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ORIGINAL

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REVIEW OF NOVA SCOTIA POWER INCORPORATED'S FUEL COSTS

For

Stewart McKelvey
Halifax, Nova Scotia
On behalf of:
Avon Valley Greenhouses et al.
December 20, 2006

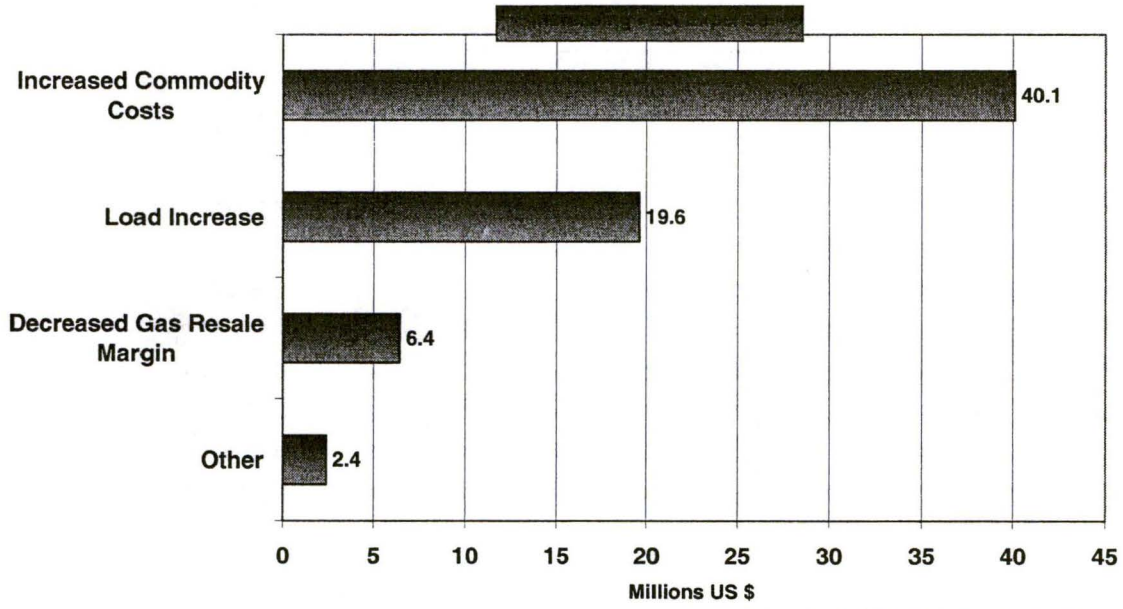
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Introduction

Nova Scotia Power, Inc. (NSPI) has requested a rate increase using 2007 as a test year. The total fuel and purchased power forecast for 2007 is C$498.7 million, an increase of C$68.5 million over the fuel amount currently set in rates. By far, the largest portion of this is an increase in commodity costs, which accounts for more than C$40.1 million. Load increase is second in importance and a decreased gas resale margin accounts for an increase of C$6.4 million. The various components of the C$68.5 million rate increase are shown in aggregate in Figure 1.

FIGURE 1
FUEL AND PURCHASED POWER CHANGE
2007F vs. 2006C



Source: NSPI, *Direct Evidence*, p.7, Figure 2.1

Table 1 breaks out the detailed components of NSPI's requested rate increase. This shows that oil-related price increases (for both HFO and LFO) account for C$29.9 million of the C$40.1 million increase in commodity cost. Coal is second in importance, accounting for an increase of C$15.7 million. The third largest component in the higher rate increase is the decreased gas resale margin, which NSPI puts at C$6.4 million.

TABLE 1
DETAILED COMPONENTS OF NSPI's REQUESTED RATE INCREASE

Increased Commodity Costs:	million C$
Increased Heavy Fuel Oil (HFO) pricing	$24.7
2006 import coal disallowance	$15.7
Increased Light Fuel Oil (LFO) pricing	$5.2
Increased natural gas pricing	$2.6
Increased import power pricing	$2.0
Solid fuel pricing and blends	($10.0)
Total commodity price increases	**$40.1**
Load Increase	
Cost of load increase	$16.1
Fuel switch at Tufts Cove to natural gas	$5.2
Heat rate improvement on Tufts Cove 4 and 5 due to higher load	($1.8)
Total cost of increased load in 2007 versus 2006C	**$19.6**
Decreased Gas Resale Margin	**$6.4**
Other	
Maintenance schedule changes	$1.2
Capacity factor changes	$5.4
Reduced hydro	$0.5
Increased post 2001 IPP	($0.4)
Reduced exports	($1.5)
Other items	($2.9)
	$2.4

Source: UARB IR-4

When the higher fuel costs are broken out to determine their impact on an mWh basis, the rising HFO and LFO prices cause double digit increases in the electricity production cost per mWh. Moreover, the aggregate of all fuels causes a rise in the per megawatt cost of electricity from [redacted] in 2006 to [redacted] in 2007; this is a 13% increase (Table 2). Such a 13% increase in electricity cost due to changes in commodity prices in 2007 seems highly inappropriate when consensus forecasting suggests that oil prices are now stable to falling and coal prices are softening and expected to fall during the next several years.

TABLE 2
NSPI 2006 AND 2007 FUEL COSTS PER mWh

(C$/mWh)	2006C	2007	Increase
Solid Fuel [a]	[redacted]		
Natural Gas			
Bunker C			
Diesel			
All Fuels			
Power Imports			
IPPs			

[a] Includes the disallowance in 2006. Without the disallowance, 2006C solid fuel was [redacted] per gWh and 2007 would be a [redacted]

Source: Avon IR-51

Stewart McKelvey, on behalf of a group of intervenors, has retained International Strategic Information Services (ISIS) to review the reasonableness of the 2007 fuel costs of NSPI. ISIS relied upon NSPI's filing, its responses to the Information Requests, confidential documents made available in NSPI's office, interviews with NSPI personnel and its general knowledge of the international fuel markets.

Summary Findings

Projections for oil (HFO and LFO) and natural gas prices play a much greater role in NSPI's 2007 test year calculations than in previous rate cases. NSPI in establishing test year costs for HFO, LFO, and natural gas relied upon futures prices from July 31, 2006 for 2007. The use of futures prices in this way should be rejected since it is unlikely to result in representative test year costs. It is a recognized phenomenon that futures prices for energy commodities (including coal) are primarily influenced by spot market prices at the time when they are set. The primary factor driving futures prices on July 31, 2006, the day used by NSPI, was that spot prices had been at record highs for crude oil and petroleum products in July 2006 due primarily to market concerns about a wider Middle Eastern conflict arising out of July's fighting between Israel and Hizbollah. It is recognized by those who have recently examined the issue that oil futures prices are not good predictors of future spot prices in the physicals market and that natural gas futures prices, for reasons that are not fully understood, are even less efficient predictors of physical prices. The methodology that NSPI has adopted for setting test year costs for HFO, LFO and natural gas is thus unreasonable and yields unrepresentative test year costs.

Although we believe that NSPI's coal costs continue to be influenced by the legacy of decisions made in 2002 and 2003 which resulted in NSPI developing its portfolio of longer-term contracts during the top of the market in the current coal pricing cycle, the Board found in its March 2006 decision that these past events would result in no further disallowances beyond the end of 2006. For the 2007 rate case, NSPI appears to have achieved its target of putting in place a portfolio of long, medium, and short-term solid fuel contracts. However, in its haste to complete its portfolio, it entered into a long-term contract [redacted] As a consequence NSPI has now locked in a high fixed price not only for 2007 but also for 2008 and 2009.

ISIS drew the following conclusions from its review of NSPI's fuel purchasing for 2007:

- Coal transactions for the year 2007 entered into subsequent to the early September rate filing have reduced NSPI's anticipated 2007 solid fuel costs by C$10.25 million;
- The contract for the period was entered into the C$5.7 million by which the contract exceeds the EVA forecast should be disallowed;
- In projecting its 2007 HFO costs, NSPI relied upon a single day's futures price in the midst of a period of several weeks that saw the highest nominal oil prices in history; futures prices have been demonstrated to not be reliable predictors of prices in the physical market as little as three months out; NSPI has thus adopted a methodology for projecting prices which is unreasonable and has major consequences, not only for oil product price expectations but also for the volume of gas available for resale;
- Improved supply conditions in the oil markets combined with a flawed price projection methodology result in no need for the C$24.7 million HFO price increase which should be rejected;
- A similar analysis for LFO combined, however, with a recognition that inventories are tightening and that improved quality is resulting in upward price pressures should result in about half (C$2.6 million) of the requested C$5.2 million being needed for 2007;
- A reduction of C$6.4 million, due to a reduced volume of gas available for resale, is unnecessary since the reduction is driven entirely by the flawed high HFO price forecast, which in turn results in NSPI's projection of gas usage for summer generation at Tufts Cove Units 1-3;
- By its own admission, NSPI has a reduction in 2007 U.S. dollar costs of C$14.7 million by the strengthening on the Canadian dollar from C$1.219 in the 2006 Rate Case to C$1.18 in the 2007 Rate Case.

NSPI's HFO Costs

Of the total fuel rate increase of C$68.50 million requested by NSPI, some [redacted] is attributable to higher HFO costs (NSPI *Direct Evidence*, October 2006 p. 7). Of the C$40.1 million in increased commodity costs, HFO accounts for [redacted] of the total. The NSPI projection for 2007 (*Direct Testimony* p.54, Figure 2.7) shows HFO costs for 2006 C vs. 2007. The 2006 price is [redacted]/mmBtu, compared to a forecast price for 2007 of [redacted]. The latter is equivalent to [redacted]/bbl delivered, an increase of some [redacted] on a unit price basis (Liberty IR-66, Attachment 4). The projection in NSPI Figure 2.7 is the company's annual price for the HFO that it expects to burn at all its thermal plants and takes into account the opening inventory at Tufts Cove (UARB IR-23).

The 2007 forecast, based on a forward price curve of end July 2006 (Liberty IR-43, Attachment 14; SEB IR-51) shows a substantial increase for the monthly estimates in US$/bbl between the actual 2006 numbers and the projected 2007 HFO prices (Avon IR-73) (Table 3). On a monthly average basis, the most NSPI paid in 2006 was February 2006, [redacted]/bbl. Prices were substantially lower by October 2006, [redacted] as the monthly average and [redacted] for November 2006. The forecast for 2007 shows a rise from [redacted] in January to [redacted]/bbl by July 2007. Converted to C$/mmBtu at individual plants this amounts to [redacted]/mmBtu at Tufts Cove due to the influence of inventory carried into 2007 at this station , as well as hedging, and to a range of [redacted] to [redacted]/mmBtu at the solid fuel stations where HFO is used for flame stabilization (Table 4). The projected HFO price from the forward price curve combined with the carried forward fuel inventory at Tufts Cove results in a C$24.70 million rate increase request for 2007 (Table 5).

TABLE 3
NSPI HFO PRICES: ACTUAL 2006 AND FORECAST 2007

US$/bbl	Actual 2006	Forecast 2007
January	[redacted]	[redacted]
February		
March		
April		
May		
June		
July		
August		
September		
October		
November		
December		

Note: ** - no oil consumed during this period.

Source: Avon IR-73

TABLE 4
NSPI FORECASTED HFO BURN AND PRICE BY STATION

	2006			2007		
	mmBtu	C$ (000s)	C$mmBtu	mmBtu	C$(000s)	C$/mmBtu
Lingan						
Trenton 5						
Trenton 6						
Point Tupper						
Tufts Cove						

Source: Liberty IR-10, Attachment 2

TABLE 5
NSPI CALCULATION OF HFO PRICE INCREASE

2007		2006C		2007	
Plant	C$/mmBtu	C$/mmBtu	Increase	mmBtu	Variance (C$ 000's)
Tufts Cove					
Lingan					
Trenton 5					
Trenton 6					
Point Tupper					

Source: UARB IR-4, Attachment 1

Actual NSPI prices and volumes in 2006 to September are substantially different from both the forecast for 2006 /mmBtu so Liberty IR-66, Attachment 2) and the actual expenditure /mmBtu so Liberty IR-33, Attachment 1, p. 1; see Table 6). The compliant unit cost for 2006 for HFO is /mmBtu for the full year. Due to a labor dispute at a major customer, NSPI's HFO volume bbls to end September 2006, compared to a budget volume of bbls (Liberty IR-24, Attachment 1, p.4).

TABLE 6
ACTUAL NSPI HFO USE (ALL PLANTS) AND PRICES, 2005 AND YTD SEPTEMBER 2006

	2005			2006 (YTD September)		
	mmBtu	C$1000s	C$/mmBtu	mmBtu	C$/1000s	C$/mmBtu
All Plants						

Source: Liberty IR-33, Attachment 1: Liberty IR-24, Attachment 1, p. 4 (copy of a Current Fuel Report)

The forward HFO price curve from which the forecast is derived was calculated on July 31, 2006 based on market indicators at the time (Avon IR-27, Attachment 2) (Table 7). The same document, however, shows estimated 2006 price projections for October 2006 of [redacted]/bbl for HFO with a 2.28 sulfur and a November 2006 price of [redacted]/bbl for the same type of product (Avon IR-27, Attachment 2 p.2), more than [redacted]/bbl above spot prices in these months.

TABLE 7
2007 HFO FUTURES PRICES ON JULY 31, 2006
(US$/bbl, 2.2% sulfur)

January	[redacted]
February	
March	
April	
May	
June	
July	
August	
September	
October	
November	
December	

Source: Liberty IR-43, Attachment 14

NSPI buys its HFO through an annual competitive tender process. [redacted]

In practice, not all of the HFO comes from U.S. refiners. [redacted]

The Request for Bids for 2007 [redacted]

Most of the HFO is burned in units 1 through 3 at Tufts Cove. However, smaller volumes are also burned at Trenton, Lingan and Point Tupper. The HFO is delivered from Tufts Cove by truck [redacted]

NSPI, in addition to the tendered contracts, is able to negotiate volumes of HFO [redacted]

Heavy fuel oil is the only major petroleum product demand for which is substantially lower at present than in the 1970s and for which demand continues to decline (Table 8). While declining demand in the USA and Canada in the past

decade has somewhat leveled off, tighter environmental regulations in Europe have resulted in a continuing reduction in demand.

TABLE 8
WORLD HEAVY FUEL DEMAND, 1971-2004
(000s bbls/day)

	World	OECD Europe	OECD Pacific	USA	Canada
1971	14,216	4,761	2,291	2,296	331
1973	16,438	5,323	2,530	2,794	368
1978	17,532	4,716	2,258	3,156	317
1990	11,876	2,336	1,267	1,223	173
1998	10,892	2,205	1,182	918	148
1999	10,585	2,071	1,205	887	129
2000	10,362	1,990	1,180	979	134
2001	10,132	2,001	1,094	890	158
2002	9,909	2,022	1,121	769	138
2003	9,902	1,991	1,138	837	173
2004	10,090	1,899	1,064	956	181

Source: IEA, *Annual Oil Statistics*

Heavy fuel oil refinery output has historically been concentrated in Europe where refineries have relied primarily upon the heavier crudes from the Middle East to produce a product slate with a substantial heavy oil component (Table 9). As a consequence, European refinery centers in the Netherlands, Belgium and the UK have become major heavy fuel oil exporters. However, the world's largest exporter is the United States.

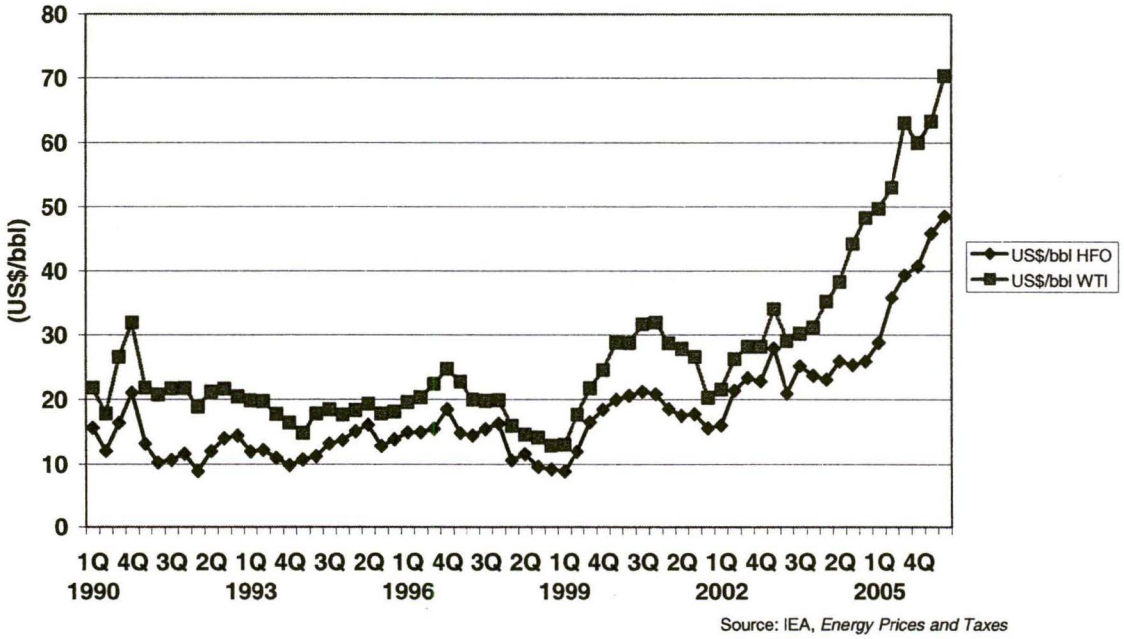
TABLE 9
REFINERY HEAVY FUEL OIL OUTPUT BY THE OECD, 1973-2004
(000s tonnes)

	OECD Europe	OECD Pacific	OECD North America
1973	308,420	124,379	82,214
1978	262,971	111,487	143,590
1980	239,907	100,064	137,839
1990	139,039	59,835	93,311
1999	125,273	74,898	77,349
2000	126,604	72,873	73,256
2001	123,388	67,809	75,174
2002	119,922	62,360	68, 831
2003	118,904	65,801	69,789
2004	121,960	62,343	68,729
2005	118,722	64,493	65,322

Source: IEA, *Annual Oil Statistics*

HFO, defined by the IEA as heavy fuel oil containing more than 1.0% sulfur, is a product with a geographically limited market: the three largest consumers in the world in 2004 (latest data available) were, in order, Mexico, Japan and Canada. Other countries who use large quantities of heavy fuel oil for electric generation, such as the United States and Italy, rely predominantly on low sulfur fuel oil (less than 1.0% sulfur). As a consequence of this limited and diminishing demand for HFO, the product trades at a significant and increasing discount to premium crude oils, such as West Texas Intermediate (WTI – 0.2% sulfur). (Figure 2).

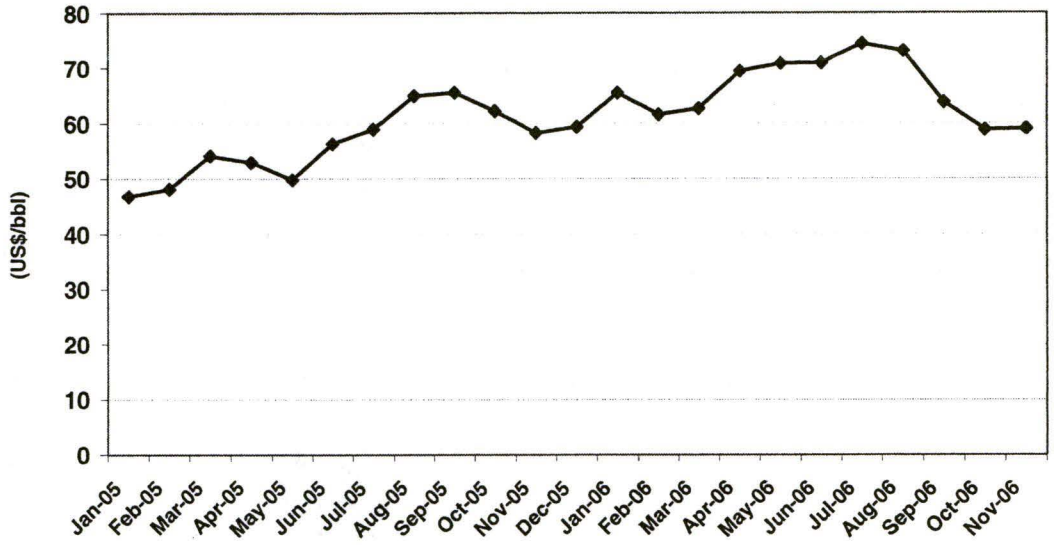
FIGURE 2
HFO AND WTI SPOT PRICES, 1990-2006, QUARTERLY



Source: IEA, *Energy Prices and Taxes*

NSPI, in selecting July 2006 as the point in time for setting its forward market price for HFO, selected the month with the absolute highest average West Texas Intermediate oil price in history. WTI, the key U.S. light crude widely utilized for domestic oil pricing as well as for the NYMEX futures contract, like all global oil prices has been on the increase since 2003. The pricing peak on a monthly average basis occurred in July 2006. Since that time, WTI prices had declined significantly. The monthly average for July was US$74.1/bbl. By November, the monthly average was down to US$59.08/bbl (Figures 2 and 3).

FIGURE 3
MONTHLY AVERAGE WTI CRUDE OIL PRICES
2005 AND 2006



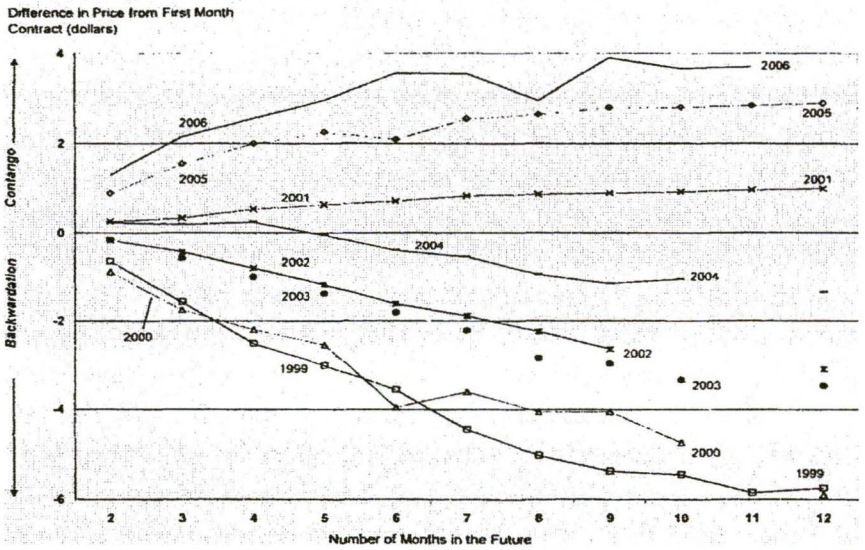
Source: EIA, *Weekly Petroleum Status Report*, Dec. 6, 2006.

The prudence of utilizing a forward pricing curve to establish next year's prices for fuel oil by a regulated utility should also be subject to question. Oil executives, petroleum economists and most recently a U.S, Senate subcommittee as well as the International Energy Agency have concerned themselves with a question of whether the rising flood of speculative funds into the oil futures market has inflated oil prices, particularly along the forward curve. Both Lord Brown, the group Chief Executive of BP and Lee Raymond (now retired) then Chairman and CEO of ExxonMobil, commented in late 2005 and early 2006 on the fact that rising inventories of crude oils and products combined with rising oil prices suggested that factors other than the fundamentals of supply and demand were influencing market prices. [1] Petroleum economists have noted that historically there was an inverse relationship between forward prices and rising inventory; that is, rising inventory which can be seen as symptomatic of an excess of supply over demand in the market put downward pressure on forward prices. However, since 2005 this has not been the case; inventories have risen to historic highs and at the same time longer-term futures prices have been higher than nearer term futures contracts. [2]

[1] Both executives are quoted in U.S. Senate Permanent Subcommittee on Investigations, Committee on Homeland Security and Government Affairs, *The Role of Market Speculation in rising Oil and Gas Prices: a Need to put the Cop back on the Beat,* June 27, 2006 p. 8; cited here after as the Coleman-Levin Report.
[2] *Wall Street Journal*, April 18, 2006

Figure 4 represents forward price curves from 1999-2006 from the Coleman-Levin Report. The report notes that the increase in the price of longer-term futures contracts provides a financial incentive for oil companies and refiners to purchase additional oil and put it into inventory.[3] Phillip Verleger, a U.S. petroleum economist, has calculated that the amount of money invested in commodity index funds increased from $15 billion in 2003 to $59 billion in 2004 and to $80 billion in March 2006. [4] Furthermore, Dr. Verleger estimated that between July 2004 and mid-March 2006 approximately $60 billion was invested in the NYMEX WTI contract. The increase in speculative trading can be measured from the Commodity Futures Trading Commission Commitments of Traders (COT) Report published every Friday, reflecting open interest from markets in which twenty or more traders hold positions equal to or above the reporting levels established by the CFTC. [5] The COT reports indicate that most of the increase in activities is due to non-commercial trading. The Coleman-Levin Report concludes that speculative purchases of oil futures "have added as much as $20-25 per barrel to the current price of crude oil. Additionally, by purchasing large numbers of futures contracts, and thereby pushing up futures prices to even higher levels than current prices, speculators have provided a financial incentive for oil companies to buy even more oil in storage." [6]

FIGURE 4
WTI FORWARD PRICE CURVES, 1992006



Source: US Senate, Permanent Subcommittee on Investigations, Committee on Homeland Security and Government Affairs, *The Role of Market Speculation in Rising Oil and Gas Prices: A Need to Put the COP Back on the Beat*, June 27 2006, p.A-7; data from NYMEX.

[3] Coleman-Levin Report, p. A-7
[4] P. Verleger, "Commodity Investors: A Stabilizing Force?" *The Petroleum Economics Monthly*, March 2006
[5] (Available from http://www.cftc.gov.)
[6] Coleman-Levin Report, p. 14

The magnitude of the speculative premium in the report is very much subject to question. However, the CFTC is implementing one of the Coleman-Levin Report's recommendations and expects in December to significantly expand its COT report to also provide coverage of large over-counter trades in commodities, which to date have escaped the market transparency efforts of the CFTC.

In the November 10, 2006 *Oil Market Report* of the IEA, there is a discussion of the entire funds-vs.-fundamentals debate. In general, the IEA comes down on the side of fundamentals moving the market rather than index fund speculative activity. However, there are aspects of the market that the IEA cannot explain and suggests that it is not possible to conclusively resolve the funds-vs.-fundamentals debate without additional data to provide further clarity. It urges regulators to segregate the hedging, fund investment and physical trading activity currently aggregated under the commercial category in the COT report. [7]

While most commentators on the issue of financial investors driving up oil futures prices are skeptical, although they do not dismiss the suggestion out of hand,[8] far more critical here is the predictive value of futures prices for prices in the physical market. NSPI asserts that futures prices from July 31, 2006 are somehow predictive of prices in the physical markets five to seventeen months hence. This in an unreasonable view and runs counter to market experience with futures prices. The primary study of this question found that on a three-month horizon oil futures prices were good predictors of future spot prices 38% of the time, and on a six-month horizon this fell to 24%. "However, it is also true that in none of the cases are futures good predictors of subsequent spot prices".[9] A single day's futures price for HFO can thus not serve as the basis of a rate increase for a year beginning five months hence.

An analysis of the fundamentals of oil supply and demand in the near term suggests that 2007 will tend towards stable or falling prices rather than further price increases. However, oil price volatility is driven to a significant degree by geopolitical forces such as disruptions due to the upcoming national elections in Nigeria in the first half of 2007, the Iran nuclear issue and other political disruptions, particularly in the Middle East. The near record levels of crude oil

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[7] IEA, *Oil Market Report*, 10/11/06, p. 4

[8] Ben S. Bernake "Oil and the Economy" lecture given October 21, 2004, Darton College, Georgia (http://www.federalreserve.gov/boardDocs/speeches/2004/20041021/default.htm) and Robert J. Wiener, "Sheep in Wolves Clothing? Spectators and Price Volatility in Petroleum Futures", Quarterly Review of Economics and Finance 42.2 (2002), pp. 391-400

[9] C. Menzie, M. LeBlanc and O. Coibion, *The Predictive Characteristics of Energy Futures: Recent Evidence for Crude Oil, Natural Gas, Gasoline and Heating Oil*, unpublished paper, University of California, Santa Cruz, October 2001

and product stocks combined with a growing surplus of available production capacity over foreseeable demand should moderate the magnitude of any price impact from the unforeseen events that continually beset the oil market.

Movements in global oil demand and world economic growth have historically been closely related. Figure 5 illustrates the close relationship between global economic growth and oil demand. A slowdown in world economic growth from, for example, 4% to 2% has historically reflected in significant reductions in world oil demand growth. In fact, the two previous major energy crises in 1973-1975 and 1979-1983 saw world economic growth drop below 2% per year, and as a consequence world oil demand growth became negative. A variety of market events have pushed nominal oil prices higher at a time of strong global economic growth in the period 2004-2006. In the aftermath of the destructive Gulf hurricanes Katrina and Rita, nominal oil prices briefly exceeded US$68/bbl. Again, in July and August to 2005 the shutting in of most of the oil production in Prudoe Bay, due to corrosion problems on the Alaska Oil Pipeline, briefly pushed prices above US$78/bbl. However, the higher prices of the period 2004-2006 in real terms remain substantially below the price peak of the early 1980s when oil prices in 2005 dollar terms exceeded US$90/bbl (Figure 6).

FIGURE 5
RELATIONSHIP OF WORLD ECONOMIC GROWTH AND WORLD OIL DEMAND GROWTH

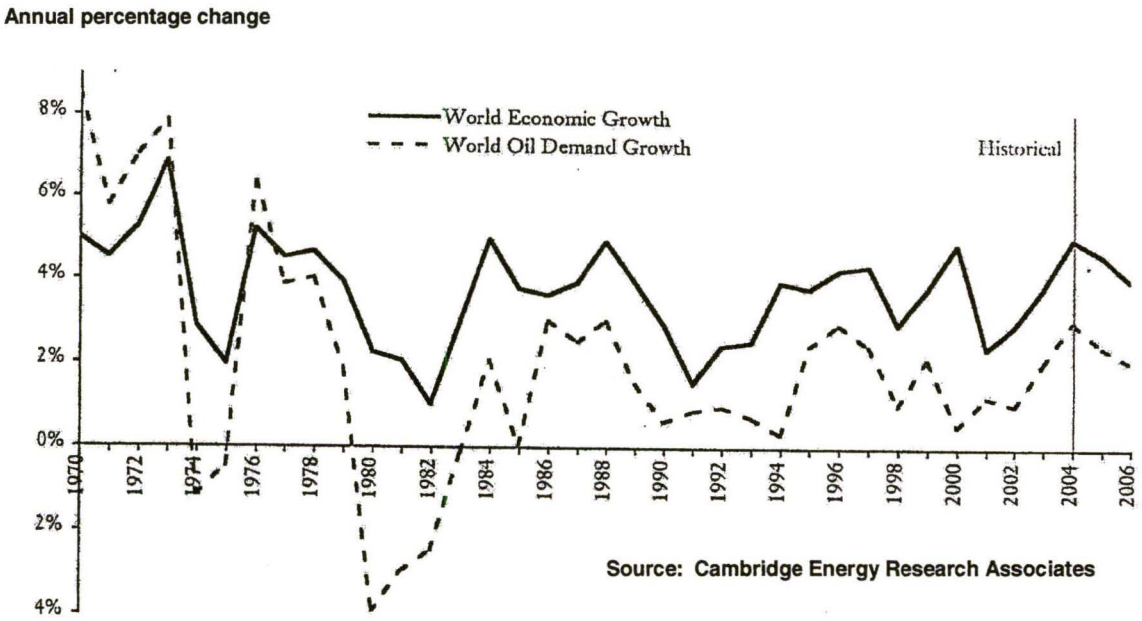
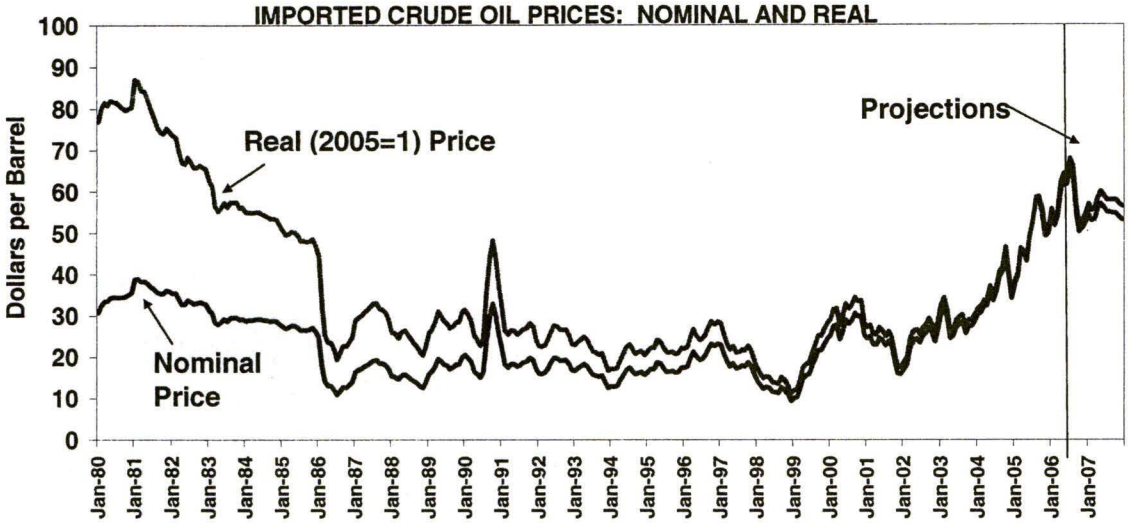


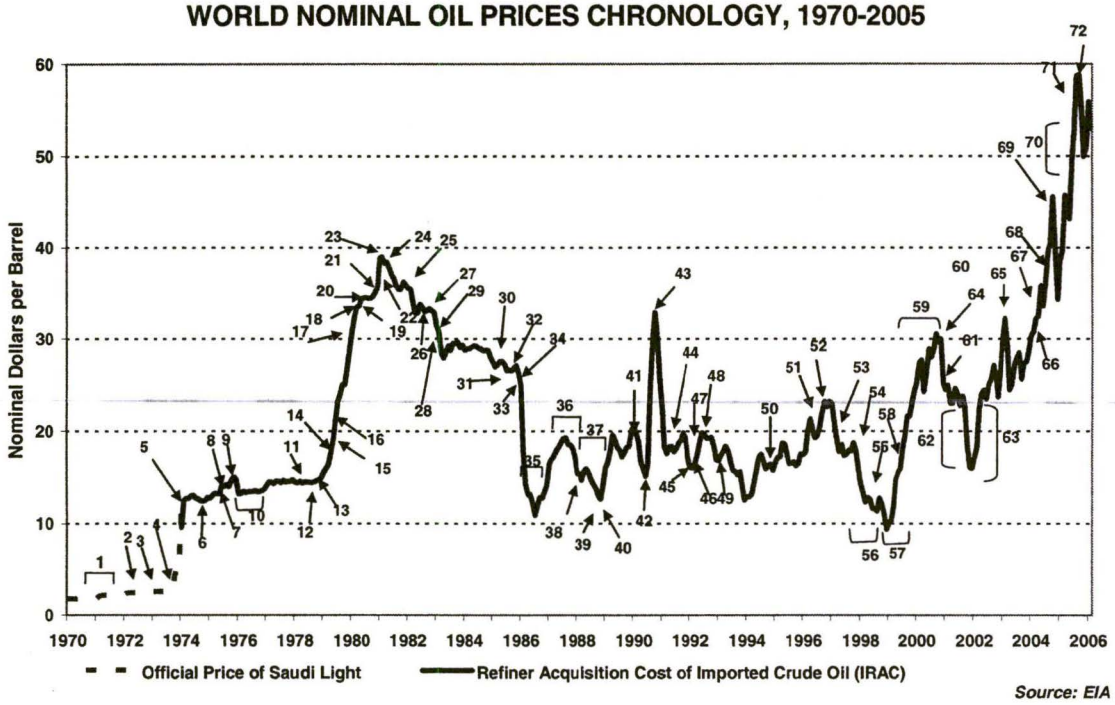
FIGURE 6
IMPORTED CRUDE OIL PRICES: NOMINAL AND REAL



Source: EIA, *Petroleum Marketing Monthly, November 2006.*

Figure 7, which contains a global oil price chronology for the period 1970-2005 demonstrates that market reaction to geopolitical events is driven largely by the magnitude of the supply cushion. Most notably the 1980s after 1982 were a period of falling nominal prices and slow demand growth. As a consequence, the Iran-Iraq War, which saw the two sides sink several of each other's tankers and stage air attacks on several hundred tankers in the Persian Gulf, was a period of relatively low and generally falling prices. This suggests that as OPEC rebuilds its surplus production buffer and as global crude and product inventories continue to grow, unexpected geopolitical events will have less of an impact on oil market prices.

FIGURE 7
WORLD NOMINAL OIL PRICES CHRONOLOGY, 1970-2005



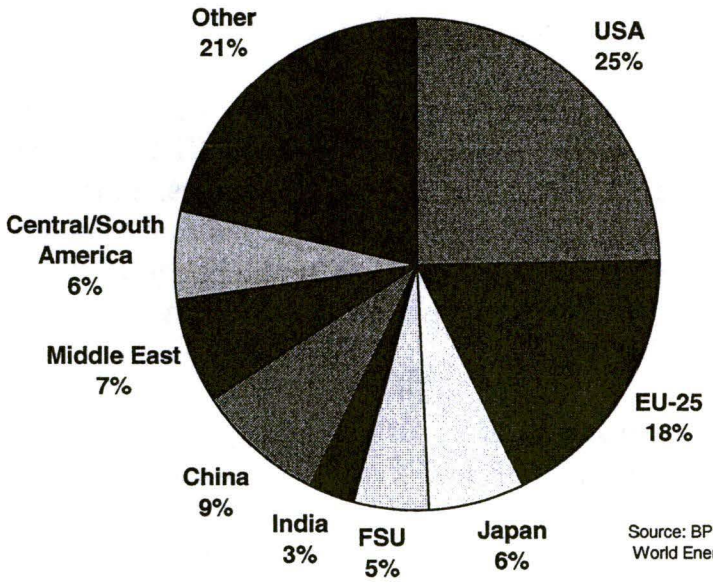
The latest IMF *World Economic Outlook* (September 2006) projects that world output will slow slightly from an estimated 5.1% in 2006 to 4.9% in 2007. However, growth in the industrial economies is projected to slow more significantly (Table 10). The IMF projects that U.S. growth will decline in 2007 from an annual rate of 3.4% in 2006 to 2.9% in 2007. The Euro area similarly will decline from 2.4% in 2006 to 2.0% in 2007, and the largest decline will be suffered by Japan falling from 2.7% in 2006 to 2.1% in 2007. The economies where the IMF projects slower growth for 2007 account for some 49.3% of total oil consumption (Figure 8).

TABLE 10
SLOWING ECONOMIC GROWTH IN THE INDUSTRIAL ECONOMIES IN 2007
(Annual GDP growth in %)

	2005	2006	2007
USA	3.2	3.4	2.9
Euro Area	1.3	2.4	2.0
Japan	2.6	2.7	2.1

Source: International Monetary Fund, September 2006

FIGURE 8
2005 OIL CONSUMPTION BY REGION



Source: BP Statistical Review of World Energy, June 2006.

Analyses since the September IMF report have tended to confirm the slower growth outlook for 2007 in the advanced economies and to expand its impact to the developing economies. The latest estimates for Japan suggest growth lowering in 2007 to 1.8%.[10] In November the European Commission raised estimates for 2006 growth in the Euro Zone to 2.6%, but left 2007 at 2.1%.[11] The four German international economic research institutes, which in October annually produce forecasts for economic activity in the coming year, confirmed the IMF's view on the advanced economies and further added that growth in East Asia (excluding China) was to slow from 5.2% in 2006 to 4.7% in 2007 and in Latin America from 4.3% in 2006 to 3.8% in 2007.[12]

The economic growth slowdowns are at least in part due to the increase in global oil prices. The IEA has calculated that a $10 oil price increase decreases world GDP by at least half of 1%; that is, the economic stimulus provided by higher oil-export earnings in OPEC and other exporting countries is more than outweighed by the deadening impact of higher oil prices on economic activity in oil importing countries. IEA noted that higher oil prices since 1999, in part the result of OPEC supply-management policy, contributed to the global economic downturn in 2000-2001, a period in which oil consumption grew at only an annual rate of 0.9%. [13] Higher oil prices appear also to have reduced the growth

[10] *Financial Times*, November 15, 2006
[11] *International Herald Tribune*, November 7, 2006
[12] *Handelsblatt*, October 21-23, 2006
[13] IEA, *Analysis of the Impact of High Oil Prices on the Global Economy*, May 2004, pp. 2-3

in demand in 2006. The IEA, in its latest *Oil Market Report* (November 10, 2006), lowered its estimate of 2006 oil product demand growth to an increase of only 1.1%. The slowed growth was attributable to a slowdown in demand growth in China as well as the mild October weather in Europe.

In the world's largest oil market, the United States, the consumer response to higher oil prices in 2005 was a reduction in demand. The American Petroleum Institute, in 2006, reported that demand for oil products, as measured by total product deliveries in the U.S., fell 0.6% in 2006 as demand was reduced due to high petroleum product prices. [14] An analysis by the Federal Trade Commission also showed that a 10% increase in gasoline prices ultimately leads to demand destruction of 546,000 bbl/day. [15]

The spare production capacity held by OPEC, which during the period of tight supplies in 2005 and early 2006, fell well 2 million bbl/day, by October 2006 had increased to an estimated 3.38 million bbl/day according to the IEA. This is a measure of the effective spare capacity in the global supply system, which indicates the ability of OPEC to expand production to offset any unexpected disruption in global oil supplies such as U.S. production shortfalls rising from the damage caused to the Gulf of Mexico production by hurricanes Katrina and Rita. [16]

The significant buildup in crude oil stocks by the OECD countries and the drop in the price of the OPEC basket of crudes of 27% between July and October 2006 has sufficiently alarmed OPEC members that at a meeting in Doha on October 19th and 20th they decided to reduce production from the OPEC-10 (excludes Iraq) by 1.2 million bbl/day (from an OPEC estimate 25 million bbl/day for September to 26.3 million bbl/day beginning November 1). OPEC cited high OECD crude stocks as signaling a fundamental market surplus while OPEC members appeared to wish to defend a price of about US$60/bbl.

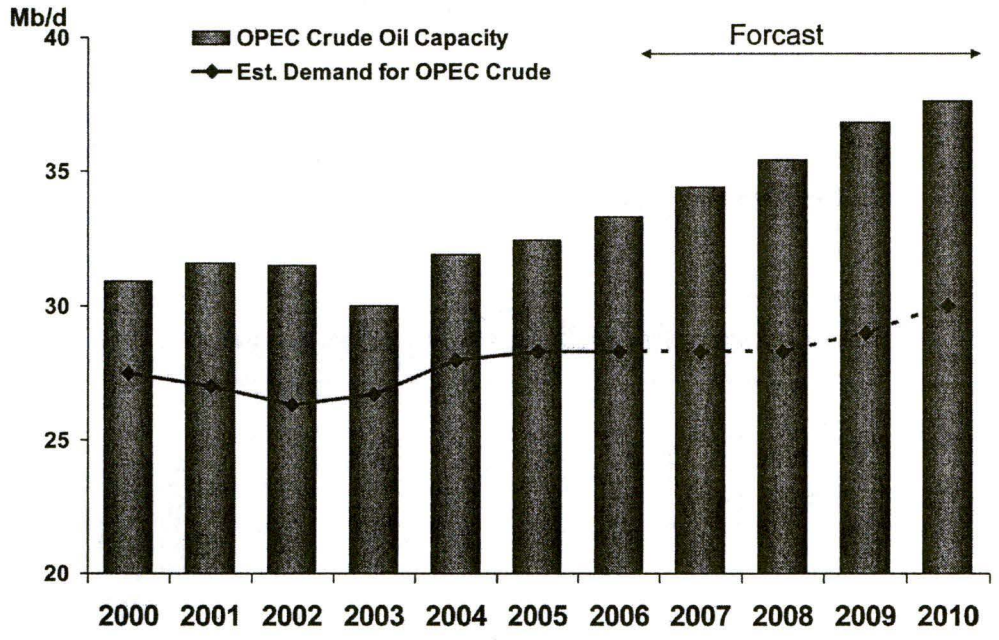
The data on tanker liftings, which in the short-term is the primary source of information on crude oil production by OPEC member states, are ambiguous as to what extent the reduction was implemented in November. At any rate, crude oil inventories have continued to climb and OPEC announced a further 500,000 bbl/day cut after its December 14 meeting in Abuja, Nigeria.[17] Saudi Oil Minister, Ali Naimi, has been quoted in the press as projecting that non-OPEC oil production is projected to increase by almost 2 million bbl/day from new

[14] *Oil & Gas Journal*, February 20, 2006, pp. 26-28
[15] *Wall Street Journal*, October 8, 2005
[16] IEA, *Oil Market Report*, November 10, 2006, p. 16
[17] *Financial Times*, December 15, 2006

sources in 2007, and that unless OPEC continues to cut its own production back, oil prices would significantly weaken in 2007. [18]

OPEC itself is also projecting significant expansion in its own production in the near term. At an OPEC seminar in Vienna in September 2006, Dr. Chakib Khelil, the Minister of Energy and Mines from Algeria, projected that OPEC crude oil production capacity would increase from about 33 million bbl/day in 2006 to approximately 37 million bbl/day by 2010 (Figure 9). In so doing, OPEC production capacity is expected to expand faster than the demand for OPEC oil.

FIGURE 9
OPEC UPSTREAM CAPACITY EXPANSION PLANS



Source : OPEC

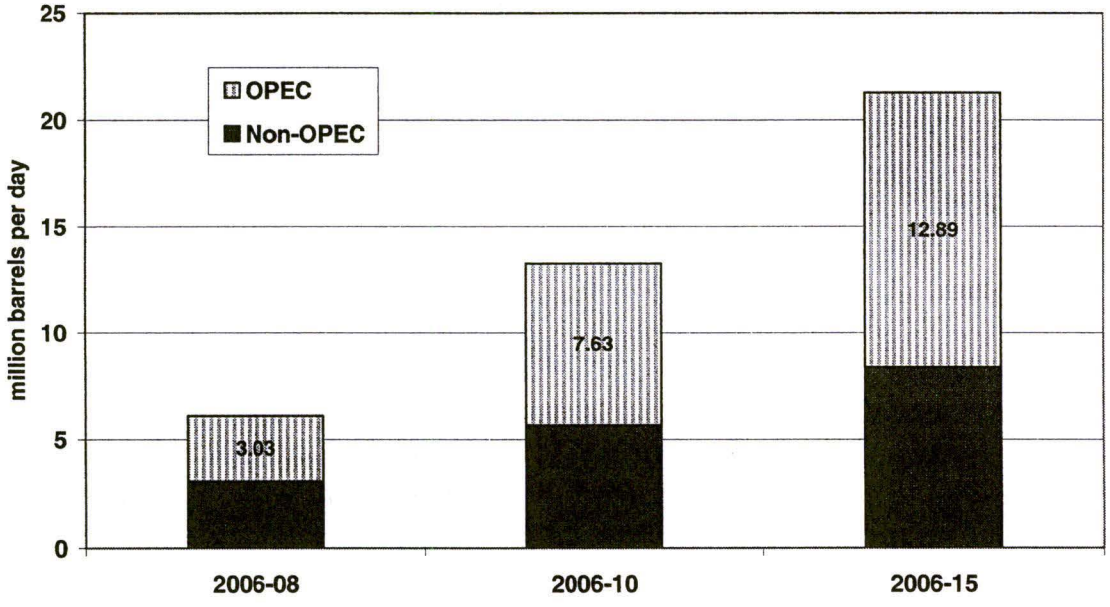
Nor are petroleum consumption and crude imports into China likely to continue expanding at the rate that occurred in the period 2000-2004 when Chinese consumption increased from 4.8 million bbl/day to 6.8 million bbl/day (in 2004). In 2005 consumption only increased 2.9% to just short of 7.0 million bbl/day. Moreover, domestic production has begun to grow more strongly with a 4.2% increase during the course of 2005, well above levels seen in the previous decade. In a report by the Chinese Delegation to an OPEC seminar in September 2006, it was noted that a combination of conservation, the commencement of operations

[18] *Financial Times*, December 11, 2006

by several coal-to-liquids projects and the increased use of ethanol and biodiesel (China is the world's third largest ethanol producer after the U.S. and Brazil) is expected to lower the rate of increase in crude imports from the level that occurred in the period 2000-2004. China still has significant oil reserves and production is anticipated to continue increasing. [19]

A comprehensive survey of global oil and liquid supply capacity published by CERA in August 2006 projects a significant increase in both OPEC and non-OPEC oil production capacity in the next nine years, with the bulk of the increase falling into the period 2006-2010 (Figure 10). CERA's examination of actual activity and production data covered existing fields and 360 new projects, of which 250 were non-OPEC and 110 were new OPEC development projects, all of which were expected to start production by 2010. The CERA analysis projected a potential growth in oil production capacity of 13.3 million bbl/day in the five years from 2006-2010, with a further 8 million bbl/day of capacity growth from 2010 to 2015. Among the particular trends noted by CERA was an increase in global gas production capacity, which in turn is driving up the volumes of associated liquids. In addition, the report noted a major increase in the pace and scale of deep water discoveries and development. [20]

FIGURE 10
CERA FORECAST OF GLOBAL OIL PRODUCTION CAPACITY GROWTH



Source: Cambridge Energy Research Associates, August 2006.

[19] Guoqiang Tang, *China's Energy Situation and its Future and New Energy Security Concept*, September 12, 2006
[20] http://www.cera.com

While media attention in the past two to three years has focused heavily on pessimistic stories of oil supply shortfalls and concerns over "peak oil", recent press reports have been significantly more bullish, particularly on the short/medium term outlook for greater supplies. For example, recently Eni announced that the giant Kashagan oil field that it is developing in Kazakhstan is expected to produce 25% more oil, once it hits peak production, than earlier estimated. Production is expected to begin in 2009 and is expected to peak at 1.5 million barrels per day, a level that the field will be able to sustain for at least ten years. [21]

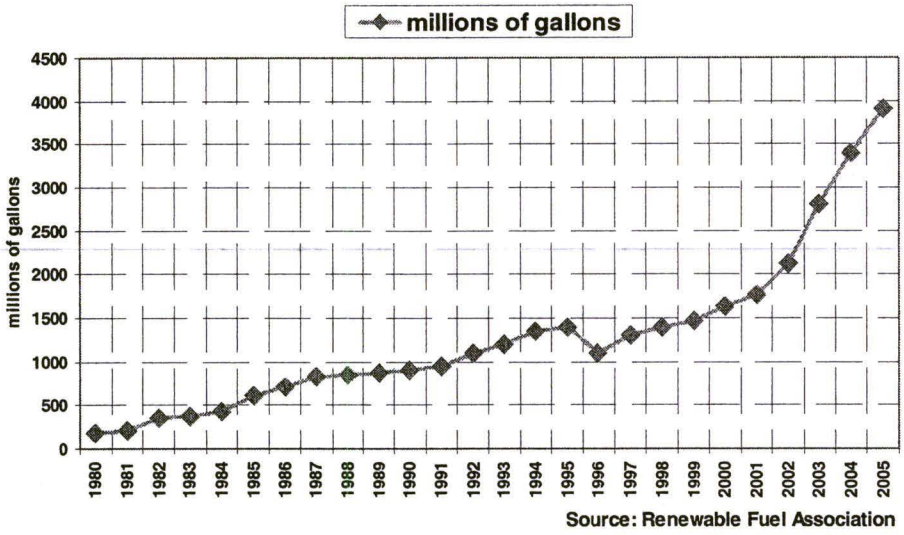
Developing incremental supplies of oil and gas typically takes time and many experts in the field have noted that the current run-up in prices is largely a reflection of a sustained period of underinvestment in upstream development in the 1990s. However, for the past three years oil and gas companies' global upstream spending has increased dramatically. The John S. Herold, Inc. survey released in September 2006 shows that 2005 upstream spending climbed to US$277 billion, an increase of 31% from 2004. This is the third consecutive year which upstream investment records have been set. Increases in capital spending have even resulted in insignificant incremental finds in the United States, which is generally considered to be mature oil province. The largest of these incremental finds generated headlines in September of this year when Chevron completed an extended well test of a Lower Tertiary well in the deep waters in the Gulf of Mexico. It is one of several recent finds in the same geological formation that has led to industry estimates of ultimate recovery of a further 9-15 billion bbl of oil equivalent. [22]

Furthermore, the rapid rise in U.S. ethanol production (in 2005 the U.S. overtook Brazil as the world's largest ethanol producer) is expected to have a dampening effect on gasoline demand, a key factor in pushing oil prices higher during peak driving months (Figure 11). The Energy Policy Act of 2005 increases the ethanol mandate to 7.5 billion gals/year by 2012. However, recent Senate Committee testimony from the Chief Economist of the U.S. Department of Agriculture indicated that so many ethanol plants are now planned or under construction that ethanol capacity will hit 8.5 billion gals/year by 2008/09 and will exceed 10 billion gals/year by 2010. [23] As of May 2006 the U.S. had 97 ethanol plants in operation (up form 54 in 2000) and a further 33 under construction.

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[21] *Financial Times*, November 27, 2006
[22] *Oil & Gas Journal*, September 25, 2006, pp. 36-38
[23] *Oil & Gas Journal*, October 9, 2006, p. 19

FIGURE 11
GROWTH IN US ETHANOL PRODUCTION
FROM 1980 TO 2005



Canada also is on track to significantly increase its oil production, primarily as a consequence of increased oil sand production from the giant Alberta bitumen regions of Peace River, Athabasca (Fort McMurray) and Cold River. The latest estimate by the Alberta Energy and Utilities Board from May 2006 indicates that these three areas contain some 173.7 billion bbl of remaining established reserves of bitumen. Although the massive investment in increased oil sand production has driven up costs and has encountered delays due to availability of key resources and labor, production, nevertheless, is expected to increase substantially in the next several years. [24] The Canadian Association of Petroleum Producers, in its Production and Supply Forecast released in May 2006, expects Canadian oil production to increase from 2.2 million bbl/day in 2005 to 3.2 million bbl/day by 2010 and 4.4 million bbl/day by 2015. All of the increase comes from either oil sands mining or oil sands in-situ production. [25]

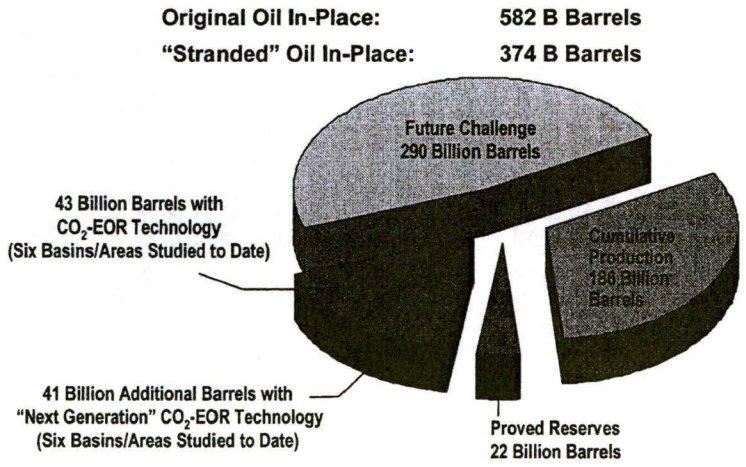
Moreover, even as in the past several years discussion about "peak oil" has increased, as it did in the energy crisis of the 1970s and 1980s, new analyses have indicated that the widespread application of carbon sequestration technology, due to the eventual advent of CO_2 constraints in the U.S., has the potential to sharply increase U.S. oil production from enhanced oil recovery (EOR) projects.

[24] *Oil & Gas Journal*, September 25, 2006, pp. 39-47
[25] CAPP, *Canadian Crude Oil Production and Supply Forecast, 2006-2020*, May 2006, p. 3

The U.S., which already has the world's largest operating network of CO_2 pipelines, could add a further 84 billion bbls of oil production (current reserves are 22 billion bbls) through the widespread application of CO_2 EOR technology (Figure 12).

FIGURE 12

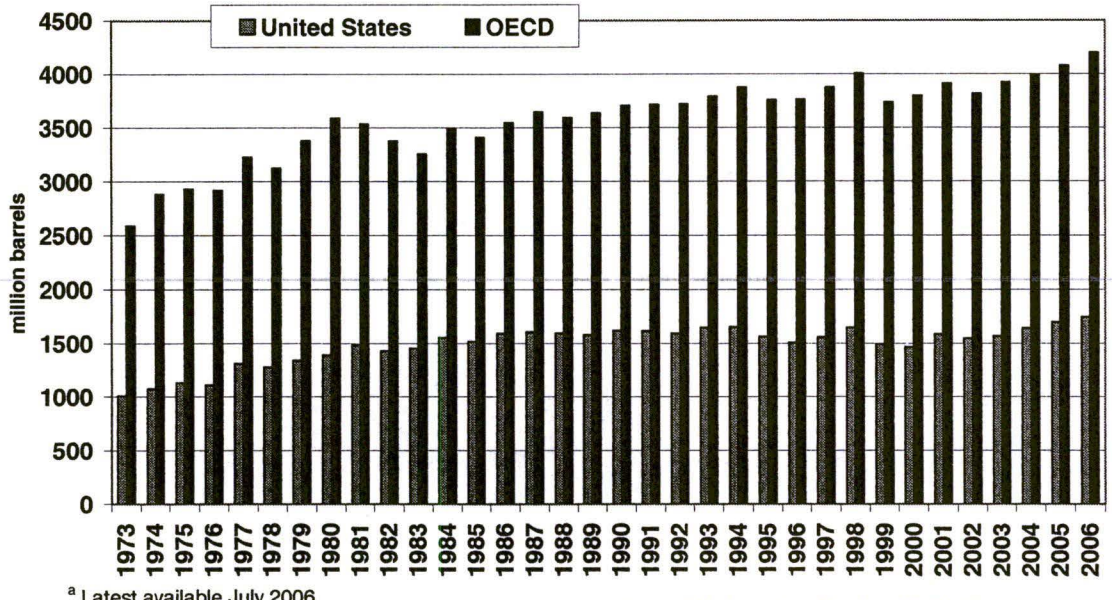
U.S. "STRANDED" DOMESTIC OIL RESOURCES IN EXISTING OIL FIELDS AND THE IMPACT OF CO_2 EOR TECHNOLOGY



Source: US DOE, Office of oil and Natural Gas, *Evaluating the Potential for "Game Changer" Improvements in Oil Recovery Efficiency from CO2 Enhanced Oil Recovery*, February, 2006

In the near term; that is, for 2007, the increased buildup in OECD crude oil stocks (Figure 13) and particularly U.S. crude oil stocks (Figure 14) is anticipated to constrain any price increases, and in fact should lead to a continuation of the soft prices seen in the period of September through December of this year. Crude oil stocks held in the U.S. (excluding the Strategic Petroleum Reserve) have risen from 286.1 million bbl in January 2005 to 332.6 million bbl by September. These are stock levels well above historic norms (Figure 13). Residual fuel oil, HFO stockpiles have also been steadily increasing in the past two years. In January 2005 U.S. stockpiles totaled 40.9 million bbls. By January 2006 this had increased to 42.6 million bbls, and the latest month available, September 2006, the stock stood at 43.4 million bbls (Figure 15). According to the EIA, U.S. residual fuel oil (including HFO) in 2006 stood well above their historic average range (Figure 16).

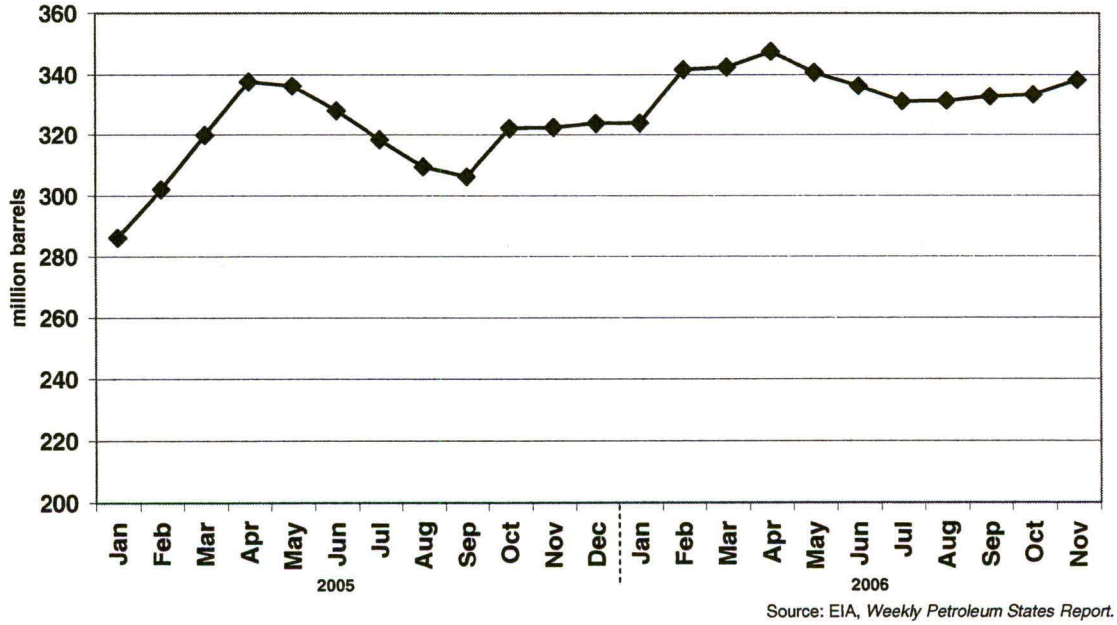
FIGURE 13
PETROLEUM STOCKS IN OECD COUNTRIES, END OF YEAR, 1973-2006[a]



[a] Latest available July 2006.

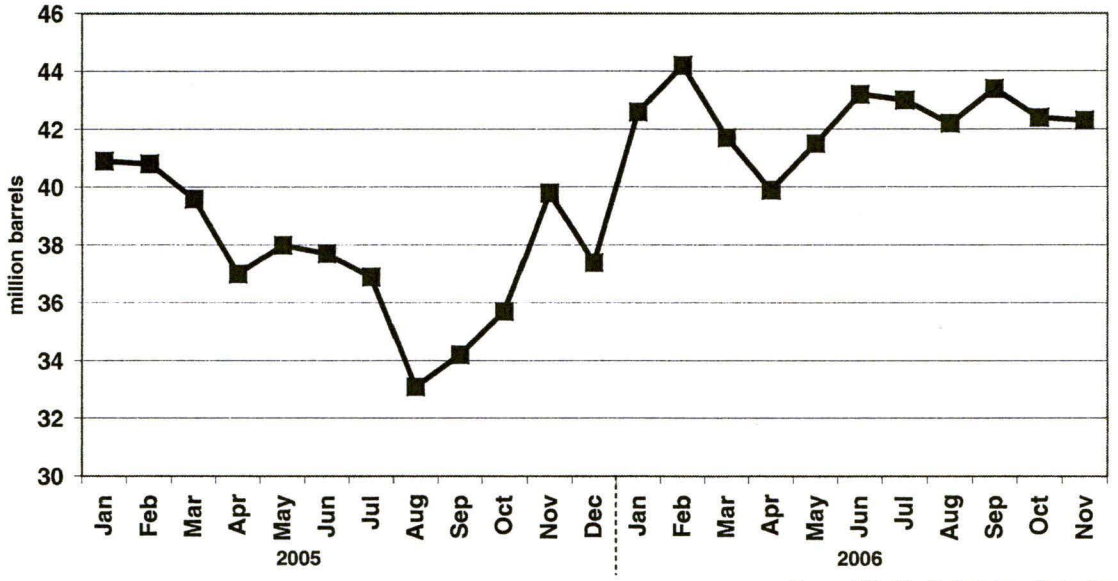
Source: EIA, *International Petroleum Monthly November*

FIGURE 14
US CRUDE OIL STOCKS, 2005-2006



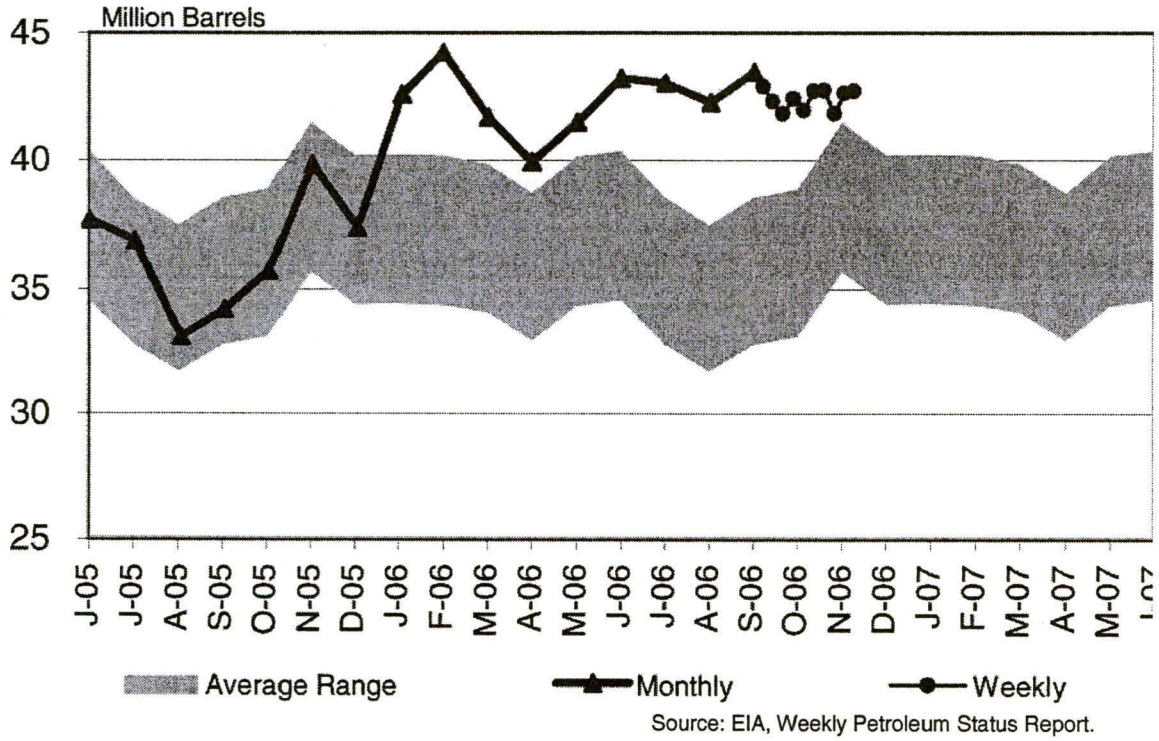
Source: EIA, *Weekly Petroleum States Report.*

FIGURE 15
US RESIDUAL OIL STOCKS, 2005-2006



Source: EIA, *Weekly Petroleum States Report.*

FIGURE 16
U.S. RESIDUAL FUEL OIL STOCKS



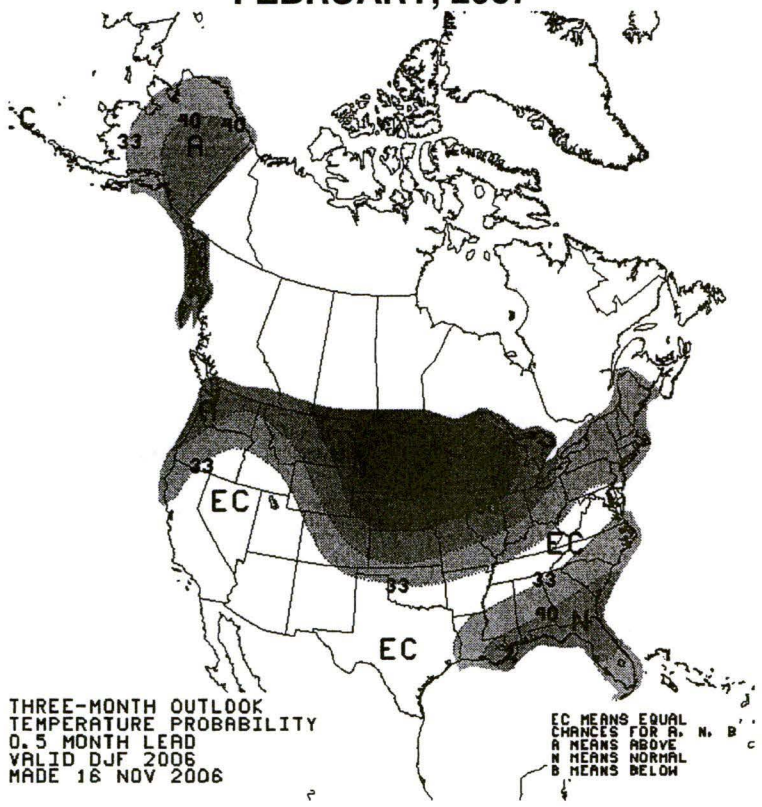
Source: EIA, Weekly Petroleum Status Report.

The EIA, in its annual *Energy Outlook 2007*, is also of the view that 2006 marked the peak in the current oil pricing cycle. It projects that average world crude oil prices will decline slowly in real terms (2005 dollars) from above $69 per barrel in 2006 to just under $50 per barrel by 2014. A 2007 reference case anticipates substantial increases in conventional oil production in both OPEC and non-OPEC countries over the next ten years. The EIA expects that OPEC will target a price range of $50-60 per barrel for the medium term. [26] The EIA, in the *International Energy Outlook 2006* released in June 2006, projects that the higher oil prices of 2006 would enable non-OPEC suppliers to retain their market share of world oil supplies through 2030. Higher prices would induce non-OPEC supply increases such that the non-OPEC market share in 2030 of 62% is greater than the 2003 non-OPEC market share of 61%. [27]

A final bearish factor for HFO and crude prices in late 2006 and early 2007 has been the weather. Europe has experienced its warmest fall (designated as the period from September through the end of November) since 1901. Specifically London had the warmest fall since temperatures began to be recorded more than 300 years ago. Preliminary estimates in the United States are that the period from May through October is the warmest such period on record. Fall, throughout much of the U.S., has been significantly above average, particularly in the key heating oil market of the Northeast. The National Snow and Ice Data Center in Boulder, Colorado recently reported that the normal expansion of sea ice in the Arctic has been extremely slow this year. The November average ice coverage was by far the lowest since satellite measurements began in 1979. This is considered to have contributed significantly to slowing the onset of winter cold fronts from the Arctic.[28] The long-range weather forecast for the U.S. by the National Oceanographic and Atmospheric Administration covering the period from December 2006 through the end of February 2007 indicates that warmer than average temperatures across the Pacific Northwest, the Northern and Central Plains, the Midwest, the Northeast and Northern Mid-Atlantic, as well as Alaska are expected for this period. Near-average temperatures are projected for the Southeast from Louisiana through North Carolina. Only Hawaii is expected to have below-average temperatures (Figure 17).

[26] *EIA, Annual Energy Outlook 2007*, pp. 4-5
[27] EIA, *International Energy Outlook 2006*, June 2006, p. 31
[28] *New York Times*, December 12, 2006

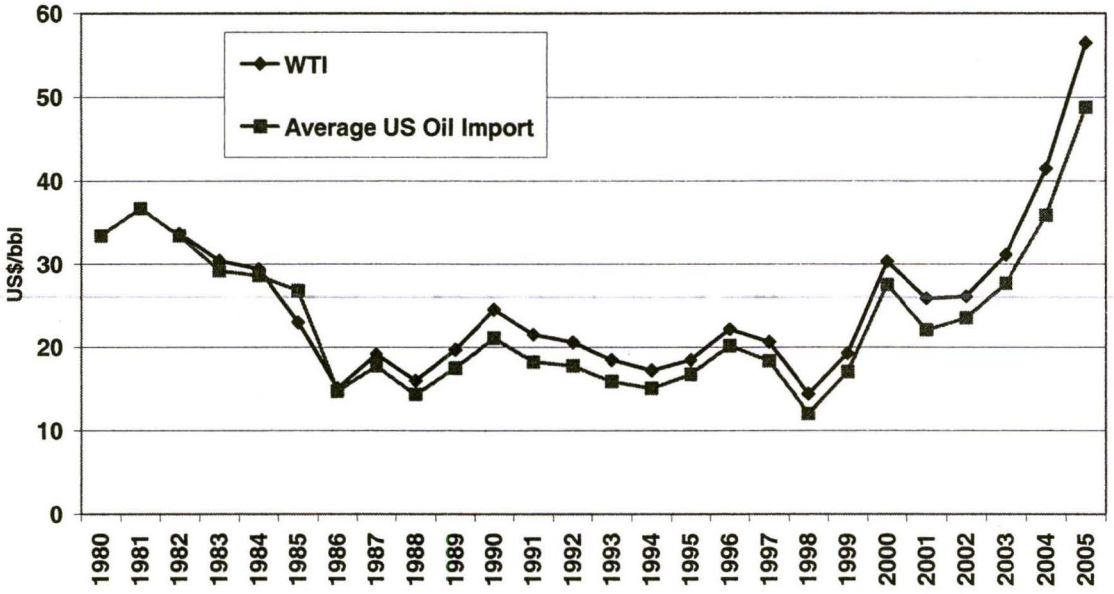
FIGURE 17
THREE-MONTH U.S. TEMPERATURE FORECAST TO END FEBRUARY, 2007



Source: National Oceanic and Atmosphere Administration.

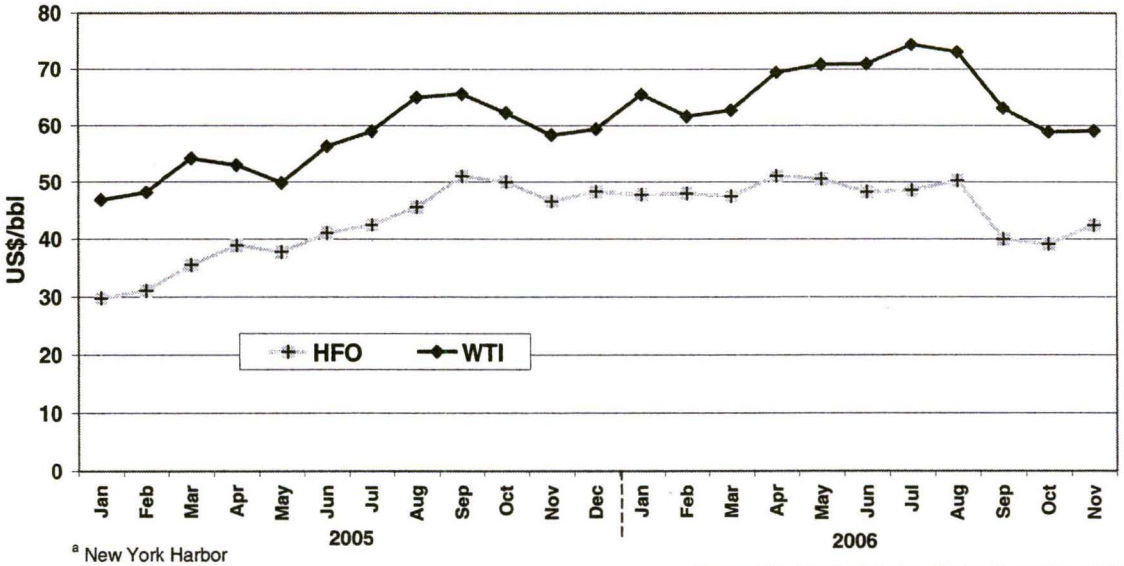
It is also important to remember how HFO prices relate to crude prices. On July 31, 2006, when NSPI picked the futures price for HFO, WTI for the first quarter of 2007 stood at [redacted] (Avon IR-27, Attachment 2, pp. 3-4). A [redacted]/bbl price for WTI corresponds approximately with a [redacted]/bbl price for HFO. WTI is a premium light crude with a sulfur content of only 0.2% and historically has been valued at well above the basket of heavier, more sour crudes that make up U.S. imports (Figure 18). Moreover, for all of the reasons listed above, HFO trades in recent times about US$20/bbl below WTI (Figure 19). Thus, WTI prices in the range of [redacted] yield approximately the same HFO price as NSPI has Board approval for in 2006.

FIGURE 18
COMPARISON OF CRUDE OIL COSTS: WTI SPOT PRICES AND AVERAGE U.S. OIL IMPORT COSTS 1980-2005



Source: IEA, *Energy Prices & Taxes.*

FIGURE 19
HFO[a] AND WTI MONTHLY AVERAGE SPOT PRICES IN 2005 AND 2006



[a] New York Harbor

Source: EIA, *Weekly Petroleum Status Report,* Dec, 6 2006

NSPI's LFO Costs

Of the total fuel rate increase of C$68.50 million requested by NSPI, some [redacted] million is attributable to higher LFO costs (UARB IR-4). NSPI has also requested C$16.1 million in the rate increase to cover the cost of a load increase. This load increase is served by a much greater than historic utilization of the combustion turbines that burn light fuel oil or diesel. In the 2006C case, the combustion turbines produced [redacted] gWh. In the 2007 Rate Case, they are forecasted to produce [redacted] gWh, an increase of [redacted] gWh (Liberty IR-75). As a consequence, diesel consumption rises from [redacted] gallons in the 2006C case to [redacted] gallons in the 2007 Rate Case (Liberty IR-66, Attachments 2 and 4).

LFO is an item whose price is not hedged by NSPI since its volume is extremely variable. It is used in peaking units and therefore is affected by customer load and external markets, and as a consequence, total volume consumption in any one year is difficult to forecast (CME IR-61 (b)).

The 2007 NSPI Rate Case involves the use of [redacted] more gallons of diesel for the combustion turbines (Liberty IR-66, Attachment 4). Thus, the increased LFO cost of [redacted] million involves a unit price increase over a much larger volume of diesel fuel than has historically been used by NSPI.

The 2006 price for LFO is [redacted]/gal. The rate increase requested is for [redacted]/gal. On an mmBtu basis, this is an increase of [redacted]/mmBtu from [redacted]/mmBtu to [redacted]/mmBtu (Table 11).

TABLE 11
NSPI CALCULATION OF THE LFO PRICE INCREASE

	2007	2006C	Increase	2007	Price Variance
	C$/mmBtu	C$/mmBtu		mmBtu	C$ (000s)
Combustion Turbines	[redacted]				
Total Price Variance					[redacted]

Source: UARB IR-4 Attachment 2

The 2007 forecast is based on a forward price curve generated on July 31, 2006 (Stutz IR-12; Avon IR-27, Attachment 5) (Tables 12 and 13).

TABLE 12
2007 LFO FUTURES PRICES ON JULY 31, 2006
(US$/US gallon)

January	[redacted]
February	
March	
April	
May	
June	
July	
August	
September	
October	
November	
December	

Source: Liberty IR-43, Attachment 14

TABLE 13
NSPI's CALCULATION OF 2007 LFO PRICES

	Jan. 07	Feb. 07	Mar. 07	Apr. 07	May 07	Jun. 07	Jul. 07	Aug. 07	Sept. 07	Oct. 07	Nov. 07	Dec. 07
NYMEX (US$/US Gallon	$2.247	$2.267	$2.260	$2.218	$2.175	$2.157	$2.165	$2.184	$2.205	$2.227	$2.252	$2.278
FX Rate	$1.180	$1.180	$1.180	$1.180	$1.180	$1.180	$1.180	$1.180	$1.180	$1.180	$1.180	$1.180
NYMEX (C$/US Gallon)	$2.652	$2.675	$2.666	$2.617	$2.567	$2.545	$2.555	$2.577	$2.602	$2.627	$2.658	$2.688

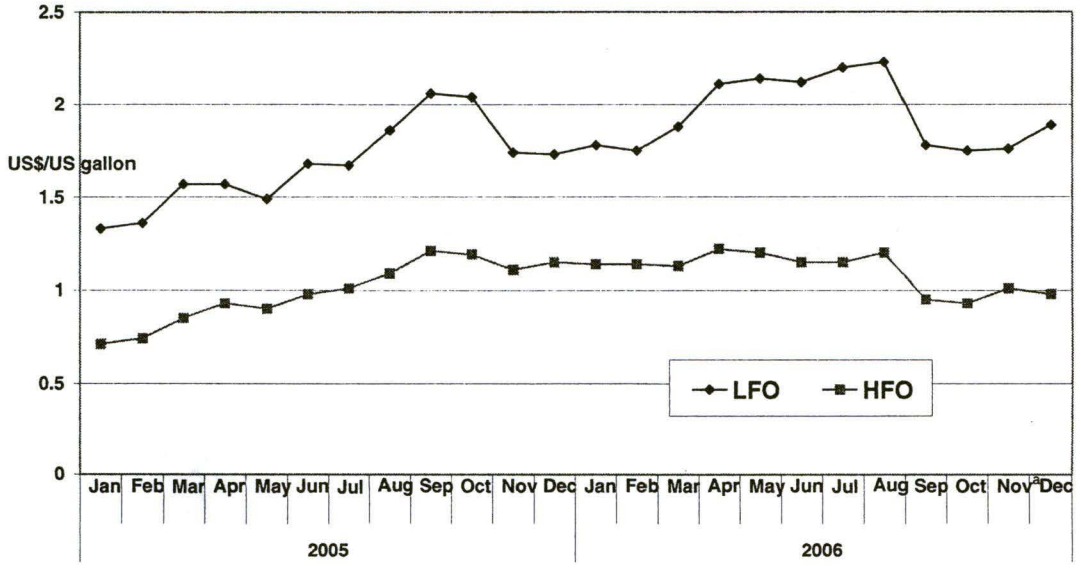
Source: Liberty IR-43, Attachment 11, p. 1

Emera Procurement buys LFO on behalf of NSPI by process of a tender. [redacted]

[redacted]

As in the case of HFO, in selecting at the end of July 2006 as the point in time for setting a forward market price for LFO, NSPI selected the month with the absolute highest average West Texas Intermediate oil price in history. Similarly, LFO prices quoted for New York Harbor barge delivery peaked in July and August. From a peak price of US$2.23/gal in August of 2006, the price has fallen by the first of December 2006 to US$1.84/gal; this is equivalent to C$2.23/gal or C$0.59/l (Figure 20).

FIGURE 20
2005-2006 SPOT PRICES, NVH, HFO AND LFO



[a] To December 8, 2006

Source: EIA, *Weekly Petroleum Status Report*

Light fuel oil, unlike heavy fuel oil, is a petroleum product much in demand. Demand for LFO has been growing globally and in all geographic regions, including the United States. The data suggest, however, that growth in Canada

has been weaker than in other parts of the world, apparently reflecting the wider use of natural gas for residential heating (Table 14).

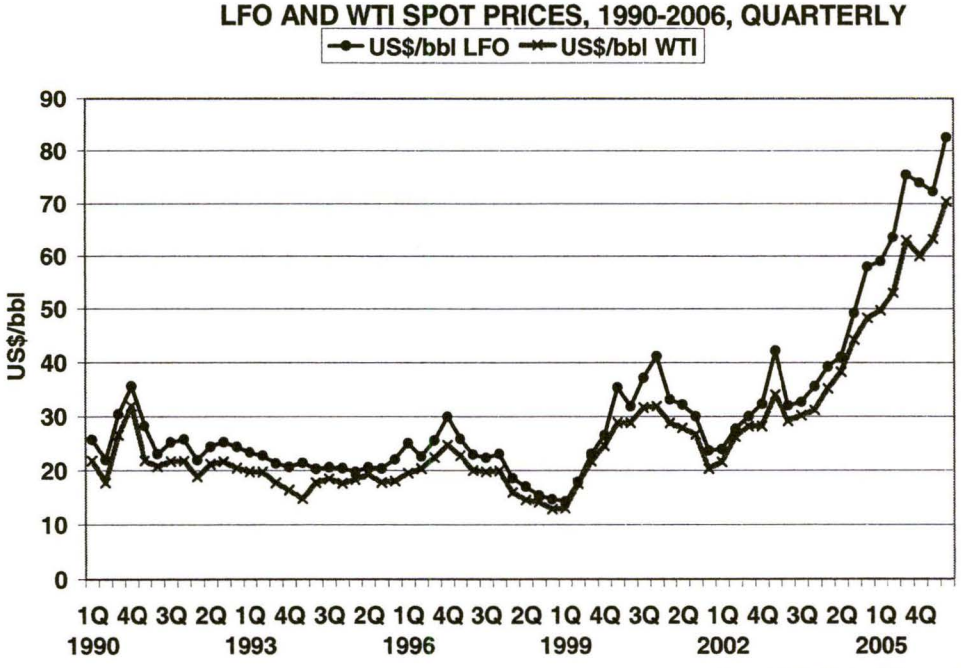
TABLE 14
WORLD LIGHT FUEL OIL DEMAND, 1971-2004
(000's bbls/day)

	World	OECD Europe	OECD Pacific	USA	Canada
1971	12,009	4,303	924	2,910	478
1973	14,036	4,996	1,223	3,296	520
1978	16,138	5,168	1,483	3,661	534
1990	17,819	4,722	2,132	3,064	413
1998	20,977	5,548	2,513	3,600	459
1999	21,565	5,550	2,625	3,684	476
2000	20,952	5,600	2,599	3,830	498
2001	22,544	5,857	2,577	3,954	481
2002	22,739	5,812	2,598	3,872	482
2003	23,372	5,984	2,565	4,038	505
2004	24,278	6,096	2,497	4,168	527

Source: IEA, Annual Oil Statistics

A comparison of LFO and WTI spot prices over the past sixteen years indicates that the movements in crude prices and LFO prices track each other very closely. However, it is noticeable that in strong markets it appears that LFO prices tend to have a widening differential with WTI spot prices (Figure 21).

FIGURE 21
LFO AND WTI SPOT PRICES, 1990-2006, QUARTERLY



Source: IEA, *Energy Prices and Taxes*

A comparison of monthly HFO and LFO prices, both on a New York Harbor basis, also demonstrates that there is no fixed differential between LFO and HFO prices. During periods of rising prices, LFO prices tend to respond more strongly and to coordinate more closely with movements in the crude market. For example, in the past several months HFO prices have tended not to respond to upward movements of the crude price. On the other hand, LFO prices, particularly in early December, have moved up strongly (Figure 20).

NSPI's Natural Gas Resale

In requesting a fuel price increase for 2007, NSPI has assumed a decreased gas resale margin of C$6.4 million in 2007, compared to the 2006 approved rates (NSPI *Direct Evidence*, p. 7). This is a consequence of the increase over 2006 C in the gas consumption in the steam units at Tufts Cove, which results in a reduction in the amount of gas available to be sold. Due to higher oil prices, the gas is burned in Tufts Cove Units 1-3 in April through October of 2007. This reduces the volume of gas available for resale from [redacted] gBtu forecasted for 2006 to [redacted] gBtu expected in 2007. This is a consequence of the consumption of [redacted] gBtu in Tufts Cove Units 1-3 (Table 15).

TABLE 15
2007 PROJECTED VOLUMES OF GAS BURNED IN TUFTS COVE UNITS 1, 2, 3
(mmBtu)

2007 January	[redacted]
February	
March	
April	
May	
June	
July	
August	
September	
October	
November	
December	
2007 Total	

Source: Avon IR-31, Attachment 3, p. 2

The much smaller volume of gas for sale in 2007 marks a distinct change from previous years. Prior to 2007, the smallest amount available for resale was in [redacted] gBtu (Table 16). The consumption of [redacted] gBtu in the five units at Tufts Cove marks a step change away from the practice in previous years, [redacted]

TABLE 16
NSPI NATURAL GAS SALES VOLUMES, 2003-2007
(mmBtu)

2003	[redacted]
2004	
2005	
2006	
2007	

Source: SEB IR-47, Attachment 1 (actual volumes to September 2006); Liberty IR-62, Attachment 1 (forecast for last three months of 2006); Attachment 2 (forecast for 2007)

TABLE 17
NSPI'S GAS CONSUMPTION, 2005-2007
(mmBtu)

	2005	2006	2007
[redacted] purchases	[redacted]	[redacted]	[redacted]
Available for use			
Consumed in Tufts Cove 4 and 5			
Tufts Cove steam units			
Total consumed			
Available for resale			

Source: Liberty IR-54, Attachment 1

This step change in the use of natural gas at Tufts Cove in 2007 is a product of the NSPI HFO price projection based on the July 31, 2006 futures price for HFO (see above). When combined with the futures price projection of the same date for natural gas, this yields a situation where Tufts Cove coverts from HFO to natural gas use [redacted] and only reconverts back to HFO [redacted] in 2007 (Table 18). As was pointed out above, the HFO price projection viewed from the perspective of late December 2006, with record high crude oil and HFO stocks, projections of a warmer than normal winter and an outlook towards declining economic growth in 2007 in the major industrial economies, appears to be significantly too high.

TABLE 18
2007 PROJECTED HFO VS. NATURAL GAS BURN AT TUFTS COVE

2007	Heavy Fuel Oil Forward Price Curve $/mmBtu	Natural Gas Forward Price Curve $/mmBtu	Fuel Burned Tufts Cove (Units 1,2,3) (Lesser Cost)
January			
February			
March			
April			
May			
June			
July			
August			
September			
October			
November			
December			

Source: Liberty IR-101

NSPI, in its *Direct Evidence* (p. 53), describes the primary features for the calculation of its natural gas margin as follows:

- Estimate the volume of natural gas that will be available for resale after expected consumption for generation at Tufts Cove;
- Estimate the amount of contract gas supply cuts that will be expected in the period;
- Determine the cost of gas NSPI will purchase as per pricing terms of the gas purchase contract;
- Determine the selling price for the gas using market forward curves;
- Calculate the margin based on the monthly volume of gas available for resale, multiplied by the expected selling price in the month, less the forecast cost of the gas;
- Reduce the margin by transportation tolls that are incurred by NSPI as part of the natural gas sales program.

This is the methodology approved in the 2003 Generic Rate Case. Most of the gas that NSPI sells is exported to the United States on the Maritime & Northeast Pipeline (M&NP) and leaves Canada at the border crossing point, St. Stephen, New Brunswick.

Market pricing in the New England market is primarily driven off the spot market in the Henry Hub with basis difference added for delivery points in New England. The first pipeline interconnection for the M&NP is Dracut in Massachusetts. This, however, is no longer a liquid trading point and therefore price discovery is difficult. In April 2004 NSPI began to use the TETCO M.3

pricing for monthly deals, and this is sufficiently liquid to be traded on the NYMEX under the NYMEX ClearPort. The basis difference between Henry Hub and TETCO M.3 varies with the seasons, typically in January the basis difference can be quite substantial as much as US$3.00/mmBtu, while most of the remaining months it falls to US$0.50/mmBtu or less. [29] An analysis of price trends by Canada's National Energy Board (NEB) has shown that prices on the NYMEX at Dracut and St. Stephen all move together. [30]

The latest projections of the near-term gas markets suggest that higher than average volumes in underground storage and anticipation of continued warm weather are depressing prices in December and possibly into January. [31] In Canada the outlook is similar. While Western Canada is expected to experience below average temperatures, the high consuming regions in Eastern Canada, like the United States are expecting average to above average temperatures in the winter of 2006-2007. [32] By the November 20th deadline for responding to IRs, NSPI also appears to have changed its view noting in one IR that it now anticipated that first quarter Henry Hub prices would be about US$8.50/mmBtu (CME IR-12).

For the 2007 Rate Case NSPI relied on forward prices for Henry Hub sampled on July 31, 2006. These showed prices above US$11.00/mmBtu for the first three months of the year (2007), with the price declining thereafter to a low of US$8.67/mmBtu in May 2007, before gradually increasing again to US$10.74 in December 2007 (Table 19).

TABLE 19
2007 NATURAL GAS FUTURES, JULY 31, 2006, HENRY HUB PRICES
(US$/mmBtu)

January	$11.69
February	$11.70
March	$11.46
April	$8.85
May	$8.67
June	$8.75
July	$8.85
August	$8.93
September	$9.02
October	$9.18
November	$9.96
December	$10.74

Source: Liberty IR-43, Attachment 14

[29] ISIS, *Review of Nova Scotia Power Incorporated's Gas Resales*, October 19, 2005
[30] NEB, *Natural Gas Prices in the Maritimes*, March 2004, pp. 10-11
[31] EIA, *Natural Gas Weekly Update*, December 14, 2006
[32] www.neb.gc.ca

From the testimony already provided in the 2006 Rate Case and in the current Rate Case, sufficient grounds to question the reasonableness of using futures prices derived from a single day to set gas prices in a Rate Case for an entire year exist. In the Rate Case for 2006, the filing occurred prior to a realization of the full impact on the Gulf of Mexico gas production of Hurricanes Katrina and Rita. NSPI relied upon NYMEX gas futures prices of May 11, 2005. These projected U.S. gas prices at just over US$8.00/mmBtu for January and February 2006. Once the impact of hurricanes Katrina and Rita on the gas production facilities in the Gulf of Mexico became clear, spot market prices and futures prices shot up. In general, NYMEX futures prices taken at any point in October 2005 indicated that January, February and March were in excess of US$14.00/mmBtu and gas prices did not fall below US$10.00/mmBtu even during the summer months of 2006. Table 20 below shows NYMEX futures prices for two days in October 2005.

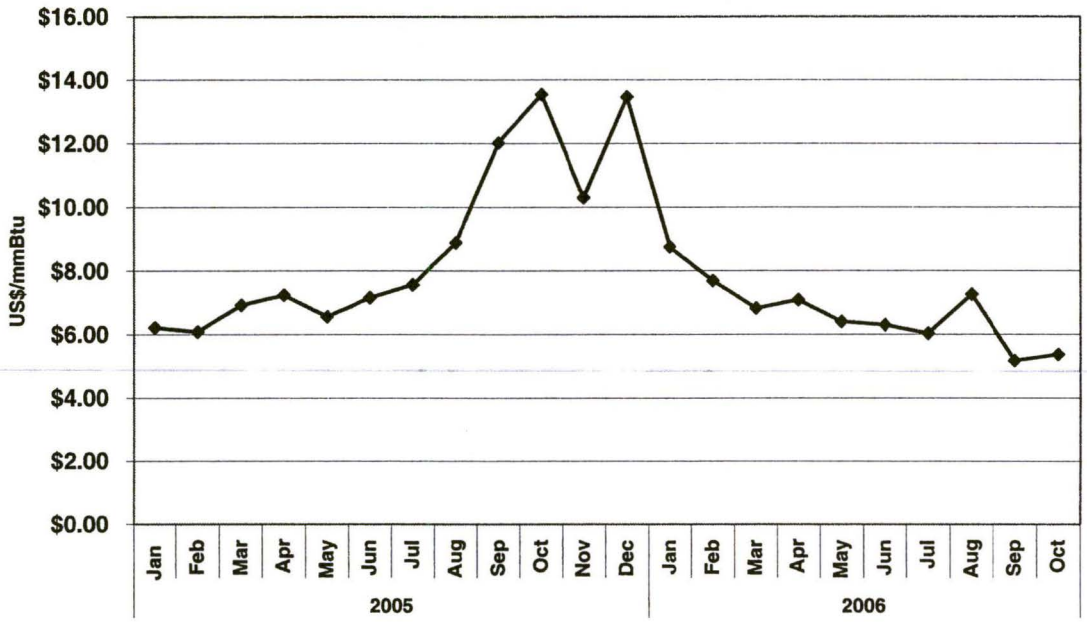
TABLE 20
NYMEX NATURAL GAS FUTURES PRICES FROM OCTOBER 2005
(US$/mmBtu)

	October 3	October 18
January 06	14.892	14.310
February 06	14.617	14.160
March 06	14.127	13.735
April 06	10.977	10.885
May 06	10.442	10.485
June 06	10.442	10.490
July 06	10.472	10.522
August 06	10.502	10.554
September 06	10.477	10.527
October 06	10.504	10.557
November 06	10.929	10.977
December 06	11.329	11.392

Source: NYMEX Natural Gas Futures

What in fact happened was quite different. Physical prices at Henry Hub peaked in October (the very month of the highest futures prices) with an average of US$13.54/mmBtu. By November they had fallen to an average for the month of US$10.30/mmBtu, and in January 2006 they were not above US14.00 but rather at US$8.74/mmBtu with further declines taking place throughout 2006 (Figure 22).

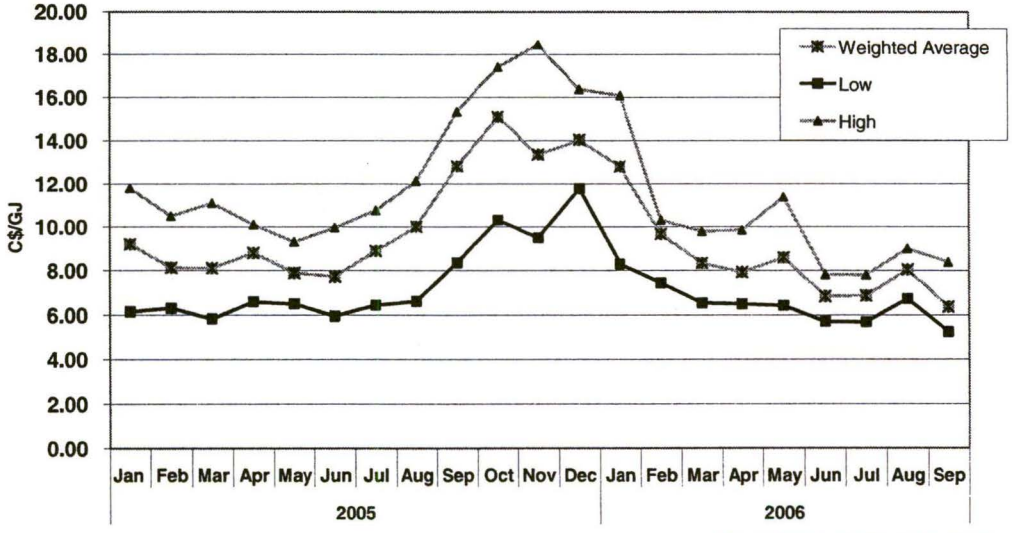
FIGURE 22
MONTHLY HENRY HUB GAS PRICES 2005-2006



Source: CA IR-5, Attachment 1.

A quite similar pattern for actual prices in Canadian Dollars was registered for natural gas export prices at St. Stephen, New Brunswick in this same time period (Figure 23) [redacted] (Table 21).

FIGURE 23
NATURAL GAS EXPORT PRICES AT ST. STEPHEN, NEW BRUNSWICK, 2005-2006



Source: Canada: National Energy Board.

TABLE 21
MONTHLY AVERAGE REALIZED PRICES
FOR NSPI's NATURAL GAS SALES
(C$/mmBtu)

	2003	2004	2005	2006
January				
February				
March				
April				
May				
June				
July				
August				
September				
October				
November				
December				
Annual (weighted volume)				

Source: SEB IR-47, Attachment 1

Well before the futures market failed to predict the behavior of gas prices after hurricanes Katrina and Rita, questions had been raised about the usefulness of using NYMEX natural gas futures prices to predict Henry Hub spot prices. A report by the EIA, Office of Oil and Gas, dated October 2005 analyzes futures contract prices for the heating seasons 2002-03, 2003-04 and 2004-05 and compares them with the average monthly spot prices at Henry Hub. The result is not encouraging for the use of futures prices as a predictor of Henry Hub gas prices: "An examination for price data for recent years shows that futures prices are relatively poor predictors of the Henry Hub spot price that is realized during the corresponding delivery or target month, and even the final futures price for a given contract often does not anticipate correctly the realized average spot price. Futures prices vary substantially over time and apparently reflect current market conditions as well as future expectations". [33] The report further notes that futures prices tend to be "indicative of the strong influence of current market conditions on the market expectations for futures spot prices...". [34] The analysis of energy futures prices cited earlier also concludes that natural gas futures

[33] EIA, Office of Oil and Gas, *An Assessment of Prices of Natural Gas Futures Contracts as a Predictor of Realized Spot Prices at the Henry Hub*, October 2005, p. 1
[34] Ibid, p. 3

prices are a "poor predictor" of future physical prices. [35] Clearly the use of a single day's futures prices to predict gas prices for a full year in a rate case is thus even more fraught with difficulty.

In calculating the gas it has available for resale, NSPI also assumed that [redacted]% of the contracted gas quantities would not be received (NSPI, *Direct Evidence*, p. 55). To the end of October 2006 under-deliveries under the [redacted] contract have amounted to approximately [redacted]. This situation does appear to be improving, however, since under-deliveries in 2005 were approximately [redacted] (Liberty IR-55; Table 22).

TABLE 22
UNDERDELIVERIES UNDER NSPI's GAS SUPPLY CONTRACT 2005-2006
(mmBtu)

	2005	2006
Jan	[redacted]	[redacted]
Feb		
Apr		
May		
June		
July		
Aug		
Sept		
Oct		
Nov		
Dec		

Source: Liberty IR-58 Attachment 2; Liberty IR-55; Liberty IR-49 Attachment 1.

The Sable Offshore Energy Project (SOEP), which originally was projected to have some 3.5 tcf of natural gas reserves, has seen that reduced to 2.3-2.6 tcf. The Tier I fields, Thebaud, Venture and North Triumph have declined in deliverability significantly faster than anticipated when the project was developed. As a consequence, the operator has accelerated the development of the Tier II fields, Alma and South Venture. Production from these have ramped up through to 2004 and 2005, but this appears not to have improved overall production by SOEP. The production reports for the project from the Nova Scotia Offshore Petroleum Board (NSOPB) show that production peaked in 2002 and has been in decline ever since. The annualized performance in the first ten months of 2005 leads to total production below 3.8 billion m^3 (Table 23). In the end of November 2006, SOEP completed the Sable Compression Platform;

[35] C, Menzie, M, LeBlanc and O. Coibion, *The predictive Characteristics of Energy Futures: Recent Evidence of Crude Oil, Natural Gas, Gasoline and Heating Oil*, unpublished paper, University of California, Santa Cruz, October 2001

however, NSPI is doubtful for various reasons whether this will end the SOEP's under-production (Liberty IR-51). [36]

TABLE 23
SABLE GAS PROJECT PRODUCTION VOLUMES
(000's m^3)

2000	3,597,155
2001	5,375,353
2002	5,474,992
2003	4,665,769
2004	4,327,895
2005	4,225,756
2006[a]	3,191,256

[a] First 10 months

Source: Nova Scotia Offshore Petroleum Board

NSPI's Solid Fuel Costs

NSPI is seeking an increase in coal costs of C$15.7 for 2007 over its allowed fuel charges in 2006. NSPI notes that it is seeking to recover the C$15.7 million by which the 2006 fuel charges were reduced by the Nova Scotia Utility and Review Board (NSUARB) (NSPI, *Direct Evidence*, p. 7). [37]

As of the application filing date of September 6, 2006, NSPI had contracted for [redacted] of its forecasted 2007 solid fuel requirements. Table 24 summarizes the status of these coal and petroleum coke contracts as of the end of the first week of September. In developing the coal costs for 2007, NSPI priced the contracts in place as of the beginning of September at their contractual levels and priced the uncommitted volumes "using market information and published forecasts" (NSPI, *Direct Evidence*, p. 56). NSPI notes that in projecting coal prices for un-contracted volumes it relied upon contemporaneous bids and forward price curves. The resulting methodology yields forecast pricing for the uncommitted volumes that is summarized in Table 25.

[36] NSOPB, *Annual Report*, 2005-2006, p. 27
[37] NSUARB, NSPI- P 882, Decision, March 10, 2006, p. 52

TABLE 24
SUMMARY OF NSPI'S SOLID FUEL CONTRACTS AS OF BEGINNING SEPTEMBER 2006
(000's tonnes)

Product	Supplier	2006	2007	2008	2009	2010
Low Sulphur Position Required (tonnes)						
LS						
LS						
LS						
LS						
LS						
LS						
CONTRACTED (tonnes)						
OPEN (tonnes)						
Mid & High Sulphur Positions Required						
MS						
MS						
MS						
CONTRACTED (Tonnes)						
OPEN (Tonnes)						
Domestic Positions Required						
Domestic						
CONTRACTED (Tonnes)						
OPEN (Tonnes)						
Petroleum Coke Positions Required (Tonnes)						
6% PC						
4% PC						
6% PC						
6% PC						
6% PC						
CONTRACTED (Tonnes)						
OPEN (Tonnes)						
Test Positions Required						
Test (LS)						
Test (LS)						
CONTRACTED (Tonnes)						
OPEN (Tonnes)						

Source: NSPI, *Direct Evidence*, Figure 2.4

TABLE 25
NSPI's PRICE PROJECTIONS FOR 2007 UNCOMMITTED VOLUMES

Commodity	Volume (tonnes)	Sulphur Content (Wt.,%)	Heat Contents (Btu/Lbs)	Commodity (C$/tonne FOB)
Imports				
Low Sulphur Coal[a]				
Mid Sulfur Coal				
High Sulphur Coal				
Petroleum Coke[b]				

[a] f.o.b. Load Port
[b] c.i.f. to the discharge port.

Source: NSPI, *Direct Evidence*, p.57, Figure 2.10

NSPI uses a wide variety of solid fuel types from LS coal to high sulfur coal and petcoke in its five solid fuel units. The variety of fuels used offers some opportunities for a blending and thus to reduce costs for presently high priced fuels, such as petcoke. Table 26 lists NSPI solid fuel deliveries and consumption as well as the 2007 delivered prices assumed for the Rate Case.

TABLE 26
NSPI 2007 SOLID FUEL DELIVERIES AND CONSUMPTION
(000's) tonnes)

	DELIVERIES		CONSUMPTION	
	Volumes	**C$/mmBtu**	**Volumes**	**C$/mmBtu**
Lingan				
LS				
MS				
HS				
Domestic				
Petcoke				
Total				
Pt. Aconi				
LS				
MS				
HS				
Domestic				

	DELIVERIES		CONSUMPTION	
	Volumes	C$/mmBtu	Volumes	C$/mmBtu
Petcoke				
Total				
Trenton 5				
LS				
MS				
HS				
Domestic				
Petcoke				
Total				
Trenton 6				
LS				
MS				
HS				
Domestic				
Petcoke				
Total				
Pt. Tupper				
LS				
MS				
HS				
Domestic				
Petcoke				
Total				
All Plants				
LS				
MS				
HS				
Domestic				
Petcoke				
Total				

Source: UARB – IR-17, Attachment 2; UARB IR-84, Attachment 1

The utilization of futures prices to form an estimation of spot prices and contract prices at some future point in time is endorsed by NSPI's fuel expert, EVA (NSPI, *Direct Evidence*, pp. 20-21, Figure 2.3.5). This methodology establishing future prices for the 2007 test year for the Rate Case assumes that future prices are somehow predictive of actual spot prices at some future point of time. As was indicated above, analysis has shown this not to be the case for oil and natural gas. The fallacy of using future prices as a guide to spot market coal prices in the future can be demonstrated.

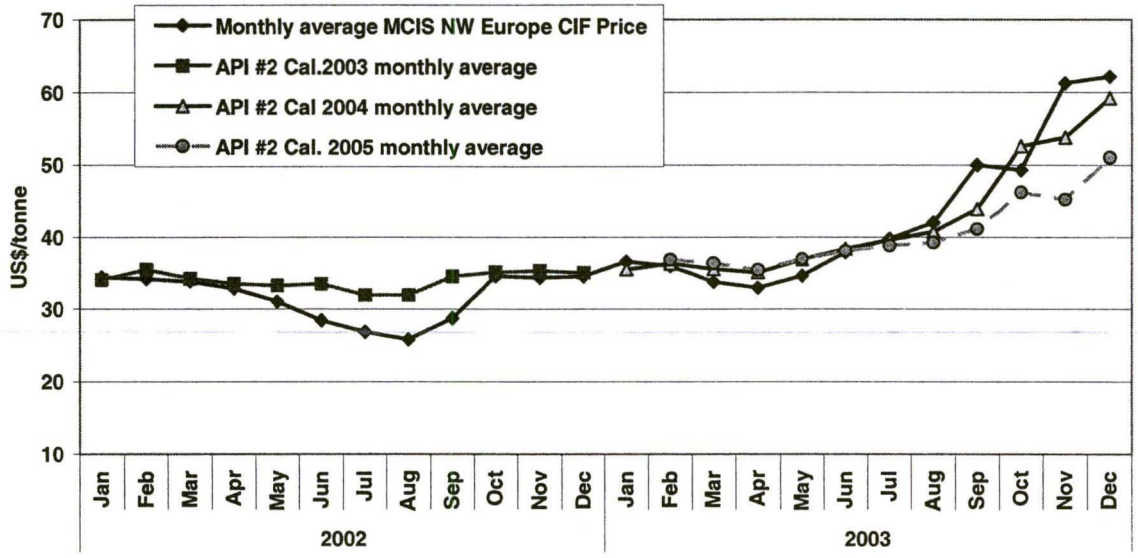
In the previous two NSPI Rate Cases, there has been much discussion of NSPI's failure to take action in 2002 and 2003 to lock in long-term contracts at a time when coal prices were low. In fact, the Board based its March 10, 2006 decision disallowing C$15.7 million of NSPI coal costs for 2006 on the evidence of the experts that there was a continuing harm in 2006 that resulted from NSPI's

failure to implement a portfolio strategy commencing in 2002 (*Board Decision*, pp. 49-52).

In May 2002 [redacted] had made an offer of a four-year contract with low-fixed prices to NSPI. Failure to accept this offer and to enter into long-term commitments in 2002 and early 2003 has been the subject of considerable testimony in both the 2005 and 2006 Rate Cases. A good test, therefore, of the efficacy of futures prices to predict the key changes in price direction of the market, would be to examine the futures prices in 2002 and 2003 to determine if NSPI, with aid of monitoring futures prices, would have been able to predict the turn in the market in September and October 2003, which led to a rapid run-up in coal prices in early 2004.

In 2002 TFS API #2 Calendar 2003 traded very close to the spot price in 2002. When 2002 spot prices fell in July and August, the futures prices for 2003 declined as well, demonstrating that in fact futures prices are heavily influenced by current market conditions. When spot prices began to increase in September and October of 2002, the 2003 futures contract rose as well from about US$32.00/tonne to US$35.00/tonne. The 2004 and 2005 futures contracts traded during the course of 2003 were not much more helpful in terms of predicting the actual future spot prices. It opened in January 2003 at about US$35.00/tonne and began a slow upward climb together with spot prices in May through August. In September when spot prices took a sudden jump, the calendar 2004 contract jumped as well. The phenomenon continued throughout the period October through December. The average 2004 futures price in December 2003 was just above US$59.00/tonne, well below what spot prices in fact turned out to be in 2004. The calendar 2005 futures contract traded in 2003 was even less helpful. It also began to rise in the period from June through August, but its increase during the rapid rise in spot prices in September through December was much slower than that of the calendar 2004 contract. As a consequence, the contract was in significant backwardation (Figure 24). The futures market, therefore, was not helpful in predicting the major turn in coal prices in the past decade, and in fact an analysis of futures prices in the 2003 to 2004 period indicates that the price in any given month simply reflected market conditions in the spot market. Thus, it is with coal as well as for oil and natural gas, futures prices are not very reliable in predicting future prices in the physical market.

FIGURE 24
COMPARSION OF NW EUROPE SPOT PRICES AND FUTURES PRICES FOR API #2 CAL. 2003, CAL. 2004, AND CAL. 2005 IN 2002 AND 2003

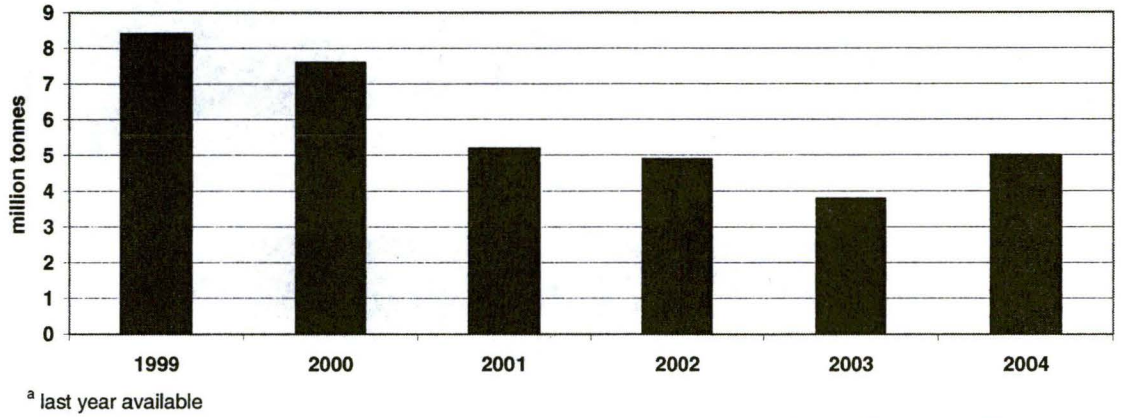


Source: *McCloskey's Coal Report;* Traditional Financial Services

Moreover, it is to be expected that for storable commodities such as crude oil petroleum products and coal, the future price is generally higher than the spot price at any given time, since the future price contains as well the cost-of-carry; that is, the cost incurred while the commodity is stored awaiting delivery at some time in the future. This is a well documented phenomenon of futures prices and explains why in most instances futures prices for storable commodities are in contago. [38] In the coal world it has been argued that the much greater use of futures contracts by European utilities in the last five years has enabled them to maintain much lower stockpiles, and thereby pass on the cost-of-carry to others. In the European utility industry, unlike the United States, there is very little information about stockpiles at individual utility power plants. Germany collected the data; however, such collection ceased in 2005. The evidence available suggests that since 2000 German utilities have sharply reduced their inventory at power plants even as their transactions in the paper market significantly increased (Figure 25).

[38] Franklin R. Edwards and Cindy W. Ma, *Futures and Options*, Singapore 1992, pp. 80-84

FIGURE 25
GERMAN UTILITY STEAM COAL STOCK PILES 1999-2004[a]

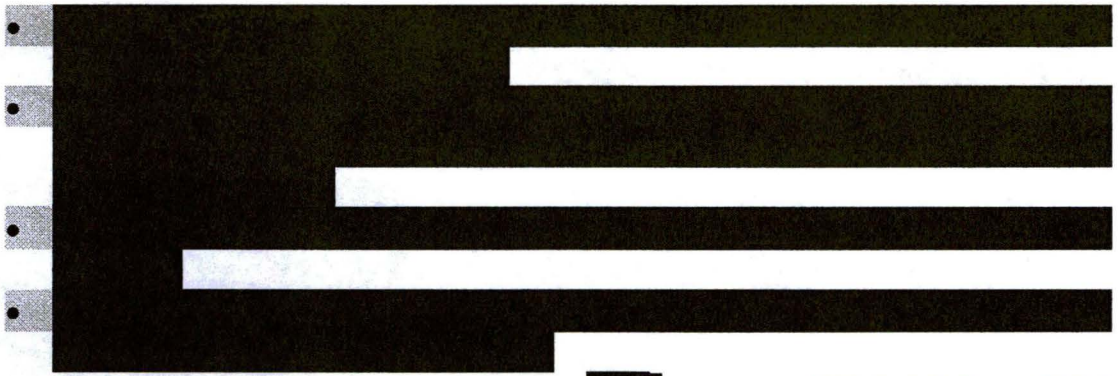


[a] last year available

Source: Statistisches Bundesamt.

Since the beginning of September, NSPI has entered into several agreements that have the effect of lowering projected solid fuel prices for 2007 below the levels envisaged in the Rate Case. The first of these contracts is a domestic coal contract [redacted] The coal is for delivery to [redacted]. This is a contract that had been under negotiation for a significant part of 2006. As part of the negotiation [redacted] EVA was retained, [redacted]

The impact of the [redacted] coal contract is to reduce the cost of solid fuels for the test year 2007 by C$5.5 million:



- Total solid fuel cost reduction from [redacted] contract: C$5,543,287 or C$5.5 million.

The NSPI data room also contained an unsolicited proposal to supply coal from to plant. fuel saving of approximately C$0.25 million.

- Solid fuel cost reduction from coal: C$273,239 or C$0.25 million.

In a further transaction since the filing of the 2007 Rate Case on September 21, 2006, NSPI entered into a coal contract with for the delivery of The uncommitted volume assumptions for the 2007 Rate Case assume that a comparable quality high sulfur coal would have an f.o.b. price of . This amounts to an f.o.b. saving of /tonne or C$566,000. The calculation is as follows:

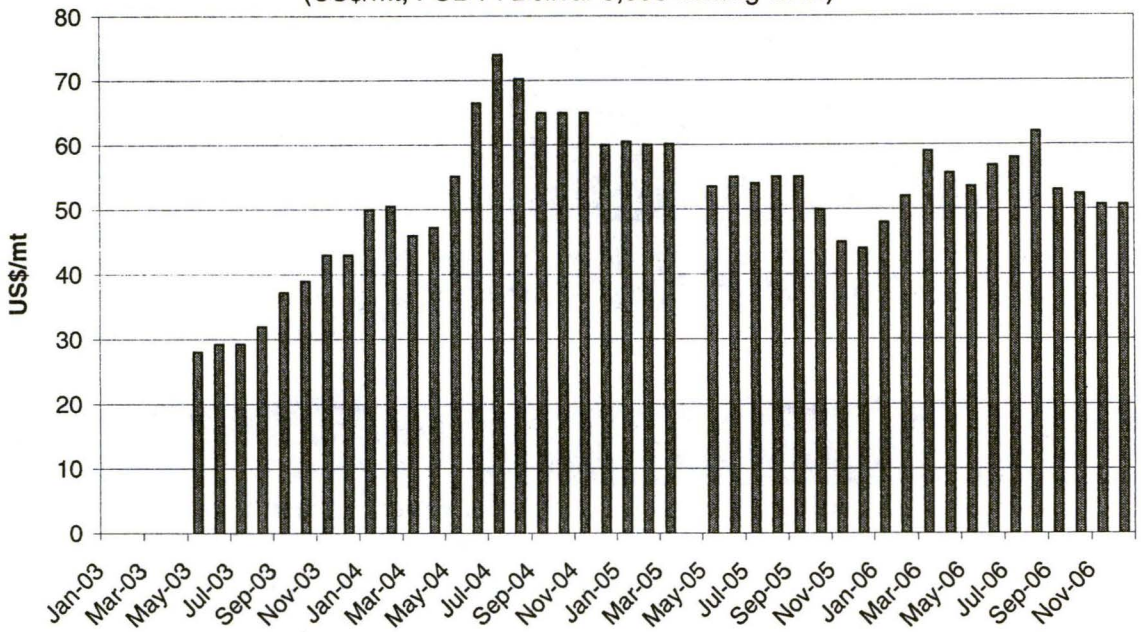
- = C$566,400.

However, the coal is to be blended with that the total savings from this process over the 2007 forecast is C$1.22 million or more than double the amount calculated above.

Since the filing of the Rate Case, NSPI has also exercised the option After softening at the end of 2005 and early in 2006, Colombian coal firmed in mid-year, however, towards the end of 2006 coal going to both North America and into ARA fell significantly (Figures 26 and 27).

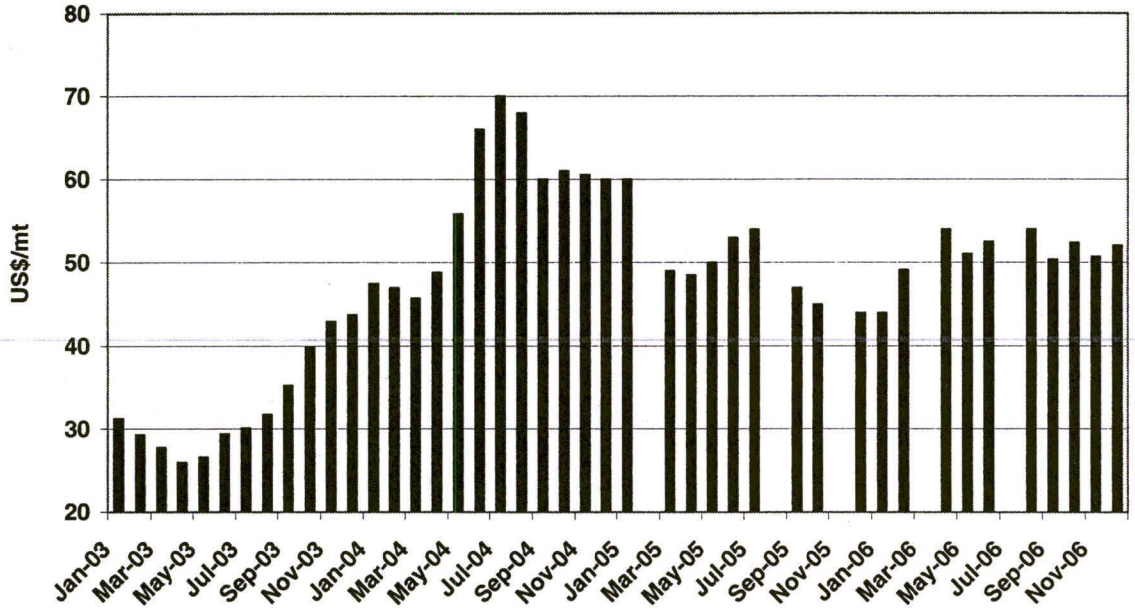
[redacted] this would mean a saving from the 2007 projected solid fuel price of [redacted] approximately C$0.7 million.

FIGURE 26
McCLOSKEY'S COLOMBIAN SPOT PRICES TO THE U.S.
(US$/mt, FOB P. Bolivar 6,300 kcal/kg GAR)



Source: *McCloskey's Coal Report*

FIGURE 27
McCLOSKEY'S COLOMBIAN SPOT PRICES TO ARA
(US/mt, FOB P. Bolivar 6,300 kcal/kg GAR)



Source: *McCloskey's Coal*

[redacted] still leaves about [redacted] tonnes of low sulfur coal according to Figure 2.10 in the *Direct Evidence* (p. 57). For the pricing of this one can look to NSPI's coal consultants whose forecasts for 2007 Colombian prices are in almost complete agreement. The Hill & Associates 2006 coal study concludes that prices are likely to fall: "As supply catches up with demand going forward, coal markets will ease and there will be downward price pressure. Both metallurgical and thermal coal prices are slowly softening". [39] Hill and Associates has a price of approximately [redacted] While EVA was not requested specifically to prepare a price forecast for NSPI, [redacted] it is noted that EVA had published a short-term price forecast for 2006 and 2007. This had a 2007 price of [redacted] /tonne for an [redacted] Btu/lb product going from Colombia to Europe. Given that the differential between this quality of coal going to Europe and going to North American locations in 2006 averaged about [redacted] /tonne higher, a reasonable number to extract from these forecasts for 2007 would be [redacted] /tonne. Based on the figures shown for the [redacted] tonnes of un-contracted LS coal in the *Direct Evidence* (p. 57, Figure 2.10), the assumed f.o.b. Colombia port price in 2007 is [redacted] /tonne. This would mean a saving of [redacted] /tonne on [redacted] tonnes or US$2.2 million, equivalent to C$2.6 million.

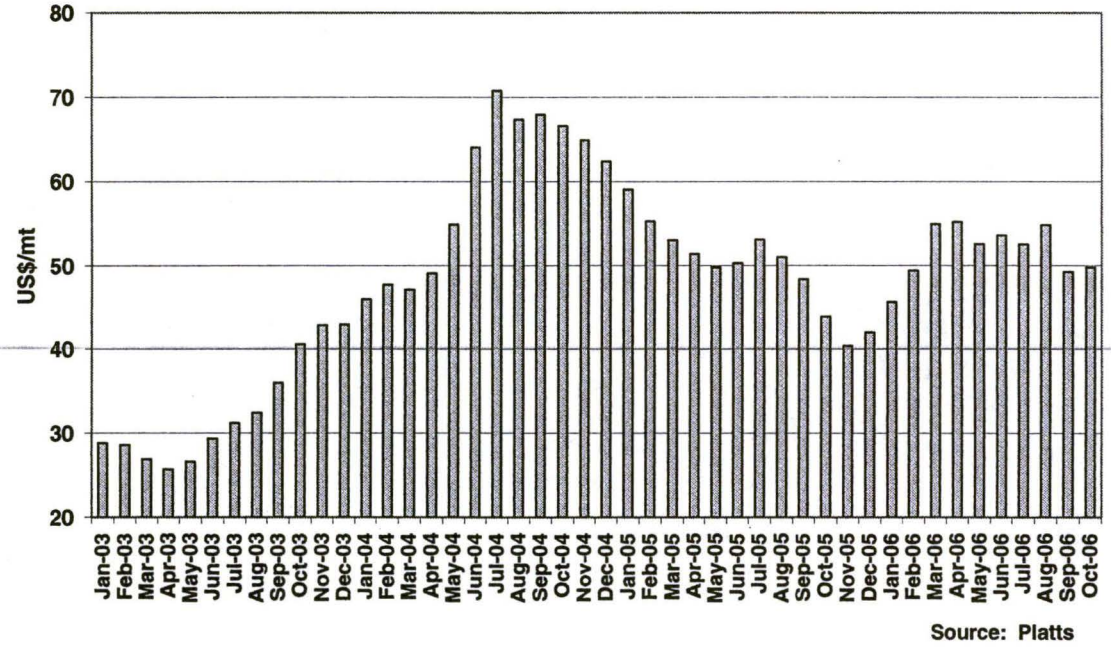
[39] Hill & Associates, 2006 Edition, *International Coal Trade: Supply, Demand & Prices to 2015*, p. E-1

NSPI also has an option for 2007 on its [redacted] contract. [redacted] NSPI issued an RFP [redacted]. The results of this solicitation are unknown as of the time of writing. However, NSPI indicated that it would decide on whether or not to exercise the [redacted] option depending on the results of this solicitation. There is thus further potential for additional reductions from the proposed 2007 solid fuel budget.

Among the long-term contracts concluded prior to the filing of the 2007 Rate Case, one stands out as raising particular concerns: [redacted]

[redacted] commenting on the process notes that no formal bid was conducted for a long-term contract, but that indicative pricing information was sought [redacted]

FIGURE 28
PLATTS 90-DAY FORWARD BENCHMARK FOR FOB P. BOLIVAR
(6,300 cal/kg)



Source: Platts

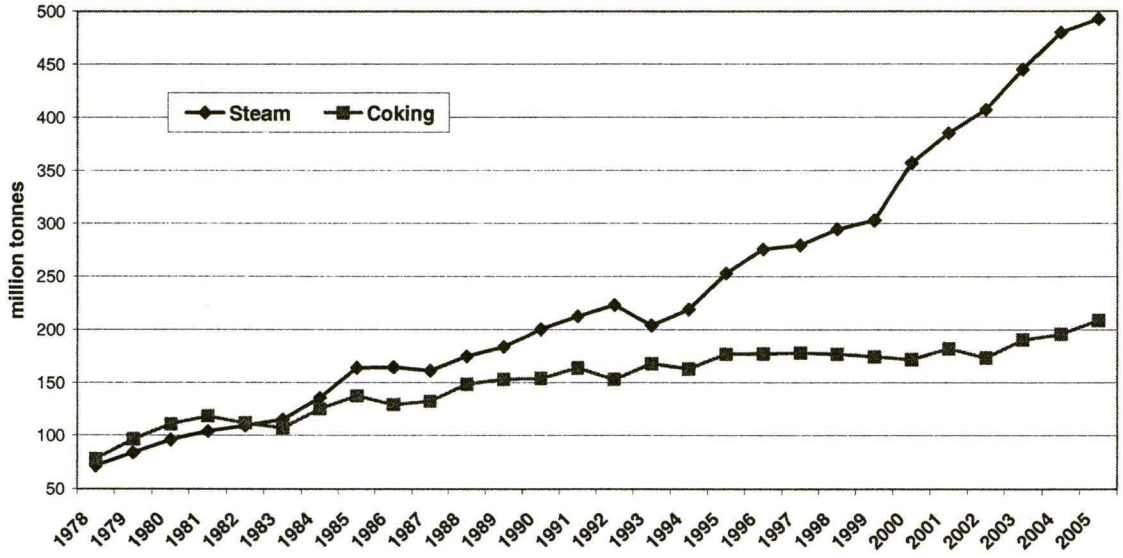
There are several things that are disturbing here. The total volume finally negotiated [redacted] was some [redacted] tonnes with a total value over the [redacted] period of [redacted] million. This is an enormous commitment to enter into simply on the basis of negotiations, and proper form requires that there should have been a tender for a [redacted] contract of this magnitude. Moreover, NSPI has committed a major portion of its low sulfur coal supplies to a single mine which had labor problems in 2006. Certainly based on today's prices and those forecasted at the time by EVA, it appears that the contract is over market by some [redacted] /tonne. In effect, NSPI is now exercising its option and is likely to only take [redacted] tonnes of the [redacted] contract during 2007. The total that the contract is therefore over [redacted], is approximately US$4.8 million or C$5.7 million.

Developments in the Atlantic Steam Coal Market

2005 was characterized by a significant reduction in the growth rate in the international seaborne hard coal market, particularly as regards steam coal. The growth from 2003 to 2004 in seaborne steam coal had been 6.9% and 7% for

coking coal. The growth between 2005 and 2006 showed a distinct slowing in the steam coal rate of increase, but a rise in coking coal. The 2005 seaborne steam coal market was 701.7 million tonnes, of which 492.7 were steam coal and 209.0 million tonnes were coking coal (Figure 29). The increase in steam coal was at an annual rate of 4%, well below the long-term trend of the last two and a half decades of 7.5%. On the other hand, the increase in coking coal was 9.1%, well above the long-term rate of increase of 2.7% per year.

FIGURE 29
THE GROWTH OF THE SEABORNE COAL TRADE, 1978-2005



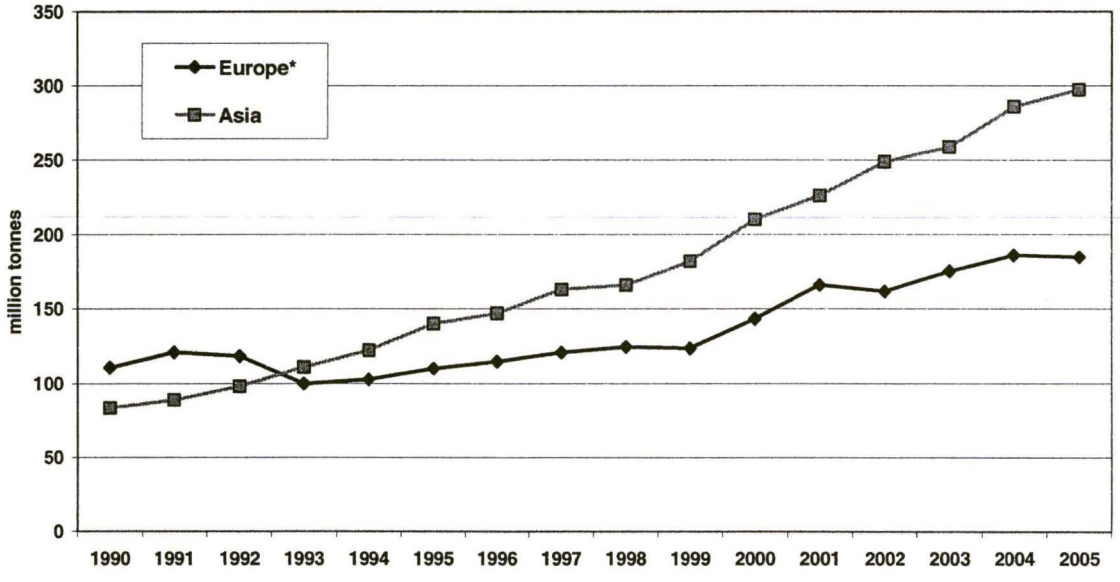
Source: *IEA/OECD Coal Statistics*

Both Europe and Asia showed anemic steam coal import growth by comparison to historic trends. Asian steam coal imports increased from 279.9 million tonnes in 2004 to 284.0 million tonnes in 2005. The low rate of increase was due primarily to a decline in Japanese imports from 120.0 million tonnes in 2004 to 114.3 million tonnes in 2005. This pushed the total Asian numbers lower.

European steam coal imports to OECD Europe showed a slight decline from 2004, falling from 185.0 million tonnes in 2004 to 184.8 million tonnes in 2005 (Figure 30). The essentially flat nature of European coal imports reflects the decline in recent years in coal-fired electric generation in OECD Europe (Figure 31). There are a number of factors that impact this, including the European CO_2 emission trading system, which was implemented beginning January 2005 and the increased use of renewables in the generating sector, which is having a

growing impact particularly in certain major coal importers including Germany, Spain and Denmark.

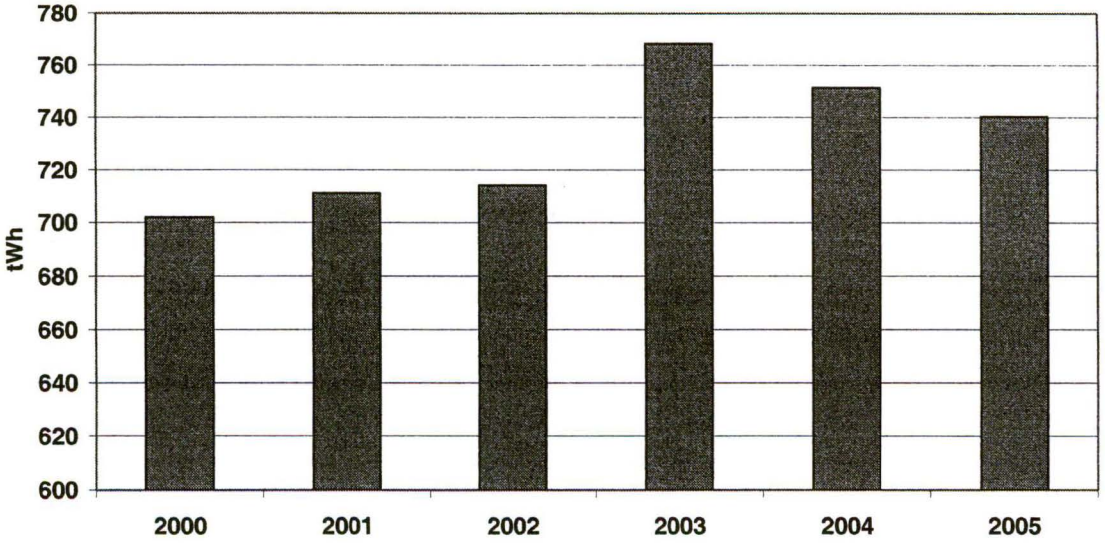
FIGURE 30
SEABORNE STEAM COAL IMPORTS TO ASIA AND EUROPE, 1990-2005



*Includes Turkey and Non-EU eastern Europe

Source: IEA/OECD Coal Statistics

FIGURE 31
ELECTRICITY GENERATION BY COAL IN EU-15, 2000-2005
(tWh)



Source: IEA/OECD, *Energy Balances of OECD Countries*.

Imports of steam coal by the EU's major steam coal importers in 2005 was up slightly by 1.0 million tonnes. Imports fell in the Netherlands, Italy, Belgium, Denmark, Finland and Germany. However, they increased substantially in the UK, which offset the declines in the other countries. The increase to 37.4 million tonnes in the UK was driven primarily by record high natural gas prices and gas shortages, which forced an increase in coal-fired generation. The addition of new pipeline capacity has eased the UK's gas shortage (Table 27).

TABLE 27
MAJOR EU STEAM COAL IMPORTERS, 2001-2005
(million tonnes)

	2001	2002	2003	2004	2005
Germany	41.6	31.6	29.4	32.1	31.0
United Kingdom	28.2	22.5	25.4	29.8	37.4
Spain	15.7	21.1	18.2	20.4	21.2
Netherlands	23.6	17.6	17.1	17.6	15.4
Italy	12.7	14.1	15.9	19.6	18.4
France	9.4	12.8	10.2	12.9	13.7
Belgium	9.1	10.4	6.2	6.2	5.2
Denmark	6.9	6.3	9.5	7.6	6.0
Portugal	4.8	5.7	5.3	5.2	5.3
Finland	4.7	4.5	8.9	6.9	3.3
Ireland	3.2	2.9	2.5	2.8	2.9
Poland	2.1	2.0	2.1	1.8	2.8
Slovak Republic	1.9	1.6	1.8	2.0	3.3
Total	**163.9**	**153.1**	**152.5**	**164.9**	**165.9**

Source: IEA/OECD Coal Statistics

Over the entire EU's generating structure the impact of pricing in CO_2 emissions is very evident in the plans for new generation and in the plant that is currently under construction. The *Power in Europe* Survey of Plants Under Construction as of August 2006 shows that some 23,185 mW of gas CCGTs are under construction, primarily in Italy, Spain and Germany. Farther out the *Power in Europe* plant project tracker shows approximately 100,000 mW of new gas CCGTs and very little coal apart from Germany. The latter is a remarkable exception in the entire picture of new plants for Europe. As of the beginning of November

2006, German utilities had announced and were largely in the process of permitting and signing EPC contracts for some 15,420 mW of new coal-fired generation. Most of this is hard coal, although three of the plants (Boxberg 1x 670 mW; Neurath 2 x 1,050 mW and Profen 1 x 660 mW) are domestic brown coal plants (Table 28). A difference between future generating plants for Germany and the rest of the EU has been widely noted and is largely attributable to the distinctive nature of the German National Allocation Plan (NAP). The first NAP, which has now been crystallized into the law governing CO_2 trading in the period 2005-2007 (ZuG 2007) allowed new coal-fired plants to receive free emissions for the first eighteen years of their life.

TABLE 28
PROPOSED NEW COAL-FIRED POWER PLANTS IN GERMANY

Online by December 2012		
Site	**mW**	**Developer**
Boxberg	670	Vattenfall Europe
Moorburg	1,640	Vattenfall Europe
Walsum	750	STEAG/EVN
Herne	750	STEAG
Neurath	2,100	RWE
Hamm	1,500	RWE
Lünen	800	Trianel
Datteln	1,100	E.ON
Bremen	800	SWB/Essent
Karlsruhe/Heilbronn	750	EnBW
Saarbrücken (?)	750	STEAG/EnBW
Ingelheimer Aue	750	Kraftwerke Mainz-Wiesbaden
Wilhelmshaven/Stade	800	Electrabel
Berlin	800	Vattenfall Europe
Profen	660	MIBRAG
Lübmin	800	WV Energie
Subtotal hard coal	**11,990**	
Subtotal brown coal	**3,430**	
Subtotal all coal	**15,420**	
No Date Yet Decided		
Südweststrom	750	Südweststrom
Hannover	1,100	E.ON/Hannover
Staudinger	1,100	E.ON
Lübmin	1,600	WV Energie
Subtotal	**4,450**	
Total	**19,970**	

Source: ISIS

The NAP-2, which was submitted to the European Commission on July 4, 2006, was only slightly less generous, allowing for fourteen years of free emission allocations. The rationale for the law was to encourage the speedy turnover in the existing fleet of older plants replacing old coal-fired units with new super critical units that burn less fuel and emitted less CO_2. To that degree, most of the construction that has been proposed in Germany replaces existing plant. However, the European Commission, recognizing that locking up CO_2 commitments for this period of time to new coal-fired generation would largely prevent Germany from making further CO_2 reductions after 2013 has, in a decision of November 28, 2006, rejected the German NAP-2 primarily because of its provisions granting free CO_2 to new generation for fourteen years. It is too soon to know what the impact on coal-fired generation will be. There has been much grumbling by the utilities and threats to cancel the proposed construction of new coal plants. In addition, the German government itself has expressed much unhappiness with the European Commission decision. It has begun a lobbying effort and has even threatened to take the Commission to court over its decision.

Other than the German exception noted above, there is very little interest in incremental coal-fired generation within the EU. In Italy Enel continues with its plans to convert a number of stations from fuel oil to coal. These include 3 x 660 mW at Torrevaldaliga Nord where construction is already underway and a fuel oil-fired unit at Porto Tolle in the Veneto region. However, in all of its projects, Enel faces substantial local opposition. There are also two new coal plants in the early stages of planning for the Netherlands, a 1,100 mW unit proposed by E.on for Maasvlakte which would replace existing older capacity on the E.on system, and a 1,200 mW IGCC proposed by Nuon at Eemshaven which is still in the early stages of the planning process and is scheduled to burn biomass as well as coal.

In the UK there are also proposals for IGCC plants, one of 800 mW by Progressive Energy in the Tees Valley, another by E.on at Killingholme and a further plant, this one super critical, proposed by RWE Npower for Tilbury in the Thames Estuary. The UK proposals are all still at an early stage and are significantly dependent upon firming up the development of carbon capture and sequestration. The long-term outlook for Europe thus in a CO_2 constrained world is for more gas and less coal, particularly since gas has the advantage of being able to respond quickly to changes in generation from the growing volume of onshore (and in the future offshore) wind projects and other renewables, such as biomass.

Coal imports into the United States, primarily from Colombia, continued to increase in 2005 to a level of 26.1 million tonnes (Table 29). One factor contributing to imports in 2005 was a major derailment contributing to the poor performance of the rail lines out of the Powder River Basin heading eastwards. However, problems with the rail system have not affected delivery out of the Powder River Basin in 2006 and rail service appears now to be restored to normal. While the capacity expansions in Colombia seem to be primarily targeting the United States, many utilities have announced plans to meet the Federal Clean Air Interstate Rule by the installation of scrubbers. Several of the coastal or near coastal plants that have announced scrubbers are significant importers of South American coals. For example, Progress Energy Florida, Inc. has historically reduced its SO_2 emissions through a mixture of Central Appalachian and South American coals. Once scrubbers are installed it proposes to use more Northern Appalachian and Illinois Basin coals. Similarly, Southern Company subsidiary, Gulf Power, has proposed to scrub its Crist, Daniel and Smith plants. The plants have taken some imported coal in the past and this is expected to change once the scrubbers are installed.

TABLE 29
U.S. STEAM COAL IMPORTS, 2000-2005
(000's tonnes)

	2000	2001	2002	2003	2004	2005
Australia	152	287	140	100	86	67
Canada	155	166	203	441	763	536
Poland	-	466	110	0	68	70
U.K.	-	69	0	1	40	1
Other OECD	6	41	29	49	103	1
PRC	18	100	56	136	133	18
Colombia	6,928	10,139	8,351	14,042	15,115	19,246
Indonesia	651	801	1,746	1,910	1,979	2,239
South Africa	-	400	70	71	31	70
Russia	-	199	79	62	239	357
Ukraine	-	-	0	0	56	55
Venezuela	1,813	3,026	3,039	4,196	4,024	3,389
Other	1	88	30	50	11	95
Total	**9,724**	**15,780**	**13,853**	**21,058**	**22,648**	**266,144**

Source: IEA/OECD Coal Statistics

Asia's seaborne steam coal demand growth has historically been dominated by three giant importers: Japan, South Korea and Taiwan. In 2005 Japanese imports declined, South Korea stayed approximately the same, and substantial growth

was only registered in Taiwan. However, the lesser importers, including China and India, registered significant gains in steam coal imports (Table 30).

TABLE 30
MAJOR ASIAN STEAM COAL IMPORTERS, 2001-2005
(million tonnes)

	2001	2002	2003	2004	2005
Japan	75.0	91.8	100.7	120.0	114.3
South Korea	42.3	44.4	51.4	57.2	56.1
Taiwan	40.3	42.6	45.8	51.6	56.8
People's Rep. of China	2.1	10.1	8.5	11.9	18.2
Hong Kong (China)	7.9	7.8	10.7	10.7	10.8
Thailand	4.9	5.6	5.1	5.3	8.5
Malaysia	4.5	5.5	7.5	10.7	9.0
Philippines	7.8	3.4	6.4	7.0	6.1
India	10.1	12.0	8.7	11.6	17.6
Total	**194.9**	**223.2**	**244.8**	**286.0**	**297.4**

Source: IEA/OECD Coal Statistics

The position of China continues to be crucial for the supply and demand balance in Asia. In 2005 exports of steam coal declined to 65.7 million tonnes from 80.2 million tonnes in 2004 (Table 31). Indications for 2006 are that exports will fall further to approximately 53 million tonnes. [40] The September 2006 thermal coal forecast from ABARE has a different projection with Chinese steam coal exports at 60 million tonnes in both 2006 and 2007. The BHP Billiton forecast is more likely to be correct. Imports also continue to rise. However, definitions vary with many classifying anthracite as a steam coal. Figure 32 contains an estimate by BHP Billiton drawn from current Chinese customs statistics and it projects Chinese steam coal imports rising to 9 million tonnes in 2006 from 6 million tonnes in 2005. This data appears to exclude all anthracite and soft coking coal (Figure 32).

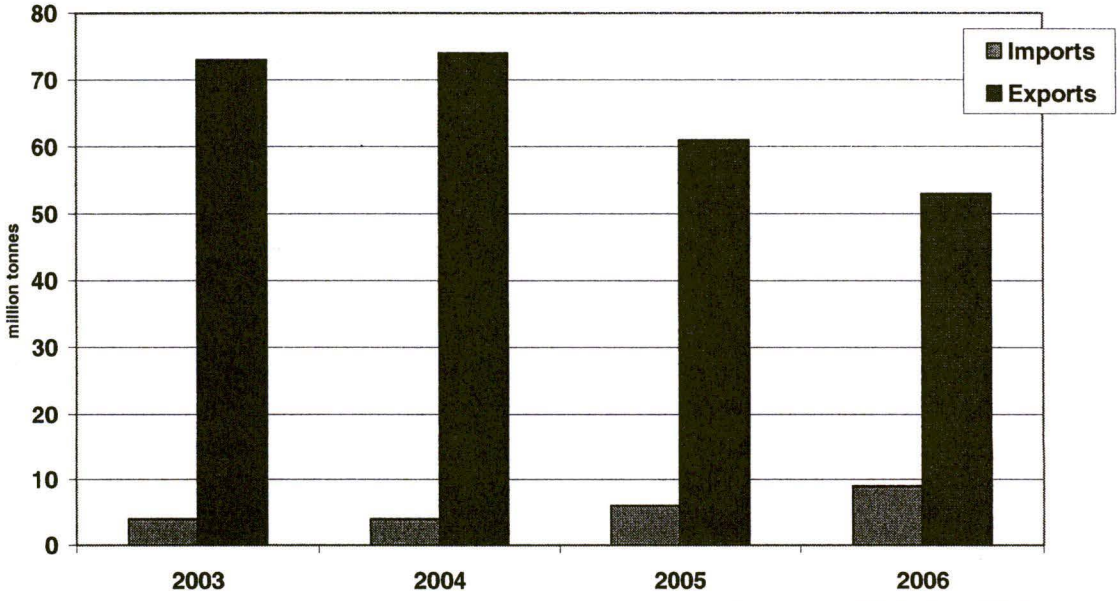
[40] Charles Liu, BHP Billiton, at a conference in Shanghai, December 4, 2006

TABLE 31
CHINA: HARD COAL EXPORTS AND IMPORTS: 1995-2005

	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005
Exports	(000s Tonnes)										
Steam Coal	24,062	30,647	26,117	27,225	32,191	48,578	74,976	70,123	79,839	80,152	65,724
Coking Coal	4,555	5,837	4,602	5,066	5,246	6,470	11,471	13,764	15,329	6,446	6,062
Imports											
Steam Coal	1,281	2,853	1,879	1,883	1,196	1,572	2,103	10,088	9,028	11,859	18,150
Coking Coal	354	364	134	175	484	547	430	1,684	3,215	6,987	7,193

Source: International Energy Agency

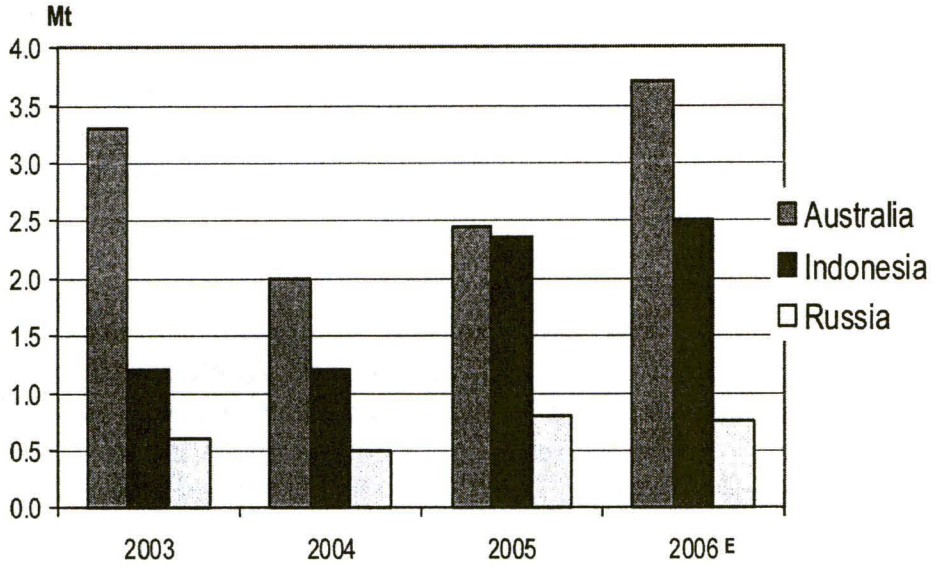
FIGURE 32
CHINA STEAM COAL EXPORTS & IMPORTS 2003-2006



Source: China Customs Statisties; China State Coal Safety Administration; BHP Billiton, Dec, 2006.

Most of the increase in steam coal imports to China is from Australia and Indonesia, although the Australian coal volumes from the official statistics appears to be significantly greater than Indonesian imports, discussions with Indonesian suppliers suggest that there is considerable volume of coal from illegal mines in Indonesia that is suspected of moving into China and is not necessarily being captured by official Chinese statistics (Figure 33).

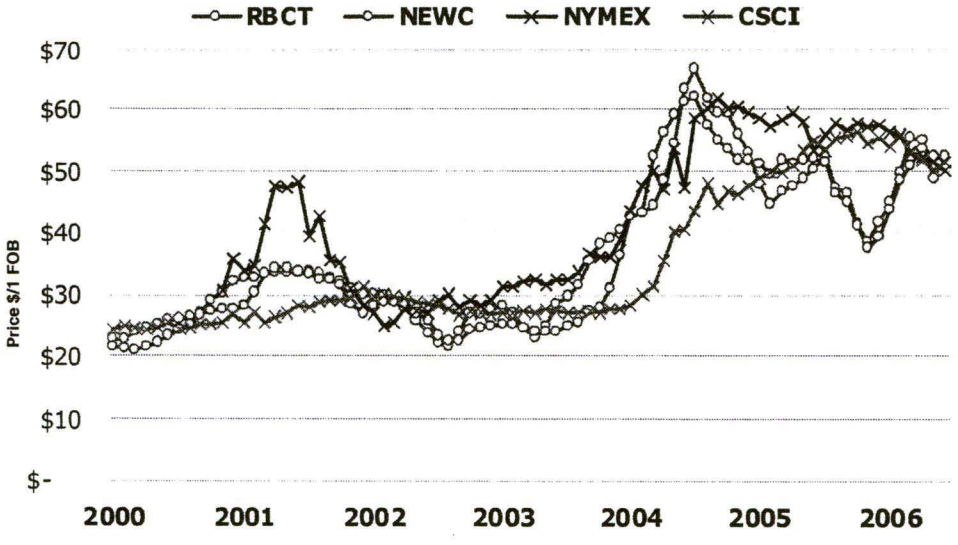
FIGURE 33
CHINA STEAM COAL IMPORTS BY ORIGIN



Source: China Custom Statistics.

Exports are anticipated to continue to decline and imports to increase. However, not at rates that will destabilize the Pacific market. China's own coal production continues to ramp up steeply with it expected to exceed 2.2 billion tonnes in 2006. However, much of the growth in generation is in coastal areas, particularly along the southern coast of China where it is easily accessible to seaborne imports. Moreover, Chinese domestic steam coal prices have been largely liberalized, and in recent years Chinese steam coal prices have tended to track, in a general sense, movements in international steam coal prices (Figure 34).

FIGURE 34
RELATIONSHIP OF CHINESE AND INTERNATIONAL COAL PRICE INDICES



Source: BHP Billiton.

However, the changing balance between exports and imports in China is more than offset by a major jump in production capability in Indonesia. In 2005 Indonesia's first generation mines produced some 116.9 million tonnes. In 2006 the plans of the mining companies suggest 139.4 million tonnes, with a further expansion in 2007 to 146.1 million tonnes. [41] The September ABARE report has a more modest steam coal export number of 136.5 million for Indonesia in 2006 and 146.5 million in 2007. [42]

While short-term Indonesia has dramatically increased its export capacity, longer-term it appears that Australia will significantly increase its ability to export steam coal to both the Pacific market and Atlantic markets. A project survey earlier in 2006 identified some 80 million tonnes per year of new steam coal capacity, much of which already is committed and is likely to come online in the next half decade (Table 32). ABARE, in its September forecast, is projecting that steam coal exports from Australia would increase from 107.6 million tonnes in 2005 to 115.5 million tonnes in 2006 and further to 120.5 million tonnes in 2007.

TABLE 32
NEW AUSTRALIAN STEAM COAL EXPORT CAPACITY UNDER DEVELOPMENT

Producer	State	Mine(s)	Approx. incremental Capacity (mt)
Rio Tinto	NSW	Mt Pleasant, Maules Creek	8-10
Anglo/Mitsui	Qld	Dawson complex	3.0
	NSW	Kyuga, Saddlers Creek	2-3
Xstrata	NSW	Glendell, Mt Owen, others	5-7
		Rolleston	8.0
BHPB	NSW	Mount Arthur	3.0
Centennial	NSW	Anvil Hill, Airly	7.0
Excel Coal	NSW	Wambo, Wilpinjong	15.0
Donaldson	NSW	Donaldson	2-3
Macarthur	Qld	Monto, West Rolleston	4-5
Ensham	Qld	Ensham underground	5-6
Sojitz/Korea Resources	NSW	Wyong	3-4
Idemitsi	NSW	Boggabri	4-5
CS Energy	Qld	Kogan Creek	2-3
Bloomfield	NSW	Bickham	2-3
Whitehaven	NSW	Belmont	1-2
TOTAL			circa 87

Source: *McCloskey's Coal Report*, January 13, 2006. p.21

[41] *International Coal Report*, June 12, 2006. p. 7
[42] ABARE, September 2006 Thermal Coal Forecast, p. 4

Australian miners have in the last several years been limited in their ability to respond to higher demand in the international market by infrastructure, both rail and port, constraints. Many of these difficulties are now being overcome through a massive infrastructure investment program which is expected to put in place improved rail and port facilities valued at US$3.6 billion by 2010. For example, the Sandgate rail grade separation project in the Hunter Valley is scheduled to be completed early in 2007 and will increase rail capacity by some 60 million tonnes to 165 million tonnes per year. As well, in mid-2006 the Wambo coal rail terminal was completed, allowing better rail access to Newcastle. In Newcastle Harbor the Kooragang Island coal loader is being expanded by 15% (or 13 million tpy) to 102 million tonnes in 2007. Capacity expansion to the Gladstone port from 45 million tonnes to 67 million tonnes a year and the Hay Point coal terminal by 4 million tonnes are scheduled to be completed in 2007. The upgrading of terminal and rail capacity is in fact proceeding at such a pace that some coal executives have considered the level of investment and the number of projects as overkill (Table 33).

TABLE 33
COMMITTED AND PLANNED AUSTRALIAN PORT CAPACITY EXPANSIONS

Ports	2005 Actual Throughput	Spare and Committed Expansion	Total in 2007	Additional Port Proposals	Proposed Capacity by 2010
Abbot pt	13.2	1.8	15.0	+35.0	50
DBCT	50.7	9.7	60.4	+24.6	85
Hay Point	35.2	8.8	44.0	+13.0	57
Wiggins Is	-	-	-	+20.0	20
RG Tanna	40.8	27.2	68.0	-	68
Barney Pt	5.5	1.5	7.0	-	7
Brisbane	3.4	0.6	4.0	-	4
Total Qld	**148.8**	**49.6**	**198.4**	**+92.6**	**291**
PWCS	80.0	25.0	105	+45	150
PKCT	10	6	16	0	16
Total NSW	**90**	**31**	**121**	**+45**	**166**
Total Australia	**238.8**	**80.6**	**319.4**	**137.6**	**457**

Note: Port proposals are subject to commitment by coal shippers, so all may not occur as announced.

Source: XStrata Coal, April 3, 2006.

The buildup in export capacity in the Pacific in 2005 due to high shipping rates did not spill over into the Atlantic as it has in some past years. Total Pacific origin coals moving into the Atlantic market in 2005 were only 23.9 million tonnes, the lowest since the year 2000. This was primarily due to declines in Australian tonnages (5.2 million in 2005 compared to 7.9 million in 2004) and a

continued decline in Chinese tonnage. Indonesian coal into the Atlantic, however, increased in 2005 to 15.6 million tonnes (Table 34). As freight rates moderate, Australian coal is expected again to return in significant volumes to the Atlantic. In the fourth quarter of 2006 there were persistent reports in the market of Australian exports to Europe increasing significantly. [43] One major Australian supplier actually announced two contracts to supply European customers. Excel Coal indicated it had a contract for 3.57 million tonnes over three years to 2009 and a second contract for more than 2 million tonnes over four years to 2010. The growing surplus of steam coal in the Pacific is thus anticipated to increasingly play a role in pricing in the Atlantic market in 2007.

TABLE 34
MOVEMENT OF PACIFIC ORIGIN COALS TO THE ATLANTIC MARKET
1995-2005

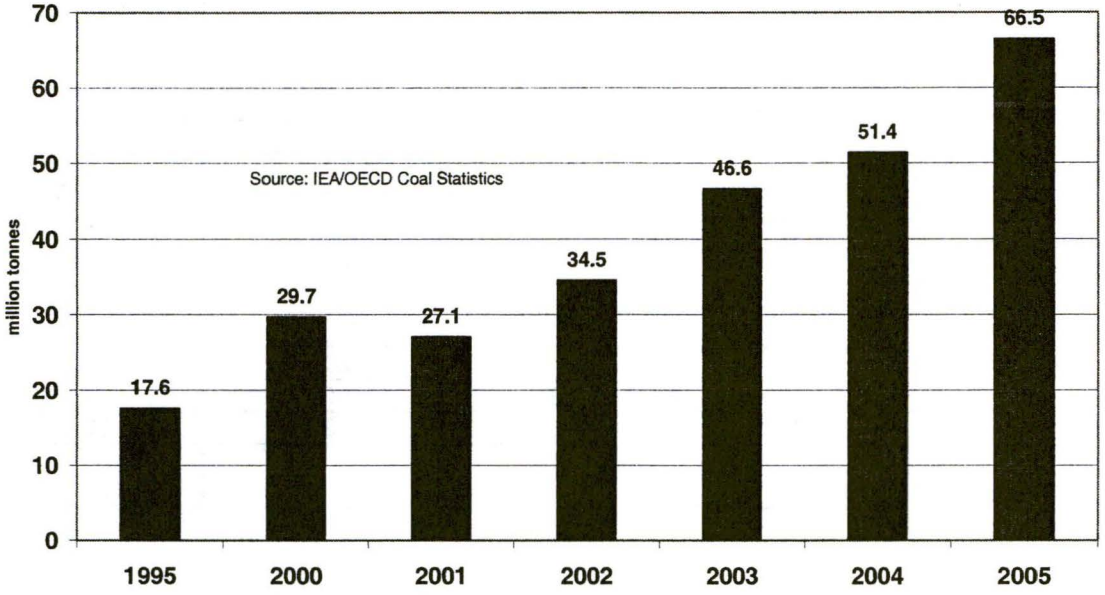
	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005
Australia	5,860	4,150	6,141	10,086	8,287	9,700	8,390	10,628	9,369	7,907	5,207
Indonesia	3,623	4,705	7,821	9,534	7,644	9,427	11,392	11,740	14,542	12,527	15,588
China	2,548	3,510	1,472	1,821	2,398	2,448	5,468	3,530	6,465	3,808	3,105
Total	**12,031**	**12,365**	**15,434**	**21,441**	**18,329**	**21,575**	**25,250**	**25,898**	**30,376**	**24,242**	**23,900**

Source: IEA/OECD Coal Statistics

The major growth of supply within the Atlantic market itself has come from Russia. The largely privatized Russian coal industry has expanded its production capacity significantly in the past several years, and Russian steam coal exports have increased rapidly from 27.1 million tonnes in 2001 to 66.5 million tonnes in 2005 (Figure 35). While some Russian exports are by rail to neighboring countries, including to Belarus, Ukraine and Poland, the major growth is in seaborne steam coal exports.

[43] *International Coal Report*, September 11, 2006; October 16, 2006

FIGURE 35
RUSSIAN STEAM COAL EXPORTS, 1995-2004



However, Russian steam coal has several significant weaknesses. A combination of extremely long distances from ports and an underinvested rail infrastructure results in Russian coal being among the most costly in the world on an f.o.b. port basis. The result is when prices fall, Russian producers are frequently heard to grumble that they would withdraw supplies. However, more importantly from the point of view of NSPI, when prices fall, Russian producers have tended to seek out nearer markets, such as the Baltic or the UK, that can be served directly by smaller ships and thereby allow producers to capture some degree of location rent compared to more remote sources of coal, such as Pacific suppliers or Colombia and South Africa. To the end of the third quarter of 2006, however, Russian exports have continued to increase suggesting that on an annualized basis Russian exports this year will be between 73-75 million tonnes. Most of the growth in exports this year has been through the Baltic and through the Northern port of Murmansk (Table 35).

TABLE 35
RUSSIAN COAL EXPORTS BY PORT, 2003 – SEPT 2006
(million tonnes)

	2003	2004	2005	Jan-Sept 2006
Baltic and North Russia				
Murmansk	5.56	8.85	11.00	8.74
Vysotosk	2.05	3.10	3.50	3.19
Riga	5.22	9.40	10.71	8.52
Ventspils	1.70	3.90	4.60	3.00
Vyborg	0.34	0.48	0.14	0.09
Arkhangelsk	0.06	0.06	0.15	0.27
Tallin (Muuga)	1.83	2.28	4.09	5.38
Ust-Luga	0.26	0.58	0.50	2.38
Kandalaksha	0.00	0.10	0.16	0.06
St.Petersburg	1.91	2.52	2.50	1.64
Sub-Total	**18.93**	**31.26**	**37.33**	**33.25**
Russia and South Ukraine				
Mariupol	2.68	2.55	2.00	1.77
Kerch	0.86	0.86	1.09	1.22
Berdyansk	0.60	0.51	0.43	0.53
Izmail	0.52	1.16	1.22	1.15
Yuzhny	3.11	4.95	4.89	3.41
Nikolaev	0.48	0.31	0.65	0.38
Ilyichevsk	0.03	0.00	0.06	0.28
Reni	0.23	0.37	0.37	0.28
Tuapse	2.79	3.15	3.10	2.39
Sub-Total	**11.30**	**13.84**	**13.81**	**11.41**
Russia's Far East				
Vostochny	11.22	14.36	14.07	11.19
Vanino	0.00	0.00	0.28	0.36
Nakhodka	0.62	0.82	0.21	0.01
Sub-Total	**11.85**	**15.18**	**14.56**	**11.55**
TOTAL	**42.08**	**60.28**	**65.70**	**56.21**

Source: McCloskey Port Survey

Although the large Colombian mines are undergoing a significant capacity expansion, in the first half of 2006 exports form Colombian were down slightly from a year earlier. At the beginning of the year it had been forecasted that they would rise from 54.6 million tonnes in 2005 to a range of 64.7 to 68.25 million in 2006 (Table 36). Xstrata is expanding Cerrejon from 26 million in 2005 to 32 million tpy by 2008. Similarly, Glencore is working on a major expansion of its Calenturitas and La Jagua mines to 15 million tonnes capacity (an increase from 5.5 million tonnes in 2005). Drummond is in the midst of expanding its mining

operations in La Loma to reach a capacity of 30 million tonnes by 2008, up from 22.4 million tonnes exported in 2005. Colombia is also investing in expanding its export infrastructure. In May 2006 the Colombian government announced the construction by 2010 of a major new terminal at Santa Marta Bay, with a capital cost of US$300 million.

TABLE 36
COLOMBIAN EXPORTS BY COMPANY 2004-2006 (est)

Exporter	2004	2005	2006 (low)	2006 (high)
Cerrejon	24.91	25.5	28	28.5
Drummond	20.92	22.4	27.5	28
Prodeco/Carbones de la Jagua	4.21	5.42	6.5	8.5
Carbones del Caribe	0.2	0.22	0.2	0.25
Others	0.75	1.05	2.5	3
Total	**50.99**	**54.59**	**64.7**	**68.25**

Source: The McCloskey Group.

While an analysis of supply and demand suggests a significant amount of new capacity in the process of coming on that should going forward have the effect of lowering prices, 2006 was a year in which accidents and weather combined to increase demand and restrict supply. For example:

- Unusually cold weather in January and February in Europe increased demand, particularly in the UK gas prices hit record levels (thus unlike previous winters coal met 50% of the weekday load in the UK);
- Labor unrest and several derailments as well as heavy rains affecting the opencast mines and a structural problem at the Richard's Bay Coal Terminal combined to lower expected South African exports to 65 million from a forecast 72 million tonnes;
- In South America a five week strike reduced annual production at Drummond's La Loma property by approximately 2 million tonnes.
- A strike at Carbones de La Jagua between May 17 and June 6 impacted production for Glencore;
- In Venezuela Carbones del Guasare declared Force Majeure on several shipments due to a strike by its truck drivers in May, which shut down 80% of the coal from Paso Diablo and Mina Norte.

NSPI's Foreign Exchange Usage

Almost the entire commodity energy budget of NSPI is denominated in U.S. Dollars, including imported coal, natural gas and HFO. This leads to a net

requirement of US$272 million for 2007 (CA IR-11). In conducting its analysis for fuel cost for the year 2007, NSPI routinely uses an exchange rate of US$1.00 = C$1.18. The monthly closing rate for the C$/US$ exchange rate has been below $1.18 since November 2005.

NSPI does not independently forecast exchange rates and relies on various bank reports. These bank reports throughout 2006 have consistently indicated that expected exchange rates for 2007 would vary between 1.10 and 1.15 (CME IR-17, Attachments 1-5).

NSPI has a policy of hedging [redacted] of its forecast U.S. Dollar requirements [redacted] NSPI currently has foreign exchange hedges going back to April 2004 when the exchange rate was 1.36. These averaged with other hedges entered into in 2005 and 2006 result in a hedged component of US$228 million with an average exchange rate of 1.1853.

The fundamentals of the Canadian economy are very strong. It is one of the very few advanced economies with a balance of payment surplus on current account consistently since 1999 and simultaneously with a federal government budget surplus. However, the appreciation in the Canadian currency against the U.S. Dollar is in part driven by strong commodities prices, and as the analysis here shows, oil prices are projected to moderate in 2007, therefore potentially halting the continued strengthening of the Canadian Dollar against the U.S. Dollar.

The incremental value of the favorable effect on 2007 fuel costs resulting from lower exchange rates since 2006C is C$14.7 million. This is derived from the reduction between the forecast 2006 exchange rate of 1.219, compared to the forecast 2007 exchange rate of $1.180. When applied to the total U.S. Dollar requirement of $375.7 million, this yields the above noted reduction (CA IR-11, NSDOE IR-6).

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1986-87: Vice President, Energy Group: Management marketing, sales, consulting and development of new products for the energy division. Together with D&B's Petroleum Information, initiated the development of a universal code for electronic data interchange for the North American gas industry.

1985: Director of Sales and Marketing, Energy.

1980-1985: **Temple, Barker & Sloan, Inc.** (Predecessor of Mercer Consulting), Lexington, MA

Associate: Developed the company's practice in gas, oil and coal consulting. Client companies (90% private sector) included oil, gas and coal producers, railroads, steel companies, electric and gas utilities, equipment vendors, banks, tanker and barge operators, state and federal agencies, trade associations and foreign governments. Provided services such as strategic planning, acquisitions and divestitures assistance, litigation support, expert witness testimony, and market research for over 60 clients.

1980-Present: Speaker and Chairman at numerous domestic and international conferences on coal, natural gas and independent power. Quoted on various occasions in the *Financial Times, Journal of Commerce, U.S. News and World Report, Coal Daily, Coal Outlook, International Coal Report, Coal Week International and International Bulk Journal.*

1979-1980	Visiting Professor, University of California, Davis CA.
1975-1979	Assistant Professor, Duke University, Durham NC.
1973-1975	Teaching Fellow, Harvard University, Cambridge MA.

DIRECTORSHIPS

1987-2000:	Board of Directors Mississippi Valley Coal Trade & Transport (trade association).
2000-2007:	Supervisory Board (Aufsichtsrat) of MIBRAG mbH (company engaged in brown coal mining and powerplant operations in Germany).
2000-2005:	Board of Directors, Entrade (Swiss company based in Prague engaged in electricity trading in eastern and central Europe).
2000-2005	Supervisory Board (Aufsichtsrat) of En-DI AG (company engaged in energy trading and development of new energy production technologies).
2005-2008	Chairman, Advisory Board (Beirat) of En~DI AG
2005-Present	Member of the CO_2 Committee of the German Association of Industrial Power Producers (VIK)

EDUCATION

1980	Certificate, Introduction to Business Program for PhD's, **Harvard University/Harvard Business School**, Cambridge, MA.
1979	PhD, Economic History, **Harvard University**, Cambridge, MA.
1970-1978	Post-graduate fellowships and research grants at the **Academia Britannica**, Rome, Italy; **British Institute**, Athens Greece; **German Academy**, Cairo, Egypt; **Oxford University**, Oxford, U.K.; and the **India Office**, London, U.K.
1969	BA, History, **University of Toronto**, Toronto, Ontario.

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INTERNATIONAL STRATEGIC INFORMATION SERVICES (ISIS)

For the past eighteen years, ISIS has focused its activities in these primary subject areas:

- Independent power development and project acquisition, domestic and overseas

  Typical projects included acquisition due diligence, particularly for privatizations in Central and Eastern Europe; market assessments, particularly focusing on market structure (liberalization measures and regulation); and competitor analysis and forecasts of market growth (electricity demand and supply).

  In the course of this work ISIS has assembled an extensive database (over 300 documents) of power supply contracts from most US states and 22 overseas countries.

- Fuel contract negotiation and fuel forecasting, particularly for coal (hard coal and lignite) and natural gas.

  Typical projects have included fuel supply due diligence for coal, fuel oil, gas, oil shale and orimulsion; negotiation of the full text of contracts for coal (hard coal and lignite), gas supply, and transportation; forecasting of future supply, demand, and prices for coal, oil, gas, and orimulsion.

  In the course of this work ISIS has developed a database of over 260 full text fuel supply contracts from the US and more than 25 overseas countries.

- Fuel supply and Independent Power Project (IPP) contract arbitration and litigation

  Typical assignments have included expert opinions on commercial terms and provisions in IPP and fuel supply contract disputes; insurance litigation involving commodities trading; fraud-related litigation; pricing disputes for steam and metallurgical coal; coal related antitrust litigation.

- CO_2 emissions trading and Greenhouse gas abatement

  Typical assignments have included CO_2 price forecasts; landfill gas projects; mine methane utilization; preparation of early action claims; preparation of compliance and lobbying strategies.

After initially focusing its activities in North America and Asia, ISIS has gained project experience in 54 countries with most years involving activities on at least four continents. ISIS' client list has grown from American companies pursuing a globalization strategy to include numerous local companies in Europe and Asia.

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INTERNATIONAL STRATEGIC INFORMATION SERVICES
SAMPLE LIST OF CLIENTS

A.T. Massey
ABB (Equipment Units in Germany and Switzerland)
ABB Energy Ventures
ABN Amro (UK)
AES
Andalex Resources
Ansaldo (Italy)
ARCO
Atel
Baker Hughes
Billiton (Netherlands)
BP Coal
Cambridge Energy Research Associates
Central Electric Generating Board (UK)
Charles River Associates
Citrus Trading Corporation
CMS Gas
CMS Generation
Coastal Corp.
COMEnergy
CRA (Australia)
Cypress Power Partners
Cyprus Minerals
Dept. of Treasure, Republic of South Africa
DG for Energy and Transportation (European Commission)
Dun & Bradstreet
Electric Power Research Institute
El Paso Energy
Empresa Municipal de Cali (Colombia)
ENDESA (Spain)
EnD~I AG (Germany)
ENEL (Italy)
Energieversorgung Halle GmbH (Germany)
Enron Gas
Enron Power
Entrade AG (Switzerland)
E.on Energie AG
European Commission
Florida Gas Transmission
Florida Progress
Goldman Sachs (Germany)
Houston Industries
Houston Natural Gas
Indeck Energy
Ingwe Coal (South Africa)
International Finance Corp.
IPCO (Singapore)
Island Creek China (China)
Island Creek Coal
Leuna AG (Germany)
Long Term Credit Bank of Japan (Japan)
Loxley Infra Ltd. (Thailand)
MIBRAG mbH (Germany)
Mitsubishi Corporation (Japan)
Mitteldeutsche Energieversorgung AG (Germany)
National Power (UK)
Nations Bank
NERCO
Nippon Kokan (Japan)
North American Coal Corp.
NRG Energy, Inc.
Occidental Petroleum of China (China)
Portland General Electric Company
PowerGen (UK)
PreussenElektra (Germany)
PT Berau (Indonesia)
Republic of South Africa, Treasury Department
Rheinbraun AG (RWE; Germany)
RWE Entsorgung AG (Germany)
Saale Energie GmbH Services (Germany)
Saar Energie AG
Siemens Power Systems (Germany)
STEAG AG
Treuhandanstalt (Germany)
VEAG (Vattenfall Europe; Germany)
Vattenfall (Sweden)
Verbundnetz Gas AG (German)
Vereinigte Elektrizitätswerke Westfalen (Germany)
Westinghouse
World Bank
Zeigler Coal

In addition: government agencies in China and Pakistan, as well as various major international law firms, including Baker & McKenzie and Davis Polk & Wardwell.

ISIS was also on the Board of Directors of the Mississippi Valley Coal Exporters Council and was a member of Western Coal Council. In addition, Manfred Raschke has been a member of the U.S. delegation to the Economics Commission for Europe and serves on the boards of two German companies and is a member of the VIK's CO_2 Committee.

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INTERNATIONAL STRAGETIC INFORMATION SERVICES
PROJECT EXPERIENCE BY COUNTRY

North America

Canada (gas, coal, IPP)
USA (gas, coal, IPP, renewables)
Mexico (gas, coal, IPP)

South America

Argentina (gas, coal, IPP)
Brazil (gas, coal, IPP, hydro)
Chile (gas, coal, IPP)
Colombia (gas, coal, IPP)
Venezuela (gas, coal, orimulsion)
Bolivia (gas, IPP)
Peru (gas)

Africa

Egypt (gas)
Morocco (coal, IPP)
South Africa (coal, IPP)

Australia (gas, coal, IPP)
New Zealand (IPP)

Europe

Germany (gas, coal, IPP, renewables)
Greece (coal, IPP)
Poland (gas, coal, IPP)
Portugal (gas, coal, IPP, orimulsion)
Spain (gas, coal, IPP)
Sweden (gas)
Turkey (gas, coal, IPP)
France (coal, IPP)
Lithuania (gas, IPP)
Netherlands (gas, coal, IPP)
Croatia (coal, IPP)
Yugoslavia (Serbia) (IPP)
UK (gas, coal, orimulsion, IPP, renewables)
Italy (gas, orimulsion, IPP)
Czech Republic (gas, coal, IPP)
Russia (gas)
Hungary (gas, coal, IPP)
Ukraine (gas, coal)
Bulgaria (gas, coal, IPP)
Estonia oil shale, IPP)
Austria (IPP)
Romania (gas, IPP)
Slovakia (gas, coal, IPP)
Switzerland (IPP)
Slovenia (IPP)

Asia

Pakistan (oil, gas, IPP)
India (coal, IPP)
Thailand (gas, coal, orimulsion, IPP)
Malaysia (gas, coal, IPP)
Myanmar (gas)
Cambodia (gas, IPP)
Jordan (oil shale, IPP)
Japan (coal, gas, orimulsion)
Indonesia (gas, coal, IPP)
Philippines (coal, IPP)
China (coal, IPP)
Singapore (gas, IPP)
Hong Kong (coal, IPP)
Israel (oil shale, IPP)

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ISIS LITIGATION EXPERIENCE

- Linklaters: ISIS served as an advisor and expert witness in a DM 2.0 billion hardship claim brought by a German utility against an American-owned IPP project. The case involved many aspects of utility liberalization in Germany as well as electricity pricing issues. ISIS participated in all aspects of the 20-month arbitration including the final settlement negotiations.

- Santee Cooper: Testimony on fuel buying in a lawsuit by an employee blowing the whistle on corruption in the fuel-buying department. The suit was eventually dropped as a consequence of a Supreme Court decision in a related case.

- Ziegler Coal vs. AEP: ISIS was selected by Ziegler Coal to assist the law firm of Kirkland & Ellis in a coal supply contract dispute. The major issue was pricing. It was settled by negotiation of the parties prior to the trial.

- Baker & McKenzie: ISIS was retained by the law firm to assist in an international arbitration with Taiwan Power, on behalf of American clients. ISIS was retained in two subsequent occasions in similar arbitration proceedings involving the same two parties.

- Ziegler Coal vs. Southern India Gas & Electric Co.: ISIS was retained to assist Kirkland & Ellis in a contract dispute. The case got no further then deposition before being settled through negotiation.

- Pretzel &Stouffer: ISIS was retained by the law firm to assist an insurance company that was defending a $50 million claim by Santee Cooper in a fuel purchasing corruption case. The case was settled after deposition but prior to trial.

- Davis, Polk & Wardwell: ISIS was retained to defend a major securities firm against a $100 million claim under California securities laws. It was alleged in the case that a security analyst had issued grossly inflated business estimates as part of an IPO. The case ultimately lasted three years before being settled.

- Van Cott, Bagley, Cornwall & McCarthy: ISIS presented testimony on behalf of a client of this Salt Lake City law firm in a coal royalty dispute.

- Baker & McKenzie: ISIS was retained to assist the law firm in a contract dispute between a US coal supplier and a Spanish customer.

- Arco Coal vs. OG&E: ISIS was retained by Arco Coal in a contract dispute with Oklahoma Gas & Electric. While the engagement lasted well over a year the case did not ultimately go to trial.

- BP Coal vs. National Steel: ISIS was retained by BP Coal in a contract dispute involving a long-term metallurgical coal contract. The dispute was ultimately settled through negotiations after ISIS had prepared a number of reports and position papers.

- Van Cott, Bagley, Cornwall & McCarthy: Litigation support in a contract dispute (hardship clause) between Valley Camp Coal Co. and Utah Power and Light. The dispute was settled after depositions but prior to trial.

- Qintette Coal: ISIS was retained by several Canadian law firms working on behalf of Nippon Steel and Nippon Kokan to assist in an international arbitration involving a price re-opener clause in a long-term metallurgical coal contract.

- Kirkland & Ellis: Retained for litigation support to provide assistance in a Florida case on behalf of PG&E. This involved the interpretation of PPA commercial terms and conditions. The dispute was ultimately settled by negotiation.

- Pretzel & Stouffer: Defending against a $500 million insurance claim by Metalgesellschaft as a consequence of a $2.3 billion loss due to the oil futures trading activities of the Benson Group in the New York

office of MG. ISIS prepared for litigation and then counseled the client in a negotiation to fend off a claim for an insurance payment.

LITIGATION EXPERIENCE PRIOR TO ESTABLISHING ISIS

- Wilmer, Cutler & Pickering: This involved railroad litigation arising from the Penn Central Bankruptcy. Eventually testimony was submitted by Dr. Raschke as an expert witness in this case. The litigation lasted approximately two years before a special judicial panel.

- Texas Utilities vs. Santa Fe Railroad: This was an anti-trust suit brought by Texas Utilities against the railroad. This was the largest anti-trust case in the energy area up to that time (1985). Dr. Raschke served as an expert witness on coal and utility issues on behalf of the Santa Fe Railroad.

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LIST OF RELEVANT COAL PROJECTS

- For an Italian IPP developer, fuel supply assistance including shipping and port logistics, coal contract indexation and overall supply analysis for a 2 x 600 mW imported coal-fired station in Brazil.

- For an American/Japanese consortium, due diligence on coal supply, ash disposal, and rail logistics and negotiation of a new financible coal supply contract for a 1,700 mW existing Polish coal-fired plant acquisition.

- For a German/American consortium due diligence on the brown coal-fired generating assets of VEAG and the brown coal mining operations of LAUBAG.

- For a German brown coal mining company, due diligence and valuation assistance in the acquisition of a 30 million tpy brown coal mine in Australia.

- For an American IPP developer, preparation of a bid for the 1,260 mW imported coal-fired power plant in Varna, Bulgaria.

- For an American IPP developer, assistance with the acquisition of a 400 mW hard coal-fired power plant in Rousse, Bulgaria.

- For a U.S.-based oil major, an assessment of the market for coal-based independent power projects in Mexico.

- For a U.S. independent power utility affiliate, a review of the lignite-fired Loy-Yang "B" project in Victoria State in Australia.

- For a U.S. independent power investor, the identification of the potential investment in a coal-based IPP project in western Australia (Collie).

- For a major European electric utility, ISIS was given the lead role in developing a 2,000+ mW coal-fired power project in Poland. This included discussions with Polish government and utility officials, negotiations with banks, fuel providers and the identification of potential joint venture partners in Germany.

- For a U.S. utility affiliate, identification of a potential 600 mW lignite-fired power project in Northern Ireland. In addition to identifying the opportunity, ISIS successfully assisted the client in becoming a participant in the joint venture developing the project.

- For a major U.S. utility independent power affiliate, ISIS did the preliminary due diligence work for a 2,000+ mW coal-fired project in New South Wales.

- For a Japanese trading company, an analysis of the investment potential in the electric power and coal sector in Unified Germany.

- For a consortium of American and European utilities, ongoing advice on a variety of issues in the bid for a 1,200 mW coal-fired powerplant in Portugal (the Pego Project). This included advice and research on a variety of environmental, political, fuel and and economic issues, as well as attendance at all major meetings between the Consortium and the host utility, the project financiers and the preparation of significant part of the bid that was submitted to the Portuguese government.

- For a major European utility, a due diligence review of fuel agreements for a proposed independent power investment in Poland.

- For a major European utility, assistance with fuel planning for an independent power project investment in Portugal.

- For a U.S. utility affiliate, assistance in bid preparation for a coal-fired independent power project in Puerto Rico.

- For an American/Indonesian group, prefeasibility study for the construction of 1,200 mW of coal-fired independent power project in Eastern Sumatra, Indonesia.

- For the developers of the Pingshou coal project in China ongoing advise (1982-1989) on economic feasibility and coal prices.

- For several Japanese steel companies an analysis of development in coking and steel making technologies and their impact on future coking coal supplies.

- For a major international bank, an analysis of the steam coal industry in South Africa.

- For a large Spanish and mining company, an analysis of future price trends for high and low sulfur coals in the international market.

- For several Japanese steel companies, an analysis of price behavior in the international spot and contract coal markets.

- For an insurance company, expert assistance in a coal contract damage dispute.

- For a major U.S. coal producer, litigation support in a coal contract breach proceeding against a midwestern utility.

- For a major independent power developer, a forecast of the price and availability of steam coal for import into Gulf of Mexico and Pacific coast power stations in Mexico.

- For a major Spanish utility, an assessment of the coal and electric power industries in unified Germany.

- For a potential coal company investor, a review of the feasibility of the Port of LA coal export terminal.

- For an independent power developer, an analysis of coal contract pricing and rail transportation pricing into Florida (including the impact of imports of Colombian and Indonesian coal).

- For a major U.S. coal exporter, testimony before an international arbitration panel on coal pricing in the international steam coal market.

- For a U.S. manufacturer, an assessment of the world market for lignite derived waxes.

- For a major U.S. exporter, an assessment of the demand for imported coal in unified Germany.

- For a major U.S. coal producer, an assessment of the potential import demand for steam coal in Mexico.

- For a European-American consortium, a forecast of steam coal prices and availability for import into northwestern Europe.

- For a European-American consortium, a study of specific contract provisions in 125 coal contracts from Australia, South America, North America, Japan and South Africa.

- On-going support (1991-2002) for an American consortium privatizing a 17 million tonne per year brown coal operation in East Germany.

- On-going support (1991-2002) for an American consortium acquiring a 400 mW share in a brown coal-fired powerplant in East Germany.

- For an Australian/British/Thai consortium, preparation of the coal supply portion of the group's IPP bid to EGAT.

- For an American/Thai joint venture, bidding to EGAT, assistance with coal supply and pricing issues.

- For an American consortium, due diligence on the acquisition of 2,000 mW of existing coal-fired capacity in the UK.

- For an American/German/French consortium, developing an 800 mW coal-fired BOT project in Turkey, assistance on coal supply and logistics.

- For a German/American joint venture, a feasibility study for a brownfield expansion of a major solid fuel-fired district heating plant in East Germany.

- For a global energy company, assistance on a variety of issues pertaining to their entry into international coal trading.

- For a major solid fuel tender investigation of the Far East market for pet coke use by utilities and IPPs.

- For DG XVII of the European commission, an in-depth analysis of international trends in coal mine ownership and imported coal policy recommendations.

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LIST OF RELEVANT GAS PROJECTS

- For an Italian IPP developer, assistance in tendering for gas supplies, supply contract and gas transportation contract negotiations for a 480 mW IPP project in northern Argentina.

- For an Italian IPP developer, assistance in tendering for gas supplies and gas transportation for a 400mW gas-fired IPP project in northern Mexico.

- For a German-American consortium feasibility review for a greenfield 600mW gas-fired station in northern Germany.

- For an American IPP developer feasibility review for a greenfield 400mW gas-fired station southern Germany.

- For an American IPP developer review of gas supply and regulatory issues for a proposed 800 mW greenfield gas-fired plant in Brazil.

- For a German-American consortium review of gas supply and transportation for several small municipal and industrial gas-fired CHP projects in Poland.

- For a major American IPP developer assistance with gas supply and gas contracting for a greenfield 400mW gas-fired project in central Italy.

- For a major American IPP developer bidding in the ENEL asset tenders, review of the Italian natural gas industry including supply, transportation, industry participants, pricing, and regulation.

- For a major American gas and power developer, review of the competitiveness (gas vs. coal vs. power by wire) of a new gas pipeline from Argentina to Chile.

- For a major American IPP developer, assistance with the negotiation of gas supply and transportation agreements, for the acquisition of a 680 mW gas-fired unit in the UK.

- For a major American IPP developer, assistance with the negotiation of gas supply agreements for a greenfield 880 mW gas-fired project in the UK.

- For a major American IPP developer, review of gas supply contract for existing 500mW gas-fired station in the European portion of Turkey.

- For a major American IPP developer feasibility review of a gas-fired industrial CHP project in Izmir Turkey.

- For the national utility of Malaysia review of terms and provisions of gas supply contracts for Malaysian IPP's.

- For a German IPP developer review of gas supply and gas transportation arrangements for a 150 mW gas-fired industrial CHP project in Malaysia.

- For a German IPP developer due diligence on an existing 135mW gas-fired IPP project in Indonesia.

- For an American joint venture, assistance with all issues relating to gas supplies, including contracting negotiations and documentation for financial close, for a 390 mW gas-fired merchant plant in the UK.

- For a major American IPP developer, an assessment of the potential for acquiring gas pipeline assets in Bulgaria and constructing a new 600 mW gas-fired power plant.

- For an American/Swedish consortium, assistance with the negotiation of a gas supply contract for a 90mW Bolivian merchant power plant.

- For a major American utility, assessment of current and future UK natural gas prices.

- For a major American utility, assistance on gas supply and strategic issues in the bid to acquire Germany's largest gas distribution company.

- For foreign-owned Bolivian power producer an analysis of future natural gas prices in Argentina, Bolivia and Brazil.

- For an American-Scandinavian joint venture reviewed economics of gas supplies, pipelines and gas-fired generation in Chile.

- For a major U.S. energy and gas pipeline company, assistance in entering the Portuguese natural gas market.

- For a major U.S. electric generating equipment manufacturer, political and due diligence assistance on gas-fired cogeneration projects in Germany.

- For a major American merchant energy company, an analysis of the natural gas industry in Thailand including supplier, customers, infrastructure and gas-fired generation.

- For a major natural gas supplier, an assessment of pricing provisions in coal, lignite and rail transportation agreements supply a Texas utility.

- For a major U.S. natural gas and independent power company, assistance with power contract negotiations in Mexico.

- For a major U.S. natural gas and independent power company, an assessment of the potential for the development of gas-fired independent power projects in Australia.

- For a U.S. utility independent power affiliate, a feasibility study for the repowering with gas combined-cycle units of a large powerplant in Ukraine.

- For a major U.S. gas company and independent power developer, participation in the team developing the United Kingdom's largest cogeneration and independent power project. ISIS's work on this project focused primarily on gas supply issues.

- For a major U.S. natural gas and independent power company, an assessment of the potential for the development of independent power projects in Malaysia.

- For a major U.S. natural gas and independent power company, a detailed assessment of the potential for independent power in Thailand. The project focused on natural gas-fired generation and involved numerous in-country meetings with government officials, electric utilities, potential local partners, etc.

- For a major U.S. natural gas and independent power company, a market study of the potential for gas-fired independent power in Pakistan. The analysis included an assessment of possible local partners and a detailed

review of the Pakistan gas and electricity sectors, as well as discussions with other developers who had proposed projects for Pakistan.

- For a major U.S. natural gas company, a study of the alternative usage of natural gas resources in Argentina, Chile, Malaysia, and Indonesia. The study compared the potential for the maximization of natural gas netbacks at the well from the use of gas in power generation or fertilizer production in each of those countries.

- For a major Japanese bank, a study of the U.S. domestic and international independent power industry, focusing specifically on the potential for gas-fired projects.

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LIST OF RELEVANT INDEPENDENT POWER PROJECTS (IPP)

- For an American IPP developer, due diligence, including contract, risk management and counter party risk review, of a Swiss electricity trading company primarily active in the Balkans, Austria, Hungary and Germany.

- For an American IPP developer, due diligence, including contract, risk management and counter party risk review of a Czech electricity trading company primarily active in Poland, Slovakia, the Czech Republic, and Germany.

- For a German/American consortium bidding for the privatization of CEZ, in addition to fuel related tasks, coordination of political activities and assistance in valuation.

- For an American IPP developer, development assistance for the acquisition of an existing 150mW coal-fired municipal CHP plant in eastern Slovakia.

- For an American IPP developer due diligence, including fuel and power agreements, on a group of small gas and coal-fired CHP projects in the Czech Republic.

- For an American IPP developer, due diligence on the electric, district heat and gas distribution facilities of a major municipality in Bulgaria.

- For an American/German consortium, development assistance for a brownfield gas-fired 90mW CHP plant in western Slovakia.

- For a major American wholesale energy company, due diligence for the privatization of BEWAG in Germany in Berlin, Germany.

- For a major American wholesale energy company assistance with gas supply questions in the privatization of GASAG in Berlin, Germany.

- For an American consortium developing a 380 mW coal and gas-fired IPP project assistance with regulatory issues and political lobbying in the Czech Republic.

- For a German brown coal mining company, negotiation of a 10 year PPA with a regional distribution company for surplus power from three CHP plants in eastern Germany.

- For a major European utility, a due diligence review of fuel agreements for a proposed independent power investment in Poland.

- For an American IPP developer, analysis of the opportunities for entry into the IPP industry in the Netherlands.

- For a major American wholesale energy company, an analysis of the prospective market for fuel cells in Germany including negotiation of a fuel cell project together with a municipal utility in eastern Germany.

- For an American/German/French consortium, developing an 800 mW coal-fired BOT project in Turkey, assistance on coal supply and logistics.

- For a major U.S. independent power utility affiliate, an analysis of the market potential for the development of coal and natural gas-based independent power projects in Poland, Czechoslovakia, and Hungary.

- For a group of large Dutch industrial customers, negotiation of a gas-tolling arrangement involving the leasing of up to 1,000 mW in Germany, the supply of Dutch gas, and supply of the power to industries in the Netherlands.

- For American/Czech joint venture, developing a 360 mW coal-fired IPP project in the Czech Republic, assistance with coal supply, coal transportation and coal contracting issues.

- For an American IPP developer, preliminary due diligence for the acquisition and repowering of a 200mWe coal-fired CHP project (Chemopetrol), in the Czech Republic.

- For an American IPP developer, preliminary due diligence for the acquisition of a 200 mWe industrial CHP project (Komorany) in the Czech Republic.

- For an American IPP developer, due diligence for the acquisition of a 60 mWe gas-fired industrial CHP plant in eastern Germany.

- For an American IPP developer, preliminary due diligence for the privatization of an electricity distribution company (GZE) in Poland.

- For an American IPP developer, preliminary due diligence for the acquisition and repowering of a 300 mWe coal/gas-fired industrial CHP project (Huta Katowice) in Poland.

- For an American IPP developer, a study of the development of the Baltic electricity market, particularly future price trends, with a focus on Estonia and Lithuania.

- For an American IPP developer; preliminary due diligence on an electricity broker with activities focused in Germany.

- For an American IPP developer, analysis of the market opportunity, investment magnitude and business structure needed to establish an electricity retail marketing company in Germany.

- For an American IPP developer, assistance with the development of a strategic plan for growth in Germany.

- For an American IPP developer, a review of gas market liberalization and its likely interfuel competitive impact in Germany.

- For an American IPP developer, preliminary due diligence for the acquisition of a minority stake in the Stadtwerke Düsseldorf, in Germany .

- For a German IPP generator, assistance with the sale of electricity under long-term contract to a municipal utility in German.

- For a German IPP generator, expert witness assistance in a German arbitration of a long-term (25 year) capacity sales contract.

- For an American wholesale energy company, an analysis of the privatization opportunities and process for electric and gas distribution companies in the Czech Republic.

- For an American wholesale generator, due diligence and negotiation assistance for the privatization of the generation assets of the Deutsche Bahn, in Germany.

- For an American IPP developer, due diligence in Turkey for a new 150 mW brown coal-fired plant and the acquisition of 600 mW of existing brown coal-fired capacity and related mining operations.

- For an American IPP developer, due diligence on the generation assets (2,609mW of coal, gas and hydro) of Viesgo Generacion being sold off by Endesa in Spain.

- For an American IPP developer, preliminary due diligence for the acquisition and repowering of a gas-fired municipal CHP plant in Romania.

- For an American IPP developer, due diligence for the acquisition of a 790mW existing gas-fired combined cycle powerplant in the UK.

- For an American IPP developer, preliminary due diligence for the acquisition of a 218 mWe/220 MWth gas-fired CHP plant in Slovakia.

- For a British IPP developer, an analysis of acquisition and greenfield development opportunities in the liberalized electric market in Germany.

- For a major American equipment vendor, assistance with the development, including PPA and gas supply contract, for 130 mW gas-fired industrial CHP plant in eastern Germany.

- For an American IPP developer, assistance with the development of a 100 mWe gas-fired industrial CHP project in eastern Germany.

- For a German brown coal mining company, assistance with the development of a brown coal fired 120 mWe municipal CHP project in eastern Germany.

- For a British/German joint venture assistance in handling coal supply and coal logistic issues for a 700 mW coal-fired IPP porject in Croatia.

- For the Treuhandanstalt (privatization agency for east German assets) assistance with the renegotiation of power and steam contracts for a major chemical complex in eastern Germany.

- For the Treuhandanstalt (privatization agency for east German assets) assistance with the renegotiation of power and steam contracts at a oil refinery and petrochemical complex in eastern Germany.

- For the Treuhandanstalt and Goldman Sachs, production of an information memorandum for the sale of a brown coal mine and related chemical complex in eastern Germany.

- For a major U.S. natural gas and independent power company an analysis of international trends driving decisions made in various countries for build-own-operate or build-own-transfer type of power projects.

- For an American IPP developer, an analysis of the IPP market, including legislation, fuel supply alternatives, and potential local partners in Taiwan.

- For a major UK electric generator, development of criteria and identification of prospective candidates for a utility acquisition in the US Midwest.

- For an American regulated utility, analysis of the prospects and opportunities for investment in overseas electric distribution businesses.

- For a major Australian mining and natural resources company, an analysis of the potential for entry into the IPP business in Australia and Southeast Asia.

- For a major U.S.-based international independent power developer, a comparison of the relative economics of gas versus coal as a fuel for power plants in different parts of the world.

- On-going advice (1991-1993) on independent generation issues in East Germany and in Central Europe for the board of directors for one of the world's largest electrical equipment manufacturers.

- At the request of the Colombian government, ISIS put together a group of European and American utilities for a jointly financed study of the feasibility of developing of various independent power projects in Colombia.

- For a large German utility, a competitor analysis of potential foreign independent power developers that were likely to seek projects in East Germany.

- For a major U.S. independent power developer, due diligence for an industrial co-generation project near Halle in East Germany.

- For an American/Indonesian group, prefeasibility study for the construction of 1,200 mW of coal-fired independent power project in Eastern Sumatra, Indonesia.

- For a U.S.-based oil major, an assessment of the market for coal-based independent power projects in Mexico.

- For a U.S. independent power utility affiliate, a review of the lignite-fired Loy-Yang "B" project in Victoria State in Australia.

- For a U.S. independent power investor, the due diligence for a potential investment in a coal-based IPP project in western Australia (Collie).

- For a major European electric utility, ISIS was given the lead role in developing a 2,000+ mW coal-fired power project in Poland. This included discussions with Polish government and utility officials, negotiations with banks, fuel providers and the identification of potential joint venture partners in Germany.

- For a U.S. utility affiliate, identification of a potential 600 mW lignite-fired power project in Northern Ireland. In addition to identifying the opportunity, ISIS successfully assisted the client in becoming a participant in the joint venture developing the project.

- For a major U.S. utility independent power affiliate, ISIS did the preliminary due diligence work for a 2,000+ mW coal-fired project in New South Wales.

- For a Japanese trading company, an analysis of the investment potential in the electric power and coal sector in Unified Germany.

- For a consortium of American and European utilities, ongoing advice on a variety of issues in the bid for a 1,200 mW coal-fired powerplant in Portugal (the Pego Project). This included advice and research on a variety of environmental, political, fuel and and economic issues, as well as attendance at all major meetings between the Consortium and the host utility, the project financiers and the preparation of significant part of the bid that was submitted to the Portuguese government.

- For a major European utility, assistance with fuel planning for an independent power project investment in Portugal.

- For the same company, the selection of a potential project of 300+ mW in western Australia, including discussions with key government officials and the identification of local partners and fuel suppliers.

- For a major European utility, an assessment of the market for gas and coal-fired independent power projects in Canada, specifically in the provinces of Ontario, Quebec and British Columbia.

- For a group of Spanish and UK utilities, an assessment of the coal and natural gas-based independent power market for projects in Mexico.

- For a major European electric utility, an assessment of the independent power market in Czechoslovakia.

- For a major European utility, a study of the potential for independent power investment in Mexico.

- For a major Spanish utility, a market analysis of the world IPP industry, including major trends, forecast of key countries and analysis of competitors.

- For a major Spanish utility, a review to identify potential independent power projects for investment in Mexico.

- For a major German utility, a competitive analysis of the international independent power companies likely to enter the German market.

- For a major European utility, an assessment of gas-fired independent power projects in Ontario and New York State.

- For a major U.S. independent power utility affiliate, a review of the potential for independent power investment in the Philippines.

- For a major U.S. natural gas company and independent power company, development of an independent power strategy for operations in the Far East. Included as part of the project was an assessment of potential local partners and a quantification of the independent power potential of all of the major markets in the Far East, South Asia and Southeast Asia.

- For a mixed Anglo/American/Indonesian consortium, assistance in preparation of a bid for a 2 x 600 mW units in Central Java.

- Participation as a representative as a major equity investor in an American/Indonesian consortium bidding for 4 x 600 mW coal-fired units at Paiton in Indonesia.

- For an independent power subsidiary of a U.S. electric utility, a strategic plan for penetrating the international power market.

- For a major German utility, the development of a strategic plan for entering into the overseas independent power business.

- For a major German utility, lead role in identifying and securing overseas cogeneration projects for development or acquisition.

- For an international IPP developer, commercial assistance in developing a large, independent power project in Italy.

- For an independent power subsidiary of a U.S. electric utility, review of fuel, rail and electric contracts as part of large powerplant acquisition in Australia.

- For a Colombian 400 mW coal-fired IPP project, assistance on coal supply, logistics and coal contracting. The assignment included preparation of the coal tender documents, negotiations with coal suppliers and all fuel related assistance up to financial close

- For an American IPP developer, due diligence in Australia on the fuel supply for a 170 mW coal-fired plant being privatized.

- For an American IPP developer, preparation of a fuel supply plan for a proposed 300 mW coal-fired powerplant in the UK.

- For a German/British/Indonesian consortium, building 2 x 600 mW of IPP capacity in Indonesia, assistance on coal supply, logistics and coal contracting Fuel supply advisors to the project until financial close.

- For an Italian/American/Indonesian consortium, building 400 mW of IPP capacity in Indonesia, assistance on coal supply, logistics and coal contracting.

- For a British/Indian joint venture, developing a coal-fired IPP project in India, assistance on coal supply, logistics and coal contracting with Coal India.

- For a German IPP developer, due diligence on a proposed 135 mW gas-fired IPP plant in Indonesia.

- For an American/Swiss joint venture, acquiring 2 x 330 mW and building an additional 2 x 330 mW of imported coal-fired IPP capacity, due diligence on fuel supply, assistance with coal transportation, coal handling, contracting and power purchase agreement negotiations (project in Morocco).

- For an American joint venture negotiated a long-term gas supply contract for a 390 mW combined-cycle merchant powerplant in the UK.

- For an American IPP developer assistance in preparing a bid for a gas-fired powerplant to serve a large German industrial customer.

- For a global energy company, due diligence assistance in the bid to acquire control of a German utility.

- For an American IPP developer, preparation of a long-term strategic plan for Europe.

- For a large German municipal utility advisory role to the Supervisory Board on trends in power liberalization in Europe and overseas.

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ISIS

LIST OF ENVIRONMENTAL/RENEWABLE ENERGY PROJECTS

- For an Italian utility, a report on German CO_2 emissions legislation and particularly its applicability to new and retrofitted plants.

- For a German green energy company, assistance with the development of a 3 mW rooftop photovoltaic solar project in the Rhine Valley

- For a Central European renewables investor, a report on the use of carbon financing for mini-hydro projects in Bulgaria and a market overview of mini-hydro prospects in Romania, Bulgaria and the Balkans.

- For a German green energy company, management of a tender for solar cells and follow-up identification of and negotiations with an American third generation solar cell manufacturer.

- For a German green energy company, identification of U.S. technologies in regard to miniature LNG operations and biogas/coal mine methane upgrading.

- For major Swiss electricity trader, investigation of 380kV and 110 kV grid constraints in Germany as a consequence of new renewable energy (primarily wind) capacity.

- For a German green energy company, ongoing monitoring and advice on the international market in CDM and JI projects under the Kyoto Protocol.

- For an Italian utility, a report on the availability of transportation and pricing of biomass (primarily wood waste) in Poland.

- For a German coal-fired generator, a report on the grid and plant operating implications of the buildup in onshore and offshore wind installations in Germany and Southern Scandinavia.

- For a German coal-fired generator, an analysis of the CO_2 implications of closing older coal-fired capacity and building replacement capacity.

- For an American energy company, a global market study (Canada, South Africa, Australia, Poland, UK, Germany and Czech Republic) of the suitability and economics of a new technology for reclaiming coal washery waste.

- For a major German energy company, a study of the Ukrainian coal mine methane industry.

- For a major German energy company, a study of the coal mine methane industry in the Czech Republic.

- For an American diversified energy company, a study of the US coal mine methane industry and the potential for monetizing methane emissions in the carbon market.

- For a European power generator, an analysis of the carbon trading market and a forecast of the future price and availability of CO_2 emission certificates.

- For a German coal-fired power generator, development of a strategy to cope with CO_2 emissions trading.

- For a German power generator, a data collection effort for the preparation of an Early Action claim under German CO_2 emission trading legislation.

- For a German renewable energy company, a review of the terms and provisions of coal mine methane supply contracts.

- For a German waste management company, assistance in identifying opportunities for waste combustion in the Czech Republic.

- For a German coal-fired powerplant operator, a review of the long-term availability and pricing of sewage sludge for co-combustion with coal.

- For a German boiler project developer, an assessment of the disposal costs and alternative disposal options for combustion ash.

- For a major German natural gas supplier, an analysis of fuel cell technology and the timing of market penetration in the residential market of such technology.

- For a major U.S. energy company, assistance with the development of the fuel cell market in Germany; project included identification of an initial test site (Halle/Saale) and ongoing support during permitting and installation.

- For the Economics Ministry of the Land of Sachsen-Anhalt (Germany), a report on U.S. regional and local CO_2 control legislation, new U.S. CO_2 reduction technology (including in landfill gas, biogas and coal mine methane) and coal gasification sequestration.

- For a German brown coal mining company, a review of carbon sequestration efforts in Norway, the UK, Canada and the United States.

- For a German renewable energy company, a study of the UK landfill gas market.

- For a major European waste company, a detailed market assessment of the US textile recycling industry including the identification of possible acquisition targets.

- For a German brown coal mining company, the negotiation of the divestiture of landfills and recycling facilities.

- For an international banking consortium, a review of the ash disposal strategy of a Czech fluidized bed IPP project undergoing project financing.

- For a German brown coal mining company, a review of gypsum disposal arrangements including technological options, long-term contracts, and transportation alternatives.