CHAPTER 6
ELECTRIC UTILITY SECTOR
CO_2 EMISSION REDUCTION STRATEGY

Key Findings

Figure 6

Utility Sector CO_2 Emission Projections Through 2010

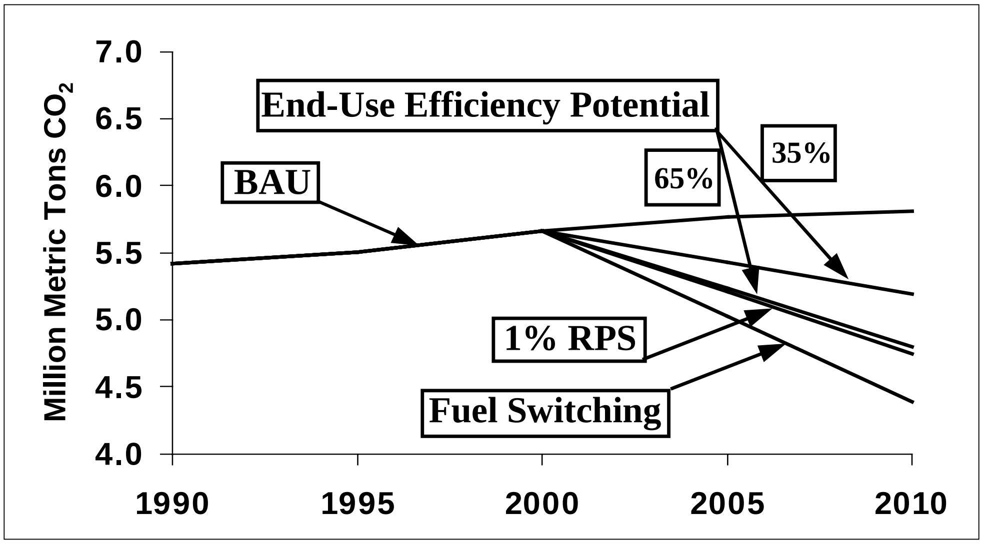

Table 6-1

Summary of Scenario Analyses to Reduce CO_2

in Delaware's Utility Sector

	Energy Use (trillion Btus)	**GHG emissions (mmtCO_2)**
1990	61.7	5.4
2010 BAU	85.0	5.8
Implementation Scenarios		
1% RPS	84.3	5.75
Fuel Switching	81.3	5.5
Avoided Electricity Losses – 35% / 65% Potential	78.5 / 72.9	5.2 / 4.8
Combined Implementation (with 65% End-Use Efficiency Potential)	68.6	4.4

Note: The summary data in Table 6-1 are sectoral emissions in 2010 resulting from the implementation of each measure and end-use scenario, whereas Figure 6-1 projections (shown above) indicate the cumulative emission reductions.

For the electric utility sector, three emission mitigation tools were analyzed: a 1% renewable portfolio standard (RPS), fuel switching, and the reduction of electricity losses associated with a 35% and 65% implementation of residential, commercial, and industrial electricity-related emission mitigation measures. Implementation of a 1% RPS scenario achieves a 1% reduction in forecasted 2010 emissions. Fuel switching of a coal-fired facility (due for repowering during the forecast period) results in a 6% reduction of emissions. Avoided electricity losses from energy efficiency actions in the end-use sectors (see Chapters 2-4) reduce emissions by 18% using the 65% (Major Commitment) scenario, and nearly 10% for the 35% (Modest Commitment) scenario. If all three mitigation tools are implemented together, the result will be a 19% reduction from the 2010 BAU (assuming a 65% implementation rate in the end-use sectors – see Figure 6-1 and Table 6-1).

Background

Improving the electricity sector's overall energy efficiency is essential for achieving Delaware's greenhouse gas emission reduction goal. Overall, the electric utility sector accounted for 46% of the state's total CO_2 emissions in 1995 (which substantially exceeded the national utility sector average of 35%). The sector represents the largest single source of CO_2 emissions in the State. Under the BAU scenario, Delaware's greenhouse gas emissions from this sector will increase by more than 7% to 5.8 mmtCO_2, between 1990 and 2010.

The electric utility sector in Delaware includes 30 generation units with a nameplate capacity of 2,287 MW. The bulk of electric generation and CO_2 emissions, however, is attributable to 11 generation units, 10 of which are owned and operated by Conectiv, the state's primary electric utility.

The electric utility industry is one of the largest consumers of fossil fuels in the U.S. (28% of national fossil fuel consumption and 88% of coal consumption) and collectively is the largest source of CO_2 emissions, accounting for 35% of total U.S.

emissions in 1996 (USEPA 1999). In 1996, U.S. CO_2 emissions from the utility sector totaled 516.8 mmtCO_2, an 8% increase over the 1990 total of 476.8 mmt. Electricity generation from coal is the primary source of national CO_2 emissions from the utility sector, and has been increasing (USEPA 1999). In 1996 coal was used to produce 57% of electricity nationally and coal-fired power plants accounted for 89% of utility sector CO_2 emissions. During 1990-1996, CO_2 emissions from coal-based generation increased 13%, accounting for 56% of the overall national increase in CO_2 emissions from fossil fuel combustion (USEPA 1999).

Reductions in electrical demand from other sectors – residential, industrial, and commercial – as a result of end-use efficiency improvements projected by the Action Plan, reduce the utility sector's energy consumption and therefore lower greenhouse gas emissions. Emission reductions in the other sectors result in a reduced demand for electricity generation and these savings are counted as reduced end-use demand in each sector. Since each kWh saved at a consumer site avoids the equivalent of 2 kWh of energy used to generate, transmit and distribute a kWh of electricity to consumers, the utility sector experiences 2-to-1 energy savings at its own facilities per customer-conserved kWh. These savings (known as "avoided electricity losses" because energy that would be consumed to generate and deliver a kWh of electricity is avoided) translate as avoided CO_2 emissions from power plants. Analysis of this sector takes into account the avoided CO_2 emissions by power plants associated with potential reductions in electricity demand within Delaware when forecasting future electricity use.

Nationally, electricity utilities are going through a period of restructuring in which both retail and wholesale transactions of the market are subject to generation deregulation. The Federal Energy Regulatory Commission has already established competition in wholesale electricity markets. Delaware and several of its neighboring states that are connected to the PJM Interconnection (the largest power pool in the U.S.) have all passed deregulation laws and are implementing retail competition initiatives. The PJM power pool has now become an independent system operator in anticipation of regional deregulation.

Sources and Trends of Utility Sector Emissions

Greenhouse gas emissions released by the electric utility sector are traceable to fossil fuel combustion in power plants, which accounts for the largest volume of fuel consumed among all sectors in Delaware. The main fuels consumed are bituminous coal, fuel oil (No. 6 and No. 2), and natural gas. In 1997, coal accounted for 63% of generation in the State, natural gas for 20% and fuel oil for 18%. The combustion of coal was the source of approximately 75% of the sector's CO_2 emissions. Combustion of fuel oil accounted for nearly 16% of sectoral CO_2 emissions, while natural gas combustion was responsible for only 10% of the sectoral total.

The fuel mix of the sector will shape future emission patterns. Delaware is part of a national trend to replace coal with natural gas as a combustion fuel for electrical generation. This trend has implications for greenhouse gas emission rates, other pollutant outputs, and the energy efficiency and cost-effectiveness of the sector.

Emission factors vary widely by fuel and plant. In 1997 Conectiv's average CO_2 emission rate for its system (this includes all plants throughout its three-state jurisdiction) was 0.89 $mtCO_2$ per MWh. The 1997 average emission factor fuel for coal was 1.06 $mtCO_2$ per MW hour, while the emission factor fuel oil was 0.77 $mtCO_2$ per MWh, and under 0.46 $mtCO_2$ per MWh for natural gas. By comparison, Conectiv reported to the USEPA in 1995 that CO_2 emission rates for its system varied between 0.96-0.84 $mtCO_2$ per MWh during 1990-1994.

This disparity is due to the differing emission factors of the various fuels, as well as the difference in the age and efficiency of Conectiv's installed generation capacity. The oldest generation unit in Delaware (Edgemoor #3) began operation in 1954, while the state's most recently built plant (Hay Road #1-4) brought its final unit on-line in 1993. Not surprisingly, the Hay Road facility is the state's most efficient and cleanest, with a heat rate of 8,230 Btu/kWh, and an estimated 1997 CO_2 emission factor of 0.315

short tons of CO_2 per MWh. Conversely, Edgemoor #3, with a heat rate of 10,550 Btu/kWh, and a 1997 emission rate of 1.43 short tons of CO_2 per MWh of generation, has the highest CO_2 emission rate in the state. However, Edgemoor #3 is approximately 0.3 cents per kWh cheaper to operate, [1] (due primarily to the price disparity between coal and natural gas) and is operated at a higher capacity factor than the Hay Road plants. Thus, the intersection of fuel and plant economics plays a key role in determining CO_2 emissions connected to the generation of electricity in Delaware.

Projections

Conectiv's 1995 and 1996 Integrated Resource Plans (IRP) predict the retirement of 262 MW of coal-fired generating capacity between 2009-2011, and the addition of 910 MW of natural gas-fired generating capacity between 2005-2011.[2] The BAU scenario assumes that all potential additional generation capacity installed between now and 2010 will consist of technologies utilizing natural gas.[3] Conectiv's installed capacity is assumed to reach 2,821 MW in 2010, comprising the following mix of fuel sources: 1,421 MW from natural gas, 759 MW from coal, and 641 MW from fuel oil.

Emission factors for coal and oil-fired plants are assumed to remain the same as present over the forecast period to 2010. Improvements in natural gas generation technologies are expected to lower emissions for natural gas-fired plants (assuming combined cycle operation) to 0.24 metric tons of CO_2 per MWh (California Energy Commission 1998).

---

[1] Of course, if the environmental costs of coal plants were included in the economic evaluation, a very different picture of operating costs would result. See, for example Hohmeyer (1992).

[2] Currently, Delaware imports approximately 20% of its electricity supply. Using the 1995 and 1996 IRPs as a guide to future utility decision making, it is expected that plants in the State will generate electricity at a level equal to the BAU forecast by 2010. Because of deregulation, this power may be marketed to other states and Delaware may receive power from plants in other states. USEPA guidelines for Action Plan development call for states to account for only the CO_2 released from in-state plants. Since Delaware will likely be neither a net exporter nor importer of electricity by 2010, this accounting guideline raises no problems for this analysis. However, if Delaware were to remain a net importer, it would be penalized by this procedure since it would not receive credit for avoided CO_2 from electricity losses that would be avoided by end-use efficiency improvements greater than the in-state generation rate.

[3] There are no plans by Delaware's municipal utilities or its electric cooperative to build new power plants in the State. For this reason, the analysis in the Action Plan focuses on the plants under the jurisdiction of the State's investor-owned utility.

Using Delaware's Econometric Model to build equations to forecast electricity consumption in the state, a BAU electricity demand of 13,185,000 MWh is expected by 2010. Given the anticipated installed capacity and plant utilization rates based on current practice, the majority of electricity generated is predicted to come from natural gas units (62%), followed by coal (33%), and fuel oil (6%). Under this 2010 projection, the utility sector is expected to emit 5.8 mmtCO_2 with a system-wide emission rate of 0.4 mt of CO_2/MWh.

Despite the forecasted increase in generation using natural gas, the majority source of sectoral CO_2 emissions will continue to be from coal combustion. Under the BAU scenario, coal-fired plants will provide 33% of total generation but cause 65% of the sector's CO_2 emissions. Natural gas combustion, while accounting for nearly two-thirds of generation, will only be responsible for 26% of CO_2 emissions. Fuel oil will account for 6% of the total generation and 9% of CO_2 emissions.

Methodology

A unit-by-unit analysis of all major electric generation units in Delaware was conducted. Data concerning annual generation, emissions, and marginal cost of generation were collected from the USEPA, EIA and Conectiv. Primary sources included: *Continuous Emission Monitoring Database* (USEPA 1999); *Electric Generator Data 1997* (EIA 1999a); *Inventory of Power Plants* (EIA 1999b); *1999 Fuel Use Forecast* (Conectiv 1998); *1996 Integrated Resource Plan* (Delmarva Power 1996); *Greenhouse Gas Emissions Reduction Strategies for California, Volume 1* (California Energy Commission 1998). Other background information utilized: *Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990-1996* (USEPA 1998), *Wisconsin Climate Change Action Plan* (Wisconsin Department of Natural Resources 1998).

Data from these sources were utilized to determine or calculate gross generation, emission factors, capacity factors and other pertinent operational data for each major generation unit in the State, using 1997 as the reference year. Recent historical data were consulted in order to assure that data from the reference year did not contain significant operational anomalies. The unit-specific data were then used to determine the operational and environmental characteristics of Delaware's generation portfolio, enabling the Action Plan to construct least-cost options for supply-side CO_2 mitigation. The unit-specific analysis focused on fuel switching and environmental dispatch options, which could be employed utilizing current generation capacity. The operational profile also allowed the Action Plan to generate a percent reduction in CO_2 emissions from the implementation of a renewable portfolio standard and the implementation of electricity efficiency measures within other sectors.

As a part of normal operating procedure, the electricity utilities in Delaware and the neighboring states of Pennsylvania, Maryland and New Jersey operate within an interconnected pool system that crosses state boundaries and dispatches units under complex rules and procedures. The PJM Interconnection determines the dispatch order for power plants operating in these states. At this time, no individual state can determine the dispatch order for plants within their borders. For this reason, the Action Plan reviews the possibility of an environmentally-based dispatch policy but did not include it as a CO_2 mitigation tool.

For the calculations regarding Delaware, CO_2 emissions regarding electrical generation in Delaware equal the projected emissions of plants expected to be operating within the State. This follows USEPA's guidelines.

<u>Analysis of Options</u>

Four GHG mitigation options were examined: avoided CO_2 emissions at power plants associated with a 35% and 65% implementation of end-use efficiency measures identified by the Action Plan for electricity-using equipment in the residential, commercial, and residential sectors (see Chapters 2-4 for details); fuel switching; and implementation of a renewable portfolio standard. An investigation of environmental dispatch operational procedures is also described. This could be a useful tool in the event that the projected development of natural gas-fired units does not fully materialize. This option does not figure into the Action Plan scenarios to reduce CO_2 emissions from this sector for the reason stated above.

End-use efficiency measures in other sectors involve a wide range of technologies that serve to reduce electricity demand (commonly referred to as 'load'). Reductions in electricity demand in the industrial, residential, and commercial sectors must be factored into the future demands on the electricity utility sector. Reduced load results in a reduction in power plant output and CO_2 emissions from the utility sector.

If 65% of the electricity savings identified in Chapter2-4 is realized, a load reduction of 3 million MWh is projected for 2010. The attendant CO_2 emission reductions due to avoided electric losses would total 1.1 mmtCO_2, given the projected utility sector fuel mix. Under a 35% implementation scenario for electricity efficiency, the reduced load falls to 1.6 million MWh and avoided CO_2 emissions are reduced to 0.6 mmtCO_2.

Changing the fuel used within an existing generating plant, which can be achieved by altering or replacing existing equipment, is known as 'fuel switching.' A generation unit was identified in a technical report by Conectiv (See its Integrated Resource Plan Report in 1996 under its prior corporate name of Delmarva Power) as a primary candidate for fuel switching because repowering from coal to natural gas would involve only relatively minor alterations. As a result, this unit was chosen as the least-cost option with which to investigate the fuel-switching scenario. According to the Action Plan analysis, switching the plant identified by Conectiv to natural gas would result in a CO_2 emission offset of 0.3 mmtCO_2 by the year 2010. This analysis applied 1997 generation data and emission factors, and assumed that fuel switching to natural gas would produce an emission factor of 0.5 short tons of CO_2 per MWh.

It is indicative of the scale of energy use within the electricity utility sector that switching one plant from coal to natural gas would result in a saving of 6% in the CO_2 emissions forecast for this sector under the BAU scenario for 2010.

The renewable portfolio standard (RPS) measure in the Action Plan assumes implementation, either through regulatory or legislative mandate, of a policy requiring that 1% of all electricity generated in Delaware must use renewable sources of energy. Technologies which could be utilized to meet this standard include: photovoltaics, solar thermal technologies, wind power, fuel cells utilizing hydrogen produced from renewable sources, or sustainable biomass. Implementation of the RPS would result in a 1% reduction in the sector's CO_2 emissions, totaling 0.06 mmtCO_2 based on the anticipated 2010 fuel mix.

Utilities and their power pools employ a process called 'least-cost dispatch' to determine which generation plants will run, and in what order, in response to prevailing system requirements. In effect, the allocation of electrical supply from the individual plants in a generating system is determined by a hierarchy whose order is determined by specific characteristics. This involves assessing system reliability to determine which plants must be available to meet loads, while maintaining the necessary voltage and frequency standards. Electricity is then dispatched from specific plants on a marginal cost basis to meet demand

An alternative approach is the environmental dispatch model. This approach incorporates the relative fuel efficiency and emission factor characteristics of various generation plants into the dispatch equation. Under an environmental dispatch scenario, plant dispatch would be determined primarily by system reliability requirements, followed by environmental performance, and then cost. The dispatch of plants would attempt to maximize environmental benefits in relation to additional marginal cost. Therefore, plants with equivalent environmental characteristics would be dispatched on a strictly marginal cost basis, while plants with marginally beneficial environmental characteristics and substantially higher generation costs would not move up in the dispatch hierarchy.

Environmental dispatch can offer substantial CO_2 offsets at low cost. An analysis for this Action Plan of an environmental dispatch scenario, utilizing individual plant data, determined that important CO_2 offsets could be achieved at low cost. The environmental dispatch scenario used the Hay Road natural gas plant and the Edgemoor #5 fuel oil/natural gas unit as baseload (65% capacity factor), rather than intermediate load plants (1997 capacity factor was utilized as a reference to determine available excess generation capacity). The shift in generation for these units was modeled for 1999, utilizing Conectiv's 1999 fuel use projection report to determine the marginal cost of CO_2 displacement. A preliminary analysis by CEEP suggested that a CO_2 emission offset of 0.95 mmtCO_2 could be achieved at modest cost. To implement this option, the PJM Interconnection, to which Conectiv belongs, would have to agree to the dispatch formula used in this analysis.

The results of this analysis are not included in the Action Plan at this time because the Action Plan can be achieved through measures that depend on State action only. However, the strategy is reported here for future consideration in the event that PJM or the federal government embraces environmental dispatch as a policy tool.

Results

Carbon dioxide emission reduction in the electric utility sector is derived in this Action Plan by combining a 1% renewable portfolio standard, fuel switching, and avoided power plant emissions associated with end-use efficiency improvements. A 65% implementation scenario (corresponding to the Major Commitment scenario discussed in Chapters 2-4) for end-use efficiency upgrades in the residential, commercial and industrial sectors achieves emission reductions of 1.1 mmtCO_2, given the projected utility sector fuel mix. For a 35% implementation scenario involving end-use electricity efficiency gains detailed in the Modest Commitment scenario (see Chapter 2-4), 0.6

$mmtCO_2$ are avoided at power plants. Fuel switching would result in a CO_2 emission offset of 0.3 $mmtCO_2$ by the year 2010. Implementation of a 1% RPS would result in a 1% reduction in the sector's CO_2 emissions, totaling 0.06 $mmtCO_2$ based on the anticipated 2010 fuel mix. Thus, 1.0-1.5 $mmtCO_2$ emissions can be avoided in the utility sector by following the Action Plan's recommended measures for this sector.

Conclusions

In 1990, the utility sector produced emissions of 5.4 $mmtCO_2$ and these are forecast to increase by 20% to 5.8 $mmtCO_2$ by 2010 under the BAU scenario. Under the Combined Implementation scenario (with implementation of 65% of end-use electricity efficiency upgrades identified by DCCAP), emissions are reduced to 4.4 $mmtCO_2$, which is a 24% reduction from the forecast level for 2010. This is equivalent to a 19% reduction from the 1990 level for this sector.

Measures utilized in this sector would have notable synergistic benefits by substantially reducing the point source emissions of criteria pollutants such as SO_2, NO_x, and PM_{10} particulates within the State, in addition to lowering CO_2 emissions. Implementation of these measures would improve air quality within Delaware and aid the State in meeting its obligations under the Clean Air Act. At the same time, Delawareans would be benefited by a more competitive State economy using efficient, environmentally sound technology. In this respect, implementation of DCCAP's utility sector strategy may be justified on the "no regrets" criterion of providing net economic benefits, even without consideration of its CO_2 effects. Specific policy actions to support the adoption of the analyzed measures for CO_2 emission reduction in the sector are identified in Chapter 9.

References

California Energy Commission. (1998) *Greenhouse Gas Emissions Reduction Strategies for California*. Volume 1. January. Sacramento, CA: California Energy Commission.

Conectiv. (1998) *Generating Unit Operations Report, Annual for Year 1999*. Schedule RCE-2. Submitted to the Delaware Public Service Commission.

Delmarva Power (1996). *1996 Integrated Resource Plan.* Submitted to the Delaware Public Service Commission.

———. (1995) EIA Form 1605. Submitted as part of Delmarva Power and Light Climate Challenge Participation Accord to the U.S. Department of Energy.

Energy Information Administration (EIA). (1999a). *Electric Generator Data 1997*. Washington, DC: National Technical Information Service. Available on the Internet at: http://www.eia.doe.gov/cneaf/fuelelectric.html.

———. (1999b) *1997 Inventory of Power Plants.* Washington, DC: National Technical Information Service. Available on the Internet at: http://www.eia.doe.gov/ cneaf/electricity/ ipp/ipp_sum.html.

Hohmeyer, O. (1992). "The Social Costs of Electricity Generation: Wind and Photovoltaic vs. Fossil and Nuclear Energy." In Byrne, J. and D. Rich (eds.)., *Energy and Environmental: The Policy Challenge*. New Brunswick, NJ: Transaction Publishers. (pp 141-186).

Wisconsin Department of Natural Resources and The Wisconsin Climate Change Committee. (1998) *Wisconsin Climate Change Action Plan: Framework for Climate Change Action*.

U.S. Environmental Protection Agency (USEPA). (1999) *Continuous Emission Monitoring Database*. Washington, DC: National Technical Information Service. Available on the Internet at: http://www.epa.gov/ardpublc/ acidrain/edata.html

———. (USEPA). (1998) *Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990-1996.* Washington, DC: National Technical Information Service.