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Oil in Power Generation: Up From The Bottom

This year has seen a major turnaround for oil in power generation, a market that since the mid-1970s had faded to a shadow of its former self. This report considers what has been behind the recent gains for oil and near-term prospects. It concludes that given continued weakness in international crude oil markets, oil can preserve its higher volumes in the power generation, perhaps even improve upon them.

Beyond the near-term, prospects for oil in the power generation market depend on decisions to maintain and modernize existing oil-burning capacity. This report analyzes a potential influence on these decisions, tightening emissions standards. It focuses on three gases: sulfur dioxide, nitrogen oxide, and carbon dioxide emissions. The first two are already regulated. The third would be a prime target of eventual national policies to limit emissions of greenhouse gases. Most of the competitive effects of the sulfur dioxide regulations have already been absorbed in the market. This is not the case for nitrogen oxide where recent regulatory decisions will cause far more problems for coal than for oil and gas, opening market opportunities for both fuels. On the other hand, restrictions on carbon dioxide emissions, should they ever be imposed, would leave existing oil units at a clear disadvantage versus gas units and, without investment in modernization, with no advantage versus coal.

Oil units will require some investment to meet the new nitrogen oxide requirements. Investment in modernization would also improve operating efficiencies. Continued low oil prices and higher utilization rates improve prospects that such investments will be made.

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Introduction and Summary

This year has seen a major turnaround for oil in power generation, a market that since the mid-1970s had faded to a shadow of its former self . In 1978, utilities consumed about 1750 kbd of oil. In 1997, oil volumes had fallen back to only about 350 kbd. But in the first seven months of 1998, oil consumption rose by over 50%, or nearly 200 kbd, compared to the first seven months of 1997. Over the same period, utility consumption of gas rose by about 12% and consumption of coal by about 3%. This report considers what has been behind the recent gains for oil and near-term prospects. The gains occurred in the context of growing electricity demand, up nearly 4% this year, enhanced oil price competitiveness, and ample spare oil-generating capacity. Continued weakness in international crude oil markets suggest that for the near term at least, oil can preserve its higher volumes in the power generation, perhaps even improve upon them.

Beyond the near-term, prospects for oil in the power generation market depend on decisions to maintain and modernize existing oil-burning capacity. (There is virtually no investment in additional oil-burning capacity apart from some in diesel units primarily for peaking.) This report analyzes a potential influence on these decisions, the tightening emissions standards being applied to power generation. It focuses on three gases emitted by fossil-fueled power generation, sulfur dioxide, nitrogen oxide, and carbon dioxide emissions. The first two are already regulated. The third is not, but would be a prime target of eventual national policies to limit emissions of greenhouse gases.

Based on data collected by the Environmental Protection Agency, it appears that in the case of sulfur, the majority of currently operating oil and coal generating units (and all gas units) are meeting not only current Federal requirements but also the more stringent requirements due to take effect in 2000. Thus most of the competitive effects of the regulations have already been absorbed in the market. This is not the case for nitrogen oxide where recent regulatory decisions will cause far more compliance problems, and higher costs, for coal than for oil and gas, opening market opportunities for both fuels.[1] On the other hand, restrictions on carbon dioxide emissions would leave existing oil units at a clear disadvantage versus gas units and, without investment in modernization, with no advantage versus coal. Even though oil used in power generation has a lower inherent emissions rate than coal on a BTU basis, this advantage is offset by lower apparent generating efficiencies of currently operating oil units.

Oil units are going to require some investment in order to meet the new NOx requirements. Investment in modernization would also have a favorable impact on operating efficiencies. Continued low oil prices and higher utilization rates improve prospects that such investments will be made.

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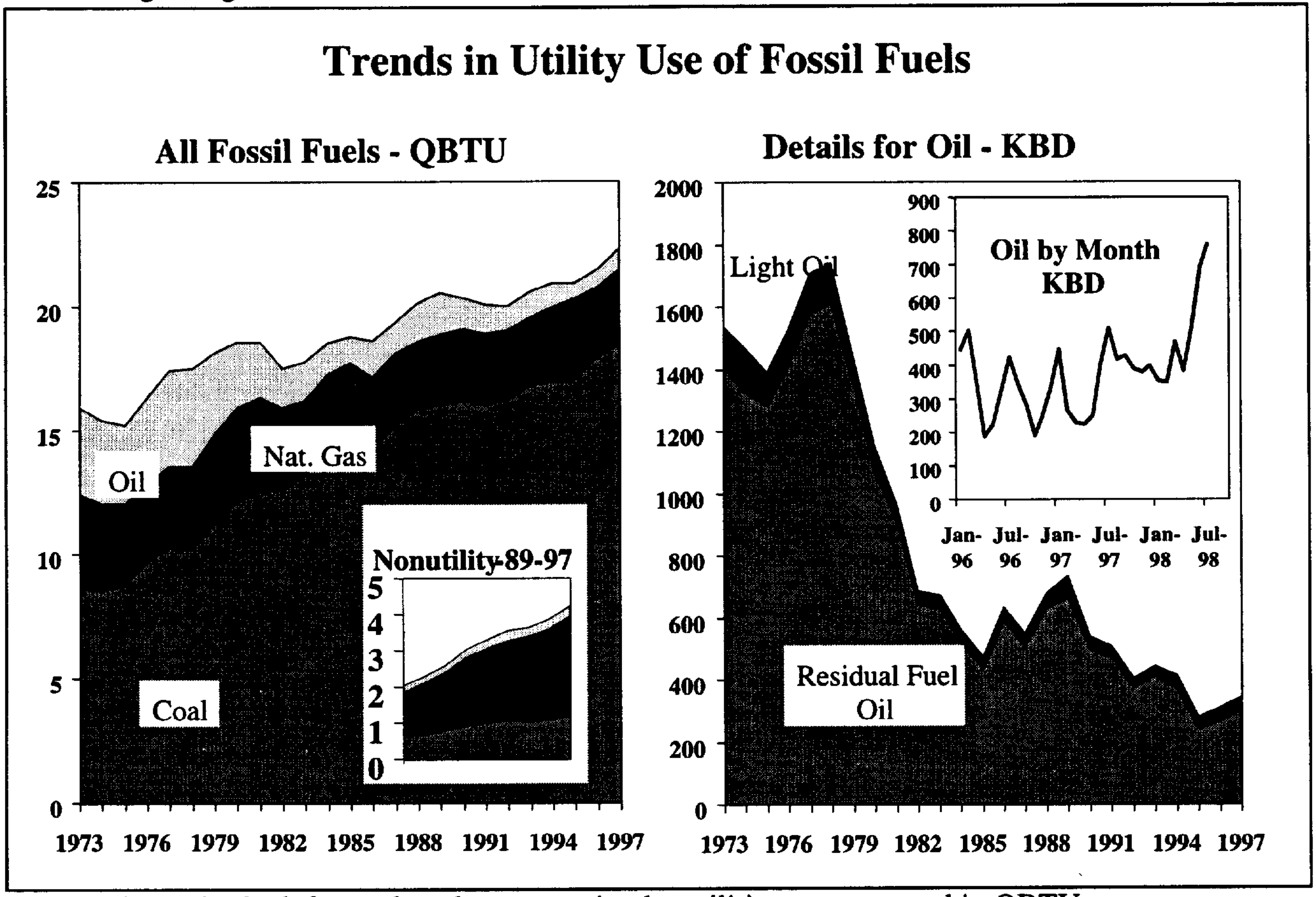
[1] Although not discussed in this report, emissions of mercury from power generation, if and when subject to regulation, would penalize coal versus oil and gas. On November 16, 1998, the Environmental Protection Agency announced its decision to require coal-fired electricity plants to submit information on mercury emissions. In a February 1998 report to Congress, the EPA identified emissions of mercury from coal-fired power plants as the toxic air pollutant of greatest concern for public health from these sources.

Trends in Fossil Fuel Use

Historically, coal has been the most important fossil fuel for US power generation. But at one time, oil appeared to be making major inroads. Between 1960 and 1973, oil's share of utility fossil fuels, as measured on a BTU basis, rose from about 8% to 22%, with the gains coming primarily at the expense of coal. The first and especially the second oil shocks changed this trend dramatically, with oil falling back, both in share and absolute volume, to a shadow of its former self. The chart below summarizes the trends in utility fossil fuel use, annually from 1973 through 1997 and also monthly details for oil since the beginning of 1996.



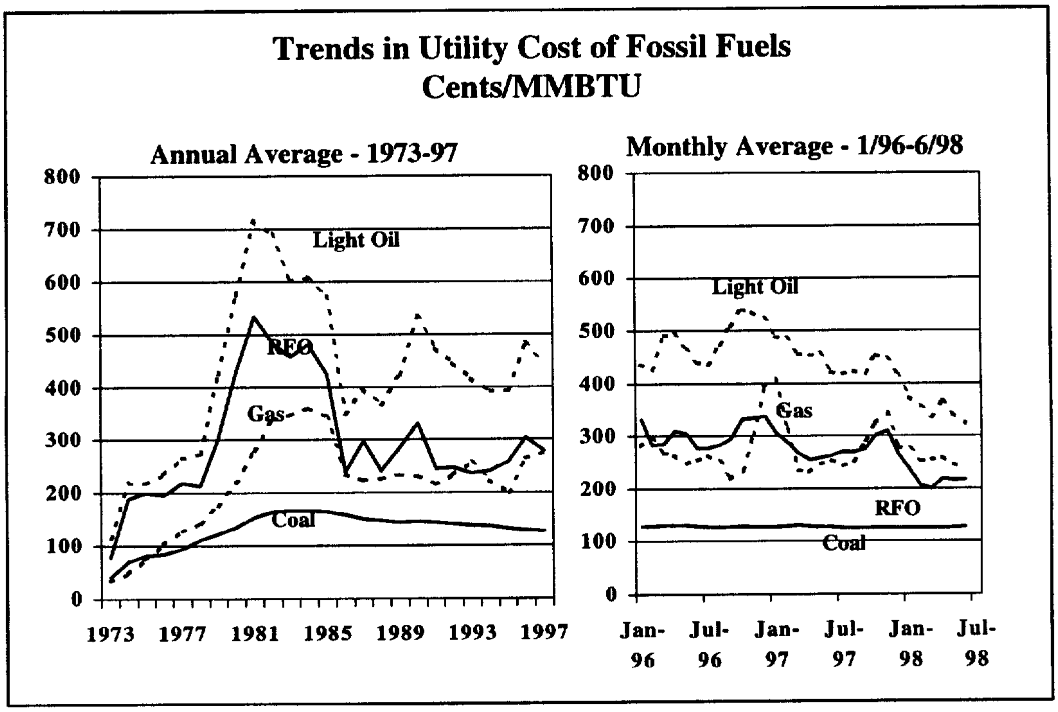
As shown in the left panel coal consumption by utilities, as measured in QBTU, more than doubled between 1973 and 1997. In 1997, coal accounted for over 80% of utility fossil fuel, up from 54% in 1973. Gas use by the utilities declined through the mid-80s and has since remained more or less stable. However utilities are no longer the primary users of gas for power generation. The inset shows fossil fuel consumption by nonutility generators for 1989-97, the years for which data are available. Gas consumption by nonutility generators more than doubled between 1989 and 1997. In 1997, gas consumption by nonutility generators approached the total for the utilities.

The right panel shows details for oil.[2] Oil consumption peaked at over 1700 kbd in 1977-78, then declined to less than 500 kbd in 1985. Although there was some pickup in the late 1980s, the 1990's saw new declines, with utility consumption in 1995-97 averaging about 300 kbd. About 85% of the oil consumed by utilities is fuel oil with the balance, (apart from petroleum coke) light oil, of which most is number 2 distillate.

As shown in the insert, the monthly pattern for oil indicates demand has moved up strongly in 1998. In the first seven months of 1998, utility consumption of oil was up 52%, or about 165 kbd versus the first half of 1997. Coal and gas consumption was up by about 3% and 11% respectively for the same period. This year has seen significant declines in the cost of oil to utilities, as well as to everyone else, and utilities appear to have reacted promptly to the lower prices by using more.[3]

Trends in the Cost of Fossil Fuels

For utilities, oil, gas, and coal are primarily bulk fuels for boilers.[4] In that role, the three fuels can be highly interchangeable, and therefore subject to price competition.[5] The chart below summarizes trends since 1973 in costs of coal, gas, and oil to utilities. Costs are stated in terms of Cents/MMBTU. The panel on the left shows annual averages for



[2] Excluding petroleum coke. About 10 to 20 kbd of petroleum coke was consumed by utilities in the 1990-97 timeframe.
[3] The Appendix table shows the geographic distribution of utility oil consumption for the first seven months of this year and the comparable period in 1997.
[4] Distillate and natural gas are also used in combustion turbines for peaking purposes but the volumes are small relative to fuel used in steam boilers. In recent years gas is increasingly being used in combined cycle technology. While growing, this medium to base load use is still relatively small as well.
[5] Competition is subject to certain limits. For example, stringent local air quality regulations rule out the use of coal for power generation in California.

1973-97. The first oil crisis produced price increases in all fossil fuels, although the increases were greatest for the two oil categories, residual fuel oil (RFO) and Light Oil, (mainly number 2 distillate), and least for coal. Gas prices rose substantially but during the 1970's, the regulatory regime in place at the time held down interstate gas prices and reduced gas supplies available to that market. The second oil crisis produced extremely wide price differentials that effectively priced oil out of most of the utility market. At its peak in 1981, the average cost of RFO to utilities reached over $5/MMBTU, nearly $4 above the cost of coal, and $2.50 above the cost of natural gas. Light Oil was nearly $2/MMBTU above the price of RFO.

Oil costs to utilities fell back in the 1980s, especially in 1986, with some modest favorable impact on utility use. But gains were limited by gently declining costs of coal and a significant reduction in the cost of gas. Average cost of gas remained below fuel oil for most of the subsequent years, with a big gap opening in 1990 as a result of the Gulf crisis.

The monthly data, shown in the right panel indicate a significant change in price relationships since early 1997. The average cost of RFO has been consistently below the cost of gas to utilities since mid-1997. In the first half of this year, the cost of RFO Was 40 cents/MMBTU below the average gas cost and only 89 cents/MMBTU above the average coal cost. With the exception of 1986, the gap between RFO and coal was narrower than at any time since 1973. Light oil remained the highest cost fuel, but the differential versus average cost of gas narrowed to under $1/MMBTU in the first half of 1998. These improvements in oil's cost competitiveness go far to explain oil's gains in the utility market in 1998.[6] Movements in spot prices since early summer indicate further competitive advantages for oil. As of late November, the spot (New York Harbor) price for 1% sulfur fuel oil was down nearly 20% from its June level while spot no. 2 distillate was down 12%. The spot (Henry Hub) price of gas was down as well but only by 3%.

Capacity Utilization Rates for Fossil Fuels

The substantial increase in oil use this year was possible because the declines of previous years have left utilities with substantial amounts of spare oil burning capacity that could be exploited in response to favorable market conditions.

The table on the right shows utility power generation by fuel and capacity utilization rates for 1997. Coal in utility steam generation plants produced nearly 1,800 terawatt hours of power in 1997, or about 85% of power generated by

Utility Power Generation From Fossil Fuels - 1997

	Terawatt hours	Capacity Utilization Rate
Steam Generation		
Coal	1,788	63%
Gas	233	26%
Oil	73	19%
Gas Turbine/Internal Combustion		
Gas	50	13%
Oil	5	2%

Note: 1997 nonutility capacity utilization rates are about 60% for power from oil and gas and over 75% for power from coal.

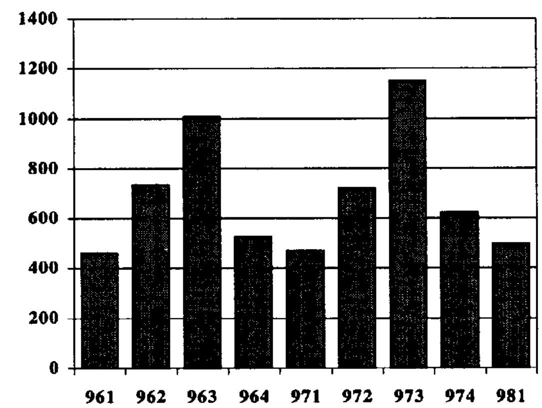
[6] The costs shown are national averages. Costs of fuels delivered to given locations, especially costs of coal and gas are sensitive to transport costs. Lower average natural gas costs could encourage greater use of gas vs. coal in regions close to production at the expense of gas delivered to more distant areas (such as the Northeast). Such diversion would also open opportunities for oil in the more marginal gas markets.

utilities from fossil fuels. Overall, coal plants showed a capacity utilization rate of 63%, indicating their primary use for base load and intermediate load power. Gas steam plants had an average utilization rate of 26% while for oil, the utilization rate was only 19%. The figures for gas turbine/internal combustion units reflect their use by utilities almost exclusively for peaking purposes. Even so, the utilization rate for oil at 2% is well below the 13% rate for gas. The oil used in these units is the more expensive light oil, mainly no. 2 distillate.

In recent years, the amount of planned additional capacity for oil-fired power generation units been minimal, and near zero for steam plants.[7] But existing capacity in place means there is plenty of room for expanded oil use in response to market opportunities. The capacity would also be drawn upon to meet unanticipated surges in electricity use as well---as was the case this past summer.

The figures suggest there is also significant room for expanded burning of gas in steam plants, however, such a conclusion is subject to important qualifications. Gas is a highly seasonal fuel with a very strong winter peak tied to residential and commercial sector use for heating. A large share of the seasonal requirements is met by an annual cycle of off-peak additions and peak period withdrawals from storage. In addition, supply diversion, through spot price increases and outright interruptions, plays a role, especially diversions from the utility sector. The chart on the right illustrates the extent of these diversions. It shows quarterly gas deliveries to the electric utilities from 1996 through the first quarter of this year. Deliveries in the first quarters of 1996 and 1997 were about 35% below their levels in the second quarters and less than half of the volumes supplied in the peak third quarters of the years (when residential and commercial sector demands are at their low point). As would be expected, differences are much narrower versus the fourth quarters of the two years since those quarters include the early months of the winter heating season.

Gas Deliveries to Electric Utilities by Quarter
Billion Cubic Feet



On a national basis, electricity demand peaks in the summer, so high utility use of gas in the third quarter would reflect underlying electricity demand as well as availability of the fuel. However, December and January are above-average months for electricity use. In New England, power generation by utilities in January 1997 was the highest of the year while in the Mid-Atlantic and East

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[7] As of January 1, 1997 electric utilities reported a total of 8,500 megawatts of planned additions to (nameplate) steam generating capacity and 30,600 megawatts of additional gas turbine/internal combustion capacity for 1997 through 2006. Oil accounted for only 3.5% of the planned additions of steam capacity and 6% of the planned GT/IC capacity. See table 4, US Department of Energy, Energy Information Administration, Electric Power Annual 1997 Volume II.

North Central regions, January electricity production was second only to July. January, of course is normally the peak month for winter heating requirements.

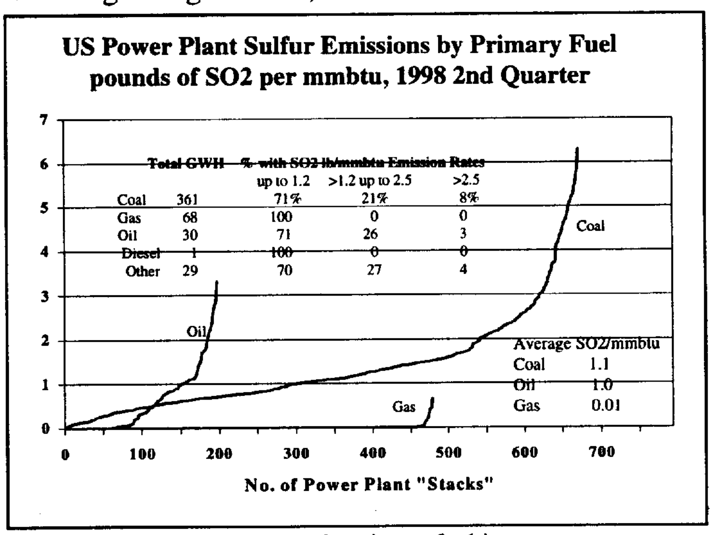
Environmental Influences

While fuel price competition is strong in electricity generation, fuel choice is also impacted by Federal and state environmental regulatory regimes. Their effects on fuel choice are growing, as environmental regulations become stringent, even though more flexible means such as emissions trading are being employed to achieve air quality objectives. The next sections focus on three gases emitted by power generators, sulfur dioxide (SO2), nitrogen oxide (NOx), and carbon dioxide (CO2). The first two are already subject to regulation, while the third would be a prime target of any national policy to contain emissions of greenhouse gases.

Under the Environmental Protection Agency's Acid Rain Program, all power generation units over 25 megawatts and new units that use fuel with a sulfur content greater than 0.05% by weight are required to measure and report emissions of SO2, NOx and CO2. The EPA preliminary report for the second quarter of 1998, the latest available, covers over 2300 reporting units that collectively accounted for over 90% of US electricity generated from fossil fuel in that period. These units are the stacks of single or multiple boilers where the emissions are measured. A sample of the data in the preliminary report, covering about 1600 units and about 90% of US electricity from fossil fuels, is used in the next sections to analyze the impact of current and proposed regulations on the three fossil fuels.[8]

Sulfur Dioxide Emissions

At the Federal level, sulfur emissions are controlled through an allowance trading system. With certain exceptions, allowances are allocated to each unit at a rate of 2.5 pound of SO2 per mmbtu (million British Thermal Units) of heat input, multiplied by average fuel consumed in the baseline period 1985-87. Beginning in 2000, the emissions rate for allowances will drop to 1.2 pounds/mmbtu. Units entering into service in 1996 or later have to buy allowances from the market or at EPA auctions. The chart on the right shows the distribution of coal, gas, and oil units by pounds of SO2 emitted per mmbtu. The top insert table shows total gigawatt-hours (GWH) of electricity produced by each fuel and the distribution of electricity production relative to the current and prospective allowance



[8] The preliminary data were screened to include only units reporting operating times, fuel input, power output, and NOx emissions greater than zero. Almost all of the excluded units were coal-fired. Since the EPA regulations of existing plants are based on emissions per mmbtu (million BTU) of fuel input, entries for electricity output get less intensive scrutiny and there were many zero entries.

levels. The lower table shows average SO2/mmbtu for each fuel.

In general, the coal-burning units have the highest emissions rates. Even so, about 600 of the nearly 700 reporting units have emissions rates below the current allowance rate and over half are already at or below the year 2000 allowance rate. The average emissions rate for all coal units is 1.1, slightly below the 1.2 rate for 2000. In terms of electricity produced from coal units in the second quarter, only 8% came from units with emissions above the current allowance rate, and 71% came from units already meeting the lower 2000 rate. In effect, whatever the costs of complying with the current and future Federal sulfur regulations, they are already incorporated in most coal-based power.

The overall emissions rate for oil plants of 1.0 pounds of SO2/mmbtu is slightly lower than the rate for coal. Of the nearly 200 oil burning units, all but 6 had emissions below the current allowance rate and the great majority had emissions rates below the 2000 allowance rate. The EPA data make a distinction between diesel (turbine and internal combustion) units and other oil burning units (steam units that use fuel oil and some petroleum coke). As shown in the table, the diesel units account for a very small share of electricity generated from oil---1 out of 30 GWH in the second quarter. This is in part because the diesel units are peaking units and in addition the second quarter is the lowest in terms of electricity generation requirements and peak power needs. As shown in the earlier price chart, diesel is more expensive than gas, (and of course coal and fuel oil) especially outside the winter months. As with gas, diesel units all show emissions below the year 2000 allowance levels.

All gas units have emissions rates well within the year 2000 allowance limit with the overall average rate near zero. As such, gas units face no cost increases as sulfur allowance limits tighten while a small but significant share of coal and oil-burning units would face somewhat higher compliance costs. How much higher is not certain but some indicators suggest the cost increase would be modest.

One option for meeting such costs would be to buy allowances in the open market. At the range of allowance prices prevailing so far in 1998---about $100 to $200 per ton of SO2--- the cost of allowances for a coal or oil unit emitting 2.5 pounds of SO2/mmbtu (the current allowance rate) to meet the year 2000 limit would range from 7 to 13 cents per mmbtu. This would be equivalent to about a 5 to 10% increase in the average price of coal delivered to utilities. For the outlier coal plants, compliance costs would be much higher. The allowance costs for a coal unit emitting say 5 pounds of SO2/mmbtu would range from 20 to 40 cents/mmbtu to meet the 2000 requirement, up from the 13 to 25 cents/mmbtu allowance cost of meeting the current 2.5 requirement. Costs of compliance would rise further if allowance prices moved beyond the $100 to $200 range in response to higher demand. There are limits to potential compliance costs, namely the cost of installing scrubbers. Based on EPA capital and operating cost assumptions, achieving compliance in this manner would raise costs by the equivalent of about $0.50/mmbtu of coal burned.[9]

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[9]The estimate is based on the Baseline Scrubber Cost Assumptions shown in table A5-7 of the report published by the Environmental Protection Agency, Office of Air and Radiation, Analyzing Electric Power

The oil outliers are at less extreme values than the coal units, with the highest oil unit reporting an emissions rate of just over 3 pounds of SO2/mmbtu as opposed to over 6 for coal. For oil-burning units, another option is to move toward lower sulfur fuel oil. Unlike the case of coal (where a shift to low sulfur coal involves a shift from eastern to far west sources), a shift from high to low sulfur oil does not raise transportation cost issues. Instead, there is the matter of the sulfur premium. About 60% of fuel oil purchased by utilities in June 1998 (the latest month available) had sulfur levels of 1% or less. About 25% of deliveries had sulfur levels of between 1 and 2% while the remaining 15% had sulfur levels between 2 and 3%. There was virtually no fuel oil delivered with sulfur levels above 3%. In the first 10 months of 1998, the cost differential between 2.2% fuel oil and 3% fuel oil was under $1 a barrel, or about 14 cents/mmbtu. The differential between 1% and 2.2% fuel oil was about $1.25 a barrel or about 20 cents/mmbtu.[10] The cost to an oil outlier of moving from say 3% fuel oil to 1% given today's differentials would thus be about 35 cents/mmbtu, about a 15% increase in fuel cost.

Overall, the tightening sulfur requirements appear to give some cost advantage to gas versus coal, and to a lesser extent oil, currently burned at "outlier" units. The advantage could widen if allowance costs or sulfur premiums rise in response to actions taken by coal and oil burning units to comply. However, volumetric implications are limited by the fact that most coal and oil units are already meeting the more stringent 2000 requirement.

NOx Emissions

The regulatory environment for nitrogen oxide is undergoing significant changes that over time are creating new problems for coal. While gas is the most obvious beneficiary, oil too may make gains.

In January 1996, Phase I of the EPA's NOx reduction program for coal fired electric generating plants came into effect. Phase I applied emissions limits of between 0.45 and 0.50 pounds of NOx/mmbtu, depending on boiler type (Tangentially Fired or Dry Bottom Wall-Fired), to 239 older coal-fired units. Phase II, which takes effect in 2000, lowers these limits to 0.4 to 0.46 for the same types of boilers and expands the number covered to just over 600. An additional 145 other types of existing coal-fired boilers became subject to limits ranging from 0.68 to 0.86 pounds of NOx/mmbtu. Existing oil and gas-fired units were not impacted by the Phase I and Phase II requirements but units over 73 megawatts going into operation or modified since 1971 have been subject to New Source Performance Standards of 0.3 pounds of NOx/mmbtu for oil and 0.2 for gas units.

Generation Under the CAAA, March 1998. Figures for capital and operating cost were combined with the average utilization and efficiency rates of the sample coal units to estimate levelized costs/mmbtu of the scrubbers. A 10% discount rate and 20 year life was assumed.

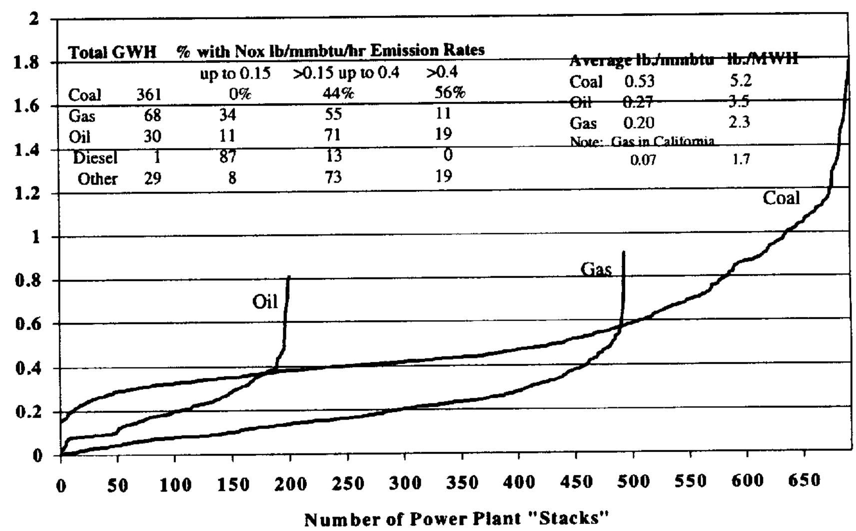
[10] Cost calculations for the sulfur premium are based on New York Harbor prices for 3%, 2.2% and 1% fuel oil.

In September of this year, the EPA issued a final rule revising the NSPS for new steam generating units. The new ruling, effective July 1997, not only tightened the standard but moved to a new "fuel neutral" basis. The NOx emission limit for newly constructed electricity steam generating units is stated as 1.6 pounds/megawatt-hour, a shift from the prior BTU input basis. The shift to an output basis was justified as promoting energy efficiency as well as pollution prevention. Steam units undergoing modification or reconstruction after the effective date are subject to heat-input based standard of 0.15 pounds/mmbtu. New gas or diesel turbines continue to be subject to a limit of 0.1 pounds of NOx/mmbtu.

These regulations regarding old and new generating units were issued under the nationwide Acid Rain Program as authorized by Title IV of the Clean Air Act Amendments of 1990. The 1990 Amendments also addressed the issue of downwind transport of ozone and its precursors, particularly NOx and the problems they create for downwind states in complying with air quality standards. In late October of this year, the EPA finalized its rule to require 22 states in the eastern part of the country plus the District of Columbia to submit State Implementation Plans for the reduction of NOx emissions that contribute to the nonattainment of ozone standards in downwind states.[11] In its ruling, the EPA is assigning ozone season NOx budgets to these jurisdictions. In arriving at these budgets, which must be implemented by May 2003, the EPA assumes a limit of 0.15 pounds of NOx/mmbtu for all large electricity generating units, in effect, a substantial, indirect tightening of requirements for existing units in the affected areas, especially coal-burning units. In 1997, the 22 states plus the District of Columbia accounted for 65% of US coal-generated power by utilities, 48% of utility generated power from oil, and 17% of the country's utility generated power from gas.

To consider what these changing standards imply for the different fuels, the next chart shows the distribution of coal, gas, and oil generating units by level of NOx emissions as measured by pounds/mmbtu. The upper left insert table shows the distribution of GWH from units meeting

US Power Plant NOx Emissions by Primary Fuel
pounds of NOx per mmbtu, 1998 2nd Quarter



[11] Published in the Federal Register, Vol. 63, No. 207, October 27, 1998. The states affected are: Alabama, Connecticut, Delaware, Georgia, Illinois, Indiana, Kentucky, Massachusetts, Maryland, Michigan, Missouri, North Carolina, New Jersey, New York, Ohio, Pennsylvania, Rhode Island, South Carolina, Tennessee, Virginia, West Virginia, and Wisconsin.

different NOx thresholds. The right table shows average NOx emission rates by fuel as measured in pounds/mmbtu and pounds/megawatt-hour.
Coal clearly has a problem, especially with the new ozone rule. None of the nation's coal reporting units meets the budget limit of 0.15 pounds/mmbtu. Of the total GWH generated by coal units, 44% were from units with emissions rates ranging from above 0.15 to 0.4 pounds/mmbtu, within the lowest limit for coal units under Phase II regulations, while 56% came from units with emissions rates above 0.4. Nearly 100 plants (with about three-quarters in areas affected by the new ozone rule) generating about 14% of coal-based electricity have emissions rates above 0.86, the highest Phase II limit for coal units.

As shown in the right table, the average emission rate for all coal plants is 0.53 pounds/mmbtu, more than three times the ozone budget limit. The average of 5.2 pounds/MWH is also more than three times the new NSPS. Where reductions in NOx emissions rates of more than 50% are needed, the EPA's own analysis indicates selective catalytic reduction (SCR) technology would be required.[12] Using the EPA's estimates of capital (about $70/kilowatt of capacity) and operating costs for this technology, the result would be to add about $0.30/mmbtu to the cost of continuing to burn coal, equivalent to about a 25% increase in the current average price of coal delivered to utilities.[13]

The profile for gas units is very different. Of the total GWH generated by gas units, 34% was from units with emissions rates at or below 0.15 pounds/mmbtu. An additional 55% came from units with emissions rates between 0.15 and 0.4 pounds/mmbtu. As shown in the right table, the average for all gas plants is 0.2, not much above the 0.15 budget limit for the 23 eastern areas of the country. Where regulations require it, gas can do much better. Much of California subjects power plants to more stringent limits than the Federal budget limit, for example, 0.015 pounds/mmbtu in the Southern California Air Quality Management District. As a result, the California plant average for gas units (virtually all fossil-fueled power is from gas) is 0.07 pounds/mmbtu, less than half of the 0.15 budget limit, and 1.7 pounds/MWH, very close to the latest NSPS.

Oil units also show a substantially lower emissions profile than coal, although not quite as favorable as for gas. About 11% of GWH from oil come from units with emissions rates at or below the 0.15 pounds/mmbtu rate (with 87% of diesel fueled power in this emissions range). An additional 71% of oil fired power come from units in the 0.15 to 0.4 range. Overall, the oil units have an average emissions rate of 0.27 pounds/mmbtu, not quite double the EPA budget limit.

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[12] Based on figures published in: Environmental Protection Agency, Office of Air and Radiation, Analyzing Electric Power Generation Under the CAAA, March 1998. SCR and SNCR capital and operating cost estimates are taken from this source as well. These are converted to levelized cost/mmbtu using the same assumptions and procedures that were applied to scrubber costs in the previous section.
[13] This is on an annual basis. Since the NOx budgets are tied to a 5-month ozone season, an alternative approach is to apply the SCR costs solely to operations over the ozone season, yielding a cost of about $0.70/mmbtu of coal burned in the ozone season. This latter approach allows a more direct comparison of costs of installing SCR versus the option of purchasing seasonal NOx credits.

The EPA estimates show much lower capital costs of applying the most expensive SCR technology to oil and gas units compared to coal, about $28 per kilowatt of capacity for oil and gas steam units as opposed to 70$ for coal. Moreover, since oil and gas units are far closer on average already to the proposed budget limit than coal, they could use a less drastic NOx reduction process at even lower cost. Overall, *if gas or oil units ran at the same utilization rates as coal*, the cost of SCR technology for oil and gas units would add only 8 cents/mmbtu to the cost of these fuels as opposed to 30 cents for coal. If less expensive selective noncatalytic reduction (SNCR) technology is used (SNCR can achieve a 50% reduction in emissions rates, sufficient to bring average oil and gas emissions rates down below the budget limit) the cost for oil and gas units would fall to only about 4 cents/mmbtu.[14] However, average utilization rates for existing utility oil and gas steam generating plants are far below utilization rates for coal units. In the case of oil, as shown earlier, the average utilization rate is only about 20%, less than one-third the nearly 65% rate for coal. At the current utilization rate for oil plants, costs on a BTU basis of the NOx control technologies would be about triple those shown for an oil unit running at the same utilization rate as the average coal plant. Prospects of sustaining higher utilization rates would be critical in improving the economics for making investments in NOx control technologies

So far, there is no evidence of investments in SCR or SNCR technology for oil units. Of the nearly 1600 units in the sample, 41 report having SCR or SNCR technology in place. Of the 41, none are oil units. Thirty-five are gas units and the remainder, coal.[15]

Emissions of CO2

Although not regulated at this time, emissions of CO2, the main greenhouse gas associated with the burning of fossil fuels could become subject to regulation in the future. The US has signed, although not ratified, the Kyoto Protocol to the UN Framework Convention on Climate Change. Under the Protocol, should it ever come into effect, the US is committed to reduce its greenhouse gas emissions by 7% versus a 1990 base level. While there are flexibility mechanisms that could reduce the required reductions from domestic sources of emissions, any significant effort to curb emissions is bound to focus on the power generation sector.[16]

Average CO2 Emissions & Generation Efficiency

Tons per:	Mmbtu	MWH	Efficiency %
Gas Units	0.06	0.6	33%
Oil	0.09	1.1	29
Coal	0.10	1.1	33

The table on the right shows average CO2 emissions for the coal, gas and oil units measured in terms of tons of

[14] In California, 22 of the 55 reporting gas generating units have SCR or SNCR.

[15] The coal units, all with SNCR, reported NOx emissions rates ranging from 0.3 to 1.0 pounds of NOx/mmbtu, far better than the national average for coal units, but still above budget limits. Five of the six units are in states subject to the new ozone regulations.

[16] In 1997, emissions of CO2 from fossil fuels accounted for about 85% of total US greenhouse gas emissions on a carbon equivalent basis. About 35% of CO2 emissions came from fossil fuels burned by electric utilities. US Department of Energy, Energy Information Administration, Emissions of Greenhouse Gases in the United States, 1997.

CO2/mmbtu and tons of CO2/MWH. Also shown is the average efficiency of the reporting units. The gas units clearly have the lowest CO2 emissions rates, 0.06 tons/mmbtu and 0.6 tons/MWH. Average oil unit emissions are lower than for coal on an mmbtu basis, 0.09 vs. 0.1 tons/mmbtu, but they are the same 1.1 tons/MWH. The lower average efficiency rate for the oil units, 29% vs. 33% for coal, accounts for this equality on an MWH basis. Most likely, the lower efficiency rate for oil units reflects their more limited use, and therefore, less incentive to invest in modernization, than is the case for coal plants running at base and intermediate load.

There is little doubt that actions to curb CO2 emissions from power generation will be favorable for gas relative to the other fossil fuels, or at least less unfavorable. However, in the near to medium term, government actions are likely to be limited to promoting renewables and perhaps encouraging an early, voluntary trading system, measures that would not significantly impact relative fuel costs. In the mean time, higher utilization rates for oil plants could encourage investment in modernization that raises efficiency rates to the levels shown for coal and gas.[17]

[17] The gas combined cycle units in the EPA data base show overall apparent efficiency rates slightly below the average for all gas units---30% efficiency for combined cycle vs. 33% for all gas units. Although combined cycle units can achieve efficiency rates of 50% or better, they do so if used to maximize electricity output. Currently, combined cycle units are used to make steam for industrial processes as well as electricity. Cogeneration of industrial steam and electricity is highly efficient, but not in terms of total mmbtu's of fuel used vs. only the electricity produced.

Appendix

Utility Consumption of Oil by Census Division – Thousand Barrels[18]

Census Division	Jan-July 1998	Jan-July 1997	%Change
New England	22,990	19,857	15.8
Middle Atlantic	17,041	9,718	75.4
South Atlantic	42,852	24,629	74
East North Central	3,043	2,135	42.5
East South Central	6,749	1,848	265.2
West North Central	1,027	811	26.6
West South Central	763	865	-11.8
Moutain	285	288	-1.2
Pacific Contiguous	148	92	60
Pacific Noncontiguous	7,319	6,935	5.5
U.S. Total	102,218	67,180	52.2

[18]Source: Table 19, U.S. Department of Energy, Energy Information Administration, Electric Power Monthly, October 1998.