VULCAN POWER COMPANY

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By FedEx

April 17, 2003

Commission Secretary
Idaho Public Utilities Commission
472 W. Washington
Boise, Idaho 83702

RE: GNR-E-03-1 - Petition For Reconsideration

Dear Commission Secretary,

Enclosed please find an original and seven (7) copies of the Petition For Reconsideration of Vulcan Power Company regarding Commission Order No. 29216 of Case No. GNR-E-03-1. Thank you.

Cordially,

Steve Munson, CEO

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cc: Mr. Peter Richardson, IEPI

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STEVE MUNSON
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April 17, 2003

BEFORE THE IDAHO PUBLIC UTILITIES COMMISSION

IN THE MATTER OF THE PETITION OF THE INDEPENDENT ENERGY PRODUCERS OF IDAHO FOR AN ORDER INCREASING THE SIZE AT WHICH A QF IS ENTITILED TO PUBLISHED AVOIDED COST RATES.	)	CASE NO. GNR-E-03-1 PETITION FOR RECONSIDERATION OF VULCAN POWER COMPANY

Vulcan Power Company, hereinafter referred to as "Vulcan" or "the Company", Petitioner herein, pursuant to RP 331 and Idaho Code 61-626, respectfully petitions the Commission for reconsideration of Order No. 29216 upon the grounds that said Order is unreasonable and inconsistent with the best interests of the state of Idaho. We do hereby request a formal public proceeding to reconsider Order No. 29216 at the earliest possible convenience.

Vulcan requests that the Commission reconsider Order No. 29216 for the following reasons and submits data and analysis herein for basis of such request.

Commission's decision to deny the Petition of the Independent Energy Producers of Idaho ("IEPI") without holding a public proceeding to gather and consider information from other Parties is unreasonable and inconsistent with the best interests of power consumers and stakeholders of the state of Idaho.

Order No. 29216 states as its basis for denial that:

> "IEPI in its Petition presents no persuasive argument for revisiting the QF eligibility capacity limit for published avoided cost rates." (Order No. 29216 at p. 3).

However, the Commission's Order does not dispute any of the facts put forth by IEPI in its Petition supporting the benefits of their request to increase the QF size to 30 MW. The Commission does not state that its goal of encouraging QF development has changed since Order No. 29069. The Commission does not dispute the IEPI assertion that there would be no negative impacts to the utilities from the increase in QF size, nor does the Commission produce any of their own conclusions citing negative impacts. Given these facts, it is in the best interest of the state of Idaho to grant, in part, the Petition of IEPI and hold a public proceeding to further investigate the Petition of IEPI, and to request the input of other Parties and experts, including other potential qualifying QFs, so that the Commission could fully evaluate the pros and cons (if any) of increasing the QF size to 30 MW.

Traditional Utility Negotiations Not Productive

The Commission notes two points in denying the Petition of IEPI. The Commission states:

> "The Commission notes that QFs greater than 10 MW are not precluded from contacting an electric utility and individually negotiating power purchase agreement. That has long been the contract procedure for large QFs. The starting point for such negotiations under the Commission approved methodology is the established posted rate. Should a utility fail to negotiate in good faith with a qualified QF, a complaint can be filed with this Commission." (Order No. 29216 at p. 3)

Vulcan does not dispute the legality of this contracting procedure, but does dispute the practicality and actual results of such a process. Vulcan has shared the frustration of other independent energy producers in attempting to conduct "good faith" contract negotiations with electric utilities of Idaho. The results of such negotiations have been disappointing and nonproductive. In fact, Vulcan believes the Commission was quite right when it stated:

> "Despite a QF history of industry reliability and an opportunity presented to utilities to diversify their resource base by adding renewables, utilities continue to regard PURPA QFs as interlopers." (Order No. 29029 at p. 5)

The perceived status of an "interloper" is not an enviable status when conducting contract negotiations. The mere implication of that type of attitude from utilities denotes utility hostility towards QFs and does not foster a healthy contract negotiating environment. This process of contract negotiation will not facilitate additional QF project development.

QF Size – FERC and PURPA

The Commission also notes in denying the Petition of IEPI that:

> "FERC requires only that published rates be made available to QFs with a design capacity of 100 kW or less." (Order No. 29216 at p. 3)

Although Vulcan agrees with this statement, we believe a statement more relevant to the current issue would be that "FERC does not require, nor does it preclude facilities greater than 100 kW from being entitled to published avoided cost rates." The PURPA laws, however, do implicitly address this issue by specifically placing an 80 MW cap on cogeneration facilities while not placing size limitations on wind, geothermal or solar facilities. By specifically not placing a cap on the renewable energy technologies, PURPA and FERC allow states to set the limits on QF size to best accomplish the intent of the PURPA laws and the goals of the state.

Indeed it was this interpretation that allowed the Commission to originally increase the QF size to 10 MW. That size was fairly arbitrary and was chosen to attempt to reach the threshold of triggering additional QF development. It is no less arbitrary than 7 MW or 12 MW, or even 100 kW, in that none of these QF sizes will achieve sufficient economies of scale to trigger the intended increase in QF development. The key factor that gives significance to the actual MW size of QFs is <u>whether or not the QF size leads to the actions desired by the goals of the Commission</u>. The 10 MW size is insufficient to trigger such actions. The <u>30 MW QF size now being suggested will be sufficient to trigger additional QF development</u> according to the very Parties that run the financial models and will eventually finance and build the QF projects and meet the stated goals of the Commission.

Raise QF Size Now or Raise Avoided Costs Later

Vulcan believes the state and the region need QF development, and believes that circumstances will eventually lead to such QF development. That time can either be now, by raising the QF eligibility from 10 MW to 30 MW which will facilitate QF development thereby helping keep avoided cost low, or the time can be later when Idaho's continued over-reliance on seasonal hydro and fossil fuels will require raising the avoided cost rate and thus opening the door for 10 MW QFs. Clearly the former would be more desirable for the people and economy of Idaho.

Vulcan agrees with the Commission that,

> "if the rates are no longer fair and accurate, the appropriate response is to adjust the rates, not to limit the size of the QFs eligible for the rates." (Order No. 29069 at p. 7)

Indeed, if sufficient steps are not taken by the Commission to encourage the diversification of resources that QF development provides, then the Parties will likely be back in a proceeding to increase the avoided cost rates.

As stated in the Petition of IEPI, the importance of diversifying energy resources has grown even stronger than it was when the Commission increased the QF size to 10 MW. Hydro and natural gas supply conditions have worsened for both the near-term and the long-term.

The Pacific Northwest is suffering from yet another below average water year. Reports have shown that some regional snowpacks are 70% of normal. This disturbing trend of low water years further underscores the fact that we cannot craft public policy for power assuming "normal" water years in the future. The future potential for hydro to even maintain its current capacity is bleak, given the widespread opposition to new hydro construction, significant regulation and costs of hydro relicensing, salmon migration issues, and the ever-increasing demand for other uses of water. There is also, of course, the uncertainty to the future hydro system that comes with the regional effects of global climate change. These problems with hydro will not go away and point to the logical conclusion that diversification of the energy system is the only logical hedge against future insufficient hydro power generation.

Vulcan also believes that the outlook for future gas fuel supplies (and prices) is bleak and agrees with the IEPI Petition that states,

> "Natural gas has now moved from the supply status of a just-in-time commodity to a commodity that is actually in deficit. It is projected to remain in deficit status for the foreseeable future. As a result prices have recently hovered near all time highs." (IEPI Petition at p. 9)

The Commission did not dispute these findings. Additional research and analysis conducted by Vulcan and other gas experts further illuminate the ominous nature of the gas fuel supply situation and is attached hereto. Data from Vulcan, Simmons & Company Int'l (Exhibit A), the National Energy Board of Canada (Exhibit B), and Platts Research and Consulting (Exhibit C) all indicate the high probability of gas fuel prices remaining at their high levels and for price spikes and increases in the future.

The fact that the volatile gas fuel supply market has changed dramatically is likely justification for readdressing the avoided cost rate in a new proceeding, but more relevant to this Petition, it further demonstrates the importance of the Commission accomplishing the admirable goals it set forth by initially raising the QF size to 10 MW, namely that:

- Energy resource diversification is desirable.
- Therefore QF development is desirable.
- Therefore increasing the QF size to encourage QF development is desirable.

The passage of time has illuminated the reality that the Order of the Commission to raise the QF size to 10 MW was the correct decision for Idaho, but it wasn't of sufficient magnitude to achieve the desired effects of the Commission. Raising the QF size to 30 MW remains consistent with the goals of the Commission and is in the best interests of the state of Idaho.

Respondent Energy Background

Mr. Steve Munson is an energy professional with thirty years participation in international energy markets including: graduate thesis in the geopolitical impacts of declining oil supplies; Wall Street energy investment banking; and correctly warning federal and state agencies and electric utilities since 1995 of the recent power shortfalls and gas supply price impacts throughout the West. He has warned power policy participants of impending electric power price increases driven by North American mature gas basin depletion rates and future foreign LNG supplies.

Mr. Munson is the CEO of Vulcan Power Company, a geothermal company that has expended very large amounts of time and money in Idaho to advance clean, baseload geothermal projects. It has been stymied along with others by the past 10 years of Idaho Power and Avista opposition to geothermal power gaining a foothold in Idaho.

Vulcan Power Company and Mr. Munson were instrumental in the passage of a 20% renewable portfolio standard in California, a 15 % renewable portfolio standard in Nevada and a 10 % renewable portfolio standard rule in New Mexico. He is a founding member of the Federal Geothermal Working Groups of Idaho, New Mexico, and Oregon. He a member of the Geothermal Resources Council. Mr. Munson holds an MBA in Finance from the Stanford Graduate School of Business and an MA in Political Science from Stanford University.

Respectfully submitted this 17th day of April, 2003.

Steve Munson, CEO
Vulcan Power Company

Exhibit A

Simmons & Company International: Natural Gas Research Reports

Simmons & Company International, an investment banking firm based in Houston, Texas, has been tracking natural gas production and price implications for years. The Simmons & Company International natural gas research reports can be accessed on their web site at www.simmonsco-intl.com.

Portions of the reports are copied which have influenced the Company opinion that the United States in general and California in particular are faced with a significant risk of relative high average annual prices for long term gas plant natural gas fuel. Also influencing this opinion are domestic gas price increases since 1999, including changes in winter-summer seasonality gas demand patterns.

In the opinion of the Company, the implication of the reports findings stated herein, are that the natural gas fuel price for referent gas plant operations beginning in 2006 may average at the high end range of the Platts CPUC workshop report of 3/4/03 which was $ 6.218 per mcf. (See Platts report attached).

Simmons authorized Vulcan Power Company to quote from the referenced reports located on their website during the CPUC process. Simmons does not provide testimony. Their research report data was used to form gas supply and price opinions. The work is subject to the disclaimer at the bottom of the first page of the report section.

Interested parties are invited to review the referenced reports concerning the larger gas supply and price picture to determine that such material is not out of context and to view the

disclaimer of Simmons & Company. The first report listed below is the latest Simmons report available at 3/26/03.

Simmons Report: "3Q02 Natural Gas Production Update" (at 11/25/02)

"The reported data (2002 year to date) have shown a consistent year/year decline trend of between 3% and 5% for the first three quarters of 2002, which is at the high end of our 3% to 4% decline estimates in November 8, 2002 research report "North American Natural Gas: Improving Upon an Already Positive Outlook.

It is interesting to note that the sequential change in actual gas production has been essentially flat during the last two quarters. (Note: with the reference to "Positive Outlook" they mean high gas prices.)

Implications

According to Baker-Hughes the US gas-directed rig count has average 690 rigs through the first three quarters of 2002. Even though this is significantly below the 2001 average activity of 940 rigs, it is still above the pre 2000 record high of approximately 650 rigs in September, 1997. With nearly 700 active rigs the continued production declines from the largest US gas producers is further evidence of the relentlessness of the decline rate treadmill.

Moreover our assessment that US natural gas production will continue to decline into 2003 continues to be on track. We forecast 1.5% decline during 2003 with a 14 % increase in rig count from 2002 levels." (See Natural Gas Supply Analysis – Simmons & Company, attached)

Natural Gas Supply Analysis

Simmons & Company International

2002 Energy Industry Research Reports

Nov. 8, 2002

Feb. 15, 2002

Simmons & Company International • 5000 Bank of America Houston, Texas 77002 • (713) 223-7840 • Fax (713) 223-7845

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"North American Natural Gas, Improving an Already Positive Outlook" (11/8/02)

As we near 2003, our outlook on the natural gas markets continues to improve, as the potential for tight supply and demand fundamentals has increased. The U.S. natural gas production treadmill is more visible than ever and with a lethargic rig count that continues to show no signs of recovery in the near-term, we believe that 2003 production will likely decline 1.5%. Moreover, the natural gas import situation has changed materially over the past few years, as Canadian production is at a zenith, and imports from Canada could decline next year while U.S. natural gas exports to Mexico are on an increasing trajectory. Thus, the burden to increase U.S. gas supply increasingly rests on the untested shoulders of LNG!

Electricity Generation (35% of total U.S. demand). Over 115,000 MW of new generating capacity has come online since 1999 (when reserve margins hit a dangerously low 7%). Approximately 95% of this new generating capacity is gas-fired. Not surprisingly, we have recently witnessed solid demand growth for natural gas to generate electricity. In 1999, 15% of electricity was generated using natural gas; in 2001, almost 17% of electricity was generated using natural gas.

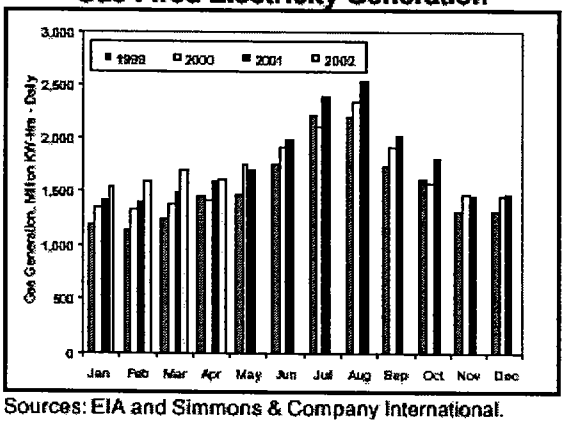
Table: Breakout Of Total And Gas-Fired Electricity Generation

	Average Daily Electricity Generation				Electricity Generation
	Natural Gas million KW-Hrs	% Change y/y	Total million KW-Hrs	% Change y/y	% Gas
1Q99	1,191		9,796		12%
2Q99	1,566		9,846		16%
3Q99	2,059		11,297		18%
4Q99	1,417		9,636		15%
FY99	1,558		10,144		15%
1Q00	1,352	13%	9,982	2%	14%
2Q00	1,700	9%	10,124	3%	17%
3Q00	2,129	3%	11,283	0%	19%
4Q00	1,505	6%	10,125	5%	15%
FY00	1,671	7%	10,379	2%	16%
1Q01	1,443	7%	10,278	3%	14%
2Q01	1,765	4%	10,069	-1%	18%
3Q01	2,315	9%	11,287	0%	21%
4Q01	1,586	5%	9,533	-6%	17%
FY01	1,777	6%	10,292	-1%	17%
1Q02	1,624	13%	9,998	-3%	16%

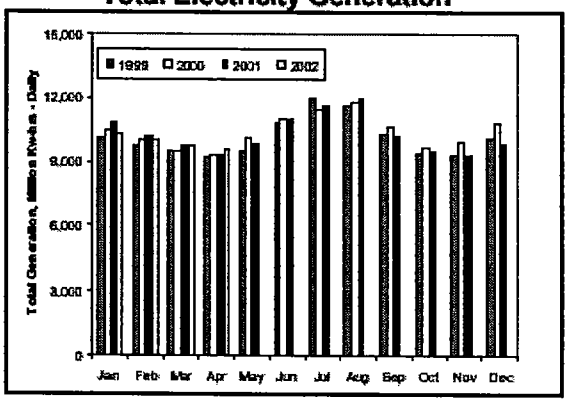
Sources: EIA and Simmons & Company International.

The figures below graphically illustrate the growth in natural gas-fired generation, even though total power generation has experienced lethargic growth over the past two years. This monthly electricity data further highlight the significant seasonality of natural gas-fired power generation demand during the summer months when air conditioning load peaks.

Gas-Fired Electricity Generation



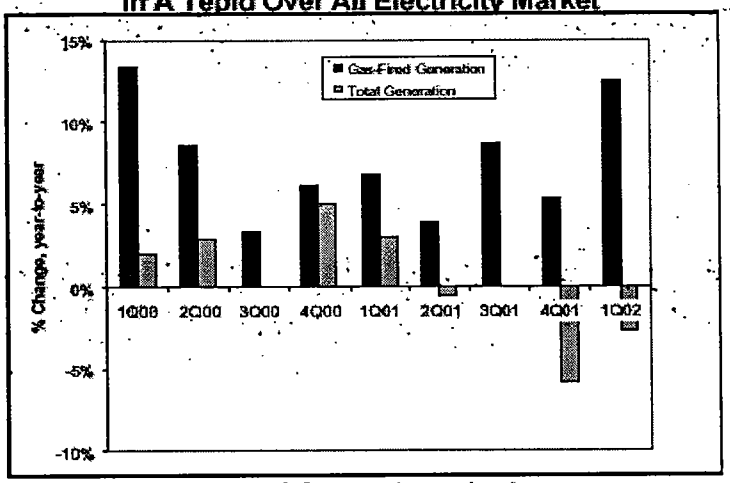
Total Electricity Generation



Sources: EIA and Simmons & Company International.

In 2001, total electricity generation was down 1%, but demand for gas to generate electricity was up 10%. Thus, even in a flat to declining *overall* electricity demand market, natural gas demand for electricity grew through increased market share. We expect this trend to continue in 2002 and 2003. With any electricity demand growth, natural gas will only gain incremental market share in the power generation market as the vast majority of the incremental generation adds (i.e., capacity margin) is natural gas-fired.

Electricity: Gas-Fired Power Growth In A Tepid Over All Electricity Market

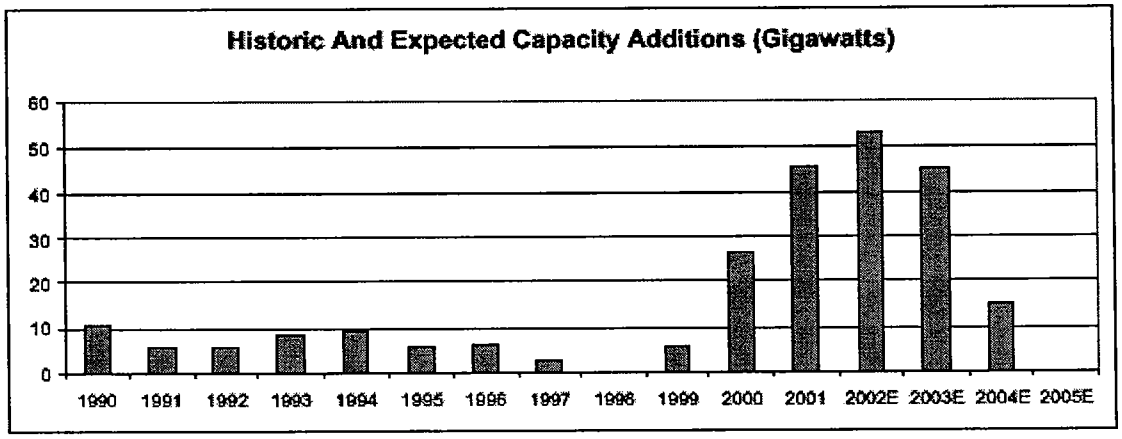


Sources: EIA and Simmons & Company International.

1 In 2002, approximately 53,000 MW of new power plants are expected to come into service over the course of the year. [Please see our October 4, 2002 report, "Evaluating The Near-term And Long-term Outlook of U.S. Electricity Fundamentals"]. Year-to-date (through April), electricity demand as reported by the U.S. Energy Information Administration was down 2%, but demand for gas to generate electricity was up 6% (or 0.9 bcf/day). This was in line with our expectations and is particularly impressive when considering that hydroelectric generation was up 16% year-over-year. Further, with year-over-year electricity demand comparisons likely positive during 2Q to 4Q02, we expect gas demand for electricity generation to continue its recent growth trend. Our estimate of a 1.3 bcf/day increase in power generation demand for gas in 2002 looks very realistic. Utility demand through the summer confirms improved electricity demand (as summer weather was approximately 15% warmer than normal).

In 2003, we expect approximately 45,000 MW of new power plants to come into service. While these new gas-fired power plants will displace some older, lesser efficient gas plants, we continue to believe that **power generation demand for gas will be up 1.0 bcf/day in 2003 compared to 2002.**

U.S. Electricity Capacity Additions



2 Source: RDI, Simmons & Company International.

For those nay-sayers in the crowd who are fearful that no new power plants will come into service in 2003 (as IPP players cancel plant construction), we note that this is not necessarily negative for gas demand. With any electricity demand growth (and no new power plants), utilization of less efficient peaking plants will increase. This would actually boost demand for gas compared to the expected scenario where the planned combined cycle plants are completed.

Beyond 2003, we expect 15,000 MW of new power generation capacity to come into service during 2004. At this point, we estimate electricity reserve margins will reach a comfortable 20% (compared to 7% in 1999).

1

U.S. Natural Gas Supply

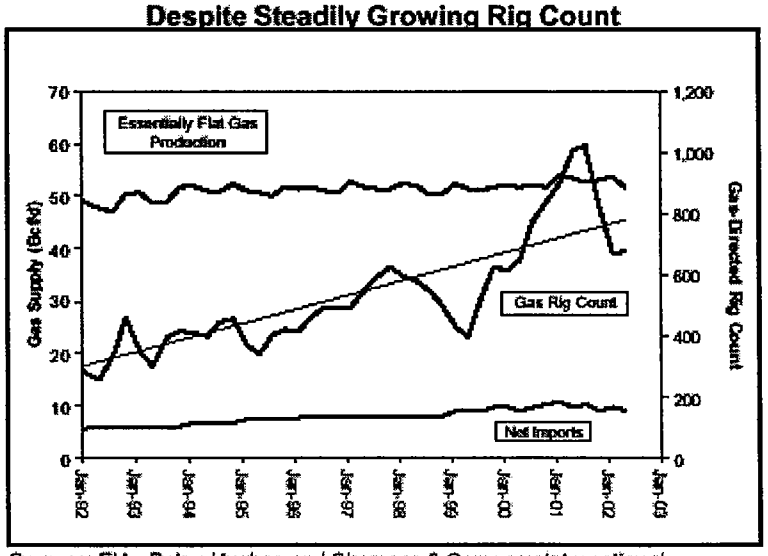
U.S. Production (accounts for 84% of total U.S. gas supply). From 1995 through 1999, the gas rig count averaged a rather consistent 450 to 550 rigs. Over this period, production per new gas well completion was also rather consistent averaging 1.05 mmcfd. In 2000, the gas rig count jumped to 720 rigs, and production per new completion declined to 0.80 mmcfd. In 2001, the gas rig count jumped further to average 937 rigs, and new production per completion dropped to 0.63 mmcfd. We argue that the rig activity levels and production response in 2000 and 2001 are indicative of the law of diminishing marginal returns.

The data from 1995 to 1999 argue that, with a base gas rig count of 500 rigs, production per new completion is approximately 1.00 mmcfd. Looking at 2000 and 2001, we believe that incremental rigs above 500 and up to 750 were drilling prospects that average 0.35 mmcfd of new production. Above 750 rigs, we believe the incremental rig drilled prospects that average 0.15 mmcfd of new production.

2

From this relationship, **we continue to estimate that U.S. production will decline by 3 to 4% in 2002** (based on expectation that the U.S. gas rig count will average 700 in 2002). Through 1H02, U.S. production was down 4.5%. With easier comparisons in 2H02, we remain comfortable with our analysis of U.S. production trends.

U.S. Natural Gas Supply – Essentially Flat Despite Steadily Growing Rig Count



Sources: EIA,, Baker Hughes and Simmons & Company International.

In 2003, with expectations that the U.S. gas rig count will average 940 rigs, we expect U.S. gas production to be flat to down 1.5%.

3

The reported natural gas production data from the U.S. EIA for 2H01 and all of 2002 are not useful due to the absence of Gulf of Mexico production data. The Minerals Management Service, the agency responsible for aggregating and publishing GOM production data, has not posted any production data since July 2001 due to a combination of legal reasons and data compilation problems. Thus, the EIA's production estimates are made without the benefit of 25% of total lower 48 production...and are not meaningful over the past several quarters.

In lieu of waiting on better production estimates from the MMS and EIA, we track Texas natural gas production data. The Texas gas well production, which comprises almost 25% of total U.S. gas well production, shows the impact of reduced drilling activity over the past few quarters. Although this data is subject to revision, we believe it is a decent proxy for total U.S. gas production. Texas gas production started to decline in 4Q01 as has continued as rig count continued to fall during 1H02. The trends in Texas natural gas production have been, so far, directionally in-line with our estimates for U.S. gas production decline of 3% to 4% in 2002.

Texas Natural Gas Production

	Natural Gas bcf/day	% Change y/y	Rig Count	% Change y/y
1Q98	13.31	-0.9%	360	18%
2Q98	13.34	1.7%	319	-6%
3Q98	13.36	2.9%	264	-27%
4Q98	13.16	-1.0%	225	-39%
FY98	13.29	0.6%	292	-15%
1Q99	12.97	-2.5%	185	-49%
2Q99	12.79	-4.1%	179	-44%
3Q99	12.77	-4.4%	227	-14%
4Q99	13.08	-0.6%	266	18%
FY99	12.91	-2.9%	214	-27%
1Q00	13.32	2.7%	275	49%
2Q00	13.37	4.5%	298	67%
3Q00	13.34	4.4%	353	55%
4Q00	13.43	2.6%	390	46%
FY00	13.36	3.5%	329	54%
1Q01	13.55	1.7%	421	53%
2Q01	13.53	1.2%	467	57%
3Q01	13.33	0.0%	472	33%
4Q01	13.25	-1.3%	394	1%
FY01	13.42	0.4%	438	33%
1Q02	13.29	-1.9%	330	-22%
2Q02	13.19	-2.5%	306	-35%
3Q02TD	13.36	0.2%	322	-32%

Sources: TRRC, Simmons & Company International and Baker Hughes.

Natural Gas Imports (account for 16% of total U.S. natural gas supply). U.S. natural gas imports have two main sources: 1) Canada, and 2) Liquified Natural Gas (LNG)...which are partially offset by natural gas exports to Mexico. We forecast total imports to the U.S. up 4% in 2003, driven by growth in Canadian and LNG imports during 1H03. Although believe Canadian production could plateau in 2003 (or even decline), we model a slight increase in 1H03 Canadian gas imports to the U.S. due to high levels of Canadian storage and stagnant industrial demand. We model 2H03 imports flat. With Canadian natural gas storage nearly full and the year-to-year comps for Canadian and LNG imports relatively "easy" due to low prices during 1H02, we model increased imports during 1H03. If this import increase does not materialize, the tight market we forecast for 2003 will certainly become tighter.

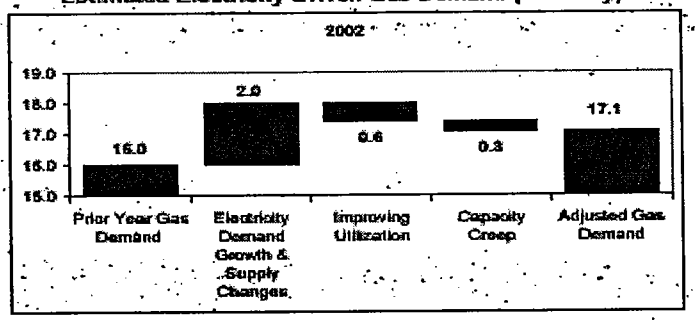
Canada. For the better part of the last 15 years, Canada has served as the marginal supplier of natural gas to the U.S. market. This story is coming to an end. With a rapidly accelerating base decline curve (from 10% to12%, 10 years ago, to 20% to 22% today), lower production per new well (1.0 mmcfd 10 years ago to 0.5 mmcfd today), and decreased drilling activity (down 29% year-to-date), Canadian imports are down 3% (or 0.2 bcf/day) year-to-date through July (according to the U.S. DOE).

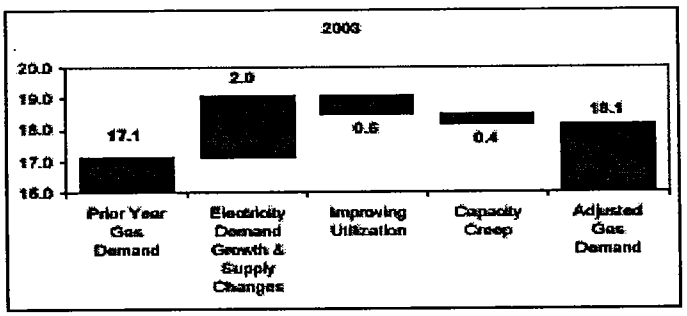
At best, we see Canadian deliverability flat in 2003. With anything approaching a normal winter, Canadian domestic gas demand will be up—resulting in a decrease in exports to the U.S. even with flat deliverability. In this scenario, we see U.S imports of Canadian gas down in 2003. If Canadian deliverability is down and domestic demand is up, exports of gas to the U.S. could be down by as much as 1.0 bcf/day.

1 **"Dynamics of Electricity-Driven Natural Gas Demand" (2/15/02)**

We estimate that natural gas demand for power was approximately 16 BCF/day in 2001. **Depending on overall demand for electricity, we believe that overall gas demand for power will increase up to 2 BCF/day per year over the next two years despite the impact of improved utilization rates of lower marginal cost fuel sources, capacity creep from nuclear and coal-fired generation, and gas on gas competition.** Assuming 2.5% annual demand growth, the following graph summarizes the relative impact of drivers to electricity-driven gas demand over the next two years.

Estimated Electricity-Driven Gas Demand (BCF/Day)





Sources: Energy Information Administration, RDI and Simmons & Company International.
Note: Assumes 2.5% annual electricity demand growth.

2

Summary

- **We do not project a material decline in electricity-related gas demand due to the effects of utilization rate changes, capacity creep and gas on gas competition over the next two years unless we have a protracted decline in overall demand for electricity. Overall demand for electricity is the largest single factor influencing electricity-driven gas demand.**

- **More than any other fuel source, gas-fired electricity production exhibits a large degree of seasonality. Furthermore, electricity-related gas demand is heavily influenced by regional characteristics. Almost 60% of electricity-driven gas demand is centered in 2 out of the 10 NERC regions (ERCOT and WSCC).**

- **Utilization rates for nuclear and coal-fired capacity are improving, and utilization rates of hydroelectric capacity are expected to improve after a severe drought in the Pacific Northwest. In total, we expect utilization rate changes to displace about 600 mmcf/day of gas demand each year over the next two years.**

- **Capacity creep in nuclear and coal-fired capacity exists. Over the next two years, we expect capacity creep could potentially displace an additional 300 to 400 mmcf/day of gas demand each year.**

- **Gas on gas competition has a material effect on electricity-related gas demand. We expect electricity-related gas demand to increase despite gas on gas competition. That said, gas on gas competition will cannibalize a total of 8 to 10 BCF/day of potential gas demand over the next two years.**

- **Fuel switching from gas to oil can have a material effect on electricity-related gas demand. When fuel switching from gas to oil occurs, we estimate that electricity-driven gas demand could decline by 1 to 2 BCF/day.**

3

Overview

There is currently a significant amount of debate surrounding the magnitude of electricity-driven natural gas demand. This report addresses some of the key issues surrounding this debate.

Supply and demand fundamentals are heavily influenced by regional characteristics that are compounded by the state of the transmission system, which currently inhibits the movement of power between regions. Therefore, we applied a ground-up, regional approach to our analysis. Although regional analysis is much more cumbersome than looking at overall changes, we feel it is absolutely necessary in order to capture the intricacies of the fragmented U.S. power market. Simple "back of the envelope" calculations that lump the entire U.S. into one calculation can lead to erroneous assumptions and misleading results.

Our analysis only includes estimates of electricity-related gas demand over the next two years. We have not attempted to make projections beyond 2003 because of lack of visibility in supply and demand fundamentals and pending environmental legislation. Federally sponsored legislation, collectively referred to as the NOx SIP Call, calls for state implementation plans (SIPs) in 22 Midwestern and Eastern states aimed at reducing nitrous oxide emissions. On track for implementation sometime in 2004, we believe there is a strong likelihood that these plans will have an impact on the ability of many existing coal-fired generating plants to operate at current utilization rates. It is difficult to assess the impact of these initiatives because it is still evolving and has many

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moving parts. However, there is a very real potential that reduced coal utilization could lead to higher utilization rates for gas-fired generation and materially impact electricity-driven gas demand.

Schools of Thought

The Optimist: The bull case for electricity-related natural gas demand. Keeping in tune with the boom in development of natural gas-fired generation over the past couple of years, approximately 41,000 MW of new gas-fired capacity came online in 2001. Only counting projects already under construction, roughly another 100,000 MW capacity should come online before the end of 2003. Virtually all of this capacity is gas-fired. New plants are expected to achieve utilization rates upwards of 65% for combined-cycle and 20% for simple-cycle, thereby increasing gas demand 4 to 5 BCF/day each year over the next few years. Improving nuclear and coal utilization will not have a huge impact because these units are typically older plants that will increasingly need to undergo maintenance and retrofits in order to be able to operate at current utilization rates. Additionally, environmental concerns should eventually force many of these plants to shut down.

The Pessimist: The bear case for electricity-related natural gas demand. Gas-fired capacity has come online at a record pace and will continue to come online through at least 2003, creating a supply glut of electric generating capacity that is only getting worse because demand has faltered with the economy. Nuclear and coal-fired utilization rates are improving every year and hydroelectric utilization is making a comeback after a severe drought in the Pacific Northwest. Existing nuclear and coal-fired units are also being retrofitted and re-rated, consistently improving their output capacity. On a marginal cost basis, nuclear and coal-fired generation operates at a lower cost than gas-fired capacity. Therefore, utilization improvements and capacity creep will displace most additional gas-fired production. New gas-fired capacity will run at lower utilization rates than what developers are planning and will mostly compete on the margin with older gas-fired capacity, creating gas on gas competition. This will actually reduce overall demand for natural gas needed to produce electricity as newer, more efficient units use less gas to produce the same amount of electricity that older units generate.

Our View: Improving utilization rates, capacity creep, and gas on gas competition exist and do negatively impact electricity-driven gas demand. A great deal of gas-fired capacity has come online over the past couple of years, and this will continue through at least 2003. As a result, there is a glut of capacity in some regions. However, the fact that some regions still face a tight supply situation has been masked by depressed electricity demand as a result of a faltering economy. Despite these factors, we believe that electricity-driven natural gas demand could grow up to 2 BCF/day each year over the next two years and that there will not be a material decline in electricity-related gas demand. However, how much gas demand growth we experience will in a large part be determined by overall demand for electricity. While it is likely that electricity demand growth will return after the malaise in the second half of 2001, indications are that it will not occur until at least the second half of 2002.

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Regional Variations

Not surprisingly, electricity-driven gas demand is higher in regions where gas-fired capacity represents a material portion of overall generating capacity. In our analysis, **we found electricity-related gas demand to be heavily concentrated in regions with a large concentration of gas-fired capacity, mainly Texas, California and New England.** Electricity-related gas demand is also affected by the relative concentration of lower marginal cost generating capacity in each region. As we have said, just because gas-fired capacity exists does not mean that it will run as developers have planned. In regions where enough generation from low-cost sources of power like nuclear and coal-fired capacity exists to meet demand, gas-fired generating capacity does not run an appreciable percentage of the time (i.e. ECAR, MAIN, MAPP). This illustrates the difficulty that new gas-fired capacity in those regions (especially baseload capacity) could have in achieving utilization rates required to make these investments economic without substantial electricity demand growth.

Using our estimates for 2002, the following table illustrates regional variation in gas demand for production of electricity.

2002 Est. Regional Gas Demand for Electricity Production (BCF/Day)

NERC Region	Gas Demand	% of Total
ECAR	0.0	0%
ERCOT	4.8	28%
FRCC	1.6	9%
MAAC	0.6	4%
MAIN	0.0	0%
MAPP	0.0	0%
NPCC	2.2	13%
SERC	1.1	6%
SPP	1.5	9%
WSCC	5.3	31%
Total	17.1	100%

Source: Energy Information Administration, RDI and Simmons & Company International.
Note: Assumes 2.5% demand growth and no fuel switching from gas to oil.

Conclusion

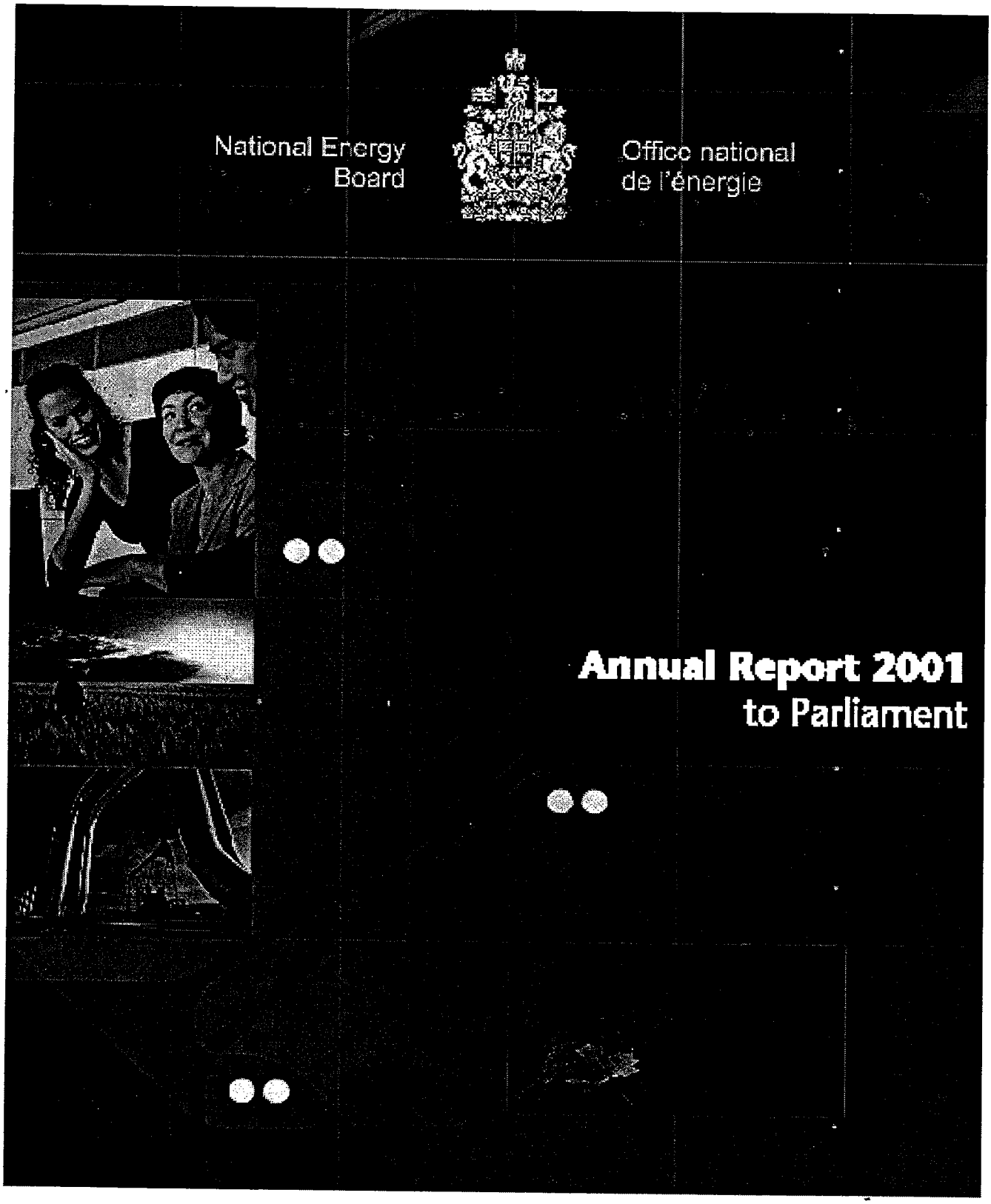
Regional, seasonal and marginal cost considerations play a large part in determining electricity-related natural gas demand. Ignoring any of these factors can lead to erroneous assumptions and therefore conclusions in estimating gas demand. Although growth of electricity-driven gas demand is not likely to be the 4 to 5 BCF/day that some are predicting, the impact of improving utilization rates and other factors negatively impacting gas demand are not likely to bring about a material decline in gas demand either. Electricity-driven gas demand is likely to grow over the next couple of years, but the amount of growth is highly dependant on overall demand for electricity. Due to lack of visibility in supply conditions and pending environmental legislation, it is difficult to make projections of electricity-driven gas demand much beyond 2003, and we are inherently skeptical of the degree of accuracy in any longer-term assessments.

Exhibit B

Natural Gas Supply Analysis

National Energy Board of Canada

2001 Annual Report


National Energy Board
Office national de l'énergie
Annual Report 2001
to Parliament

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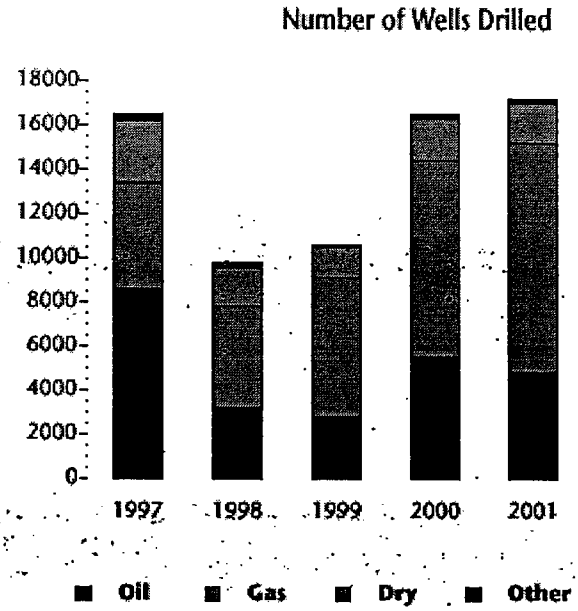
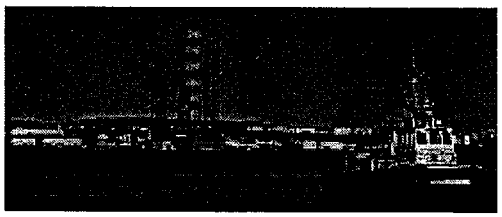


Upstream Activity

A record 17 983 total wells were drilled in year 2001, exceeding the previous high of 16 507 wells established in year 2000 (Figure 3). This record level of drilling activity was in response to the high natural gas and oil prices that prevailed in the early part of the year. The focus of the drilling was on natural gas, with the number of gas well completions up by 16 percent in 2001 from 2000, and making up 69 percent of all wells completed. Oil well completions for 2001 were 14 percent lower than the previous year, with oil drilling dropping off after the first quarter as oil prices decreased.

Competition for land remained high in 2001 as revenue from land sale bonuses collected by the four western Canadian provinces totalled more than $1.6 billion or 10 percent higher than in 2000. While the average price, at $292 per hectare, was down slightly from $299 per hectare received in 2000, the total land area involved in sales was up 15 percent from 2000, to 5.5 million hectares. In the frontier areas, the majority of land sale activity was concentrated in the Nova Scotia offshore where there is keen interest surrounding the proposed natural gas development at Deep Panuke.

Seismic survey activity also remained strong in 2001, with the number of active crews up eight percent over the previous year. This increase reflects a greater level of activity in the first half of 2001, with second-half levels similar to those of 2000. Seismic activity in Western Canada was focused in the southeast, foothills, and northwest regions of Alberta as well as in the northeast region of British Columbia. Record expenditures of $20 billion for exploration and development of Canadian conventional and frontier areas (excluding oil sands) were made in 2001, up 10 percent from the previous year. Exploration spending continues to be about one-third of the total oil and gas exploration and development expenditure in Canada.



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Production

Despite record gas well drilling and completions in Alberta and Saskatchewan in 2001, production increased only marginally. Canadian marketable natural gas production in 2001 totaled 180.7 billion cubic metres, up about 2 percent from 2000 levels. The main sources of new production were the Sable Island offshore project in Nova Scotia and a new gas field at Ladyfern in northeast British Columbia. These sources of incremental production have slightly shifted the distribution of Canadian natural gas supply at the expense of Alberta and Saskatchewan. Alberta now accounts for 79 percent of total Canadian production, down from 81 percent in 2000, and Saskatchewan accounts for 3 percent, down from 4 percent in 2000. British Columbia now contributes almost 14 percent, Nova Scotia 3 percent, Northwest Territories/Yukon 1 percent and Ontario less than 0.5 percent of total Canadian gas production.

3

Reserves

The NEB's estimate of remaining established reserves of marketable natural gas as at year-end 2000 is 1 622 billion cubic metres. This includes reserves from the East Coast offshore and the Liard Region of the Northwest Territories (Table 6). The volume of remaining established reserves declined from 1999, albeit by less than one percent, as production continued to outpace reserves additions.

TABLE 6
Estimates of Established Reserves of Marketable Natural Gas at 31 December 2000
(billion cubic metres)

	Initial	Remaining
British Columbia[a]	607.8	234.3
Alberta[b]	4 063.5	1 210.7
Saskatchewan[c]	200.3	70.0
Ontario[c]	44.3	11.6
NWT and Yukon	25.9	14.4
Nova Scotia - Offshore[d]	85.0	81.4
Total	5 026.8	1 622.4

(a) British Columbia Ministry of Energy & Mines and NEB common database
(b) Alberta Energy & Utilities Board and NEB common database
(c) Provincial estimate for 31 December 2000
(d) Canadian Association of Petroleum Producers

From 1996 to 2000, cumulative additions of marketable gas reserves replaced only 73 percent of total production. Without the Nova Scotia and Liard reserves additions, this would only be 62 percent. Continued and strong concentration by industry on gas exploration resulted in year 2000 additions being the highest in recent years (Table 7). While new discoveries in the Ladyfern area of British Columbia are not fully reflected in the additions for year-end 2000, further drilling in 2001 has provided enhanced delineation of the pool. New discoveries and fewer downward revisions to reserves estimates for existing gas pools resulted in a replacement of 153 billion cubic metres, or 88 percent of natural gas production during 2000. The fact that gas production has been outstripping reserves additions despite very high rates of drilling is an indication that the WCSB is maturing as a producing basin. It will likely be difficult to maintain increases in annual production without ongoing development in the northern and western-most portions of the WCSB, the east coast offshore, and the Mackenzie Delta region.

TABLE 7
Natural Gas Reserves, Additions and Production
(billion cubic metres)

	1996	1997	1998	1999	2000	Total
Additions[a]	50	130	119	152	153	604
Production[b]	159	161	165	170	173	828
Total Remaining Reserves	1 721	1 698	1 651	1 629	1 622	

(a) East Coast reserves added in 1997, production started in late 1999
(b) Canadian Association of Petroleum Producers

Natural Gas Exports and Imports

Although there were no major pipelines constructed in 2001, increased throughput on the Alliance and M&NP systems enabled Canadian gas exports and imports to reach new record highs. In 2001, net export volumes were 102.8 billion cubic metres, an increase of 3 percent from 2000 and an increase of 26 percent over the last five years.

The export market continues to grow as net exports now account for 57 percent of total Canadian production (Figure 7). This is up from 56 percent in 2000 and 50 percent five years ago. The increase in 2001 is primarily due to enhanced access to new markets as a result of the start-up and first full year of operation of Alliance and increased volumes from the Sable Island project on the M&NP system. Gross exports in 2001 reached a record 108.7 billion cubic metres due, in part, to record gas volumes being re-imported to Canada. As much as 30 percent of the gas moved on Alliance is imported back into southern Ontario via Vector's pipeline. Imports on Vector accounted for about 4.2 billion cubic metres in 2001, or 72 percent of the 5.8 billion cubic metres of total imports. Prior to this, gas import volumes had been negligible.

The distribution of export sales in 2001 reflects the increased volumes flowing to the Midwest and Northeast on these pipelines and are now as follows: 39 percent to the Midwest, 30 percent to the Northeast, 16 percent to California, 14 percent to the Pacific Northwest, and less than 1 percent to the Mountain Region (Figure 8).

The proportion of Canadian gas exported under short-term orders increased significantly in 2001 to almost 80 percent from 73 percent in 2000. The increase in short-term arrangements since November 2000 is due largely to increased volumes on the Alliance and M&NP systems. Both the volume and average price for exports in 2001 were up significantly from 2000.

Higher export volumes and higher average prices for Canadian gas have translated into increased revenue from natural gas exports. In 2001, the revenue from Canadian natural gas exports rose by 25 percent to a record $26.0 billion, up from $20.7 billion in 2000. Gas imports also rose to a record level of $1.4 billion, resulting in net export revenues of $24.6 billion for the year.

FIGURE 7
Canadian Natural Gas Production and Net Exports
(billion cubic metres)

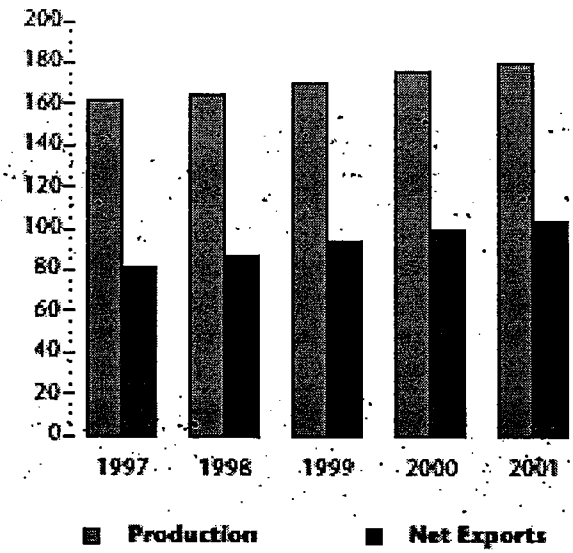
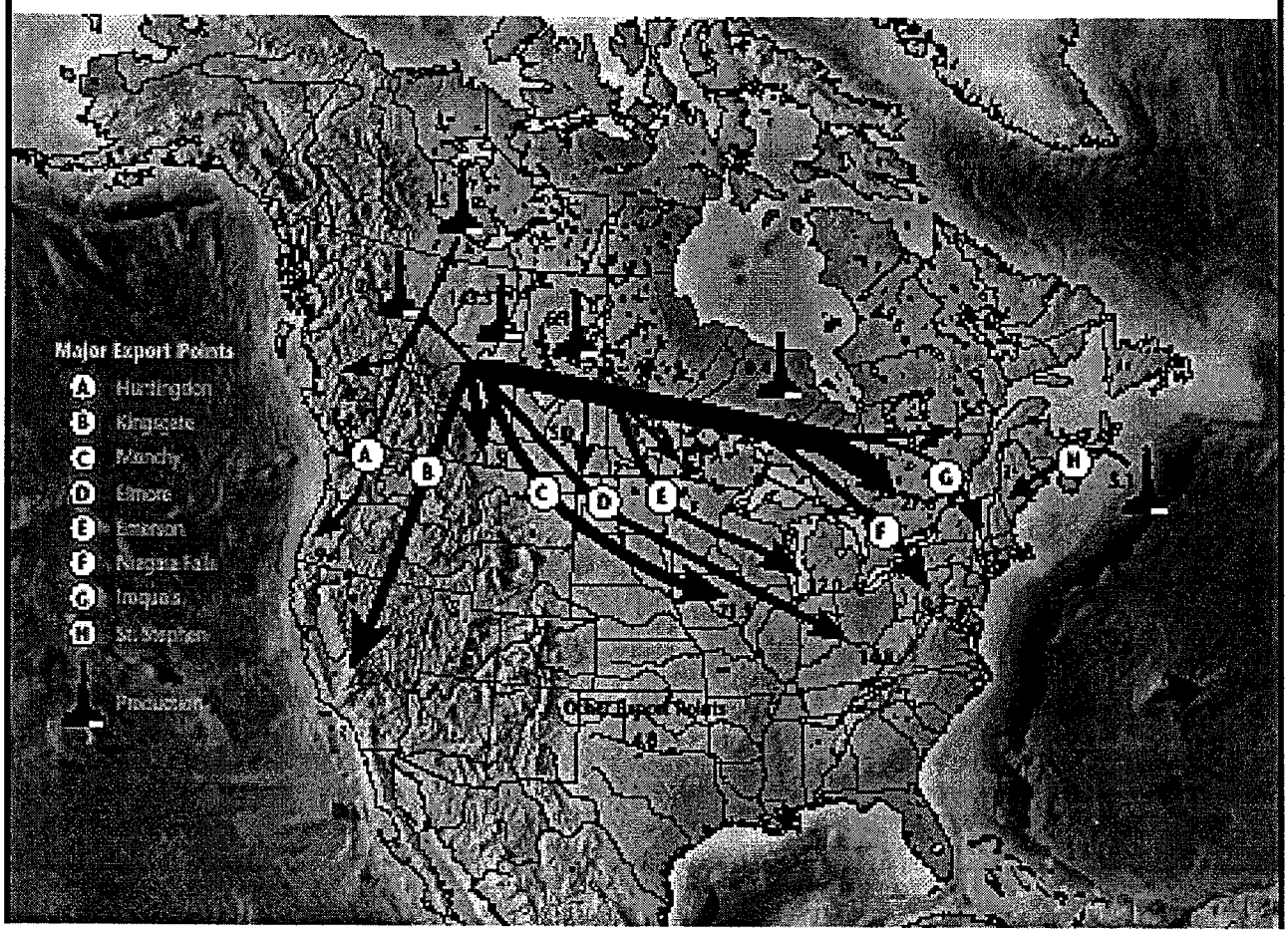


FIGURE 8
Natural Gas Supply and Disposition
(billion cubic metres)



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A5. Natural Gas Liquids Supply and Disposition
(thousand cubic metres per day)

	1997	1998	1999	2000	2001[e]
Supply					
Canadian Production[a]	93.5	96.3	101.2	99.8	92.2
Imports[b]	1.2	1.3	1.4	1.6	1.5
Total Supply[d]	94.7	97.6	102.6	101.4	93.7
Disposition					
Domestic[c]	63.3	62.6	72.4	68.1	66.9
Exports[c]	31.0	37.6	34.0	35.0	28.0
Total Disposition[d]	94.3	100.2	106.4	103.1	94.9

(a) Source: NEB
(b) Source: NEB Form 145
(c) Source: NEB Forms 157 and 86A
(d) Total supply may not equal total disposition due to inventory changes.
(e) Estimate

A6. Geophysical Activity
(active seismic crews)

	1997	1998	1999	2000	2001
January	79	75	48	49	39
February	78	74	37	49	50
March	78	55	36	45	61
April	31	12	13	22	23
May	33	22	10	16	27
June	39	37	16	15	31
July	35	36	24	38	36
August	39	27	37	34	37
September	26	22	38	20	34
October	39	24	40	28	25
November	42	27	38	34	23
December	64	43	40	27	24

Source: Petroleum Explorer

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A7. Exploration and Development Expenditures
(million $)

	1997	1998	1999	2000	2001[c]
Exploration					
Conventional Areas[a]	5,229	4,840	3,873	5,932	6,530
Frontier Areas[b]	139	214	513	639	705
Total Canada	5,368	5,054	4,386	6,571	7,235
Development					
Conventional Areas[a]	10,710	8,076	6,842	10,557	11,625
Frontier Areas[b]	900	1,865	2,347	1,492	1,640
Total Canada	11,610	9,941	9,189	12,049	13,265
Total Expenditures	16,978	14,995	13,575	18,620	20,500

(a) Alberta, British Columbia, Saskatchewan, Manitoba, Ontario
(b) Northwest Territories, Yukon Territory and Offshore
(c) Estimate
Source: Canadian Association of Petroleum Producers

A8. Sales of Exploration Rights in Western Canada

	1997	1998	1999	2000	2001[a]
Area (1000 ha)					
Alberta	5 150	3 015	2 996	3 831	3 908
British Columbia	736	483	731	693	854
Saskatchewan	944	509	398	283	373
Manitoba	50	4	4	5	22
Total	6 880	4 011	4 129	4 812	5 157
Price (million $)					
Alberta	1,153	597	593	1,142	1,086
British Columbia	216	96	176	248	440
Saskatchewan	130	61	46	48	56
Manitoba	6	0	0	1	1
Total	1,505	754	815	1,439	1,583

(a) Estimated
Source: Daily Oil Bulletin

Exhibit C

Platts Research and Consulting

Research Reports:

The Value of Renewables as a Physical Hedge Against Natural Gas Price Movements

April 2003

&

The Cost of New Gas-Fired Generation

March 28, 2003

Platts Research & Consulting (PR&C)
3333 Walnut Street
Boulder, CO 80301

April 2003

The Value of Renewables as a Physical Hedge Against Natural Gas Price Movements

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A. Executive Summary
B. Key Findings
C. Gas Price Forecast
D. Securing Reliable Gas at Fixed Price
E. Putting the Pieces Together

Brandon Owens (brandon_owens@platts.com)
Brandon has extensive experience developing and leading original research for both public and private sector research organizations. An expert witness and invited speaker at renewable energy events, he's produced numerous reports and technical articles on renewable energy technologies, markets, and policies. Before joining Platts, Brandon served as senior energy analyst at the National Renewable Energy Laboratory in Golden, Colorado, and in Washington, D.C. Brandon holds an M.S. degree in Mineral Economics from the Colorado School of Mines, and bachelor degrees in Mathematics and Economics from the University of Colorado.

The Value of Renewables as a Physical Hedge Against Natural Gas Price Movements

Brandon Owens

A. Executive Summary

Renewable energy technologies, which do not require fossil fuel to generate electricity, promote power price stability by avoiding the risks associated with underlying natural gas price escalation, volatility, and delivery. In this report, we estimate the hedge-value of renewables by quantifying the costs faced by gas-fired generators in order to secure reliable natural gas supplies at a fixed price. We derive this cost by calculating the direct expenses that must be paid by gas-fired power plants to: (1) guarantee gas delivery, (2) eliminate price volatility, and (3) remove gas price escalation.

Using the total of these expenses as a proxy for the hedge value, we conclude that under our baseline gas price scenario, the total cost associated with meeting gas deliverability requirements through the use of gas storage, and the cost associated with fixing future gas prices using options under our baseline gas price forecast, is $5.20/MWh. However, this value assumes perfect foresight with respect to future fuel use requirements and therefore represents a lower bound. This value also depends critically upon the timing of the introduction of non-traditional gas supply sources to offset incremental demand growth and may rise substantially if these sources are delayed.

In practice, the hedge-value is plant-specific and a function of geography, regional market dynamics, and future expectations. Ultimately, project-specific modeling and scenario analysis are required to arrive at an analytically defensible figure of merit for an individual plant. Further, we note that the hedge-value is only one component of the total renewable energy value. In the end, a comprehensive valuation approach that considers the full risks and rewards of both renewables and conventional generation options is the only way to determine the appropriate role for

renewable energy technologies in the fully competitive power markets that lie ahead.

B. Key Findings

- Where available, underground storage, with rapid injection and withdrawal capabilities, is often the best and least-cost method to provide guaranteed gas delivery. Although the cost of storage varies considerably and is based on underlying storage field economics, using FERC Form 2 data, we estimate that average costs are $0.45/mmBtu range. For a new combined-cycle gas-fired generator with a heat rate of 7,100 Btu/kWh, this translates into an incremental cost of $3.20/MWh.

- Subject to the costs of margin accounts and the transaction costs of entering into and then closing out futures contracts, power generators can dramatically reduce their exposure to natural gas price volatility at a low cost through the use of natural gas futures contracts. However, because futures traders do not have the ability to lock in a *specific* gas price, but rather must purchase gas for future delivery at *prevailing* contract prices, futures cannot be used to eliminate the risks associated with gas price escalation. Instead, gas price escalation must be addressed through the use of options, which allow buyers to specify a specific price for future gas delivery. However, the use of options does not protect buyers from basis risk and may entail transaction costs such as the bid-ask spread.

- An options trading strategy called a "collar" can be used to lock in a fixed price of gas, thus removing both volatility and escalation simultaneously. This can be done by buying a "call" option and selling a "put" option with the same "strike" price for every delivery month in the fuel supply term. The long-term cost of this strategy can be estimated using a relationship known as the "put-call parity" and is a function of future natural gas prices. Using our baseline gas price forecast, in which prices are expected to average $3.54/mmBtu (2003 dollars) through 2020, we estimate that the

cost of a collar strategy to hold fuel costs constant over the life of a gas-fired plant is $2.00/MWh.

- Non-traditional gas supply sources, such as Artic gas, coal bed methane, and liquefied natural gas (LNG) play an important role in determining the hedge-value of renewables. In our baseline gas price forecast, we assume that these sources enter the market in 2006. However, if this assumption is relaxed by 2 years, we expect natural gas prices to increase significantly relative to our baseline forecast. The 30-year cost of enacting a collar strategy to hold gas prices constant under this delayed-supply scenario doubles from $2/MWh to $4/MWh. Further, if the introduction of non-traditional sources is delayed by more than two years, the hedge-value of renewables increases dramatically.

In practice, the hedge-value is plant-specific and a function of geography, regional market dynamics, and future expectations. Ultimately, project-specific modeling and scenario analysis are required to arrive at an analytically defensible figure of merit for an individual plant. Further, we note that the hedge-value is only one component of the total renewable energy value proposition. In the end, a comprehensive valuation approach that considers the full risks and rewards of both renewables and conventional generation options is the only way to determine the appropriate role for renewable energy technologies in the fully competitive power markets that lie ahead.

C. Gas Price Forecast

Our gas price forecasts are generated using the Gas Pipeline Competition Model (GPCM), which is a combination software-database linear optimization system that includes detailed representation of gas production, transportation, storage, marketing, and distribution. GPCM is the latest in a series of systems and models built by Dr. Robert E. Brooks from the mid-1970s through the present. Platts Research & Consulting is the exclusive distributor of GPCMdat, a GPCM-compliant quarterly data service that is essential for the operation of GPCM.

In our baseline gas forecast, we project U.S. natural gas demand to grow at an annual average growth rate of 1.4 percent with real prices averaging $3.54/mmBtu (2003 dollars) through 2020. We expect increasing gas demand to be driven by a robust electric sector annual growth rate of 5.2 percent. Traditionally, the industrial, residential, and commercial sectors are roughly twice the size of the electric generation sector. However, our outlook for new gas-fired generation has the electric sector surpassing industrial consumption by 2010 and end-use demand by 2012.

In our baseline forecast, we expect production from traditional gas-producing regions expected to be flat or declining over the forecast period with the following non-traditional supply sources stepping in to offset demand growth:

- We expect Rocky Mountain coal bed methane supply deliverability to grow at nearly 3.0 percent annually throughout the forecast period. This prediction is bolstered by the recent, favorable environmental assessment released by the Bureau of Land Management (BLM) promoting coal bed methane development.

- We assume that McKenzie Delta Artic gas will enter the lower-48 market in January 2010. North Slope Artic gas is assumed to come online in January 2012.

- We believe that liquefied natural gas (LNG) deliverability will reach a number similar to that of present day Gulf of Mexico offshore production by 2015. Our current outlook calls for all existing LNG terminals to be operational and expanded, and two additional proposals to be constructed, with the first one operational in 2006.

However, given the high degree of uncertainty related to both timing and magnitude of supply, we also acknowledge that our baseline assumptions with regard to the introduction of non-traditional sources may be aggressive. To demonstrate the importance of these assumptions, we constructed "limited supply" and "pessimistic supply" scenarios to complement our baseline price forecast. In the limited supply scenario, we assume that the introduction of non-traditional supply sources is delayed by 2 years; and, in the pessimistic supply forecast, we assume that

demand is met only through traditional supply sources through 2020.

We expect gas prices to increase substantially in both of these supply scenarios. In the limited supply case, real prices average $4.16/mmBtu from 2003 to 2020, versus $3.54/mmBtu in the baseline forecast. More importantly, gas prices climbs to $4.39/mmBtu in the middle of the forecast before converging toward the baseline price at the end of the forecast horizon. The price impact is even more dramatic in the pessimistic supply forecast. Near-term real prices quickly exceed to $4.50, and approach $5.50/mmBtu by the end of the forecast period.

We stress that the baseline forecast represents our expected price path for natural gas prices; however, the limited and pessimistic supply scenarios are enlightening because they highlight the tight balance between natural gas demand and supply moving forward.

D. Securing Reliable Gas Supplies at a Fixed Price

Meeting Deliverability Requirements Through Underground Storage

Large gas consumers, such as power generators, can mitigate the costs associated with adverse gas price movements through physical or financial hedging. As already mentioned, renewable energy technologies represent one physical option for eliminating fuel price risk. Financial hedging instruments such as natural futures and options contracts represent another option. In order to understand the hedge-value of renewables, we must examine the costs associated eliminating gas price uncertainty using financial instruments. However, the use of financial instruments does not occur in a vacuum. Power generators must enact strategies to procure, transport, and store gas supplies even in the presence of a financial hedging strategy. Thus, to properly estimate the hedge-value of renewables, we must examine the gas supply strategies of power generators to determine if they entail costs that are above the expected market price of gas. These costs must be quantified and included in our estimate of the hedge-value of renewables.

Supply. In a gas supply contract, buyers and sellers must agree upon the volume of gas to be delivered, the type of service (firm or interruptible), the length of the contract, and the contract price. Contract terms vary widely depending upon the purchaser's overall supply strategy. Natural gas contract prices are typically pegged to publicly available gas price indices. Contract prices include an additional premium or discount to account for the difference in gas prices between Henry Hub and the delivery location. This "basis differential" premium or discount varies over time systematically with seasonal variations, or secularly with broader fundamentals. Two publications, Platts' monthly *Inside FERC* and *Gas Market Daily*, both published by The McGraw-Hill Company, are widely used for pricing information in the natural gas industry.

The fact that supply contract prices are typically tied to cash or futures market indices is very important for our purposes, because this means that often the price that power companies pay for gas will ultimately reflect the prevailing long-run spot market price. Thus, the price paid by gas purchasers in supply contracts is unlikely to be above and beyond the expected market price. Supply contract prices must therefore be excluded from our estimate of the hedge-value of renewables.

Transportation. Because the basis differential is an inherent amalgamation of firm and interruptible costs in primary and secondary markets between two trading hubs, it can be used as a proxy for the transportation costs associated with moving gas supplies from Henry Hub to the plant. Again here, as with gas supply contract prices, the basis differential does not represent a premium to secure reliable gas, but rather the embedded market costs associated with acquiring gas supplies. As such, basis differential estimates do not mitigate fossil fuel price risk for gas-fired generators.

Storage. Where available, underground storage, with rapid injection and withdrawal capabilities, is often the best and least-cost method to provide guaranteed gas delivery. Thus, procuring the services of underground gas storage facilities is often the final step the gas generators take to ensure that reliable gas supplies are available to meet the demands of gas-fired generators.

Indeed, variations in generation load requirements are frequently addressed through the use of underground gas storage facilities, which can be used to provide the high level of deliverability and pressure required for the operation of new combined-cycle power plants. The ability to store gas ensures reliability during periods of heavy demand by supplementing pipeline capacity. Storage also enables greater system efficiency by allowing more level production and transmission flows. End-use customers gain from this increased efficiency with reduced overall costs of service.

The use of gas storage is particularly important for new gas-fired power plants, which have higher pressure requirements and place more demands on the gas transportation systems than older gas-fired boilers. Underground storage located near the plant is often the best and cheapest method of meeting surge requirements. Storage can also be used to reduce the amount of firm pipeline capacity required to provide natural gas service to some generating units.

Storage rates vary from facility to facility, depend heavily on the usage profile, and are often based on negotiated contracts that are not publicly available. However, in FERC Form 2, pipelines file revenue and volume information by rate class for storage services provided to others. According to FERC Form 2, in 2001, 2.6 quads of gas were moved through storage with an average revenue of $0.45/mmBtu (Platts GASDat database). This agrees well with published estimates of storage facility costs. For a new combined-cycle gas-fired generator with a heat rate of 7,100 Btu/kWh, this translates into an incremental cost of $3.20/MWh.

Unlike supply and transportation contract prices, the costs associated with natural gas storage *do* indeed represent an above market premium that generation asset owners must pay to guarantee gas delivery. In practice, this cost is optional, and many gas-fired generation assets owners do not use gas storage for all or a portion of their supplies. However, the goal here is to quantify the costs that must be borne by gas-fired generators to guarantee gas delivery; and in the absence of prohibitively expensive firm transportation contracts for peaking generation needs, storage is the least-cost method of guaranteeing gas

delivery. Thus, we use $3.20/MWh as a proxy for costs associated with guaranteeing fuel delivery for a gas-fired plant.

Using Derivatives to Eliminate Price Volatility and Escalation

Futures. In order to lock in future gas prices, power companies must turn to the financial markets and make use of natural gas "derivatives, " financial instruments derived from a cash market commodity such as natural gas. Derivatives are important in the context of determining the hedge-value of renewables because they provide a means by which gas-fired generators can eliminate the risks associated with unfavorable natural gas price movements, which is one of the major components of the renewable energy hedge-value.

Natural gas futures contracts are one form of derivatives; they were first offered by the New York Mercantile Exchange (NYMEX) on April 3, 1990. A futures contract is a legally binding agreement between a buyer and a seller, whereby the buyer is obligated to take delivery and the seller is obligated to provide future delivery of a fixed amount of natural gas at a predetermined price at a specified location. The quantity of natural gas covered by a futures contract, the delivery period, the specifications and the location for delivery, and the timing and method of payment are all standardized.

The cost of futures trading. The use of futures contracts requires payment both on an initial margin, a minimum deposit per contract required when a futures position is opened, and a maintenance margin, a sum which must be maintained on deposit at all time. The level of the maintenance margin is determined by the credit rating of the trader and can be very high for companies with less than superior credit ratings. In light of the U.S. energy sector credit crisis, in which S&P downgraded 135 utility-holding companies and their subsidiaries in 2002 alone, fewer and fewer power companies have favorable credit ratings. This can represent a substantial barrier to the use of derivatives to hedge gas price volatility.

Some analysts cite an additional premium associated with purchasing gas in advance with futures and other derivatives,

such as forwards and swaps. For example, Mark Bolinger et al. (2002) compare the price of a 10-year natural gas swap to a 10-year natural gas price forecast developed by the U.S. Energy Information Administration (EIA), which they assume reflects what the market is expecting spot natural gas prices to be over the next 10 years.[1] They find that over the past two years natural gas users have had to pay a premium as high as $0.76/mmBtu over expected spot prices to lock in natural gas prices for the next 10 years. Based on this finding, they conclude that the incremental cost to hedge gas price risk exposure is potentially large enough to tip the scales away from new investments in variable-price, natural gas-fired generation and in favor of fixed-price investments in renewable energy.

However, at this stage, it is our position that the findings of Bolinger et al. must be viewed tentatively for two important reasons. First, even if a positive differential presently exists between financial derivative contract prices (as represented by Enron swap prices in Bolinger et al.) and gas price forecasts (as represented by EIA's gas price forecast in Bolinger et al.,) we can neither conclude that the premium will persist, nor can we state authoritatively that this value represents the premium that gas buyers must bear in order to reduce gas price risk. Among other explanations, the positive differential may simply reflect the difficulties associated with forecasting gas prices that are in line with market expectations. Indeed, one could argue that in the 1990s, as gas prices declined, forecasters systematically overestimated future gas prices, and that today as gas prices increase forecasters are systematically underestimating future gas prices (i.e. they are chasing a moving target). Second, the basic premise of Bolinger at al. cannot be validated empirically; instead, one must identify underlying theoretical support for the assertion that the contract price for future gas delivery is

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[1] Mark Bolinger, Ryan Wiser, Devra Bachrach, and William Golove, "Quantifying the value that energy efficiency and renewable energy provide as a hedge against volatile natural gas prices," Report LBNL-50272 (May, 2002), Lawrence Berkeley National Laboratory (LBNL), 1 Cyclotron Road, MS 90-4000, Berkeley, CA 94720.

different than "market expectations," which is an aggregation of producer and consumer sentiment. Thus far, theoretical evidence (which has centered upon the use of the Capital Asset Pricing Model (CAPM) to detect systematic risk in gas prices that would explain the existence of a premium) has been inconclusive.

In the absence of conclusive theoretical evidence, we believe that it is prudent to adopt the most conservative posture and assume that there is no premium associated with the purchase of natural gas futures contracts. Thus, at the present time, we conduct that large gas users can dramatically reduce their exposure to natural gas price volatility at little cost, subject to the costs of margin accounts and the transaction costs of entering into and then closing out futures contracts. We will revisit this conclusion as additional information becomes available.

The limits of futures trading. It is important to note that while futures contracts provide traders with the ability to lock in a gas price, they do not lock in a *specific* price. Rather, market participants must pay the *prevailing* futures contract price. Further, because futures contracts are less liquid beyond 12 months gas consumers are unlikely to lock in the prevailing price beyond one year. To understand why this is important, consider a gas-fired combined cycle plant that was built on the assumption that cash market gas prices would average $4.00/mmBtu for a period long enough to enable full debt repayment and adequate returns to equity investors. One year after plant completion—and every year thereafter—purchasing additional futures contracts doesn't help minimize the risks gas price escalation. Market price expectations have already risen, and the plant owner now faces the prospect of paying a higher price for natural gas than initially anticipated. This is why even though futures contracts likely provide a low-cost hedge against volatility, but are not useful in addressing natural gas price escalation. For this, we must turn to options.

Options. A second type of natural gas derivative traded on the NYMEX are options, which work like an insurance policy. The buyer

of a natural gas option pays a premium to acquire the right, but not the obligation, to buy gas at a specified "strike" price. If the price of gas exceeds the market price on the delivery date, then the option buyer pays the strike price and takes delivery of the gas. On the other hand, if the price of gas is lower than the market price, then the buyer lets the option expire and purchases gas on the spot market. The option buyer of the contract receives the right, but not the obligation, to take delivery, and the seller is obligated to provide future delivery of a fixed amount of natural gas at a predetermined price at a specified location.

There are two types of options: "puts" and "calls." A call gives the holder of the contract the right to buy the underlying futures contract at a predetermined price and gives the seller the obligation to sell the underlying futures contract at the same price if called upon to do so. A put option gives the holder the right to sell the underlying futures contract at a predetermined price, and gives the seller the obligation to buy the underlying futures contract at the same price if called upon to do so.

The cost of locking gas prices using options. Unlike natural gas futures, which only lock in expected spot prices, options can provide protection from both gas price volatility and gas price escalation. The risk manager for a gas-fired generator can purchase gas for future delivery at any specific price by purchasing a call option. With a call option, the buyer is protected from upward gas price movements but can still profit from downward price movements.

Remember, however, that in order to quantify the renewable energy hedge-value, we must estimate the expenses required to mimic the fuel risk profile of renewables. Renewables, once installed, do not provide such options to profit from downward fuel price movements. If we only include costs associated with purchasing call options, then we would be overestimating the value of renewables as a hedge against gas price increases. Fortunately, we can combine two options contracts into what is called a "collar" to duplicate the fuel certainty profile provided by renewable energy technologies. To create a collar, traders purchase a call option and sell a put option simultaneously.

Collars allow the reduction or elimination of the options premium by trading off participation in a favorable price move beyond a certain level.

Like the futures market, liquidity in the natural gas options market declines substantially beyond one year. On the surface then, using market-based data, it appears that we cannot calculate the cost of a collar strategy for the life of a gas-fired power plant. Fortunately, for our purposes the net cost of purchasing a call and selling a put with the same strike price and delivery date is defined by the following theoretical relationship, known as the "put-call parity":

$$c - p = S - Xe^{-rt}$$

where c is the call option premium, p is the put option premium, and S is the spot market price of natural gas at the time of purchase, X is the strike price that is locked in, r is the risk-free discount rate (usually represented by the interest rate of 90-day U.S. Treasury bills), and t is the time to maturity. This relationship states that the difference between a call and a put option with the same strike price and exercise date is equal to the expected spot market price less the strike price discounted by the time value of money for a risk-free investment. The put-call parity is a theoretical relationship driven by the presence of arbitrageurs in the market, however, in well-formed markets, it describes actual pricing of options very well. We can, therefore, use the put-call parity to estimate the long-term cost of enacting a collar strategy to fix gas prices.

E. Putting the Pieces Together

In this report, we delineated the direct costs faced by owners of gas-fired assets in order to secure reliable gas supplies as a fixed price. We conclude that the expenses related to underground gas storage and the net costs associated with purchasing options that lock in future gas prices are the only true costs that should be included as expenses. We not turn to the valuation of the impact of these expenses on the annualized cost-of-electricity for a state-of-the-art combined-cycle gas-fired power plant.

We've already estimated the costs of mitigating deliverability risk through the use of underground storage to be $3.20/MWh based on a 7,100 Btu/kWh heat rate. Now, by combining the put-call parity relationship with our baseline gas price forecasts, we can compute the net costs of using financial derivatives to lock in future gas prices. To estimate the options cost, we assume that the generation owner employs a strategy whereby options are purchased annually in 1-year blocks to lock gas prices at $4.00/mmBtu. We use $4.00/mmBtu, because this is our forecast the approximate starting price of gas when the plant is assumed to begin in 2005. We assume a 5 percent risk-free rate throughout the plant life.

Using this methodology, we find that under our baseline gas price scenario the annualized cost of electricity for a state-of-the-art combined-cycle gas-fired generator increases by $2.00/MWh when the costs of purchasing financial options to remove price volatility and lock in gas prices are included. Thus, the direct cost associated with procuring reliable gas supplies while protecting against gas price escalation is approximately $5.20/MWh. However, if we assume that non-traditional gas supply sources are delayed by 2 years and use our limited supply forecast in place of our baseline gas price forecast, then gas prices increase and the cost of purchasing options to protect against gas price escalation rises to $4/MWh, and the total cost associated with procuring reliable gas supplies while protecting against gas price escalation rises to $7.20/MWh.

It is important to remark that these values are likely to underestimate the costs associated with procuring gas supplies while protecting against gas price escalation. In practice, plant owners will be unable to accurately predict future fuel use requirements. This means that they may purchase either too many or too few options. If too many options are purchased, they will either go unused and the options costs will be wasted, or they will be sold at the prevailing subjecting the hold to option price risk. If too few options are purchased, additional gas supplies will have to be acquired in the cash market, subjecting the plant owner to uncertain gas market prices. These costs are not quantified in this analysis.

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The Cost of New Gas-Fired Generation

The Value of Renewable Energy Technologies

SB1078 RPS

Market Price Workshop

March 28th REVISION

R.01-10-024

CPUC Hearing Room E, 505 Van Ness Avenue, San Francisco

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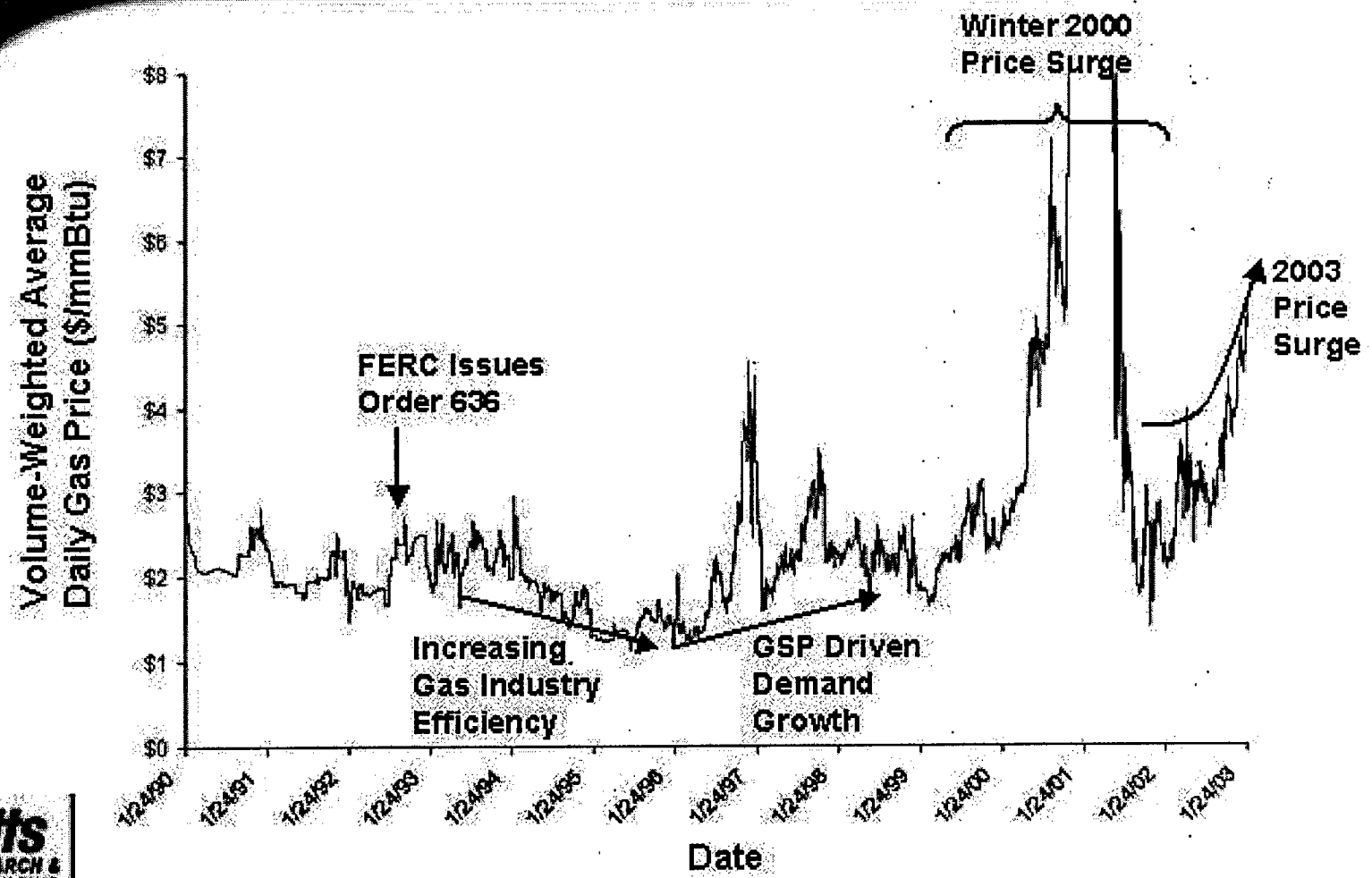
Historical Natural Gas Prices

SoCal Gas Prices (1/90 - 1/03)



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Source: GASdat (1/03)

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Gas Price Volatility

Future Expectations

Moving forward, gas price volatility is expected to increase for the following reasons:

- Limited lower-cost domestic gas supplies relative to increasing demand will ensure a tight supply-demand balance.
- Decreasing fuel-switching ability and increased competition between end-uses will limit demand-side flexibility.
- Lagged producer response to price spikes and delayed rig count "rationalization" will exacerbate and prolong price spikes.
- Technological improvements, which allow producers to drain smaller fields at a faster rate, will exacerbate price swings as suppliers enter and exit the market more quickly.

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Source: Platts Research & Consulting

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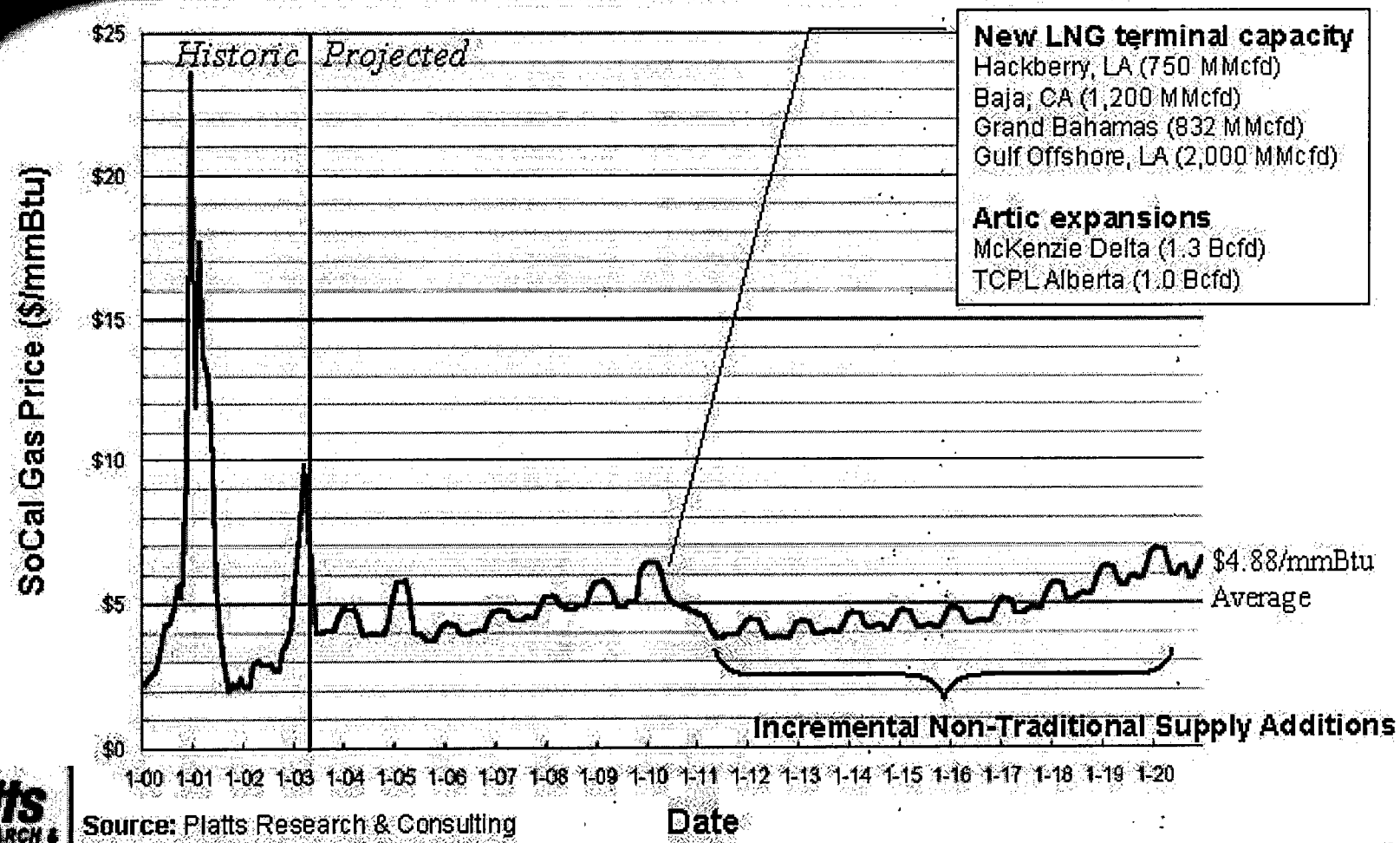
SoCal Gas Price Forecast

Client Baseline



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Source: Platts Research & Consulting

Notes: Modified baseline forecast assumes no major pipeline interruptions and normal hydro conditions.

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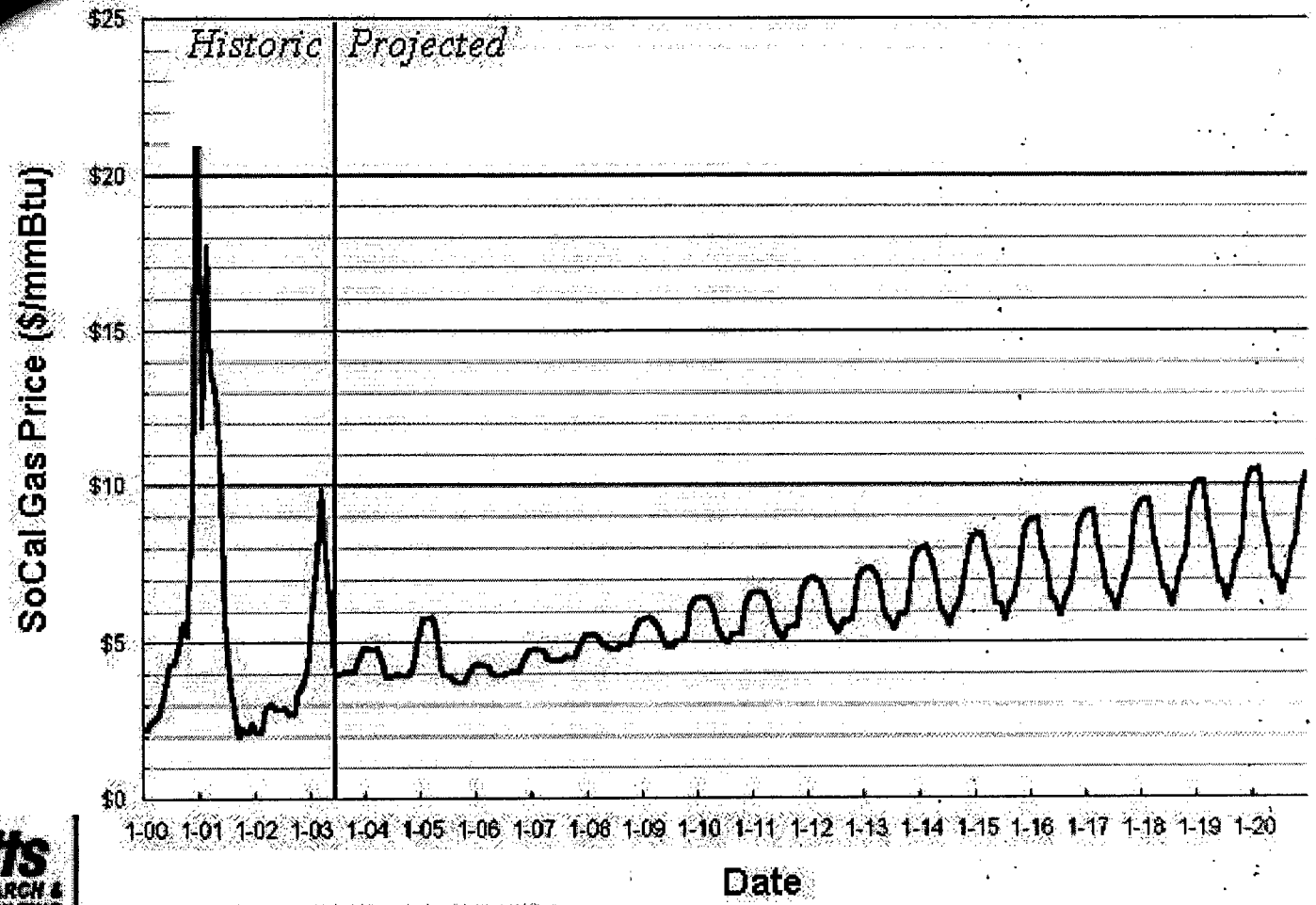
SoCal Gas Price Forecast

Outside Estimate



$6.28/mmBtu
Average

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Source: Platts Research & Consulting

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Cost-of-Electricity Analysis

Key Technology Assumptions

Technology	Gas-Fired Combined-Cycle
On-Line Year	2005
Plant Size	500 MW
Plant Life	30 Years
Capacity Factor (%/yr)	77.5%
Capital Cost ($/kW)*	$550/kW
Heat Rate (Btu/kWh)	7,100 Btu/kWh
Fixed O&M ($/kW)*	$15/kW
Variable O&M ($/MWh)*	$2/MWh
Air-Cooling Performance Penalty (% of Output)**	2.1%
Air-Cooling Capital Cost (% of Capital Cost)**	6.5%
Air-Cooling O&M Cost ($/kW)**	$10.57/MWh

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*Does not include the costs of emissions offsets
**Preliminary estimates subject to revision
Source: Platts Research & Consulting

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Cost-of-Electricity Analysis

Key Financial Assumptions

Debt/Equity Ratio	60:40
Equity Hurdle Rate (%/yr)	15%
Debt Term (Years)	15 Years
Debt Interest Rate (%/yr)	7.00%
Minimum DSCR	1.40
Effective Income Tax Rate (%/yr)	40.75%
Expected Inflation Rate (%/yr)	2.3%
PPA Escalation Rate	2.3%

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Source: Platts Research & Consulting

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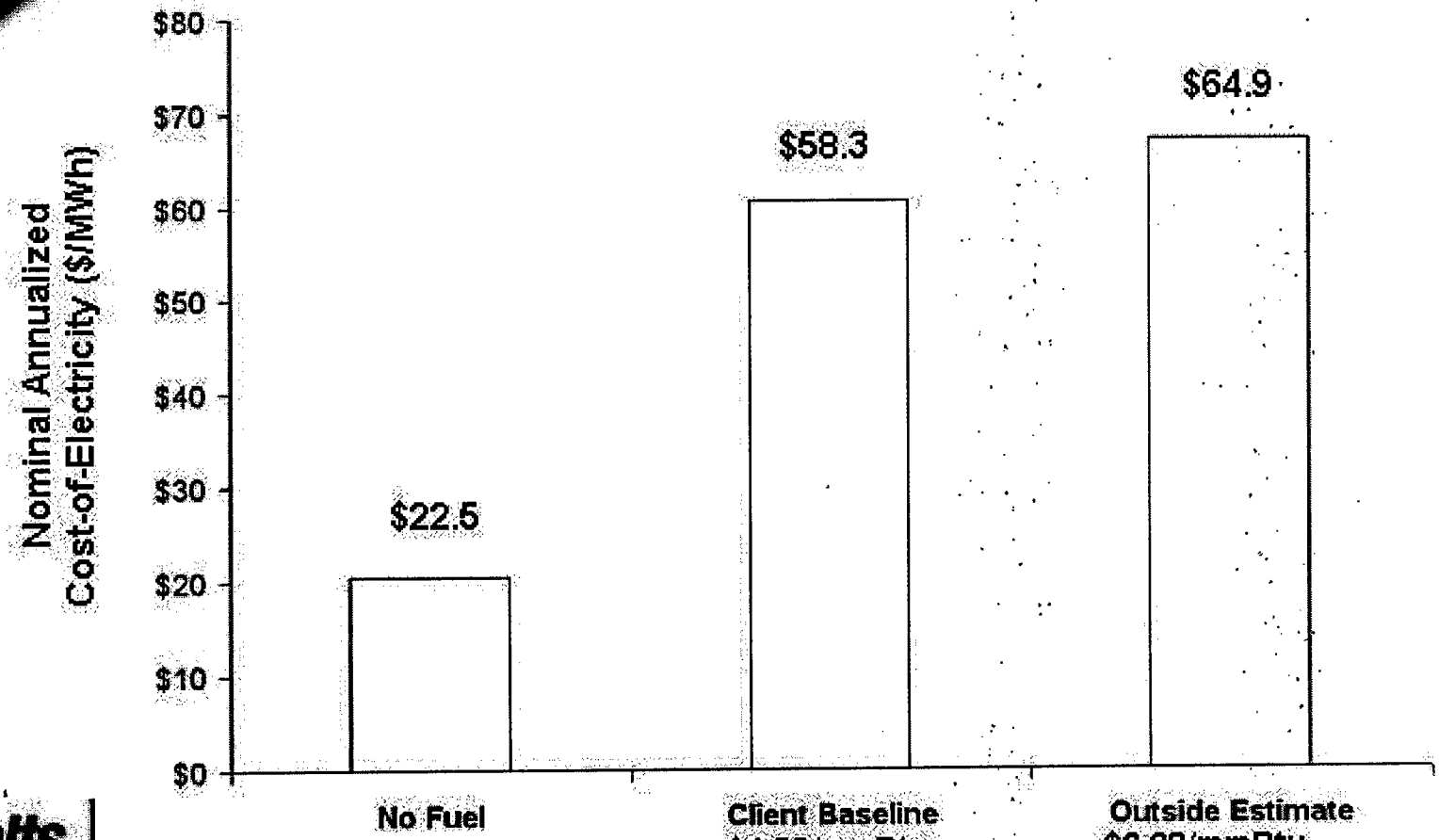
New Generation Cost-of-Electricity

Average CA Results



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Source: Platts Research & Consulting

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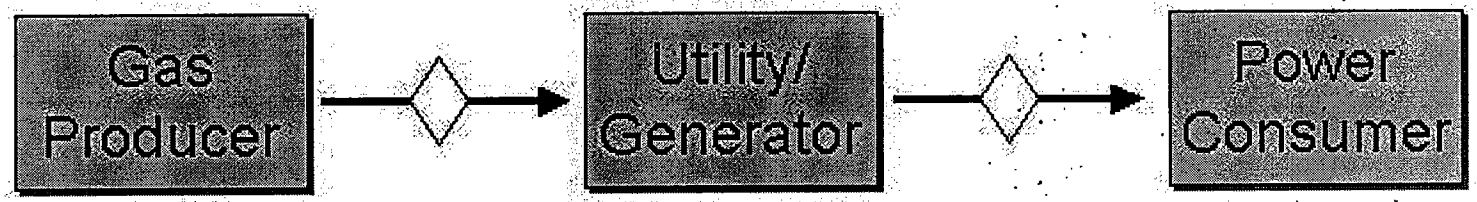
Value of Power Price Stability

Renewables As a Hedge Against Gas Price Movements

Natural gas price-risk is typically passed from gas producers to power consumers in the following manner:



In a gas supply contract, buyers and sellers must agree upon the volume of gas to be delivered, the type of service (firm or interruptible), the length of the contract, and the contract price. Contract terms vary widely depending upon the purchaser's overall supply strategy.

Gas contract prices are typically pegged to publicly available gas price indices. This means that the price that large consumers pay for gas will ultimately reflect the prevailing spot market price.

Utilities usually transfer the risk of gas price uncertainty to consumers using gas adjustment clauses (GACs) and power adjustment clauses (PACs).

GACs and PACs provide a means to adjust costs between rate cases and they provide a "shock absorber" that smooths the peaks and valleys of volatile natural gas and wholesale power markets before these costs are passed on to electric consumers.

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Source: Platts Research & Consulting

Value of Power Price Stability

Renewables As a Hedge Against Gas Price Movements

- Renewables promote power price stability by avoiding the risks associated with underlying natural gas price escalation, volatility, and delivery.
- In a recent report, we estimated the hedge-value by by calculating the direct expenses that must be paid by gas-fired power plants to: (1) guarantee gas delivery, (2) eliminate price volatility, and (3) remove gas price escalation.
- **We concluded that the total cost associated with meeting gas deliverability requirements through the use of gas storage, and the cost associated with fixing future gas prices using natural gas options contracts is $5.20/MWh.**

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Source: Platts Research & Consulting

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