COAL RESOURCE ASSESSMENT - 2006

INTRODUCTION

This assessment characterizes coal use, production, prices, transportation, reserves, and related mining operations in New York and the United States. It also addresses recent trends and developments in the coal industry, including advanced coal technologies and environmental factors that affect the use of coal. In addition, current New York and Federal programs and initiatives that relate to coal use are identified.

UNITED STATES COAL OVERVIEW

The United States (U.S.) has 27% of the world's known coal reserves, the most of any country, followed by Russia (17%), China (13%) and India (10%). The U.S. has a 250-year supply of coal based on its current rate of use.

Among world producers, U.S. coal production (20%) is second only to China's (30%). In 2004, over one billion tons of coal were mined in 25 coal-producing states. U.S. coal is mainly found in three regions: Appalachian, Interior and Western. Wyoming is the largest coal producer, with 397 million tons mined in 2004, representing 36% of U.S. production. Approximately two-thirds of U.S. coal production is surface mined. Nearly all of U.S. coal production is used domestically.

As shown in Table 1, over one billion tons of coal were used in the U.S. in 2004, with 92% used in the electric power sector. Coal-fired power plants account for 52% of all U.S. electricity generation. In 2004, the U.S. exported 48 million tons of coal, mostly to Canada and Europe.

Table 1

2004 United States Coal Production, Use, and Prices (Million Tons and Nominal Dollars)		
Production by Region	**million tons**	**%**
Appalachian	389.9	35
Interior	146.0	13
Western	575.2	52
Total	**1,112.1**	
Use by Sector	**million tons**	**%**
Electric Power	1,015.1	92
Coke Plants	23.7	2
Other Industrial Plants	61.2	6
Residential/Commercial Users	4.2	-
Total	**1,104.3**	
Average Delivered Price	**$/ton**	
Electric Utilities	$27.28	
Independent Power Producers	$27.18	
Coke Plants	$61.50	
Other Industrial Plants	$39.30	

Source: U.S. DOE, Energy Information Administration, *U.S. Coal Supply and Demand: 2004 Review*

Coal is by far the least expensive fossil fuel on a dollar per British thermal unit ($/Btu) basis, averaging less than one-half the prices of petroleum and natural gas in 2004, the latest year for which price data are available. Approximately two-thirds of all coal mined in the U.S. is transported by rail. The remaining one-third is transported by barge and truck. Hauling coal is the largest single source of freight revenue for U.S. railroads. Coal is also the largest freight revenue commodity moved by barges on the nation's inland waterways.

United States Coal Production

U.S. coal production has remained steady, despite the closing and consolidation of mines, because the average size and productivity of the remaining mines continue to grow. The 10 largest coal mines account for more than one-third of U.S. production and the 10 largest coal producing companies account for two-thirds of U.S. production.

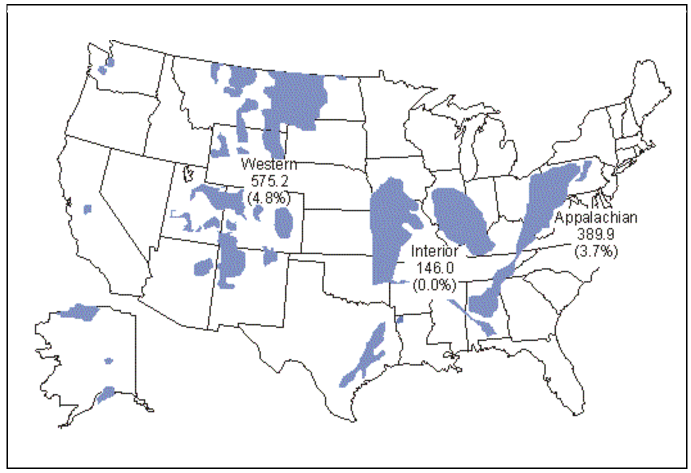
As shown in Figure 1, in 2004, coal production in the U.S. totaled 1,112.1 million tons from the Appalachian, Interior, and Western coal supply regions, a production level still below the 2001 record level of 1,127.7 million tons.

Table 2

2004 United States Coal Production by Coal-Producing State		
Region and State	**Number of Mines**	**Production** (Million Tons)
Appalachian Region	**1,193**	**389.9**
Alabama	49	22.3
Kentucky, Eastern	397	90.6
Maryland	19	5.1
Ohio	52	23.2
Pennsylvania	260	66.0
Tennessee	32	2.9
Virginia	123	31.4
West Virginia	261	147.9
Interior Region	**100**	**146.0**
Illinois	19	31.9
Indiana	29	35.1
Kansas	1	0.1
Kentucky, Western	22	23.2
Louisiana	2	3.8
Mississippi	1	3.6
Missouri	3	0.5
Oklahoma	8	1.8
Texas	13	45.9
Western Region	**64**	**575.2**
Alaska	1	1.5
Arizona	2	12.7
Colorado	13	39.9
Montana	6	40.0
New Mexico	4	27.2
North Dakota	4	29.9
Utah	13	21.7
Washington	1	5.7
Wyoming	20	396.5

Source: U.S. DOE, Energy Information Administration, *U.S. Coal Supply and Demand, 2004 Review, Annual Coal Report, 2004*

Figure 1. Coal Production by Coal-Producing Region, 2004
U.S. Total: 1,112.1 Million Tons
Percent Change from 2003: 3.8%



Source: Energy Information Administration, *Annual Coal Report*, 2004

Coal production in the Appalachian Region was 389.9 million tons in 2004 and West Virginia is the largest coal producing state in the Region, followed by Kentucky and Pennsylvania, as shown in Table 2. Coal production in the Interior Region was 146.0 million tons in 2004. Texas is the largest coal producing state in the Interior Region, followed by Indiana and Illinois. In 2004, a total of 575.2 million tons of coal was produced in the Western Region, dominated by Wyoming, which accounted for 69% of the regional production and 36% of the U.S. production. Wyoming produced 396.5 million tons of coal, nearly the sum of the next four largest coal-producing states. Coal production has grown in the Western Region in recent years and is now 52% of U.S. production.

Despite coal production being up in 2004, it was impacted by severe weather and by transportation problems that affected the amount of coal moved to markets. With the majority of coal being shipped by rail, and the railroads transporting record levels of not only coal, but other commodities in 2004, the resulting bottlenecks throughout the country led to several delays in delivering coal to utilities during the year. Also in 2004, hurricanes caused numerous problems for the coal industry, including disruptions in deliveries due to flooding and the inability of employees to get to the mines in southeastern coal producing states.

Coal is classified based on its carbon content, volatile matter and moisture content, and its heating value as shown in Table 3. For the most part, the higher ranks of coal contain more heat-producing energy. Anthracite is ranked highest in heating quality, while lignite is ranked lowest in heating quality.

Table 3

Types of Coal and their Characteristics					
Coal Type	**Percent Carbon**	**Heating Range Values (million Btu per ton)**	**Heating Avg. (million Btu per ton)**	**Moisture Content by Weight**	**Sulfur Content by Weight**
Anthracite (hard coal	86-97%	22 to 28	25	usually < 15 %	0.6%
Bituminous (soft coal)	45-86%	21 to 30	24	usually < 20%	1.4%
Subbituminous (black lignite)	35-45%	17 to 24	18	20%-30%	0.4%
Lignite (brown coal)	< 35%	9 to 17	13	as much as 45%	1.0%

Source: U.S. DOE, Energy Information Administration

The Appalachian Region is the principal source of bituminous coal and the only source of anthracite coal in the U.S. Anthracite coal is found only in Pennsylvania and is used mostly for space heating and limited electricity generation. The Western Region coal includes some bituminous coal, but is primarily subbituminous coal and lignite. Table 4 provides U.S. coal production statistics by classification of coal, mining methods, and origin.

Table 4

United States Coal Production, 2004 (Million Tons)		
Classification	**million tons**	**%**
Bituminous Coal	546.6	49
Subbituminous Coal	479.6	43
Lignite	83.5	8
Anthracite	1.7	-
Mining Method	**million tons**	**%**
Underground	367.5	33
Surface	744.0	67
Origin	**million tons**	**%**
West of the Mississippi	627.3	56
East of the Mississippi	484.1	44

Source: U.S. DOE, Energy Information Administration, *Annual Energy Review, 2004*

United States Coal Use

In 2004, coal use in the U.S. reached an all-time peak of 1,104.3 million tons, with approximately 92% of all coal used by the electric power sector. The remaining 8% was used by the industrial, commercial, and residential sectors. In 2004, coal was used to produce 52% of all electricity generated in the United States. The 1,015.1 million tons of coal used in the electric power sector does not include coal used for combined-heat-and power. Use of coal for combined heat and power is contained in industrial and commercial sector figures reported by U.S. DOE, Energy Information Administration (U.S. DOE/EIA), thus actual contribution of coal to electricity generation is slightly higher than conventionally reported.

On a regional basis, the East North Central Region (Illinois, Indiana, Michigan, Ohio, and Wisconsin) accounts for the largest amount of coal use (23%) followed by the South Atlantic Region (Florida, Georgia, North and South Carolina, Virginia, and West Virginia (17%). On a statewide basis, respectively, Indiana, Texas, Pennsylvania, Ohio, and Kentucky, were the top five coal users.

United States Coal Reserves

The demonstrated reserve base (DRB) is the estimated quantity of in-ground coal resources. The DRB in the U.S. was 495 billion tons (estimated by U.S. DOE/EIA) in 2004, with nearly half located in the Western Region. Although the DRB is approximately 500 times the U.S. annual coal production rate, all coal in the DRB is not recoverable. More than half of the DRB (267 billion tons) is estimated by U.S. DOE/EIA to be recoverable economically with the application of current extraction technologies.

The amount of recoverable reserves at active mines in the U.S. is estimated at 18 billion tons, based on information from mine operators for each active property. The majority of active recoverable reserves are in the Western Region (12 billion tons), followed by the Appalachian Region (4 billion tons), and Interior Region (2 billion tons). Table 5 provides coal estimates by coal producing regions in the U.S. for the demonstrated reserve base, estimated recoverable reserves, and recoverable coal reserves at producing mines.

Table 5

Demonstrated Reserve Base, Estimated Recoverable Reserves, and Recoverable Coal Reserves at Producing Mines, 2004
(in billion tons)

Region	Demonstrated Reserve Base	Recoverage Reserves	Recoverable Coal Reserves at producing mines
Appalachian	102.3	52.1	3.9
Interior	157.7	67.8	2.1
Western	234.5	147.4	12.1
U.S. Total	**494.5**	**267.3**	**18.1**

Source: U.S. DOE, Energy Information Administration, *Annual Coal Report, 2004*

United States Coal Mining

The U.S. coal mining industry has undergone considerable change in the past several decades that has resulted in a significant decrease in the total number of coal mines, while at the same time bringing about improvements in the productivity of mines. Coal mine productivity, in tons of coal produced per miner hour, improved both in underground and surface mines in all three coal-producing regions. Between 1995 and 2004, as labor productivity improved from 5.4 to 6.8 tons per employee per hour, the average number of employees working daily declined from 90,000 to 74,000. Labor composes roughly half of total mining costs, making it a major cost component for coal producers. See Table 6 for additional U.S. coal mining statistics.

Table 6

United States Coal Mining Statistics			
	1995	**2000**	**2004**
Production (in million tons)			
Underground	396	374	368
Surface	637	700	744
Total	1,033	1,074	1,112
Number of mines (active)			
Underground	977	839	586
Surface	1,127	749	771
Total	2,104	1,588	1,357
Number of employees (in thousands)			
Underground	58	46	42
Surface	32	32	32
Total	90	78	74
Productivity (tons per employee hour)			
Underground	3.4	3.9	4.0
Surface	8.5	10.3	10.6
Weighted Average	5.4	6.5	6.8

Source: U.S. DOE, Energy Information Administration, *Annual Energy Review, 2004, Annual Coal Report, 1999*

The U.S. coal mining industry has adopted a number of technological changes to improve the productivity and cost-effectiveness of mining operations. Examples of such changes include improved mining equipment, better material handling techniques, and enhanced automation of equipment monitoring and operation.

United States Coal Price

Coal prices rose in 2004, reversing a thirty year downward trend. Some of the forces pushing coal prices higher include problems with railroad deliveries and greater demand for American coal, both domestically and abroad. As reported by the U.S. DOE/EIA in the *Annual Energy Review - 2004*, the 2004 national average price for coal by class was $60.16/ton for anthracite, $30.47/ton for bituminous, $12.35/ton for lignite, and $8.51/ton for subbituminous. Spot market coal prices for some of the producing regions set record levels in 2004 and average contract delivered prices also increased for the year. Due to the fact that coal deliveries to the electric power sector are mostly done through long-term contracts, the delivered price of coal to the electric power sector increased slightly in 2004. Coal prices for electric utilities increased 5.7 % from 2003 to $27.28 per ton. Coal prices to independent power producers increased in 2004 to $27.18 per ton, an increase of 3.9% from 2003. The increase in delivered price of coal to the other sectors was higher since they rely on short-term contracts and the spot market.

Because of differences in shipping distance and transportation mode, transportation costs vary greatly among the coal producing regions. Appalachian and Interior Region coal is costlier at the minemouth, but its transportation costs are lower, involving relatively shorter hauls to consumers by rail and barge. Low-cost Western Region coal is shipped primarily by rail over great distances, thus incurring higher transportation costs than Appalachian and Interior Region coal. Coal transportation costs on average represent 50%, 20%, and 12% of the delivered price for Western, Appalachian, and Interior Region coal, respectively.

United States Coal Transportation

Coal is an important commodity to the rail industry. In 2003, railroads received 20% of their revenues from transporting coal, and coal comprised over 40% of the total tons of freight hauled by rail. Over the past ten years, the rail industry's share of coal transportation has increased, primarily to satisfy increased demand for low-sulfur western coal. Nearly three quarters of U.S. low-sulfur coal reserves are located in Montana and Wyoming. Domestic railroads carried 65% of the nation's coal, transporting an average of

15 million tons of coal per week in 2003. Coal is also moved by barges, ships, and trucks, when these modes of transportation are more economical. A few electricity-generating facilities are located near coal mines and receive their coal directly by conveyor or coal-slurry pipeline (coal-slurry is crushed coal mixed with water).

Average coal rail hauls are getting longer, again reflecting the increased penetration of low-sulfur western coal carried by rail into southern and eastern U.S. markets. Higher capacity cars and more powerful locomotives have dramatically increased railroads' coal-carrying efficiency. Railroads continually adopt technological innovations that offer customers greater flexibility. One example is the "coaltainer", a container designed especially for transporting coal by rail and by truck. Another innovation for transporting coal by rail is the use of real-time satellite monitoring and computerized traffic management systems to improve the scheduling and routing of trains. These electronic traffic management systems will become increasingly important as more electricity generators move toward "just-in-time" inventory management.

NEW YORK STATE OVERVIEW

New York used 260 trillion Btu of coal in 2004. This amount represents 7% of the State's total primary energy use of 4,057 trillion Btu. New York has no coal mining activity and no known coal reserves. In 2004, the average cost of coal delivered to New York electricity generators was $41.19 per ton, over 50% higher than the national average of $27.30 per ton. This is due in large part to the long haul of low-sulfur western coal to New York and the high cost of coal from the Appalachian Region.

Coal Use in New York

In 2004, nearly 12.9 million tons of coal were used in New York, representing 1% of the nation's demand. About 80% of this coal was used to produce electricity; the industrial sector accounted for 19%; residential and commercial use accounted for the remaining 1%. Over the past several years, the amount of coal used for electricity generation has remained stable, while coal used by the other end-use sectors (residential, commercial, and industrial) has declined. In 2004, New York ranked twenty-eighth among U.S. states in tons of coal used.

New York Electricity Coal Prices

In the electricity generation sector, the average delivered cost of coal to New York has remained "relatively" stable, as shown in Table 7, having increased by 31% in nominal dollars since 1980. However, in real dollars the cost of coal to New York has declined by 43% since 1980.

Table 7

Average Delivered Cost of Coal to New York Electric Generation Plants
(dollars per million Btu)

Year	Nominal Dollars	Constant 2004 Dollars
1980	$1.47	$3.37
1985	$1.72	$3.02
1990	$1.61	$2.33
1995	$1.41	$1.75
2000	$1.49	$1.63
2001	$1.42	$1.51
2002	$1.73	$1.81
2003	$1.60	$1.64
2004	$1.93	$1.93

Source: U.S. DOE, Energy Information Administration, *State Energy Price and Expenditure Report, and Quarterly Coal Report*

New York Coal-Fired Generating Units

New York has 13 coal-fired electricity generating plants located in twelve counties of the State. These facilities, listed in Table 8, represent nearly 3,505 megawatts of net summer capability for the New York electricity system, accounting for 14% (21,184 gigawatt-hours) of electricity generated in the State in 2005. These plants are all located outside of the metropolitan New York City area, with the greatest concentration in Western New York.

Table 8

Coal-Fired Generating Units in New York (as of April 1, 2006)			
Company and Plant Name	**County**	**Units**	**Summer Capacity (MW)**
1. AES Corp. - Cayuga	Tomkins	2	305
2. AES Corp. - Greenidge	Yates	2	159
3. AES Corp. - Somerset	Niagara	1	681
4. AES Corp. - Westover	Broome	2	126
5. Dynegy Power - Danskammer	Orange	2	368
6. Jamestown, City of	Chautauqua	2	44
7. Mirant Corp. - Lovett	Rockland	2	344
8. NRG Power - Dunkirk	Chautauqau	4	522
9. NRG Power - Huntley	Erie	4	539
10. RG&E - Russell	Monroe	4	231
11. Select Energy - Fort Drum	Jefferson	1	55
12. Trigen Corp. - Syracuse	Onondaga	1	80
13. WPS Energy - Niagara	Niagara	1	50

Source: New York Independent System Operator, 2006 Load and Capacity Report, April, 2006

Origin of Domestic Coal Used in New York

In 2003, domestic coal delivered to New York originated in six states. West Virginia and Pennsylvania combined accounted for 89%. By far the dominant mode of coal transportation into New York is rail.[1] Coal is also moved by barge and trucks to end-users in New York. Table 9 lists the origin of domestic coal delivered to New York in 2003 by method of transportation.

Table 9

Origin of Domestic Coal Delivered to New York by Method of Transportation, 2003 (thousand tons)					
State:	**Railroad**	**River**	**Great Lakes**	**Trucks**	**Total**
Kentucky	317	156	0	0	473
Ohio	0	149	0	33	182
Pennsylvania	3,040	643	113	481	4,277
Virginia	28	0	0	0	28
West Virginia	4,457	248	0	14	4,719
Wyoming	416	0	0	0	416
Total	**8,258**	**1,196**	**113**	**528**	**10,095**

Source: U.S. DOE, Energy Information Administration, *Coal Distribution Report, 2003*

[1] On December 6, 2005, Governor Pataki announced the Rail Freight and Passenger Rail Assistance Program, a five-year, 100 million dollar rail funding program that will help New York railroads make infrastructure and capacity improvements. This assistance program will modernize the state's rail network and keep it competitive as a mode of transportation for moving freight and passengers.

TRENDS AND DEVELOPMENTS IN THE COAL INDUSTRY

Generation Technology

Pulverized Coal System (PC) is the traditional coal burning technology, used in more than 1,000 coal-fired power plants in the United States, in which finely ground coal is burned to make steam and then flue gases are cleaned up.

The concept of burning coal that has been pulverized into a fine powder stems from the belief that if the coal is made fine enough, it will burn almost as easily and efficiently as a gas. The feeding rate of coal is controlled by computers and varies according to the boiler demand and the amount of air available for drying and transporting the pulverized coal fuel. Pieces of coal are crushed between balls or cylindrical rollers that move between two tracks. The raw coal is then fed into the pulverizer along with air heated to about 650˚F from the boiler. As the coal is crushed by the rolling action, the hot air dries it and blows the usable fine coal powder out to be used as fuel. The powdered coal from the pulverizer is blown directly to a burner in the boiler. The burner mixes the powdered coal in the air suspension with additional pre-heated combustion air and forces it out of a nozzle similar in action to fuel being atomized by a fuel injector in modern cars. Under normal operating conditions, there is enough heat in the combustion zone to ignite all the incoming fuel. As environmental emission regulations have been tightened, many PC plants have installed high-tech equipment like electrostatic precipitators and flue gas scrubbers.

Advanced Coal Technologies

Technologies are available and emerging to reduce emissions from coal burning at three different stages; pre-combustion, combustion, and post-combustion. Pre-combustion cleaning involves the removal of impurities from coal with physical, chemical or biological processes. Advanced combustion processes include improvements in existing coal combustion processes and new processes that remove pollutants from coal as it is burned. Post-combustion cleaning involves the removal of pollutants from the downstream flue gas after combustion and before exiting the stack. Another category of advanced coal technologies involves the conversion of coal into another form of fuel (e.g., gas or liquid). In most of these cases, the new fuel form provides both energy and environmental benefits by reducing the pollutants emitted from combusting the new fuel as compared to coal.

Most advanced coal technologies are the products of research conducted over the last 25 years. In recent years, technological advancements have led to substantial reductions in the cost of controlling SO_2 and NO_X emissions. Some of the most successful advancements are low-NO_X burners, selective catalytic reduction and scrubbers. Advanced pollution controls installed on existing power plants or built into new facilities can provide more effective and lower-cost ways to reduce sulfur dioxide and nitrogen emissions. Advanced power generation technologies are complete electric power generating systems that offer superior efficiency and environmental performance over conventional coal-burning systems. These new combustion processes, such as circulating fluidized bed (CFB) combustion, improve both efficiency and emission control.

Fluidized-bed combustion evolved from efforts to find a process able to control pollutant emissions without external emission controls (such as scrubbers). The CFB technology suspends solid fuels on upward-blowing jets of air during the combustion process. The result is a turbulent mixing of gas and solids. The tumbling action, much like a bubbling fluid, provides more effective chemical reactions and heat transfer. The technology allows burning at temperatures well below the threshold where nitrogen oxides form. In addition, the mixing action of CFB brings the flue gases into contact with a sulfur-absorbing chemical, such as limestone or dolomite, capturing more than 95 percent of the sulfur pollutants inside the boiler. The popularity of fluidized bed combustion is due not only to its capability of meeting sulfur dioxide and nitrogen oxide emission standards without the need for expensive add-on controls but also technology's fuel flexibility. Almost any combustible material, from coal to municipal waste, can be used for fuel. Most boiler manufacturers currently offer this technology as a standard package.

Another emerging combustion technology, integrated gasification combined cycle (IGCC), converts coal to a gaseous form similar to natural gas before being burned. This advanced technology converts coal into a combustible synthetic gas by reaction with oxygen and heat/steam. The gas is cleaned and then burned in gas turbine. IGCC systems are extremely clean, and are much more efficient than traditional coal-fired systems. IGCC uses a combined cycle format with a gas turbine generator fueled by the gasified coal and the resulting exhaust gases used to produce steam that then drives a steam turbine. Typically 60-70% of the power comes from the gas turbine with IGCC. The result is an integrated gasification combined-cycle configuration that provides ultra-low pollution levels and high system efficiencies.

Development and implementation of advanced coal technologies can be a significant contributor to achieving the State’s energy, economic, and environmental goals. Advanced coal combustion technologies can provide opportunities for re-powering or upgrading existing coal-fired electricity generating facilities, maximizing use of the in-place infrastructure.

Environmental Factors

Coal mining has significant negative effects on land and water resources. Soil subsidence and erosion are long-standing problems associated with underground and surface mining. Several laws regulate coal mining in an attempt to remediate or eliminate harm to the environment. Nationally, coal mining waste is used as fill for mine land reclamation projects. In New York, coal combustion wastes have a variety of uses, including: as an ingredient in the manufacture of cement, asphalt, roofing shingles, gypsum, calcium chloride, lightweight aggregate, lightweight block, and low-strength backfill; as a traction agent for roadways and cement; as an aggregate substitute in concrete; and as structural fill in building foundations. It is estimated by New York State Department of Environmental Conservation that 452,000 tons of coal combustion waste were reused in 2003.

Coal combustion results in air pollutant emission as well, including sulfur dioxide (SO_2), nitrogen oxides (NO_x), particulate matter (PM), carbon dioxide (CO_2), and mercury (Hg). SO_2, NO_x, and PM emissions are associated with air quality impacts and acidification of water resources (acid rain). CO_2 emissions contribute to global warming and mercury emissions result in neurological damage to both humans and wildlife. In-state emissions of SO_2 from coal-fired plants have been reduced significantly as a result of New York’s State Acid Deposition and Control Act (SADCA) implemented in 1984, and Title IV of the federal Clean Air Act (CAA) Amendments of 1990. As a result of these initiatives, total SO_2 emissions from New York’s electricity generation plants have been reduced by 50% from 1980 levels. NO_x emissions, which combine with volatile organic compounds (VOCs) in the presence of sunlight to form ozone (or smog), are being addressed by Title I of the federal CAA amendments. Substantial staged reductions in summer ozone season NO_x emissions from electricity generation plants were made in 1995 and 1999 (up to 55% for upstate coal-fired plants).

The Governor's Acid Deposition Reduction (ADR) Program announced in 1999 is expected to result in regulations that will require New York's electricity generation plants to reduce SO_2 emissions by 50% below the levels required by the federal CAA Amendments of 1990. The ADR Program will also require such plants to implement year-round controls for NO_X, a substantial extension of the five-month summer ozone season controls required under current federal and State regulations. The first full year of fully-implemented NO_X controls was 2005, and SO_2 controls are expected to be fully phased in by January 2008. NO_X compliance actions may include a mix of end-of-pipe emission control technologies, such as selective catalytic reduction (SCR) and selective non-catalytic reduction (SNCR). SO_2 compliance actions may include switching to lower-sulfur coal, retiring certain coal plants, and installation of flue gas desulfurization (FGD) equipment, or scrubbers, on a substantial proportion of existing coal plants. While the primary objective of the ADR Program is to reduce emissions of precursors of acid rain, modeling analysis indicates that emissions of CO_2, the principal greenhouse gas associated with global warming, could be reduced by up to 10%. This indirect benefit would likely result in shifts from coal and oil-fired generation to natural gas.

Table 10 shows typical emission rates for SO_2, NO_X, CO_2, and Hg for existing upstate coal plants in New York compared to estimated emission rates for coal plants that burn low-sulfur coal, plants with emission controls, new coal plants that have incorporated two advanced coal technologies and new natural gas combined-cycle plants. Burning low-sulfur coal could reduce SO_2 emissions from an uncontrolled plant by two-thirds; installing a scrubber could reduce emissions by 90% or more. These representative emission-reduction actions could be undertaken at existing coal-fired plants to meet the emission targets of the ADR Program.

Table 10

Emission Rates for Electric Generation Plants
(pounds per megawatthour)

	SO_2	NO_X	CO_2	Hg
Existing Upstate Coal Plant[1]	28.4	4.7	2,310	0.000110
Existing w/Low-Sulfur Coal[2]	9.5	4.7	2,310	0.000054
Existing w/Advanced Controls[3]	3.0	1.6	2,412	0.000074
New Advanced Coal: CFB[4]	1.6	0.6	1,912	0.000009
New Advanced Coal: IGCC[5]	0.00	0.15	1,623	0.000004
Natural Gas Combined-Cycle	0.00	0.07	871	0.0

[1]Existing upstate coal plant assumes 1.8% sulfur coal with no scrubber; low-NO_X. burners.
[2]Low-sulfur coal assumes 0.6% sulfur coal; low-NO_X. burners.
[3]Advanced controls assumes 90% SO_2 reduction and 35% Hg reduction by scrubber and 65% NO_X reduction by selective catalytic reduction.
[4]Circulating fluidized bed.
[5]Integrated gasification combined cycle.

Source: NYSERDA, Energy Analysis Program

Federal Initiatives

FutureGen is an initiative to build the world's first integrated sequestration and hydrogen production research power plant. The $1 billion project is intended to create the world's first zero-emissions fossil fuel plant (275 megawatt prototype plant). When operational, the prototype will be the cleanest fossil fuel fired power plant in the world. FutureGen is a public-private partnership involving the U.S. Department of Energy and an alliance of industrial coal producers and electric utilities, as well as state government and international participants.

The Energy Policy Act of 2003 provided authorizations for $600 million per year for the U.S. Department of Energy's Fossil Program for existing and new research and development projects and authorizations of $1.8 billion for the U.S. Department of Energy's (U.S. DOE) Clean Coal Power Initiative. Clean Coal Power Initiative provides funding for demonstrations of innovative technologies to improve the performance and economics of both new and existing coal-fired electric power plants. The Policy Act also mandates that at least 60% of the $1.8 billion will be used for projects on coal-based gasification technology, and that these projects meet stringent environmental performance standards and vastly increased efficiency standards.

The U.S. Environmental Protection Agency's (EPA) Clean Air Interstate Rule (CAIR) caps emissions of SO_2 and NO_x across 28 eastern states and the District of Columbia. This rule will achieve the largest reduction in air pollution in more than a decade, by reducing SO_2 emissions in these states by over 70% and NO_x emissions by over 60% from 2003 levels. A related action is the EPA Clean Air Mercury Rule, the first ever federally mandated requirements that coal-fired electric utilities reduce their emissions of mercury. Together the Clean Air Mercury Rule and the Clean Air Interstate Rule created a multi-pollutant strategy to reduce emissions throughout the United States.

New York Initiatives

The Advanced Clean Coal Power Plant Initiative (ACCPPI) was created to encourage the deployment of new coal technologies in New York. While New York electricity markets are highly dependent on natural gas and oil prices, with coal as a U.S. domestic resource, clean coal power generation could reduce New York's exposure to natural gas and foreign oil fluctuations.

The ACCPPI[2] project will demonstrate clean coal power generation and host a working laboratory for research and development related to capturing greenhouse gases. The Governor's Office of Regulatory Reform has been designated to lead a "Shovel Ready Team [3]," a multi-agency[4] effort to create the selection criteria, identify potential sites, and encourage private sector power developers to participate in this process.

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[2] http://www.cleancoal-ny.com and http://www.gorr.state.ny.us

[3] The agencies involved also have incorporated input from the Stakeholders Group which includes interested parties from the private sector, not-for-profit groups, and the general public.

[4] The "Shovel Ready Team" is made up of representatives of the following New York State agencies: Governor's Office of Regulatory Reform (GORR), New York State Energy Research and Development Authority (NYSERDA), New York Power Authority (NYPA), Department of Environmental Conservation (DEC), Public Service Commission (PSC), and Empire State Development (ESD).

Private sector power plant developers will have the opportunity to identify one or more suitable sites and be selected to construct and operate the clean coal plants(s). The timetable shows request for proposal (RFPs) issued on September 1, 2006, applications are due October 31, 2006, and December 2006 for the announcement of winning proposal(s)[5] and site(s).

Under the Regional Greenhouse Gas Initiative (RGGI), seven Northeast states have agreed to implement a cap-and-trade program to lower carbon dioxide (CO_2) emissions, a major contributor to global warming. This is the first mandatory cap-and-trade program for CO_2 emission in U.S. history. In addition to New York, other states signing the regional Memorandum of Understanding for RGGI are: Connecticut, Delaware, Maine, New Hampshire, New Jersey, and Vermont. Maryland is expected to become the eighth state to adopt RGGI. The cap-and-trade system utilizes credits or allowances to limit the total amount of emissions. Beginning in 2009, emissions of CO_2 from power plants in the region would be capped at current levels – approximately 121 million tons annually – with this cap remaining in place until 2015. The states would then begin reducing emissions incrementally over a four-year period to achieve a 10 percent reduction by 2019. The participating states have issued a draft model rule for public review and comment. Each individual state will then proceed with the required legislative or regulatory approvals to adopt the program. Pending the completion of this process, the RGGI program is slated to begin on January 1, 2009.

New York Coal Demand and Price Forecast Summary

Overall, New York's total coal demand in TBtu's is projected to decrease 1% annually over the next 20 years. Over the period 2006-2025, coal demand within the residential, industrial, and electric generation sectors is projected to decline, while demand in the commercial sector is projected to remain at current levels. As shown in Table 11, residential, industrial, and electric generation sectors are projected to decrease at annual rates of 1.4%, 0.3%, and 1.2%, respectively. Table 11 displays the projected electric generation sector coal demand in gigawatthours through 2025. Electric generation sector coal prices in constant 2004 dollars are projected to decrease at an annual rate of 0.3% over the next twenty years, as shown in Table 13.

Table 11

New York Coal Demand Forecast by Sector					
Year	**Residential (TBtu)**	**Commercial (TBtu)**	**Industrial (TBtu)**	**Electric Generation (TBtu)**	**Total**
2006	0.4	2.0	49.7	254.4	306.5
2010	0.4	2.0	49.1	215.7	267.1
2015	0.4	2.0	48.3	196.1	246.8
2020	0.3	2.0	47.6	224.5	274.5
2025	0.3	2.0	46.9	199.7	248.9
Annual Growth Rate (2006-2025)	-1.4%	0.0%	-0.3%	-1.2%	-1%

Source: NYSERDA, Energy Analysis Program

[5] The project developers will be required to allow their power plant to be used by NYSERDA for research and development related to carbon capture and/or sequestration.

Table 12

New York Electric Generation Sector Coal Demand in GWh	
Year	**Electric (GWh)**
2006	25,533
2010	21,784
2015	19,879
2020	23,908
2025	21,471

Source: NYSERDA, Energy Analysis Program

Table 13

New York Coal Price Forecast Electric Generation Sector ($/ton)		
Year	**Constant 2004 $**	**Nominal $**
2006	$41.76	$44.04
2010	$34.84	$39.71
2015	$39.34	$51.31
2020	$38.57	$58.42
2025	$39.42	$69.07

Source: NYSERDA, Energy Analysis Program

This Coal Resource Assessment was prepared by NYSERDA Energy Analysis Program Staff. If you have any questions, please contact:

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