wholesale spot market, Gianunzio said.

The Palo Alto-canceled contracts involved one signed April 11, 2001, for a portion of the city's natural gas supply and one on May 7, 2001, for 25 MW through 2004. The city had signed two contracts July 1, 2001, for natural gas services.

"We became increasingly concerned about Enron's ability to deliver on its contractual obligations to us as reports about the company's financial instability became more serious," said John Ulrich, director of the City of Palo Alto Utilities. "Once Enron's bond rating was downgraded, we felt it was in the city's best interest to terminate these contracts immediately."

The state of California is seeking to renegotiate all its long-term energy contracts and began those efforts prior to the Enron debacle, state officials said. "We're trying to renegotiate our long-term contracts, but we don't want it to be construed as directly related to Enron," said a spokesman for the California Dept. of Water Resources, which began buying power last year when the wholesale price spikes debilitated the state's biggest utilities.

California has 56 short- to long-term contracts that range from one to 10 years. None involve Enron, but the state is eyeing the ripple effects on their suppliers that do deal with Enron. The state estimates that Enron might have 800 to 1,200 MW of power in the California market. If the marketer cannot deliver, the state might be forced to cover or absorb the load.

But DWR said the state is not worried. While California was forced to buy 100% of its power on the spot market last year under the threat of blackouts, the state's contracts and conservation efforts have put it in a much better position, according to DWR.

In the meantime, the state is looking for "mutually beneficial deals" that can involve delivery points to building new generation. "It was not done in the light of Enron news, but done prior to that," the department spokesman said.

Meanwhile, BPA last week said it would honor five-year contracts to buy 300 MW of power from Enron. The contracts mostly began in January 2002 and extend for five years at an average price of $52/MWh, although prices range from $30/MWh to $85/MWh, a BPA spokesman said. Enron amounts to 10% of BPA's total purchase book and the purchases represent 3% of BPA's total load, he said. Most of the contracts were signed in fall 2000 and spring 2001.

"We are very comfortable with our position and that we made good decisions under the circumstances last year," said the spokesman. Although power prices are low now, they could rise and over time the price BPA paid

Prices of Spot Electricity

WEEK ENDING FEBRUARY 9—DAILY OFF-PEAK INDEXES

($ per MWh)

Daily Index	*February 3 Sunday*	*February 4 Monday*	*February 5 Tuesday*	*February 6 Wednesday*	*February 7 Thursday*	*February 8 Friday*	*February 9 Saturday*
COB	20.59	20.59	19.78	20.16	20.90	20.68	20.68
Mid-C	19.45	19.45	18.77	19.72	19.93	18.06	18.06
Palo Verde	19.10	19.10	16.01	16.81	17.07	14.86	14.86
Four Corners	19.75	19.75	17.82	18.60	18.21	18.08	18.08
NP15	22.51	22.51	20.21	20.87	22.33	21.56	21.56
SP15	22.32	22.32	19.99	20.93	22.13	20.87	20.87
New England	N.A.	20.00	21.25	22.00	23.00	21.75	N.A.
PJM WesternHub	N.A.	17.00	18.53	20.06	17.56	16.14	N.A.
VACAR	N.A.	16.75	18.42	19.85	18.29	18.00	N.A.
Southern, into	N.A.	18.00	19.00	23.00	17.38	16.30	N.A.
Florida	N.A.	18.50	17.00	17.00	17.00	20.00	N.A.
TVA, into	N.A.	13.50	14.00	14.00	14.00	14.50	N.A.
ECAR, North	N.A.	15.77	17.50	17.76	16.80	14.44	N.A.
Into Cinergy	N.A.	13.25	14.79	15.30	14.09	12.85	N.A.
MAIN, North	N.A.	13.25	14.25	15.00	14.50	13.00	N.A.
MAIN, South	N.A.	13.68	14.57	15.34	14.23	13.75	N.A.
ComEd, into	N.A.	13.50	14.43	15.00	14.38	13.17	N.A.
MAPP, North	N.A.	13.50	13.38	14.06	14.50	13.50	N.A.
MAPP, South	N.A.	13.25	13.50	14.00	14.50	13.50	N.A.
SPP, North	N.A.	12.92	13.55	14.92	14.13	13.31	N.A.
Entergy, into	N.A.	14.00	14.50	15.00	15.00	14.50	N.A.
ERCOT	N.A.	14.01	14.59	15.01	14.99	14.61	N.A.

NOTE: Index prices are for daily prescheduled, off-peak (8 hours) electricity. The off-peak indexes for these markets are based on financially firm or physically firm power. Western Monday off-peak deals includes power for delivery around-the-clock Sunday. Indexes are calculated based on prices of actual transactions reported by both buyers and sellers. The chief determinant of the index price is the volume-weighted average. However, the straight average, median, and mode are also considered.

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R. Lafferty
Avista Corporation

"significant drop" in the prices that day and that no other market fundamentals pertained.

Before signing the contracts with Morgan Stanley and others, Christensen said the PUD sent an RFP to 17 suppliers. Only five replied, and two of those replies were not responsive. None of the remaining three would supply more than 25 MW, but the utility had a hole of 75 MW to 100 MW, "so we had no choice of suppliers." Nor were any of the three willing to keep their offers open for five days as the RFP requested. "They insisted on the right to 'refresh' their prices. So we could either sign them sight unseen at the prices cited or read the contracts and watch the prices go up." During the five days the PUD took to review the contracts, the prices for all three went up 15 percent, even though the market rose only 10 percent, he said.

Christensen said the PUD did try to find evidence as to whether there was collusion among the suppliers. "It looks pretty stinky. There is this question of [whether] this was a strategy driven by what was going on in the short-term market or if there was some more nefarious dealings among them." But he said either way, the redress the utility seeks is the same.

Judy Hitchen, a spokesperson for Morgan Stanley, rejected any suggestion of collusion. "We didn't know how many other bidders there were" or who they were, she said. "Needless to say, we didn't have conversations with any of bidders, and we had no information about their bids or the terms." She said the contract M-S signed with Snohomish "was entirely proper, arm's-length and fully negotiated" *[Ben Tansey].*

[14] Power Planning Council's 20-year Plan Assumes Mixed System ■ *from [5]*

The Northwest Power Planning Council has drafted a paper outlining the issues to be addressed in its next 20-year Northwest Power Plan.

By law the council must forecast demand for electricity and present strategies for meeting that demand.

In the draft, the council noted competitive wholesale markets require utilities to think in much shorter time frames. The next five to seven years will be a special focus of the plan, but the drafters said long-term planning makes sense as well.

The plan assumes the Northwest will continue to have a mixed system in which there is competition in the wholesale market, but little at the retail level. It also assumes retail rates will continue to be established by regulatory agencies.

"It is unlikely that there will be any significant reversal of national policy encouraging wholesale competition," the drafters wrote. They said their policy goal is not to restructure power markets overall, but to seek "improvements within this mixed market structure that will allow it to function more efficiently and effectively."

The difference in the market experiences of wholesale and retail buyers was one of the first problems addressed in the draft. "The council and most other analysts agree that the crisis [of 2000-2001] was heightened and prolonged by the lack of response of electricity demand to the growing shortage and increasing price of electricity. In California, this was because retail rates were frozen while stranded costs were recovered. In other parts of the West, it was a result of a continuing mix of regulated retail markets with little attention to what is needed in order to allow the competitive wholesale market to work effectively."

The council said the mixed system needs mechanisms to increase retail demand's responsiveness to wholesale prices. Real-time pricing was suggested for commercial customers, as was PGE's Demand Exchange, in which a utility pays customers for load reduction.

The council also suggested alternative rate designs for all consumers that would provide predictable rates for a base amount of consumption, with market rates for additional electricity use.

'Conservation that was not done in the late 1990s and 2000 would have almost entirely paid for itself at the market prices that existed between June 2000 and June 2001.'

Direct service industries could continue to offer flexibility in shortage situations. The drafters noted that "most of the load reduction achieved over the last year was from the Direct Service Industries, primarily aluminum smelters." In deciding what power DSIs get from Bonneville after 2006, the council said the benefit of having large users that can be cut off should be considered.

The draft of issues to be addressed in the 20-year plan also looked at how market signals lead to the development of new generation. "Most, although not all, new generation is being developed by independent developers," the draft said. Of 6679 MW added or to be brought on line between 1994 and 2003, 71 percent comes from independent generating companies, the draft said, and 24 percent from utilities.

The council said the Northwest's hydropower system can vary 4000 aMW plus or minus the mean of 16,000 aMW. "Thus a period of near-average or better water conditions could hold down prices and destroy the profitability of a power plant. Conversely, a low-water year or two can result in large profits." The hydro factor "could adversely affect the amount and timing of investment and, therefore, the adequacy and reliability of the power supply."

Overall, the council said, "Inadequate investment in generation and conservation may lead to not just price volatility, but also actual electricity supply shortages and interruptions and the attendant economic disruptions."

Some options suggested were providing capacity payments as incentives for investment in generation; empowering some entities to build to maintain a particular capacity margin; or requiring utilities to maintain a particular capacity margin.

On conservation, the council said in the draft that the flexible conservation investment of the past has not

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