ORIGINAL

SEMINOLE ELECTRIC COOPERATIVE, INC.

Petition to Determine Need for

Electric Power Plant

March 2006

Direct Testimony of:

Wm. Jack Reid

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Seminole Electric
COOPERATIVE, INC.
IN PARTNERSHIP WITH THOSE WE SERVE

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

SEMINOLE ELECTRIC COOPERATIVE, INC.

DIRECT TESTIMONY OF WM. JACK REID

DOCKET NO. 06____-EU

March 10, 2006

Q. Please state your name, occupation and business address.

A. My name is William Jack Reid. I am employed by Seminole Electric Cooperative, Inc. ("Seminole") as Director of Fuel Supply. My business address is 16313 N. Dale Mabry Highway, Tampa, Florida 33618.

Q. Please describe your duties and responsibilities as Director of Fuel Supply.

A. I am responsible for management and planning of fossil fuels at Seminole's generating facilities and at those purchased power facilities for which Seminole has fuel supply responsibilities. In this role, I am responsible for the availability, reliability and transportation of fossil fuels, the optimization of the fossil fuel supply chain cost, the maintenance of adequate fossil fuel inventories, and the evaluation of alternative fossil fuel supply opportunities. My responsibilities also include fuel price risk management, the administration of Seminole's natural gas price hedging program, and shared responsibility for fuel procurement (with Seminole's Supply Management Department).

Q. Please summarize your background and experience.

A. I have 30 years experience in the electric utility industry, with 24 years in power generation fuel management. I have substantial experience in preparing fuel price forecasts, generation resource budgets, strategic fuel plans and operation plans, all of which are used to make major corporate decisions.

Much of this experience was gained in my former positions with Kansas Gas and Electric Company (KG&E), which later became Western Resources Inc. (WR). I started at KG&E in June 1976 in its generation group, where my responsibilities included engineering, generation planning and fuel planning. In 1983, I was promoted to Fossil Fuels Manager for KG&E. In April 1992, following the merger that created WR, I was promoted to Director of Fuel Supply for WR. In those positions, I spent nearly a decade coordinating the supply and transportation of fuels.

I joined Seminole in my current position as its Director of Fuel Supply on February 1, 2002. I am Seminole's designated member to the National Coal Transportation Association and was recently seated as a member of the Board of Directors of this organization. I also represent Seminole on, and serve as chair of, the Florida Reliability Coordinating Council (FRCC) Gas Electricity Interdependency Task Force.

Q. Have you previously testified before the Commission?

A. No. However, I have testified and been accepted as an expert witness on fuel supply, transportation and forecasting in various electric and natural gas proceedings before the Kansas Corporation Commission. I have also presented testimony before several federal agencies on behalf of KG&E and WR.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to introduce and describe the Seminole fuel price forecasts used in the evaluations that led to the selection of SGS Unit 3, explain Seminole's fuel procurement strategy related to the Seminole Generating Station (SGS), and address the supply of fuels for SGS Unit 3.

Q. Are you sponsoring any exhibits in this case?

A. Yes. I have prepared and attached to my testimony the following Exhibits:

Exhibit WJR-1, August 2003 Fuel Price Forecast

Exhibit WJR-2, April 2004 Fuel Price Forecast

Exhibit WJR-3, December 2004 Fuel Price Forecast

Exhibit WJR-4, August 2005 Fuel Price Forecast

Exhibit WJR-5, June 2005 Global Insights Report

Exhibit WJR-6, July 2005 Pace Global Energy Services Report

Q. Are you sponsoring any portion of Seminole's Need Study in this docket?

A. Yes, I am co-sponsoring portions of Sections IV and VI of Seminole's Need Study, and I am sponsoring Appendices C and F to the Need Study.

I. SEMINOLE'S FUEL PRICE FORECASTS

Q. Please describe Seminole's fuel price forecast methodology.

A. Seminole first prepares a forecast of fuel supply (commodity) and fuel transportation prices for fuel purchases under Seminole's existing contracts. These internally generated forecasts start with known prices and rates for contract fuels and their related transportation prices. Over the current contract term, prices are escalated based on underlying contractual pricing formulae.

For fuel supply requirements not currently covered by contract, Seminole uses long term spot market prices (i.e., long term spot market prices are used for all such long term fuel requirements, including the significant portion of such future fuel supply which will likely be under contract in future years). Most spot market prices are provided by an independent forecasting consultant, Global Insights. To address short-term price volatility, Seminole periodically updates the early years of its forecast by using other sources of price information (e.g., NYMEX pricing for natural gas and oil and recent bid prices for coal and pet coke). In the analyses undertaken to assess Seminole's 2012 need, Seminole's use of these short term price adjustments had minimal impact, because by the time of the in service date of the options being considered, 2012, the fuel forecasts used only long term pricing provided by Global Insights.

Seminole develops internally the projections of fuel transportation costs (including related services) that are not presently covered by contract. Fuel transportation includes costs paid directly to transporters (railroads, pipelines, trucking companies, etc.) plus the costs for related services required to deliver fuels to Seminole (i.e., railcars, import terminal services). When a contract renewal is required, Seminole analyzes market conditions and historic price increases to insure that future costs reflect provide for such events.

Q. Does Seminole consider fuel price volatility in the future planning of its operations?

A. Yes. Seminole utilizes sensitivity analyses to assure that its plans are resilient to market shifts and robust relative to fuel price uncertainty. As described further in Mr. Mahaffey's testimony, Seminole has used a combination of qualitative and quantitative techniques to assess the risks associated with fuel price uncertainty. Seminole also seeks to maintain a diverse fuel supply portfolio, which combines long-term and short-term commitments as a hedge against market uncertainty.

Q. What fuel price forecasts have been used by Seminole in its economic assessments related to SGS Unit 3?

A. Seminole has relied primarily on a long term fuel price forecast. During the time period in which Seminole assessed its need for base load capacity and evaluated alternative resources (2003 – 2005), Seminole updated its long term fuel price forecast to reflect new information provided by Global Insight, the independent forecasting consultant retained by Seminole. This periodic updating of fuel price assumptions is part of Seminole's normal practice of updating key variables to ensure that its economic models are current.

During the period in which Seminole's 2012 base load capacity need was assessed, Seminole updated its fuel forecasts three times. The four fuel forecasts Seminole used are included as Exhibits WJR-1, WJR-2, WJR-3 and WJR-4.

Exhibit WJR-1 is Seminole's August 2003 fuel price forecast based upon a March 2003 updated forecast by Global Insights. This forecast was used by Seminole in estimating Seminole's base load needs at the time Seminole formulated its April 2004 RFP.

Exhibit WJR-2 is Seminole's April 2004 fuel price forecast based upon a December 2003 updated forecast by Global Insights. This fuel forecast was used in economic screening of self-build and purchased power alternatives in the RFP evaluation.

Exhibit WJR-3 is Seminole's December 2004 fuel price forecast based upon an October 2004 updated forecast by Global Insights. This fuel price forecast was used in Seminole's initial present worth revenue requirements analyses in early 2005 which were used as the underlying base case for the R.W. Beck risk assessment.

Exhibit WJR-4 is Seminole's August 2005 fuel price forecast based upon a June 2005 updated forecast by Global Insights. This fuel price forecast was used in Seminole's final economic results underlying the need application and is Seminole's most recent fuel forecast (as of the time of Seminole's need filing). It is a delivered price forecast for various fuels used on Seminole's system and covers the 25 year period from 2006 through 2030.

Exhibit WJR-5 is Global Insights' written report associated with its June 2005 fuel price forecast depicted in Exhibit WJR-4. This report contains background information and the rationale underlying the June 2005 fuel price forecast.

Q. Please address Seminole's current forecast of delivered natural gas prices.

A. Seminole forecasts the delivered natural gas prices for both pipeline systems serving Florida: the Florida Gas Transmission (FGT) and Gulfstream Natural Gas (GS) systems. The natural gas price starts at $ 9.11 /MMBtu for GS and at $9.25/MMBtu for FGT in 2005. The difference in cost between the pipelines relates to the amount of fuel reimbursement required for the pipelines' compressor operations. The forecast anticipates that delivered natural gas prices will decline from current levels until 2010, when they will begin to rise again.

Because the near term commodity price of natural gas for 2005 through 2009 was heavily impacted by the 2005 hurricanes (this is captured by the use of NYMEX pricing rather than Global Insights longer term forecast), any comparison of a near term price to a future price is not representative of the future market expectations for price increases. A valid comparison can, however, be made between the 2010 and 2030 prices. In 2010, natural gas prices delivered on the GS and FGT pipelines respectively are \$6.16 and \$6.25/MMBtu and increase to \$9.91 and \$10.08/MMBtu in nominal dollars (i.e., no adjustment to remove the effects of inflation) in the year 2030. Over this 20 year period the nominal gas price grows at an average annual rate of 2.4% per year.

Q. Please address Seminole's current forecast for delivered distillate oil.

A. As with natural gas, the near term market prices for distillate oil (diesel) have been impacted by recent events and do not provide appropriate comparisons to future prices. However, the 2010 and 2030 prices provide a good indication of long term growth in prices, excluding impacts from recent events. The diesel price starts at \$10.86/MMBtu in 2010 and increases to \$14.37/MMBtu in nominal dollars in the year 2030. Over this 20 year time period the nominal diesel price grows at an average rate of 1.4% per year.

Q. Please address Seminole's current forecast of delivered coal and petroleum coke prices.

A. Traditionally, the main source of coal for SGS comes from the Illinois Basin, and this coal's delivered prices range from $2.16/MMBtu in 2005 to $3.35/MMBtu in 2030, which represents a nominal coal price growth at an average rate of 1.8% per year for the 25 year period.

The delivered price for petcoke starts at $1.77/MMBtu in 2005 and increases to $3.12/MMBtu for 2030, which represents a nominal petcoke price growth at an average rate of 2.3% per year for the 25 year period.

Consistent with recent experience, the near term prices for solid fuels are not forecast to be as volatile as prices for natural gas and diesel. Also, as the forecast shows, over the entire 25 year term coal enjoys significant price advantages relative to natural gas. Thus, while gas combined cycle technology had for a number of years served as the technology of choice for base load capacity, sustained gas price increases for the last several years as well as a forecast of high sustained gas prices and a significant differential between the cost of gas and coal suggest that coal would be a preferable fuel for a base load technology.

Q. Are the fuel price forecasts used by Seminole in its resource planning analyses that led to the selection of SGS Unit 3 reasonable?

A. Yes. Seminole used the same fuel price forecast methodology in developing each of the four fuel price forecasts used in the resource planning analyses that led to the selection of SGS Unit 3. That methodology is a reasonable methodology that accounts for both fuel and transportation costs that are under contract and those that are not under contract. For commodity prices not under contract, Seminole uses forecasts from a reputable independent forecasting consultant, and Seminole has updated those forecasts as circumstances warranted. Each of the forecasts used in Seminole's resource planning analyses was reasonable for that purpose at the time it was made, and the most recent of those forecasts continues to be used by Seminole for planning purposes today.

II. FUEL PROCUREMENT AND TRANSPORTATION STRATEGY

Q. How much fuel will be required to operate the Seminole Generating Station after completion of SGS Unit 3?

A. SGS is expected to burn over 6 million tons of solid fuel per year once SGS Unit 3 becomes operational.

Q. What fuels will be used by the SGS Unit 3?

A. As explained by Mr. Opalinski, Seminole plans to burn coal in combination with as much as 30% petcoke in SGS Unit 3. This is the same mix currently employed in SGS Units 1 and 2. Similar to SGS Units 1 and 2, distillate oil will be utilized as a start up and flame stabilization fuel. Distillate oil use at SGS (for unit startup and flame stabilization purposes) has amounted to only a very small portion of SGS total fuel requirements (i.e., approximately 0.3% of total mmBtu).

Q. Please explain Seminole's strategy for procuring solid fuel for SGS Units 1 and 2 and the new SGS Unit 3.

A Seminole's primary objective is to achieve a balanced portfolio of long term and shorter term opportunity (spot market) commodity supply arrangements. Seminole will develop complimentary transportation arrangements.

Seminole is currently operating under long term coal supply arrangements with Alliance Coal, LLC to supply 2,750,000 tons of coal a year through the year 2012, with an option to extend 4 years through 2016. The Alliance contracts and other long term contracts act as a physical hedge to mitigate fuel availability and price risk, providing reliable supply and stable pricing with quarterly price adjustments tied to industry indices. Currently, Alliance provides approximately 70% of Seminole's annual coal requirements from multiple mines in Kentucky and Illinois. Seminole intends that in future years a significant portion of its solid fuel supply will continue to be met through long term supply contracts. Seminole's remaining annual requirements for solid fuels (coal and/or petroleum coke) which exceed the long term contract supply will be secured through spot market agreements for specified quantities for periods typically ranging from 1 to 18 months.

Seminole routinely reviews the short and long term market for opportunities and researches other alternative fuel sources such as petroleum coke and other non traditional fuel types to obtain the lowest delivered cost of fuel at the quality parameters required. Petroleum coke is an opportunity fuel from both domestic and international refineries that can be delivered directly to SGS by rail from domestic sources and/or by rail through terminal facilities located along the U.S. coast.

III. FUEL AVAILABILITY FOR SGS UNIT 3

Q: Has any independent evaluation of fuel availability been undertaken?

A. Yes. Seminole requested Pace Global Energy Services ("Pace Global") to provide an independent review of the long term supply availability of solid fuels (petcoke and coal) for the Seminole Generating Station. Pace Global's report found that "the supply of solid fuel from domestic and foreign sources will be adequate over the study period (present through the year 2040) to meet the requirements of Seminole's existing and new generation." The report also states that "over the period 2005-2040, adequate supplies of petroleum coke will be available from domestic and foreign suppliers to meet the partial or full fuel demand requirements of new solid-fuel-fired generation in Florida."

In light of Pace Global's findings, Seminole envisions a flexible solid fuel supply strategy to maintain reliable and economical sources of solid fuel from domestic and foreign sources of supply. Seminole intends to continue to use petroleum coke as a supplemental fuel when it is economical and meets environmental requirements. The Pace Global Report is included as Exhibit WJR-6.

Q. What is Seminole's current arrangement for transporting solid fuel to SGS?

A. Seminole currently transports all solid fuels to SGS by way of CSX rail. CSX provides for the transportation of coal from the major eastern U.S. supply regions of Illinois Basin, Central Appalachia and North Appalachia and provides for coal imports through terminals accessed by CSX at Mobile, Alabama, Charleston, South Carolina, and Port St. Joe, Florida. Seminole is working with CSX to add other terminals (e.g., Tampa, Florida), to the CSX Contracts.

CSX transportation is provided under a long term rail transportation contract, which runs through December 31, 2008.

Q. What are Seminole's coal transportation alternatives for meeting its long term needs for SGS Units 1, 2, and 3?

A. Seminole will negotiate for an extension or renewal of the contract with CSX for service beginning in 2009. Such an extension or renewal would meet Seminole's long term fuel supply objectives. CSX has confirmed that the additional transportation capacity required for SGS Unit 3 is available, and that CSX requires 1-2 years advance notice to ramp up equipment and crew levels to accommodate the additional tonnage. Such future rail rates are subject to negotiation and/or resolution before the Surface Transportation Board.

In addition to its CSX relationship, Seminole is also looking at other rail, as well as water, delivery alternatives. For example, Seminole is presently researching the potential use of the Norfolk Southern Railroad, which could provide alternative rail access to east coast international coal terminals, as well as to coal supply from mines in Virginia, Kentucky and Indiana. While this and other alternatives are still being developed, if implemented they would give Seminole additional fuel supply and transportation alternatives.

Q. **When does Seminole plan on entering into the long term fuel and transportation contracts required to support SGS Unit 3?**

A. Seminole will begin a formal process for solid fuel supply acquisition upon receipt of its environmental permits. Before December 31, 2008, Seminole will be required to complete the negotiations for an extension or renewal of its existing CSX contract, or make other transportation arrangements. The resulting contract(s) are anticipated to include the arrangements for the transportation of solid fuel for SGS Unit 3, which is currently expected to begin inventory build up during 2011.

Q. **In your opinion, will SGS Unit 3 have a reliable supply of fuel?**

A. Yes, I am confident there will be reliable sources of fuel for SGS and reliable transportation for that fuel. This conclusion is based on my own experience as well as the Pace Global fuel supply assessment commissioned by Seminole and on Seminole's assessment of its transportation options for that fuel. Seminole will continue to maintain a balanced portfolio of long term and short term supply so as to maintain flexibility, minimize the delivered cost of fuel, and address any emergency situations that could affect supplies to SGS.

Q. Does this conclude your testimony?

A. Yes.

AUGUST 2003 FUEL PRICE FORECAST (Nominal $/MBtu)
Based on the March 2003 Global Insight Long Term Fuel Price Forecast
DELIVERED PRICES (2)

Year	Distillate Oil	GS (1) Natural Gas	Pittsburg Seam 13,000 Btu/Lb	Petroleum Coke 14000 Btu/Lb
2005	5.02	5.01	1.79	0.97
2006	5.31	4.84	1.78	0.99
2007	5.51	4.96	1.78	1.00
2008	5.66	5.11	1.80	1.02
2009	5.80	5.21	1.86	1.03
2010	5.97	5.36	1.89	1.05
2011	6.15	5.63	1.91	1.07
2012	6.38	5.83	1.92	1.09
2013	6.73	6.00	1.93	1.11
2014	7.04	6.13	1.94	1.13
2015	7.38	6.33	1.96	1.15
2016	7.72	6.50	1.98	1.18
2017	8.03	6.66	2.00	1.20
2018	8.34	6.86	2.02	1.23
2019	8.70	7.04	2.04	1.26
2020	9.04	7.24	2.06	1.28
2021	9.38	7.49	2.08	1.31
2022	9.75	7.73	2.11	1.34
2023	10.14	7.99	2.13	1.37
2024	10.57	8.24	2.15	1.41
2025	10.97	8.50	2.18	1.44
AAGR (4)				
2005-2025	4.0%	2.7%	1.0%	2.0%
2010-2025	4.1%	3.1%	0.9%	2.1%

Notes:

(1) Natural gas delivered into Florida market area.

(2) Delivered prices represent:

Distillate Oil: 1) Commodity price to terminals inland from Gulf of Mexico or Atlantic ports plus 2) an appropriate adder for transportation by truck to SGS.

Natural Gas: 1) Commodity price of natural gas; plus 2) FERC tariff fuel reimbursement and 3) FERC tariff variable fees (incl. interruptible transportation) delivered prices do not include any FERC transportation capacity reservation charges.

Coal: 1) Commodity price of coal from Pittsburg seam plus 2) rail transportation, freight rate, plus cost of rail cars.

Petcoke: Similar to coal.

(3) AAGR means Average Annual Growth Rate

APRIL 2004 FUEL PRICE FORECAST (Nominal $/MBtu)
Based on the December 2003 Global Insight Long Term Fuel Price Forecast
DELIVERED PRICES (3)

Year	Distillate Oil	FGT (1) Natural Gas	GS (2) Natural Gas	Illinois Basin High Sulfur 12,000 Btu/Lb	Petroleum Coke 14000 Btu/Lb
2005	6.68	6.30	6.24	1.79	1.06
2006	6.22	5.88	5.83	1.80	1.10
2007	6.06	5.57	5.52	1.84	1.13
2008	5.90	5.47	5.42	1.89	1.16
2009	5.85	5.38	5.33	2.13	1.36
2010	6.25	5.38	5.33	2.20	1.40
2011	6.47	5.60	5.55	2.27	1.43
2012	6.70	5.78	5.73	2.31	1.46
2013	7.05	5.99	5.93	2.35	1.48
2014	7.36	6.16	6.10	2.43	1.54
2015	7.68	6.39	6.33	2.48	1.59
2016	8.01	6.56	6.50	2.53	1.61
2017	8.31	6.77	6.71	2.57	1.62
2018	8.62	7.00	6.93	2.63	1.64
2019	8.97	7.24	7.17	2.72	1.70
2020	9.33	7.49	7.42	2.78	1.72
2021	9.69	7.74	7.66	2.83	1.75
2022	10.07	8.01	7.93	2.89	1.77
2023	10.48	8.27	8.20	2.95	1.79
2024	10.93	8.56	8.48	3.05	1.86
2025	11.34	8.86	8.78	3.12	1.88
2026	11.79	9.16	9.07	3.18	1.91
2027	12.27	9.48	9.39	3.25	1.93
2028	12.76	9.82	9.73	3.31	1.96
2029	13.31	10.16	10.06	3.38	1.99
2030	13.82	10.52	10.42	3.45	2.01
AAGR (4)					
2005-2030	3.0%	2.1%	2.1%	2.7%	2.6%
2010-2030	4.0%	3.4%	3.4%	2.3%	1.8%

Notes:

(1) FGT means Florida Gas Transportation

(2) GS means Gulfstream Natural Gas System

(3) Delivered prices represent:

Distillate Oil: 1) Commodity price to terminals inland from Gulf of Mexico or Atlantic ports plus 2) an appropriate adder for transportation by truck to SGS.

Natural Gas: 1) Commodity price of natural gas; plus 2) FERC tariff fuel reimbursement and 3) FERC tariff variable fees (incl. interruptible transportation); delivered prices do not include any FERC transportation capacity reservation charges.

Coal: 1) Commodity price of coal from Illinois basin plus
2) rail transportation, freight rate, plus cost of rail cars.

Petcoke: Similar to coal.

(4) AAGR means Average Annual Growth Rate

DECEMBER 2004 FUEL PRICE FORECAST (Nominal $/MBtu)
Based on the October 2004 Global Insight Long Term Fuel Price Forecast
DELIVERED PRICES (3)

Year	Distillate Oil	FGT (1) Natural Gas	GS (2) Natural Gas	Illinois Basin High Sulfur 12,000 Btu/Lb	Petroleum Coke 14000 Btu/Lb
2005	9.95	8.96	8.87	2.61	1.89
2006	8.69	8.27	8.20	2.41	1.61
2007	7.43	7.11	7.04	2.10	1.32
2008	7.28	6.87	6.80	1.78	1.04
2009	7.30	6.62	6.56	2.03	1.24
2010	7.29	6.38	6.32	2.09	1.31
2011	7.23	6.13	6.07	2.15	1.37
2012	7.17	6.27	6.21	2.19	1.40
2013	7.24	6.44	6.38	2.23	1.44
2014	7.48	6.57	6.51	2.30	1.52
2015	7.75	6.76	6.70	2.34	1.56
2016	8.02	6.92	6.86	2.38	1.62
2017	8.29	7.12	7.05	2.42	1.67
2018	8.56	7.17	7.10	2.46	1.72
2019	8.83	7.39	7.32	2.54	1.81
2020	9.10	7.61	7.54	2.58	1.87
2021	9.37	7.81	7.73	2.63	1.91
2022	9.65	8.01	7.93	2.67	1.94
2023	9.92	8.21	8.13	2.72	1.97
2024	10.20	8.42	8.34	2.81	2.04
2025	10.48	8.63	8.55	2.86	2.07
2026	10.76	8.85	8.76	2.90	2.10
2027	11.04	9.07	8.99	2.95	2.12
2028	11.33	9.30	9.21	3.00	2.15
2029	11.61	9.54	9.45	3.06	2.18
2030	11.90	9.78	9.69	3.11	2.22
AAGR (4)					
2005-2030	0.7%	0.4%	0.4%	0.7%	0.6%
2010-2030	2.5%	2.2%	2.2%	2.0%	2.7%

Notes:

(1) FGT means Florida Gas Transportation

(2) GS means Gulfstream Natural Gas System

(3) Delivered prices represent:

Distillate Oil: 1) Commodity price to terminals inland from Gulf of Mexico or Atlantic ports plus 2) an appropriate adder for transportation by truck to SGS.

Natural Gas: 1) Commodity price of natural gas; plus 2) FERC tariff fuel reimbursement and 3) FERC tariff variable fees (incl. interruptible transportation); delivered prices do not include any FERC transportation capacity reservation charges.

Coal: 1) Commodity price of coal from Illinois basin plus
2) rail transportation, freight rate, plus cost of rail cars.

Petcoke: Similar to coal.

(4) AAGR means Average Annual Growth Rate

AUGUST 2005 FUEL PRICE FORECAST (Nominal \$/MBtu)
Based on the June 2005 Global Insight Long Term Fuel Price Forecast
DELIVERED PRICES (3)

Year	Distillate Oil	FGT (1) Natural Gas	GS (2) Natural Gas	Illinois Basin High Sulfur 12,000 Btu/Lb	Petroleum Coke 14000 Btu/Lb
2005	12.70	9.25	9.11	2.16	1.77
2006	12.91	9.36	9.23	2.39	1.55
2007	12.19	8.85	8.73	2.10	1.58
2008	11.64	7.98	7.87	2.10	1.64
2009	11.21	7.11	7.02	2.37	1.92
2010	10.86	6.25	6.16	2.44	2.00
2011	9.28	6.41	6.32	2.49	2.07
2012	9.44	6.56	6.47	2.53	2.12
2013	9.48	6.94	6.84	2.57	2.17
2014	9.49	7.13	7.04	2.60	2.22
2015	9.50	7.26	7.16	2.64	2.28
2016	9.61	7.41	7.31	2.67	2.35
2017	9.74	7.89	7.78	2.74	2.45
2018	9.88	7.41	7.30	2.78	2.52
2019	10.02	7.75	7.64	2.82	2.58
2020	10.16	8.05	7.93	2.85	2.65
2021	10.68	8.16	8.04	2.89	2.70
2022	11.07	8.38	8.26	2.97	2.78
2023	11.56	8.59	8.47	3.01	2.82
2024	11.98	8.81	8.68	3.05	2.86
2025	12.41	9.03	8.90	3.09	2.90
2026	12.80	9.23	9.10	3.13	2.93
2027	13.20	9.44	9.30	3.22	3.02
2028	13.57	9.65	9.51	3.26	3.05
2029	13.95	9.87	9.73	3.30	3.09
2030	14.37	10.06	9.91	3.35	3.12
AAGR (4)					
2005-2030	0.5%	0.3%	0.3%	1.8%	2.3%
2010-2030	1.4%	2.4%	2.4%	1.6%	2.3%

Notes:

(1) FGT means Florida Gas Transportation

(2) GS means Gulfstream Natural Gas System

(3) Delivered prices represent:

Distillate Oil: 1) Commodity price to terminals inland from Gulf of Mexico or Atlantic ports plus 2) an appropriate adder for transportation by truck to SGS.

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2) rail transportation, freight rate, plus cost of rail cars.

Petcoke: Similar to coal.

(4) AAGR means Average Annual Growth Rate

GLOBAL INSIGHT

Energy Price Forecast

Prepared for
Seminole Electric

June 2005

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Short-term Outlook

Overview

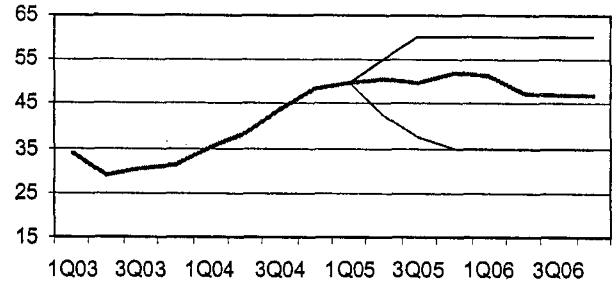
The past month has done little to ameliorate the "anomalies, paradoxes, mysteries, and uncertainties" we commented on a month ago. Crude price have fallen further, scarcely surprising as stocks have risen higher, but despite crude stocks in the United States now at levels last seen in mid 1999, when the price of WTI was around $20/barrel, prices still remain close to $50/barrel. Accepting that the historic relationship between crude prices and stock levels in days cover is currently in abeyance, nevertheless one must ask how much longer can stocks go on building without some major downward adjustment in prices? Latest data from the IEA includes a further upward adjustment to first quarter OECD stock levels so that end March cover is now estimated at some 53 days. If OPEC carries on producing at close to current levels, as it is indicating it will, then total OECD stocks could potentially remain around 53 days all year. If that is so then there is no reason to expect serious problems in the fourth quarter, and one of the key underpinnings of high prices would be removed. For the present, however, the market is likely to remain skeptical of such a potentially rosy outcome and the latest fall in prompt prices has merely served to steepen the contango; clearly concern remains about the fourth quarter.

OPEC's stance cannot be taken for granted. Although Ministers take every opportunity to emphasize their role in promoting market stability and price moderation, the facts are not so clear. Several points should be noted: (1) first quarter production was at least 0.5 million b/d below that in the fourth quarter, (2) April output barely exceeded the new 27.5 million b/d target for the OPEC 10, (3) discussion on the second 0.5 million b/d tranche of extra production agreed at the March 16 meeting was quickly shelved when prices softened in April, despite prices remaining at levels that OPEC spokesmen constantly affirm are "too high", (4) Saudi prices for Western markets for June are set at unattractive levels, possibly not unreasonably as it is in the East that crude stocks are low, but scarcely a factor promoting lower prices. OPEC will have a few weeks to digest the implications of the latest IEA data, and June's data will be published nearly a week before the next Ministerial meeting, on 15 June. We would not be surprised to hear talk of output cuts.

Although global stocks appear to be rising strongly, it is more often US data that moves the market. US refineries have been slow to return from maintenance, but are expected to ramp up output steeply in coming weeks which will pull down crude stocks. Gasoline stocks will decline anyway. Although both of these developments are normal for the time of year, reports of lower stocks could put an end to further falls in the crude price. Moreover, the next bout of speculative pressure could be an upward push.

Our expectation is that prices will not fall much further, will hover around current levels for a month or two and will then begin to rise again. OPEC actions could be the factor that will precipitate the turnaround, but may not be. We expect that concerns about the fourth quarter will remain, and will focus on the increase in call between the third and fourth quarter without looking too closely at the role that stocks might play in alleviating this increase. An outside possibility exists, however, that slowing economic growth and further rises in stocks could see prices plunge sharply.

WTI Price Outlook Scenarios
(Quarterly, dollars per barrel)



Market Review

Average prices in April were lower than in March as the market seesawed downwards. WTI peaked at nearly $57.50/barrel on April 1, fell to around $50/barrel and subsequently spiked to nearly $55/barrel in the middle weeks, and ended the month some $7/barrel below where it started, having briefly dropped below $49/barrel on April 29. In early May prices encountered an important psychological support level at $50/barrel, and tended to rebound quickly whenever they edged below this level. WTI broke through the barrier in mid May and is currently trading n the $47-48/barrel range for prompt crude. The market in the Atlantic basin is still characterized by a steep contango, with August WTI trading at over $2/barrel above June, and December at nearly $4/barrel above June. Although this reflects prompt weakness and expectations of later strength, paradoxically it also helped to underpin the $50/barrel support level as any fall was quickly offset by short covering, which can be profitable in this market structure.

Marker Crude Prices
(Dollars per barrel)

	March	April	May 1-18
WTI	54.28	51.89	49.98
BFO	53.03	52.85	48.78
OPEC Reference Basket	49.49	47.68	46.85

BFO prices have moved broadly with WTI but the differential between the two markers has become very narrow. WTI prices are depressed by very high crude stocks in the Midwest, as refineries have been slow to return fully from maintenance. Meanwhile, BFO prices have been supported by an open arbitrage to Asia

Pacific for Atlantic Basin sweet crudes. Movements of West African crudes to Asia Pacific in May are expected to be at the highest level since last October, when refiners were building stocks for the winter.

A number of factors underlie the downward trend in prices. Rising US crude stocks, seen as a proxy for global stocks, have reached levels not seen since July 1999. Gasoline stocks are also looking healthy, although the market is still nervous about the summer. The prospects for total crude supply look good following upward revisions to OECD stocks data and as OPEC output continues to rise and is seen as rising further, albeit there remains an imbalance in terms of crude quality, with the market looking for light/sweets and only heavier/sours on offer at the margin. Saudi Aramco reports that is has offered its term customers more crude but has had no takers of the quality on offer. There seems to be no shortage of prompt supplies. The belief is developing that demand growth rates are slowing; concern about the impact of high oil prices on economic activity is growing, while the data suggest slowing growth in the United States, and possibly China, the two primary motors of oil demand growth. Speculative support has also faded as strengthening of the U.S. dollar has contributed to the hedge funds moving investments away from commodities and into currency. The net long position of the non-commercial players on NYMEX has fallen very sharply, from a new peak at the beginning of April at over 88 thousand lots, most recent data shows holdings down to less than one hundred lots.

For some weeks, there was a widespread feeling among market analysts and commentators that prices "ought" to have fallen further. Most believed that the $50/barrel support level would eventually be breached and then prices would fall to the mid $40s/barrel, before rising again later in the summer and, in the view of some, reaching new records next winter. Now that the $50 support level has been breached, the market needs to catch its breath and decide where it goes next. The contango structure is still being maintained, however, by strong expectations of tightness later in the year, whether in crude markets as the U.S. and Asia-Pacific compete for available supplies, or in product markets as demand stretches the capabilities of refining systems, especially in the United States, and has actually deepened since mid month.

Demand and Supply Fundamentals

Economics

Doubts about the world economy's short-term outlook have once again increased, mainly because of renewed inflation worries, high global energy prices, and signs of weakness in some G-7 economies. Furthermore, the global economy's growth engine—the US economy—appears to have downshifted this year more than had been anticipated by most forecasters, including Global Insight. This less robust economic outlook is reflected in recent financial market volatility and lower yields on long-term government bonds. While the downside risks have increased, one should not exaggerate them. Despite its slowdown, the US economy still has a considerable amount of steam, most of Asia outside of Japan is going very strong, and other emerging markets are growing at paces well above their trend. In a similar vain inflation concerns appear to be excessive, since the global economy's persistent gap between potential and actual output should continue to constrain inflationary pressures around the globe, as well as dissuade central banks from tightening their monetary policies too aggressively. Furthermore, periodic currency appreciation in countries that float their exchange rates against the US dollar has further reduced inflationary pressures in many countries, including most major economies in Europe and Asia, giving the monetary authorities a strong reason to delay raising their policy rates. To be sure, the dollar's depreciation does act as a headwind for economies with floating currencies against the greenback, such as the Eurozone members. In a world where the US economy remains the main engine of global growth, however, a depreciating US dollar will be the only remedy for avoiding global stagnation. Given the huge US current account deficit, there can only be two ways of escaping from this predicament. Either the other major industrialized countries adopt policies that put their economies on a much more robust growth path, or there will be a dollar crash and US recession, which would in all likelihood trigger a global recession and unleash deflationary pressures around the globe.

Forecast Highlights: Global Insight's latest bottom-up forecast of the global economy, which was completed 15 May, projects world economic growth to slow from 4.1% in 2004 to 3.1% in 2005. The estimated number for 2004 represents a substantial improvement from the world economy's lackluster performance during the preceding three years; however, it no longer has any significant cushion to allow for potential policy errors or external shocks, since the projected, 3.1% annual pace is equal the global economy's long-term trend growth rate. On a year-on-year basis, we estimate the world economy's quarterly growth decelerated to 3.5% in the fourth quarter of 2004, after having peaked at 4.4% in the second quarter of last year. We estimate global growth further decelerated in the first quarter of this year, to about 3% year-on-year (y/y), but moderating global oil prices and strong international trade growth should sustain the pace close this trend rate for the remainder of 2005. With recent data releases indicating that the US economy is holding up better in the second quarter than had been anticipated, we expect adjustments to our forecasts will elevate our June global GDP growth projections by at least one or two tenths of a point, which puts the world economy in a less-vulnerable position in case there are adverse shocks or policy errors.

Real GDP Growth, World and Major Seven Economies
(Year-on-Year percent change)

	2004	2005				2006
	Q4	Q1	Q2	Q3	Q4	Q1
US	3.9	3.6	3.5	3.4	3.2	3.0
Canada	3.0	2.9	2.5	2.4	2.6	2.7
France	2.3	2.0	1.8	2.3	1.9	2.0
Germany	0.4	0.5	0.5	0.9	1.6	1.3
Italy	0.8	-0.2	-0.3	-0.4	0.5	1.3
UK	2.9	2.8	2.4	2.4	2.2	2.2
Japan	1.0	0.3	0.7	1.1	1.5	1.3

World	3.5	3.1	3.0	3.2	3.2	3.1

Demand

Latest estimates of demand continue to show divergent views of the prospects for this year. Whereas the IEA has made another marginal reduction to its growth estimate, albeit leaving it at 1.8 million barrels per day (b/d) in round numbers, and most other analysts are also tending to hold or even reduce their growth estimates, this month the U.S. Department of Energy (DOE) has *increased* its estimate of growth to 2.3 million b/d. The increase results from a 0.1 million b/d downward adjustment to 2004 actuals, but the effect is to leave the DOE much more optimistic than others.

Provisional demand data for the first quarter shows European demand much weaker than expected, primarily due to very low deliveries of gasoil and diesel in Germany. This may be partly because the timing of Easter meant the reduced number of working days occurred in the first quarter this year, but also reflects the ongoing reluctance of German consumers to restock with heating oil at current prices, and may be indicative of economic weakness. Elsewhere North American demand also shows signs of a slowing in gasoline sales, thought to be a response to high prices at the pump, and in diesel, as truck tonnage movements are reported down. Fuel oil use has been high, however, in response to high natural gas prices, and jet continues to grow strongly. In Asia, Japanese nuclear power station output remains below expectations which results in increased use of low sulfur fuel oil (LSFO) and crude for direct burning, and in South Korea demand has recently been looking up, with higher consumption in both the industrial and transport sectors.

For China, there are the usual conflicting reports. Some reports focus on signs of a slowing in apparent demand, but this is heavily influenced by stocks movements, which are believed to have been abnormal over the past year. If this effect is excluded, it may be that a more steady growth pattern can be seen in which slowdown is scarcely evident. A further complication is the impact of Government price control measures that shield consumers from the full effect of international prices and so diminish the incentive to economize. At the same time, however, the inability to recover their costs discourages traders from importing products, so supply falls short of potential demand. If domestic oil prices were raised and electricity prices de-controlled, that would end one constraint on consumption, but it might also lead to price-induced conservation. What the net result of these two effects would be remains a matter of substantial uncertainty.

Non-OPEC Production

There is general agreement that non-OPEC production will increase this year but views differ concerning the scale and timing of the increase. There is also general agreement that, whatever the increase, it will not match the rise in demand so an increased call on OPEC is inevitable. The uncertainties over timing are significant in that most of the increases are scheduled for the second half of the year. If they come through on time, that will ease the pressure on OPEC and the reduction of its spare capacity cushion in the winter quarters. If the more pessimistic estimates prove correct -- especially if combined with robust demand growth -- then the winter quarters could be very tight indeed.

Globally production from around 60 new projects is due this year but the location of the largest scheduled increments - Russia, Brazil, and Angola, with increases also due in the U.S. Gulf of Mexico - explains and underlines the uncertainty over timing. In Russia conflicting projections create uncertainty, while in the deep offshore waters of Brazil and Angola the scope for last minute technical problems remains substantial. In the Gulf of Mexico there remains scope for further technical problems and delays, and for summer disruptions from hurricanes; full recovery from hurricane Ivan is still some months away. The BTC pipeline carrying Azeri crude from the Caspian to the Mediterranean is due to start filling and testing in July, with first exports due in the fourth quarter, resulting in further large increments to supply next year, but any problems that come to light during testing could delay first exports into next year. Estimates of total annual growth are between 0.5 million b/d and 1.0 million b/d, but in the light of the record of recent years we are inclined to discount the higher end estimates and continue to include a non-specific downward adjustment averaging some 0.2 million b/d over the balance of the year.

OPEC Production

OPEC output rose by a further 0.5 million b/d in April to approaching 29.5 million b/d (IEA assessment), with the largest increase again in Saudi Arabia but with other countries recording smaller rises, though Iraq remains stuck on some 1.8 million b/d. Although OPEC ministers continue to make much of their efforts to supply what the market needs and to contribute to market stability and a lessening of prices, these protestations need to be tempered by the facts, as emphasized in the Forecast Highlights section; OPEC rhetoric and action continue to be slightly out of sync. In fairness, it should be added that further output increases are expected in May, but any decision on further formal additions now seems scheduled to await discussion at the June 15 meeting.

The IEA's assessment of OPEC capacity is unchanged this month, save for a decision to settle on a figure for Saudi capacity of 10.5 million b/d in place of the 10.0-10.5 range shown for some months, and leaves effective spare capacity at some 1.3 million b/d, almost all in Saudi Arabia. The assessment of OPEC capacity will be raised steadily as the year progresses as a succession of new projects come on stream. By the end of the year, sustainable capacity should be conservatively at least 0.5 million b/d higher than at the beginning. This excludes any increases in Saudi Arabia, where the build up in Qatif and Abu Safah should take the total increment to 1 million b/d or more, while additions from countries where current reliable information is lacking may add more still.

OPEC Compliance in April 2005
(Million barrels per day)

	Target as of Mar.16	Production (1) Apr 2004	Production vs. Target	Estimated Sustainable Capacity (2) (IEA Mar 05)	Spare Capacity
Algeria	0.878	1.35	0.47	1.35	0.00
Indonesia	1.425	0.95	-0.48	1.00	0.05
Iran	4.037	3.90	-0.14	4.00	0.10
Kuwait (3)	2.207	2.45	0.24	2.50	0.05
Libya	1.473	1.64	0.17	1.65	0.02
Nigeria	2.265	2.45	0.19	2.45	0.00
Qatar	0.713	0.78	0.07	0.80	0.02
Saudi Arabia (3)	8.937	9.45	0.51	10.50	1.05
UAE	2.400	2.45	0.05	2.55	0.10
Venezuela	3.165	2.16	-1.01	2.20	0.05
OPEC 10	**27.500**	**27.57**	**0.08**	**29.00**	**1.43**
Iraq (4)		1.83		1.95	0.12
Total OPEC		**29.40**		**30.95**	**1.55**
Excl. Venezuela/Nigeria/Indonesia/Iraq					1.33

1. Secondary source estimates of OPEC production regulary differ. The above reflects the IEA estimate except for Iraq.

2. Capacity figures are levels achievable within 30 days and sustainable for 90 days.

3. Figures for Saudi Arabia and Kuwait each include 50% of the Neutral Zone.

Note: Saudi Arabia capacity figure represents mid point of IEA's estimate of 10.0-10.5. Saudi Arabia itself claims its capacity is now 11 million b/d.

4. Iraq estimate represents the average of the past twelve months. Post war production has not yet exceeded 2.5 million b/d.
Iraq capacity figure represents gross capacity, before any reinjection.

Market Balance

Total OECD Commercial Inventories

Following last month's large upward adjustment to the estimated end January stock position, another large adjustment has been made this month, this time to the end February position. End February stocks are now assessed as 21 million barrels higher than was thought a month ago. The first look at the end March position for total OECD suggests a small stock draw during March, as refinery maintenance allowed crude stocks to rise while product stocks were drawn down, more than off-setting the build in crude. This leaves end March stocks 119 million barrels above those of March 2004. The first quarter as a whole now shows a contra-seasonal build of 0.2 million b/d for total OECD and forward cover at the end of the first quarter is assessed by the IEA at 53 days, two days above year-ago levels. This is the first time since 1996 that total OECD stocks have built in the first quarter; by comparison, the past five years have seen an average first quarter stock draw of some 0.4 million b/d.

Turning to the global position, the top-down balance still suggests demand exceeded supply in the first quarter, suggesting a stock draw of around 0.5 million b/d was necessary. A stock draw of around 0.7 million b/d in non-OECD areas is thus indicated. Increasing evidence is accumulating that Chinese stocks were drawn down heavily in the first quarter, so a large non-OECD stock draw is certainly credible although the size of the implied draw is quite large. Any reductions in demand estimates for the first quarter in non-OECD areas would reduce the scale of the implied stocks draw.

The table below shows the overview position in each region and illustrates the unbalanced nature of stocks holdings. It also shows the danger of making generalizations about stocks levels. Total OECD stocks are high while those in Asia-Pacific remain low as stocks in OECD Asia Pacific represent only some 17% of total OECD stocks. Moreover, within a region stocks for an individual product can be worryingly lower or higher than for all products taken together.

Crude and Product Stock Levels by OECD Regions at end March
Relative to Average of Previous Five Years

	N. America	Europe	Asia-Pacific	Total OECD
Crude	High	High	Low	High
Products	High	High	Low	High
Total	High	High	Low	High

Atlantic Basin Inventories

US

Crude stocks have continued to rise, notably in PADD 2 and at Cushing, thereby contributing to softening of the WTI price, as well as price more generally. Total stocks at end April reached 327 million barrels according to weekly data, up by 10 million barrels since end March and some 17 million barrels above the average of the previous five years. Imports were again above 10 million b/d, as they have been for eight of the past twelve months, but were scarcely changed from March's level, and the other element of supply, domestic production, fell slightly. The major reason for the further rise in stocks was the slow return of refineries from maintenance: crude throughput in April averaged 15.3 million b/d, below the average of the previous five years, and only 0.13 million b/d above March's level. Runs this year, however, have been atypical, with January to March all well above any previous year's levels, but with April barely above March, whereas the average March-to-April increase of the previous five years was 0.7 million b/d. Runs are still expected to be ramped up sharply once maintenance is finally completed to well over 16 million b/d and utilization later in the summer could again match last year's figures of around 97%. This will inevitably pull crude stocks down and imports will need to average consistently above 10.5 million b/d over the summer months in order to keep end-summer stocks in line with the average of the previous five years.

Gasoline stocks rose by 2 million barrels in April, to end the month at 214 million barrels, 8 million barrels above the average of the previous five years. A rise like this is around the norm for the time of year. Although the average gasoline yield over April was a new record high for the month, it was eclipsed by the increase in distillate yields as refiners apparently took advantage of the high absolute level of gasoline stocks to maximize distillate yields and thereby benefit from distillate and diesel prices above those of gasoline, as well as contributing to replenishing low distillate stocks.

Despite this unseasonal preference for making distillate over gasoline, distillate stocks still fell by 2 million barrels over the month to 102 million barrels, slightly below the average of the previous five years of 105 million barrels, but above the past two years. A modest stock draw in April is normal, with the stock build in preparation for winter normally beginning in May. Achieving an adequate stock build over the summer still should not prove a problem as gasoline yields are not expected to need to be exceptionally high, allowing distillate yields to move towards the top end of the range.

Europe

According to provisional Euroilstock data, crude stocks in Europe fell slightly during April, but remain very high, close to record levels for the time of year. The narrow differential between BFO and WTI has kept the transatlantic arbitrage closed and penned North Sea crudes into Europe. The arbitrage is expected to open in coming months and North Sea output will reduce with normal summer maintenance, so stocks are expected to drift downwards over the summer but with rising output in Nigeria and Libya, and later in the year from Azerbaijan, Europe should remain well supplied with crude.

Gasoline stocks have been falling since January, following the normal seasonal pattern, after the abnormal rise in January. With continuously declining demand, stocks would be expected to be at the bottom of their historic range, but in fact current gasoline stocks are above the level of three of the past four years as, despite modest yields, total levels of throughput have been high, producing high gasoline output. Stocks of gasoline in independent storage in the Rotterdam area were at the highest early May level of the past ten years.

Gasoil stocks are also high. European refinery production and Russian exports have both been at record high levels for the time of year while demand has been weak as German heating oil consumers continue to avoid buying at high prices. Stocks in independent storage in the Rotterdam area, however, are relatively low.

Prospects for the Global Balance

The upward revisions to the end January and end February stocks positions over the past two months have put a rather different gloss on the global outlook. Stocks in terms of days cover looked low at 50-51 days, but the end March level of 53 days (will next month's data show another upward adjustment, this time to March?) provides a much more secure basis for the remainder of the year. Moreover a recent statement from the OPEC President that OPEC will continue to increase its output to 30.5 million b/d should reassure the market that OPEC is not currently thinking of a cut to output when ministers meet on June 15.

Assuming that OPEC output continues around current levels through the summer in order to allow stocks to build, and that demand and non-OPEC supply turn out broadly as currently projected, then global stocks could remain between 53 and 54 days for the remainder of the year, a level that just a few months ago seemed inconceivable, but now possible because of upward revisions to stocks and a change in OPEC attitude. The exact end year position obviously depends on the particular combination of supply and demand projections, hence a projection based on the IEA's figures plus flat OPEC output implies around 54 days by the end of the year, while the U.S. DOE, which has higher projections for demand growth and lower projections for non-OPEC supply, estimates cover equivalent to 51 days. Our projection, assuming demand might still prove a little stronger than current estimates and that new non-OPEC supply might suffer some deferments, indicates end year cover of around 53 days.

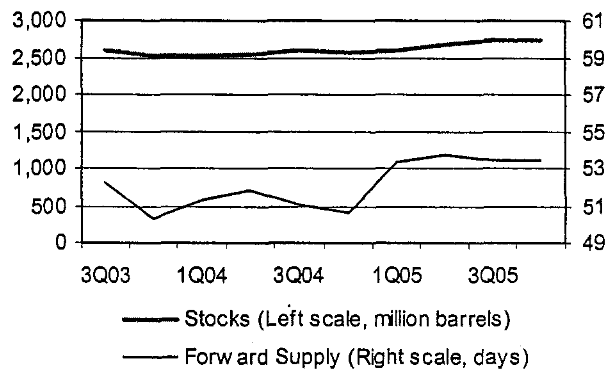
This is all rather different to the way things looked only a short while ago. On these figures the summer stock build should certainly prove sufficient to allow a draw in the winter quarters. Even a fourth quarter stock build is not impossible, indeed balance suggests that unless OPEC cuts back then a small build looks likely. Increases in output from new capacity to be commissioned in Nigeria and Iran over the summer months now look secure, and neither country will be inclined to make compensating cuts elsewhere. The outlook for the fourth quarter could still vary between tight and relatively easy depending on OPEC capacity increments over coming months.

Stock cover of this magnitude would traditionally have been associated with much lower prices, but that link between stocks and prices remains broken, at least as an indicator of absolute price levels. On the other hand, the rising level of stocks in the Atlantic basin is undoubtedly one factor responsible not only for the steep contango in Atlantic basin prices, but also for the decline in the absolute level of prices. How OPEC will view this turn of events remains to be seen.

Turning away from global stocks levels and looking at the regional and quality imbalance, however, yields a different perspective. U.S. refinery runs have been kept low by an extended maintenance season, but could rise by as much as 1 million b/d over coming weeks, which would reduce crude stocks by nearly 30 million barrels over a month unless supply increases to offset the fall. Domestic production should rise in the third quarter but imports will need to rise too. Much depends on the quality of crude that U.S. refiners will seek. Many are understood to have invested heavily over the past year so as to be able to handle higher volumes of heavy/sour crudes, on which margins are potentially more attractive, and if that enables them to absorb high volumes of Middle East crude without needing to compete unduly with Asia/Pacific refiners for light/sweets then obtaining the necessary levels of imports should not be a problem. Crude stocks would still fall seasonally, but the fall should not cause alarm. Given the unpredictability of market reactions to stocks reports over recent months, however, a rational response is far from assured. Similarly falling gasoline stocks over May to August, although a normal seasonal pattern, could easily spook a market looking for excuses to mark up prices.

Asia/Pacific also remains a wild card. Cold weather in the first quarter has depleted stocks of middle distillate heating fuels in Japan and Korea, and Chinese stocks both of crude and products are believed to have been run down sharply. Refineries in the region are mostly running close to capacity and if China needs to import to replenish depleted inventories and if recent firm demand in Japan and Korea continues, then the call for both crude and products imports from outside the region could prove substantial.

OECD Commercial Stocks and Forward Supply



Crude Price Forecast

Base Case

Now that the $50/barrel support level for WTI has been breached there would appear to be scope for some further downside movement in price in response to stock levels which are looking increasingly healthy, even bloated, in the Atlantic basin. How long such softness might last, however, is a major uncertainty. The global balance now looks easier, and the prospects for the fourth quarter could be seen as less worrying, but the substantial rise in the "call on OPEC crude plus stocks" between the third and fourth quarters could still worry a market focused more on OPEC's output versus capacity and less on the potential contribution of changes in stocks; a rise of say 1.5 million b/d in the call does not mean OPEC needs to increase output by that amount, as the third quarter will see a stock build and the fourth a draw, so much of the increase in call will be met by stock movements. This is not the popular perception, however, as the steep contango WTI between June and December suggests not just prompt oversupply but continued concern about the winter.

The behavior of non-commercial players on NYMEX could prove important. They have currently reduced their net long holding to virtually nil and if prices fall further might begin buying again, supporting a price rise, though they may wait a while longer to see how things develop. OPEC actions are also uncertain. Now that the balance is looking easier and prices have fallen below $50/barel the more hawkish members may want to press again for output cuts to prevent further falls in response to higher stocks. The Kuwaiti minister and OPEC President reportedly recently suggested, however, that $40/barrel would be an acceptable level for the OPEC basket, some $5/barrel below its current level. If that thinking proves dominant, then no cuts would be expected.

We still expect prices to remain below $50/barrel for a while, reflecting the ready availability of prompt crude and oversupply in the Atlantic basin, but $50/barrel proved a much more resilient support level than we had anticipated, and the hedge funds unexpectedly fast liquidation of their holdings now makes them more likely to support a rise than a fall in prices. Even if OPEC do not make actual cuts, the tone of their pronouncements may change. Accordingly we now think that prices may even recover sooner than previously projected, on the back of falling stocks of crude and gasoline in the United States, and continued concerns about the winter, even despite the easier outlook for the balance.

Short Term Marker Crude Price Forecast
(Dollars per barrel)

	Apr	May	Jun	July	Aug	Sep	Oct
WTI	52.85	50.00	48.50	49.00	49.50	50.00	51.00
BFO	51.89	48.75	47.25	47.50	48.00	48.25	49.00

Alternative Cases

High-Price Scenario: A higher price scenario could result from:

- Further terrorist attacks/political tension in the Middle East;
- Geo-political concerns;
- Renewed Chinese imports;
- Major losses in Nigeria, Iraq, or elsewhere;
- OPEC implementing cuts in fear of prices falling too rapidly;
- Disappointments with increments to OPEC capacity;

- Further disruptions and delays in new non-OPEC production;
- Further upward pressure from financial traders.

The greatest concern remains terrorist action, which could result in price spiking to very high levels. Absent such a development, prices above $60/barrel for WTI now look less likely but remain possible. Any major loss of output anywhere would cause a spike, as the spare capacity cushion will remain thin all year. It is uncertain what scale of loss would drive governments to take emergency action to curb consumption and release strategic stocks, however if they did so we would be in a wholly different world and prices would depend on these reactions and their timing. Cuts by OPEC or a succession of geo-political alarms could push price sharply up.

Low-Price Scenario: A lower price scenario could result from:

- Recession or at least further economic slowdown, and resultant substantially weaker demand, especially from the United States and China;
- Further upward revisions to stocks data;
- Further easing of concerns about loss of supply due to higher stocks and slowing demand growth;
- OPEC are slow to cut as stocks rise due to internal dissent;
- Non-OPEC supply proves more robust than expected;
- Financial traders build net short positions.

In this situation, prices would moderate steadily but would remain above $35/barrel due to the perception of tightness next winter. It will still take some time for a sizeable cushion of spare capacity to be restored.

Oil Product Prices

Gasoline

Weekly data for April show demand growth of 0.9%. Monthly data for the first quarter now shows growth of 1.2%, less than indicated by previous weekly data. Monthly gasoline demand data is very volatile, hence, year-on-year comparisons can be misleading as the growth in any individual month is influenced by developments in the same month a year earlier. Hence, although U.S. gasoline consumption remains on a growing trend, the rate of growth is still highly variable. By removing seasonality and reducing month-to-month volatility by taking a twelve month moving average, it is clear that the rate of growth has been slowing since the middle of last year, when it had reached 2%; it is now down to below 0.9%. Data from the Department of Transportation show a decline in "Highway miles traveled" since around the same time. Moreover, the DOE's "Product Supplied" data does not, strictly speaking, report actual demand, i.e. purchases at the pump, but deliveries from primary storage into the distribution system which take place some weeks in advance of purchases at the pump and are based on assumptions about consumer demand. If motorists reduce consumption, there will be a lag before this shows up in DOE statistics. Nevertheless, a recent reported survey showed 58% of U.S. motorists saying they would drive less if prices stay high. All these signals seem to suggest that demand is slowing, possibly due to price, but whether this will seriously reduce demand for the summer driving season remains to be seen. The DOE's forecast is unchanged this month at 1.8% growth for the summer quarters.

Stocks at end April were high in absolute terms and closely in line with the average of the previous five years in terms of days cover. As mentioned in the stocks section, refiners achieved a new record high yield of gasoline for April, at 57.1%, and this despite also setting a new record high yield for distillate. Distillate stocks are towards the low end of the range for the time of year but there is plenty of time to raise them before winter, so there is no reason to think that gasoline yields cannot be very high this summer if necessary. Imports of finished gasoline and components, which amount to around 10% of total gasoline supply, have also been high recently, with imports of finished gasoline very high and the 4 week average for total imports including components has been over 1 million b/d for the past three weeks. The issues of unscheduled refinery outages and grade proliferation remain sources of concern, however, despite a supply outlook that looks healthy.

Gasoline prices relative to crude were volatile over April and reports of problems at refineries, mostly on gasoline units, resulted in upward spikes, but latterly high imports and rising stocks have led to a softening. Spreads are currently very close to where we projected for the month. Supplies of high octane components remain tight but this does not seem to be seriously affecting prices of regular grades. The arbitrage from Europe has only been open intermittently as European prices, although falling, have remained stubbornly high, and further adjustments are still expected. We expect U.S. prices relative to crude to continue to soften through the summer as it becomes apparent that supply is adequate, and for European prices to fall further to maintain a (mostly) open arbitrage. The forecast spreads are unchanged.

Distillate

Latest data brings yet another marking down of distillate deliveries. Although March still shows a year on year increase of 4.5% following cold weather early in the month, data for January and February now point to declines in both months. Overall deliveries over the first quarter now exactly match those of last year. Within the total, highway diesel continues to grow, although growth in January and February was well below the trend rate, while deliveries of heating oil were very low, as the weather in the North East in January and February was much milder than in the previous two winters. Weekly data for April shows total distillate deliveries 2.2% up on a year ago.

Stocks are towards the lower end of the historic range but we do not anticipate a problem in replenishing them in time for next winter. Although by this stage of the year distillate yields in the refineries would normally be well down on their early winter peak and moving toward their mid summer low, this year yields have risen steadily since January with April a full percentage point above any previous April, at just over 26%, a level not normally reached till October or later. It appears that, in distinction to the market, refiners felt sufficiently relaxed about the gasoline position to be able to maximize distillate yields to take advantage of distillate and diesel prices above those of gasoline in April. With diesel prices still well above gasoline, and expected to remain so for a couple of months more at least, we expect refiners to continue to favor distillate, though recent data suggests that to do so does not necessarily imply low gasoline yields. Imports in April were lower than in the first quarter but were in line with April imports over recent years; indeed during April the Gulf Coast was exporting diesel to Europe where prices were very high, a reversal of the more usual direction of trade.

As mentioned last month, to see such high prices this late in the year is unprecedented. April spreads for all three middle distillate grades were not only extremely high for April but in each case set a new record high for any month of the year, at least for the past ten years. It is not possible to explain these prices in terms of developments in the U.S. market alone, such prices must rather be seen in the context of very high prices in Europe also, which in turn partly reflect high prices East of Suez. The whole complex of high prices seems to be inter-related, with extra Indian demand the only clearly identifiable unusual feature, since elsewhere in the East demand has been relatively muted in the face of high prices. Spreads of all three grades in New York Harbor have now come off several dollars from the peak levels reached in late April, but are still extremely high for the time of year. In Europe, spreads are narrowing and in the East we expect some moderation as Persian Gulf refineries return from maintenance. Nevertheless, Far East maintenance only peaks in May and June so some additional demand may still be expected there and India continues to draw in low sulfur diesel. China remains a major uncertainty. Its stocks are believed low and there are reports of diesel shortages in the retail sector, but Government price control measures make importing product uneconomic as local prices are below international prices.

In the absence of any real clarity as to exactly why global middle distillate prices should be at such unusually high premia, we feel the best course is to profile spreads back down to lower levels but to keep them at the upper end of historic ranges.

Residual Fuel

High natural gas prices have continued to contribute to increased resid use by utilities. Deliveries over the first four months of the year were higher than for the same period in the previous three years. Refiners, meanwhile, continue to squeeze resid yields down, leaving an increased proportion of total deliveries to be met from imports; 51% of deliveries were supplied by imports in the January to April period. In addition, increased Mexican utility demand has resulted in increased exports.

Regarding prices, the past month has seen a change from the trend we commented on a month ago. Whereas resid prices had been following crude closely, with discounts little changed since last October, over the past month, as crude price have fallen, low sulfur resid prices have declined more slowly, and high sulfur grades have actually risen in absolute terms. Discounts relative to crude have thus narrowed by some $7-8.barrel. The strength of higher sulfur grades has been caused by the coincidence of higher Mexican demand and reduced exports from Venezuela due to refinery maintenance, and partly by strength of import demand in Asia where refinery maintenance has reduced local supply. With the end of maintenance around the world, the expected summer peak of Russian exports, and with more increases in Middle East crude supply, the supply of high sulfur resid is expected to ease and discounts to widen again. Similarly for the lower sulfur grades the relatively higher price may draw in more exports and push prices down again relative to crude. We are not, therefore, assuming that recent price strength heralds the beginning of an imminent major narrowing of resid spreads, but as crude prices begin to harden again we expect discounts to widen again.

Long-term Outlook

Making the link between the immediate and the longer term is always a challenge in projections that extend some years into the future. Changes in the here-and-now do not necessarily mean that the outlook for say five or ten years hence has changed. However, crude oil prices have stayed at or near $50/barrel since October 2004. Faced by a short term change of this magnitude the requirement to consider the implications for not just the short/medium term is unavoidable. It has become our view, however, that developments over recent months have implications for the longer term.

Changes since January include the following:

- Prices have remained much higher;
- Nevertheless, demand expectations have been stronger;
- Supply expectations have been weaker; with yet more non-OPEC disappointments; and increased uncertainty over OPEC capacity increments;
- The call on OPEC crude has increased;
- OPEC aspirations have changed.

It is the final point that we believe is crucial. Up till early April high there did not seem to be any substantial evidence that prices were having any effect on demand. All the indications were that demand growth estimates for 2005 might again be understated and that OPEC would again be called on to produce at close to capacity. Over the course of April some doubts have begun to creep in regarding the apparent insensitivity of demand to price, but nevertheless the high call on OPEC crude this year seems unlikely to change even if there are no more increases in demand growth estimates. OPEC members have observed the inexorable rise in prices since early 2002, but especially since early 2004, an era when price have consistently exceeded $30/barrel, and have seen demand rising strongly, apparently oblivious to price. If the market could bear $50/barrel, why should OPEC settle for less?

With the formal abandonment of the $22-28/barrel price band, OPEC has set itself free to decide on a new target price. Whilst no formal decision has yet been made, aspirations have risen with rising prices. OPEC now seems to aspire to a price for its Reference Basket (ORB) of $40-50/barrel. Until the middle of 2004 the value of the ORB was $0.50-$1.50/barrel below Brent. Since mid 2004, however, as prices have risen sharply and as OPEC output increases have put more heavy crude onto the market, the value relative to Brent has fallen to a discount of $3-5/barrel. An aspiration of $40-50/barrel for the ORB therefore implies a range of say $44-54/barrel for Brent and somewhat higher for WTI

With aspirations having ratcheted up, the issue then becomes: if OPEC members now aspire to prices in this range, what is there to stop their achieving them?

Supply Prospects

Non-OPEC output is not expected to be able to respond much in the next few years as oil companies are already fully committed to a number of long lead time projects and do not have the capacity in terms of manpower to start additional projects. Oil companies anyway remain cautious and will not assume that high prices are necessarily here to stay, but will stick with lower "screening values" for assessing the profitability of projects.

As for OPEC, with production close to capacity the old problem of cheating on quotas has, for the present, ceased to be an issue. Even if those members with increments to capacity scheduled to come on stream over the next year or so choose to produce from those increments, regardless of any agreements on production restraint, that might still have little impact on prices, as many of the increments are of light sweet crudes that can be easily placed in the market without depressing prices. Relatively few increments to capacity are definitely expected in the Middle East, and even if those that are expected produce at maximum, Saudi Arabia could easily cut back its own output by sufficient to keep prices from falling, and would probably involve other Arab Middle East producers in the policy.

It has been observed that OPEC has been powerless over recent months to stop prices from rising. That is largely true, but it remains far from powerless to stop them from falling. Even just the threat from Saudi Arabia to cut back on output would probably be sufficient to end a fall in price in current circumstances. So how far would the Saudis be prepared to allow prices to fall before stepping in and cutting output?

In recent high level discussions with the U.S. Government prominent Saudis have opined that prices around $55/barrel are "too high". Such references are probably to WTI rather than the ORB. That would suggest that currently it is recognised that the upper end of the potential $40-50/barrel band for the ORB is regarded as too high, too liable to induce economic slowdown at this stage of the economic cycle, and too liable to induce measures that might undermine the long term demand for oil. On the other hand it is unlikely that $40/barrel as a floor has been conceded. We therefore believe that for the next two to three years OPEC will seek to defend a floor for the ORB around $40/barrel, say $45/barrel for WTI.

Over the next few years every member of OPEC will see increments to capacity from developments already under way. The list of projects is long and includes light, medium, and heavy crudes. Longer term, however, OPEC members will have to decide how much to invest in adding more new capacity. They all recognise that most projections of the longer term future indicate an increased call on OPEC crudes, as the rate of growth of non-OPEC output falls short of that of demand. On the other hand no-one wants to spend money on adding to capacity that will then sit idle as part of the spare capacity cushion that the present world oil market seems to require. In addition growing budgetary requirements from areas other than oil, notably welfare expenditure as many countries are facing high levels of youth unemployment, create increasing competition for revenues from oil. One policy option therefore would be to delay investments, just sufficient to keep the market tight and prices high. That would increase the probability of being able to utilise new capacity and not keep it idle, while also maximising the price, and making money available for other projects. The difficulty, however, is that such a policy, whilst nominally possible, would require OPEC members to show a degree of co-ordination that has historically not been seen. While competition for revenue may delay investments to a certain degree, therefore, nevertheless individual states are still likely to make their own independent decisions, each member believing that in its own uniqueness and in its ability to sell all its production without depressing the price; the problem of having to maintain idle capacity will be someone else's. Indeed, there may be some truth in this: many members face circumstances that mean that there is always a strong demand for their particular production, provided it is competitively priced relative to other crudes, and therefore that their production can be maximised with little impact on general price levels. For example:

Libya, Algeria, Nigeria	All produce light sweet crudes that are in strong demand for their quality in both Europe and North America, and increasingly even in Asia Pacific as regional production of such qualities is static while demand is rising.
Venezuela	Is close to the US, meaning freight costs are low and output can respond more quickly to demand. Supply is regarded as secure despite political differences. Many US refineries have been built specifically to use cheap extra-heavy Venezuelan crudes.
Indonesia	Produces sweet crudes and enjoys proximity to fast-growing Asian markets. Indonesia is anyway now a net importer of oil.
UAE	Most of its grades are lighter than other Middle East crudes and some are particularly highly prized in Japan for their quality.

This means that it is predominantly the Middle East producers of heavier, more general purpose crudes, Saudi Arabia, Kuwait, Iran, Iraq, and Qatar, who could face greater difficulties with marketing their output, and on whom the burden of maintaining spare capacity would primarily fall. Neither Iran nor Qatar have good track records on quota compliance, but equally neither is expected to be able to add very much to its capacity. When Iraq manages to restore and build up its output it is likely to be granted special status in relation to quotas. Thus the burden may come to rest mostly on Saudi Arabia, possibly aided by Kuwait, a situation not that different from today.

Against this background, in the longer term the spare capacity cushion could increase in size again, easing market concerns, while individual OPEC members choose to utilize the capacity on which scarce revenue resources have been spent. All the more would this be so if, as a response to price, demand does not grow as strongly as previously projected.

Demand Prospects

At price levels around or below \$50/barrel we do not believe that the resultant retail prices to consumers in OECD countries, or even in China or other richer non-OECD countries, will be high enough to provoke widespread "don't consume" decisions. Such prices may be high enough to encourage consumers to consider investing in more energy efficient appliances when those appliances are next due for replacement, but are probably not high enough to bring forward that date. The progressive introduction of more efficient appliances, notably cars, will eventually impact on demand, but it will take some years before that impact becomes sizeable. Nevertheless there are early indications that behaviour is moving in that direction, for example a downsizing by US motorists from large SUVs to medium and small SUVs. Even small SUVs may be rather fuel inefficient, but less so than their larger counterparts. With around 50% of new car sales in the US in terms of SUVs the impact of this over time could be significant. In Brazil sales of dual fuel vehicles able to run on cheap locally-produced ethanol, as well as on gasoline, have increased dramatically. In the longer term, therefore, even in OECD countries the cumulative effect of individual decisions to use energy more efficiently, aided by continuing technological progress in improving efficiency, and possibly abetted by a variety of regulatory, fiscal, or policy measures, may result in slower demand growth.

Outside OECD, however, even short term reactions to high prices may be different. Here prices may prove high enough to provoke "don't consume" decisions among poorer consumers. More importantly, however, in many such countries retail prices of fuels to households are subject to price control and are kept well below international market levels by systems of subsidies. There are signs that the burden of maintaining these subsidies at current prices is becoming intolerable for some governments. Hence there have been reports of increases in retail prices recently in a number of Asian countries, China, Malaysia, Thailand, Indonesia, Vietnam. If this trend spreads, which we expect to occur, it will have an impact on demand. Subsidies, once removed, are unlikely to be reinstated, so an increasing proportion of consumers will progressively be exposed to the true international cost of the fuels they use.

Implications for Price

Beyond the next few years, therefore, we still expect OPEC to seek to defend a price in the $40-50/barrel band, but with the progress of time this may become more difficult.

- Demand may be trimmed both by income-elasticity and price-elasticity effects, aided by technology improvements and the turn-over of the capital stock, and policy measures;
- Non-OPEC capacity will continue to rise and while we do not expect significant supply responses to price in the early years, nevertheless high prices will provide an incentive to get projects on stream as quickly as possible;
- Later, additional non-OPEC supply may result as settled high prices are progressively factored into project evaluations;
- OPEC's own output capacity will rise, and there will be increasing pressures to use that capacity rather than keep it idle;
- The spare capacity cushion may rise, easing market concerns.

Against this background we have decided to raise our projection of prices beyond just the short term. We have projected the price of WTI to fall to around $45/barrel by 2008 and then staying fairly constant in nominal terms for some years. This implies a falling real terms price, reflecting the difficulties we believe OPEC will face in maintaining high prices; they will be forced to accept broadly flat nominal prices but will be unable to maintain their real-terms value.

NATURAL GAS OUTLOOK

Short-term

Natural gas supply trends remain negative in the United States, but slightly positive for Canada. The most recent supply-and-demand indicators show a neutral position of the market in March and April after it tightened this winter.

Canadian receipts into Alliance and Nova slightly exceeded year-ago levels while Canadian demand is down; thus exports to the United States are up. Also, Mexico is reported as having reduced its imports of natural gas from the United States. Natural gas demand appears weak, while fuel oil demand rises despite high oil prices. Although this usually signals some inter-fuel substitution away from gas, there cannot be much remaining capacity to switch. Almost all the indicators are now showing supply difficulties.

US natural gas demand fell about 6% in January and February according to EIA monthly reports. Canadian demand was also down, as high prices and weather trends contributed to weaker consumption. Most of the decrease was in the core sectors, with industrial demand down about 5%, and power generation demand actually neutral. These trends could be reflective of 2005 as a whole. Industrial natural gas consumption has been lagging output since 2003, and with manufacturing growth slowing in 2005, natural gas consumption could decrease. The power-generation sector is expected to increase demand for natural gas 6% in 2005. Significant new power generation is coming on line in Florida, and along with stringent environmental regulations, high oil and coal prices, and limited hydroelectric availability, natural gas has room to grow even with $7 prices. Overall natural gas demand will decrease by 1.6% in 2005, reflecting near $7-prices.

US natural gas prices fell to less than $7 in mid-April, and then battled back and forth, finally entering May headed lower. The June bid week price is expected to also hold at $6.62. The daily shifts in natural gas prices have apparently been following the movements of the crude oil market. Summer prices are expected to remain at $6.50–$7, as high oil prices, negative trends in U.S. supply, and the start of storage injections all contribute to a tightening market and sustained, high expectations.

The outlook for North American natural gas supply remains negative, as the huge decline in offshore production in 2004 and the recent drop in onshore Texas production would have to be reversed for it to be otherwise. Net imports of natural gas will increase in 2005, but this will only offset part of the U.S. production drop. During 2004, offshore gas production declined more than 1 billion cubic feet per day (bcf/d). In January and February 2005, Texas onshore production also fell more than 1 bcf/d. It is increasingly likely that U.S. production will decline more rapidly in 2005 than in 2004. Other information—such as expansive reserves additions in the United States, high levels of drilling, recovery from hurricane damage, and high natural gas prices—suggest some possible offsets to the recent negative trends in production later in 2005 or in 2006. A small gain in LNG imports is expected for 2005, to a more than 2-bcf/d level.

The supply and demand balance occurs at a lower volume level in 2005 and at a higher price than in 2004. LNG imports are expected to change this deteriorating balance, but a surge in LNG imports is still several years away.

Supply

If the decline in Texas onshore production is correct, U.S. natural gas supply will decrease 2–4% in 2005. This follows a drop of 1.3% in 2004, mostly in the second half of 2005, and primarily from the offshore markets. The trends in other U.S. regions are more down than up, although the Rocky Mountains region continues to expand.

Still, there are positive trends for some areas of the US production outlook for 2005:

- Reserve additions continue to exceed production. Part of the reserve additions reflects higher prices rather than additions to discoveries or producing wells.
- The Cheyenne Plains pipeline will add 540 million cubic feet/day (mmcf/d) of takeaway capacity for the Rocky Mountains. Production is increasing in Colorado and Wyoming. Rocky Mountain production is growing around 0.3–0.5 bcf/d per year.
- Drilling activity will remain strong at 2,000 gas wells/month and a 160 increase in the rig count as of May 2005.
- Recovery from Hurricane Ivan will restore most of the 150 bcf of offshore production lost during 2004.
- Deepwater gas production continued to increase in 2004, with 14 new projects coming online. Several large offshore projects are expected to come online this year, including Thunder Horse. Shallow-water declines overwhelm the deep-water increases, however. The Minerals and Management Service (MMS) expects total offshore production to increase after 2007.

The MMS has released a forecast showing that the production from the Gulf of Mexico will increase substantially after 2007. This will be a welcome change, as Gulf production fell 500 bcf in 2004, and may continue to fall in 2005. Trends in onshore production are generally ambiguous in 2005, while trends in total production are negative. Most other onshore basins will experience neutral to net decreases in supply; thus, it is becoming more difficult to find evidence that production will reverse these negative trends in 2005.

Although net imports will increase in 2005, most of this is expected to come from Mexico and Canada rather than from LNG. For 2006, LNG will provide most or all of the gain from net trade. Although LNG imports will increase in 2005, most of the growth will come at the end of 2005 and continue into 2006.

Demand

Demand destruction is likely to occur in 2005, as a decrease in overall availability coupled with growing demand in the power sector squeeze consumption in energy-intensive industry. Thus, several sectors will be squeezed, such as fertilizers, chemicals, paper and other energy-intensive industry. Consumption levels are expected to decline despite both economic and weather trends favorable to growth. Early indicators for 2005 show a decrease in consumption of natural gas.

Power generation is growing about 1% so far into 2005. The growth rate is expected to increase this summer with hot weather. Also, low hydro levels will support an increase in natural gas use. Cooling degree-days will increase at the national level, but this will not have as great an impact on gas generation. In 2004, the Northeast and some other northern states had a very mild summer, while the South experienced fairly normal temperatures. Since most of the nation's gas generation occurs in Texas, Louisiana, Florida, and California, and since these states had nearly normal weather in 2004, the increase in gas demand in 2005 will be lower than extrapolating from national degree days.

Natural gas demand in the power sector is expected to increase in 2005, as a result of growing demand and constraints from other power sources. From 2003 to 2010, the power sector will account for nearly 80% of US natural gas demand growth. Utilization of baseload coal and nuclear plants has been trending up. During periods of slow growth, increased utilization of coal plants has meant weaker gas demand, as seen in 2004. The difference for 2005 is that demand growth of 1.2% will be higher than the increases in coal and nuclear generation, implying greater gas usage.

Price

U.S. natural gas prices fell to less than $7 in mid-April, and then battled back and forth, finally entering May headed lower before turning back up in June. The daily shifts in natural gas prices have apparently been following the movements of the crude oil market. Although other fundamentals for natural gas have slowly been shifting to a more neutral position, oil prices remain near $50/barrel and supply difficulties support high prices.

- The weather adjusted changes in storage suggest a neutral supply-and-demand balance for recent months.
- Working gas in storage remains 200 bcf better than year-ago levels.
- Although production trends are negative, the rig count has risen 160 during the past year.
- Demand growth is negative for the first part of 2005, although forecasts of gas use for power generation show significant growth for 2005.
- Although natural gas demand is down, fuel oil consumption is up, suggesting some additional switching capacity has come to the market.
- Natural gas net imports are up so far in 2005, with LNG, Canada, and reduced exports to Mexico all contributing.

- Natural gas production is reportedly up in Mexico and Canada so far in 2005, although the increase is minor, and could be reversed.
- Weather effects are supportive of high prices, as water flows in the Pacific Northwest are expected to be about 70% of normal, while summer temperatures could be warmer.
- In the longer term, energy policy is evolving towards clean coal and new nuclear as well as opening up areas for drilling.

The most recent data on U.S. natural gas production is showing a sharp decline in January and February in Texas that contributes to a 2% decrease for the country as a whole. Although high frequency data is often revised, the simultaneous decrease in consumption, the increase in net imports, and the relative neutrality of the storage indicator support rather than contradict a downward trend in U.S. production. Since the United States still supplies 85% of its own natural gas consumptions, this remains quite serious. The implication is that high natural gas prices will be with us for a longer time than would be the case if production were increasing. Summer prices are expected to remain at $6.50–$7, as high oil prices, negative trends in U.S. supply, and the start of storage injections all contribute to a tightening market and sustained, high expectations.

Long-term Outlook

LNG's Importance Will Increase. Although demand growth has been restrained by high prices recently, a steady pace of growth is expected over the long term. Annual increases are expected to average about 1 bcfd between 2005 and 2030. With prospects for traditional gas supply sources bearish, natural gas prices will evolve to reflect the interaction between new domestic and imported sources of natural gas. Supply costs for potential incremental supplies are all higher than supply costs during the previous decade. LNG will be the predominant source of incremental supplies, owing to more limited growth prospects for other domestic and import sources.

The contribution from new supply sources in size, timing, and cost will be a major determinant of long-term natural gas prices. Although LNG imports are already increasing, the first big test of the impact of LNG on prices will come later this decade when several LNG terminals come on-line. Prices could fluctuate temporarily, depending on how trends in domestic production and Canadian imports evolve between now and then. Continued weakness in North American supplies would provide a supply gap large enough for the higher LNG supplies to fill, while improvements in those other supplies could cause supply capacity surpluses during this period that would drive down prices temporarily. We are currently anticipating that this buildup in LNG supplies will supplement North American supplies sufficiently to enable prices to drop down to a more sustainable level. Fluctuations are not depicted in our projections because they cannot be timed with precision.

Prospects for North American supplies are somewhat uncertain in the near term, but generally weak in the long term. The Minerals and Management Service has recently projected that production from the Gulf of Mexico, which has been declining, will increase after 2007. Onshore U.S. production in general is ambiguous, with Rocky Mountain increases offsetting declines in most other areas.

The Gap Between Demand and Traditional Supplies Will Grow. With the Canadian gas industry facing struggles similar to those confronting U.S. producers, imports from Canada have little scope to rise, and are most likely to decline in the long term. Canadian natural gas reserve additions have lagged production for several years, implying lower gas production in the future. Canada is planning to undertake the Mackenzie Delta pipeline project, with construction starting in 2006. However, this project is relatively expensive, at $7 billion, and the established reserves are still lagging the desired level to support the pipeline. Rising costs and lagging reserves may delay this project.

Alaskan North Slope gas will begin to flow to the lower-48 states during the second half of the forecast period, eventually rising to 3 trillion cubic feet (tcf) per year. The required increase in LNG imports will be more than twice this amount.

LNG currently makes up a very small portion of U.S. supplies, just 2% in 2003 and 3% in 2004. That share will grow substantially, potentially exceeding one-fourth of total supplies by 2030. There will be a market for 5-9 additional LNG terminals by 2010 and 15–20 new LNG terminals by 2030. Imports projected for the medium term reflect analysis of known projects, as discussed in detail in a separate section below.

Long-Term Prices Will Average $4.00–4.50. While expanding LNG imports will fill most of the growing gap between domestic demand and domestic supply, it is unclear if LNG will actually displace U.S. production. The difference is important for pricing. When demand and supply increase at about the same rate, the impact on prices would be less. If LNG displaces lower-48 production, the resulting price competition would drive prices down. Global Insight expects that the process will be a combination of the two; LNG will meet all growth other than that met by Arctic pipelines. Also, LNG will cost a little less to produce that the marginal U.S. supply. LNG will thus displace a small part of U.S. lower-48 production, thereby lowering prices. The supply cost of incremental supplies of U.S. lower-48 gas is expected to be between $4 and $5 per mmBtu in 2003 dollars. Future LNG supply costs are about $3.00 to $3.75 at a 10% rate of return. At a normal 16% return and with a higher level for sovereign take, LNG will price closer to $4.50. Thus the interaction between the two supply sources is expected to produce prices in the middle of this range of supply costs, at around $4.00–4.50.

Technically speaking, there will be no "supply gap" per se, but rather, a market niche for LNG *at a given price*. This is because demand and supply eventually balance at a given price level. A much higher price than projected here would both destroy more demand and attract more domestic supplies, requiring fewer LNG supplies. With ample LNG supplies available at lower prices, though, competition would eventually drive prices back toward the levels projected here. Given our expectation of the prices of competing fuels and competing sources of natural gas, the projection of long-term wellhead prices in the $4.00–4.50 range reflects our estimation of the point at which a stable long-term supply/demand balance could best be achieved.

Prices are expected to decline toward this range as LNG supplies build up later this decade. Prices will then gradually shift to a slow growth within this range, as supply costs gradually rise. Although below current prices, this expected long-term price level is nevertheless about $2.00 above 1990s levels. Not only were there more incremental supplies available at lower costs then, but there was an overhang of spare producing capacity.

How LNG Will Help Set the Price Level. The interaction between domestic gas and LNG in setting the price level is complex. LNG costs are a bit lower than current U.S. supply costs, and LNG is the principal marginal supply on an annual average basis. Domestic production will continue to account for the majority of gas supply, such that it will remain the swing supply source—at least at times—in many U.S. regions. Thus, the costs of both supplies will contribute to the general natural gas price level, with LNG costs setting a floor price while domestic supply conditions determine the peak and seasonality of prices. Prices will hold close to the supply cost at which domestic supply can be sustained but above the supply costs for new LNG facilities. Thus LNG will be able to pick up market share by providing for demand growth and also a small amount of displacement.

The five to eight year gestation period for LNG projects and the relatively high cost of some projects will make it difficult for LNG to substantially displace U.S. conventional production. There are many reasons why the costs of conventional domestic supplies should remain a key driver of U.S. natural gas prices. While LNG and Arctic gas supplies are expected to meet most of the increase in U.S. demand, conventional production from the lower-48 is still expected to provide the majority of required supplies. U.S. conventional production can adjust quickly downwards (though only slowly upwards) to changes in market balances, thanks to the rapid decline rate for existing U.S. conventional production, which in 2001 averaged 27%. Because about one-fourth of U.S. production has to be replaced each year, a slowdown in exploration would quickly eliminate any oversupply. Also, because production now operates at high rates throughout the year while U.S. demand is strongly seasonal with a high variability depending on weather, prices will be influenced by the value placed upon firm supply during the peak winter heating season. Storage supplements production and imports during the winter peak, but storage capacity is not unlimited. Thus, U.S. natural gas prices in peak periods rise until prices constrain demand to available supply, which at times in recent winters has been far above domestic supply costs. Estimates of LNG supply costs are a measure of the lower price in the market rather than the average natural gas price. That LNG will be on the margin does not mean that seasonal price variations will disappear. Rather, most LNG producers will be able to obtain some rent in the U.S. market from the occasional seasonal peaks.

LNG Projects

Because of the rising importance of LNG in natural gas pricing, this section provides detail on LNG projects. LNG infrastructure in the United States is already expanding, and increases in LNG imports are expected to accelerate in the next few years as multiple new projects come into operation. Increases over the latter part of this decade will be equivalent to one new LNG terminal per year.

Increases in LNG Imports Expected This Decade

Year	LNG Imports (TBTU)	LNG Imports (Bcf/day)	LNG Imports Change from Prior Year (Bcf/day)
2003	506	1.38	0.6
2004	649	1.78	0.4
2005	740	2.0	0.2
2006	1247	3.3	1.3
2007	1744	4.7	1.3
2008	2072	5.9	1.2
2009	2579	7.1	1.2
2010	3018	8.3	1.2

LNG receiving and regasification terminals in this country are being proposed in conjunction with development of LNG supply projects in producing countries. Considering the LNG terminals in conjunction with the supply projects is useful in determining whether and when the projects might proceed. Some LNG industry participants are choosing to specialize. Marathon has decided to develop the LNG project in Equatorial Guinea and sell the LNG to BG Group. Other companies, such as Cheniere, Main Pass Energy, and Excelerate Energy, are developing LNG import terminals for the United States. These are specialized companies. While most world trade in LNG is supplied by integrated companies such as Royal Dutch Shell, this is not the case for the United States at present. By 2010, the major oil companies could reassert their dominance, since they have a large stake in many of the projects that are likely to be developed.

The United States imported 506 bcf of LNG in 2003 and will likely import 3 tcf by 2010 if most of the approved projects and several of the proposed projects go ahead. In order to support our market balance forecast that relies upon LNG, Global Insight surveyed the potential supply to ensure that the timing of supplies to satisfy needed increases is feasible.

Construction is under way on several projects. The projects that are judged most likely to go forward are those that (1) have sufficient reserves of natural gas to support world-scale LNG plants, (2) have the active support of a coalition of international oil companies and support of the host country, (3) have plans and progress on developing an LNG terminal, and (4) have a likely market. Projects now under construction will increase U.S. LNG imports to about 40 billion cubic meters (bcm) by 2007. Likely projects should add about 60 bcm to imports by 2010. These projects are not definite, and there is room for more projects or replacement projects. Also, there will be a significant short-term trading in LNG that could provide 10 to 20 bcm to the United States by 2010 from other projects.

LNG Terminals

The United States has expedited the LNG terminal approval process so that decisions will be made within a definitive time frame. Several LNG terminals have already received licenses from FERC. Offshore terminals are regulated by the U.S. Coast Guard, while FERC permits are required for the pipeline facilities. International projects require only pipeline permits from FERC to serve the U.S. market. LNG terminals in Canada that use existing export pipelines to the United States would not be subject to any U.S. permitting requirements.

There are four existing LNG terminals in the United States, and all have applied for expansions. Approvals have either been received or are in process for all four existing terminals: Lake Charles, Elba Island, Cove Point, and Distrigas. In addition, several proposed LNG terminals have received approvals:

- Sempra: Hackberry LNG in Louisiana has its FERC license but construction was deferred until later in 2005.
- Cheniere: Freeport Texas LNG terminal is licensed and under construction; Sabine Louisiana LNG terminal has FERC approval.
- Excelerate Energy: Energy Bridge platform, 100 miles offshore Texas, will receive its first cargo in mid-March 2005.

Many other terminals are at various stages of the permitting process. Over 40 terminals have been proposed, and 5–9 new LNG terminals will be constructed in the United States by 2010. In addition, LNG terminals are being developed in the Bahamas, Baja California, and eastern Canada to serve the U.S. market.

LNG Supply Projects

There are six LNG plants under construction that will supply the U.S. gas market. More than 15 additional LNG plants that are either planned or proposed could be operational by 2010. In total, these projects have the potential of adding up to 5.7 tcf to U.S. gas supplies within seven years, more than twice the amount that will be required within this time frame. Their level of commitment to the U.S. market at this point varies from project to project.

World LNG Projects with Potential to Supply the U.S. Market This Decade

Country and LNG Project	2005-2006 Under Construction (Bcf/Year)	2006/2007 Planned (Bcf/Year)	2008+ Planned or Proposed (Bcf/Year)	Planned or contracted U.S. LNG Terminal
Algeria-Arzew			194	U.S., Europe
Angola-Soya			390	CVT, U.S.
Egypt-Idku II	175			Europe, BG Lake Charles, Elba Island
Egypt-Idku III			175	BG, U.S., Europe
Equatorial Guinea- Boiko Island		165		BG, Lake Charles
Nigeria-Trains IV&V	399			Shell,Total Europe, U.S.
Nigeria-Train VI		200		Shell, Total U.S.
Nigeria-Brass River			487	CP, CVT
Nigeria-West Niger Delta			240	U.S.
Nigeria-Floating LNG			250	Shell
Norway-Snohvit	199			Europe, Statoil, Cove Point
Norway-Snohvit II			200	Statoil, Cove Point
OMAN-Qalhat	160			BP, Shell Cove Point
PERU-Camisea		194		Hunt Oil
Qatar-Qatargas III			380	Conoco Phillips Freeport
Qatar-RasLaffan V&VI			730	Exxon Mobil Sabine
Russia-Sakhalin II	233	233		Shell Baja, Mexico
Trinidad-Train IV	253			Tractebel, BG, BP, Repsol Lake Charles, Cove Point, Elba Island
Trinidad-Debottlenecking trains I,II and III		100		Tractebel, BG, BP, Repsol Lake Charles, Cove Point, Elba Island
Trinidad-Trains V&VI			500	Tractebel, BG, BP, Repsol Lake Charles, Cove Point, Elba Island
Venezuela			228	Shell U.S., Mexico
Total	**1741**	**892**	**3190**	

COAL OUTLOOK

Short-term Outlook

- We're in the shoulder months, but coal prices are still firming
- The first signs of coal-on-coal competition are beginning to emerge
- Production is rising but must grow more to meet rising demand
- Imports are booming as foreign coal prices look more attractive

Market Outlook

We are still officially in the shoulder months, when markets are traditionally soft, but we are seeing a slight firming in most markets and strong upward price movement in the Western coals. Even though Appalachian (both North and Central) coal prices are currently high, low inventories throughout much of the East have kept coal purchases moving at a steady pace. For Western coal regions, improvements in rail shipments are allowing demand to expand throughout the Midwest and East in response to $800+ SO2 prices and those high Appalachian prices.

Indeed, we are seeing significant price shifts in both the Powder River Basin and Western Bituminous coals. We have been expecting the PRB move for some time, and the price of the 8800 Btu coal from that region, which began the year below $6/ton, has now moved into the $8 range. Earlier in the year, we were less confident that the Western Bituminous coal price would rise as quickly, but events have transpired that have led us to revise our outlook for this year by adding a few dollars per ton to the outlook, as opposed to dropping the price several dollars over the year. Specifically, the Western Bituminous coals have benefited from the second surge in SO2 prices that created greater urgency among Eastern/Midwestern buyers, the belief that buying out of the West should be diversified due to transportation issues, and the continued uncertainty on the environmental front due to significant doubts as to the viability of the mercury regulations.

For Eastern and Midwestern coal buyers, the question of buying coal from the West means greater concern about transportation rates and service than mine-mouth prices. Not that the latter is insignificant; as mentioned last month, the precipitous rise in PRB prices in early 2001 sent many prospective coal buyers who were looking at that region into a hasty retreat. Yet there is no doubt that the rail rate is the major component of the delivered coal price as Western coal tries to penetrate further east. Several recent developments are being watched carefully by Eastern/Midwestern coal buyers in that regard, specifically the suits against the BNSF and UP pricing practices out of the PRB (filed separately by the WCTL and the U.S. Department of Justice) and a major approval by the Surface Transportation Board for the DM&E to be a third option out of the PRB.

In this *Coal Monthly* issue, we have expanded our price coverage out through the end of December 2008. With natural gas prices so high and very little excess coal capacity in evidence, most observers agree that we are there is nothing to constrain coal prices in the current market. Yet, as shown in our forecast, we do foresee a moderation in prices coming down the road. This will not arrive overnight, but already we are beginning to see the first signs of coal-on-coal competition beginning to emerge. Specifically, foreign import prices have been falling dramatically and the volume moving into the United States is already rising sharply. We are forecasting imports of 31.3 million tons for this year (up from 27.3 million last year), but this figure is less than half what could ultimately be imported if there is no downward price response from Central Appalachia. Likewise, we are just now starting to see PRB coal moving further east, posing the question of how much market share Appalachian producers are willing to cede before adjusting their price as well. The coal-on-coal situation only intensifies as scrubbers are added, allowing buyers to leverage off a number of competing regions as well as alternatives such as petroleum coke.

Coal Production

Higher electricity generation, coupled with greater tonnage needed due to more use of lower Btu western PRB coal, leads us to forecast a roughly 22 million ton increase in production for 2005, nearly 2% above last year's output. We show lower exports and higher imports for both 2005 and 2006, but these are offset by anticipated growth in stockpile levels as many power companies seek to get out from underneath the hand-to-mouth lifestyle they have been forced to deal with due to extremely low inventory numbers.

We anticipate that electricity demand will drive coal demand even higher in 2006, aided in part by a few new units (Gilbert, Hardin) and greater transmission access by coal-fired generators to areas such as PJM.

Output in the **East** dropped significantly in the first quarter, but we are expecting a gradual recovery to slightly higher levels over the next several quarters. Growing imports continue to cut into the (largely Central) Appalachian market share, but Powder River Basin coal is also beginning to show signs of impacting Northern Appalachian markets in light of high SO2 prices coupled with generally high Appalachian coal prices. By 2006, however, we anticipate stronger growth in the Appalachian market as come coals are forced to become more price-competitive and demand for coal-fired electricity generation continues to rise.

Production from the **Interior** region began with a very strong push in the first quarter of this year, but now appears to have settled to a more sustainable level for the short term. While many observers (such as the Department of Energy) are looking for a relatively substantial decline in output from this region, we are projecting a modest increase. This more optimistic outlook is based less on any intrinsic superiority of Interior coals, and more on the inability of other regions to increase their production any more than we are currently forecasting.

Production in the **West** has been increasing at the rate of about 20 million tons annually, a development pushed by high SO2 prices, high Eastern coal prices, and a grudgingly slow improvement in transportation out of the region. We anticipate a strong near-term market for coals out of both the PRB and Western Bituminous regions for the same reasons.

The Stock Situation

"Exceeding low inventories" has been the catchphrase in describing the coal stockpile situation over the last six months, but the situation is not necessarily as clear-cut as that term implies. A first glance at the first-quarter 2005 consumption and production estimates suggests that very little was actually added to inventory levels, but we question that assumption in light of the lower burn (relative to the first quarter of 2004), even after adjusting for more Western coal in the mix (due to lower heating values). In any event, we are anticipating inventories rising to just short of 165 million tons by the end of June, a level that actually exceeds last year's level. With a normal summer drawdown, however, we are looking at about 155 million tons by the end of the year. Nevertheless, unless several regions ante up with increased production, this will be a stretch and we may end 2005 with an inventory level no larger than the 147 million tons registered at the end of 2004.

Coal Stocks (million tons)

Jan 2005	Jan 2004	Percent Difference	EOY 2004	EOY 2005	Percent Change
146.1	152.0	-3.9%	147.3	154.9	5.2%

Exports & Imports

Coal exports slowed considerably in the first quarter of 2005 after a very fast start in January, but are still running about 5% ahead of the 2004 pace. Met coal shipments continue to lead the way and we expect demand for this component of steelmaking to remain strong throughout the year. On the steam coal side, there is still very little interest in Atlantic markets. Indeed, global markets have not really responded with higher prices to a series of supply disruptions in South Africa (major rail delays), a roof fall at a major Australian mine, and adverse weather disrupting Indonesian operations. Canadian imports are down so far this year and U.S. coal exporters continue to watch the Ontario deliberations carefully, but the likelihood that all coal plants could be closed even within several years of the 2007 target date set by the new provincial government appears remote at this time.

The major price decline that has occurred in Colombian and most other Atlantic coals has not been met by reciprocal reductions in Central Appalachian coals, so interest by U.S. power companies is mounting. Preliminary data for March, released on May 11, suggests that imports topped 3 million tons in a single month for the first time. This greater interest in imports is beginning to manifest itself in the form of inland plants, as in the case of the Gainesville (Florida) Deerhaven station, which is starting to solicit foreign bids for the first time. U.S. railroads are reportedly being more cooperative in considering these kinds of shipments, although the railroads will still likely evaluate them on a case-by-case basis.

U.S. Exports and Imports (Million Tons)

	YTD 2005*	YTD 2004*	Percent Change	Forecast 2005	Forecast 2006
U.S. Exports-Total	10.1	9.7	4.6%	43.8	38.8
U.S. Imports	7.7	5.3	43.9%	31.3	34.1

**YTD is through March 2005*

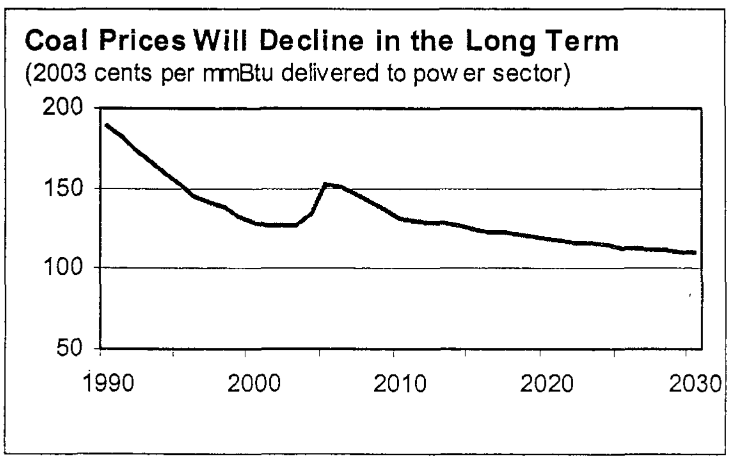
Long-Term Outlook

The issue of long-term coal pricing is one lacking widespread consensus, perhaps a problem common to more fuels than just coal. In this article, we will critically examine our contention that most coal prices will eventually decline in real terms, with a start date perhaps sooner than most expect. We review the major issues that lead us to the conclusion that the kind of pricing we have seen recently in many mining regions of the country is not sustainable.

A number of well-versed coal consultants believe that high coal prices are a permanent fixture of the energy landscape. They point to:

- the absence of any meaningful competition from natural gas in the electricity dispatch order due to high fuel prices,
- the rise in production costs in coal mining, and
- the consolidation of the coal industry that has led to unprecedented market power for a very small number of suppliers.

In this article, we will address these issues and explain why we believe they will ultimately work in the direction of lower prices.

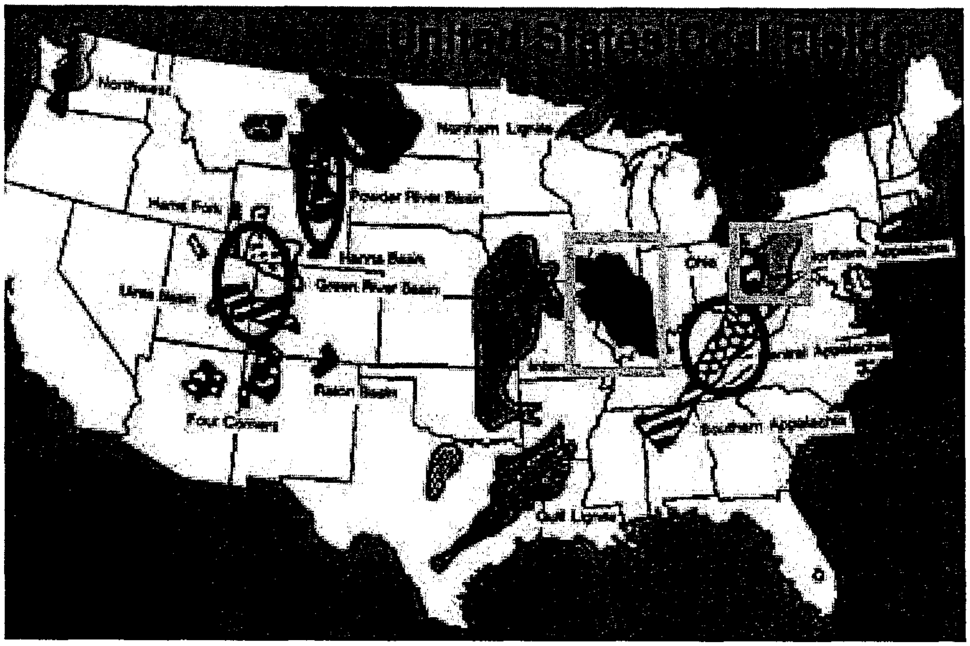


What do we mean by high or low prices? In discussing coal prices in general, this may be little more than a semantic problem. Our perspective is that prices will and must be considerably higher than they have been historically (pre-2000), but that current pricing levels are too high to be sustained. Yet we continually encounter the assumption that prices will not move too far from the current markers, so we do believe there exists a strong professional difference on this point.

The high energy price environment. There have been major price increases in virtually every fuel source since 2000, including coal, oil, natural gas, and uranium. There is a feeling among many observers that high prices in other energy sectors breed high prices in all of them, and to a limited extent, we concur. Certainly the very high price of natural gas lifts the ceiling on how high coal prices can be (although, as we will explain further, they do not necessarily mean that coal prices will rise significantly). Yet we also believe that each of those four fuels have individual industry structures, resource availabilities, and production differences that, under the right circumstances, would allow one or more to break from the pack. With regard to coal, we believe that is the case. Its abundance in the United States allows for potentially strong competition (which currently does not exist) so long as the return on new coal investment appears promising, which we think it will.

What about a lack of competition from other fuels? Indeed, natural gas prices at $6.00–7.00 per million Btu (mmBtu) will do nothing to strike fear into the hearts of coal producers. Yet we anticipate gas prices to subside to levels at which we believe coal suppliers will have to exercise some pricing restraint if they still wish to capture a significant share of the new generation market, factoring in the cost of high capital investment in boiler equipment and environmental compliance. Moreover, if coal prices really do remain as high as current levels, how much more attractive does that make nuclear power, which is already gaining significant momentum on the bases of both improved plant performances and, perhaps more importantly, concern over global climate change? Yet, as described in the next paragraph, it is really the prospect of coal-on-coal competition—not competition with natural gas—that leads us in the direction of lower prices.

Coal-on-coal competition. Our theory of coal-on-coal competition as a principal source of lower coal pricing rests heavily on the additional leverage power companies can attain by accessing coal from beyond their current procurement areas. In the near term, this may mean bringing Powder River Basin or western bituminous coal into the Midwest and East, a trend now well under way. Over the next few years, however, a much broader form of inter-regional coal competition should emerge as power plants add pollution control equipment, particularly scrubbers for SO2 control. Plants that currently rely on low-sulfur coal are highly restricted to three coal regions—the Powder River Basin (PRB), the western bituminous regions (Uinta and Green River Basins), and Central Appalachia. Installing scrubbers gives plants in the Midwest and East a good shot at using coal from two regions of low mining cost and high reserves, the Illinois Basin and Northern Appalachia. The low-sulfur areas are highlighted on the map in ovals and the high-sulfur areas are depicted with rectangles.



Critics of this theory often counter that the extreme consolidation in the coal industry simply means that everyone's prices will remain high and that competition will not actually develop. That certainly is a possibility. Yet as we look at major battlegrounds as to where we think this competition might develop (the Carolinas, for example), we find it hard to accept that coal companies will "stick to their guns" on high pricing when they are reaping such strong profits and face losing a massive market opportunity. With regard to the Carolinas, we foresee strong competition involving both two high-sulfur regions (Northern Appalachia and Illinois Basin). In looking at Central Appalachia producers, the current "incumbents" in the Carolina market, we also find it difficult to believe that they will be willing to give up their current status without a fight, especially considering that the Carolinas are their own backyard in market terms.

Finally, we expect foreign (import) coal prices to be much more attractive as prices fall in the face of lower ocean freight rates and declining demand as the Kyoto greenhouse-gas treaty begins to take a toll on European coal demand. To that end, with regard to our recent example, it is noteworthy that Progress Energy (Carolina) is currently testing foreign coals at stations other than their Sutton plant, which has taken South American coal for the past few years. Finally, we are aware of a large number of companies exploring in earnest the possibility of burning petroleum coke (petcoke). As production of that byproduct of the refining process continues to ramp up, power companies are finding it an attractive source of lower-than-coal cost fuel. Its (generally) much higher sulfur content becomes largely a non-issue when units are equipped with scrubbers. While certain qualities of petcoke (e.g., volatile matter) may prohibit 100% burning in existing coal-based units, a substantial percentage of the fuel can in fact be burned in most instances.

The theme of this argument is that following the 2005–06 period, power companies are likely to have a much wider array of coal opportunities at their disposal. While we do not expect this development to lead to "low" coal prices, we do anticipate that the prices we project in our long-term forecasts accurately portray achievable pricing levels we will see in a more competitive environment.

Production costs. The final component of the argument that coal prices will not fall is based on the premise that production costs have risen and will not be coming down. We counter with three items in this regard.

First, a good deal of the rise in production cost increase has been based on the rise in diesel fuel and steel markets (affecting a wide array of items, such as mining machinery parts). These material costs, like energy, have also experienced major price spikes. While certain contributors to production costs, such as trucking in Central Appalachia, will not be retreating from their recent rises, the majority of the material costs that increased substantially in the past few years are going to decline in the years ahead, although they will not reach their pre-2000 levels.

Second, in looking at "production costs," many analysts include the various fees and taxes to which coal is subjected. Yet some of these, such as royalties and severance taxes, are based on a percentage of the selling price. If the selling price were to decline, so would these so-called "production costs," with virtually no impact on the profit picture for the coal company.

Finally, and most importantly, production costs are heavily affected by productivity changes, and we expect this picture to improve for most of the coal industry. There has always been a strong correlation between capital investment and productivity levels in the coal industry, and as coal prices began to wane in the late 1990s, we saw capital investment decline markedly as well. The failure of new capital investment to return until just recently has had a major, negative impact on productivity levels in virtually all regions. There may be some regions where reserve degradation argues against any productivity improvement (notably Central Appalachia), but we expect most regions to respond as investment recovers. We are not looking for the historical productivity gains that were registered in much of the 1980s and 1990s, because many of those gains were achieved by simply closing less-efficient mines. We do expect, however, that the targeted, selective investment that is now becoming the trademark of the coal industry will produce worthwhile returns in both financial and productivity terms that will result in a lowering of production costs for coal mines.

Conclusion: In conclusion, we do not expect a return to the low pre-2000 coal price levels; however, we do see a substantial set of factors that will lead coal pricing away from the very high levels we have experienced over the last year or so. These reasons include potential competition from other fuel sources (natural gas and nuclear), lower production costs in the future, and—most importantly—competition from within the coal industry itself.

U.S. ECONOMIC OUTLOOK[1]

Highlights

- Real GDP growth will average 3.0% per year in 2004–30.
- The outlook for inflation remains moderate. Consumer price index (CPI) inflation will average 2.6% per year over the forecast period. Core inflation will average 2.7%.
- High investment and a slower growing labor force should result in higher productivity growth. Nonfarm business productivity growth averages 2.4% over the forecast period, compared with the 2.2% average experienced since 1953.
- The current account deficit is negative through 2025. Afterward, the current account surpluses grow.
- Real oil prices will creep up over the forecast period. The real price of imported oil is $26.3 per barrel in 2003 to $30.4 per barrel in 2030.
- The labor market improves over the forecast period, with the unemployment rate eventually settling at 4.95%.
- The federal budget deficit remains in deficit throughout the forecast period.

Long-Term Forecast

Real GDP. The trend projection assumes that the U.S. economy experiences no major mishaps between now and 2030. The projection is identical with our February 2005 baseline forecast through 2015, and represents Global Insight's best estimate of the economy's path over that period. Beyond 2015, the projection should be interpreted as the mean of all possible "near-full-employment" paths the economy could follow. The smooth-growth characteristics of the trend projection make it most useful for tasks largely impervious to short-term cyclical fluctuations, such as planning capacity additions and evaluating new markets. This projection is also the best base from which to evaluate the effects of various assumptions about key exogenous elements, such as fiscal policy or energy prices, on the overall economic outlook.

Annual real GDP growth averages 3.0% in 2004–30, about the same rate as the average of the past 25 years. The economy's underlying growth will slow after 2011, as baby boomers begin to retire, slowing labor force growth. Potential output growth should hold up fairly well in the future, with greater business fixed investment and R&D spending offsetting the slowdown in labor force growth. Eventually, though, the effects of weaker labor force growth become dominant and, in a sense,

[1] Global Insight's Long-term US Economic Outlook, February 2005.

self-perpetuating. As output growth drops off, business fixed investment rises more slowly, limiting capital stock growth and thus future output gains.

Employment. Slower long-run increases in the labor force indicate more moderate long-run employment growth in the future. Total civilian employment will rise at an average annual rate of 1.0% from 2004 to 2030. Total establishment employment will rise from 131.5 million in 2004 to 172.0 million in 2030, an increase of 31%. Manufacturing's share of total employment will continue to decline over the forecast period, falling to 7.3% in 2030, from 10.9% in 2004. The broad service sector will generate an increasing share of employment growth in the forecast period, although the federal government's share of employment will decline during the forecast period.

Inflation. Over the long run, inflation is a monetary phenomenon. Its future course will be determined by policies implemented by Alan Greenspan and his successors. Since we do not know who his successors will be, we assumed the Fed will try to stabilize the inflation rate in the second half of the forecast.

The CPI is expected to average 2.6% annual increases in 2004–30, somewhat less than the 4.4% average in 1977–2003. The broader-based GDP deflator will rise 2.3% per year.

Consumption. Expenditures, in the long term, are primarily determined by the growth of real permanent income, demographic influences, and changes in relative prices. The share of personal consumption expenditures in GDP will stabilize at just under 70% of GDP. Real consumption expenditure growth will average 2.7% per year over the forecast. In per capita terms, growth will advance about 1.9% per year, down 0.3 percentage point from the 1978–2004 rate. The share of consumption devoted to services will rise, mainly because of rising health expenditures, while that for goods will fall over the forecast period.

The long-term outlook for auto and light truck sales calls for a slowdown in the rate of increase relative to past performances. Vehicle sales growth will average close to 1.0% over the next 25 years. Light-vehicle sales are forecasted to reach 21.4 million units by 2030. Although the number of vehicles per person has increased significantly in the past 20 years, the United States is approaching a saturation point in the rate of vehicle ownership. Future growth in vehicle sales will be primarily driven by growth in population and demand for replacement vehicles. Automobile sales should be relatively strong throughout the projection period, averaging 7.9 million units per year.

Energy conservation efforts will continue. This stems partly from a stock/flow phenomenon: despite the trend toward minivans and sport/utility vehicles, for example, the average new vehicle is still more fuel-efficient than the existing stock. Gasoline usage per vehicle should fall for several more years, even if relative energy prices remain flat. Similar considerations apply to business capital and housing stocks. The ongoing employment shift from manufacturing to services also implies lower energy usage per unit of output.

Real personal disposable income, which climbed 3.2% in 1970–2003, will rise 3.1% annually over the next 25 years. This does not take into account the rising volume of withdrawals from existing retirement plans.

Housing. Household growth clearly depends on population growth, but real incomes, employment, the age distribution of the population, and societal values also influence it. Net additions to the housing stock are closely linked to household growth, which is the primary driver of housing starts. Many analysts tend to overlook another key factor for housing starts: the geographic location of the demand for net additions.

The 25–34-age cohort is key for the demand for new housing. This is the age group where individuals typically purchase their first home. The demand for new housing was boosted by the large gains in this age group in the late 1960s and 1970s, as the baby-boom generation entered the housing market. Unfortunately for the housing sector, the baby-boom generation began to pass through this age bracket in the mid-1980s, limiting the demand for additions to the housing stock. The number of households in this cohort will begin a modest increase after 2005. The overall headship rate will gradually increase toward older segments due to the shift in the age composition.

The demographic demand for housing will be about the same over the next 25 years as over the past 25 years. Thus, housing starts are projected to average 1.6 million units annually in 2003–29, about the same as during 1972–2004. Meanwhile, the housing stock will climb from 111.4 million units in 2004 to 142.5 million units in 2030.

Business Fixed Investment. Good profitability and solid demand growth should keep investment healthy over the next 25 years. The share of GDP devoted to business fixed investment will hover around 10.0–12.5% of GDP through most of the forecast period. The effective capital stock (in 2000 dollar terms) is projected to increase 3.7% annually, below the average growth rate recorded for 1970–2003. Inventory investment will remain a small percentage of GDP. Although inventories have played significant roles during past business cycles, inventory investment represents an average in the stable growth scenario and is thus artificially smooth. Capital inflow will contribute to net domestic investment throughout the forecast period, although the federal debt clearly hurt it in the later years of the forecast. The government saving projection assumes that state and local governments continue to run modest operating surpluses.

The composition of investment will continue to change in the forecast period; both structures' share of investment and equipment's share rises over the forecast period.

International Trade. A decline in the dollar relative to industrialized-country-currencies, combined with modest unit labor cost growth, will stimulate U.S. exports abroad and result in an eventual improvement in the U.S. current account balance. Global Insight projects that real exports will expand at an average annual rate of 7.3% over the entire forecast period. Real imports, meanwhile, will grow at an average annual rate of 5.2%.

FORECAST TABLES

RESIDUAL FUEL OIL #6 - GULF COAST CARGOES
SPOT PRICE - DOLLARS PER BARREL

	SULFUR CONTENT		
	0.7%	1.0%	3.0%
Jan-99	11.08	10.28	8.14
Feb-99	9.77	9.06	7.60
Mar-99	11.58	10.80	10.10
Apr-99	14.04	13.22	12.72
May-99	14.39	14.12	12.90
Jun-99	14.39	14.09	13.34
Jul-99	16.49	15.57	15.02
Aug-99	19.36	18.49	17.71
Sep-99	20.57	19.95	19.01
Oct-99	20.24	19.56	18.51
Nov-99	21.15	20.37	18.13
Dec-99	18.86	18.47	18.03
Jan-00	20.03	19.40	19.09
Feb-00	22.19	21.11	20.79
Mar-00	23.80	22.91	21.38
Apr-00	23.18	22.28	18.70
May-00	26.12	24.93	20.99
Jun-00	28.89	27.70	22.66
Jul-00	27.78	26.58	20.37
Aug-00	28.89	27.24	20.28
Sep-00	32.49	31.06	23.48
Oct-00	32.47	31.26	22.98
Nov-00	33.45	30.41	20.56
Dec-00	31.18	27.74	16.48
Jan-01	30.09	27.52	18.48
Feb-01	26.86	25.33	20.62
Mar-01	25.09	24.14	18.62
Apr-01	25.11	23.85	15.10
May-01	24.69	23.52	16.76
Jun-01	22.96	21.77	17.54
Jul-01	21.46	20.51	17.34
Aug-01	21.38	19.88	17.57
Sep-01	23.16	22.24	19.57
Oct-01	19.34	18.84	15.54
Nov-01	16.83	16.17	13.64
Dec-01	17.78	16.44	14.63
Jan-02	16.40	15.43	14.65
Feb-02	16.44	15.28	15.00
Mar-02	20.42	19.28	18.92
Apr-02	23.46	22.60	21.66
May-02	24.03	22.89	21.64
Jun-02	24.49	23.30	21.26
Jul-02	23.25	22.40	21.83
Aug-02	25.24	24.15	22.50
Sep-02	26.45	25.53	24.66
Oct-02	28.57	27.36	22.90
Nov-02	24.92	23.68	18.73

Dec-02	27.28	25.89	22.21
Jan-03	32.01	30.90	29.37
Feb-03	34.77	33.75	27.76
Mar-03	33.60	32.71	22.70
Apr-03	25.25	24.30	19.64
May-03	26.61	25.65	21.10
Jun-03	28.11	27.15	22.38
Jul-03	29.95	28.98	25.51
Aug-03	29.13	28.14	25.84
Sep-03	25.73	24.78	22.31
Oct-03	28.37	27.42	24.27
Nov-03	28.02	26.78	23.96
Dec-03	26.98	25.63	22.29
Jan-04	26.78	25.86	22.55
Feb-04	25.41	24.66	21.99
Mar-04	25.24	24.57	23.36
Apr-04	28.70	27.63	24.65
May-04	32.23	31.07	27.25
Jun-04	31.98	30.89	24.97
Jul-04	30.36	29.38	24.87
Aug-04	29.64	28.63	25.42
Sep-04	29.61	28.52	25.98
Oct-04	34.42	33.27	31.29
Nov-04	31.08	29.71	22.01
Dec-04	28.76	27.32	22.44
Jan-05	30.89	29.83	26.66
Feb-05	29.91	29.03	27.01
Mar-05	34.70	33.77	30.56
Apr-05	39.92	38.43	34.57
May-05	40.01	38.57	36.83
Forecast			
Jun-05	39.04	37.70	32.50
Jul-05	38.43	37.19	32.00
Aug-05	37.97	36.67	32.45
Sep-05	37.54	36.16	31.01
Oct-05	37.40	36.16	31.01
Nov-05	38.37	36.67	31.51
Dec-05	39.69	37.70	32.50
Jan-06	39.05	37.70	32.50
Feb-06	38.32	37.19	32.00
Mar-06	36.08	35.12	30.02
Apr-06	35.41	34.09	29.02
May-06	36.43	35.12	30.02
Jun-06	37.97	36.67	31.51
Jul-06	36.83	35.64	30.51
Aug-06	35.29	34.09	29.02
Sep-06	34.32	33.06	28.03
Oct-06	33.66	32.54	27.54
Nov-06	34.58	33.06	28.03
Dec-06	35.34	33.57	28.53

DISTILLATE FUEL OIL #2 - GULF COAST CARGOES
SPOT PRICE - CENTS PER GALLON

	Posted Price at Tampa, FL	Spot Price at Gulf Coast
Jan-99	35.77	30.99
Feb-99	33.25	28.35
Mar-99	40.99	36.09
Apr-99	47.19	40.60
May-99	45.91	39.66
Jun-99	n.a.	41.27
Jul-99	n.a.	48.07
Aug-99	n.a.	53.20
Sep-99	n.a.	58.25
Oct-99	n.a.	56.47
Nov-99	n.a.	62.15
Dec-99	n.a.	64.41
Jan-00	n.a.	72.16
Feb-00	83.88	74.76
Mar-00	83.85	72.63
Apr-00	76.39	69.74
May-00	80.82	73.09
Jun-00	81.74	75.97
Jul-00	80.43	76.30
Aug-00	89.42	86.47
Sep-00	100.97	96.53
Oct-00	98.35	93.98
Nov-00	101.93	96.33
Dec-00	92.03	82.25
Jan-01	103.51	84.73
Feb-01	88.49	76.81
Mar-01	74.88	69.07
Apr-01	80.39	73.11
May-01	82.43	75.24
Jun-01	79.36	74.12
Jul-01	71.69	68.09
Aug-01	74.74	71.68
Sep-01	74.45	71.31
Oct-01	64.11	60.32
Nov-01	56.10	52.39
Dec-01	53.28	50.04
Jan-02	54.19	50.82
Feb-02	54.70	51.63
Mar-02	64.01	61.17
Apr-02	67.49	64.22
May-02	67.58	63.93
Jun-02	65.24	62.03
Jul-02	68.76	65.38
Aug-02	71.23	68.03
Sep-02	78.89	75.62
Oct-02	79.64	75.46

Nov-02	75.21	70.03
Dec-02	82.86	79.36
Jan-03	90.54	87.52
Feb-03	114.35	104.68
Mar-03	104.61	87.83
Apr-03	84.95	71.96
May-03	78.53	70.10
Jun-03	77.56	73.50
Jul-03	80.30	76.19
Aug-03	83.36	79.29
Sep-03	75.68	71.30
Oct-03	83.49	79.44
Nov-03	84.52	80.72
Dec-03	88.52	84.57
Jan-04	98.46	94.42
Feb-04	91.87	87.36
Mar-04	97.39	88.77
Apr-04	99.40	89.42
May-04	105.92	99.00
Jun-04	104.79	96.83
Jul-04	111.93	106.59
Aug-04	119.05	114.41
Sep-04	127.25	124.23
Oct-04	151.41	145.98
Nov-04	138.64	131.90
Dec-04	126.44	118.95
Jan-05	134.16	126.60
Feb-05	135.75	129.55
Mar-05	159.35	151.48
Apr-05	158.95	149.27
May-05	148.36	138.87
Forecast		
Jun-05	136.24	125.77
Jul-05	134.97	124.61
Aug-05	136.24	125.77
Sep-05	138.78	128.07
Oct-05	143.22	132.11
Nov-05	145.76	134.42
Dec-05	148.30	136.73
Jan-06	148.30	136.73
Feb-06	139.41	128.65
Mar-06	133.70	123.46
Apr-06	129.90	120.00
May-06	126.09	116.53
Jun-06	123.55	114.23
Jul-06	124.31	114.92
Aug-06	127.36	117.69
Sep-06	132.94	122.77
Oct-06	131.93	121.84
Nov-06	131.67	121.61
Dec-06	131.48	121.44

RESIDUAL FUEL OIL #6 - GULF COAST CARGOES
SPOT PRICE - DOLLARS PER BARREL

	NOMINAL			*CONSTANT 2004 DOLLARS*		
	0.7%	1.0%	3.0%	0.7%	1.0%	3.0%
1995	15.18	14.69	13.77			
1996	18.04	17.47	15.58			
1997	16.59	16.15	14.41			
1998	12.85	12.14	9.69			
1999	15.99	15.33	14.28			
2000	27.54	26.05	20.65	29.82	28.21	22.36
2001	22.90	21.68	17.12	24.21	22.93	18.10
2002	23.41	22.32	20.50	24.35	23.21	21.32
2003	29.04	28.02	23.93	29.67	28.62	24.44
2004	29.52	28.46	24.73	29.52	28.46	24.73
2005	36.99	35.76	31.44	36.34	35.13	30.88
2006	36.11	34.82	29.73	34.87	33.63	28.71
2007	34.90	33.66	28.61	33.08	31.90	27.12
2008	34.59	33.36	28.32	32.12	30.97	26.30
2009	38.24	36.88	31.00	34.79	33.55	28.20
2010	37.40	36.07	29.94	33.28	32.10	26.64
2011	38.36	37.00	30.41	33.34	32.15	26.43
2012	38.82	37.44	30.50	32.93	31.76	25.87
2013	38.69	37.31	30.15	32.05	30.91	24.97
2014	38.49	37.12	29.72	31.15	30.04	24.06
2015	38.26	36.90	29.28	30.25	29.17	23.15
2016	38.48	37.11	29.18	29.71	28.65	22.53
2017	38.78	37.39	29.13	29.22	28.18	21.96
2018	39.09	37.70	29.10	28.74	27.72	21.40
2019	39.39	37.99	29.04	28.26	27.25	20.84
2020	39.71	38.29	29.00	27.80	26.81	20.30
2021	41.56	40.07	30.05	28.39	27.38	20.54
2022	42.85	41.32	30.68	28.57	27.55	20.46
2023	44.53	42.94	31.57	28.97	27.94	20.54
2024	45.91	44.28	32.23	29.15	28.11	20.46
2025	47.33	45.64	32.88	29.32	28.28	20.37
2026	48.87	47.13	33.95	29.54	28.49	20.53
2027	50.45	48.66	35.05	29.76	28.70	20.68
2028	51.94	50.09	36.08	29.89	28.83	20.77
2029	53.47	51.56	37.15	30.02	28.95	20.86
2030	55.12	53.16	38.30	30.20	29.12	20.98

DSTILLATE FUEL OIL #2 - GULF COAST CARGOES
SPOT PRICE - CENTS PER GALLON

	NOMINAL		CONSTANT 2004 DOLLARS	
	Posted Price at Tampa, FL	Spot Price at Gulf Coast	Posted Price at Tampa, FL	Spot Price at Gulf Coast
1995	50.68	47.48		
1996	63.75	58.98		
1997	58.57	54.10		
1998	42.17	38.19		
1999	50.99	47.07		
2000	88.17	80.85	95.47	87.55
2001	75.28	68.91	79.61	72.87
2002	69.15	65.64	71.93	68.28
2003	87.20	80.59	89.08	82.32
2004	114.38	108.16	114.38	108.16
2005	137.70	133.38	135.28	131.03
2006	126.06	121.65	121.74	117.49
2007	122.21	117.91	115.85	111.76
2008	119.66	115.41	111.11	107.16
2009	121.29	116.94	110.34	106.38
2010	118.00	113.72	105.01	101.21
2011	122.67	118.18	106.62	102.72
2012	124.96	120.34	105.99	102.08
2013	125.47	120.80	103.94	100.06
2014	125.62	120.89	101.67	97.85
2015	125.72	120.96	99.40	95.63
2016	127.30	122.43	98.28	94.52
2017	129.14	124.15	97.32	93.56
2018	131.06	125.96	96.37	92.62
2019	132.94	127.72	95.38	91.63
2020	134.90	129.56	94.46	90.72
2021	142.12	136.44	97.11	93.23
2022	147.50	141.56	98.36	94.40
2023	154.31	148.04	100.41	96.33
2024	160.15	153.59	101.68	97.52
2025	166.18	159.32	102.96	98.71
2026	171.53	164.49	103.70	99.44
2027	177.06	169.83	104.44	100.18
2028	182.22	174.82	104.88	100.62
2029	187.54	179.97	105.32	101.07
2030	193.31	185.55	105.90	101.65

Seminole Natural Gas Price Forecast
Henry Hub & FGT Mobile Bay Zone 2
(Dollars per Million Btu)

Year	Henry Hub	(Current) FGT Bidweek	FGT Cash	Deflator (2004=1.0)	Henry Hub	(2004$) FGT Bidweek	FGT Cash
1998	2.11	2.09	2.00	0.891	2.31	2.29	2.19
1999	2.27	2.26	2.21	0.904	2.45	2.44	2.39
2000	3.88	3.89	4.22	0.924	4.10	4.11	4.46
2001	4.26	4.26	3.81	0.946	4.39	4.40	3.93
2002	3.22	3.24	3.33	0.961	3.27	3.29	3.38
2003	5.38	5.39	5.49	0.979	5.38	5.39	5.49
2004	6.13	6.15	6.10	1.000	6.02	6.04	5.99
2005	6.79	6.75	6.89	1.018	6.56	6.52	6.65
2006	6.81	6.81	6.78	1.035	6.48	6.48	6.45
2007	6.57	6.57	6.47	1.055	6.13	6.14	6.04
2008	5.69	5.69	5.61	1.077	5.21	5.21	5.13
2009	4.89	4.89	4.85	1.099	4.38	4.38	4.34
2010	5.13	5.13	5.09	1.124	4.49	4.49	4.46
2011	5.28	5.29	5.26	1.151	4.52	4.52	4.49
2012	5.43	5.43	5.41	1.179	4.53	4.53	4.52
2013	5.79	5.79	5.77	1.207	4.72	4.73	4.71
2014	5.98	5.99	5.96	1.236	4.76	4.77	4.75
2015	6.11	6.11	6.09	1.265	4.74	4.75	4.73
2016	6.25	6.25	6.26	1.295	4.74	4.74	4.75
2017	6.71	6.72	6.69	1.327	4.97	4.97	4.95
2018	6.25	6.25	6.25	1.360	4.50	4.51	4.50
2019	6.57	6.58	6.59	1.394	4.62	4.62	4.63
2020	6.86	6.87	6.87	1.428	4.70	4.71	4.71
2021	6.97	6.97	6.98	1.464	4.65	4.66	4.66
2022	7.18	7.18	7.19	1.500	4.67	4.67	4.68
2023	7.39	7.39	7.39	1.537	4.68	4.69	4.69
2024	7.60	7.60	7.60	1.575	4.69	4.70	4.70
2025	7.81	7.81	7.82	1.614	4.70	4.70	4.71
2026	8.01	8.01	8.02	1.654	4.70	4.70	4.70
2027	8.21	8.21	8.21	1.695	4.69	4.69	4.69
2028	8.41	8.41	8.42	1.737	4.68	4.68	4.68
2029	8.62	8.62	8.63	1.781	4.67	4.67	4.67
2030	8.80	8.80	8.81	1.825	4.65	4.65	4.65

Table B-1

Seminole Natural Gas Price Forecast
Henry Hub & FGT Mobile Bay Zone 2
(Current Dollars per Million Btu)

Year	Henry Hub	FGT Bidweek	FGT Cash
Jan-98	2.27	2.28	
Feb-98	2.04	2.01	2.17
Mar-98	2.26	2.25	2.19
Apr-98	2.33	2.29	2.38
May-98	2.27	2.25	2.09
Jun-98	2.03	2.01	2.06
Jul-98	2.36	2.36	2.06
Aug-98	1.93	1.92	1.75
Sep-98	1.63	1.61	1.91
Oct-98	2.07	2.03	1.79
Nov-98	2.00	1.99	2.02
Dec-98	2.12	2.10	1.64
Jan-99	1.80	1.79	1.80
Feb-99	1.81	1.78	1.72
Mar-99	1.64	1.62	1.75
Apr-99	1.88	1.89	2.12
May-99	2.35	2.35	2.20
Jun-99	2.23	2.23	2.24
Jul-99	2.28	2.27	2.23
Aug-99	2.62	2.62	2.73
Sep-99	2.90	2.90	2.47
Oct-99	2.55	2.54	2.67
Nov-99	3.06	3.03	2.30
Dec-99	2.14	2.14	2.31
Jan-00	2.36	2.35	2.36
Feb-00	2.61	2.63	2.61
Mar-00	2.61	2.63	2.74
Apr-00	2.88	2.90	2.98
May-00	3.08	3.08	3.55
Jun-00	4.37	4.41	4.21
Jul-00	4.36	4.38	3.88
Aug-00	3.83	3.83	4.32
Sep-00	4.62	4.62	4.96
Oct-00	5.29	5.29	4.92
Nov-00	4.50	4.51	5.39
Dec-00	6.02	6.03	8.70

Table B-1

Seminole Natural Gas Price Forecast
Henry Hub & FGT Mobile Bay Zone 2
(Current Dollars per Million Btu)

Year	Henry Hub	FGT Bidweek	FGT Cash
Jan-01	9.91	9.94	8.00
Feb-01	6.22	6.27	5.37
Mar-01	5.03	5.05	5.01
Apr-01	5.35	5.34	5.08
May-01	4.87	4.86	3.90
Jun-01	3.73	3.74	3.42
Jul-01	3.16	3.21	2.99
Aug-01	3.19	3.18	2.87
Sep-01	2.34	2.35	2.11
Oct-01	1.86	1.86	2.40
Nov-01	3.16	3.13	2.27
Dec-01	2.24	2.26	2.31
Jan-02	2.61	2.61	2.19
Feb-02	2.03	2.06	2.23
Mar-02	2.39	2.41	2.96
Apr-02	3.41	3.44	3.42
May-02	3.36	3.40	3.55
Jun-02	3.37	3.42	3.29
Jul-02	3.26	3.30	3.07
Aug-02	2.95	3.01	3.14
Sep-02	3.27	3.30	3.58
Oct-02	3.72	3.72	4.13
Nov-02	4.13	4.26	3.85
Dec-02	4.13	3.93	4.55
Jan-03	4.96	4.94	5.44
Feb-03	5.66	5.68	7.73
Mar-03	9.11	8.85	5.94
Apr-03	5.14	5.11	5.26
May-03	5.12	5.13	5.81
Jun-03	5.95	5.98	5.81
Jul-03	5.30	5.49	5.03
Aug-03	4.69	4.73	4.99
Sep-03	4.93	4.96	4.61
Oct-03	4.43	4.43	4.63
Nov-03	4.45	4.48	4.47
Dec-03	4.86	4.86	6.14

Table B-1

Seminole Natural Gas Price Forecast
Henry Hub & FGT Mobile Bay Zone 2
(Current Dollars per Million Btu)

Year	Henry Hub	FGT Bidweek	FGT Cash
Jan-04	6.16	6.16	6.14
Feb-04	5.76	5.78	5.37
Mar-04	5.15	5.17	5.40
Apr-04	5.37	5.37	5.71
May-04	5.94	5.95	6.33
Jun-04	6.68	6.69	6.27
Jul-04	6.14	6.17	5.93
Aug-04	6.04	6.07	5.41
Sep-04	5.08	5.10	5.17
Oct-04	5.81	5.75	6.96
Nov-04	7.67	7.64	7.76
Dec-04	7.81	7.97	6.80
Jan-05	6.21	6.24	6.26
Feb-05	6.29	6.30	6.30
Mar-05	6.30	6.24	6.96
Apr-05	7.33	7.33	6.98
May-05	6.80	6.75	6.66
Jun-05	6.10	6.14	6.68
Jul-05	6.76	6.79	6.59
Aug-05	6.53	6.55	6.38
Sep-05	6.35	6.37	6.51
Oct-05	6.66	6.65	7.27
Nov-05	7.65	7.64	7.88
Dec-05	8.02	8.01	8.17
Jan-06	8.23	8.22	7.89
Feb-06	7.66	7.65	7.48
Mar-06	7.34	7.33	6.73
Apr-06	6.39	6.37	6.27
May-06	6.23	6.23	6.23
Jun-06	6.29	6.30	6.20
Jul-06	6.21	6.25	6.03
Aug-06	5.99	6.01	5.89
Sep-06	5.90	5.92	6.08
Oct-06	6.25	6.25	7.07
Nov-06	7.58	7.57	7.63
Dec-06	7.66	7.66	7.88

Table B-1

Seminole Natural Gas Price Forecast
Henry Hub & FGT Mobile Bay Zone 2
(Current Dollars per Million Btu)

Year	Henry Hub	FGT Bidweek	FGT Cash
Jan-07	7.98	7.97	7.44
Feb-07	7.11	7.10	7.14
Mar-07	7.15	7.13	6.65
Apr-07	6.38	6.36	6.30
May-07	6.30	6.29	6.25
Jun-07	6.29	6.30	6.08
Jul-07	6.02	6.06	5.83
Aug-07	5.79	5.81	5.68
Sep-07	5.69	5.71	5.84
Oct-07	6.00	6.00	6.58
Nov-07	6.98	6.96	7.08
Dec-07	7.17	7.16	6.75
Jan-08	6.51	6.51	5.95
Feb-08	5.64	5.63	5.64
Mar-08	5.65	5.64	5.68
Apr-08	5.73	5.71	5.62
May-08	5.61	5.61	5.71
Jun-08	5.84	5.85	5.49
Jul-08	5.37	5.40	5.24
Aug-08	5.24	5.27	5.13
Sep-08	5.15	5.17	5.30
Oct-08	5.47	5.47	5.73
Nov-08	5.96	5.94	6.04
Dec-08	6.13	6.13	5.75
Jan-09	5.55	5.55	5.01
Feb-09	4.73	4.73	4.75
Mar-09	4.79	4.78	4.85
Apr-09	4.94	4.92	4.84
May-09	4.86	4.86	4.97
Jun-09	5.12	5.13	4.75
Jul-09	4.63	4.67	4.50
Aug-09	4.51	4.54	4.39
Sep-09	4.41	4.43	4.54
Oct-09	4.71	4.71	4.91
Nov-09	5.11	5.10	5.17
Dec-09	5.27	5.26	5.46

Seminole Electric
Coal Prices (FOB CSX)
(Current Dollars per Ton)

Year	Illinois Basin Medium Sulfur 11,000 Btu/LB	Illinois Basin High Sulfur 12,000 Btu/Lb	Central Appalachia 12,400 Btu/Lb	Pittsburg Seam 13100 Btu/Lb	Petroleum Coke 14000 Btu/Lb	Colombian Low Sulfur 11300 Btu/Lb	Venezuelan Low Sulfur 12200 Btu/Lb
1998	21.85	19.90	25.77	22.74		26.01	28.45
1999	21.42	18.81	24.30	20.84		23.47	27.32
2000	21.26	17.51	24.70	22.25	14.75	25.12	28.44
2001	31.96	29.93	46.71	36.31	14.03	32.08	38.75
2002	25.45	23.34	28.96	27.75	9.45	25.36	31.51
2003	24.10	22.09	34.00	28.93	14.07	30.60	32.61
2004	34.22	31.83	58.15	48.33	12.17	53.96	45.76
2005	40.16	31.52	63.31	51.77	16.01	46.38	51.13
2006	37.48	29.66	58.13	41.47	9.33	36.84	42.42
2007	35.48	29.33	49.12	33.11	9.33	36.13	41.53
2008	36.03	28.74	46.67	32.73	10.46	36.55	40.76
2009	36.36	28.53	46.21	33.11	11.66	36.41	40.59
2010	36.70	28.85	46.26	34.24	13.30	34.58	38.56
2011	37.18	30.02	47.21	34.92	14.69	34.29	38.23
2012	37.93	30.87	48.50	35.53	15.56	34.29	38.23
2013	38.77	31.52	49.74	35.88	16.43	34.51	38.49
2014	39.62	32.12	50.73	36.20	17.39	34.94	38.96
2015	40.49	32.74	51.46	36.52	18.45	35.43	39.51
2016	41.40	33.37	52.59	36.85	19.93	36.28	40.45
2017	42.35	34.03	53.96	37.17	21.10	37.19	41.47
2018	43.33	34.72	55.36	37.51	22.27	38.18	42.57
2019	44.35	35.42	56.78	37.86	23.43	39.21	43.72
2020	45.38	36.12	58.21	38.20	24.89	40.28	44.91
2021	46.44	36.84	59.69	38.52	25.59	41.06	45.78
2022	47.53	37.58	61.21	38.83	26.11	41.90	46.72
2023	48.64	38.33	62.77	39.15	26.58	42.78	47.71
2024	49.79	39.10	64.37	39.50	26.98	43.72	48.75
2025	50.95	39.88	66.01	39.85	27.39	44.68	49.82
2026	52.15	40.68	67.33	40.19	27.62	45.21	50.41
2027	53.38	41.50	68.68	40.53	27.86	45.76	51.03
2028	54.63	42.34	70.07	40.89	28.10	46.35	51.68
2029	55.92	43.19	71.48	41.25	28.35	46.95	52.35
2030	57.25	44.06	72.93	41.61	28.60	47.57	53.04

Price Deflator (2004=1.0)
0.891
0.904
0.924
0.946
0.961
0.979
1.000
1.018
1.035
1.055
1.077
1.099
1.124
1.151
1.179
1.207
1.236
1.265
1.295
1.327
1.360
1.394
1.428
1.464
1.500
1.537
1.575
1.614
1.654
1.695
1.737
1.781
1.825

Seminole Electric
Coal Prices (FOB CSX)
($2004 Dollars per Ton)

Year	Illinois Basin Medium Sulfur 11,000 Btu/LB	Illinois Basin High Sulfur 12,000 Btu/Lb	Central Appalachia 12,400 Btu/Lb	Pittsburg Seam 13100 Btu/Lb	Petroleum Coke 14000 Btu/Lb	Colombian Low Sulfur 11300 Btu/Lb	Venezuelan Low Sulfur 12200 Btu/Lb
1998	24.52	22.34	28.92	25.52		29.19	31.93
1999	23.70	20.81	26.89	23.05		25.96	30.23
2000	23.02	18.96	26.75	24.09	15.97	27.20	30.80
2001	33.79	31.64	49.39	38.40	14.84	33.93	40.97
2002	26.48	24.28	30.13	28.87	9.83	26.38	32.77
2003	24.62	22.56	34.73	29.55	14.37	31.26	33.31
2004	**34.22**	**31.83**	**58.15**	**48.33**	**12.17**	**53.96**	**45.76**
2005	39.46	30.97	62.19	50.86	15.73	45.56	50.23
2006	36.19	28.65	56.14	40.05	9.01	35.58	40.97
2007	33.63	27.80	46.56	31.39	8.85	34.24	39.37
2008	33.45	26.68	43.34	30.39	9.71	33.94	37.85
2009	33.07	25.95	42.04	30.12	10.61	33.12	36.93
2010	32.66	25.67	41.17	30.47	11.84	30.78	34.32
2011	32.31	26.09	41.03	30.35	12.77	29.80	33.23
2012	32.18	26.19	41.14	30.14	13.20	29.08	32.43
2013	32.12	26.11	41.20	29.72	13.61	28.59	31.88
2014	32.07	25.99	41.06	29.30	14.08	28.28	31.53
2015	32.01	25.89	40.68	28.87	14.59	28.01	31.24
2016	31.96	25.76	40.60	28.45	15.39	28.01	31.23
2017	31.92	25.65	40.66	28.01	15.90	28.03	31.25
2018	31.86	25.53	40.71	27.58	16.37	28.07	31.30
2019	31.82	25.41	40.74	27.16	16.81	28.13	31.37
2020	31.78	25.29	40.76	26.75	17.42	28.20	31.45
2021	31.73	25.18	40.79	26.32	17.49	28.05	31.28
2022	31.69	25.06	40.81	25.89	17.41	27.94	31.15
2023	31.65	24.94	40.84	25.48	17.30	27.84	31.04
2024	31.61	24.83	40.87	25.08	17.13	27.76	30.95
2025	31.57	24.71	40.90	24.69	16.97	27.68	30.87
2026	31.53	24.60	40.71	24.30	16.70	27.33	30.48
2027	31.49	24.48	40.52	23.91	16.43	27.00	30.10
2028	31.45	24.37	40.33	23.53	16.18	26.68	29.75
2029	31.41	24.25	40.14	23.16	15.92	26.36	29.40
2030	31.36	24.14	39.95	22.80	15.67	26.06	29.06

Florida
Delivered Coal Prices
(Current Dollars per Ton)

Year	Illinois Basin Medium Sulfur 11,000 Btu/LB from Farmersburg Indiana	Illinois Basin High Sulfur 12,000 Btu/Lb from Providence, Kentucky	Central Appalachia 12,400 Btu/Lb from Pike County, Kentucky	Pittsburg Seam 13100 Btu/Lb from Waynesburg, Pennsylvania	Petroleum Coke 14000 Btu/Lb	Colombian Low Sulfur 11300 Btu/Lb from Puerto Bolivar	Venezuelan Low Sulfur 12200 Btu/Lb from Lake Maricaibo
2000	38.17	36.72	40.97	45.05			
2001	49.18	49.49	63.29	59.54			
2002	42.65	42.41	45.51	50.94			
2003	41.90	41.56	51.13	52.92	25.69	38.72	44.23
2004	**52.63**	**51.46**	**75.86**	**73.15**	**30.54**	**66.81**	**64.14**
2005	59.06	51.33	81.49	77.25	35.19	59.79	70.31
2006	56.34	49.68	76.27	66.90	20.84	44.89	53.93
2007	54.52	49.52	67.44	58.79	16.03	40.81	48.23
2008	55.28	49.17	65.20	58.70	16.58	40.83	46.88
2009	55.92	49.25	65.03	59.48	18.22	40.99	47.15
2010	56.54	49.85	65.35	60.99	20.18	39.39	45.44
2011	57.36	51.32	66.62	62.13	21.94	39.35	45.48
2012	58.45	52.49	68.24	63.19	23.09	39.55	45.77
2013	59.63	53.48	69.81	64.01	24.23	39.97	46.29
2014	60.84	54.42	71.14	64.81	25.46	40.58	47.03
2015	62.07	55.37	72.22	65.62	26.80	41.27	47.86
2016	63.36	56.34	73.72	66.45	28.51	42.28	49.04
2017	64.69	57.37	75.46	67.30	29.80	43.27	50.17
2018	66.07	58.48	77.24	68.17	31.14	44.38	51.44
2019	67.50	59.61	79.05	69.07	32.50	45.54	52.78
2020	68.95	60.76	80.89	69.98	34.15	46.76	54.18
2021	70.46	61.94	82.80	70.90	35.37	47.89	55.56
2022	71.99	63.13	84.75	71.81	36.45	49.12	57.05
2023	73.56	64.36	86.74	72.75	37.36	50.32	58.49
2024	75.17	65.62	88.80	73.73	38.19	51.55	59.96
2025	76.81	66.90	90.89	74.72	39.04	52.82	61.47
2026	78.50	68.21	92.68	75.71	39.71	53.66	62.50
2027	80.22	69.55	94.51	76.72	40.32	54.47	63.49
2028	81.98	70.92	96.37	77.75	40.75	55.19	64.33
2029	83.78	72.32	98.28	78.80	41.28	55.99	65.28
2030	85.63	73.75	100.23	79.87	41.82	56.81	66.26

NOTE: All transportation rates are assumed to be from the CSX origin points listed above except for the petroleum coke and South American shipments made by ocean vessel.

Florida
Delivered Coal Prices
($2004 Dollars per Ton)

Year	Illinois Basin Medium Sulfur 11,000 Btu/LB from Farmersburg Indiana	Illinois Basin High Sulfur 12,000 Btu/Lb from Providence, Kentucky	Central Appalachia 12,400 Btu/Lb from Pike County Kentucky	Pittsburg Seam 13100 Btu/Lb from Waynesburg, Pennsylvania	Petroleum Coke 14000 Btu/Lb	Colombian Low Sulfur 11300 Btu/Lb from Puerto Bolivar	Venezuelan Low Sulfur 12200 Btu/Lb from Lake Maricaibo
2000	41.33	39.76	44.36	48.78			
2001	52.01	52.33	66.92	62.96			
2002	44.37	44.11	47.34	52.98			
2003	42.80	42.45	52.22	54.06	26.24	39.55	45.18
2004	**52.63**	**51.46**	**75.86**	**73.15**	**30.54**	**66.81**	**64.14**
2005	58.02	50.43	80.05	75.89	34.57	58.73	69.07
2006	54.41	47.98	73.66	64.61	20.13	43.35	52.08
2007	51.68	46.94	63.93	55.73	15.20	38.68	45.72
2008	51.33	45.66	60.54	54.50	15.39	37.91	43.53
2009	50.87	44.80	59.16	54.11	16.58	37.29	42.89
2010	50.32	44.37	58.16	54.28	17.96	35.06	40.44
2011	49.85	44.60	57.91	54.00	19.07	34.21	39.53
2012	49.58	44.52	57.89	53.60	19.59	33.55	38.82
2013	49.40	44.30	57.83	53.02	20.07	33.11	38.35
2014	49.24	44.04	57.58	52.45	20.61	32.84	38.06
2015	49.07	43.78	57.10	51.88	21.19	32.63	37.84
2016	48.91	43.50	56.91	51.30	22.01	32.64	37.86
2017	48.75	43.24	56.86	50.72	22.45	32.61	37.81
2018	48.58	43.00	56.80	50.13	22.89	32.63	37.82
2019	48.42	42.77	56.72	49.55	23.31	32.67	37.87
2020	48.28	42.54	56.64	49.00	23.91	32.74	37.93
2021	48.14	42.32	56.58	48.44	24.17	32.73	37.96
2022	48.01	42.10	56.51	47.89	24.30	32.76	38.04
2023	47.87	41.88	56.44	47.34	24.31	32.74	38.06
2024	47.73	41.66	56.38	46.81	24.25	32.73	38.07
2025	47.59	41.45	56.31	46.29	24.19	32.73	38.08
2026	47.46	41.24	56.03	45.77	24.01	32.44	37.78
2027	47.32	41.03	55.75	45.26	23.78	32.13	37.45
2028	47.18	40.82	55.47	44.75	23.45	31.76	37.02
2029	47.05	40.61	55.19	44.25	23.18	31.44	36.66
2030	46.91	40.40	54.91	43.76	22.91	31.12	36.30

NOTE: All transportation rates are assumed to be from the CSX origin points listed above except for the petroleum coke and South American shipments made by ocean vessel.

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Long-Term Solid Fuel Availability Analysis

Prepared for:

Seminole Electric Cooperative, Inc.

July 19, 2005

F-I-N-A-L

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EXECUTIVE SUMMARY

BACKGROUND & OVERVIEW

Seminole Electric Cooperative, Inc. ("Seminole") retained Pace Global Energy Services, LLC ("Pace Global") to assess from the present through the year 2040 (the "Study Period") the supply availability of petroleum coke, low-sulfur coal, and mid- to high-sulfur coal (collectively referred to as "solid fuel") for proposed new electric generation facilities in Florida. Pace Global analyzed the availability of petroleum coke supply and engaged Hill & Associates Inc. as a subcontractor to evaluate the availability of coal supply for Seminole's new generation. Key findings providing an integrated view on solid fuel availability are presented below; the supporting analysis and commentary underpinning these statements follows in individual reports dedicated to petroleum coke and coal.

KEY FINDINGS

1. Seminole's proposed new solid-fuel-fired generation in Florida is expected to require on an annual basis 0.6-8.0 million short tons ("mmt") of petroleum coke and 1.2 mmt or more of coal, in addition to its existing annual requirements of approximately 4.0 mmt of solid fuel. These estimates assume certain fuel heat contents and blends. Seminole's existing and new generation's actual fuel requirements will likely vary from these estimates, but not significantly enough to change materially the conclusions of this report.

2. The supply of solid fuel from domestic and foreign sources will be adequate over the Study Period to meet the requirements of Seminole's existing and new generation.

3. Seminole's existing and new generation will most likely access petroleum coke supply from Gulf Coast, Midwest, and Caribbean refineries. These facilities currently supply quantities of fuel adequate to meet Seminole's existing and new generation's projected annual requirements.

4. Over the Study Period, refineries in the aforementioned regions are anticipated to add incremental coking capacity in response to the increased demand for transportation fuels and more sour, heavy crude streams.

5. Coal supply for Seminole's new generation is expected to come from Central Appalachia, Illinois, Northern Appalachia, Colombia, and Venezuela. These coal supply basins over the Study Period are expected to produce at levels sufficient to meet the incremental demand resulting from the commercial operation of Seminole's new generation.

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6. All of the aforementioned coal supply basins, with the exception of Central Appalachia, are expected either to increase their level of production or have the capability to do so in the future.

7. Supply from Central Appalachia will decrease over the Study Period from its present level of 190 mmt, but growth in production in Illinois and Northern Appalachia as well as increased imports will offset the decline in Central Appalachian production.

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Long-Term Petroleum Coke Supply Availability Analysis

Prepared for:

Seminole Electric Cooperative, Inc.

July 19, 2005

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EXHIBITS

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KEY FINDINGS

1. Pace Global expects over the period 2005-2040 (the "Study Period") adequate supplies of petroleum coke ("pet coke") will be available from domestic and foreign suppliers to meet the partial or full fuel demand requirements of new solid-fuel-fired generation in Florida.

2. The world's supply of pet coke will increase from current production levels in response to the increased production of transportation fuels from an increasingly heavy and sour quality crude oil stream.

3. New solid-fuel-fired generation in Florida will most likely access pet coke supply from Gulf Coast, Caribbean, and Midwest refineries. These facilities are expected to add additional coking units in response to the increased demand for higher value transportation fuels.

4. Although increased worldwide demand for and utilization of pet coke is expected over the Study Period, particularly in Asia, Pace Global anticipates that Gulf Coast, Caribbean, and Midwest supply will largely remain in the Atlantic Basin.

5. Due to the Kyoto Protocol, pet coke demand in Northern Europe and the Mediterranean region, the alternative market for Gulf Coast and Caribbean supplies, is expected to stagnate or decline gradually over the Study Period.

6. The cement industry is expected over the Study Period to remain the dominant end user of pet coke, however, the paper and fertilizer industries, which have relied extensively on natural gas as an energy and feed stock have recently shown increasing interest in pet coke as a source of energy and raw material for their plants. Power generators are expected to increase their share of pet coke consumption, as they increasingly install fluidized-bed boilers and scrubbers to comply with emissions restrictions.

7. The majority of pet coke production in the Gulf and Caribbean will be only water accessible, while pet coke shipments in the Midwest region will continue to rely on railroads and river barges.

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INTRODUCTION

Seminole Electric Cooperative, Inc. ("Seminole") has retained Pace Global Energy Services, LLC ("Pace Global") to assess from the present through the year 2040 the supply availability of pet coke to meet the partial fuel requirements of new base-load electric generation facilities in Florida whose development is under consideration. Based on information previously conveyed by Seminole, Pace Global has for the purposes of this report assumed that Seminole is contemplating a new plant of approximately 800 megawatts that has the capability to burn both coal and pet coke starting around 2012.

A number of variables will determine the plant's actual pet coke consumption—including, but not limited to its: efficiency, annual capacity factor, and heat content of its fuel. For the purposes of this report, it is assumed that Seminole's new generation will consume annually 0.6-0.8 million short tons ("mmt") of pet coke,[1] in addition to Seminole's existing annual requirement of approximately 1.0 mmt of pet coke. This projection is included to serve as a very high-level estimate of what Seminole's proposed plant might require and to facilitate discussion in the report. Seminole's new generation's actual fuel requirements will likely vary from these estimates, but not significantly enough to change materially the conclusions of this report.

Given the estimated requirements established above, Pace Global in the four sections of the report that follow: 1) provides background discussion on pet coke qualities which make it desirable as a fuel; 2) reviews current pet coke supply; 3) identifies pet coke end uses; and 4) details pet coke market dynamics. The Study Period covers a lengthy span of time—the present, the projected start up of Seminole's new generation facility in five years, and the distant future. In the commentary that follows, Pace Global provides a review of the current market, expectations for the period 2006 through 2025, and probable trends for the period 2026-2040.

[1] All tonnage figures used throughout this report are expressed in tons of 2,000 pounds (so-called "short tons"). Pet coke internationally is priced and sold in metric tons. One short ton is equivalent to 0.907 metric tons.

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PET COKE BACKGROUND

When discussing pet coke, it is important to remember that pet coke is a by-product of the process to refine crude oil into more valuable finished products, such as gasoline and jet fuel. The supply of pet coke results from the demand for refined petroleum products, not for pet coke itself. Refiners continuously monitor and adjust their refinery processes to accommodate differing crude slates; consequently, pet coke quality varies considerably making it impossible to identify pet coke with a single set of specifications. The typical specification ranges for pet coke are as follows:

- Moisture: The water content of pet coke is usually low, (less than 0.5 percent to 10.0 percent);
- Ash: Pet coke has less than 1.0 percent ash;
- Energy content: Pet coke averages approximately 14,000 British Thermal Units per pound ("Btu/lb."); and
- Hardness: Pet coke ranges on the Hardgrove Grindability Index ("HGI") from 32 to 70.[2]

In addition to these physical properties, sulfur content also plays a key role in determining how pet coke supply is used. Exhibit 1 provides an overview of the typical sulfur content of pet coke used in various applications.

Exhibit 1: Typical Pet Coke Sulfur Content by Application

Sulfur Content	Application	Industry
High-Sulfur (>4.5 %)	Fuel	Cement Electric Utilities
Mid-Sulfur (>2.5 %)	Manufacturing	Aluminum Steel
Low-Sulfur (>1.00%)	Product Component	Additives Modifiers

Source: Pace Global.

Seminole intends to utilize pet coke as a fuel; therefore, this report will focus on "fuel-grade" pet coke as opposed to "anode-grade" coke, which typically has sulfur content of 2.5 percent or less. Through blending, however, the sulfur level in some fuel-grade product can be reduced to levels

[2] The HGI test attempts to mimic the operation of a continuous solid-fuel pulverizer. The test results in a value generally between 30 and 100. The higher the HGI value of the material input into a solid-fuel processing mill, the closer that mill will operate near its design capacity. The HGI test is highly non-linear, such that a change in HGI from 90 to 80 results in a small decrease in mill capacity while a change from 50 to 40 leads to a considerably greater decrease in mill capacity.

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suitable for anode-grade applications. Consequently, in practice, there is not a bold distinction purely on the basis of sulfur content between fuel-grade and anode-grade product. Other parameters, such as HGI and metals content also determine how pet coke is utilized.

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SUPPLY

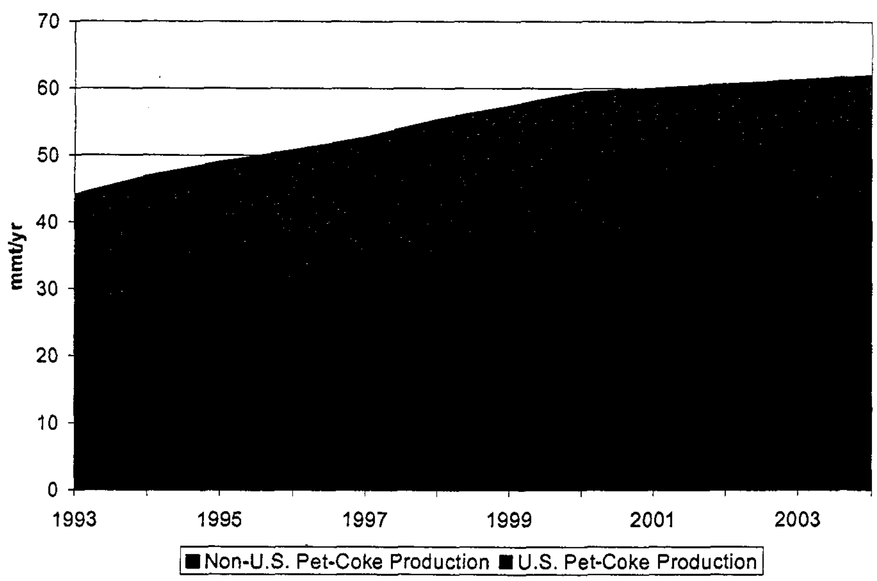
PRODUCTION

In 2004, total worldwide pet coke production is estimated to have totaled around 62 mmt. The major centers for pet coke production are North America producing slightly less than 42 mmt, South America producing almost 10 mmt, Asia producing just less than 6 mmt, and Europe producing 4 mmt. U.S. marketable pet coke production in 2004 was slightly more than 43 mmt (37 mmt of fuel-grade product and 6 mmt of anode-grade product).

Given transportation costs, Pace Global anticipates the pet coke for Seminole's proposed new generation will come from refineries: situated on the Gulf Coast, in the Caribbean, and in the Midwest. These three regions currently produce approximately 66 percent of the world's supply pet coke. When combined, the Gulf Coast and Midwest regions account for 82 percent of pet coke production in the U.S.

Worldwide production of pet coke has increased over the past ten years at a compound annual growth rate of slightly more than three percent. Exhibit 2 provides an overview of domestic and foreign pet coke production over the past decade.

Exhibit 2: Pet-Coke Production, 1993-2004



Source: Pace Global

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The primary drivers behind this growth are increasing demand for refined products and deteriorating qualities of crude oil. Currently, the U.S. is the single largest producer of pet coke; its world market dominance results from high U.S. demand for transportation fuels and light petroleum products and the ability of its Gulf Coast refineries to process cheaper, heavier crude oils located in nearby countries, such as Venezuela and Mexico.

PRODUCTION CAPACITY

There are 674 refineries in the world, 108 of them currently have coking units. Worldwide annual pet coke capacity at the end of 2004 was estimated to stand at approximately 82 million mmt, with just over 48 mmt of this capacity located in the U.S.

With more than 24 mmt/year of installed production capacity, the U.S. Gulf Coast is home to the largest concentration of fuel-grade coking facilities in the world. The Caribbean region contains an additional 8 mmt/year of fuel-grade production capacity. Refineries in the Midwest are currently shipping pet coke to end users in Florida; therefore, Pace Global has also views these production facilities as possible supply sources for Seminole's new generation. The Midwest thus offers an additional 8 mmt of capacity. Seminole's proposed new generation in Florida would at present likely have access to over 40 mmt of production capacity.

In Exhibits 3, 4, and 5, Pace Global details annual fuel-grade pet coke production capacity by the major regions expected to supply Seminole's proposed new generation.

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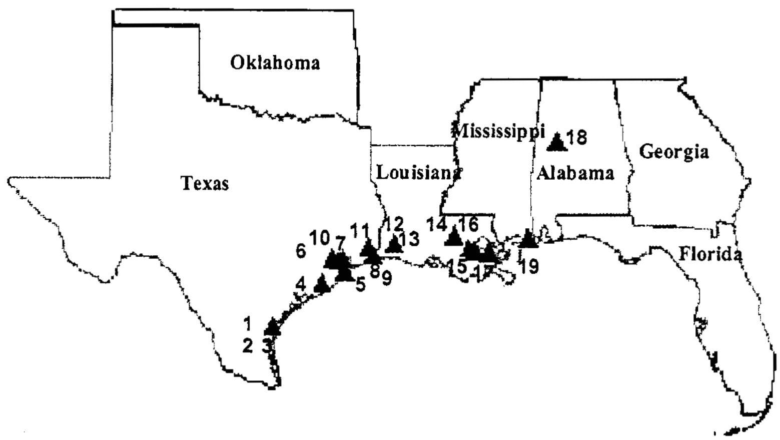
Gulf Coast

Exhibit 3: Gulf Coast



No.	Company	Facility	Annual Production Capacity (mmt)	Sulfur (%)	HGI
1	Citgo	Corpus Christi, TX	0.8	3.9	45-50
2	Flint Hill Resources	Corpus Christi, TX	0.3	3.0-5.5	70
3	Valero Refining Co.	Corpus Christi, TX	0.4	n/a	n/a
4	Phillips 66	Sweeny TX	1.5	4.3	52
5	BP	Texas City, TX	1.0	6.0	80
6	Deer Park Refining LTD Partnership*	Deer Park, TX	1.5	6.3-6.5	38-42
7	Exxon Mobil	Baytown, TX	0.9	6.0-7.0	35
8	Motiva	Port Arthur, TX	1.2	6.0-6.5	60-65
9	Premcor	Port Arthur, TX	1.9	6.5	30-35
10	Lyondell / Citgo	Houston, TX	2.1	3.8-4.0	55-60
11	Exxon Mobil	Beaumont, TX	1.1	6.0	48-55
12	Citgo	Lake Charles, LA	2.4	4.5-5.0	50-65
13	Conoco	Lake Charles, LA	1.2	6.0	40
14	Exxon Mobil	Baton Rouge, LA	2.6	5.0-7.5	45-90
15	Chalmette Refining, LLC**	Chalmette, LA	0.8	4.5	45-50
16	Marathon	Garyville, LA	0.8	7.5	30
17	Orion	Good Hope, LA	1.5	4.5	45-55
18	Hunt	Tuscaloosa, AL	0.3	5.0	40
19	Chevron Texaco	Pascagoula, MS	1.8	5.0	65
	Total Fuel-Grade Pet Coke Production Capacity		**24.1**		

*Joint venture between Shell and Petroleos Mexicanos (PEMEX)
**Joint venture between ExxonMobil and PDV Chalmette, Inc.
Source: Energy Argus Petroleum Coke, EIA, and Pace Global.

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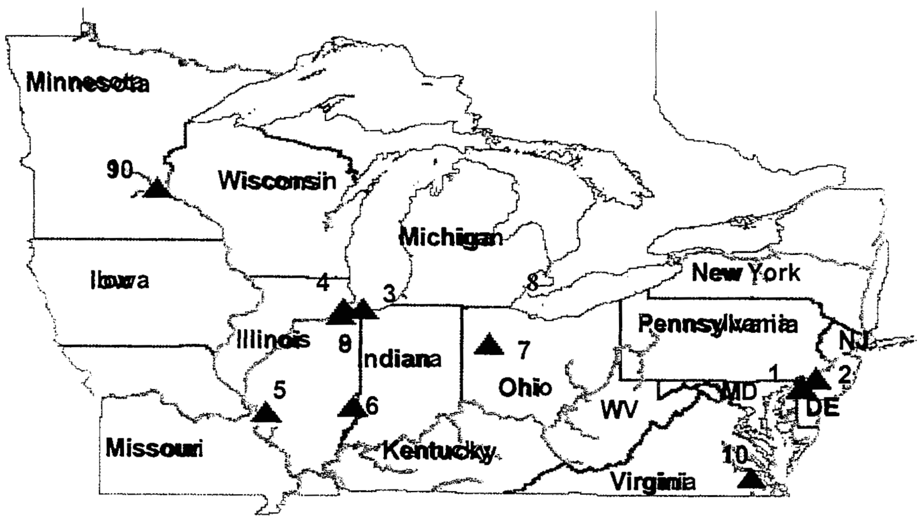
Midwest

Exhibit 4: Midwest



No.	Company	Facility	Annual Production Capacity (mmt)	Sulfur	HGI
1	Motiva	Delaware City, DE	1.1	4.0-6.0	37
2	Valero	Paulsboro, NJ	0.6	6.0-6.5	<50
3	BP	Whiting, IN	0.8	4.0-5.0	n/a
4	Citgo	Lemont, IL	0.8	4.5-5.5	50
5	Conoco Phillips	Hartford, IL	0.4	6.5	30-35
6	Marathon	Robinson, IL	0.6	4.1	65
7	Premcor	Lima, OH	0.5	6.5	30-35
8	ExxonMobil	Joliet, IL	1.3	5-5.5	45-50
9	Flint Hill Resources	Rosemount, MN	1.6	6.0	40
10	Giant Industries	Yorktown, VA	0.5	1.5	80
	Total Fuel-Grade Pet Coke Production Capacity		8.2		

Source: RDI, Energy Argus Petroleum Coke, and Pace Global.

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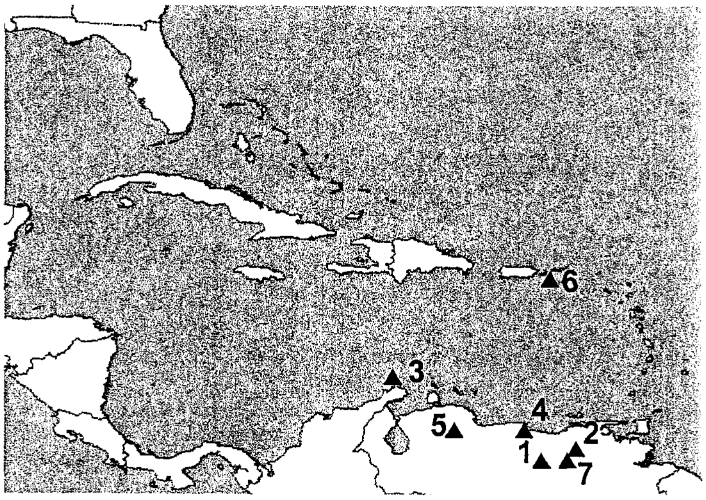
Caribbean

Exhibit 5: Caribbean Region



No.	Company	Annual Production Capacity (mmt)	Sulfur	HGI
1	Conoco Petrozuata	1.2	4.00%	65
2	Exxon Cerro Negro	0.9	4.50%	60
3	Valero Aruba	1.7	6.00%	50
4	PDVSA Lagoven	0.7	4.20%	55
5	PDVSA Maraven	1.5	4.00%	45
6	Hovensa	1.3	4.50%	30
7	Hamaca Project	1.3	4.00%	40
Total Fuel-Grade Pet Coke Production Capacity		**8.6**		

Source: Energy Argus Petroleum Coke and Pace Global.

The majority of coking capacity additions are expected to take place in the U.S. (particularly along the Gulf Coast to handle sour imported crude and in the Midwest to process heavy crude from Canada) and the Caribbean. Over the longer-term, e.g., the next 20 years, Pace Global expects additional delayed coking capacity to come on-line throughout the world with continued emphasis on the North America due to its proximity to large heavy sour crude oil reserves and the lower investment cost of adding coking capacity, instead of other technological solutions, to serve growing transportation fuels demand.

In Exhibit 6, Pace Global details the nine fuel-grade coker additions that are either being planned or considered for the Gulf Coast, Midwest, and Caribbean.

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Exhibit 6: Potential Fuel-Grade Pet Coker Additions

Producer	Refinery Location	Status	Expected Onstream Year of Incremental Capacity
Premcor	Port Arthur, TX	Under construction	2006:Q2
Citgo	Lake Charles	Planning	2008
ConocoPhillips	Hartford, IL	Planning	2008
Premcor	Lima, OH	Planning	2008
Marathon	Robinson, IL	Under review	2008
Hamaca	Venezuela	Under review	2010
El Palito	Venezuela	Under review	2010
Puerto La Cruz	Venezuela	Under review	2010

Source: Pace Global

Through its industry sources, Pace Global has learned that the refineries listed above intend to increase their pet coke production capacity in the next five to ten years. For instance, ConocoPhillips has recently confirmed budgeting to expand their coking operations at its Wood River, Illinois refinery.

PET COKE QUALITY

Pace Global expects that pet coke quality will continue to deteriorate as refineries process increasingly heavy-sour crude oils. Within the past decade, the gravity, as measured on the American Petroleum Institute ("API") Scale, of the crude processed at refineries in the U.S. has decreased at a rate in excess of 0.10 degree per year. This decline in crude quality is expected to accelerate in the future and will produce pet coke, which is generally harder and contains higher quantities of sulfur and metals. Any plant adding pet coke to its current fuel mix will likely require additional crushing capacity to handle supply that is often harder than coal.

The level of sulfur content, hardness, and metals concentrations determine the pet coke's application and thus its market value. A carbon usage pet coke generally requires a sulfur content of less than 2.5 percent and low metals content. When the sulfur content exceeds 2.5 percent, the pet coke becomes less suitable as a carbon source. The higher sulfur, fuel-grade pet cokes have been categorized into four price ranges based on their sulfur content and hardness. The best quality fuel-grade pet coke has sulfur content of 4.5 percent and an HGI of less than 50. The next best pet coke quality has the same sulfur limit, but is has a hardness of greater than 50 HGI. The other two fuel-grade pet cokes have a higher sulfur level of 6.5 percent and HGI's of less than 50 or greater than 50.

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Pace Global anticipates that the average sulfur and metal contents of the fuel-grade pet coke will continue to continue increase through the Study Period. Currently, 33 percent of U.S. pet coke production is "shot pet coke." Shot pet coke has a HGI of less than 50, usually in the range of 35 to 45. It is expected that within 10 years, the U. S. production of shot pet coke will increase to 55 percent of the country's pet coke supplies. Consumers of fuel-grade pet coke will need to plan on grinding a harder pet coke between 2005 and 2040.

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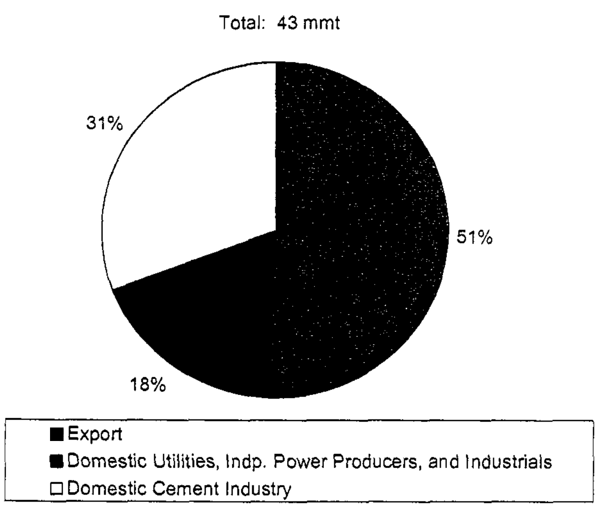
CONSUMPTION

The global cement industry is the largest purchaser of fuel-grade pet coke. It accounted for 71 percent of traded fuel-grade pet coke in the last decade. The cement industry has limited flexibility when using pet coke as a fuel because the pet coke's ash becomes part of the cement clinker during process. Pet coke is considered important fuel, but not a critical fuel to the cement industry.

Exhibit 7 provides a snapshot of pet coke consumption in the U.S. in 2004 and shows approximately 22 mmt of supply exported abroad.

Exhibit 7: U.S. Pet Coke Consumption by Sector, 2004



Source: Pace Global & Energy Argus Petroleum Coke Report.

Total non-cement industry consumption of pet coke in the U.S. market was just over 7 mmt in 2004, with approximately 46 percent of non-cement-industry pet coke consumption coming from utilities. Exhibit 8 depicts by end-use type domestic pet coke consumption.

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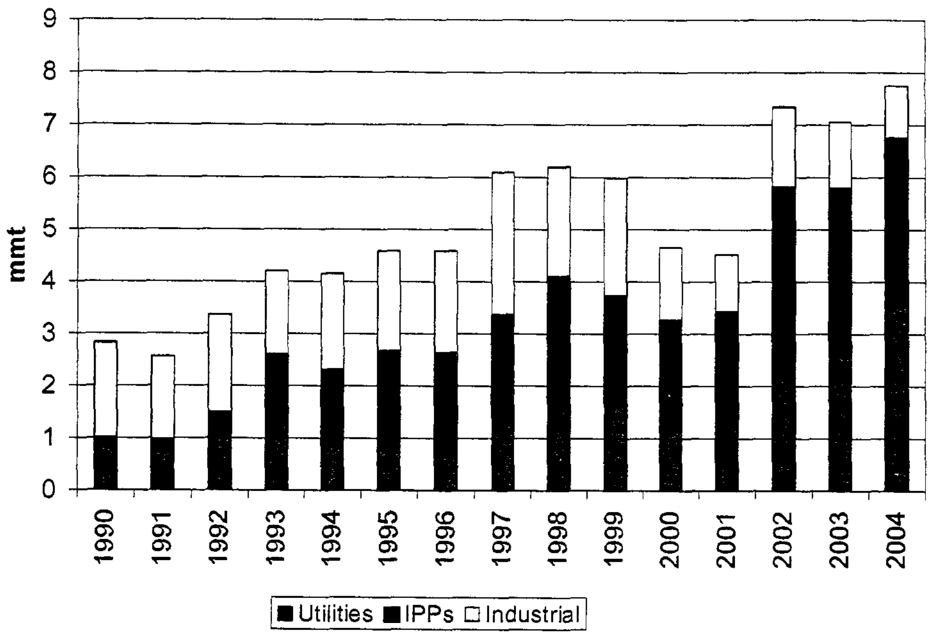
Exhibit 8: U.S. Pet coke Consumption, 1990-2004



Source: EIA

In the U.S., the power generation sector is a growing consumer of pet coke and is assuming a "swing" role in the market. Utilities over the past five years have increased their consumption of pet coke at a compound annual growth rate of almost 33 percent. Power stations have the flexibility of storage and fuel switching since pet coke is generally considered a secondary (opportunity) fuel to a station's overall fuel needs.

Power generators remain concerned about their existing plants' ability to use pet coke due to the tighter NO_x emission restrictions as well as expected tightening of the SO_2 emission allowance market towards the end of the decade. Due to these environmental concerns and the volatility of market-based pet coke prices, many end users consider pet coke as an "opportunity" fuel, e.g., they only use it to blend with coal, when pet coke is cheap. Hence, Pace Global expects pet coke demand from power generators to grow, though such demand is also expected to exhibit a high degree of price elasticity.

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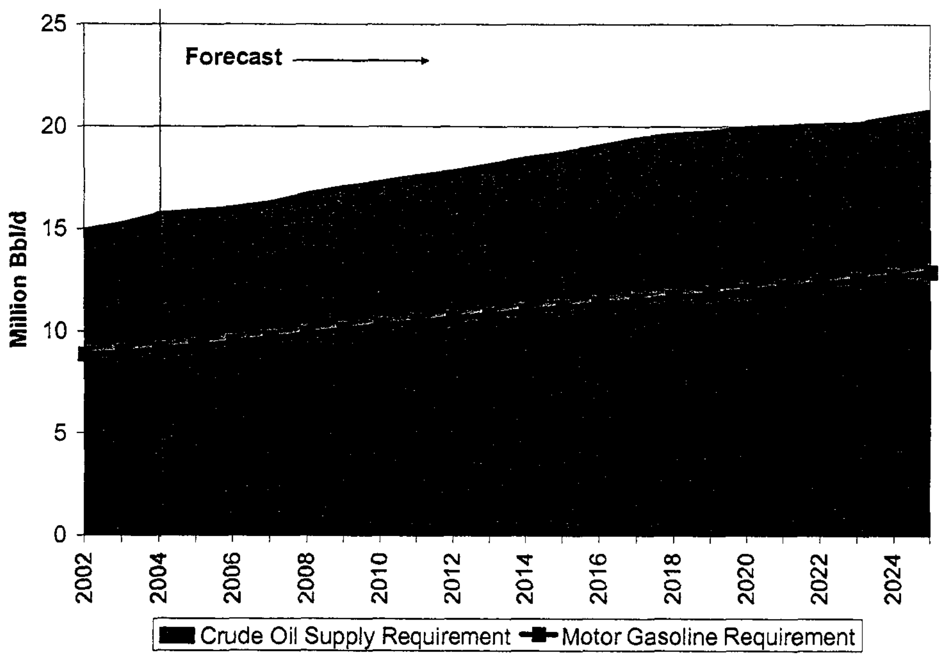
MARKET DYNAMICS

It is Pace Global's view that pet coke production capacity will be added regardless of projected pet coke demand or pricing. The production of fuel-grade pet coke is dependent on the world's demand for transportation fuels, especially motor gasoline, produced from increasingly heavy sour crudes. EIA has forecast that the world's demand for crude oil will continue to grow at an average of 1.9 percent per year until 2025. As shown in Exhibit 9, the consumption of crude oil in the U.S. is expected to grow from almost 16 million barrels per day ("Bbl/d") in 2004 to slightly more than 20 million Bbl/d in 2025, a compound annual growth rate of 1.3 percent. U.S. motor gasoline supply is expected over that same period to increase at a compound annual growth rate of 1.7 percent.

Exhibit 9: U.S. Crude Oil and Motor Gasoline Consumption Forecast



Source: EIA

Growth in world oil demand will move from the industrialized countries and regions, such as the United States, Western Europe, and Japan, to emerging areas such as Eurasia and the developing countries in Asia, South America, and Africa. The quality of annual crude production is expected to continue its decline to heavier and more sour crudes in all areas of the world. Thus the world's refineries will be under pressure to increase their coking operations to accommodate the poorer crude qualities.

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As the demand for transportation fuels increases during the next two decades it is likely new refineries, with cokers, will be built nearer these emerging markets. As this trend accelerates, the U.S. will gradually lose its dominant position as the world's leading producer of pet coke but will likely continue to produce 45 to 55 mmt of fuel-grade product because of its transportation fuel requirements.

The demand for fuel-grade pet coke as a combustion fuel is likely to decrease in the industrialized countries and reduce U.S. exports. Due to the Kyoto Protocol, demand in Northern Europe and the Mediterranean region, the alternative market for Gulf Coast and Caribbean supply, is expected to stagnate or decline gradually over the Study Period. Similarly in Japan, a drop of 3 percent in in its current usage of pet coke (approximately 3.4 mmt annually) is anticipated to result from its emissions reduction programs. Due to transportation costs, displaced supply from Europe is likely to stay in the Atlantic Basin and enter the domestic market.

FUTURE PET COKE PRODUCTION

2005-2025

By 2010, annual pet coke production worldwide is forecast to exceed 85 mmt. The supply of pet coke in the following 15 years will continue to increase as the world's demand for crude oil is anticipated to to grow at a 1.9 percent compound annual growth rate. Much of the incremental crude supply will come from heavy sour crudes. Between 2010 and 2025, pet coke production is expected continue to increase at an annual average growth rate in excess of 3 percent, with annual production of pet coke production reaching just over 138 mmt in 2025. Pet coke production in the U.S. will likely reach its maximum during these two decades.

2026 to 2040

The world production of fuel-grade pet coke during this period will likely flatten out as the conservation of transportation fuels picks up its pace. Alternative methods of transportation, such as the hydrogen-based fuel cells, may begin to replace carbon-based fuel consumption. However, the decline of fossil fuels consumption will be slow and not reach significantly lower levels until the turn of the century.

COAL BASIN SUPPLY AVAILABILITY EVALUATION TO 2040

Prepared for:
SEMINOLE ELECTRIC COOPERATIVE, Inc.

By:
Hill & Associates, Inc.

June 24, 2005

HILL & ASSOCIATES INC.

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COAL BASIN SUPPLY AVAILABILITY EVALUATION TO 2040 FOR SEMINOLE ELECTRIC, FLORIDA

INTRODUCTION

Hill & Associates (H&A) was retained as a subcontractor to Pace Global Energy Services, Fairfax, VA to provide an evaluation of coal supply availability to 2040 for the following coal basins and supply countries:

- Central Appalachia
- Illinois Basin
- Northern Appalachia
- Colombia
- Venezuela

The report generated in response to this assignment is organized in the following manner. First, an **overview** of each basin is provided at the beginning of the section. The overview provides a description of the region from geologic and coal mining perspectives.

Then, a section is devoted to **production** for each basin, including historical and projected production according to sub-region (if applicable) and coal quality type. This section also contains discussion on current mining technologies employed in the basin and trends for future mining.

The section on **reserves** attempts to respond to the issue of availability of reserves to satisfy mining to 2040. Tables are included in this section that display reserves by coal quality type or level of reserve definition (e.g., measured, indicated, inferred, etc.).

The last section of each basin presentation provides a review of **key issues and drivers** impacting current and future mining in that basin.

Tonnage references throughout this report relate to short, or net, tons of 2000 lb. For all coal basins, reference to *mmt* references "million short tons."

KEY FINDINGS

Summary comments. The evaluation of the several coal sources reviewed in this study shows adequate reserves available to produce low-, mid- and high-sulfur coals at current levels far beyond 2040. Coal production will continue in all of the U.S. coal basins and will be increasingly supplemented by foreign sources evaluated in this review through year 2040. There are variances among the sources in sustainability by product type but, with prudent and strategic purchasing policies in place, the overall supply of coal to Florida generating plants should present no serious problem.

All of the basins either are expanding or have adequate expansion potential beyond 2040, with the exception of Central Appalachia which has been declining since 1998. Hill & Associates' outlook for the basins indicates that Central Appalachian coals will continue to be displaced in utility blends in the future. Illinois Basin and Northern Appalachian mid- and high-sulfur coals will move into the south and southeastern markets to serve those plants that install scrubbers. Both of these basins are likely to expand production to meet this new demand. Imported coals will compete in utility blends to free up SO_2 credits, to offset higher sulfur coals or, displace Central Appalachian coals. The penetration of imports will occur along the coastal regions from the northeast down and across the Gulf region. As railroads begin to embrace the import concept, H&A predicts that more imports will arrive at inland plants by rail in coming years.

Table 1 shows the production alignment of each coal source according to coal type for 2005:

Table 1

Coal Basin Production Alignment by Coal Type – 2005

Coal Source lb. SO2/mmBtu	Compliance <1.2	Near-Compliance 1.2-2.5	Mid-sulfur >2.5-5.0	High-Sulfur >5.0	Total
Central Appalachia - mmt	53.2	133.0	3.8	0.0	190.0
percent	*28*	*70*	*2*	*0*	*100*
Northern Appalachia	1.5	29.3	54.8	37.7	123.3
percent	*1*	*24*	*44*	*31*	*100*
Illinois Basin	2.1	23.1	18.5	52.0	95.7
percent	*2*	*24*	*20*	*54*	*100*
Colombia	24.3	49.4	0.0	0.0	73.7
percent	*33*	*67*	*0*	*0*	*100*
Venezuela	8.0	2.0	0.0	0.0	10.0
percent	*80*	*20*	*0*	*0*	*100*

The table shows that mid- to high-sulfur coals are most prevalent in the Northern Appalachian region and Illinois Basin region. Lower sulfur, compliance and near-compliance coals are found in all coal sources but the important volumes of compliance grade coals from Central Appalachia, which are declining, will, when replacement is required, be most available from Colombia. Near-compliance coals are also prevalent in all coal sources in sufficient amounts that would indicate less difficulty in the long term to obtain supply of this type of coal from several sources.

The following paragraphs summarize the key findings by source region or country. Full basin/country presentations follow this summary.

Central Appalachia. This basin is in decline and few large-scale economic reserve blocks remain. There are higher-cost reserves in deeper seams that can be developed and certain producers will be able to expand production at or near existing mine operations. CAPP will decline significantly by 2040 but, even then, we expect production at levels in the range of 50 to 100 mmt per year. Low-sulfur CAPP production will be replaced by Powder River Basin coals and imported coals from Latin America, Indonesia, South Africa and Russia.

Illinois Basin. Tremendous coal reserves exist and significant expansion is possible in the ILB. At existing or even greatly expanded production the basin will continue production well past year 2040. The ILB produces high-sulfur coals and will be positively impacted by the shift in demand to high sulfur coals that will occur in U.S. generating stations that will be adding scrubbers to meet emissions standards.

Northern Appalachia. Remaining Pittsburgh seam reserves would support production at existing levels for over 36 years. There are large reserves blocks controlled by major producers such as Consol and Foundation Coal that must be developed to sustain production. At present, H&A's forecast indicates NAPP production could begin to decline around 2015 but should still be producing at levels near 100 mmt per year by 2040. This source of mid- to high-sulfur coals will compete with the ILB in scrubber markets but both sources are capable of movement to Florida plants.

Colombia. Ample reserves and production will be available to ensure adequate supply of Colombian coals beyond 2040. This source is still in the developing stage and enormous reserves of low-sulfur thermal coals exist. Major producers Drummond and Cerrejon Coal are targeting aggressive expansion plans at generating and industrial plants in the U.S.

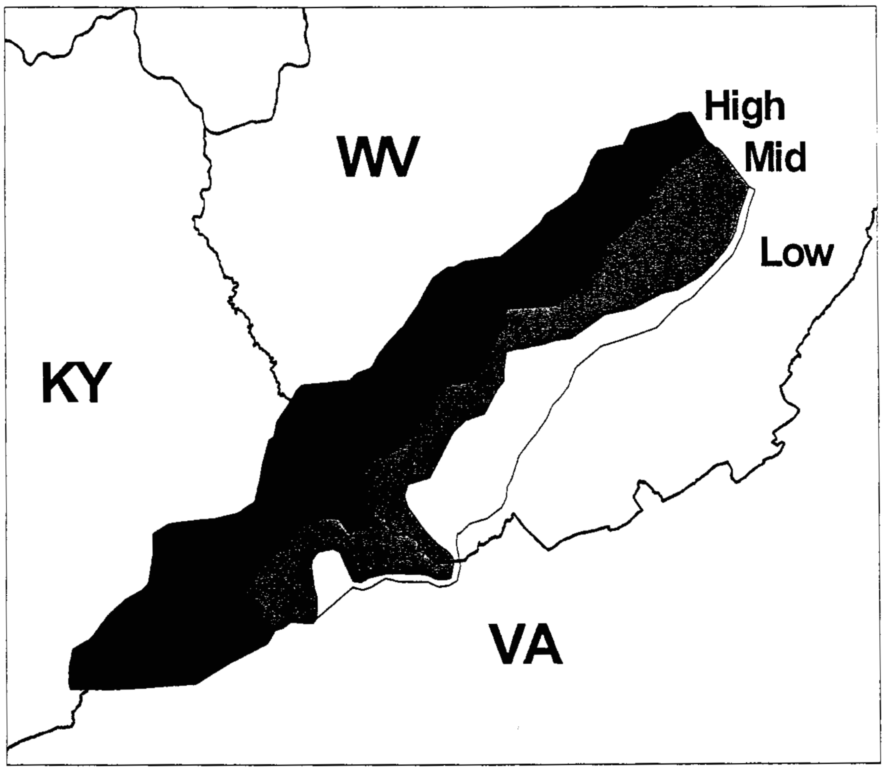
Venezuela. Like Colombia, Venezuela is only just developing its coal reserves. There are enormous reserves in Venezuela and the few producers there have solid plans to increase production significantly from around 8 mmt per year to over 20 mmt per year by 2014. This increase will come about after development of rail/port infrastructure which is now being undertaken. This coal source produces a high-calorific value, low-sulfur product that will compete with and replace dropping CAPP coal in the future. Supply availability beyond 2040 is assured unless there is a political upheaval that disrupts trade.

CENTRAL APPALACHIA

CENTRAL APPALACHIA OVERVIEW

The Central Appalachian coal region (CAPP) is comprised of bituminous coal production, principally from mines in southern West Virginia, eastern Kentucky, southwestern Virginia, and Tennessee (see Figure 1). The coal is generally high in Btu value, ranging from 12,000 – 13,000 Btu, and is low in sulfur content, ranging from 0.7% compliance coals up to 2.0% sulfur coals. The CAPP basin is the second largest producing region in the U.S., accounting for about 232 million tons of annual coal production. This is almost 20% of all U.S. coal production.

Figure 1
Central Appalachian Coalfields by Volatile Content



As the figure shows, the coal mining area of CAPP is aligned northeast to southwest. The region is the primary U.S. source of high quality metallurgical coals and low-sulfur, high-Btu thermal coals. Most of the thermal coals are high volatile content coals (i.e., greater than 32% volatile matter) and are produced in the areas shown in red in the figure.

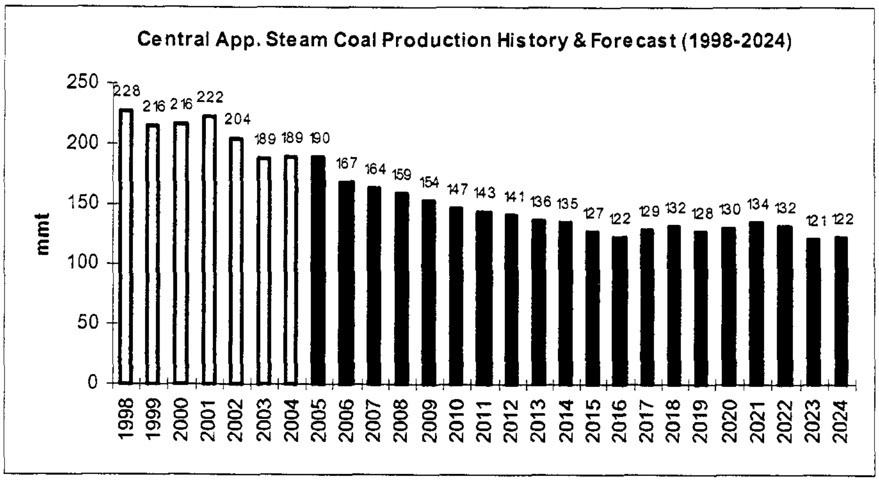
A brief description of the geology of the coal measures of each CAPP production area, by state, follows.

- **Southwestern West Virginia.** The major producing sub-region, SW WV produces about 45.6% of CAPP production. The rugged landscapes of West Virginia are held up by the presence of a series of rocks that thickens to the Southeast. When the coals were deposited, the southern part of the state subsided at a more rapid rate than the northern part. This resulted in a thicker rock package that contained more coal seams in the south. This is one of the key reasons why mountaintop removal is a popular form of mining in southern West Virginia.
- **Kentucky,** the second-largest producing CAPP state, contributes about 39.6% of CAPP production. The stratigraphic section of the eastern Kentucky coalfields is composed of a thick series of rocks that form a wedge shape, which thickens to the southeast. The rock package contains a few widespread shales with distinctive marine fossils that are easy to correlate. These zones aid geologists in determining the position of coal seams, how they relate to each other and include the Betsie, Kendrick and Magoffin shales. Most of the mineable coals in Kentucky occur within Breahitt Group. Most of the sub-groups of the Breahitt Formation start at the base of one of these shales.
- **Virginia** produces 13.7% of CAPP production. The coal-bearing portion of Virginia consists of a thick package of rocks that includes numerous coal seams. The following formations are present: Pocahontas, Lee, Norton and Wise.
- **Tennessee** produces a minor amount of coal (<2%). The Tennessee coalfields occupy the area where the Appalachian coalfields are very narrow (about 40 miles). In general, Tennessee coals contain higher sulfur content; the most significant coal seams include: the Walnut Mountain, Jellico, Sewanee and Richland seams.

CENTRAL APPALACHIA - PRODUCTION

Figure 2 shows that CAPP steam coal production is forecast to decline from 228 mmt in 1998 to 190 mmt in 2005, a 17% decrease. H&A's forecast predicts that CAPP will continue to experience a decline in production to as low as 121 mmt in 2024, a 46% decrease from 1998. Beyond H&A's formal forecast to 2024, our expert opinion is that coal production will continue well beyond 2024 in CAPP across all coal types in the remaining reserves of CAPP. Production is expected to continue to decline, possibly to a level of around 100 mmt by 2040, unless higher prices stimulate new projects in deeper, thinner seam coal resources in the future as described below.

Figure 2



About 28% of the Central Appalachian coals that are sold to utilities are compliance grade, containing less than 1.2 $LBSO_2$ per million Btus. 70% of the coals sold to utilities are "near-compliance grade", ranging between 1.2 and 2.5 $LBSO_2$ per million Btus. The remaining 2% of steam coals from the region are mid-sulfur coals, which contain greater than 2.5 $LBSO_2$ per million Btus.

The following figures depict H&A production projections across different coal quality types for S.WV, E.KY and VA coals:

Figure 3

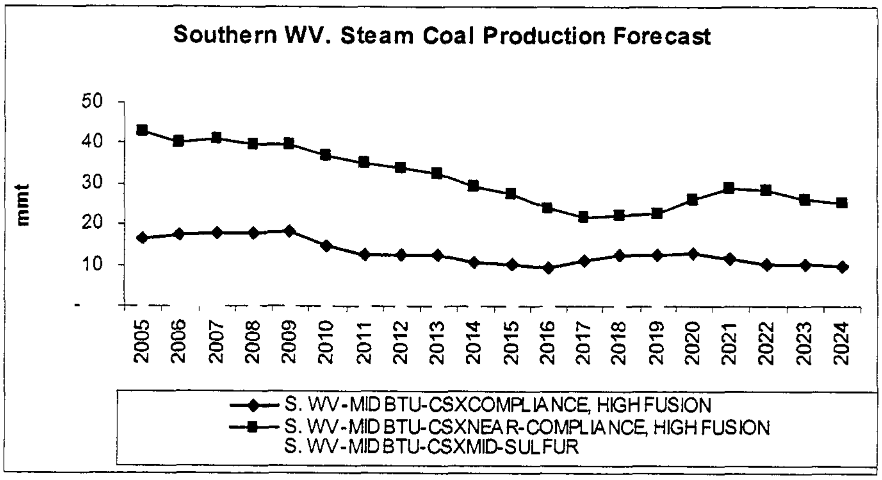


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Figure 4

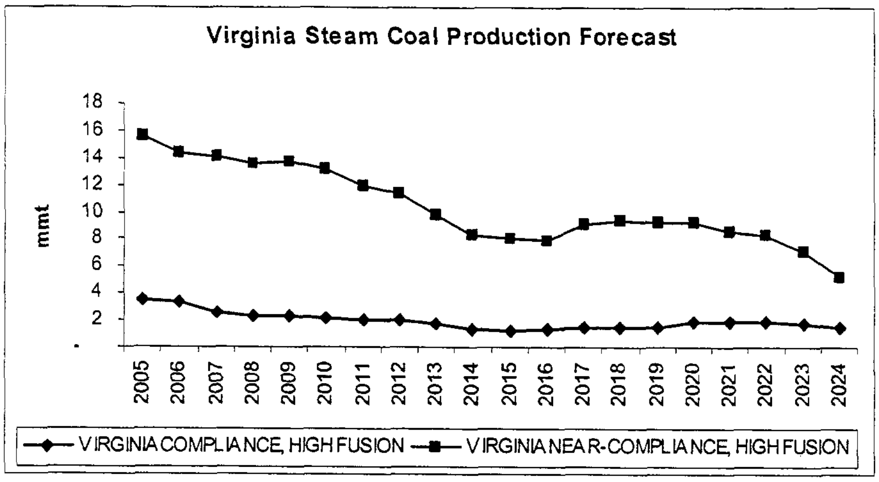
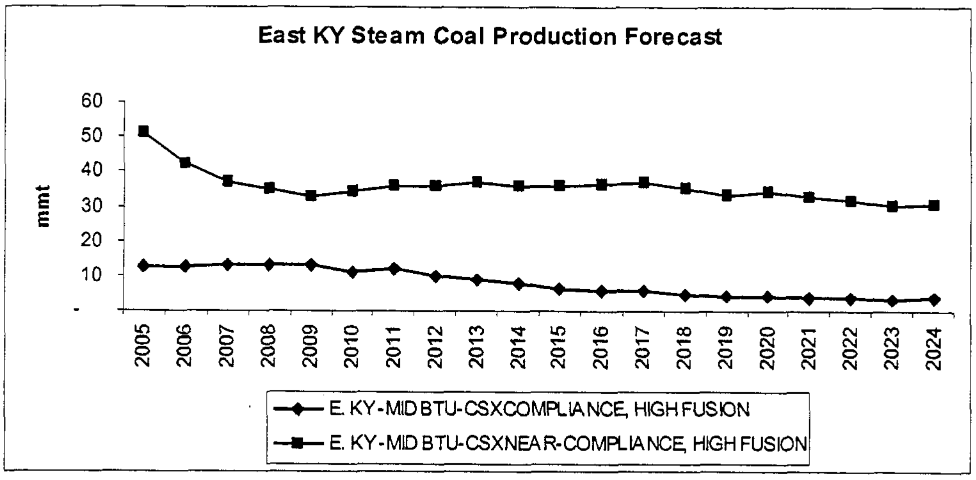


Figure 5



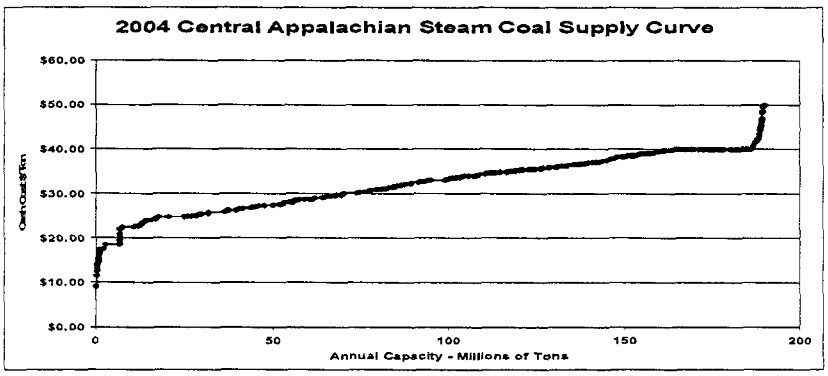
CAPP coal production is approximately 57.2% underground mined and 42.8% surface mined. Up until the past few years surface mined coal was increasing rapidly. However, the issue of mountain-top removal and legislation covering permitting and environmental compliance has caused this trend to stall. The future of surface mining in the region is threatened. Environmental groups and the general public have gained momentum in their challenges to the coal industry, on issues such as refuse impoundment stability; coal truck weight limits (especially in West Virginia); cumulative hydrological impact assessments.

In the past two years, with higher prices prevailing, there is renewed interest in accessing underground mineable reserves that are deeper and more difficult than those previously mined. Some operators are considering developing slopes to access coal seams in areas where the coal is below the drainage and does not outcrop. This type of mining, obviously, is more expensive and requires significant capital expenditure even to get into the producing coal.

The majority of underground mines utilize continuous miner technology although there are some productive longwalls remaining in CAPP. However, it is not likely that many, if any, new longwall mines will be developed in CAPP because there are no large reserve blocks remaining where a longwall could be employed. Many of the larger producers have adapted a specialized continuous mining technology, called "super-section" mining where two continuous miners are used on one section of a coal mine with one crew. This is more expensive in terms of initial equipment investment, but much more productive than a standard continuous miner section.

Cash costs for production CAPP have been steadily increasing due to mining regulations, decreasing productivity, thinner coal seams, reserve depletion, and deeper coal reserves. There was a significant increase in cash costs in 2004. Figure 6 shows the 2004 steam coal mine cash costs for the cumulative potential production capacity in Central Appalachia. The figure shows FOB cash costs ranging from about $10 – $40 per ton.

Figure 6



The supply curve suggests that the marginal cost of production will be about $40 per ton at the 190 million tons per year production level. Coal prices above the $40 per ton range will be required for marginal producers to remain viable. Some of the higher cost production is supported with high priced contracts or industrial sales, and some of the higher costs are at mines that have closed.

Industry consolidation in the CAPP region has been robust. Sine 1998, the consolidation of large producers changes dramatically as: Massey added to its portfolio of properties, AEI Resources added substantial holdings in the late 1990's Arch and

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Ashland merged into Arch Coal. AEI Resources purchased Zeigler Coal and Cyprus Amax's eastern operations which were later acquired by RAG American which, in turn, has become an IPO named Foundation Coal Corp.; James River bought Blue Diamond, much of Transco and Sun; Alpha Natural Resources Partners acquired the Pittston assets and several other producing entities; and there have been others.

Massey has increased production in 2004 and now holds a firm lead on Central Appalachian production of 42 million tons. Arch's production was 29.9 million tons in 2004, about 3.6 million tons more than it was in 2003; Peabody's production was 11.8 million tons. James River Coal produced 8.8 million tons. TECO increased production with the addition of Perry County Coal and "pushing more coal" through synfuel plants and was 8.1 million tons of production in 2004. Foundation produced 6.9 million tons. In summary, concentration in the region has been significant. This has allowed some of the companies, such as Massey, to command higher prices in the market due to their control of so much CAPP coal.

When prices went sky high in 2001, CAPP producers (as well as the rest of the country) opened higher cost mines to meet the demand. A similar occurrence again happened in 2003-2004, with prices even higher. CAPP steam coal was at 189 million tons in 2004; however, despite higher prices, the region is not able to further respond to the strong demand and H&A now projects that CAPP steam coal production will end up at 190 million tons in 2005.

We continue to project that production in the region will continue to decline in the long run, as the relatively easily accessible reserves are quickly depleting. However, if higher price levels are sustained in the long term, albeit at lower levels than today's prices, then investment groups will look favorably on big mining projects that will access deeper coal resources than are feasible today.

CENTRAL APPALACHIA – COAL RESERVES

The bulk of the remaining reserve base in Central Appalachia is characterized by thinner seams and associated geological problems. Most of the high-quality thick coal has been mined. There are few large blocks of coal remaining that can be extracted using longwalls or draglines. Over time, mines in this region will have trouble maintaining the productivity growth of the past few decades. Productivity levels and production will decline in the future and productivity growth is likely to slow significantly.

Table 2 summarizes CAPP's economic reserves across different sulfur content categories. The bulk of the reserves are in the near compliance bracket. These reserves exhibit the following characteristics:

- Depleting
- Long-term mining has extracted the thicker and more accessible coalbeds, the remaining thinner and deeper coal deposits are or will be progressively less competitive.

Table 2
CAPP Estimated Economic Reserves (mmt) by Sulfur Content (lbs/mmBtu)

State/SO2 Content	<1.2	1.21-2.49	2.5-4.49	Totals
E.KY	682	2,054	72	2,807
TN	25	95	30	150
VA	192	589	33	814
S.WV	1,348	2,525	317	4,190
Totals	2,247	5,263	452	7,961

The table indicates that reserves in southern West Virginia and eastern Kentucky combined could support production levels at current rates well beyond 2040, particularly for a near-compliance product. H&A predicts that, indeed, mines will continue to operate in this region. However, the increasing cost structure could diminish the amount of economic reserves in the future and will definitely do so, should prices drop significantly. Prices, according to our estimates, must sustain the range of $35 to $40 dollars, minimum or higher, in the future to sustain mining and encourage new investment.

KEY ISSUES AND DRIVERS FOR CAPP

- Rapid depletion of coal reserves is occurring (substantial decreases have occurred in the past 3 years and more are to come);
- Coal production costs are high, primarily due to deteriorating geologic conditions;
- Bonding, permitting problems and labor shortages will make it harder to expand existing mines or develop new ones;
- Increased competition from Western coal;
- With CAIR kicking in, more plants are investing in SO_2 clean-up equipment, which would allow them to use cheaper mid- and high-sulfur coals or even completely switch to PRB coal;
- Large mines are controlled by a few major coal producers (Peabody, Arch, Massey, etc.), but there are many smaller mines in the region;
- Most mines have either CSX or NS rail service, but not both;
- Productivity is declining because operations are moving into harder-to-reach coal; and
- There are significant coal mining regulatory and environmental issues in West Virginia (hollow-fills and Section 404 permits).

ILLINOIS BASIN

ILLINOIS BASIN - OVERVIEW

The coalfields of Illinois, Indiana, and western Kentucky lie in the Eastern Region of the Interior Coal Province, better known as the Illinois Basin (ILB). The ILB coal region is comprised of bituminous coal production, principally from mines in western

Kentucky, Indiana, and Illinois. The coal is wide ranging in quality, generally spanning from 10,000 to 12,800 BTU, and from about 0.5 % to 5.0 % sulfur. The ILB is the fourth largest coal-producing region in the U.S., accounting for about 91 million tons of coal production in 2004.

The entire Basin covers more than 50,000 square miles, which are underlain by the coal bearing sequence of rocks that constitute the Pennsylvanian System. Numerous coal beds are exposed at depths ranging from a few feet to over 1,500 feet in the center of the Basin. In Illinois, the beds outcrop in the southern, western, and northern portion of the field and gradually become deeper in the center of the Basin. The coal bearing strata in western Kentucky generally dips to the northwest, but is interrupted by major fault systems. In Indiana, the beds crop out in the eastern portion of the field and gradually become deeper westward.

The mineable beds are relatively thick, flat lying and continue over extensive areas. Beds one to ten feet thick (5.5 feet average) are mined utilizing surface and underground mining methods. The remaining large surface reserve blocks at low (< 19:1 clean) ratios are mainly controlled by Peabody, who has done a tremendous job of maximizing production from these reserves. However, these low-ratio, surface mineable reserves are depleting fast. Over the next 5-10 years most of the large surface mines will have depleted their reserve base and will likely close. Abundant reserves exist with ratios in the 19:1-24:1 range; however, these will probably not be mined due to the high cost versus expected future prices. There are only a few remaining draglines that can mine economically at these depths. Peabody controls most of these machines.

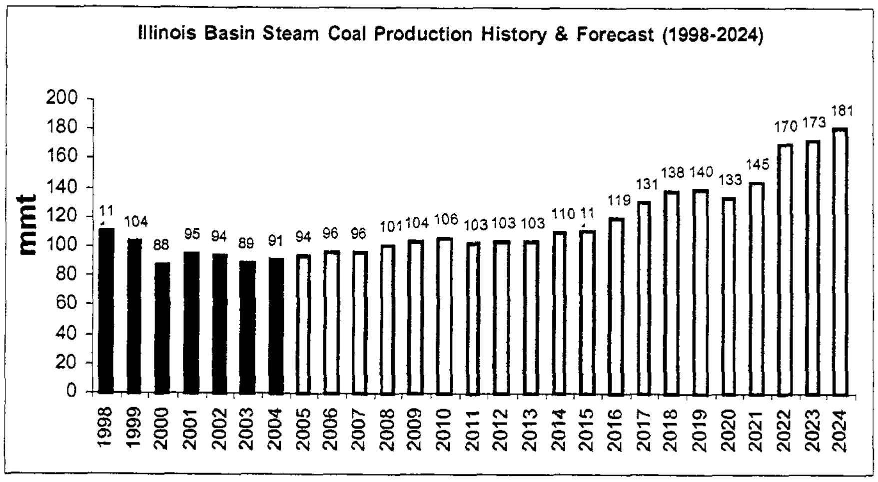
The Basin contains a tremendous underground reserve base, which is about 5 times larger than the Pittsburgh 8 seam reserve base in Northern Appalachia. As the surface reserves deplete and as demand increases and assuming prices justify, these reserves will likely be developed in the next ten years and will be able to support production from the basin well beyond 2040. The deeper reserves, however, contain higher chlorine content than those closer to the surface. And, even though the deeper reserves tend to support low-cost longwall technology, such technology may not be applied if the reserve is below prime farmland where subsidence could present problems.

The strongest companies in the future will be those with large reserve positions that can be developed as non-union mines or mines under modified United Mine Workers of America (UMWA) contracts. Peabody is the largest holder of resources with Alliance, Freeman, Consol, Addington, Horizon, Arch, Freeman, and ExxonMobil also having large reserve positions.

ILLINOIS BASIN - PRODUCTION

As illustrated in Figure 7 below, ILB production is forecast by H&A to increase from 94 mmt in 2005 to about 181 mmt in 2024. Beyond 2024, and prior to 2040 the basin production is expected to peak and begin a slow decline. This is because the existing mining operations begin to deplete and basin production begins to rely more on deeper, more costly operations to sustain production.

Figure 7



In the 1970s and early 1980s, approximately 63% of the Basin's production came from surface mines. Since 1983, there has been a trend toward more underground production, because many of the large surface mines have closed due to reserve depletion. In 2000, surface production reached a low and only represented 38% of the total Illinois Basin production in that year. As predicted by H&A in its 2001 study and thanks to a strong market and expansions by Peabody's non-union operations, surface production increased by 6-8 mmt in 2001 and 2002. It now represents 40-43% of the Basin's production.

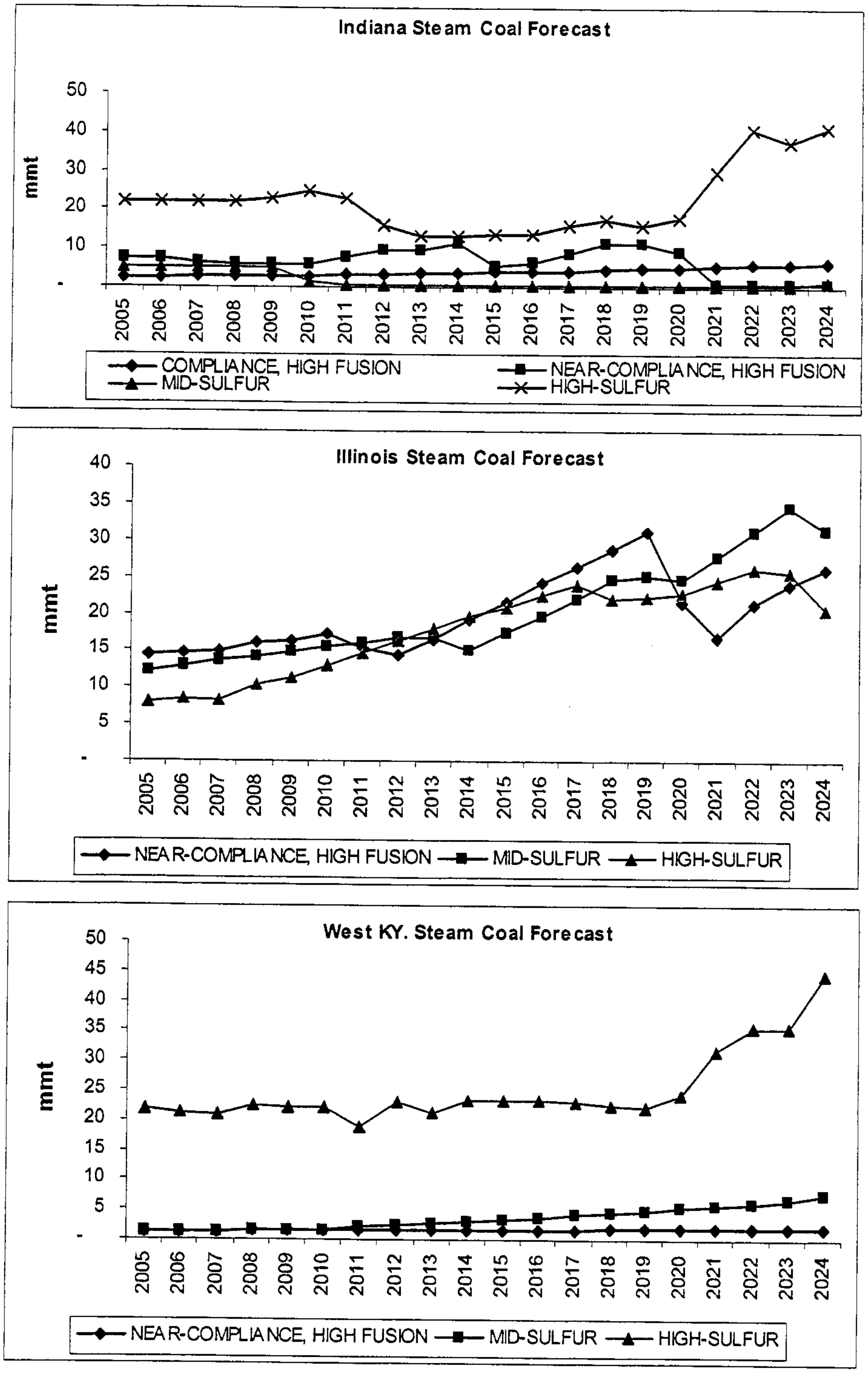
H&A's analysis has identified enough projects to suggest that Illinois Basin capacity could potentially increase to more than 200 million tons per year by 2013, if such demand is present; however, production will probably only be in the 100-105 million tons per year range. Peabody, the dominant producer in the region, is expanding its southeastern operations, and Jim Bunn/Steve Carter (Knighthawk) is consolidating holdings in the southwestern part of the state and could expand soon. Arc Light is under pressure to develop its TVA Franklin County reserve in the next two years.

A significant amount of consolidation took place in the Basin during the 1990s and, as a result, several operations have been closed or idled. Overall mine productivity has dropped by 10-15% over the last two years, mainly due to underutilized mines, and the higher prices of 2001, which allowed new mine development in higher cost reserves. In 2004, costs went up also due to raw materials and fuel cost increases. Mine costs are up 35% as a result of this, which will hurt Illinois Basin demand in the future, as it has to compete with lower cost alternatives.

Figure 8 provides three graphs to show the production forecast for Indiana, Illinois and western Kentucky coal, according to coal quality type. The charts indicate that Illinois is likely to produce the majority of the coals across all coal types. Indiana and western Kentucky have the potential to develop significant production of high-sulfur coals.

Figure 8

Illinois Basin Production Forecast to 2024 by State and Coal Quality Type

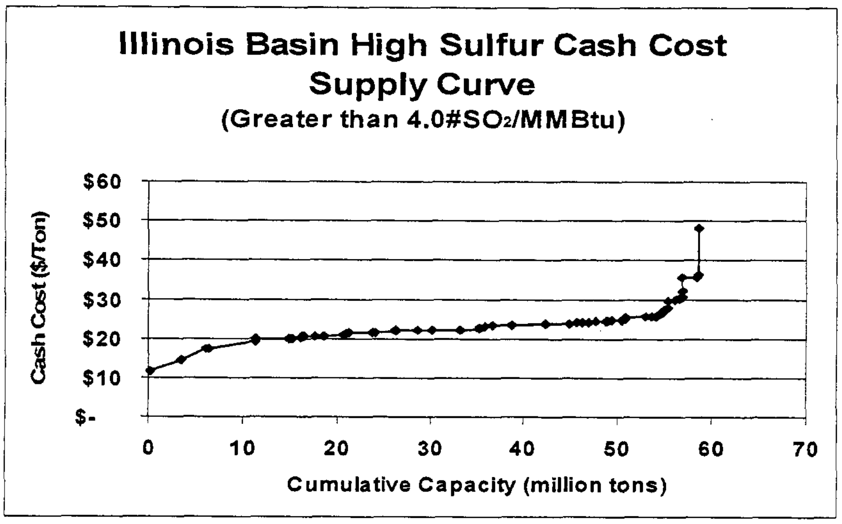


The above charts, if extended to 2040, would all display production at sustained levels or depleting marginally. As mentioned previously, the Illinois Basin is expected to produce adequate amounts of coals of near-compliance, mid-sulfur and high-sulfur type to sustain well beyond 2040.

Marginal mine cash costs for high sulfur Illinois Basin coals are shown in Figure 9. This figure shows that the cash costs for 11,700 Btu/lb. Western Kentucky production ranges from around $11.70 per ton to over $36.00 per ton. There are 55 million tons of high-sulfur coal capacity in the basin at under $30 cash cost in the railcar.

There are other, lower sulfur, products in the Illinois Basin, which could be considered also. However, the capacity for the other coals is far lower than that of the high-sulfur products. There is approximately 13 million tons of capacity of mid-sulfur coal (greater than 2.5/less than 4.0#SO_2/MMBtu) at mine cash costs below $27 per ton. Similarly, there is 25 million tons of capacity of low-sulfur coal (less than 2.5#SO_2/MMBtu) at mine cash costs of $32 or less.

Figure 9



ILLINOIS BASIN – COAL RESERVES

The Basin contains a tremendous underground reserve base, which is about 5 times larger than the Pittsburgh 8 seam reserve base in Northern Appalachia. As the surface reserves deplete, and as demand increases, these reserves will likely be developed in the next ten years. Table 3 summarizes the economic reserves for Illinois Indiana and W.KY.

The table shows adequate reserves available to produce mid- and high-sulfur coals at current levels far beyond 2040. The basin is expected to develop to serve scrubbed utility plants along the river system and, potentially, in the southeast.

Table 3
Illinois Basin Coal Reserves (mmt) by Sulfur Content (lbs/mmBtu)

State	<1.2	1.21-2.49	2.5-4.49	>=4.5	Grand Total
IL		897	2,894	5,623	9,414
IN	352	189	242	964	1,746
KY	4	15	486	1,097	1,602
Grand Total	356	1,101	3,623	7,683	12,763

KEY ISSUES AND DRIVERS FOR ILLINOIS BASIN

- Tremendous coal reserves exist and significant expansion is possible in the ILB;
- The large mines are controlled by a few major producers (Peabody, Alliance, Freeman, Consol, etc.), but there are also a number of smaller mines in the region;
- Most mines have either CSX or NS rail service, but not both;
- Some mines have access to waterways, but at additional transportation cost to the docks;
- Production has declined in recent years (but as shown in our production forecasts, this production is expected to grow);
- The region will benefit when scrubbers are installed to meet air quality requirements; and
- ILB is a swing coal and is expected to be a blending partner for low sulfur PRB coal.

NORTHERN APPALACHIA

NORTHERN APPALACHIA OVERVIEW

The Northern Appalachian (NAPP) coal region is comprised of bituminous coal production principally from mines in northern West Virginia, western Pennsylvania and southeastern Ohio. NAPP is the third largest coal-producing region in the U.S., accounting for about 135 million tons of annual coal production in 2004. Total regional production (about 65%) is dominated by Pittsburgh seam coal, which is produced by a few major producers including Consol Energy, Foundation Coal Corp. and American Energy (Robert Murray). The three sub-regions of NAPP are described below:

- **Pennsylvania.** Historically, in southwestern Pennsylvania, the Pittsburgh 8 seam has had good coking properties resulting in steel companies tying up much of the reserve base for their own captive use. However, because of changing long-term resource requirements and the need for lower sulfur coals, steel companies have relinquished control of these reserves and mines. What was once a major metallurgical coal resource has now become a major steam coal resource as utilities value the seam's characteristic high Btu (13,000) and relatively low sulfur (1.5-2.5%), low ash (6-10%), and low moisture content (6-8%).

Production from the Pittsburgh seam has historically come from Allegheny, Greene, Washington, Westmoreland, and Fayette counties. Because of good access to the coal crop and to navigable water, mines tended to be built along the Monongahela River. Thus, with a history of over 200 years of mining, most of the shallow, easily accessed coal along the river or along the coal outcrop in Allegheny and Fayette counties has been mined out; therefore, production has moved to deeper mines, further from the river. Virtually all production in this region now comes from Greene and Washington counties.

- **Northern West Virginia.** Production in Northern West Virginia historically serves two rivers. Mines in Monongalia, Marion, and Harrison counties typically serve or have access to the Monongahela River, while the mines in the West Virginia panhandle counties of Marshall, Ohio, and Brooke counties serve the Ohio River. The Northern West Virginia region is defined by those mines that are best served by the Monongahela River. The West Virginia mines on the Ohio River are present in the Ohio Valley region.

  In northern West Virginia, large blocks of higher sulfur Pittsburgh coal have been developed by CONSOL and Eastern Associated (Peabody) to supply coal to local power plants built along the Monongahela River. The Btu content of coal produced in this region varies from 12,500 to 13,300, sulfur values range from 2.5% to 3.5 %, and ash ranges from 7 to 12%. With 74% of the production tied up, CONSOL is the dominant producer and coal controller in this region. Peabody has 25%. The remainder is minor production from small producers operating in outliers of the Pittsburgh seam.

- **Ohio Valley Region.** West of the Pennsylvania/West Virginia state line, the Pittsburgh seam rapidly deteriorates in quality. Ash and sulfur content increase, and the Btu content drops from 13,000 Btu/lb. to around 12,000 Btu/lb in the Ohio Valley region. Because of its proximity to the river and the large utility and industrial markets, large amounts of Pittsburgh seam production have occurred in Ohio along the banks of the Ohio River. Most of the reserve in Ohio has been mined out and what remains is mainly controlled by CONSOL and Bob Murray. Substantial reserves remain in Northern West Virginia, and most of these reserves are controlled by CONSOL. Like the other areas, mining has moved away from the river over time. Many of the remaining mines transport raw coal production 5 to 15 miles underground to access the portal.

  Currently, CONSOL controls 54% of the production and Bob Murray controls about 46% of the production. With CONSOL's planned expansion of the McElroy, CONSOL will probably expand its control to 63% in 2005, while Murray drops to 37%. Alliance controls a major reserve block in West Virginia and hopes to open a mine in the next ten years.

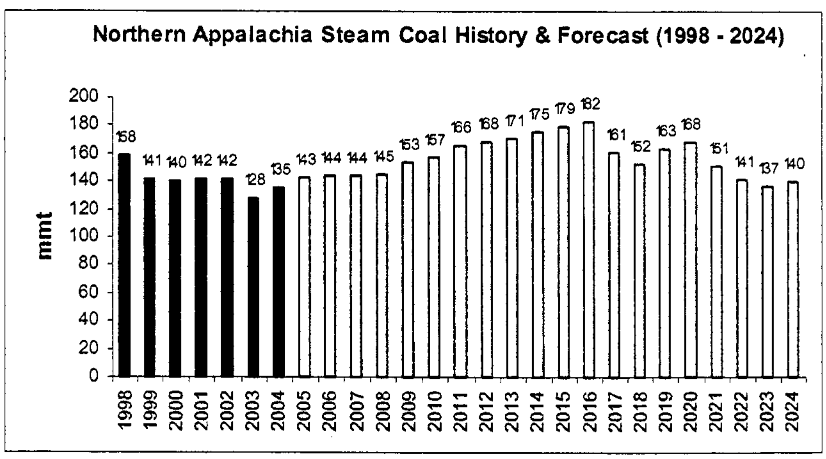
The coal is shipped to markets within the U.S. by rail, or rail-to-water, with some local deliveries by truck. As with CAPP, two major railroads, the NS and CSX, originate a great deal of the NAPP shipments, and then deliver the coal directly to power plants or to rail-to-barge docks for water delivery to other plants.

NORTHERN APPALACHIA - PRODUCTION

The Pittsburgh seam is the primary seam in NAPP, although other seams are produced, such as the Upper and Lower Freeport seams and the Bakerstown seam. The Freeport seams have metallurgical properties and both Freeport and Bakerstown seams can contain relatively high sulfur content. We focus on Pittsburgh seam coal in this report because of its dominance and because the transportation efficiencies that are available from large-scale loading facilities, which are unit train capable. Also, there are abundant reserves of mid- and high-sulfur coal available for underground mining. Consol Energy is the largest Pittsburgh seam producer. Pittsburgh seam coal is generally high in BTU value, ranging from 12,000 – 13,300 BTU, and is mid-to-high in sulfur content, ranging from about 2.2 % - 5.0 %.

Production from this region has taken place for over 200 years and will continue for years to come. Remaining Pittsburgh seam reserves would support production at existing levels for over 36 years. Our modeling shows that coal production in Northern Appalachia will reach a peak in about 10 years, as reserves in the important Pittsburgh Seam begin to deplete, and the remaining reserve base is unable to compensate for the loss of Pittsburgh Seam production. As seen in Figure 10, production from NAPP for 2005 is estimated to reach 143 million tons, which is 8 million tons up from 2004.

Figure 10



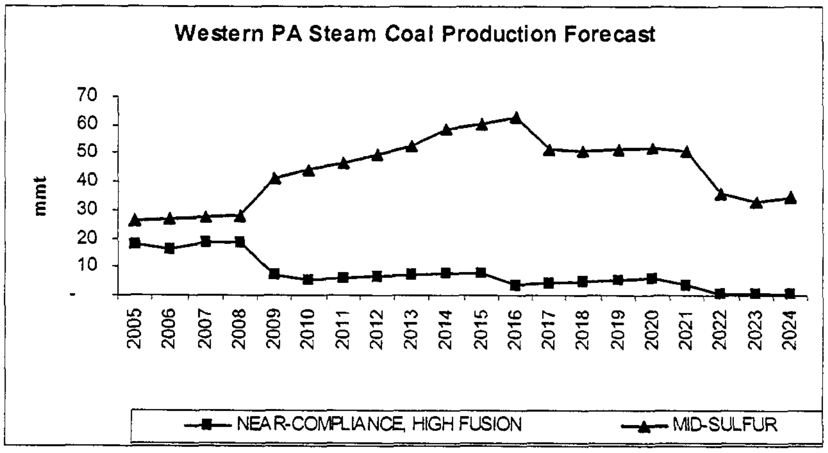
The Pittsburgh seam ranges from 5 to 8 feet thick and it is laterally extensive. As such, the seam is conducive to large scale, longwall mining methods. Almost 97% of Pittsburgh seam production comes from longwall operations, which provides for highly mechanized, very high productivity and very low cost coal mining. This has enabled the market prices for Pittsburgh seam coals to remain very low over the years and maintain a highly competitive presence in both U.S. and export coal markets.

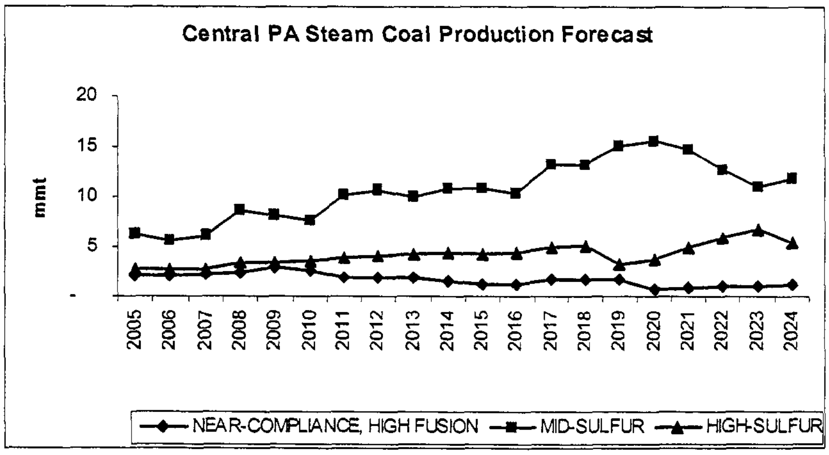
Assuming the market conditions maintain, several new greenfield mines could open up in the 2005-2011 timeframe. If so, Pittsburgh seam production could expand to 150 million tons per year by 2011. All proposed greenfield operations will be in mid- to high-sulfur coals.

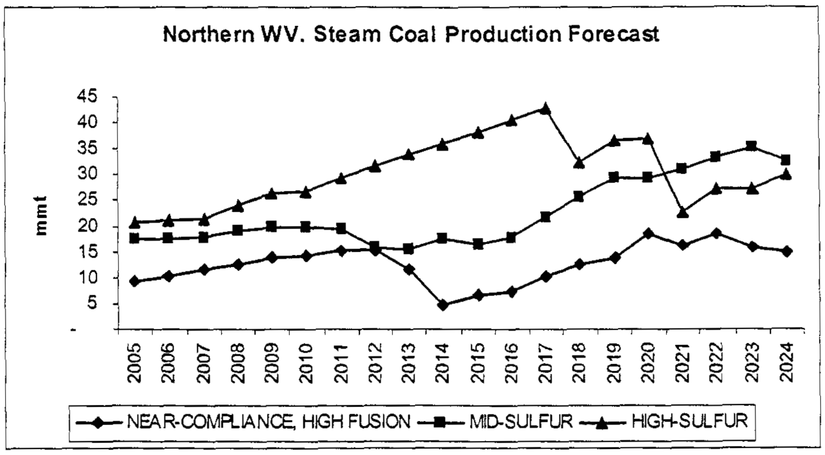
The following graphs illustrate our forecast for WPA, Central PA, NWV and Ohio NAPP coals by sub-region and coal quality type.

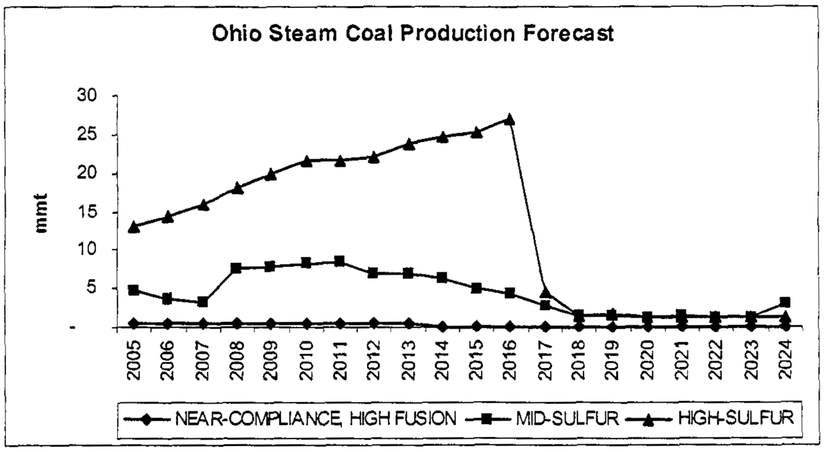
Figure 11

Northern Appalachia Production Forecast to 2024 by Sub-region and Coal Quality









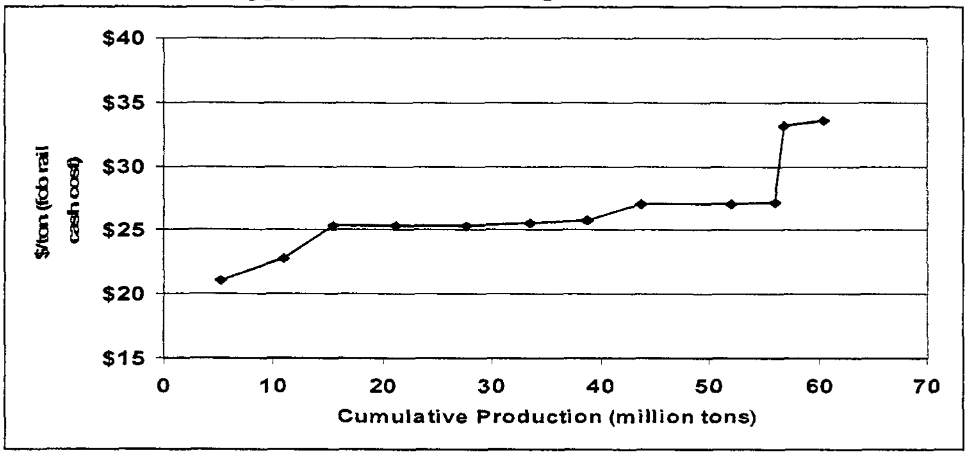
The graphs displayed above show that H&A anticipates production of Pittsburgh seam coal to peak out in the 2016-2017 time period and decline from that point forward. Other coal types in the basin are, relatively, much lower in productive capacity and are generally represented by numerous smaller producers. The decline will extend past 2040 and overall NAPP production could decline to a level of +/-100 mmt by 2040. This production level is still adequate to consider as a long-term fuel alternative for a new generating plant.

Since 1994, numerous mines producing coal from the Pittsburgh seam have closed due to reserve depletion or high costs. About 30 million tons of annual production has been lost due to depletion and another 22 million tons are anticipated to be lost by 2010. The lost production was offset by new mine openings or by expansions at other mines.

The SO_2 credit bank will be depleted around 2007, thus with a depleted credit bank and tighter SO_2 limits under the Clean Air Interstate Rules (CAIR), power plants will likely add scrubbers. Because of the Pittsburgh Seam's strong reserve base (although much smaller than ILB or CAPP) and relatively low costs (as compared to other producing regions), Pittsburgh Seam mid- and high-sulfur coal will likely be the beneficiaries of this new demand.

The 2004 NAPP supply curve for Pittsburgh Seam mines shows the low-cash mining costs for the region, ranging from around $21.00 to $33.56 per ton, as shown in Figure 12. Most of the mines have cash costs ranging from $25.30 to $27.20.

Figure 12
Coal Supply Curve for Pittsburgh Seam Mines -- 2004



According to our long-range forecasts, we project that mining costs in this region may decrease by $3 to $6 per ton by 2011, based upon improvements in productivity and the replacement of old longwall mining equipment with newer and more efficient ones. There is a possibility that our productivity improvement projections may not materialize because the coal seams are getting thinner and underground coal haulage will be longer. However, we anticipate that overall productivity in the region will increase over the next 8 – 10 years.

As tighter limits on SO_2 emissions take effect the SO_2 credit market will tighten and more plants will be installing scrubbers. New scrubber construction will cause an increase in demand for mid- to high-sulfur coals. The Illinois Basin and Northern Appalachia regions will compete fiercely for the new scrubber market that will be developing over the next decade.

Northern Appalachia has an inferior reserve base to the Illinois Basin. Although, current mining costs are comparable, the Illinois Basin has the edge over Northern Appalachia; but Northern Appalachia has higher Btu coal than the Illinois Basin, which makes it more attractive. In the near term, however, it appears that the Illinois Basin can expand more rapidly.

NORTHERN APPALACHIA - RESERVES

Table 4

NAPP Total Steam Coal Reserves by Lbs SO_2/mmBtu and Total Pittsburgh Seam Reserves

Region/SO2 Content	=<1.2	1.21-2.49	2.5-4.49	>=4.50	Totals
Maryland	20	25	85	0	**130**
Ohio	200	400	2,900	2,000	**5,500**
Central PA	30	45	165	40	**280**
Western PA	10	10	800	30	**850**
N.WV	10	12	850	450	**1,322**
Totals	**270**	**492**	**4,800**	**2,520**	**8,082**
Pittsburgh seam total	n/a	131	1,427	1,471	3,029

The table indicates that reserves will sustain production at current levels well beyond 2040 before depleting. This assessment also assumes that several new greenfield longwall mines are developed in the Pittsburgh seam including Consol's Berkshire and Green Hill properties and Foundation's Green Manor reserves.

KEY ISSUES AND DRIVERS FOR NORTHERN APPALACHIA

- There are significant coal reserves and potential for expansion;
- Mining productivity is high and production costs are low at many mines due to long-wall mining;
- Most of the large mines are controlled by a few major coal producers (Consol, Foundation, etc.);
- There are many smaller mines, but they principally serve local industrial and utility plants;
- There is significant production capacity that has access to both CSX and NS rail service (e.g. Consol's Mine 85, Bailey and Enlow Fork complexes);
- A limited number of mines have access to waterways at additional cost of transportation to get to the docks; and
- Rail service to utilities in Florida is expected to carry a high rail rate.

COLOMBIAN COAL

COLOMBIA OVERVIEW

The Colombian coal industry is comprised of bituminous coal production principally from the following coalfields: **Cerrejón, La Loma,** and **La Jagua**. The coal is mid-to-high BTU, ranging from 11,400 – 12,200 BTU, and is very low in sulfur content, ranging from 0.6% to 0.8%. Colombia produces and exports about 64 – 69.5

million tons of coal annually to various markets in the U.S. and to other countries. We project that Colombian production and exports will grow to as much as 83 - 87 million tons by 2010. Figure 13 shows the major export mines in Colombia.

The country is a primary exporter of coal, and it has enormous amounts of coal equivalent to almost 7.7 billion tons of measured reserves. About 90%, or 6.90 billion tons, of the country's coal reserves are for steam coal use.

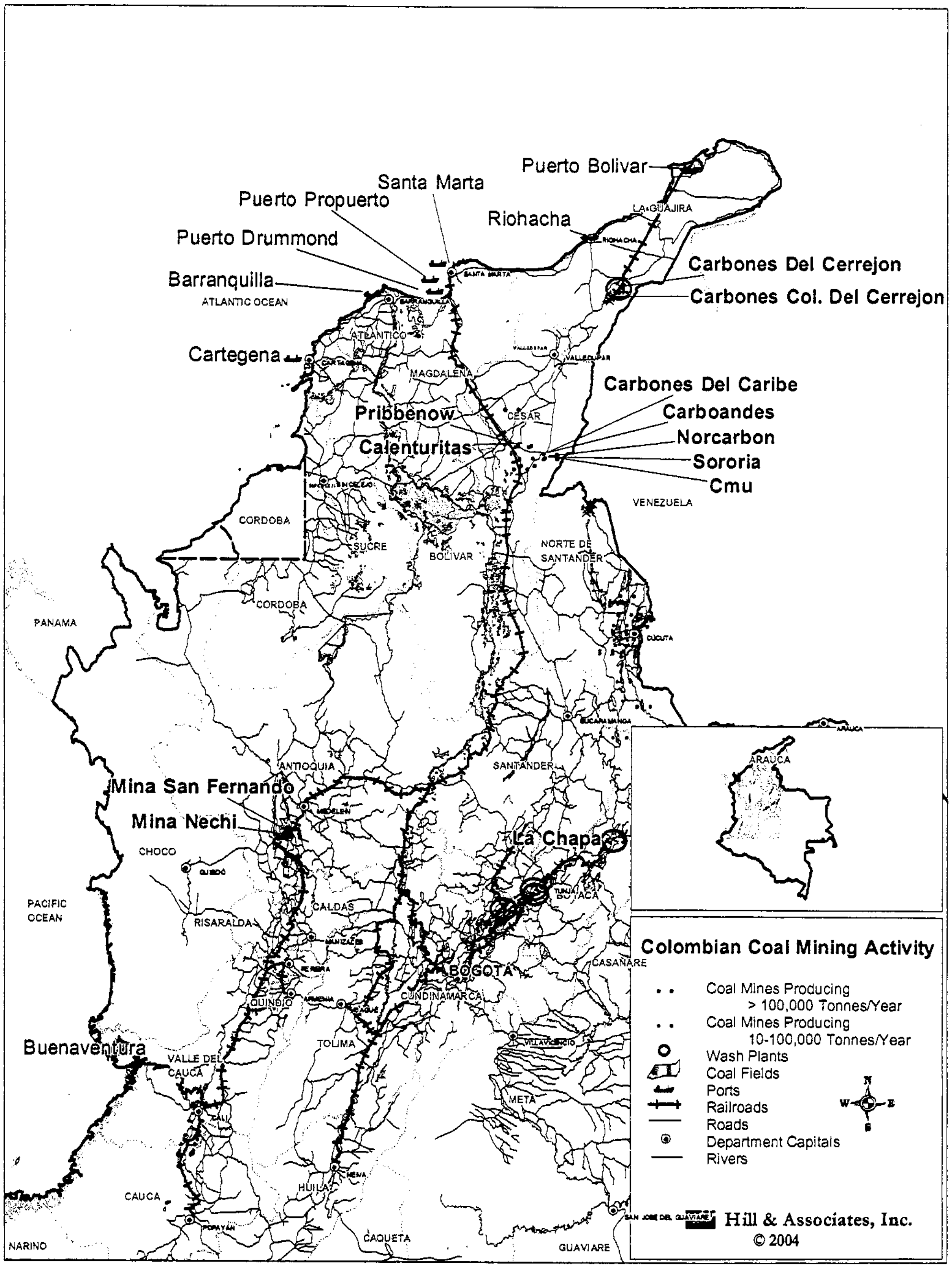
The vast majority of export tonnage comes from the Cerrejón, La Loma, and La Jagua regions. These three regions contain the bulk of the defined coal resources and offer relatively easy access to the coast. The mines in these regions share similar characteristics:

- Almost all production comes from surface operations;
- All are mining multiple seams at stripping ratios of approximately 6.5:1;
- In most, the seams are steeply pitched and lend themselves to truck and shovel methods;
- All have high quality coal with low-sulfur and ash, and medium- to high-BTU values; and
- Each region now has one large mine, and one or more smaller operations.

Most of the production is controlled by a small number of producers with the mine ownership in the hands of about 3 major supplies: Cerrejón Coal Company (BHP-Billiton, Anglo American and Glencore); La Loma (Drummond); and Carbones del Caribe. A number of smaller mines are owned by a mix of domestic and foreign companies.

Most of the mines in Colombia move their coal by truck to ports on the coast. A few mines have access to rail. A few other producers use barges on the Magdelena River to get coal into vessels. The expansion of rail service to additional mines will probably come in due time, but this has been slow to develop.

Figure 13
Major Coal Activity in Colombia



COLOMBIA - PRODUCTION

In the late 1970s, Colombian coal production was used to supply internal consumption, with the exception of small volumes of metallurgical coal for exports. In the 1980s, when the Cerrejón North Zone Project was developed, the country doubled coal production, going from 4.7 mmt to 9.8 mmt from 1980-1985.

During 1997, total production reached 36.0 mmt, increasing by 9.7% with respect to 1996's production of 32.5 mmt. In 1997, 84.2% of production (30.4 mmt) was exported to the international market and 15.7% (approximately 5.6 mmt) was for internal consumption.

During 1998, total production increased 3.17% with respect to 1997, reaching a total value of 37.2 mmt. Coal exports increased 2.49 mmt, totaling 33.0 mmt, while internal consumption was reduced to 4.2 mmt.

Total production fell to only 35.1 mmt in 1999, of which 32.9 mmt were shipped to the foreign markets and only 2.2 mmt were used for internal consumption. The slightly lower shipment levels in 1999 were the result of low international prices and the domestic economy's recession.

Contrary to the previous year, Colombian production in 2000 grew 16.54%, reaching 40.9 mmt which represents an increase of 5.8 mmt. On the shipment side, the growth was 16.26%, representing an increase in the exported volume of 5.4 mmt with respect to 1999 figures. The Colombian shipments totaled 41.6 mmt in 2000.

This growth during 2000 was supported mainly by a firm international market price and production increments of 2.07 mmt at Drummond's Pribbenow mine and 1.74 mmt at Carbones del Cerrejón, which returned to its normal production level after securing access to the railroad and Puerto Bolivar infrastructure. Cerrejón North Zone operations increased by a modest 0.97 mmt, and Carbones del Caribe also contributed with an additional 0.93 mmt.

During 2001, the country's total production reached 46.9 mmt, an increase of 6.0 mmt, which represents a production growth of 14.65% with respect to 2000 figures. Shipments totaled 41.83 mmt, a figure 9.28% above the 2000 shipments, representing an increase of 3.55 mmt.

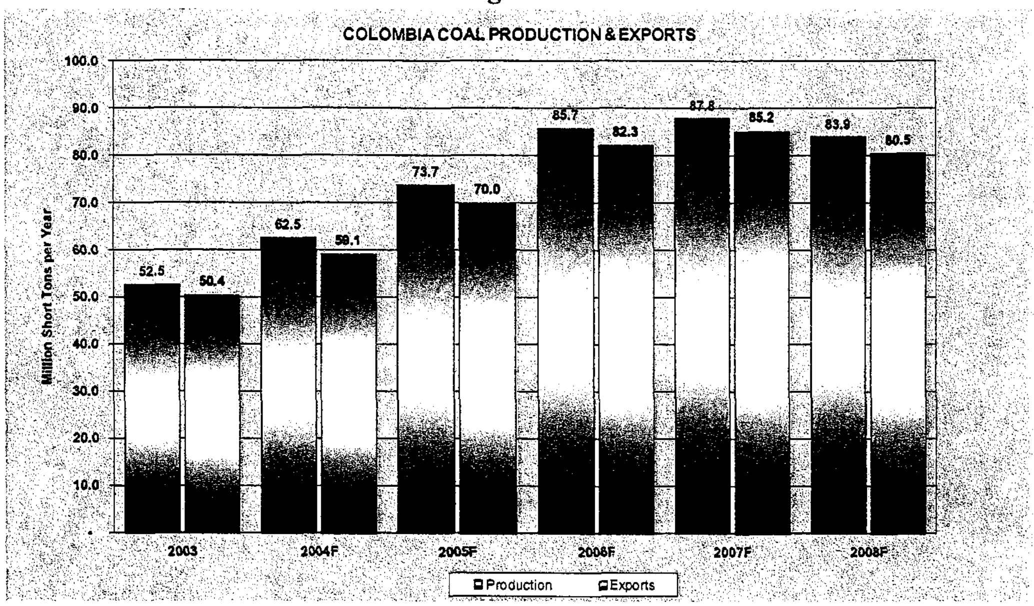
In 2002, Colombian production was 42.65 mmt, representing a reduction of 4.25 mmt in comparison with 2001 figures. This coal production reduction was due to the high mine inventory levels at the beginning of the year, the production cut announced by Cerrejón Coal Company, and the downward trend in the international coal prices.

Export shipments in 2002 were 40.22 mmt, a decrease of 1.6 mmt in comparison with 2001 shipments. This 3.83% reduction is due to the above-mentioned high inventory levels at the beginning of the year and the production cut of Cerrejón Coal.

Coal production during 2003 rebounded to 52.49 mmt (Figure 20), increasing 9.84 mmt or 23.08% when compared with 2002 figures. This increase was supported by production increases in Cerrejón, Drummond, and Carbones del Caribe. Following the production trend, the coal exports from Colombia reached 50.35 mmt, an increase of 10.12 mmt or 25.17%, returning coal inventories to normal levels.

In 2004, Colombia exported 59.08 mmt, which is 8.7 mmt above 2003, or 17% higher (Figure 14).

Figure 14



Cerrejon Coal. After the early 1999 access agreement signed between Cerrejón North Zone and Carbones del Cerrejón, modifications to the Cerrejón North Zone coal handling infrastructure were introduced, allowing these companies to increase the yearly capacity of the preparation plant, railroad, and Puerto Bolivar's coal handling infrastructure. The current capacity of the Cerrejón Coal infrastructure is approximately 32 mmt per year. Cerrejón Coal reaches this capacity by using short trains that allows for sending convoys more frequently, thus increasing the railing capacity.

After the consolidation of the above two companies, the existing plans to expand the coal handling infrastructure above 32 mmt per year are being reevaluated by the new owners of the Cerrejón Coal complex. Any production increment will be evaluated carefully in light of international coal demand. Any expansions will also have to be in accordance with the corporate plans of the three big companies forming the consortium (BHP Billiton, Anglo American, and Glencore).

Consolidation of mines in Colombia will bring more discipline to the supply side of the coal market. New Cerrejón owners have a different market strategy. Cerrejón Coal Company is now a "swing producer" and its output level will depend on the coal prices in South Africa and North America. If South African coal prices lower due to an excess of coal supply in the international market, Cerrejón Coal Company will continue withholding production increases. If necessary, Cerrejón Coal will reduce production as it was forced to do in 2002. Cerrejón's production forecast for 2005 is currently 30.3 mmt. Recently Cerrejón has adjusted its market strategy to avoid production tonnage and price reduction in the European markets. Most of the additional coal that will come from Cerrejón will be offered in the USA.

Drummond Coal. In the Cesar Department, Drummond has been continuing with the expansion of its Pribbenow mine and its port in Cienaga. Drummond had announced plans to increase production to 33 mmt in 2008. Early in 2004, Drummond announced that the company will produce 24.3 mmt, increasing its exports by about 6.15 mmt. We have not included this number in our yearly forecast; however, because rail constraints currently allow only a maximum export level of 23 mmt.

The future increase of production from Drummond will come from its new coal resources in El Descanso. This area will initiate production in 2005 and will reach a production of 11 mmt in 2008.

Other Producers. The other coal producers from El Cesar will increase production modestly. It is estimated that ***Carbones del Caribe*** will produce nearly 4.4 mmt in its operations of La Lagua and La Victoria mine. Another producer is ***Prodeco*** with its project Calenturitas. After several restart attempts to, Calenturitas mine was restarted and produces 0.55 mmt per year. Prodeco's Calenturitas plan was to gradually increase production to reach 2.2 mmt per year in 2008. ***Carbones del Cesar's*** El Paso mine started production in 2004 with 110,000 tons and should be at 660,000 tons by 2008.

As shown in Figure 15, the Colombian coal supply curve shows about 50 mmt per year of export capacity available at an FOBT cash cost of less than US$19 per ton. This tonnage is available from the two largest producers; Drummond and Cerrejon Coal. In addition, there will be another 8 mmt available at progressively higher costs.

Figure 15

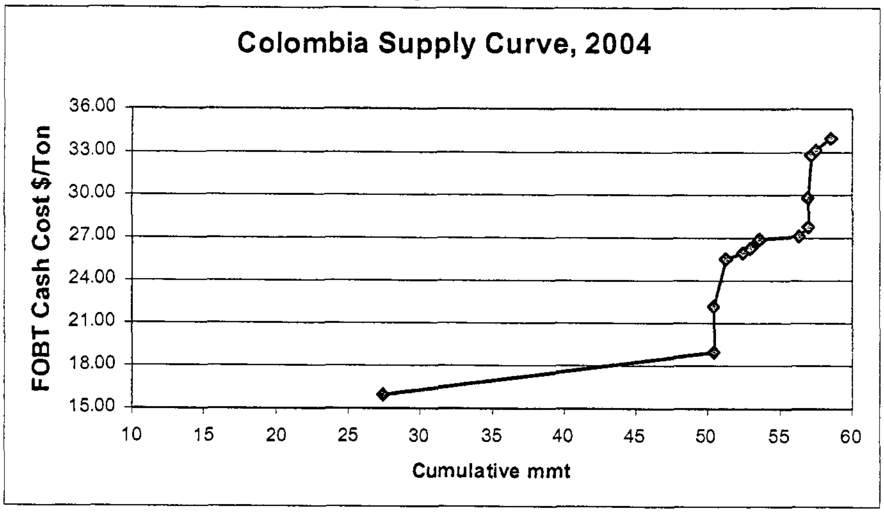


Table 5 shows the average ROM coal quality on an as-received basis for each coalfield. The Colombian coal is generally recognized for having a low-ash, high-volatile matter, low-sulfur content, and a high calorific value. The younger coals of the Cordoba Department in the San Jorge area are an exception to the rule; they exhibit a calorific value of 8,180 Btu/lb. with ash content of 17% and sulfur content of 1.50%. Other coals that exhibit high ash content are in Valle del Cauca and Santander where ash content ranges from 22 to 26%.

Table 5
Coal Qualities of the Colombian Coalfields

Zone	Moisture (%)	Ash (%)	Volatile Matter (%)	Sulfur (%)	Cal.Val (Btu/lb)
ANTIOQUIA	10.1	9.5	37.9	0.63	10,769
BOYACA					
• Sogamoso-Jericó	5.2	11.6	35.4	1.4	12,401
• Samacá-Ráquira	3.6	10.4	25.7	0.86	13,356
• Paipa-Tunja	9.9	11	40	1.74	11,340
CESAR					
• El Descanso	13.6	10.6	32.3	0.57	10,374
• La Jagua	7.1	5.3	35.7	0.62	12,606
• La Loma	10.3	5.6	36.8	0.59	11,616
CORDOBA					
• San Jorge	17	17	33.7	1.5	8,180
CUNDINAMARCA					
• Cogua Lenguazaque	3.8	10.2	28.1	0.92	13,185
GUAJIRA					
• Cerrejon North	11	8.9	33.4	0.75	11,550

Zone	Moisture (%)	Ash (%)	Volatile Matter (%)	Sulfur (%)	Cal.Val (Btu/lb)
• Central Cerrejon	9.5	8.0	33.9	0.66	11,900
NORTE DE SANTANDER					
• Tasajero	2.6	7.7	33.7	0.85	13,925
• Zulia Sur	3.4	11.9	35.3	1.27	12,967
• Zulia Norte	3.7	9.2	37.6	0.95	12,602
SANTANDER					
• San Luis	2.7	25.9	28.1	1.76	10,913
VALLE DEL CAUCA	2.7	22.4	28.1	2.85	11,088

COLOMBIA - COAL RESERVES

Colombian coal resources are distributed in the three main mountain ranges (Oriental, Central, and Occidental), mainly on the north coast and in the interior part of the country. The Colombian government has calculated measured plus indicated coal resources of 12.5 billion short tons, of which 7.7 billion tons are classified as measured resources and 4.8 billion tons as indicated. This represents 88 years of production at a level of 89 mmt per year. Colombia can adequately supply well beyond 2040.

Of the reserve total, approximately 90% is located in the North Coast area. The thermal coals are located mainly in the departments of Guajira, Cesar, Cordoba, Antioquia, Caldas, Valle del Cauca, and Cauca. Metallurgical coals are located in the central and eastern parts of the country in the departments of Cundinamarca, Boyacá, Santander, and Norte de Santander. Also, there are some anthracitic coal resources in these departments.

Table 6 shows the Colombian coal reserves by region.

Table 6

Resources and Reserves							
		Reserves			Hypothetical		Type of
Zone	Area	Measured	Indicated	Inferred	Resources	Total Resources	coal
La Guajira	Cerrejón North	3,306.93	-	-	-	3,306.93	S
	Cerrejón Central	738.55	-	-	-	738.55	S
	Cerrejón South	290.24	494.72	140.54	29.87	955.37	S
	Total	4,335.72	494.72	140.54	29.87	5,000.85	S
Cesar	La Loma	1,969.65	1,790.51	2,270.99	1,095.18	7,126.33	S
	La Jagua de Ibirico	284.73	-	-	-	284.73	S
	Total	2,254.38	1,790.51	2,270.99	1,095.18	7,411.06	S
Córdoba-Norte de Antioquia	Alto San Jorge	419.98	375.89	-	-	795.87	S
	Totales	419.98	375.89	-	-	795.87	S
Antioquia-Antiguo Caldas	Venecia-Fredonia	9.85	44.25	18.60	-	72.70	S
	Amagá-Angelópolis	13.05	70.15	101.78	27.98	212.96	S
	Venecia-Bolombolo	63.88	93.48	20.67	-	178.02	S
	Titiribí	12.49	41.06	4.91	1.18	59.64	S
	Totals	99.27	248.93	145.95	29.16	523.31	S
Valle del Cauca - Cauca	Yumbo-Asnazú	33.84	62.19	52.35	12.10	160.49	S
	Río Dinde-Quebrada Honda	4.82	18.36	21.70	-	44.89	S
	Mosquera-El Hoyo	7.03	21.01	33.86	-	61.91	S
	Total	45.69	101.57	107.92	12.10	267.28	S
Cundinamarca	Jerusalén-Guataquí	2.00	6.32	5.82	3.56	17.69	S
	Guaduas-Caparrapí	5.08	28.60	21.76	1.00	56.45	M
	San Francisco-Subachoque-La Pradera	12.51	53.13	67.12	7.12	139.88	M. S
	Guatavita-Sesquilé-Chocontá	24.14	70.89	117.81	11.18	224.02	M. S
	Tabio-Río Frío-Carmen de Carupa	21.42	61.53	60.45	27.32	170.71	M.S
	Checua-Lenguazaque	154.79	380.78	232.21	17.91	785.69	M.S
	Suesca-Albarracín	36.29	96.68	75.95	-	208.92	S
	Zipaquirá-Neusa	1.81	5.47	11.48	-	18.75	M.S.A
	Total	258.03	703.41	592.60	68.09	1,622.13	
Boyacá	Checua-Lenguazaque	39.34	143.16	127.69	-	310.19	M.S
	Suesca-Albarracín	8.61	47.72	117.13	-	173.46	S
	Tunja-Paipa-Duitama	26.49	107.16	188.95	-	322.59	S.M
	Sogamoso-Jericó	113.36	454.43	522.18	-	1,089.97	M.S
	Total	187.80	752.46	955.95	-	1,896.21	
Santander	San Luis	61.82	119.76	136.07	-	317.64	M. S
	Capitanejo-San Miguel	-	19.84	1.58	-	21.42	A.S
	Miranda	-	6.05	-	-	6.05	A.S
	Molagavita	-	8.76	-	-	8.76	A.S
	Páramo del Almorzadero	-	130.34	26.86	-	157.20	A.S
	Total	61.82	284.75	164.51	-	511.08	
Norte de Santander	Chitagá	0.73	2.18	8.16	-	11.07	A. M
	Mutiscua-Cácota	1.72	0.73	0.18	-	2.62	S. M
	Pamplona-Pamplonita	3.08	6.89	5.32	-	15.29	S. M
	Herrán-Toledo	5.27	16.13	10.11	-	31.50	S. M
	Salazar	8.50	17.09	6.39	-	31.98	S. M
	Tasajero	15.63	35.84	61.98	-	113.45	S. M
	Zulia-Chinácota	44.15	136.85	113.76	-	294.76	M
	Catatumbo	56.57	140.40	217.09	-	414.06	S
	Total	135.64	356.10	422.99	-	914.73	
Grand Total		7,736.51	4,823.58	4,636.94	1,234.40	18,431.43	

KEY ISSUES AND DRIVERS FOR COLOMBIAN COAL

- Colombia has enormous reserves so mining at high levels can sustain well past year 2040;
- Coal production is controlled by a small number of major coal producers
- Coal production costs are low;
- Large coal loading ports have been built for exports;
- Imports are making in-roads into the U.S.;
- Prices can be competitive with U.S. coal supplies, but they are subject to global competition for the coals and ocean freight rate variation;
- A medium degree of political and civil instability exists in Colombia;
- High ocean freight rates exist at the present time – likely to ease but slowly; and
- U.S. railroads have been reluctant to provide cost-competitive rail rates for imported coals destined for inland plants in the U.S.

VENEZUELAN COAL

VENEZUELA - OVERVIEW

The Venezuelan coal industry is comprised of bituminous coal production principally from the Guasare coalfield where over 95% of Venezuelan coal is produced. The coal is high BTU, ranging from 12,200 – 13,000 BTU, and is low in sulfur content, ranging from 0.7% to 0.83%. Venezuela produces and exports about 8.7 million ton of coal annually not including 1.3 mmt of coal from Colombia that is shipped via Maracaibo lake ports to various markets in the U.S. and to other countries.

We project that Venezuelan production and exports will grow to as much as 27.5-28.7 million tons by 2014. This growth takes into account the development of projects like Socuy, Las Carmelitas (Cosila), Cachiry and Casigua.

The country has an enormous amount of coal, equivalent to almost 770 million ton of measured reserves. About 70%, or 540 million ton, of the country's coal reserves are for steam coal use.

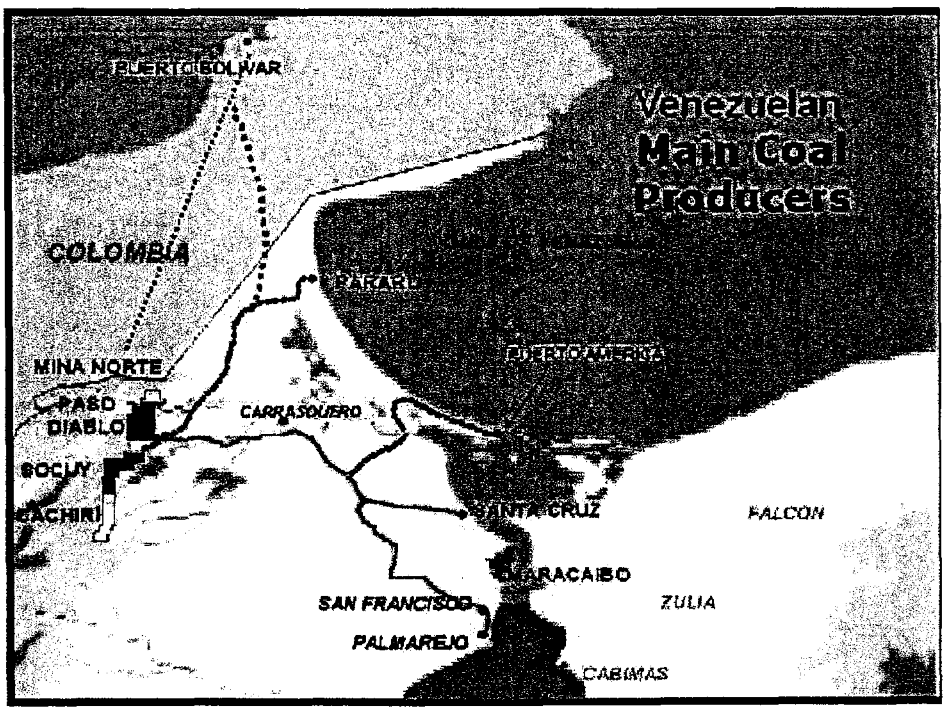
The vast majority of export tonnage comes from the Guasare basin and Tachira with a small amount from Fila Maestra in the eastern part of Venezuela. Paso Diablo and Mina Norte are the primary mines but there are also small mines in Tachira state with a marginal production of 0.2 mmt. Maracaibo lake ports also serve the coal produced in the Cucuta area in the Norte de Santander department. These regions contain the bulk of the defined coal resources and offer relatively easy access to the coast. The mines in these regions share similar characteristics:

- Almost all production comes from surface operations;
- All are mining multiple seams at stripping ratios of approximately 7.2:1;
- In most, the seams are steeply pitched and lend themselves to truck and shovel methods; and
- All have high quality coal with low-sulfur and ash and high-BTU values.

Venezuela coal transport infrastructure is limited, and inefficient. With the current infrastructure, and with some efficiencies gain, Venezuela export capacity will probably reach 11 -12 mmt. However, Carbozulia is currently negotiating a deal with a Brazilian company to develop the Socuy mine project, transport, and port infrastructure that will allow Venezuelan coal supply to reach about 28.7 mmt by 2014.

Figure 16, shows the location of producing coal mines and projects in Venezuela. As can be seen these are all located close to the northern shore of Venezuela and access export markets through ports on Lake Maracaibo or along the Gulf of Venezuela.

Figure 16
Venezuelan Coal Activity Map



VENEZUELA - PRODUCTION

Venezuela is the third largest producer of coal in Latin America after Colombia and Brazil. The Venezuelan coal industry marginally increased coal production during

2004, to 8.7 mmt, mainly through a production increase at Paso Diablo Mine, which was partially offset by a reduction of Mina Norte production. Mina Norte Production was affected by the rainy season that caused the destruction of the main bridge on the road connecting the mine with the ports.

Over 95% of Venezuelan coal production originates from the Guasare coalfield where the Paso Diablo and Mina Norte Mines are operated by Carbones del Guasare and Carbones de la Guajira, respectively. Carbozulia is a wholly-owned subsidiary of Corpozulia, a government entity in charge of the economic development of Zulia State.

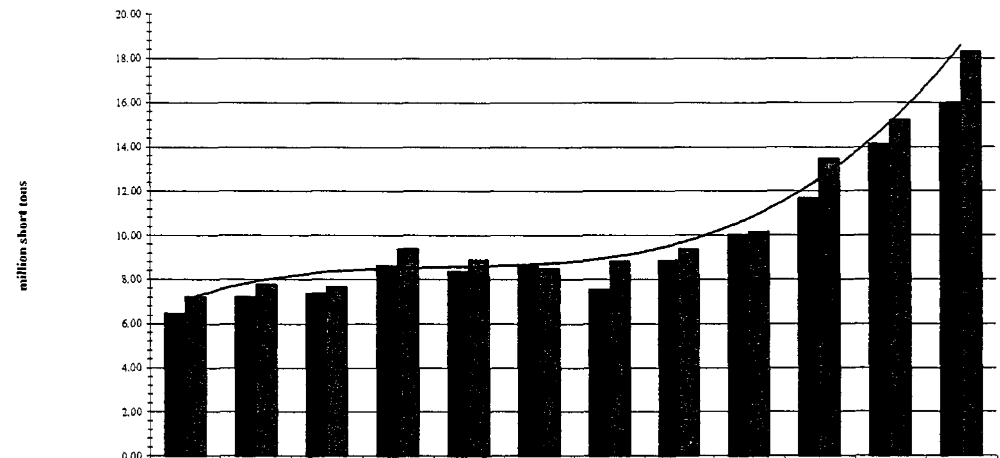
The Guasare coalfield is the most important of the coalfields, and Venezuela relies on this coalfield for future expansion of coal production. Expansion of production capacity at this field depends on the improvement of transport and port systems.

In 2000, coal production totaled 8.63 mmt and during 2001, coal production decreased to 8.34 mmt. In 2001, Venezuelan coal production was reduced by 3.4 % mainly because of the production problems encountered by Mina Norte, which produced approximately 772,000 tons, 330,000 tons lower than its normal level.

In 2002, coal production reached 8.61 mmt despite a civil strike that paralyzed the country from December 2002 to January 2003. The consequences of the civil strike on the economy and the severe foreign exchange currency restrictions imposed by the government also affected Venezuelan coal production in 2003, which reached 7.55 mmt, a decrease of 12.3%. Venezuelan coal production recovered again during 2004, reaching a production level of 8.86 mmt. It is estimated that Mina Norte will continue expanding its production, and new developments like Cosila in el Guasare basin and Fila Maestra in the east will come online, increasing the total production of Venezuela to 16 mmt in 2008. Figure 17 shows the export trends from 1997 to 2008.

Figure 17

Venezuela Coal Production and Export History



	1997	1998	1999	2000	2001	2002	2003	2004	2005 F	2006 F	2007 F	2008 F
■ Production mmt	6.47	7.22	7.37	8.63	8.34	8.61	7.55	8.86	10.03	11.68	14.11	15.98
■ Exports mmt*	7.21	7.78	7.65	9.37	8.89	8.49	8.84	9.37	10.14	13.45	15.21	18.30

■ Production mmt ■ Exports mmt* — Exports trend

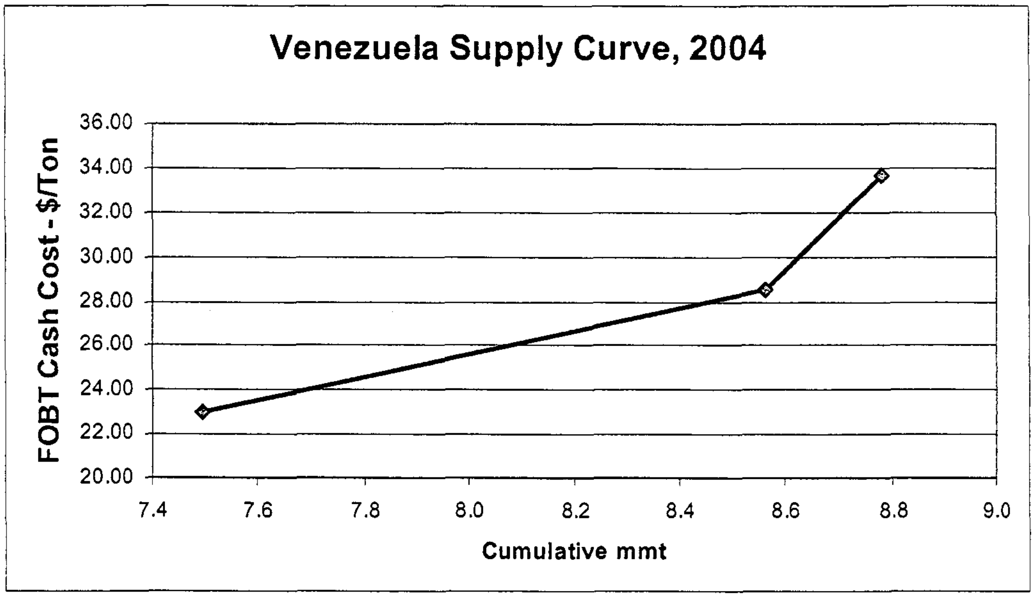
Venezuela's opportunities for increasing production in the future will be dependent on Carbones de Guasare's expansion projects in Paso Diablo and the development of the Socuy project mentioned above, as well as Carbones de la Guajira's Mina Norte and Cachiri projects.

Future Venezuelan coal industry growth will depend on the development of an effective transportation and port system, also mentioned above, that allows Guasare Basin producers to reduce FOBT cash costs and increase throughput capacity.

Due to infrastructure constraints, Venezuelan coal exports are currently limited to a maximum of about 12 mmt per year. Above this tonnage level, Venezuela will require a coal railroad transportation system and the development of one of several options for a modern port capable of handling capesize vessels. The port options include Puerto América and Pararu.

The FOBT cash cost curve for Venezuelan coal mines is shown in Figure 18. The chart shows that cash cost for the three operations range from $23.00 to $33.66. A total of 8.8 mmt cumulative capacity is available at cash costs below $34.00. New projects are expected to come in below the lower end of this curve, around $19-20 per ton FOBT. The lower costs will be attributable to efficiencies of a new rail and port infrastructure.

Figure 18



The typical coal qualities of the main Venezuelan coalfields are shown in Table 7. Venezuelan coals have an advantage over most Colombian coals in terms of higher heating value. Of course, a premium price is paid for this in comparison to the prices for Colombian products. The Venezuelan coals are generally lower in sulfur content than CAPP coals and, thus, compete very well against CAPP coals in coastal plants in the northeast of the U.S.

Table 7
Venezuelan Typical Coal Quality (GAR Basis)

	INHERENT MOISTURE (%)	ASH (%)	SULFUR (%)	(BTU/LB)
Paso Diablo	4 – 7	6 - 8	0.55 - 0.70	12,200 - 12,750
Naricual	4 – 6	6 - 7	0.80 - 1.1	12,800 - 13,100
Lobatera	NA	16 - 19.2	0.90 - 1.0	11,300 - 11,500

VENEZUELA - COAL RESERVES

The main coal reserves of Venezuela are distributed in four different areas -- Zulia, Táchira, Falcón, and Anzoátegui -- comprising a total estimated coal resource of 9,412 mmt. These coalfields are mainly located on the north coast. As Table 8 shows, the Venezuelan coal resources of the Zulia area are the most important.

Table 8
Venezuela Coal Reserves (mmt)

State	Reserves			Total Resources mmt
	Measured mmt	Indicated mmt	Inferred mmt	
Zulia	1,204	2,468	4,050	7,722
Táchira	163	263	732	1,159
Anzoátegui	134	98	31	263
Falcón	18	30	122	170
Merida	NA	NA	10	10
Guarico	NA	NA	55	55
Aragua	NA	NA	33	33
Total	**1,519**	**2,859**	**5,033**	**9,412**

The table indicates that, considering only measured and indicated reserves, Venezuela has the potential to support coal production at levels above 22 mmt per year for over 100 years. Reserves will not be the constraint in our view, it will be the development of those reserves that limits access to Venezuelan coals in the future.

KEY ISSUES AND DRIVERS FOR VENEZUELAN COAL

- Venezuela has adequate reserves to sustain existing & planned mines;
- Coal production is controlled by a small number of major coal producers;
- Coal production costs are low;
- Deepwater port infrastructure is lacking and necessary to expand exports;
- Imports are making in-roads into the U.S., particularly in the Northeast;
- Prices are can be competitive with U.S. coal supplies, but they are subject to global competition for the coals and ocean freight rate variation;
- A higher degree of political and civil instability exists in Venezuela versus Colombia;
- High ocean freight rates exist at the present time – likely to ease but slowly; and
- U.S. railroads have been reluctant to provide cost-competitive rail rates for imported coals destined for inland plants in the U.S.