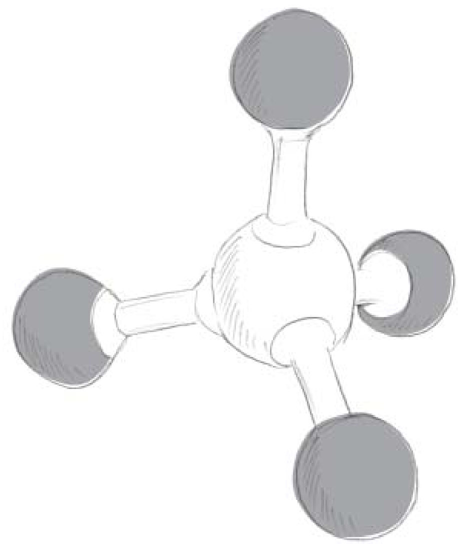
The effects of carbon legislation on independent power producers



The threat of global warming resulting from CO_2 emissions continues to be a top policy agenda item for U.S. lawmakers as they debate legislation that would provide for reductions to CO_2 emissions.

On May 12, 2010, Sens. John Kerry and Joseph Lieberman unveiled a draft bill named the American Power Act (APA). This proposed legislation is aimed at reducing CO_2 emissions and furthering the development of clean technology. The announcement of this draft legislation was followed by the finalization of the Environmental Protection Agency's (EPA) greenhouse gas tailoring rule, which outlines permitting requirements for large emitters of greenhouse gases.

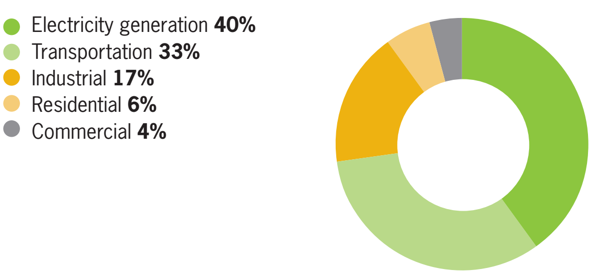
With electricity generation accounting for 40%[1] of all U.S. energy-related CO_2 emissions (Table 1), passage of the proposed legislation would bring significant changes to the power-generation industry. Large amounts of capital will need to be deployed in order for power companies to keep up with the tighter emissions standards. While regulated utilities might pass regulatory costs through to customers relatively easily, independent power producers (IPPs) will most likely have a more difficult time dealing with these additional costs.

The APA mandates carbon reduction measures across the entire economy using 2005 emissions as a baseline. The APA establishes a goal of reducing emissions to 95.25% of 2005 emissions by 2013, 83% of 2005 emissions by 2020, 58% of 2005 emissions by 2030 and 17% of 2005 emissions by 2050[2].

The proposed legislation includes a significant focus on carbon capture and sequestration (CCS) technology. This technology essentially captures CO_2 before it is released into the atmosphere and stores it underground. There are commercially available technologies in use today, but there has been no attempt to integrate CCS and power production technology on the scale necessary to make significant reductions in CO_2 emissions from typical large-scale power plants.

Table 1

U.S. energy-related CO_2 emissions by end-use sector – 2008
(million metric tons CO_2)



Source: EIA

[1] Source: Energy Information Administration (EIA)
[2] Source: American Power Act (APA) Section 702

Table 2: CO_2 emissions by fuel type

Fuel type	CO_2 (lbs/mmbtu)
Petroleum coke	225
Lignite coal	215
Subbituminous coal	213
Waste oil	210
Bituminous coal	205
Synthetic	205
Waste coal	205
Tire-derived fuel	190
Residual fuel oil	174
Distillate fuel	161
Kerosene	160
Jet fuel	156
Propane gas	139
Natural gas	117
Municipal solid waste	92
Geothermal	17
Nuclear	—
Average	**158**
Median	**174**

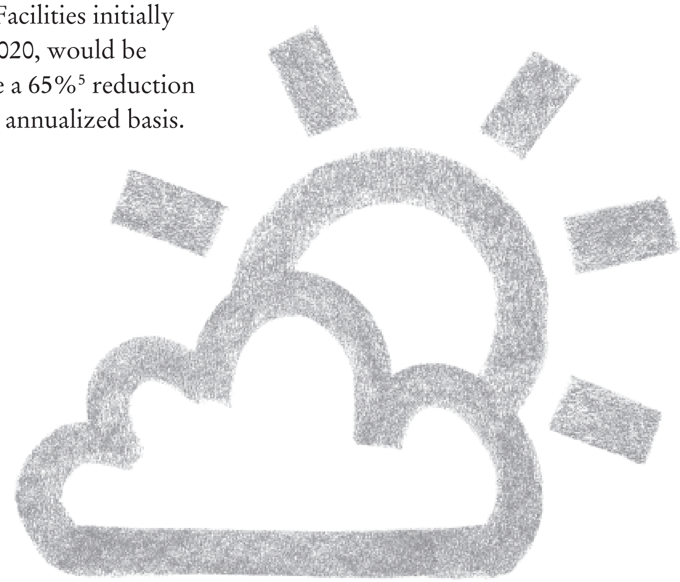
Sources: EIA/DOE; Tudor, Pickering, Holt & Co.

With coal-fired plants being one of the largest emitters of CO_2 in the electricity-generation industry (Table 2), these plants have been proposed as the most likely candidates for CCS implementation. Their smokestacks would be retrofitted with CCS technology, thus allowing the CO_2 to be filtered out of the released gases. To promote the use of commercial-scale CCS, the proposed legislation directs an administrator to establish regulations for the distribution of emissions allowances, including incentives for facilities that deploy CCS technology early or capture larger amounts of CO_2. However, it remains uncertain whether the implementation of CCS technology is commercially and economically viable.

With CCS still in the early stages of development, trying to measure the costs of implementing this technology is not yet feasible. The Coal Utilization Research Council has estimated that CO_2 capture systems could increase the cost of electricity from coal-fired plants by 40% to 75%[3]. Those IPPs with portfolios weighted toward coal-fired plants are particularly vulnerable to this uncertainty. Government intervention in the form of grants, tax incentives or subsidized loans could become necessary to assist coal-fired plants with the adoption of CCS.

The draft legislation amends the Clean Air Act to add a performance standard for power plants that require a Section 503(a) permit and derive at least 30% of their heat energy from coal or petroleum coke. Units that were initially permitted for a preconstruction permit after Jan. 1, 2009, and until Dec. 31, 2019, would be required to reduce their CO_2 emissions by 50% by 2020[4] or four years after the EPA determines that certain CCS technologies have been implemented, whichever comes first. Facilities initially permitted after Jan. 1, 2020, would be required to demonstrate a 65%[5] reduction in CO_2 emissions on an annualized basis.

Another major focus of the APA is reducing CO_2 emissions by establishing cap-and-trade regulations. The purpose of these programs is to require emitters of fossil fuel-based greenhouse gases to hold allowances or offsets in excess of their annual emissions. Greenhouse gases are measured in units of CO_2 equivalent, which measures the climate change that would be exacted by one metric ton of CO_2. The market-based provisions apply to "covered entities." As defined, a covered entity includes, among many other categories, any electricity source or refined product provider, as well as a stationary source emitting at least 25,000 tons[6] of CO_2 equivalent per year. That amount is comparable to the emissions from burning 131 rail cars of coal or the annual energy use of about 2,200 homes[7], according to the Environmental Defense Fund. By raising the standard to 25,000 tons, the new rule exempts millions of smaller sources of CO_2 emissions such as bakeries, soft drink bottlers, dry cleaners and hospitals.



3 Source: Coal Utilization Resource Council
4 Source: APA Section 794
5 Source: APA Section 801
6 Source: APA Section 713
7 Source: Environmental Defense Fund

The cap-and-trade program establishes an initial number of allowances starting in 2013 and gradually decreasing through 2050. Emissions levels are set on an annual basis, with the exception of refiners to ensure domestic fuel production. In addition to using allowances to meet the requirements of the proposed legislation, entities may use up to 2 billion tons[8] of offset credits per year, depending on the size of the emitting facility. The proposed legislation establishes an advisory board to ensure the integrity of offset credits and gives the board the authority to determine which kinds of activities count as offsets.

The impact of cap-and-trade policies

Given its natural abundance in the United States, coal has historically been the least expensive fuel source for power generation. Table 3 below details the existing variable production costs of coal-fired plants relative to natural gas-fired plants.

As reflected in Table 3, coal-fired plants have a lower variable cost than natural gas-fired plants per megawatt-hour of electricity generated. This has resulted in coal being the predominant base load fuel source for electricity generation in the United States (see Table 4).

Since coal has a lower variable production cost, one might ask why the historically more expensive natural gas-fired plants are even needed as a power supply source. However, demand for electricity is highly volatile, and electricity cannot be stored in anticipation of these spikes in demand. Consequently, a power supply source is needed that can generate electricity on short notice to meet these unplanned spikes in demand. Unlike coal-fired plants, natural gas-fired plants can fire up quickly and begin producing electricity within a few minutes, which makes natural gas-fired plants the perfect secondary supply stack source to meet the short-term demand spikes that occur throughout the day.

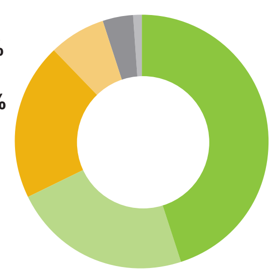
Table 3: Variable production costs ($/MWh)

	Coal*	Combined cycle gas turbine (CCGT)	Simple cycle gas turbine (GT)
Fuel costs			
Commodity			
$/ton	$60.00	NM***	NM
$/mmbtu	1.40	4.00	4.00
Transport			
$/ton	12.00		
$/mmbtu	0.50	0.50	0.50
Total fuel cost ($/mmbtu)	1.90	4.50	4.50
Heat rate (mmbtu/MWh)	10.00	7.00	10.00
Total fuel cost ($/MWh)	19.00	31.50	45.00
Emission allowance costs**			
NOx and SO_2	4.00	NM	NM
Variable operating and maintenance costs	5.00	2.50	3.00
Total variable costs	$28.00	$34.00	$48.00

* Marginal Appalachia coal-fired facility with no emissions control equipment
** Pricing NOx @ $1,000/ton, pricing SO_2 @ $250/ton, and assuming coal has 3% sulfur content
*** Not meaningful
Sources: EIA/DOE; Tudor, Pickering, Holt & Co.

Table 4

2009 electricity generation by fuel type



Source: EIA

[8] Source: APA Section 722

Using coal as the base load supply stack source for electricity generation and natural gas as the secondary supply stack source makes perfect sense given the existing variable cost structure advantages of coal. However, an important question arises: How will the economics of coal and natural gas be affected by a cap-and-trade program that aims to include the cost of CO_2 emissions in the cost of production?

As indicated in Table 2, both coal-fired plants and natural gas-fired plants generate CO_2 emissions while producing electricity. However, coal-fired plants emit almost twice as much CO_2 emissions as natural gas in order to produce the same amount of electricity. The following table compares the variable cost structure of coal and natural gas, assuming an estimated CO_2 emissions allowance cost of $25 per ton:

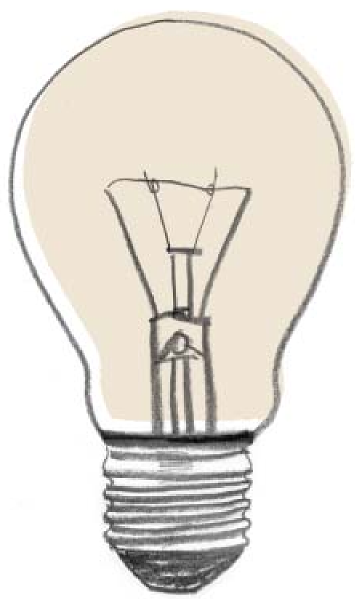
Table 5: Variable production costs, including CO2 ($/MWh)

	Coal*	Combined cycle gas turbine (CCGT)	Simple cycle gas turbine (GT)
Fuel costs			
Commodity			
$/ton	$60.00	NM***	NM
$/mmbtu	1.40	4.00	4.00
Transport			
$/ton	12.00		
$/mmbtu	0.50	0.50	0.50
Total fuel cost ($/mmbtu)	1.90	4.50	4.50
Heat rate (mmbtu/MWh)	10.00	7.00	10.00
Total fuel cost ($/MWh)	19.00	31.50	45.00
Emission allowance costs**			
NOx and SO_2	4.00	NM	NM
CO_2			
Allowance price ($/ton)	25.00	25.00	25.00
Emissions (lbs/MWh)	2,050.00	819.00	1,170.00
	26.00	**10.00**	**15.00**
Variable operating and maintenance costs	5.00	2.50	3.00
Total variable costs	**$54.00**	**$44.00**	**$63.00**

* Marginal Appalachia coal-fired facility with no emissions control equipment
** Pricing NOx @ $1,000/ton, pricing SO_2 @ $250/ton, and assuming coal has 3% sulfur content
*** Not meaningful
Sources: EIA/DOE; Tudor, Pickering, Holt & Co.

When the cost of CO_2 emissions are included in the variable cost structure, combined cycle natural gas-fired plants have a lower variable cost than coal-fired plants, as reflected in Table 5. In a world where combined cycle natural gas-fired plants have a lower variable cost structure than coal-fired plants, natural gas could replace coal as the primary base load supply stack source. In theory, coal-fired plants would then be utilized as a secondary supply stack source to meet the daily short-term spikes in electricity demand. However, unlike natural gas-fired plants, coal-fired plants cannot be deployed on short notice, nor can they produce electricity within a few minutes. Significant capital investment would be required to retrofit coal-fired plants so that they could ramp up on short notice, and it is currently unclear whether such retrofits would make economic sense or would even be commercially feasible.

The assumption that combined cycle natural gas-fired plants have a lower variable cost structure than coal-fired plants is predicated upon natural gas prices of $4 per mmbtu and coal prices of $60 per ton. As the electricity supply stack shifts to using more natural gas, the corresponding increase in demand will result in higher natural gas prices. This could be partially offset by advances in technology, such as improvements in horizontal drilling techniques and exploration of unconventional shale plays that may enable natural gas supplies to meet higher demand levels.



Correspondingly, as the supply stack shifts to using less coal, decreased demand will result in lower coal prices. Over time, natural gas prices will increase and coal prices will decrease until the variable costs of electricity production using natural gas and coal reach equilibrium. Predicting the optimal supply stack mix of natural gas versus coal in electricity generation may be difficult for now, but it is already clear that the implementation of a CO_2 emissions charge will cause natural gas-fired electricity generation to displace a certain percentage of coal-fired electricity generation.

Preparing for carbon legislation

The passage of a market-based cap-and-trade policy in conjunction with CCS laws will ultimately improve the economics of gas-fired power plants relative to coal-fired power plants. In that context, IPPs should begin preparing themselves for the ramifications of carbon legislation. If possible, IPPs should shift their power plant portfolios toward natural gas-fired plants and away from coal-fired plants. Carbon legislation may also make capital investment in natural gas-fired plants more economical. However, IPPs will also face new complexities as a result of carbon legislation that must be considered when making decisions on whether to build new natural gas power plants. First, they must understand the price movements in natural gas that will result from increased demand. If natural gas prices were to rise considerably, coal-fired plants could still have a lower variable cost structure, even after factoring in the cost of CO_2 emissions. IPPs must also understand the effects of the expected cost of CO_2 emissions. As shown in Table 5, a combined cycle natural gas-fired plant has a lower variable cost structure than a coal-fired plant using an expected CO_2 price of $25 per ton. However, given lower price levels for CO_2, a coal-fired plant may have a lower variable cost structure than a natural gas-fired plant. Thus, the price of CO_2 will become a key variable affecting the overall economics of IPPs.

Given the importance of the price of CO_2, new financial derivatives may need to be developed to allow for the trading and hedging of CO_2 allowance and offset credits. This will create an opportunity for IPPs to develop risk management programs, which could be used both to reduce IPPs' susceptibility to fluctuations in CO_2 prices and to reduce their exposure to the risks of emitting more than the allowed amount of CO_2. IPPs that can perfect these risk management programs can create competitive advantages over their competitors.

IPPs can also start to implement controls and changes as they get ready for the passage of pending legislation. Beyond waiting to purchase allowances for emissions, IPPs have started installing emissions control equipment, which often bears a high price tag. From 2008 through 2011, Dynegy, Mirant, NRG and RRI will spend a combined $3.7 billion, or roughly 50% of their capital expenditures[9], to install pollution controls. However, given the pending carbon legislation this makes economic sense.

Over time, natural gas prices will increase and coal prices will decrease until the variable costs of electricity production using natural gas and coal reach equilibrium.

[9] Source: Tudor, Pickering, Holt & Co. *Electric Power Industry Primer April 2009*

Conclusion

Given the current political climate in the United States, it is hard to predict if the APA in its current form will be what is finally passed into law. Significant procedural hurdles remain: The Senate must pass a bill and then reconcile that bill with the one previously passed by the House of Representatives. What is certain is that IPPs can no longer put their responses on hold regarding the changes that are set to take place in the power-generation industry. Carbon legislation will improve the economics of natural gas-fired plants and make coal-fired plants less competitive. Carbon legislation may also result in capital investment in natural gas-fired plants becoming economical. In a post-carbon legislation world, the price of CO_2 will become an increasingly important variable for IPPs. Successful IPPs will work to develop markets for the trading and hedging of CO_2 allowances so that they can use risk management of CO_2 to their advantage. •

Carbon legislation will improve the economics of natural gas-fired plants and make coal-fired plants less competitive.

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