Appendix II-A: Supporting Tables for Analysis of Reliant Natural Gas Transactions

Table II-A1. EOL Western Gas Spot Trades, November 2000 – June 2001, Counterparties With the Greatest Daily Gross Trading (continued on next page)

Rank	Location	Transaction Date	Counterparty	Gross Quantity (MMBtu)[1]
1	SoCal Topock EPNG	2/2/01	Reliant Energy Services, Inc.	3,705,000
2	SoCal Topock EPNG	12/1/00	Reliant Energy Services, Inc.	2,280,000
3	SoCal Topock EPNG	12/15/00	Reliant Energy Services, Inc.	1,824,000
4	SoCal Topock EPNG	1/31/01	Reliant Energy Services, Inc.	1,740,000
5	SoCal Topock EPNG	12/8/00	Reliant Energy Services, Inc.	1,440,000
6	SoCal Topock EPNG	2/16/01	Reliant Energy Services, Inc.	1,420,000
7	SoCal Topock EPNG	11/22/00	Reliant Energy Services, Inc.	1,400,000
8	SoCal Topock EPNG	12/11/00	Reliant Energy Services, Inc.	1,354,000
9	SoCal Topock EPNG	1/26/01	Reliant Energy Services, Inc.	1,230,000
10	EPNG SoCal Ehrenberg	3/2/01	Reliant Energy Services, Inc.	1,215,000
11	SoCal Topock EPNG	3/23/01	Reliant Energy Services, Inc.	1,110,000
12	SoCal Topock EPNG	1/5/01	Reliant Energy Services, Inc.	1,020,000
13	SoCal Topock EPNG	12/22/00	Reliant Energy Services, Inc.	925,000
14	SoCal Topock EPNG	12/5/00	Reliant Energy Services, Inc.	911,000
15	EPNG SoCal Ehrenberg	3/23/01	Reliant Energy Services, Inc.	900,000
16	SoCal Topock EPNG	12/6/00	Reliant Energy Services, Inc.	803,000
17	SoCal Topock EPNG	11/17/00	Reliant Energy Services, Inc.	780,000
18	SoCal Topock EPNG	12/13/00	Reliant Energy Services, Inc.	773,000
19	SoCal Topock EPNG	1/3/01	Reliant Energy Services, Inc.	730,000
20	SoCal Topock EPNG	11/17/00	Aquila Energy Marketing Corporation	720,000
21	SoCal Topock EPNG	2/13/01	Reliant Energy Services, Inc.	710,000
22	SoCal Topock EPNG	12/7/00	Reliant Energy Services, Inc.	700,000
23	SoCal Topock EPNG	12/19/00	Reliant Energy Services, Inc.	670,000
24	SoCal Topock EPNG	2/23/01	Reliant Energy Services, Inc.	630,000
25	SoCal Topock EPNG	2/9/01	Reliant Energy Services, Inc.	622,500
26	PG&E Ctygte Pool	5/25/01	Duke Energy Trading and Marketing, L.L.C.	600,000
27	SoCal Topock EPNG	11/22/00	Southern California Gas Company	600,000
28	SoCal Topock EPNG	6/11/01	Reliant Energy Services, Inc.	574,000
29	SoCal Topock EPNG	12/12/00	Reliant Energy Services, Inc.	570,000
30	SoCal Topock EPNG	1/12/01	Dynegy Marketing and Trade	560,000
31	PG&E Ctygte Pool	5/4/01	Duke Energy Trading and Marketing, L.L.C.	555,000

[1] Gross quantity is adjusted for the duration of the contract: a 1-day spot contract for 10,000 MMBtu/d would contribute 10,000 MMBtu to the gross quantity, while a 3-day weekend spot contract for 10,000 MMBtu/d would contribute 30,000 MMBtu to the gross quantity. Almost all spot contracts are for 1 or 3 days, although contracts for holiday weekends are generally for 4 days and contracts for the Thanksgiving weekend are for 5 days.

Rank	Location	Transaction Date	Counterparty	Gross Quantity (MMBtu)[1]
32	SoCal Topock EPNG	2/1/01	Reliant Energy Services, Inc.	550,000
33	EPNG SoCal Ehrenberg	3/23/01	El Paso Merchant Energy, L.P.	525,000
34	PG&E Ctygte Pool	11/10/00	Duke Energy Trading and Marketing, L.L.C.	525,000
35	SoCal Topock EPNG	12/15/00	Dynegy Marketing and Trade	525,000
36	SoCal Topock EPNG	1/26/01	Duke Energy Trading and Marketing, L.L.C.	525,000
37	SoCal Topock EPNG	1/12/01	Duke Energy Trading and Marketing, L.L.C.	520,000
38	SoCal Topock EPNG	12/4/00	Reliant Energy Services, Inc.	513,000
39	SoCal Topock EPNG	11/30/00	Reliant Energy Services, Inc.	502,000
40	SoCal Topock EPNG	11/27/00	Reliant Energy Services, Inc.	490,000

Table II-A2. EOL Western Gas Spot Trades, November 2000 – June 2001, Counterparties With the Greatest Daily Net Purchases (continued on next page)

Rank	Location	Transaction Date	Counterparty	Gross Quantity (MMBtu)[2]	Net Purchases (MMBtu)
1	SoCal Topock EPNG	2/16/01	Reliant Energy Services, Inc.	1,420,000	1,380,000
2	SoCal Topock EPNG	12/15/00	Reliant Energy Services, Inc.	1,824,000	1,356,000
3	SoCal Topock EPNG	2/2/01	Reliant Energy Services, Inc.	3,705,000	1,065,000
4	SoCal Topock EPNG	1/5/01	Reliant Energy Services, Inc.	1,020,000	1,020,000
5	SoCal Topock EPNG	11/22/00	Reliant Energy Services, Inc.	1,400,000	900,000
6	SoCal Topock EPNG	12/1/00	Reliant Energy Services, Inc.	2,280,000	780,000
7	SoCal Topock EPNG	12/22/00	Reliant Energy Services, Inc.	925,000	775,000
8	SoCal Topock EPNG	1/26/01	Reliant Energy Services, Inc.	1,230,000	690,000
9	PG&E Ctygte Pool	5/25/01	Duke Energy Trading and Marketing, L.L.C.	600,000	600,000
10	SoCal Topock EPNG	1/3/01	Reliant Energy Services, Inc.	730,000	570,000
11	SoCal Topock EPNG	1/12/01	Dynegy Marketing and Trade	560,000	560,000
12	SoCal Topock EPNG	12/13/00	Reliant Energy Services, Inc.	773,000	557,000
13	PG&E Ctygte Pool	5/4/01	Duke Energy Trading and Marketing, L.L.C.	555,000	555,000
14	SoCal Topock EPNG	12/8/00	Reliant Energy Services, Inc.	1,440,000	540,000
15	EPNG SoCal Ehrenberg	3/2/01	Reliant Energy Services, Inc.	1,215,000	495,000
16	SoCal Topock EPNG	11/17/00	Reliant Energy Services, Inc.	780,000	480,000
17	SoCal Topock EPNG	11/27/00	Reliant Energy Services, Inc.	490,000	470,000
18	SoCal Topock EPNG	12/18/00	Reliant Energy Services, Inc.	480,000	460,000
19	SoCal Topock EPNG	2/23/01	Reliant Energy Services, Inc.	630,000	450,000
20	SoCal Topock EPNG	1/16/01	Reliant Energy Services, Inc.	445,000	445,000
21	SoCal Topock EPNG	4/27/01	Reliant Energy Services, Inc.	420,000	420,000
22	SoCal Topock EPNG	12/12/00	Reliant Energy Services, Inc.	570,000	410,000
23	SoCal Topock EPNG	2/12/01	Reliant Energy Services, Inc.	470,000	410,000
24	SoCal Topock EPNG	2/14/01	Reliant Energy Services, Inc.	430,000	410,000
25	PG&E Ctygte Pool	11/17/00	Duke Energy Trading and Marketing, L.L.C.	465,000	405,000
26	SoCal Topock EPNG	2/22/01	Reliant Energy Services, Inc.	470,000	390,000
27	Waha	11/3/00	Aquila Energy Marketing Corporation	450,000	390,000
28	SoCal Topock EPNG	5/11/01	Reliant Energy Services, Inc.	390,000	390,000
29	PG&E Ctygte Pool	1/12/01	Duke Energy Trading and Marketing, L.L.C.	460,000	380,000
30	SoCal Topock EPNG	12/20/00	Reliant Energy Services, Inc.	400,000	380,000
31	SoCal Topock EPNG	1/22/01	Reliant Energy Services, Inc.	380,000	380,000
32	SoCal Topock EPNG	2/13/01	Reliant Energy Services, Inc.	710,000	370,000

[2]Gross quantity and net purchases are adjusted for the duration of the contract: buying a 1-day spot contract for 10,000 MMBtu/d would contribute 10,000 MMBtu to the gross quantity and net purchases, while buying a 3-day weekend spot contract for 10,000 MMBtu/d would contribute 30,000 MMBtu to the gross quantity and net purchases. Almost all spot contracts are for 1 or 3 days, although contracts for holiday weekends are generally for 4 days and contracts for the Thanksgiving weekend are for 5 days.

Rank	Location	Transaction Date	Counterparty	Gross Quantity (MMBtu)[2]	Net Purchases (MMBtu)
33	SoCal Topock EPNG	2/1/01	Reliant Energy Services, Inc.	550,000	370,000
34	SoCal Topock EPNG	12/29/00	Reliant Energy Services, Inc.	440,000	360,000
35	SoCal Topock EPNG	1/2/01	Reliant Energy Services, Inc.	340,000	340,000
36	PG&E Ctygte Pool	1/19/01	Duke Energy Trading and Marketing, L.L.C.	450,000	330,000
37	PG&E Ctygte Pool	11/3/00	Duke Energy Trading and Marketing, L.L.C.	390,000	330,000
38	SoCal Topock EPNG	2/15/01	Reliant Energy Services, Inc.	330,000	330,000
39	SoCal Topock EPNG	2/20/01	Reliant Energy Services, Inc.	345,000	325,000
40	SoCal Topock EPNG	12/14/00	Reliant Energy Services, Inc.	358,000	322,000

Table II-A3. EOL Western Gas Spot Trades, November 2000 – June 2001, Counterparties With the Greatest Daily Net Sales (continued on next page)

Rank	Location	Transaction Date	Counterparty	Gross Quantity (MMBtu)[3]	Net Sales (MMBtu)
1	SoCal Topock EPNG	11/22/00	Southern California Gas Company	600,000	600,000
2	EPNG SoCal Ehrenberg	3/23/01	El Paso Merchant Energy, L.P.	525,000	525,000
3	SoCal Topock EPNG	12/15/00	Dynegy Marketing and Trade	525,000	525,000
4	SoCal Topock EPNG	12/15/00	Southern California Gas Company	484,638	484,638
5	SoCal Topock EPNG	3/23/01	El Paso Merchant Energy, L.P.	480,000	480,000
6	SoCal Topock EPNG	12/22/00	Dynegy Marketing and Trade	450,000	450,000
7	SoCal Topock EPNG	2/23/01	El Paso Merchant Energy, L.P.	442,500	442,500
8	SoCal Topock EPNG	1/12/01	Duke Energy Trading and Marketing, L.L.C.	520,000	440,000
9	SoCal Topock EPNG	1/5/01	El Paso Merchant Energy, L.P.	435,000	435,000
10	SoCal Topock EPNG	11/3/00	Aquila Energy Marketing Corporation	420,000	420,000
11	EPNG SoCal Ehrenberg	3/9/01	El Paso Merchant Energy, L.P.	396,000	396,000
12	SoCal Topock EPNG	12/1/00	Dynegy Marketing and Trade	390,000	390,000
13	SoCal Topock EPNG	12/8/00	Dynegy Marketing and Trade	390,000	390,000
14	SoCal Topock EPNG	2/16/01	El Paso Merchant Energy, L.P.	380,000	380,000
15	EPNG SoCal Ehrenberg	3/2/01	El Paso Merchant Energy, L.P.	360,000	360,000
16	SoCal Topock EPNG	11/22/00	Duke Energy Trading and Marketing, L.L.C.	350,000	350,000
17	SoCal Topock EPNG	1/26/01	Duke Energy Trading and Marketing, L.L.C.	525,000	345,000
18	SoCal Topock EPNG	11/3/00	Duke Energy Trading and Marketing, L.L.C.	345,000	345,000
19	SoCal Topock EPNG	11/17/00	Aquila Energy Marketing Corporation	720,000	330,000
20	EPNG SoCal Ehrenberg	3/30/01	El Paso Merchant Energy, L.P.	330,000	330,000
21	EPNG SoCal Ehrenberg	5/18/01	Reliant Energy Services, Inc.	330,000	330,000
22	PG&E Ctygte Pool	3/2/01	Duke Energy Trading and Marketing, L.L.C.	330,000	330,000
23	SoCal Topock EPNG	11/22/00	Williams Energy Marketing & Trading Company	325,000	325,000
24	PG&E Ctygte Pool	1/12/01	El Paso Merchant Energy, L.P.	300,000	300,000
25	SoCal Topock EPNG	11/10/00	Aquila Energy Marketing Corporation	300,000	300,000
26	SoCal Topock EPNG	12/22/00	Aquila Energy Marketing Corporation	300,000	300,000
27	EPNG SoCal Ehrenberg	3/16/01	El Paso Merchant Energy, L.P.	285,000	285,000
28	EPNG SoCal Ehrenberg	6/15/01	Reliant Energy Services, Inc.	285,000	285,000
29	SoCal Topock EPNG	1/19/01	Duke Energy Trading and Marketing, L.L.C.	285,000	285,000
30	SoCal Topock EPNG	1/12/01	Williams Energy Marketing & Trading Company	280,000	280,000
31	PG&E Ctygte Pool	1/19/01	El Paso Merchant Energy, L.P.	270,000	270,000
32	SoCal Topock EPNG	2/2/01	El Paso Merchant Energy, L.P.	270,000	270,000

[3] Gross quantity and net sales are adjusted for the duration of the contract: selling a 1-day spot contract for 10,000 MMBtu/d would contribute 10,000 MMBtu to the gross quantity and net sales, while selling a 3-day weekend spot contract for 10,000 MMBtu/d would contribute 30,000 MMBtu to the gross quantity and net sales. Almost all spot contracts are for 1 or 3 days, although contracts for holiday weekends are generally for 4 days and contracts for the Thanksgiving weekend are for 5 days.

Rank	Location	Transaction Date	Counterparty	Gross Quantity (MMBtu)[3]	Net Sales (MMBtu)
33	PG&E Ctygte Pool	5/25/01	Calpine Energy Services, L.P.	260,000	260,000
34	SoCal Topock EPNG	1/5/01	Duke Energy Trading and Marketing, L.L.C.	255,000	255,000
35	SoCal Topock EPNG	2/2/01	Duke Energy Trading and Marketing, L.L.C.	255,000	255,000
36	PG&E Ctygte Pool	11/10/00	Aquila Energy Marketing Corporation	480,000	240,000
37	EPNG SoCal Ehrenberg	3/2/01	Southern California Gas Company	240,000	240,000
38	EPNG SoCal Ehrenberg	4/6/01	Reliant Energy Services, Inc.	240,000	240,000
39	PG&E Ctygte Pool	4/27/01	Enron Energy Services, Inc.	240,000	240,000
40	SoCal Topock EPNG	12/8/00	Aquila Energy Marketing Corporation	240,000	240,000

Table II-A4. EOL Topock and Ehrenberg Gas Spot Trades, November 2000 – June 2001, Largest Net Sellers to Enron by Month (continued on next page)

Transaction Month	Rank Within Month	Counterparty	Counterparty Net Sales (MMBtu)[4]	Gross Volume (MMBtu)
Nov-00	1	Aquila Energy Marketing Corporation	2,615,000	3,575,000
	2	Duke Energy Trading and Marketing, L.L.C.	2,210,000	2,720,000
	3	Southern California Gas Company	1,375,000	1,405,000
	4	San Diego Gas & Electric Company	595,000	595,000
	5	PG&E Energy Trading-Gas Corporation	555,000	785,000
Dec-00	1	Dynegy Marketing and Trade	3,545,000	3,605,000
	2	Aquila Energy Marketing Corporation	2,110,000	2,140,000
	3	Southern California Gas Company	1,807,638	1,827,638
	4	Mirant Americas Energy Marketing, L.P.	1,381,000	1,381,000
	5	Enserco Energy, Inc.	917,000	917,000
Jan-01	1	Duke Energy Trading and Marketing, L.L.C.	2,720,850	3,280,850
	2	Williams Energy Marketing & Trading Company	1,020,000	1,020,000
	3	Coral Energy Resources, L.P.	872,708	892,708
	4	El Paso Merchant Energy, L.P.	741,000	1,821,000
	5	Aquila Energy Marketing Corporation	439,000	791,000
Feb-01	1	El Paso Merchant Energy, L.P.	2,806,000	3,086,000
	2	Duke Energy Trading and Marketing, L.L.C.	1,454,000	1,884,000
	3	Aquila Energy Marketing Corporation	595,000	935,000
	4	Mirant Americas Energy Marketing, L.P.	524,000	554,000
	5	Southern California Gas Company	332,500	332,500
Mar-01	1	El Paso Merchant Energy, L.P.	5,484,000	5,624,000
	2	Southern California Gas Company	790,000	1,080,000
	3	Aquila Energy Marketing Corporation	641,000	1,037,000
	4	Texaco Natural Gas Inc.	391,000	391,000
	5	Burlington Resources Trading Inc.	215,808	215,808

[4]Net sales and gross quantity are adjusted for the duration of the contract: selling a 1-day spot contract for 10,000 MMBtu/d would contribute 10,000 MMBtu to the net sales and gross quantity, while buying a 3-day weekend spot contract for 10,000 MMBtu/d would contribute 30,000 MMBtu to the net sales and gross quantity. Almost all spot contracts are for 1 or 3 days, although contracts for holiday weekends are generally for 4 days and contracts for the Thanksgiving weekend are for 5 days.

Transaction Month	Rank Within Month	Counterparty	Counterparty Net Sales (MMBtu)[4]	Gross Volume (MMBtu)
Apr-01	1	El Paso Merchant Energy, L.P.	2,653,488	2,763,488
	2	Duke Energy Trading and Marketing, L.L.C.	1,037,754	1,177,754
	3	Mirant Americas Energy Marketing, L.P.	944,767	944,767
	4	Coral Energy Resources, L.P.	941,000	979,000
	5	Southern California Gas Company	500,000	520,000
May-01	1	El Paso Merchant Energy, L.P.	2,114,222	2,634,222
	2	Enserco Energy, Inc.	530,000	570,000
	3	Calpine Energy Services, L.P.	380,500	878,500
	4	PG&E Energy Trading-Gas Corporation	169,598	169,598
	5	AEP Energy Services, Inc.	144,022	864,022
Jun-01	1	Duke Energy Trading and Marketing, L.L.C.	888,646	1,158,646
	2	Mirant Americas Energy Marketing, L.P.	601,238	601,238
	3	El Paso Merchant Energy, L.P.	566,336	1,056,336
	4	Aquila Energy Marketing Corporation	523,162	749,262
	5	BP Energy Company	392,500	432,500
Total	1	El Paso Merchant Energy, L.P.	14,365,046	16,985,046
	2	Duke Energy Trading and Marketing, L.L.C.	7,486,100	12,420,100
	3	Aquila Energy Marketing Corporation	7,268,162	10,414,262
	4	Southern California Gas Company	5,014,188	6,134,188
	5	Mirant Americas Energy Marketing, L.P.	4,202,889	4,312,889
	6	Coral Energy Resources, L.P.	2,632,665	4,448,623
	7	Williams Energy Marketing & Trading Company	2,566,134	4,336,134
	8	Dynegy Marketing and Trade	1,853,013	11,778,971
	9	Enserco Energy, Inc.	1,808,500	2,398,500
	10	BP Energy Company	1,696,000	2,491,000

Table II-A5. EOL Western Gas Spot Trades, November 2000 – June 2001, Counterparties With the Greatest Monthly Net Purchases

Rank	Location	Transaction Month	Counterparty	Gross Quantity (MMBtu)[5]	Net Purchases (MMBtu)
1	SoCal Topock EPNG	December 2000	**Reliant Energy Services, Inc.**	15,296,000	8,024,000
2	SoCal Topock EPNG	February 2001	**Reliant Energy Services, Inc.**	11,422,500	7,227,500
3	SoCal Topock EPNG	January 2001	**Reliant Energy Services, Inc.**	8,438,350	6,131,650
4	PG&E Ctygte Pool	May 2001	Duke Energy Trading and Marketing, L.L.C.	2,968,475	2,478,475
5	SoCal Topock EPNG	November 2000	**Reliant Energy Services, Inc.**	5,172,000	2,188,000
6	Opal	April 2001	BP Energy Company	2,391,266	2,044,942
7	SoCal Topock EPNG	May 2001	**Reliant Energy Services, Inc.**	1,934,479	1,914,479
8	PG&E Ctygte Pool	January 2001	Duke Energy Trading and Marketing, L.L.C.	2,815,000	1,885,000
9	PG&E Ctygte Pool	November 2000	Duke Energy Trading and Marketing, L.L.C.	3,075,000	1,735,000
10	SoCal Topock EPNG	June 2001	**Reliant Energy Services, Inc.**	2,635,059	1,542,059
11	Waha	March 2001	BP Energy Company	1,465,000	1,465,000
12	EPNG SoCal Ehrenberg	May 2001	Sempra Energy Trading Corp.	1,295,000	1,275,000
13	Opal	December 2000	Dynegy Marketing and Trade	1,285,000	1,275,000
14	PGT Malin	November 2000	Dynegy Marketing and Trade	1,480,000	1,255,000
15	PG&E Topock	June 2001	PG&E Energy Trading-Gas Corporation	1,243,030	1,199,030
16	PG&E Ctygte Pool	April 2001	Mirant Americas Energy Marketing, L.P.	1,065,000	1,065,000
17	PG&E Ctygte Pool	June 2001	Duke Energy Trading and Marketing, L.L.C.	1,599,500	1,059,500
18	SoCal Topock EPNG	January 2001	Dynegy Marketing and Trade	1,384,000	1,034,000
19	Waha	April 2001	BP Energy Company	960,000	960,000
20	SoCal Topock EPNG	April 2001	**Reliant Energy Services, Inc.**	1,570,000	950,000
21	Waha	February 2001	BP Energy Company	955,000	935,000
22	EPNG SoCal Ehrenberg	May 2001	**Reliant Energy Services, Inc.**	2,205,000	915,000
23	PG&E Ctygte Pool	April 2001	Duke Energy Trading and Marketing, L.L.C.	1,290,000	860,000
24	PG&E Ctygte Pool	November 2000	Coast Energy Canada, Inc.	1,055,000	855,000
25	Waha	June 2001	Duke Energy Field Services Marketing, LLC	835,000	835,000
26	Opal	November 2000	Dynegy Marketing and Trade	910,000	820,000
27	PG&E Ctygte Pool	November 2000	Pacific Gas & Electric Company	820,000	820,000
28	Opal	November 2000	Cook Inlet Energy Supply L.L.C.	1,985,000	795,000
29	PG&E Ctygte Pool	March 2001	Duke Energy Trading and Marketing, L.L.C.	1,615,000	675,000
30	PGT Malin	February 2001	Enron Energy Services, Inc.	655,000	655,000
31	EPNG SoCal Ehrenberg	June 2001	Sempra Energy Trading Corp.	677,500	637,500
32	Opal	December 2000	Barrett Resources Corporation	715,000	615,000

[5]Gross quantity and net purchases are adjusted for the duration of the contract: buying a 1-day spot contract for 10,000 MMBtu/d would contribute 10,000 MMBtu to the gross quantity and net purchases, while buying a 3-day weekend spot contract for 10,000 MMBtu/d would contribute 30,000 MMBtu to the gross quantity and net sales. Almost all spot contracts are for 1 or 3 days, although contracts for holiday weekends are generally for 4 days and contracts for the Thanksgiving weekend are for 5 days.

Table II-A6. Trading in EOL Spot Gas, Topock and Ehrenberg Points Only, November 2000 – June 2001, Busiest EOL Trading Days for Individual Counterparties

Rank	Transaction Date	Counterparty	Number of Transactions
1	1/31/01	Reliant Energy Services, Inc.	174
2	12/11/00	Reliant Energy Services, Inc.	136
3	2/2/01	Reliant Energy Services, Inc.	124
4	12/5/00	Reliant Energy Services, Inc.	89
5	12/1/00	Reliant Energy Services, Inc.	76
6	12/13/00	Reliant Energy Services, Inc.	74
7	1/3/01	Reliant Energy Services, Inc.	73
8	12/6/00	Reliant Energy Services, Inc.	72
9	12/7/00	Reliant Energy Services, Inc.	71
10	2/13/01	Reliant Energy Services, Inc.	71
11	12/19/00	Reliant Energy Services, Inc.	67
12	3/23/01	Reliant Energy Services, Inc.	66
13	6/11/01	Reliant Energy Services, Inc.	61
14	12/15/00	Reliant Energy Services, Inc.	58
15	12/12/00	Reliant Energy Services, Inc.	57
16	2/1/01	Reliant Energy Services, Inc.	55
17	12/4/00	Reliant Energy Services, Inc.	52
18	6/13/01	Reliant Energy Services, Inc.	52
19	11/30/00	Reliant Energy Services, Inc.	51
20	11/27/00	Reliant Energy Services, Inc.	48
21	12/8/00	Reliant Energy Services, Inc.	48
22	12/18/00	Reliant Energy Services, Inc.	48
23	2/12/01	Reliant Energy Services, Inc.	47
24	2/22/01	Reliant Energy Services, Inc.	47
25	5/22/01	Reliant Energy Services, Inc.	47
26	2/14/01	Reliant Energy Services, Inc.	45
27	1/16/01	Reliant Energy Services, Inc.	44
28	1/26/01	Reliant Energy Services, Inc.	42
29	3/2/01	Reliant Energy Services, Inc.	42
30	5/10/01	Reliant Energy Services, Inc.	42

Table II-A7. Purchases and Sales of at Least 100,000 MMBtu/d by Counterparty and Location (Topock and Ehrenberg Combined)

Counterparty	Location	Transaction Date	Number of Transactions	Sell (MMBtu/d)	Buy (MMBtu/d)	Gross Volume (MMBtu/d)
Reliant Energy Services, Inc.	SoCal Topock	11/1/00	21	100,000	100,000	200,000
Duke Energy Trading and Marketing, LLC	PG&E Ctygte	11/9/00	34	125,000	185,000	310,000
Reliant Energy Services, Inc.	SoCal Topock	11/13/00	40	190,000	200,000	390,000
Aquila Energy Marketing Corporation	SoCal Topock	11/16/00	28	170,000	100,000	270,000
Reliant Energy Services, Inc.	SoCal Topock	11/30/00	51	182,000	320,000	502,000
Reliant Energy Services, Inc.	SoCal Topock	12/1/00	76	250,000	510,000	760,000
Reliant Energy Services, Inc.	SoCal Topock	12/4/00	52	203,000	310,000	513,000
Reliant Energy Services, Inc.	SoCal Topock	12/5/00	89	311,000	600,000	911,000
Reliant Energy Services, Inc.	SoCal Topock	12/6/00	72	313,000	490,000	803,000
Reliant Energy Services, Inc.	SoCal Topock	12/7/00	71	220,000	480,000	700,000
Reliant Energy Services, Inc.	SoCal Topock	12/8/00	48	150,000	330,000	480,000
Reliant Energy Services, Inc.	SoCal Topock	12/11/00	136	554,000	800,000	1,354,000
Reliant Energy Services, Inc.	SoCal Topock	12/13/00	74	108,000	665,000	773,000
Reliant Energy Services, Inc.	SoCal Topock	12/19/00	67	200,000	470,000	670,000
Reliant Energy Services, Inc.	SoCal Topock	1/31/01	174	730,000	1,010,000	1,740,000
Reliant Energy Services, Inc.	SoCal Topock	2/2/01	124	440,000	795,000	1,235,000
Reliant Energy Services, Inc.	SoCal Topock	2/13/01	71	170,000	540,000	710,000
Reliant Energy Services, Inc.	SoCal Topock	2/28/01	33	120,000	210,000	330,000
Reliant Energy Services, Inc.	SoCal Topock	3/1/01	31	155,000	160,000	315,000
Reliant Energy Services, Inc.	SoCal Topock	3/2/01	42	120,000	285,000	405,000
Reliant Energy Services, Inc.	SoCal Topock	3/20/01	27	110,000	160,000	270,000
Reliant Energy Services, Inc.	SoCal Topock	3/22/01	23	130,000	100,000	230,000
Reliant Energy Services, Inc.	SoCal Topock	3/23/01	66	320,000	350,000	670,000
Reliant Energy Services, Inc.	SoCal Topock	4/3/01	22	120,000	100,000	220,000
Reliant Energy Services, Inc.	SoCal Topock	6/11/01	61	224,000	400,000	624,000
Reliant Energy Services, Inc.	SoCal Topock	6/13/01	52	110,000	379,479	489,479

Table II-A8. December 2000 Price Chart, *Gas Daily* Index and EOL Prices With Churn Day Indication

Transaction Date	Contracted Flow Date or Flow Period	Reliant Gross Volume (MMBtu/d)	Gas Daily Midpoint Price ($/MMBtu)	EOL High ($/MMBtu)	EOL Low ($/MMBtu)	Weighted Price ($/MMBtu)	EOL Opening Price ($/MMBtu)	EOL Closing Price ($/MMBtu)	Reliant Churn Day
11/30/00	12/1/00	502,000	18.90	20.25	16.50	18.89	17.00	18.25	Yes
12/1/00	12/2 – 12/4/00	760,000	18.50	20.25	17.00	18.80	18.50	19.25	Yes
12/4/00	12/5/00	513,000	21.61	23.25	19.00	21.80	19.00	21.50	Yes
12/5/00	12/6/00	911,000	26.60	28.00	23.25	26.57	23.25	28.00	Yes
12/6/00	12/7/00	803,000	36.25	41.00	33.00	38.05	34.50	33.00	Yes
12/7/00	12/8/00	700,000	42.02	53.00	32.00	43.19	45.00	38.00	Yes
12/8/00	12/9 – 12/11/00	480,000	54.66	59.00	42.00	55.42	42.00	58.00	Yes
12/11/00	12/12/00	1,354,000	59.42	68.00	34.00	59.19	58.00	50.00	Yes
12/12/00	12/13/00	570,000	32.75	47.00	20.00	31.80	47.00	26.00	
12/13/00	12/14/00	773,000	20.26	24.00	14.00	20.16	22.00	19.00	Yes
12/14/00	12/15/00	358,000	19.03	24.00	15.00	19.23	16.00	15.00	
12/15/00	12/16 – 12/18/00	608,000	17.06	19.50	14.00	16.88	17.00	18.00	
12/18/00	12/19/00	480,000	20.39	22.50	17.00	20.52	17.00	19.50	
12/19/00	12/20/00	670,000	19.56	23.00	15.00	20.11	21.00	17.00	Yes
12/20/00	12/21/00	400,000	20.36	23.00	19.00	20.91	19.00	21.50	
12/21/00	12/22/00	335,000	18.98	22.00	18.00	18.95	22.00	18.00	
12/22/00	12/23 – 12/27/00	185,000	18.78	19.00	17.00	17.98	18.50	18.50	
12/27/00	12/28/00	220,000	16.64	18.50	15.50	16.76	18.50	15.50	
12/28/00	12/29 – 12/31/00	100,000	14.41	15.50	14.20	14.62	14.50	14.50	

Table II-A9. EOL Western Gas Spot Trades, November 2000 – June 2001, Most Trades Within a Clock Minute[6] (continued on next page)

Rank	Location	Transaction Date	Counterparty	Number of Transactions
1	SoCal Topock EPNG	2/2/01	Reliant Energy Services, Inc.	16
2	SoCal Topock EPNG	2/2/01	Reliant Energy Services, Inc.	15
3	SoCal Topock EPNG	2/2/01	Reliant Energy Services, Inc.	13
4	SoCal Topock EPNG	1/31/01	Reliant Energy Services, Inc.	12
5	SoCal Topock EPNG	1/31/01	Reliant Energy Services, Inc.	12
6	SoCal Topock EPNG	2/2/01	Reliant Energy Services, Inc.	12
7	PGT Malin	5/10/01	Enserco Energy, Inc.	11
8	SoCal Topock EPNG	1/31/01	Reliant Energy Services, Inc.	11
9	SoCal Topock EPNG	2/2/01	Reliant Energy Services, Inc.	11
10	SoCal Topock EPNG	6/11/01	Reliant Energy Services, Inc.	11
11	EPNG SoCal Ehrenberg	3/2/01	Reliant Energy Services, Inc.	10
12	SoCal Topock EPNG	12/15/00	Reliant Energy Services, Inc.	10
13	SoCal Topock EPNG	12/20/00	Reliant Energy Services, Inc.	10
14	SoCal Topock EPNG	1/31/01	Reliant Energy Services, Inc.	10
15	SoCal Topock EPNG	2/2/01	Reliant Energy Services, Inc.	10
16	EPNG SoCal Ehrenberg	4/11/01	Reliant Energy Services, Inc.	9
17	EPNG SoCal Ehrenberg	4/26/01	Reliant Energy Services, Inc.	9
18	EPNG SoCal Ehrenberg	5/10/01	Reliant Energy Services, Inc.	9
19	SoCal Topock EPNG	12/4/00	Reliant Energy Services, Inc.	9
20	SoCal Topock EPNG	12/5/00	Reliant Energy Services, Inc.	9
21	SoCal Topock EPNG	12/15/00	Reliant Energy Services, Inc.	9
22	SoCal Topock EPNG	1/26/01	Reliant Energy Services, Inc.	9
23	SoCal Topock EPNG	1/31/01	Reliant Energy Services, Inc.	9
24	SoCal Topock EPNG	1/31/01	Reliant Energy Services, Inc.	9
25	SoCal Topock EPNG	1/31/01	Reliant Energy Services, Inc.	9
26	SoCal Topock EPNG	2/1/01	Reliant Energy Services, Inc.	9
27	SoCal Topock EPNG	2/13/01	Reliant Energy Services, Inc.	9
28	SoCal Topock EPNG	6/13/01	Reliant Energy Services, Inc.	9
29	PG&E Ctygte Pool	4/26/01	Enron Energy Services, Inc.	8
30	SoCal Topock EPNG	12/11/00	Reliant Energy Services, Inc.	8
31	SoCal Topock EPNG	12/11/00	Reliant Energy Services, Inc.	8
32	SoCal Topock EPNG	12/11/00	Reliant Energy Services, Inc.	8
33	SoCal Topock EPNG	12/11/00	Reliant Energy Services, Inc.	8
34	SoCal Topock EPNG	12/13/00	Reliant Energy Services, Inc.	8
35	SoCal Topock EPNG	1/4/01	Reliant Energy Services, Inc.	8
36	SoCal Topock EPNG	1/16/01	Reliant Energy Services, Inc.	8

[6]A clock minute is defined as starting at, for example, 8:51:00 and extending to 8:51:59.

Rank	Location	Transaction Date	Counterparty	Number of Transactions
37	SoCal Topock EPNG	1/31/01	Reliant Energy Services, Inc.	8
38	SoCal Topock EPNG	2/13/01	Reliant Energy Services, Inc.	8
39	SoCal Topock EPNG	2/13/01	Reliant Energy Services, Inc.	8
40	SoCal Topock EPNG	2/16/01	Reliant Energy Services, Inc.	8

Table II-A10. EOL Western Gas Spot Trades, November 2000 – June 2001, Most Trades Within 5 Clock Minutes[7] (continued on next page)

Rank	Location	Transaction Date	Counterparty	Number of Transactions
1	SoCal Topock EPNG	1/31/01	Reliant Energy Services, Inc.	49
2	SoCal Topock EPNG	2/2/01	Reliant Energy Services, Inc.	39
3	SoCal Topock EPNG	2/2/01	Reliant Energy Services, Inc.	34
4	SoCal Topock EPNG	6/11/01	Reliant Energy Services, Inc.	32
5	SoCal Topock EPNG	1/31/01	Reliant Energy Services, Inc.	25
6	SoCal Topock EPNG	1/31/01	Reliant Energy Services, Inc.	25
7	SoCal Topock EPNG	12/11/00	Reliant Energy Services, Inc.	24
8	SoCal Topock EPNG	12/1/00	Reliant Energy Services, Inc.	23
9	SoCal Topock EPNG	1/31/01	Reliant Energy Services, Inc.	23
10	SoCal Topock EPNG	11/27/00	Reliant Energy Services, Inc.	22
11	SoCal Topock EPNG	12/11/00	Reliant Energy Services, Inc.	21
12	SoCal Topock EPNG	2/2/01	Reliant Energy Services, Inc.	21
13	SoCal Topock EPNG	6/13/01	Reliant Energy Services, Inc.	21
14	SoCal Topock EPNG	11/17/00	Reliant Energy Services, Inc.	20
15	SoCal Topock EPNG	12/5/00	Reliant Energy Services, Inc.	20
16	SoCal Topock EPNG	1/3/01	Reliant Energy Services, Inc.	20
17	SoCal Topock EPNG	1/31/01	Reliant Energy Services, Inc.	20
18	SoCal Topock EPNG	2/2/01	Reliant Energy Services, Inc.	20
19	SoCal Topock EPNG	12/11/00	Reliant Energy Services, Inc.	19
20	SoCal Topock EPNG	12/19/00	Reliant Energy Services, Inc.	19
21	SoCal Topock EPNG	12/20/00	Reliant Energy Services, Inc.	19
22	SoCal Topock EPNG	2/22/01	Reliant Energy Services, Inc.	19
23	SoCal Topock EPNG	12/4/00	Reliant Energy Services, Inc.	18
24	SoCal Topock EPNG	12/15/00	Reliant Energy Services, Inc.	18
25	SoCal Topock EPNG	1/22/01	Reliant Energy Services, Inc.	18
26	SoCal Topock EPNG	1/31/01	Reliant Energy Services, Inc.	18
27	SoCal Topock EPNG	2/1/01	Reliant Energy Services, Inc.	18
28	SoCal Topock EPNG	2/13/01	Reliant Energy Services, Inc.	18
29	EPNG SoCal Ehrenberg	3/2/01	Reliant Energy Services, Inc.	17
30	SoCal Topock EPNG	1/17/01	Reliant Energy Services, Inc.	17
31	SoCal Topock EPNG	11/13/00	Reliant Energy Services, Inc.	16
32	SoCal Topock EPNG	12/13/00	Reliant Energy Services, Inc.	16
33	EPNG SoCal Ehrenberg	5/10/01	Reliant Energy Services, Inc.	15
34	SoCal Topock EPNG	12/13/00	Reliant Energy Services, Inc.	15
35	SoCal Topock EPNG	12/15/00	Reliant Energy Services, Inc.	15

[7] A period of 5 clock minutes is defined as starting at, for example, 8:51:00 and extending to 8:55:59.

Rank	Location	Transaction Date	Counterparty	Number of Transactions
36	SoCal Topock EPNG	2/21/01	Reliant Energy Services, Inc.	15
37	EPNG SoCal Ehrenberg	6/15/01	Reliant Energy Services, Inc.	14
38	PGT Malin	5/10/01	Enserco Energy, Inc.	14
39	SoCal Topock EPNG	11/22/00	Reliant Energy Services, Inc.	14
40	SoCal Topock EPNG	12/1/00	Reliant Energy Services, Inc.	14

Table II-A11. EOL Western Gas Spot Trades, November 2000 – June 2001, Most Consecutive Transactions by One Firm[8] (continued on next page)

Rank	Location	Transaction Date	Counterparty	Consecutive Transactions
1	SoCal Topock EPNG	1/31/01	Reliant Energy Services, Inc.	43
2	SoCal Topock EPNG	2/2/01	Reliant Energy Services, Inc.	34
3	SoCal Topock EPNG	11/27/00	Reliant Energy Services, Inc.	23
4	SoCal Topock EPNG	1/31/01	Reliant Energy Services, Inc.	22
5	SoCal Topock EPNG	2/2/01	Reliant Energy Services, Inc.	20
6	SoCal Topock EPNG	3/23/01	Reliant Energy Services, Inc.	18
7	EPNG SoCal Ehrenberg	5/10/01	Reliant Energy Services, Inc.	16
8	SoCal Topock EPNG	1/31/01	Reliant Energy Services, Inc.	16
9	SoCal Topock EPNG	12/11/00	Reliant Energy Services, Inc.	15
10	EPNG SoCal Ehrenberg	6/15/01	Reliant Energy Services, Inc.	14
11	SoCal Topock EPNG	1/31/01	Reliant Energy Services, Inc.	14
12	SoCal Topock EPNG	1/31/01	Reliant Energy Services, Inc.	14
13	SoCal Topock EPNG	12/11/00	Reliant Energy Services, Inc.	14
14	SoCal Topock EPNG	2/2/01	Reliant Energy Services, Inc.	13
15	SoCal Topock EPNG	1/4/01	Reliant Energy Services, Inc.	13
16	SoCal Topock EPNG	12/1/00	Reliant Energy Services, Inc.	13
17	Waha	3/16/01	BP Energy Company	13
18	SoCal Topock EPNG	1/31/01	Reliant Energy Services, Inc.	12
19	Waha	3/19/01	BP Energy Company	12
20	SoCal Topock EPNG	6/11/01	Reliant Energy Services, Inc.	11
21	SoCal Topock EPNG	2/5/01	El Paso Merchant Energy, L.P.	11
22	SoCal Topock EPNG	1/31/01	Reliant Energy Services, Inc.	11
23	SoCal Topock EPNG	12/11/00	Reliant Energy Services, Inc.	11
24	SoCal Topock EPNG	12/11/00	Reliant Energy Services, Inc.	11
25	SoCal Topock EPNG	12/11/00	Reliant Energy Services, Inc.	11
26	SoCal Topock EPNG	11/3/00	Aquila Energy Marketing Corporation	11
27	EPNG SoCal Ehrenberg	4/26/01	Reliant Energy Services, Inc.	10
28	EPNG SoCal Ehrenberg	4/11/01	Reliant Energy Services, Inc.	10
29	EPNG SoCal Ehrenberg	4/5/01	Reliant Energy Services, Inc.	10
30	EPNG SoCal Ehrenberg	3/23/01	El Paso Merchant Energy, L.P.	10
31	EPNG SoCal Ehrenberg	3/8/01	El Paso Merchant Energy, L.P.	10
32	SoCal Topock EPNG	6/11/01	Reliant Energy Services, Inc.	10
33	SoCal Topock EPNG	5/11/01	Reliant Energy Services, Inc.	10
34	SoCal Topock EPNG	2/21/01	Reliant Energy Services, Inc.	10

[8] These are the longest sequences of transactions for spot gas at a single location that are buy or sell transactions by a single firm.

Rank	Location	Transaction Date	Counterparty	Consecutive Transactions
35	SoCal Topock EPNG	2/2/01	Reliant Energy Services, Inc.	10
36	SoCal Topock EPNG	1/18/01	Reliant Energy Services, Inc.	10
37	SoCal Topock EPNG	12/11/00	Reliant Energy Services, Inc.	10
38	EPNG SoCal Ehrenberg	3/26/01	Reliant Energy Services, Inc.	9
39	EPNG SoCal Ehrenberg	3/2/01	Reliant Energy Services, Inc.	9
40	SoCal Topock EPNG	6/13/01	Reliant Energy Services, Inc.	9

Table II-A12. EOL Western Gas Spot Trades, November 2000 – June 2001, Most Consecutive "Buy" Transactions By One Firm[9] (continued on next page)

Rank	Location	Transaction Date	Counterparty	Consecutive Transactions
1	SoCal Topock EPNG	11/27/00	Reliant Energy Services, Inc.	23
2	SoCal Topock EPNG	3/23/01	Reliant Energy Services, Inc.	18
3	EPNG SoCal Ehrenberg	5/10/01	Reliant Energy Services, Inc.	16
4	SoCal Topock EPNG	2/2/01	Reliant Energy Services, Inc.	13
5	SoCal Topock EPNG	1/4/01	Reliant Energy Services, Inc.	13
6	Waha	3/16/01	BP Energy Company	13
7	Waha	3/19/01	BP Energy Company	12
8	SoCal Topock EPNG	6/11/01	Reliant Energy Services, Inc.	11
9	SoCal Topock EPNG	1/31/01	Reliant Energy Services, Inc.	11
10	SoCal Topock EPNG	5/11/01	Reliant Energy Services, Inc.	10
11	SoCal Topock EPNG	2/21/01	Reliant Energy Services, Inc.	10
12	SoCal Topock EPNG	2/2/01	Reliant Energy Services, Inc.	10
13	SoCal Topock EPNG	1/18/01	Reliant Energy Services, Inc.	10
14	SoCal Topock EPNG	12/11/00	Reliant Energy Services, Inc.	10
15	SoCal Topock EPNG	6/11/01	Reliant Energy Services, Inc.	9
16	SoCal Topock EPNG	4/27/01	Reliant Energy Services, Inc.	9
17	SoCal Topock EPNG	2/12/01	Reliant Energy Services, Inc.	9
18	SoCal Topock EPNG	2/1/01	Reliant Energy Services, Inc.	9
19	SoCal Topock EPNG	1/26/01	Reliant Energy Services, Inc.	9
20	SoCal Topock EPNG	1/25/01	Reliant Energy Services, Inc.	9
21	SoCal Topock EPNG	1/18/01	Reliant Energy Services, Inc.	9
22	SoCal Topock EPNG	1/16/01	Reliant Energy Services, Inc.	9
23	SoCal Topock EPNG	1/3/01	Reliant Energy Services, Inc.	9
24	SoCal Topock EPNG	11/21/00	Reliant Energy Services, Inc.	9
25	Waha	11/6/00	Aquila Energy Marketing Corporation	9
26	SoCal Topock EPNG	6/13/01	Reliant Energy Services, Inc.	8
27	SoCal Topock EPNG	6/13/01	Reliant Energy Services, Inc.	8
28	SoCal Topock EPNG	4/23/01	Reliant Energy Services, Inc.	8
29	SoCal Topock EPNG	4/16/01	Dynegy Marketing and Trade	8
30	SoCal Topock EPNG	2/15/01	Reliant Energy Services, Inc.	8
31	SoCal Topock EPNG	2/1/01	Reliant Energy Services, Inc.	8
32	SoCal Topock EPNG	2/1/01	Reliant Energy Services, Inc.	8
33	SoCal Topock EPNG	1/31/01	Reliant Energy Services, Inc.	8
34	SoCal Topock EPNG	1/31/01	Reliant Energy Services, Inc.	8
35	SoCal Topock EPNG	1/31/01	Reliant Energy Services, Inc.	8

[9]These are the longest sequences of transactions for spot gas at a single location that are buy transactions by a single firm.

Rank	Location	Transaction Date	Counterparty	Consecutive Transactions
36	SoCal Topock EPNG	1/25/01	Reliant Energy Services, Inc.	8
37	SoCal Topock EPNG	1/22/01	Reliant Energy Services, Inc.	8
38	SoCal Topock EPNG	1/17/01	Reliant Energy Services, Inc.	8
39	SoCal Topock EPNG	1/3/01	Reliant Energy Services, Inc.	8
40	SoCal Topock EPNG	1/2/01	Reliant Energy Services, Inc.	8

Table II-A13. EOL Western Gas Spot Trades, November 2000 – June 2001, Most Consecutive "Sell" Transactions By One Firm[10] (continued on next page)

Rank	Location	Transaction Date	Counterparty	Consecutive Transactions
1	EPNG SoCal Ehrenberg	6/15/01	Reliant Energy Services, Inc.	14
2	SoCal Topock EPNG	2/5/01	El Paso Merchant Energy, L.P.	11
3	SoCal Topock EPNG	1/31/01	Reliant Energy Services, Inc.	11
4	SoCal Topock EPNG	11/3/00	Aquila Energy Marketing Corporation	11
5	EPNG SoCal Ehrenberg	4/26/01	Reliant Energy Services, Inc.	10
6	EPNG SoCal Ehrenberg	4/11/01	Reliant Energy Services, Inc.	10
7	EPNG SoCal Ehrenberg	4/5/01	Reliant Energy Services, Inc.	10
8	EPNG SoCal Ehrenberg	3/23/01	El Paso Merchant Energy, L.P.	10
9	EPNG SoCal Ehrenberg	3/8/01	El Paso Merchant Energy, L.P.	10
10	SoCal Topock EPNG	6/11/01	Reliant Energy Services, Inc.	10
11	EPNG SoCal Ehrenberg	3/26/01	Reliant Energy Services, Inc.	9
12	SoCal Topock EPNG	6/13/01	Reliant Energy Services, Inc.	9
13	SoCal Topock EPNG	3/23/01	Reliant Energy Services, Inc.	9
14	SoCal Topock EPNG	3/21/01	El Paso Merchant Energy, L.P.	9
15	SoCal Topock EPNG	1/31/01	Reliant Energy Services, Inc.	9
16	SoCal Topock EPNG	1/29/01	Aquila Energy Marketing Corporation	9
17	SoCal Topock EPNG	12/19/00	Reliant Energy Services, Inc.	9
18	SoCal Topock EPNG	12/5/00	Reliant Energy Services, Inc.	9
19	SoCal Topock EPNG	12/1/00	Reliant Energy Services, Inc.	9
20	EPNG SoCal Ehrenberg	5/23/01	BP Energy Company	8
21	EPNG SoCal Ehrenberg	3/27/01	El Paso Merchant Energy, L.P.	8
22	EPNG SoCal Ehrenberg	3/22/01	Reliant Energy Services, Inc.	8
23	PG&E Topock	4/2/01	El Paso Merchant Energy, L.P.	8
24	SoCal Topock EPNG	12/15/00	Southern California Gas Company	8
25	SoCal Topock EPNG	12/11/00	Reliant Energy Services, Inc.	8
26	SoCal Topock EPNG	12/11/00	Reliant Energy Services, Inc.	8
27	SoCal Topock EPNG	11/20/00	Reliant Energy Services, Inc.	8
28	SoCal Topock EPNG	11/1/00	Dynegy Marketing and Trade	8
29	CIG Mainline	12/11/00	BP Energy Company	7
30	EPNG SoCal Ehrenberg	4/16/01	Reliant Energy Services, Inc.	7
31	EPNG SoCal Ehrenberg	3/29/01	Southern California Gas Company	7
32	EPNG SoCal Ehrenberg	3/16/01	El Paso Merchant Energy, L.P.	7
33	EPNG SoCal Ehrenberg	3/13/01	El Paso Merchant Energy, L.P.	7
34	PG&E Ctygte Pool	1/22/01	El Paso Merchant Energy, L.P.	7
35	PGT Malin	5/1/01	Enserco Energy, Inc.	7

[10] These are the longest sequences of transactions for spot gas at a single location that are sell transactions by a single firm.

Rank	Location	Transaction Date	Counterparty	Consecutive Transactions
36	SoCal Topock EPNG	2/13/01	Reliant Energy Services, Inc.	7
37	SoCal Topock EPNG	2/7/01	El Paso Merchant Energy, L.P.	7
38	SoCal Topock EPNG	2/2/01	Reliant Energy Services, Inc.	7
39	SoCal Topock EPNG	2/2/01	Reliant Energy Services, Inc.	7
40	SoCal Topock EPNG	1/31/01	Reliant Energy Services, Inc.	7

Table II-A14. Reliant's Profit From EOL-Reliant Netting Agreement, Highest Daily Profit From the Netting Agreement ($100,000 or More)

		Reliant Selling to EOL			Reliant Buying From EOL				
Transaction Date	**Churn Day**	**Transactions**	**Volume (MMBtu)**	**Price**	**Transactions**	**Volume (MMBtu)**	**Price**	**Reliant's Net Buy From EOL**	**Profit From the Netting Agreement**
12/11/00	Yes	56	554,000	$60.77	80	800,000	$57.84	246,000	$1,622,025
12/08/00	Yes	15	450,000	$57.73	33	990,000	$54.21	540,000	$1,584,545
03/01/01	Yes	15	155,000	$26.03	16	160,000	$22.43	5,000	$558,156
01/31/01	Yes	73	730,000	$14.21	101	1,010,000	$13.62	280,000	$431,267
02/13/01	Yes	17	170,000	$36.78	54	540,000	$34.30	370,000	$421,343
02/02/01	Yes	44	1,320,000	$16.24	80	2,385,000	$15.96	1,065,000	$369,726
12/05/00	Yes	29	311,000	$27.34	60	600,000	$26.22	289,000	$350,617
12/01/00	Yes	25	750,000	$19.21	51	1,530,000	$18.75	780,000	$345,000
03/06/01	No	7	70,000	$30.07	6	60,000	$24.42	(10,000)	$339,286
11/17/00	No	1	150,000	$10.50	21	630,000	$8.30	480,000	$329,929
12/06/00	Yes	23	313,000	$38,68	49	490,000	$37.78	177,000	$282,265
11/30/00	Yes	19	182,000	$19.82	32	320,000	$18.28	138,000	$280,313
03/02/01	Yes	12	360,000	$30.22	30	855,000	$29.46	495,000	$273,158
12/04/00	Yes	21	203,000	$22.54	31	310,000	$21.39	107,000	$233,919
12/07/00	Yes	23	220,000	$43.85	48	480,000	$43.00	260,000	$186,000
11/20/00	No	8	80,000	$13.75	7	70,000	$11.19	(10,000)	$179,250
02/23/01	No	3	90,000	$14.33	18	540,000	$12.38	450,000	$176,250
02/09/01	No	9	232,500	$15.95	13	390,000	$15.45	157,500	$115,529
12/19/00	Yes	20	200,000	$20.53	47	470,000	$19.98	270,000	$109,255
19 Days	14 Churn Days	420	6,540,500		777	12,630,000		6,089,500	$8187,833

Total Profit on the Churn Days	$7,047,590	86.07%
Total Profit on the other Days	$1,140,243	13.93%

Table II-A15. EOL-Reliant Netting Agreement's Impact on Physical Spot Trading Outcomes, Highest Daily Profit From the Netting Agreement ($100,000 or More)

Transaction Date	Churn Day	Profit From the Netting Agreement	Average Buy Price: Without the Netting Agreement	Average Buy Price: Applying Profit From the Netting Agreement, Assuming 60% Flow	GasDaily SoCal Large Packages Midpoint Price Index
12/11/00	Yes	$1,622,025	$51.24	$46.85	$59.42
12/08/00	Yes	$1,584,545	$51.28	$49.32	$54.66
03/01/01	Yes	$558,156	N/A[11]	N/A[11]	$23.95
01/31/01	Yes	$431,267	$12.08	$11.05	$13.75
02/13/01	Yes	$421,343	$33.16	$32.40	$34.53
02/02/01	Yes	$369,726	$15.61	$15.38	$15.39
12/05/00	Yes	$350,617	$25.00	$24.19	$26.60
12/01/00	Yes	$345,000	$18.31	$18.01	$18.50
03/06/01	No	$339,286	N/A[12]	N/A[12]	$25.27
11/17/00	No	$329,929	$7.61	$7.15	$9.60
12/06/00	Yes	$282,265	$36.18	$35.12	$36.25
11/30/00	Yes	$280,313	$16.25	$14.90	$18.90
03/02/01	Yes	$273,158	$28.91	$28.54	$27.79
12/04/00	Yes	$233,919	$19.20	$17.74	$21.61
12/07/00	Yes	$186,000	$42.28	$41.81	$42.02
11/20/00	No	$179,250	N/A[12]	N/A[12]	$13.42
02/23/01	No	$176,250	$11.98	$11.72	$12.68
02/09/01	No	$115,529	$14.72	$14.23	$14.83
12/19/00	Yes	$109,255	$19.57	$19.30	$19.56

[11] On March 1, 2001, Reliant bought 160,000 MMBtu on EOL and sold back 155,000 MMBtu. The net purchase, 5,000 MMBtu, is very small relative to the gross volume (only 1.59 percent). The profit generated by the difference between the buy price and the sell price for the 155,000 MMBtu is $558,156.
[12] On March 6, 2001 and November 20, 2000, Reliant was a net seller on EOL.

Table II-A16. Reliant's Profit From EOL-Reliant Netting Agreement for 24 Churn Days

	Reliant Selling to EOL			Reliant Buying From EOL				
Transaction Date	Transactions	Volume (MMBtu)	Price	Transactions	Volume (MMBtu)	Price	Reliant's Net Buy From EOL	Profit From the Netting Agreement
11/01/00	10	100,000	$5.07	11	100,000	$5.11	0	($4,700)
11/13/00	19	190,000	$7.41	21	200,000	$7.40	10,000	$3,605
11/30/00	19	182,000	$19.82	32	320,000	$18.28	138,000	$280,313
12/01/00	25	750,000	$19.21	51	1,530,000	$18.75	780,000	$345,000
12/04/00	21	203,000	$22.54	31	310,000	$21.39	107,000	$233,919
12/05/00	29	311,000	$27.34	60	600,000	$26.22	289,000	$350,617
12/06/00	23	313,000	$38.68	49	490,000	$37.78	177,000	$282,265
12/07/00	23	220,000	$43.85	48	480,000	$43.00	260,000	$186,000
12/08/00	15	450,000	$57.73	33	990,000	$54.21	540,000	$1,584,545
12/11/00	56	554,000	$60.77	80	800,000	$57.84	246,000	$1,622,025
12/13/00	7	108,000	$20.69	67	665,000	$20.72	557,000	($3,549)
12/19/00	20	200,000	$20.53	47	470,000	$19.98	270,000	$109,255
01/31/01	73	730,000	$14.21	101	1,010,000	$13.62	280,000	$431,267
02/02/01	44	1,320,000	$16.24	80	2,385,000	$15.96	1,065,000	$369,726
02/13/01	17	170,000	$36.78	54	540,000	$34.30	370,000	$421,343
02/28/01	12	120,000	$12.76	21	210,000	$12.93	90,000	($20,429)
03/01/01	15	155,000	$26.03	16	160,000	$22.43	5,000	$558,156
03/02/01	12	360,000	$30.22	30	855,000	$29.46	495,000	$273,158
03/20/01	11	110,000	$11.17	16	160,000	$11.01	50,000	$17,863
03/22/01	13	130,000	$11.09	10	100,000	$10.80	(30,000)	$29,077
03/23/01	31	960,000	$11.12	35	1,050,000	$11.12	90,000	$4,929
04/03/01	12	120,000	$15.09	10	100,000	$14.56	(20,000)	$53,167
06/11/01	21	224,000	$7.23	40	400,000	$6.84	176,000	$89,460
06/13/01	11	110,000	$8.98	41	379,479	$8.51	269,479	$50,950
							Total Profit	**$7,267,962**

Table II-A17. EOL-Reliant Netting Agreement's Impact on Physical Spot Trading Outcomes for 24 Churn Days

Transaction Date	Profit From the Netting Agreement	Average Buy Price		GasDaily SoCal Large Packages Midpoint Price Index
		Without the Netting Agreement	Applying Profit From the Netting Agreement, Assuming 60% Flow	
11/01/00	($4,700)	N/A[13]	N/A[13]	$5.20
11/13/00	$3,605	$7.04	$6.79	$7.37
11/30/00	$280,313	$16.25	$14.90	$18.90
12/01/00	$345,000	$18.31	$18.01	$18.50
12/04/00	$233,919	$19.20	$17.74	$21.61
12/05/00	$350,617	$25.00	$24.19	$26.60
12/06/00	$282,265	$36.18	$35.12	$36.25
12/07/00	$186,000	$42.28	$41.81	$42.02
12/08/00	$1,584,545	$51.28	$49.32	$54.66
12/11/00	$1,622,025	$51.24	$46.85	$59.42
12/13/00	($3,549)	$20.72	$20.73	$20.26
12/19/00	$109,255	$19.57	$19.30	$19.56
01/31/01	$431,267	$12.08	$11.05	$13.75
02/02/01	$369,726	$15.61	$15.38	$15.39
02/13/01	$421,343	$33.16	$32.40	$34.53
02/28/01	($20,429)	$13.16	$13.31	$12.96
03/01/01	$558,156	N/A[14]	N/A[14]	$23.95
03/02/01	$273,158	$28.91	$28.54	$27.79
03/20/01	$17,863	$10.65	$10.42	$11.04
03/22/01	$29,077	N/A[15]	N/A[15]	$11.00
03/23/01	$4,929	$11.06	$11.03	$11.13
04/03/01	$53,167	N/A[15]	N/A[15]	$14.71
06/11/01	$89,460	$6.33	$5.99	$6.74
06/13/01	$50,950	$8.33	$8.20	$8.47
Total Profit	**$7,267,962**			

[13]On November 1, 2000, Reliant bought 100,000 MMBtu on EOL and sold back the whole amount. Since the net purchase is zero, the average price cannot be calculated.

[14]On March 1, 2001, Reliant bought 160,000 MMBtu on EOL and sold back 155,000 MMBtu. The net purchase, 5,000 MMBtu, is very small relative to the gross volume (only 1.59 percent). The profit generated by the difference between the buy price and the sell price for the 155,000 MMBtu is $558,156.

[15]On March 22, 2001 and April 3, 2001, Reliant was a net seller on EOL.

Table II-A18. Reliant's Profit From EOL-Reliant Netting Agreement for December 2000 Flow

		Reliant Selling to EOL			Reliant Buying From EOL				
Transaction Date	Churn Day	Transactions	Volume (MMBtu)	Price	Transactions	Volume (MMBtu)	Price	Reliant's Net Buy From EOL	Profit From the Netting Agreement
11/30/00	Yes	19	182,000	$19.82	32	320,000	$18.28	138,000	$280,313
12/1/00	Yes	25	750,000	$19.21	51	1,530,000	$18.75	780,000	$345,000
12/4/00	Yes	21	203,000	$22.54	31	310,000	$21.39	107,000	$233,919
12/5/00	Yes	29	311,000	$27.34	60	600,000	$26.22	289,000	$350,617
12/6/00	Yes	23	313,000	$38.68	49	490,000	$37.78	177,000	$282,265
12/7/00	Yes	23	220,000	$43.85	48	480,000	$43.00	260,000	$186,000
12/8/00	Yes	15	450,000	$57.73	33	990,000	$54.21	540,000	$1,584,545
12/11/00	Yes	56	554,000	$60.77	80	800,000	$57.84	246,000	$1,622,025
12/12/00	No	8	80,000	$29.38	49	490,000	$30.04	410,000	($53,265)
12/13/00	Yes	7	108,000	$20.69	67	665,000	$20.72	557,000	($3,549)
12/14/00	No	2	18,000	$21.06	34	340,000	$19.97	322,000	$19,569
12/15/00	No	5	234,000	$17.79	53	1,590,000	$17.83	1,356,000	($9,764)
12/18/00	No	1	10,000	$20.50	47	470,000	$21.10	460,000	($5,957)
12/19/00	Yes	20	200,000	$20.53	47	470,000	$19.98	270,000	$109,255
12/20/00	No	1	10,000	$21.00	39	390,000	$21.72	380,000	($7,179)
12/21/00	No	6	60,000	$20.33	28	275,000	$18.78	215,000	$93,091
12/22/00	No	2	75,000	$17.67	17	850,000	$18.76	775,000	($82,353)
12/27/00	No	0	0	N/A	22	220,000	$17.17	220,000	$0
12/28/00	No	0	0	N/A	10	300,000	$15.17	300,000	$0
12/29/00	No	2	40,000	$15.50	20	400,000	$14.95	360,000	$22,000
20 Days	10 Churn Days	265	3,818,000		817	11,980,000		8,162,000	$4,966,5325

Total Profit on the Churn Days	$4,990,390
Total Profit on the other Days	-$ 23,859

Table II-A19. EOL-Reliant Netting Agreement's Impact on Physical Spot Trading Outcomes for December 2000 Flow

Transaction Date	Churn Day	Profit From the Netting Agreement	Average Buy Price: Without the Netting Agreement	Average Buy Price: Applying Profit From the Netting Agreement, Assuming 60% Flow	GasDaily SoCal Large Packages Midpoint Price Index
11/30/00	Yes	$280,313	$16.25	$14.90	$18.90
12/1/00	Yes	$345,000	$18.31	$18.01	$18.50
12/4/00	Yes	$233,919	$19.20	$17.74	$21.61
12/5/00	Yes	$350,617	$25.00	$24.19	$26.60
12/6/00	Yes	$282,265	$36.18	$35.12	$36.25
12/7/00	Yes	$186,000	$42.28	$41.81	$42.02
12/8/00	Yes	$1,584,545	$51.28	$49.32	$54.66
12/11/00	Yes	$1,622,025	$51.24	$46.85	$59.42
12/12/00	No	-$53,265	$30.17	$30.26	$32.75
12/13/00	Yes	-$3,549	$20.72	$20.73	$20.26
12/14/00	No	$19,569	$19.91	$19.87	$19.03
12/15/00	No	-$9,764	$17.84	$17.84	$17.06
12/18/00	No	-$5,957	$21.11	$21.12	$20.39
12/19/00	Yes	$109,255	$19.57	$19.30	$19.56
12/20/00	No	-$7,179	$21.74	$21.75	$20.36
12/21/00	No	$93,091	$18.35	$18.06	$18.98
12/22/00	No	-$82,353	$18.87	$18.94	$18.78
12/27/00	No	$0	$17.17	$17.17	$16.64
12/28/00	No	$0	$15.17	$15.17	$14.41
12/29/00	No	$22,000	$14.89	$14.85	$14.33
Volume Weighted Price			$23.71	$23.30	$24.09

Table II-A20. Reliant's Balance-of-Month Swap Trading Activities and Profits, November 27, 2000 – December 29, 2000

Trader	Transaction Date	Transaction Time	Buy/ Sell	Swap Volume (MMBtu/d)	Price	Contract Begin Date	Contract End Date	Counterparty	Profit Statistics: Profit Generated per Trade	Profit Statistics: Total Profit Generated
Financial Trader A	11/28/00	3:49 PM	S	-30,000	14.68	12/1/00	12/31/00	ENRON NORTH AMERICA CORP.	-$9,114,750	-$9,114,750
	11/30/00	7:46 AM	B	10,000	15.20	12/1/00	12/31/00	MIRANT AMERICAS ENERGY MARKETING, LP	$3,063,050	
		7:52 AM	B	30,000	15.10	12/1/00	12/31/00	ENRON NORTH AMERICA CORP.	$9,282,150	
		2:25 PM	B	5,000	17.07	12/1/00	12/31/00	ENRON NORTH AMERICA CORP.	$1,241,675	
		2:34 PM	B	5,000	16.85	12/1/00	12/31/00	ENRON NORTH AMERICA CORP.	$1,275,775	
		2:38 PM	B	10,000	16.94	12/1/00	12/31/00	MIRANT AMERICAS ENERGY MARKETING, LP	$2,523,650	
		3:52 PM	B	10,000	17.50	12/1/00	12/31/00	SEMPRA ENERGY TRADING CORP.	$2,350,050	
		3:54 PM	B	10,000	17.20	12/1/00	12/31/00	ENRON NORTH AMERICA CORP.	$2,443,050	
		3:55 PM	B	5,000	16.96	12/1/00	12/31/00	ENRON NORTH AMERICA CORP.	$1,258,725	$23,438,125
	12/1/00	12:42 PM	B	15,000	16.05	12/2/00	12/31/00	ENRON NORTH AMERICA CORP.	$4,158,900	
		12:44 PM	B	5,000	16.27	12/2/00	12/31/00	ENRON NORTH AMERICA CORP.	$1,353,300	
		12:45 PM	B	5,000	16.15	12/2/00	12/31/00	ENRON NORTH AMERICA CORP.	$1,370,925	
		12:53 PM	S	-5,000	16.56	12/2/00	12/31/00	ENRON NORTH AMERICA CORP.	-$1,309,800	
		12:55 PM	S	-5,000	16.12	12/2/00	12/31/00	ENRON NORTH AMERICA CORP.	-$1,375,800	
		1:56 PM	S	-2,000	16.70	12/2/00	12/31/00	SOUTHERN CALIFORNIA GAS COMPANY	-$515,220	$3,682,305
	12/4/00	3:44 PM	B	5,000	18.83	12/5/00	12/31/00	ENRON NORTH AMERICA CORP.	$973,575	
		4:25 PM	S	-5,000	22.39	12/6/00	12/31/00	ENRON NORTH AMERICA CORP.	-$496,900	
		4:26 PM	S	-5,000	22.48	12/6/00	12/31/00	ENRON NORTH AMERICA CORP.	-$485,850	-$9,175
	12/6/00	2:06 PM	S	-5,000	35.32	12/7/00	12/31/00	ENRON NORTH AMERICA CORP.	$1,140,375	$1,140,375
	12/7/00	1:58 PM	B	2,000	37.00	12/9/00	12/31/00	DYNEGY MARKETING AND TRADE	-$548,680	
		2:00 PM	B	10,000	37.25	12/9/00	12/31/00	SEMPRA ENERGY TRADING CORP.	-$2,800,900	
		2:24 PM	S	-10,000	38.00	12/8/00	12/31/00	DYNEGY MARKETING AND TRADE	$2,933,200	-$416,380
	12/12/00	12:38 PM	B	1,500	22.60	12/14/00	12/31/00	AQUILA, INC. D/B/A AQUILA NETWORKS	-$129,405	-$129,405
	12/13/00	8:53 AM	B	5,000	24.00	12/14/00	12/31/00	ENRON NORTH AMERICA CORP.	-$557,350	-$557,350
									Total =	$18,033,745

Table II-A21. Reliant's Balance-of-Month Swap Trading Activities and Profits, February 6, 2001 – February 24, 2001

Trader	Transaction Date	Transaction Time	Buy/ Sell	Swap Volume (MMBtu/d)	Price	Contract Begin Date	Contract End Date	Counterparty	Profit Statistics: Profit Generated per Trade	Profit Statistics: Total Profit Generated
Financial Trader A	2/6/01	10:59 AM	S	-5,000	15.00	2/7/01	2/28/01	SOUTHERN CALIFORNIA GAS COMPANY	-$530,525	-$530,525
	2/12/01	4:00 PM	B	10,000	17.50	2/14/01	2/28/01	WILLIAMS ENERGY MARKETING & TRADING COMPANY	$702,550	
		4:03 PM	B	5,000	17.75	2/14/01	2/28/01	DUKE ENERGY TRADING & MARKETING. L.L.C.	$332,525	
		4:04 PM	B	10,000	18.00	2/14/01	2/28/01	MIRANT AMERICAS ENERGY MARKETING, LP	$627,550	
		4:06 PM	B	5,000	18.00	2/14/01	2/28/01	DUKE ENERGY TRADING & MARKETING. L.L.C.	$313,775	
		4:13 PM	B	5,000	18.79	2/14/01	2/28/01	ENRON NORTH AMERICA CORP.	$254,525	
		4:14 PM	B	5,000	19.74	2/14/01	2/28/01	ENRON NORTH AMERICA CORP.	$183,275	
		4:16 PM	B	5,000	19.30	2/14/01	2/28/01	WILLIAMS ENERGY MARKETING & TRADING COMPANY	$216,275	
		4:24 PM	B	5,000	16.90	2/13/01	2/28/01	WILLIAMS ENERGY MARKETING & TRADING COMPANY	$410,650	
		4:26 PM	B	5,000	17.85	2/13/01	2/28/01	ENRON NORTH AMERICA CORP.	$334,650	
		4:28 PM	B	5,000	17.50	2/13/01	2/28/01	ENRON NORTH AMERICA CORP.	$362,650	
		4:32 PM	B	5,000	19.10	2/14/01	2/28/01	J. ARON & COMPANY	$231,275	
		4:33 PM	B	5,000	19.25	2/14/01	2/28/01	ENRON NORTH AMERICA CORP.	$220,025	
		4:34 PM	B	5,000	19.50	2/14/01	2/28/01	CINERGY MARKETING & TRADING, LLC	$201,275	$4,391,000

Total = $3,860,475

Appendix II-B: Econometric Analysis of Impact of Reliant Trading on Gas Prices

Intraday EOL Price Analysis

The dependent variable in the analysis is the percentage price change over a trade day (i.e., the intraday change in spot price, measured as the log ratio of the price of the last EOL trade over the price of the first EOL trade). We present two regressions, one with each measure of Reliant's churning activity. The period of interest is November 1, 2000 through June 2001.

For the discrete specification of churning, we estimate the following regression:

$$LCO = \beta 0 + \beta 1\ BNS100K + \beta 2\ DEC2000 + \beta 3\ MONDAY + \beta 4\ LSUMASD + \beta 5\ LNBNDD + \varepsilon,$$

Where:

- ♦ LCO is the intraday change in the logarithm of the SoCal spot price.
- ♦ BNS100K is a binary variable indicating whether there are buys and sells of at least 100,000 MMBtu/d on a specific day.
- ♦ DEC2000 and MONDAY are binary variables indicating that the transaction occurs in December 2000 or for Saturday to Monday flow, respectively.
- ♦ LSUMASD and LNBNDD are the interday changes in the logarithms of gas prices at Sumas and San Juan Non-Bondad, respectively.[1]
- ♦ ε captures the remaining unexplained component of LCO.

For the continuous specification of churning, we estimate the same regression as above, but for the second churn measure:

$$LCO = \beta_0 + \beta_1\ CHURN + \beta_2\ DEC2000 + \beta_3\ MONDAY + \beta_4\ LSUMASD + \beta_5\ LNBNDD + \varepsilon,$$

Where:

- ♦ CHURN is the minimum of sales and purchases (in thousands of MMBtu/d).
- ♦ All other variables are as previously defined.

[1]We use the *Gas Daily* Midpoint Price Index.

The results for these two models are provided in Table II-B1 and can be interpreted as follows:

- For both regression specifications, churning is found to be positively correlated with intraday gas price changes and is statistically significant. Stated differently, when Reliant churned, prices rose.
- Changes in gas prices at Sumas and San Juan Non-Bondad, and whether a trade occurs on Friday for weekend flow, are also positively correlated with intraday price changes.
- The coefficient on the December 2000 variable is negative, indicating that intraday price changes were smaller (i.e., more negative) during this period.

Table II-B1. Intraday Regression Results

Churn Measure	Regression Variable	Variable Definition	Parameter Estimate (Absolute value of t statistics)
Purchases and sales of at least 100,000 MMBtu/d	BnS100K	Binary variable indicating whether there are purchases and sales of at least 100,000 MMBtu/d on a specific day	0.0731 (2.74)
	Lsumasd_mid	Logarithm of the interday change in gas price at Sumas	0.4714 (5.82)
	Lnbndd_mid	Logarithm of the interday change in gas price at San Juan Non-Bondad	0.1941 (1.77)
	Monday	Binary variable indicating that the transaction occurs for Sat-Mon flow	0.0557 (2.43)
	Dec2000	Binary variable indicating that the transaction occurs in December 2000	-0.0678 (2.40)
Minimum of total sales and total purchases	Churn	Minimum of total purchases and total sales	0.0002 (2.34)
	Lsumasd_mid	Logarithm of the interday change in gas price at Sumas	0.4919 (6.05)
	Lnbndd_mid	Logarithm of the interday change in gas price at San Juan Non-Bondad	0.1751 (1.55)
	Monday	Binary variable indicating that the transaction occurs for Sat-Mon flow	0.0528 (2.27)
	Dec2000	Binary variable indicating that the transaction occurs in December 2000	-0.0618 (2.19)

Interday EOL Price Analyses and Counterfactual Gas Prices

The calculation of counterfactual gas prices is based on regression analysis similar to that described in the previous section, with three main differences:

First, we include overnight price changes in our analysis. We analyze the interday price change (i.e., the difference between the average EOL price on a trading day and the price on the next trading day).

Second, we model the churn's dynamic effect on prices on days subsequent to the churning days by including lags of the churn variables.[2] In other words, we investigate whether today's churn affects price changes for several days in the future.[3] We estimated our model using different numbers of lags. We found that the effect of churn could not be estimated precisely beyond three lags, so we report results based on the three-lags specifications. Even in some of these specifications, the effects of some lags of churn are not statistically significant. The counterfactual prices that we computed based on regressions including greater numbers of lags were qualitatively similar.

Third, because we are concerned with price dynamics, we also model general mean-reversion in prices that are independent of the effect of churn. Energy prices tend to mean-revert, at least in the medium to long term. High prices induce further exploration and production, leading to increased supply. To the extent that demand is price-sensitive, high prices may also reduce demand. By inducing additional supply and reducing demand, high current prices tend to lead to lower prices in the future. Conversely, low prices today tend to lead to higher prices in the future.

We model the daily price change on the churn variable, lags of the churn variable, and the difference between the lagged EOL price and an estimate of the equilibrium price. For the interday models with the discrete specification of churning, we estimate the following regression:

$$\text{LCC} = \beta_0 + \beta_1\ \text{LAGCH0} + \beta_2\ \text{LAGCH1} + \beta_3\ \text{LAGCH2} + \beta_4\ \text{LAGCH3} +$$

$$\beta_5\ (\text{LGLGP-EQLOGP}) + \varepsilon,$$

Where:

- LCC is the change in the logarithm of the EOL price from the previous day.
- LAGCH0, LAGCH1, LAGCH2, and LAGCH3 are binary variables indicating whether there are purchases and sales of at least 100,000 MMBtu/d on the day associated with the observation, the previous day, two days earlier, and three days earlier.
- LGLGP is the lagged log EOL gas price level.
- EQLOGP is the estimated log equilibrium price.
- ε captures the remaining unexplained component of LCO.

There are two model specifications for each of the two churn definitions (discrete and continuous) for which regressions are performed and counterfactual prices are estimated. These model specifications correspond to alternative methods of specifying the equilibrium price. In the first approach, we include levels of the lagged log price and other independent variables, primarily log prices at various upstream locations, in the regression. Levels of the independent

[2]We also include lags of other independent variables in our regressions.
[3]There are at least two possible reasons why the effects of churn might persist beyond the day on which it occurs. First, churning on one day may push up prices on subsequent days if it changes market psychology and generates momentum. Second, because churning does not change fundamental supply and demand conditions, to the extent that churning results in inflated prices one might expect prices to revert to a "normal" level relatively quickly.

variables determine the "equilibrium" level of the log EOL Topock gas price. To the extent that the lagged log price is above this equilibrium level, prices tend to fall, i.e., price changes are more negative. To the extent that the lagged log price is below this equilibrium level, prices tend to rise, i.e., price changes are more positive. Hence, this type of econometric model is sometimes known as an error-correction model (ECM).[4] Our ECM is specified as follows:

$$
\begin{aligned}
\Delta \log p_t^{EOLT} &= \alpha + \beta^{NOV} NOV + \beta^{DEC} DEC + \sum_{j=1}^{5} \beta^{DOW_j} DOW_j \\
&+ \sum_{i=0}^{3} \left\{ \begin{array}{l} \beta_i^{CHURN} CHURN_{t-i} + \beta_i^{Sumas} \Delta \log p_{t-i}^{Sumas} \\ + \beta_i^{SJNB} \Delta \log p_{t-i}^{SJNB} + \beta_i^{DSHOCK} \log DSHOCK_{t-i} \end{array} \right\} \\
&+ \lambda \left\{ \log p_{t-1}^{EOLT} - \left[\gamma^{Sumas} \log p_t^{Sumas} + \gamma^{SJNB} \log p_t^{SJNB} + \gamma^{QASYS} \log QASYS \right] \right\} + \varepsilon_t
\end{aligned}
$$

Where:

- $\Delta \log p_t^{EOLTopock}$ is the first difference of the log of the EOL Topock price.
- $CHURN_{t-i}$ is the i'th lag of churn.
- $\Delta \log p_{t-i}^{Sumas}$ and $\Delta \log p_{t-i}^{SJNB}$ are the i'th lags of the first differences of the logs of the Sumas and San Juan Non-Bondad prices.
- $\log DSHOCK_{t-i}$ is the i'th lag of the difference between the log realized ISO system load and the day-ahead forecast.
- NOV and DEC are dummy variables for the months of November and December.
- DOW_j is a dummy variable for day-of-week j. In the estimation, the constant and all five day-of-week dummies are collinear and cannot be estimated uniquely, so we drop one of the day-of-week dummies.
- $\log p_{t-1}^{EOLTopock}$ is the lagged level of the log of the EOL Topock price.
- $\log p_t^{Sumas}$ and $\log p_t^{SJNB}$ are the logs of the contemporaneous Sumas and San-Juan Non-Bondad prices.
- $\log QASYS$ is the log of realized ISO system demand.
- ε_t is the error.

In this specification, $\log p_t^{Sumas}$, $\log p_t^{SJNB}$, and $\log QASYS$ determine an equilibrium log price and λ measures the speed of mean-reversion toward the equilibrium price.

[4]See William Greene, *Econometric Analysis*, 4th ed., Chapter 17, for a brief overview of error-correction and related models.

The second approach is a simplification of the first approach. Rather than modeling an equilibrium price that can change in response to changes in certain variables, we assume that the equilibrium price is fixed, so the regression equation becomes:

$$\begin{aligned}\Delta \log p_t^{EOLT} = {} & \alpha + \beta^{NOV} NOV + \beta^{DEC} DEC + \sum_{j=1}^{5} \beta^{DOW_j} DOW_j \\ & \sum_{i=0}^{3} \begin{Bmatrix} \beta_i^{CHURN} CHURN_{t-i} + \beta_i^{Sumas} \Delta \log p_{t-i}^{Sumas} \\ + \beta_i^{SJNB} \Delta \log p_{t-i}^{SJNB} + \beta_i^{DSHOCK} \log DSHOCK_{t-i} \end{Bmatrix} \\ & + \lambda \left\{ \log p_{t-1}^{EOLT} - \phi \right\} + \varepsilon_t \end{aligned}$$

where ϕ is the log of the estimated long-run equilibrium price. Note that the equilibrium price cannot be estimated if an additive constant is included in the model, i.e., α and $\lambda\phi$ cannot be identified separately.

Which of these models is "better" is ultimately an empirical question. Estimation of the first specification suggests that some of the parameters that determine the equilibrium price, i.e., the γ 's, are statistically significantly different from zero. In other words, the *levels* of current upstream prices and California load help predict price movements and hence should be included in the model. The second specification is more parsimonious but less completely models price movements.

For the continuous specification of churning, we estimate the same regression as above but with the second churn measure, i.e., the minimum of sales and purchases (in thousands of MMBtu/d). Thus, the variables LAGCH0–LAGCH3 are continuous variables defined as the minimum of sales and purchases for the observation day (LAGCH0) and three prior days (LAGCH1–LAGCH3).

The regression results are summarized in Table II-B2. We report results for four different specifications based on combinations of the churn variable, i.e., a binary churn variable or the actual volume of churn, and the two methods of modeling the equilibrium price. The results of all specifications are similar and show that:

- ♦ Churn tends to elevate prices close to when it occurs, but the effect dissipates after several days.
- ♦ Mean-reversion seems to be present but is not necessarily statistically significant. In every specification, the coefficient on the lagged log price is negative, i.e., when prices are high they tend to fall, and when prices are low they tend to rise.

The mean-reversion parameter is statistically significant only in the specifications in which we allow the equilibrium price to vary as a function of data.

Table II-B2. Interday Regression Results

		Model 1		Model 2	
		Binary Churn			
Coefficient		**Coef.**	**Se**	**Coef.**	**Se**
Churn	Lag				
	0	0.0975	0.0243	0.1016	0.2468
	1	0.0664	0.0248	0.0634	0.0251
	2	(0.0560)	0.0243	(0.0628)	0.0247
	3	(0.0125)	0.0240	(0.0189)	0.0243
Lagged log EOL price		(0.0621)	0.0170	(0.0112)	0.0099
		Continuous Churn			
		Coef.	**Se**	**Coef.**	**Se**
Churn	Lag				
	0	0.0003	0.0001	0.0003	0.0001
	1	0.0002	0.0001	0.0002	0.0001
	2	(0.0002)	0.0001	(0.0002)	0.0001
	3	(0.0001)	0.0001	(0.0001)	0.0001
Lagged log EOL price		(0.0575)	0.0170	(0.0109)	0.0102

All Models The dependent variable is the change in the log price from the previous day.
Model 1 Time-varying equilibrium price is assumed to be a function of independent variables.
Model 2 Constant equilibrium price is assumed.

Table II-B3 shows how counterfactual prices are calculated from the model for an example day—April 3, 2001, one of the Reliant churn days. This example is illustrative and ignores the effects of mean-reversion. The actual log price change for April 3 (the logarithm of the price change from April 2, 2001 to April 3, 2001) is 0.172. Based on a set of regression results (for Model 1 with discrete churn variable), we estimate that churn raises log prices by 0.098 on the day on which it occurs; therefore, we estimate that the price change in the absence of churn would have been 0.075, the value shown in the fourth column. The sum of this counterfactual price change and the previous period's price, 2.520, results in an estimated counterfactual log price of 2.595. This log price corresponds to a price in levels of 13.40, the value shown in the seventh column. The counterfactual log price then forms the basis for the subsequent day's counterfactual price calculation until the fourth day from the churn event, at which point we assume that the actual and counterfactual prices are equal.[5]

[5]This illustrative calculation ignores mean-reversion. When mean-reversion is modeled, not only does the counterfactual price for one day form the starting point for the calculation of the counterfactual price on the subsequent day, but it also affects the extent of mean-reversion on the subsequent day.

Table II-B3. Sample Counterfactual Price Calculation

Date	Churn dummy	[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]
2-Apr-01	0	2.520	0.010	0.000	0.010	2.520	12.43	12.43	0.00
3-Apr-01	1	2.693	0.172	0.098	0.075	2.595	14.77	13.40	1.37
4-Apr-01	0	2.743	0.051	0.066	-0.016	2.579	15.54	13.19	2.35
5-Apr-01	0	2.752	0.009	-0.056	0.065	2.645	15.68	14.08	1.60
6-Apr-01	0	2.664	-0.089	-0.013	-0.076	2.568	14.35	13.05	1.31
9-Apr-01	0	2.613	-0.051	0.000	-0.051	2.613	13.64	13.64	0.00

Where:

- [1] log mean EOL price
- [2] log mean EOL price - log mean EOL price$_{(-1)}$
- [3] Effect of churn (regression coefficients on churn binary variable)
- [4] Counterfactual log price changes ([2] - [3])
- [5] Counterfactual log price (in churn "event" window = [5]$_{(-1)}$ + [4], else = [1])
- [6] Mean EOL price
- [7] Counterfactual price (exp([5]))
- [8] [6] - [7]

Appendix V-A: Details of Data Validation

Introduction

Staff's long-term transaction data consist of sellers' responses to Staff's data request, including backup data in the form of the underlying contracts and contract confirmation notices. We audited contracts and contract confirmations and use this information to validate reported transaction data. In this section, we discuss this audit process and describe how the dataset used for the regression analysis was created.

Auditing Sales Contracts and Confirmations

The first step was to audit contracts and/or contract confirmations to determine if they could be used to validate reported transaction data. To be useful for validation the contract or confirmation had to include name of seller, name of purchaser, sales price, commencement date, termination date, execution date, type of service (flat, on-peak, or off-peak), and delivery point. We also narrowed the number of contracts and confirmations we audited by the following criteria:

- Only fixed-price contracts were audited, i.e., contracts with time-varying prices or prices tied to index or fuel prices were not included.
- Only contracts for delivery at PV, NP15, SP15, COB, or Mid-C were audited.
- Only contracts where the type of service was "on-peak" were audited.

There were 1,630 written contracts or confirmations that met the criteria for auditing. The data entry process was straightforward because the contracts and confirmations were generally unambiguous. To prevent the introduction of error in the audit process, all data entries were double-checked.

The number of audited contracts/confirmations varied widely across sellers. Table V-A1 summarizes the number of audited contracts/confirmations by seller and trading hub.

Table V-A1. Number of Audited Contracts/Confirmations by Seller and Trading Hub

Seller	COB	Mid-C	NP15	PV	SP15	Total
AEP	1	1		20	2	**24**
Avista	4	5		11	11	**31**
Cargill-Alliant				1		**1**
City of Burbank				2		**2**
Coral			75	7	64	**146**
Duke	38	79	228	211	233	**789**
Dynegy				1	1	**2**
El Paso Merchant	8	21	57	115	114	**315**
Merrill Lynch				11		**11**
Morgan Stanley	3	3		15	6	**27**
PSC of New Mexico				5		**5**
Reliant	2	5	2	73	72	**154**
Sempra	9	13	16	28	28	**94**
Strategic Energy					3	**3**
TransAlta		2				**2**
Williams	2	1		12	9	**24**
Total	**67**	**130**	**378**	**512**	**543**	**1,630**

Of the 1,630 audited contracts/confirmations, 73 transactions were dropped because they were signed before January 1, 2000. We added 26 long-term power purchases by the California Department of Water Resources to the remaining 1,557 audited contracts/confirmations. These contracts have received extensive scrutiny and so their terms are well understood. The California State Auditor's characterization of these contracts was used.[1]

Matching Audited Contracts/Confirmations and Reported Transactions

The audited contracts/confirmations were compared with the sales transactions reported by various sellers. The comparison was made using several specifications, including buyer and seller names, contract price and sales amount (MWh), trading hub, type of service, and execution, commencement, and termination dates.

In most cases the match was perfect. In cases where the match was not perfect, a decision was made as to whether a match was "close enough." Generally, if one field varied slightly between the two data sources but all other fields matched, a match was declared. Specifically, contracts/confirmations were matched with their corresponding reported sale transaction if one of the following conditions was present:

[1]See California State Auditor, Bureau of State Audits, *California Energy Markets: Pressures Have Eased But Cost Risks Remain*, December 2001.

- Execution dates varied by no more than 1 day and all other fields matched (12 matches).
- Prices differed by no more than a few percent and could reasonably be attributed to different interpretations of illegible documents and all other fields matched (28 matches).
- Either the commencement date or termination date varied by 1 year, but all other fields matched (9 matches).
- Either the commencement or termination day of month varied, but all other fields matched, including commencement or termination month and year (69 matches).
- Delivery locations did not match (e.g., PV vs. Mid-C), but all other fields matched (3 matches).
- Buyer names did not match, but the different buyers were affiliated (27 matches).
- Sales amount varied by no more than 25 MWh, but all other fields matched (117 matches).

All audited contracts/confirmations were matched with reported sales transactions. However, not all sellers provided adequate backup documentation to sufficiently validate their reported sales transactions. Table V-A2 provides the number of reported sales transactions that were adequately documented and not adequately documented by sellers.

Table V-A2. Adequacy of Reported Sales Transaction Documentation

	Number of Reported Sales Transactions	
Seller	**Without Adequate Documentation**	**With Adequate Documentation**
Mirant	569	-
Allegheny	170	-
Duke	83	769
El Paso Merchant	61	315
MIECO	35	-
Reliant	35	119
Idaho Power	24	-
Calpine	22	-
Coral	19	146
Morgan Stanley	16	21
Other	17	13
AEP	5	24
PGE	5	-
Avista	4	31
Dynegy	3	1
Merrill Lynch	1	11
Sempra	-	92
Williams	-	15
All	**1,069**	**1,557**

Comparison of Regression Results Based on Validated-Only Data and All Data

Since 40 percent of reported sales transactions lack adequate backup documentation, it is important to determine if the inclusion of these transaction data has a significant effect on regression parameter estimates. To address this issue, we ran a basic “twelve bin” regression (described in Appendix V-C) on the two sets of data. The first set included 1,583 validated transactions (1,557 transactions with adequate backup documentation and 26 transactions from publicly available California power purchase contracts). The second set included 1,583 validated transactions and 1,069 unvalidated transactions. Tables V-A3 and V-A4 summarize parameters estimates for each regression run for the “during” and “after” periods.

Table V-A3. Validated vs. All Comparison: "During" Period

Validated Transactions

Hubs	Time-to-Delivery Class	Gas Futures Estimates						Spot Power Estimates						R^2		Obs
		Ordinary Least Squares (OLS)			With Instrumental Variables (IV)			Ordinary Least Squares (OLS)			With Instrumental Variables (IV)			OLS	IV	
		Coeff.	Std. Err.	t-stat	Coeff.	Std. Err.	t-stat	Coeff.	Std. Err.	t-stat	Coeff.	Std. Err.	t-stat			
Mid-C/ COB	1-2 Years	-0.34	0.51	-0.67	0.50	0.76	0.65	0.49	0.18	2.71	0.24	0.25	0.94	36%	34%	42
	3-4 Years	0.54	0.20	2.81	0.36	0.33	1.16	0.14	0.06	2.56	0.18	0.09	2.22	89%	88%	32
	5-8 Years	-0.14	0.17	-0.82	0.07	0.84	0.09	-0.05	0.05	-1.04	-0.09	0.15	-0.59	97%	95%	8
NP15	1-2 Years	1.29	0.29	4.82	1.43	0.31	5.09	0.01	0.13	0.07	-0.04	0.14	-0.34	87%	87%	19
	3-4 Years	2.02	0.32	6.42	2.15	0.39	5.66	0.16	0.05	3.34	0.15	0.05	3.19	85%	84%	52
	5-8 Years	-0.24	0.22	-1.08	-0.08	0.23	-0.34	0.04	0.04	0.97	0.05	0.04	1.25	59%	57%	20
PV	1-2 Years	0.49	0.21	2.41	0.42	0.21	2.05	0.32	0.06	5.11	0.33	0.06	5.38	64%	64%	141
	3-4 Years	0.92	0.26	3.71	0.98	0.26	3.91	0.01	0.05	0.17	0.00	0.05	-0.03	56%	56%	85
	5-8 Years	-0.04	0.13	-0.29	-0.04	0.13	-0.28	0.10	0.03	3.26	0.10	0.03	3.26	65%	65%	43
SP15	1-2 Years	0.37	0.15	2.47	0.60	0.17	3.59	0.19	0.08	2.54	0.11	0.08	1.32	62%	63%	81
	3-4 Years	0.26	0.13	2.16	0.24	0.14	1.80	0.04	0.04	1.05	0.05	0.04	1.12	36%	36%	91
	5-8 Years	0.16	0.20	0.82	0.15	0.20	0.75	0.05	0.04	1.29	0.05	0.04	1.32	48%	48%	46

All Transactions

Hubs	Time-to-Delivery Class	Gas Futures Estimates						Spot Power Estimates						R^2		Obs
		Ordinary Least Squares (OLS)			With Instrumental Variables (IV)			Ordinary Least Squares (OLS)			With Instrumental Variables (IV)			OLS	IV	
		Coeff.	Std. Err.	t-stat	Coeff.	Std. Err.	t-stat	Coeff.	Std. Err.	t-stat	Coeff.	Std. Err.	t-stat			
Mid-C/ COB	1-2 Years	0.03	0.27	0.10	0.62	0.42	1.45	0.38	0.09	4.16	0.21	0.13	1.66	43%	43%	101
	3-4 Years	0.52	0.16	3.15	0.26	0.22	1.21	0.13	0.04	3.12	0.19	0.05	3.58	79%	78%	62
	5-8 Years	0.40	0.09	4.43	0.63	0.16	3.84	0.00	0.03	-0.13	-0.01	0.03	-0.41	86%	83%	36
NP15	1-2 Years	1.09	0.31	3.52	0.82	0.34	2.42	0.22	0.13	1.64	0.29	0.14	2.10	65%	62%	40
	3-4 Years	1.69	0.26	6.52	1.76	0.31	5.65	0.14	0.04	3.16	0.14	0.05	3.01	83%	83%	72
	5-8 Years	-0.03	0.26	-0.12	-0.10	0.28	-0.38	0.06	0.05	1.33	0.06	0.05	1.20	63%	63%	24
PV	1-2 Years	0.09	0.19	0.49	0.02	0.19	0.09	0.38	0.06	6.58	0.40	0.06	6.90	49%	49%	221
	3-4 Years	0.42	0.14	3.00	0.46	0.14	3.26	0.09	0.04	2.37	0.08	0.04	2.14	50%	51%	122
	5-8 Years	0.10	0.09	1.10	0.10	0.09	1.11	0.07	0.02	3.36	0.07	0.02	3.35	66%	66%	74
SP15	1-2 Years	0.27	0.15	1.76	0.51	0.17	2.99	0.23	0.08	2.99	0.14	0.08	1.69	60%	60%	89
	3-4 Years	0.28	0.10	2.63	0.29	0.11	2.52	0.07	0.03	2.33	0.07	0.03	2.28	39%	39%	142
	5-8 Years	-0.23	0.07	-3.49	-0.24	0.07	-3.60	0.04	0.03	1.29	0.04	0.03	1.35	46%	47%	83

Table V-A4. Validated vs. All Comparison: "After" Period

Validated Transactions

Hubs	Time-to-Delivery Class	Gas Futures Estimates						Spot Power Estimates						R^2		Obs
		Ordinary Least Squares (OLS)			With Instrumental Variables (IV)			Ordinary Least Squares (OLS)			With Instrumental Variables (IV)			OLS	IV	
		Coeff.	Std. Err.	t-stat	Coeff.	Std. Err.	t-stat	Coeff.	Std. Err.	t-stat	Coeff.	Std. Err.	t-stat			
Mid-C/ COB	1-2 Years	0.70	0.13	5.47	0.54	0.14	3.77	0.01	0.05	0.16	0.04	0.05	0.69	75%	72%	50
	3-4 Years	0.27	0.28	0.95	0.34	0.44	0.78	0.37	0.12	3.03	0.35	0.13	2.72	81%	81%	32
	5-8 Years	0.17	0.16	1.09	0.06	0.20	0.29	0.16	0.07	2.08	0.17	0.08	2.23	89%	89%	24
NP15	1-2 Years	0.69	0.07	10.58	0.64	0.07	9.56	0.09	0.03	3.24	0.10	0.03	3.54	89%	88%	123
	3-4 Years	0.76	0.12	6.51	0.74	0.13	5.69	0.03	0.03	1.11	0.03	0.03	1.16	81%	81%	92
	5-8 Years	0.32	0.10	3.16	0.23	0.10	2.21	0.02	0.03	0.63	0.03	0.03	0.86	71%	70%	60
PV	1-2 Years	0.02	0.32	0.07	0.00	0.32	0.01	0.26	0.13	2.09	0.26	0.13	2.10	13%	13%	93
	3-4 Years	1.01	0.17	6.21	1.00	0.17	6.13	0.00	0.04	-0.05	0.00	0.04	-0.03	73%	73%	65
	5-8 Years	0.00	0.25	0.00	-0.05	0.25	-0.18	0.12	0.06	1.88	0.11	0.06	1.84	28%	28%	46
SP 15	1-2 Years	0.63	0.08	7.81	0.62	0.09	7.00	0.14	0.04	3.91	0.15	0.04	3.85	65%	65%	196
	3-4 Years	0.71	0.12	6.01	0.71	0.12	5.88	0.08	0.03	3.17	0.08	0.03	3.13	81%	81%	103
	5-8 Years	0.64	0.18	3.50	0.64	0.18	3.50	0.20	0.05	3.77	0.20	0.05	3.77	76%	76%	39

All Transactions

Hubs	Time-to-Delivery Class	Gas Futures Estimates						Spot Power Estimates						R^2		Obs
		Ordinary Least Squares (OLS)			With Instrumental Variables (IV)			Ordinary Least Squares (OLS)			With Instrumental Variables (IV)			OLS	IV	
		Coeff.	Std. Err.	t-stat	Coeff.	Std. Err.	t-stat	Coeff.	Std. Err.	t-stat	Coeff.	Std. Err.	t-stat			
MIDC/ COB	1-2 Years	0.73	0.12	6.10	0.61	0.13	4.64	0.03	0.05	0.67	0.05	0.05	1.05	78%	76%	91
	3-4 Years	0.76	0.19	3.97	0.87	0.27	3.26	0.38	0.08	4.83	0.37	0.08	4.46	80%	80%	45
	5-8 Years	0.22	0.16	1.39	0.04	0.21	0.19	0.14	0.07	1.94	0.17	0.08	2.16	89%	89%	27
NP 15	1-2 Years	0.71	0.05	13.10	0.68	0.06	12.25	0.08	0.02	3.17	0.08	0.02	3.43	86%	86%	204
	3-4 Years	0.72	0.11	6.87	0.65	0.11	5.71	0.02	0.02	0.90	0.03	0.02	1.17	68%	67%	145
	5-8 Years	0.38	0.11	3.31	0.28	0.12	2.41	0.02	0.03	0.70	0.03	0.03	0.96	53%	51%	80
PV	1-2 Years	0.28	0.18	1.63	0.28	0.18	1.60	0.10	0.06	1.74	0.10	0.06	1.74	20%	20%	197
	3-4 Years	0.67	0.16	4.07	0.65	0.16	3.93	0.02	0.05	0.53	0.03	0.05	0.57	53%	53%	106
	5-8 Years	-0.04	0.22	-0.17	-0.07	0.22	-0.33	0.13	0.06	2.30	0.13	0.06	2.27	34%	34%	56
SP15	1-2 Years	0.70	0.05	13.86	0.72	0.06	12.99	0.07	0.02	3.26	0.06	0.02	3.04	68%	67%	395
	3-4 Years	0.70	0.09	7.69	0.69	0.09	7.28	0.09	0.02	3.82	0.09	0.02	3.88	76%	76%	177
	5-8 Years	0.78	0.16	4.76	0.79	0.16	4.79	0.09	0.04	2.29	0.09	0.04	2.28	69%	69%	63

Tables V-A3 and V-A4 show that for most statistically significant estimates, the estimated parameters based only on validated transactions are close to parameter estimates based on all reported transactions, thus implying that the inclusion of unvalidated transaction data in the regression analysis has a minimal effect on our parameter estimates.

Appendix V-B: Comparison of Forward Gas Curves

Comparison of Forward Gas Curves

Table V-B1. TFS Historical Forward Gas Prices ($/MMBtu)

	Malin Delivery Dates				**Southern California Border** Delivery Dates			
Month	7/1/2001	7/1/2002	7/1/2003	7/1/2004	7/1/2001	7/1/2002	7/1/2003	7/1/2004
Jan 01	7.15	5.58	4.70	n.a.	7.56	5.78	5.10	n.a.
Feb 01	7.67	6.07	5.10	n.a.	8.83	6.50	5.47	n.a.
Mar 01	8.34	6.20	4.86	n.a.	10.17	6.72	5.24	n.a.
Apr 01	9.94	7.34	5.02	n.a.	13.72	8.40	*5.32*	n.a.
May 01	7.32	5.84	4.66	n.a.	11.22	6.44	4.78	n.a.
Jun 01	4.63	4.33	4.04	n.a.	6.91	4.56	4.06	n.a.

Table V-B2. Williams' Historical Forward Gas Prices ($/MMBtu)

	Malin Delivery Dates				**Southern California Border** Delivery Dates			
Month	7/1/2001	7/1/2002	7/1/2003	7/1/2004	7/1/2001	7/1/2002	7/1/2003	7/1/2004
Jan 01	8.18	6.36	4.32	4.19	8.18	6.36	5.46	5.04
Feb 01	8.61	7.06	4.57	4.53	8.61	7.06	6.03	5.65
Mar 01	9.54	6.45	4.87	4.76	9.99	6.67	5.82	5.59
Apr 01	10.97	6.78	5.19	5.06	13.83	7.75	5.19	5.06
May 01	7.73	5.52	4.66	4.79	11.80	6.01	4.66	4.79
Jun 01	3.75	4.41	4.15	4.29	6.88	4.65	4.07	4.22

Table V-B3. Enron's Historical Forward Gas Prices ($/MMBtu)

	Malin Delivery Dates				**Southern California Border** Delivery Dates			
Month	7/1/2001	7/1/2002	7/1/2003	7/1/2004	7/1/2001	7/1/2002	7/1/2003	7/1/2004
Jan 01	7.73	5.89	4.42	4.06	8.18	6.29	5.18	4.68
Feb 01	7.74	6.62	5.11	4.40	8.59	7.05	5.51	5.06
Mar 01	8.44	6.20	4.84	4.48	10.06	6.70	5.24	5.06
Apr 01	10.16	6.39	4.70	4.26	13.86	7.80	5.16	4.78
May 01	7.80	5.38	4.11	4.08	11.75	6.07	4.61	4.56
Jun 01	4.40	4.19	3.47	3.51	6.90	4.66	3.97	3.99

Table V-B4. Morgan Stanley's Historical Forward Gas Prices ($/MMBtu)

	PG&E Citygate Delivery Dates				Southern California Border Delivery Dates			
Month	7/1/2001	7/1/2002	7/1/2003	7/1/2004	7/1/2001	7/1/2002	7/1/2003	7/1/2004
Jan 01	8.06	6.30	5.51	4.90	7.99	6.24	5.45	4.84
Feb 01	8.63	7.00	5.75	5.20	8.56	6.94	5.69	5.14
Mar 01	9.05	6.41	5.39	5.16	10.08	6.55	5.34	5.09
Apr 01	11.70	6.58	5.08	4.79	13.85	7.55	5.02	4.71
May 01	9.79	5.57	4.67	4.71	11.79	5.85	4.47	4.50
Jun 01	5.78	4.71	4.24	4.25	7.27	4.58	3.98	4.00

TFS vs. Other Forward Gas Curves

Table V-B5. TFS vs. Williams

	Malin Delivery Dates			Southern California Border Delivery Dates		
Month	7/1/2001	7/1/2002	7/1/2003	7/1/2001	7/1/2002	7/1/2003
Jan 01	14%	14%	-8%	8%	10%	7%
Feb 01	12%	16%	-11%	-3%	9%	10%
Mar 01	14%	4%	0%	-2%	-1%	11%
Apr 01	10%	-8%	3%	1%	-8%	-3%
May 01	6%	-5%	0%	5%	-7%	-2%
Jun 01	-19%	2%	3%	0%	2%	0%

Table V-B6. TFS vs. Enron

	Malin Delivery Dates			Southern California Border Delivery Dates		
Month	7/1/2001	7/1/2002	7/1/2003	7/1/2001	7/1/2002	7/1/2003
Jan 01	8%	6%	-6%	8%	9%	1%
Feb 01	1%	9%	0%	-3%	8%	1%
Mar 01	1%	0%	0%	-1%	0%	0%
Apr 01	2%	-13%	-6%	1%	-7%	-3%
May 01	7%	-8%	-12%	5%	-6%	-4%
Jun 01	-5%	-3%	-14%	0%	2%	-2%

Table V-B7. TFS vs. Morgan Stanley

	Southern California Border Delivery Dates		
Month	7/1/2001	7/1/2002	7/1/2003
Jan 01	6%	8%	7%
Feb 01	-3%	7%	4%
Mar 01	-1%	-3%	2%
Apr 01	1%	-10%	*-6%*
May 01	5%	-9%	-6%
Jun 01	5%	0%	-2%

Appendix V-C: Disaggregated Regressions

The following tables summarize spot power and forward gas parameter estimates for various regression formulations. Each regression includes only on-peak transactions that were executed between January 1, 2000 and June 30, 2001 ("during period") or between July 1, 2001 and March 31, 2002 ("after period") for power deliveries at NP15, SP15, COB, PV, or Mid-C. All regressions use TFS' historic natural gas basis and historic NYMEX forwards at Henry Hub. To address the potential simultaneity of the explanatory variables, we perform both the ordinary least squares (OLS) estimation and the instrumental variable (IV) estimation.

Twelve Bin Regressions

In this formulation we aggregate time-to-delivery class periods 1-2 years, 3-4 years, and 5-8 years and the Mid-C/COB hubs. We then run a separate regression for each combination of aggregated hubs and time-to-delivery classes (i.e., 12 regressions). The results of these regressions are summarized in Tables V-C1 and V-C2.

Table V-C1. Twelve Bin Regression for "During" Period

Hubs	Time-to-Delivery Class	Gas Futures Estimates						Spot Power Estimates						R^2		Obs
		Ordinary Least Squares (OLS)			With Instrumental Variables (IV)			Ordinary Least Squares (OLS)			With Instrumental Variables (IV)			OLS	IV	
		Coeff.	Std. Err.	t-stat	Coeff.	Std. Err.	t-stat	Coeff.	Std. Err.	t-stat	Coeff.	Std. Err.	t-stat			
Mid-C/ COB	1-2 Years	0.03	0.27	0.10	0.62	0.42	1.45	0.38	0.09	4.16	0.21	0.13	1.66	43%	43%	101
	3-4 Years	0.52	0.16	3.15	0.26	0.22	1.21	0.13	0.04	3.12	0.19	0.05	3.58	79%	78%	62
	5-8 Years	0.40	0.09	4.43	0.63	0.16	3.84	0.00	0.03	-0.13	-0.01	0.03	-0.41	86%	83%	36
NP15	1-2 Years	1.09	0.31	3.52	0.82	0.34	2.42	0.22	0.13	1.64	0.29	0.14	2.10	65%	62%	40
	3-4 Years	1.69	0.26	6.52	1.76	0.31	5.65	0.14	0.04	3.16	0.14	0.05	3.01	83%	83%	72
	5-8 Years	-0.03	0.26	-0.12	-0.10	0.28	-0.38	0.06	0.05	1.33	0.06	0.05	1.20	63%	63%	24
PV	1-2 Years	0.09	0.19	0.49	0.02	0.19	0.09	0.38	0.06	6.58	0.40	0.06	6.90	49%	49%	221
	3-4 Years	0.42	0.14	3.00	0.46	0.14	3.26	0.09	0.04	2.37	0.08	0.04	2.14	50%	51%	122
	5-8 Years	0.10	0.09	1.10	0.10	0.09	1.11	0.07	0.02	3.36	0.07	0.02	3.35	66%	66%	74
SP15	1-2 Years	0.27	0.15	1.76	0.51	0.17	2.99	0.23	0.08	2.99	0.14	0.08	1.69	60%	60%	89
	3-4 Years	0.28	0.10	2.63	0.29	0.11	2.52	0.07	0.03	2.33	0.07	0.03	2.28	39%	39%	142
	5-8 Years	-0.23	0.07	-3.49	-0.24	0.07	-3.60	0.04	0.03	1.29	0.04	0.03	1.35	46%	47%	83

Table V-C2. Twelve Bin Regression for "After" Period

Hubs	Time-to-Delivery Class	Gas Futures Estimates: Ordinary Least Squares (OLS)			Gas Futures Estimates: With Instrumental Variables (IV)			Spot Power Estimates: Ordinary Least Squares (OLS)			Spot Power Estimates: With Instrumental Variables (IV)			R^2		Obs
		Coeff.	Std. Err.	t-stat	Coeff.	Std. Err.	t-stat	Coeff.	Std. Err.	t-stat	Coeff.	Std. Err.	t-stat	OLS	IV	
Mid-C/COB	1-2 Years	0.73	0.12	6.10	0.61	0.13	4.64	0.03	0.05	0.67	0.05	0.05	1.05	78%	76%	91
	3-4 Years	0.76	0.19	3.97	0.87	0.27	3.26	0.38	0.08	4.83	0.37	0.08	4.46	80%	80%	45
	5-8 Years	0.22	0.16	1.39	0.04	0.21	0.19	0.14	0.07	1.94	0.17	0.08	2.16	89%	89%	27
NP15	1-2 Years	0.71	0.05	13.10	0.68	0.06	12.25	0.08	0.02	3.17	0.08	0.02	3.43	86%	86%	204
	3-4 Years	0.72	0.11	6.87	0.65	0.11	5.71	0.02	0.02	0.90	0.03	0.02	1.17	68%	67%	145
	5-8 Years	0.38	0.11	3.31	0.28	0.12	2.41	0.02	0.03	0.70	0.03	0.03	0.96	53%	51%	80
PV	1-2 Years	0.28	0.18	1.63	0.28	0.18	1.60	0.10	0.06	1.74	0.10	0.06	1.74	20%	20%	197
	3-4 Years	0.67	0.16	4.07	0.65	0.16	3.93	0.02	0.05	0.53	0.03	0.05	0.57	53%	53%	106
	5-8 Years	-0.04	0.22	-0.17	-0.07	0.22	-0.33	0.13	0.06	2.30	0.13	0.06	2.27	34%	34%	56
SP15	1-2 Years	0.70	0.05	13.86	0.72	0.06	12.99	0.07	0.02	3.26	0.06	0.02	3.04	68%	67%	395
	3-4 Years	0.70	0.09	7.69	0.69	0.09	7.28	0.09	0.02	3.82	0.09	0.02	3.88	76%	76%	177
	5-8 Years	0.78	0.16	4.76	0.79	0.16	4.79	0.09	0.04	2.29	0.09	0.04	2.28	69%	69%	63

"Pool by Hub" Regressions

In this formulation, we aggregate time-to-delivery class periods 1-2 years, 3-4 years, and 5-8 years and aggregate all hubs. We run a separate regression for each aggregated time-to-delivery class. The results of these regressions are summarized in Tables V-C3 and V-C4.

Table V-C3. Pool by Hub Regression for "During" Period

Time-to-Delivery Class	Gas Futures Estimates: Ordinary Least Squares (OLS)			Gas Futures Estimates: With Instrumental Variables (IV)			Spot Power Estimates: Ordinary Least Squares (OLS)			Spot Power Estimates: With Instrumental Variables (IV)			R^2		Obs
	Coeff.	Std. Err.	t-stat	Coeff.	Std. Err.	t-stat	Coeff.	Std. Err.	t-stat	Coeff.	Std. Err.	t-stat	OLS	IV	
1-2 Years	0.29	0.08	3.57	0.46	0.12	3.96	0.33	0.03	9.80	0.27	0.04	6.34	50%	50%	451
3-4 Years	0.31	0.06	5.17	0.34	0.07	4.95	0.12	0.02	6.54	0.11	0.02	5.73	52%	52%	398
5-8 Years	0.04	0.04	0.82	(0.05)	0.05	(1.10)	0.05	0.01	3.36	0.06	0.01	4.18	51%	50%	217

Table V-C4. Pool by Hub Regression for "After" Period

Time-to-Delivery Class	Gas Futures Estimates: Ordinary Least Squares (OLS)			Gas Futures Estimates: With Instrumental Variables (IV)			Spot Power Estimates: Ordinary Least Squares (OLS)			Spot Power Estimates: With Instrumental Variables (IV)			R^2		Obs
	Coeff.	Std. Err.	t-stat	Coeff.	Std. Err.	t-stat	Coeff.	Std. Err.	t-stat	Coeff.	Std. Err.	t-stat	OLS	IV	
1-2 Years	0.66	0.04	16.74	0.60	0.05	12.08	0.12	0.02	7.15	0.13	0.02	7.41	58%	55%	887
3-4 Years	0.72	0.05	15.03	0.60	0.07	8.34	0.12	0.02	7.12	0.14	0.02	7.35	70%	67%	473
5-8 Years	0.46	0.06	7.23	0.18	0.10	1.77	0.15	0.02	6.83	0.17	0.02	7.22	58%	51%	226

Pool by Hub Regressions With Additive and Spot Power Interacted Hub Dummies

For each time-to-delivery class, we estimate regressions that include transactions for all hubs. We specify separate intercepts and spot power coefficients for each hub, but constrain the forward gas coefficient to be equal across hubs. Our regression equation is as follows:

$$\log(FP_{it}) = c\ \log(FG_{it}) + \sum_i HubDummy_i \{d_i + b_i \log(SP_{it})\} + e_{it}$$

where d_i and b_i are the hub-specific intercepts and spot power coefficients, respectively. The results of these regressions are summarized in Tables V-C5 and V-C6.

Table V-C5. Pool by Hub Regressions With Additive and Spot Power Interacted Hub Dummies for "During" Period

Hub-specific Interacted Dummy on Spot Power	Time-to-Delivery Class	Ordinary Least Squares (OLS)			With Instrumental Variables (IV)		
		Coeff.	Std. Err.	t-stat	Coeff.	Std. Err.	t-stat
Mid-C/COB	1-2 Years	0.31	0.05	6.76	0.28	0.05	5.49
	3-4 Years	0.17	0.03	5.31	0.16	0.03	5.11
	5-8 Years	(0.02)	0.03	(0.56)	(0.01)	0.03	(0.48)
NP15	1-2 Years	0.42	0.10	4.17	0.39	0.10	3.75
	3-4 Years	0.21	0.04	5.83	0.21	0.04	5.78
	5-8 Years	0.07	0.04	1.73	0.07	0.04	1.75
PV	1-2 Years	0.35	0.04	8.56	0.32	0.05	7.07
	3-4 Years	0.11	0.02	4.51	0.11	0.02	4.31
	5-8 Years	0.09	0.02	5.46	0.10	0.02	5.76
SP15	1-2 Years	0.26	0.07	3.64	0.22	0.08	2.75
	3-4 Years	0.07	0.03	2.65	0.07	0.03	2.58
	5-8 Years	0.00	0.02	0.00	0.01	0.02	0.30

Time-to-Delivery Class	Gas Futures Estimates						R^2		
	Ordinary Least Squares (OLS)			With Instrumental Variables (IV)			OLS	IV	Obs
	Coeff.	Std. Err.	t-stat	Coeff.	Std. Err.	t-stat			
1-2 Years	0.27	0.10	2.63	0.38	0.12	3.08	52%	52%	451
3-4 Years	0.37	0.07	5.20	0.38	0.08	4.95	57%	56%	398
5-8 Years	(0.04)	0.04	(1.01)	(0.08)	0.05	(1.79)	60%	60%	217

Table V-C6. Pool by Hub Regressions With Additive and Spot Power Interacted Hub Dummies for "After" Period

Hub-specific Interacted Dummy on Spot Power	Time-to-Delivery Class	Ordinary Least Squares (OLS)			With Instrumental Variables (IV)		
		Coeff.	Std. Err.	t-stat	Coeff.	Std. Err.	t-stat
Mid-C/COB	1-2 Years	0.22	0.03	6.79	0.22	0.03	6.77
	3-4 Years	0.21	0.03	6.98	0.21	0.03	7.02
	5-8 Years	0.22	0.03	8.60	0.23	0.03	8.75
NP15	1-2 Years	0.11	0.03	3.52	0.11	0.03	3.50
	3-4 Years	0.01	0.02	0.49	0.01	0.02	0.62
	5-8 Years	0.04	0.03	1.28	0.05	0.03	1.61
PV	1-2 Years	0.08	0.02	3.54	0.08	0.02	3.54
	3-4 Years	0.08	0.02	3.90	0.08	0.02	3.95
	5-8 Years	0.10	0.02	4.13	0.10	0.02	4.20
SP15	1-2 Years	0.08	0.02	3.38	0.08	0.02	3.36
	3-4 Years	0.10	0.02	5.25	0.10	0.02	5.33
	5-8 Years	0.15	0.03	5.35	0.15	0.03	5.44

Time-to-Delivery Class	Gas Futures Estimates						R^2		
	Ordinary Least Squares (OLS)			With Instrumental Variables (IV)			OLS	IV	Obs
	Coeff.	Std. Err.	t-stat	Coeff.	Std. Err.	t-stat			
1-2 Years	0.58	0.05	12.42	0.57	0.05	11.74	62%	62%	887
3-4 Years	0.67	0.06	11.01	0.64	0.07	9.86	76%	76%	473
5-8 Years	0.34	0.07	4.51	0.25	0.08	3.08	70%	70%	226

Pool by Hub Regressions With Spot Power Interacted Hub Dummies

These regressions are identical to those in the previous section except that we exclude hub-specific intercepts. Therefore, the regression equation for each time-to-delivery class is as follows:

$$\log(FP_{it}) = a + c\ \log(FG_{it}) + \sum_i b_i HubDummy_i * \log(SP_{it}) + e_{it}$$

The results of these regressions are summarized in Tables V-C7 and V-C8.

Table V-C7. Pool by Hub Regressions With Spot Power

Interacted Hub Dummies for "During" Period

Hub-specific Interacted Dummy on Spot Power	Time-to-Delivery Class	Ordinary Least Squares (OLS)			With Instrumental Variables (IV)		
		Coeff.	Std. Err.	t-stat	Coeff.	Std. Err.	t-stat
Mid-C/ COB	1-2 Years	0.32	0.04	8.44	0.28	0.04	6.37
	3-4 Years	0.14	0.02	7.33	0.14	0.02	7.17
	5-8 Years	0.05	0.01	3.43	0.05	0.01	3.86
NP15	1-2 Years	0.35	0.04	9.00	0.31	0.05	6.78
	3-4 Years	0.12	0.02	5.87	0.12	0.02	5.72
	5-8 Years	0.06	0.02	3.82	0.07	0.02	4.30
PV	1-2 Years	0.34	0.04	9.47	0.30	0.04	7.30
	3-4 Years	0.12	0.02	6.50	0.12	0.02	6.38
	5-8 Years	0.05	0.01	3.47	0.05	0.01	3.89
SP15	1-2 Years	0.34	0.04	8.26	0.30	0.05	6.05
	3-4 Years	0.11	0.02	5.79	0.11	0.02	5.64
	5-8 Years	0.06	0.01	4.48	0.07	0.01	4.95

Time-to-Delivery Class	Gas Futures Estimates						R^2		Obs
	OLS			IV			OLS	IV	
	Coeff.	Std. Err.	t-stat	Coeff.	Std. Err.	t-stat			
1-2 Years	0.25	0.10	2.47	0.38	0.13	3.06	52%	52%	451
3-4 Years	0.37	0.07	5.40	0.36	0.07	4.91	55%	55%	398
5-8 Years	(0.04)	0.05	(0.80)	(0.08)	0.05	(1.77)	56%	56%	217

Table V-C8. Pool by Hub Regressions With Spot Power Interacted

Hub Dummies for "After" Period

Hub-specific Interacted Dummy on Spot Power	Time-to-Delivery Class	Ordinary Least Squares (OLS)			With Instrumental Variables (IV)		
		Coeff.	Std. Err.	t-stat	Coeff.	Std. Err.	t-stat
Mid-C/COB	1-2 Years	0.08	0.02	4.43	0.08	0.02	4.44
	3-4 Years	0.07	0.02	4.02	0.07	0.02	4.03
	5-8 Years	0.13	0.02	5.93	0.13	0.02	6.04
NP15	1-2 Years	0.10	0.02	5.44	0.10	0.02	5.45
	3-4 Years	0.09	0.02	5.48	0.10	0.02	5.46
	5-8 Years	0.15	0.02	7.15	0.16	0.02	7.29
PV	1-2 Years	0.10	0.02	5.91	0.10	0.02	5.92
	3-4 Years	0.10	0.02	5.90	0.10	0.02	5.89
	5-8 Years	0.15	0.02	6.99	0.15	0.02	7.10
SP15	1-2 Years	0.10	0.02	5.63	0.10	0.02	5.63
	3-4 Years	0.09	0.02	5.50	0.10	0.02	5.48
	5-8 Years	0.15	0.02	6.92	0.16	0.02	7.07

Time-to-Delivery Class	Gas Futures Estimates						R^2		Obs
	Ordinary Least Squares (OLS)			With Instrumental Variables (IV)			OLS	IV	
	Coeff.	Std. Err.	t-stat	Coeff.	Std. Err.	t-stat			
1-2 Years	0.59	0.05	12.81	0.59	0.05	12.01	61%	60%	887
3-4 Years	0.65	0.06	10.26	0.64	0.07	9.21	74%	73%	473
5-8 Years	0.30	0.08	3.69	0.23	0.09	2.58	63%	63%	226

"Pool by Class" Regressions

Here we aggregate the Mid-C and COB hubs and pool across all time-to-delivery classes. We run a separate regression for four aggregated hubs. The results of these regressions are summarized in Tables V-C9 and V-C10.

Table V-C9. Pool by Class Regression for "During" Period

Hubs	Gas Futures Estimates: Ordinary Least Squares (OLS)			Gas Futures Estimates: With Instrumental Variables (IV)			Spot Power Estimates: Ordinary Least Squares (OLS)			Spot Power Estimates: With Instrumental Variables (IV)			R^2		Obs
	Coeff.	Std. Err.	t-stat	Coeff.	Std. Err.	t-stat	Coeff.	Std. Err.	t-stat	Coeff.	Std. Err.	t-stat	OLS	IV	
Mid-C/COB	0.62	0.15	4.19	0.89	0.21	4.29	0.13	0.04	3.04	0.07	0.05	1.29	38%	38%	199
NP15	1.35	0.16	8.41	1.23	0.17	7.14	0.12	0.05	2.54	0.13	0.05	2.67	73%	72%	136
PV	0.79	0.11	6.99	0.78	0.11	6.87	0.05	0.03	1.79	0.06	0.03	1.85	34%	34%	417
SP15	0.72	0.06	11.73	0.47	0.07	6.35	(0.04)	0.03	(1.27)	0.00	0.03	(0.07)	41%	27%	314

Table V-C10. Pool by Class Regression for "After" Period

Hubs	Gas Futures Estimates: Ordinary Least Squares (OLS)			Gas Futures Estimates: With Instrumental Variables (IV)			Spot Power Estimates: Ordinary Least Squares (OLS)			Spot Power Estimates: With Instrumental Variables (IV)			R^2		Obs
	Coeff.	Std. Err.	t-stat	Coeff.	Std. Err.	t-stat	Coeff.	Std. Err.	t-stat	Coeff.	Std. Err.	t-stat	OLS	IV	
Mid-C/COB	0.54	0.08	7.09	0.44	0.09	5.04	0.13	0.03	3.92	0.14	0.03	4.13	77%	76%	163
NP15	0.68	0.04	18.58	0.64	0.04	17.15	0.04	0.01	2.54	0.04	0.01	2.91	77%	76%	429
PV	0.27	0.09	2.89	0.25	0.09	2.67	0.09	0.03	2.74	0.09	0.03	2.75	27%	27%	359
SP15	0.46	0.03	13.64	0.47	0.04	13.24	0.12	0.01	8.54	0.12	0.01	8.41	66%	66%	635

"Pool by Class and Hub" Regressions

We run a single regression by pooling across all time-to-delivery classes and hubs. The results of these regressions are summarized in Table V-C11.

Table V-C11. Pool by Class and Hub Regression Results

Period	Gas Futures Estimates: Ordinary Least Squares (OLS)			Gas Futures Estimates: With Instrumental Variables (IV)			Spot Power Estimates: Ordinary Least Squares (OLS)			Spot Power Estimates: With Instrumental Variables (IV)			R^2		Obs
	Coeff.	Std. Err.	t-stat	Coeff.	Std. Err.	t-stat	Coeff.	Std. Err.	t-stat	Coeff.	Std. Err.	t-stat	OLS	IV	
"During"	0.61	0.05	13.17	0.63	0.06	11.19	0.07	0.02	4.48	0.07	0.02	3.83	36%	34%	1066
"After"	0.57	0.02	23.11	0.46	0.03	15.02	0.14	0.01	12.32	0.15	0.01	13.17	60%	57%	1586

"No Aggregation" Regression

We run a separate regression for each disaggregated time-to-delivery class and hub. As illustrated in Tables V-C12 and V-C13, the results of these regressions are somewhat irregular due to an insignificant number of transactions in many time-to-delivery class and hub bins.

Table V-C12. No Aggregation Regression for "During" Period

Hubs	Time-to-Delivery Class	Gas Futures Estimates: OLS Coeff.	OLS Std. Err.	OLS t-stat	Gas Futures Estimates: IV Coeff.	IV Std. Err.	IV t-stat	Spot Power Estimates: OLS Coeff.	OLS Std. Err.	OLS t-stat	Spot Power Estimates: IV Coeff.	IV Std. Err.	IV t-stat	R^2 OLS	R^2 IV	Obs
COB	1 year	(7.01)	0.45	(15.62)	(6.63)	0.53	(12.57)	(0.65)	0.14	(4.74)	(0.75)	0.16	(4.76)	100%	100%	9
	2 years	2.23	0.28	7.86	2.17	0.30	7.19	(0.24)	0.10	(2.33)	(0.22)	0.11	(2.04)	93%	92%	28
	3 years	0.85	0.17	4.87	0.60	0.21	2.81	0.06	0.05	1.27	0.13	0.06	2.16	98%	98%	24
	4 years	3.88	0.14	28.62	3.88	0.14	28.62	(0.39)	0.04	(9.63)	(0.39)	0.04	(9.63)	100%	100%	4
	5 years	0.00	.	.	0.00	.	.	0.68	.	.	0.68	.	.	100%	100%	2
	7 years	0.00	.	.	0.00	.	.	0.63	.	.	0.63	.	.	100%	100%	3
Mid-C	1 year	(18.86)	18.44	(1.02)	109.08	314.38	0.35	1.51	5.86	0.26	(39.15)	99.92	(0.39)	100%	94%	8
	2 years	0.29	0.14	2.05	1.58	0.55	2.90	0.47	0.04	11.44	0.18	0.13	1.39	91%	80%	56
	3 years	0.46	0.39	1.17	0.61	0.40	1.52	0.15	0.06	2.24	0.13	0.07	2.03	68%	68%	22
	4 years	2.09	0.09	23.72	1.99	0.11	17.51	0.04	0.08	0.55	0.06	0.09	0.63	100%	100%	12
	5 years	0.62	0.19	3.25	0.62	0.19	3.25	0.00	0.04	(0.03)	0.00	0.04	(0.03)	87%	87%	26
	6 years	0.00	.	.	0.00	.	.	0.68	0.00	737.17	0.68	0.00	737.17	.	.	5
NP15	1 year	2.33	.	.	2.33	.	.	(0.04)	.	.	(0.04)	.	.	100%	100%	4
	2 years	1.24	0.38	3.27	0.82	0.42	1.97	0.17	0.16	1.07	0.29	0.17	1.73	64%	60%	36
	3 years	2.21	0.33	6.77	2.29	0.39	5.91	0.12	0.05	2.61	0.12	0.05	2.46	82%	81%	56
	4 Years	0.91	0.62	1.48	1.20	0.99	1.21	0.24	0.17	1.45	0.25	0.17	1.47	92%	92%	16
	5 Years	(0.65)	0.13	(5.07)	(0.61)	0.13	(4.71)	0.07	0.03	2.43	0.08	0.03	2.58	93%	93%	15
	6 Years	2.52	.	.	2.52	.	.	0.00	.	.	0.00	.	.	100%	100%	3
	7 Years	0.52	0.00	.	0.52	0.00	.	(0.04)	0.00	.	(0.04)	0.00	.	100%	100%	6
PV	1 Year	(0.02)	0.90	(0.03)	(0.02)	0.90	(0.03)	0.12	0.18	0.67	0.12	0.18	0.67	39%	39%	48
	2 Years	1.15	0.14	8.34	1.10	0.14	7.96	0.19	0.04	4.71	0.20	0.04	4.99	84%	84%	173
	3 Years	0.46	0.22	2.09	0.58	0.22	2.59	0.09	0.06	1.53	0.06	0.06	1.11	57%	58%	77
	4 Years	0.19	0.15	1.25	0.19	0.15	1.28	0.11	0.04	2.44	0.10	0.04	2.41	50%	50%	45
	5 Years	0.22	0.16	1.38	0.22	0.16	1.39	0.05	0.04	1.30	0.05	0.04	1.29	62%	62%	51
	6 Years	0.03	0.06	0.54	0.03	0.06	0.53	0.10	0.02	6.13	0.10	0.02	6.13	93%	93%	16
	7 Years	0.79	0.56	1.40	0.79	0.56	1.40	(0.22)	0.22	(0.99)	(0.22)	0.22	(0.99)	87%	87%	7
SP15	1 Year	(0.69)	0.38	(1.82)	(0.63)	0.75	(0.83)	0.34	0.19	1.82	0.33	0.21	1.62	78%	78%	31
	2 Years	0.72	0.12	6.21	0.84	0.13	6.55	0.17	0.05	3.30	0.13	0.06	2.28	87%	87%	58
	3 Years	0.22	0.14	1.59	0.27	0.14	1.93	0.07	0.04	1.58	0.06	0.04	1.40	32%	33%	96
	4 Years	0.88	0.20	4.48	0.89	0.21	4.21	0.14	0.04	3.84	0.14	0.04	3.83	73%	73%	46
	5 Years	(0.26)	0.06	(4.38)	(0.27)	0.06	(4.48)	0.04	0.03	1.51	0.05	0.03	1.58	64%	65%	61
	6 Years	(0.10)	0.83	(0.11)	(0.44)	0.85	(0.52)	0.16	0.11	1.47	0.18	0.11	1.59	35%	36%	15
	7 Years	0.76	0.57	1.34	0.76	0.57	1.34	(0.05)	0.07	(0.84)	(0.05)	0.07	(0.84)	99%	99%	7

Table V-C13. No Aggregation Regression for "After" Period

Hubs	Time-to-Delivery Class	Gas Futures Estimates						Spot Power Estimates						R^2		Obs
		Ordinary Least Squares (OLS)			With Instrumental Variables (IV)			Ordinary Least Squares (OLS)			With Instrumental Variables (IV)			OLS	IV	
		Coeff.	Std. Err.	t-stat	Coeff.	Std. Err.	t-stat	Coeff.	Std. Err.	t-stat	Coeff.	Std. Err.	t-stat			
COB	1 Year	(0.48)	0.67	(0.71)	(0.48)	0.67	(0.71)	1.19	0.22	5.51	1.19	0.22	5.51	99%	99%	4
	2 Years	1.84	0.23	7.98	1.84	0.23	7.98	(0.50)	0.07	(7.05)	(0.50)	0.07	(7.05)	100%	100%	6
	3 Years	0.45	0.04	10.09	0.45	0.04	10.09	0.79	0.02	49.53	0.79	0.02	49.53	100%	100%	5
	6 Years	0.00	.	.	0.00	.	.	1.19	0.00	4,222.98	1.19	0.00	4,222.98	.	.	3
	7 Years	0.00	.	.	0.00	.	.	0.88	.	.	0.88	.	.	.	.	1
Mid-C	1 Year	(0.38)	0.52	(0.73)	(0.39)	0.52	(0.74)	(0.21)	0.10	(2.08)	(0.21)	0.10	(2.08)	95%	95%	8
	2 Years	0.93	0.23	4.00	0.67	0.24	2.76	0.03	0.07	0.48	0.07	0.07	1.06	79%	78%	73
	3 Years	0.33	0.41	0.80	0.43	0.42	1.03	0.35	0.26	1.36	0.36	0.26	1.38	90%	90%	18
	4 Years	1.15	0.37	3.14	1.13	0.38	2.98	0.11	0.19	0.57	0.11	0.19	0.60	68%	68%	22
	5 Years	(0.11)	0.40	(0.27)	(0.11)	0.40	(0.27)	0.48	0.25	1.93	0.48	0.25	1.93	92%	92%	15
	6 Years	0.00	.	.	0.00	.	.	1.16	.	.	1.16	.	.	.	.	1
	7 Years	3.56	1.33	2.68	3.56	1.33	2.69	0.87	0.32	2.73	0.87	0.32	2.73	97%	97%	7
NP15	1 Year	0.36	0.17	2.08	0.36	0.18	2.04	(0.01)	0.08	(0.07)	(0.01)	0.08	(0.07)	86%	86%	18
	2 Years	0.88	0.07	12.32	0.81	0.07	11.14	0.05	0.03	2.07	0.06	0.03	2.55	88%	88%	186
	3 Years	0.81	0.11	7.47	0.84	0.12	6.92	0.02	0.02	0.93	0.02	0.02	0.78	83%	83%	83
	4 Years	0.79	0.22	3.53	0.60	0.24	2.52	0.00	0.06	0.00	0.02	0.06	0.37	52%	49%	62
	5 Years	0.39	0.16	2.48	0.28	0.16	1.76	0.00	0.04	0.06	0.02	0.04	0.40	73%	73%	42
	6 Years	0.18	0.08	2.26	0.19	0.08	2.24	(0.07)	0.01	(4.59)	(0.07)	0.01	(4.59)	95%	95%	13
	7 Years	(0.21)	0.36	(0.59)	(0.29)	0.36	(0.80)	0.01	0.17	0.09	0.01	0.17	0.07	29%	30%	25
PV	1 Year	0.39	6.38	0.06	(1.35)	6.58	(0.20)	(0.56)	1.36	(0.41)	(0.32)	1.38	(0.23)	4%	4%	15
	2 Years	0.78	0.09	8.32	0.77	0.09	8.28	0.06	0.03	2.20	0.06	0.03	2.21	66%	66%	182
	3 Years	1.07	0.31	3.46	1.00	0.31	3.20	(0.01)	0.06	(0.10)	0.00	0.06	(0.01)	54%	54%	55
	4 Years	0.52	0.23	2.24	0.52	0.23	2.21	0.04	0.08	0.56	0.04	0.08	0.57	57%	57%	51
	5 Years	0.21	0.39	0.56	0.22	0.39	0.56	0.14	0.08	1.66	0.14	0.08	1.66	36%	36%	26
	6 Years	0.68	0.48	1.41	0.67	0.48	1.41	0.00	0.18	0.01	0.00	0.18	0.01	98%	98%	11
	7 Years	(0.17)	0.44	(0.39)	(0.32)	0.45	(0.72)	0.02	0.12	0.19	0.04	0.12	0.33	55%	55%	19
SP15	1 Year	0.76	0.52	1.46	0.29	0.66	0.44	0.18	0.20	0.92	0.32	0.23	1.38	48%	45%	27
	2 Years	0.70	0.04	16.20	0.79	0.05	16.66	0.04	0.02	2.82	0.03	0.02	1.63	81%	81%	368
	3 Years	0.74	0.12	6.13	0.72	0.12	5.81	0.08	0.03	2.63	0.08	0.03	2.68	76%	76%	135
	4 Years	0.50	0.19	2.68	0.51	0.19	2.75	0.12	0.04	3.12	0.12	0.04	3.08	77%	77%	42
	5 Years	0.71	0.27	2.61	0.71	0.27	2.61	0.07	0.06	1.15	0.07	0.06	1.15	68%	68%	45
	6 Years	1.30	1.17	1.11	1.30	1.17	1.11	0.16	0.08	1.96	0.16	0.08	1.96	64%	64%	11
	7 Years	(0.58)	0.12	(4.96)	(0.58)	0.12	(4.96)	0.38	0.03	10.91	0.38	0.03	10.91	99%	99%	7

Appendix V-D: Serial Correlation

Our statistical model attempts to capture the main determinants of forward power prices. Inference based on standard OLS or IV coefficient estimates and standard errors assumes that there is no systematic variation in the portion of the dependent variable, in this case the price of forward power, that is not explained by the statistical model (i.e., the error). Serial correlation occurs when the errors in the estimates are not independent. In the presence of serial correlation, standard errors from conventional OLS and IV estimation tend to be understated and, therefore, claims of statistical significance of model coefficients tend to be overstated.[1]

To test the sensitivity of our regression results to the potential presence of serial correlation, we re-estimated one model specification using techniques that produce standard errors that explicitly account for the presence of serial correlation. Because our data are organized as an unbalanced panel (i.e., we have contracts signed at irregularly spaced points in time for different delivery periods and locations), correcting for serial correlation could be computationally intensive. We have chosen a method that requires minimal amounts of computation but requires some aggregation of the underlying data. We perform a panel version of Prais-Winsten estimation[2] and treat each combination of hub and time-to-delivery as a subpanel.[3] Within each subpanel, multiple contracts signed on the same day are averaged. The Prais-Winsten estimation is performed on these aggregated data. We constrain the extent of serial correlation to be equal across subpanels. The results are shown in Table V-D1 below. The table also shows OLS results on the aggregated data for comparison with our OLS results on the disaggregated data.[4]

[1]See William Greene, *Econometric Analysis*, 4th ed., Chapter 13, for a description of how the presence of serial correlation affects statistical inference.
[2]See William Greene, *Econometric Analysis*, 4th ed., p. 546.
[3]Our estimation is performed using Stata's "xtpsce" command. See the Stata, version 7 manuals for the details of this command.
[4]The OLS parameter estimates for the disaggregated data match the estimates in Table V-3, but the standard errors are slightly different. The parameter estimates in Table V-D1 are the result of a single stacked regression rather than four separate hub-specific regressions. In this particular stacked regression, we constrain our estimate of the error variance to be equal across hubs. This constraint affects estimated standard errors but not parameter estimates.

Table V-D1. Prais-Winsten Estimates of the Spot Power Coefficient

Hubs	Time-to-Delivery Class	Coefficient on log spot power					
		Disaggregated Data		Aggregated Data			
		OLS (stacked)		OLS (stacked)		Prais-Winsten	
		Coef.	Std. Err.	Coef.	Std. Err.	Coef.	Std. Err.
Mid-C/ COB	1 Year	0.375	0.053	0.364	0.061	0.422	0.056
	2 Years	0.135	0.076	0.163	0.088	0.162	0.080
	3 Years	-0.004	0.131	-0.016	0.134	-0.018	0.123
NP15	1 Year	0.219	0.129	0.227	0.160	0.201	0.141
	2 Years	0.141	0.091	0.112	0.124	0.104	0.113
	3 Years	0.063	0.132	0.057	0.160	0.059	0.142
PV	1 Year	0.383	0.045	0.314	0.058	0.246	0.053
	2 Years	0.088	0.045	0.079	0.057	0.100	0.051
	3 Years	0.070	0.059	0.066	0.079	0.064	0.074
SP15	1 Year	0.232	0.066	0.207	0.074	0.225	0.070
	2 Years	0.072	0.044	0.017	0.058	0.004	0.055
	3 Years	0.037	0.065	0.043	0.076	0.044	0.069
N			1066		598		598
rho							0.433

Neither aggregation nor controlling for serial correlation produces qualitatively different results. That is, the coefficients do not differ between the OLS disaggregated case and the OLS aggregated case, nor between the OLS aggregated case and the Prais-Winsten case. The standard errors in the OLS aggregated case and the Prais-Winsten case are also similar. This last result shows that serial correlation does not affect the precision of our estimates. In part, this is because the estimated degree of serial correlation, labeled "rho" in Table V-D1, is modest. In addition, there are significant gaps in the data. Successive transactions with the same delivery location and time to delivery may be several days apart. Even if serial correlation is present, if trades are spaced far enough apart in time, it may not matter.[5]

[5]Serial correlation is a more serious issue for similar analyses based on daily index prices. See Harvey and Hogan, *op. cit.*, note 2.

Appendix IX-A: A Detailed Description of Trader 1's Trading Positions and Profits for the June 14, 2001 Market Test

This appendix describes trading of NYMEX look-alike swaps on EOL on June 14, 2001 by one trader. As described in detail in Chapter III, one of the most common OTC derivative products is known as the OTC swap or the NYMEX look-alike swap. This swap derives its value from the price of the NYMEX natural gas futures contract. Henry Hub physical transactions strongly correlate with the NYMEX futures and the related OTC NYMEX look-alike swaps because the NYMEX futures directly settle based on the Henry Hub physical delivery price.

Following the run-up in prices in the next-day physical market from 10:12 a.m. through 10:35 a.m., trader 1 of the Central desk entered short transactions in July delivery OTC swaps through four sales of 15,000 MMBtu swaps at 4.095, 4.09, 4.085, and 4.09, respectively (where the four average $4.09).[1] The total volume amounted to 60,000 MMBtu in July delivery OTC swaps. That is, the trader promised to sell 60,000 MMBtu of gas every day for the next month (July) at an average price of $4.09/MMBtu. If the NYMEX price for the July gas on a given day in June is more that $4.09, then the trader has incurred losses for that day because he is selling gas (whether he actually has the gas or needs to buy it) at a price below the market value. Conversely, if the price is below $4.09, then his position is profitable because he is selling gas for more than the market value.

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[1]Data reflect that the Enron trader was net short OTC swaps prior to the beginning of the day. However, because the market first rose and then fell back to the approximate opening price, Staff only allocated the financial trades that occurred during the physical manipulation as vehicles potentially purchased to profit by the manipulation.

Recall that this manipulation involved first selling slowly into the market and then repurchasing quickly. The strategy did not involve additional downward pressure in the physical market at the end of the manipulation as was displayed in the July 19 manipulation. In that manipulation, Staff allocated the opening short position as a vehicle to profit from the manipulation due to Enron's apparent intent to push the market down further. The data reflected this intent where they showed Enron was a net seller of Henry Hub next-day physical gas for the day. This was also supported by depositional testimony.

These swaps have a term of 31 days and the quoted volume is a daily volume; therefore, 60,000 multiplied by 31 days yields an intraday short position of 1,860,000 MMBtu. Trader 1 then increased the short position by the additional sale of another 15,000 MMBtu/d (for a total of 465,000 MMBtu) at the price of $4.045/MMBtu at 11:24 a.m., resulting in a total increase of his intraday short position to 75,000 MMBtu/d (for a total of 2,325,000 MMBtu) and an average sell price of $4.081. In essence, the trader has promised to sell 75,000 MMBtu of gas for every day of July at an average price of $4.081.

Between 2:19 and 2:20 p.m., after the market test ceased, trader 1 reduced his net short position by buying 25,000 MMBtu/d at $4.05. Here, the trader has promised to purchase 25,000 MMBtu of gas for each day in July at a price of $4.05. If the NYMEX price for July gas on a given day in June is above $4.05, the trader earns a profit because he is buying gas below market value. If the price is below $4.05, he is incurring a loss because he is buying gas above the market price. This purchase is used to meet and close out 25,000 MMBtu of his promise to sell. Since the trader bought at $.031 less than his obligation to sell, he generates a profit of $24,025.[2]

Trader 1 then further reduced his short position by 30,000 MMBtu/d. He bought the 30,000 MMBtu/d at an average price of $4.0883, generating a loss of $6,820 on this portion of his position or a net gain of only $17,205. He is effectively buying the gas at $4.0883 for every day of July to fulfill his promise to sell the gas at $4.081, generating a loss of $.0073/MMBtu for each of the 31 days in July.

Trader 1 retained the remaining 20,000 MMBtu/d of his short position until the end of trading, when the market closed at $4.02. This generated additional profits of $37,820. He now has a promise to sell 20,000 MMBtu of gas for each day of July at a price of $4.081 and can meet that obligation by purchasing gas at a market value of $4.02, generating a profit of $37,820.

Trader 1's total profit arising from the market test amounted to $55,025.

[2]Trader 1 sold at an average price of $4.081 and bought at an average price of $4.05, yielding a profit of 3.1 cents/MMBtu ($.031 multiplied by 25,000 MMBtu/d and then multiplied by 31 days in the contract yields a profit of $24,025).