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NATIONAL COUNCIL FOR AIR AND STREAM IMPROVEMENT

ESTIMATED CO_2 EMISSIONS RESULTING FROM COMPLIANCE WITH U.S. FEDERAL ENVIRONMENTAL REGULATIONS IN THE FOREST PRODUCTS INDUSTRY

SPECIAL REPORT NO. 98-02

DECEMBER 1998

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PRESIDENT'S NOTE

The U.S. forest and paper industry has a number of studies under way intended to clarify the potential significance of greenhouse gas emission reduction targets proposed by the Kyoto Protocol of the United Nations Framework Convention on Climate Change. As part of the information being gathered by NCASI to understand the impact of meeting the proposed targets, an estimate of the annual carbon dioxide emissions resulting from compliance with existing, proposed, or otherwise expected U.S. federal environmental regulations has been developed. This information shows the extent to which meeting other environmental objectives conflicts with achieving reductions in greenhouse gas emissions.

This report describes the calculations of estimated energy use and resulting carbon dioxide emissions due to environmental controls currently or expected to be in operation at the industry's primary manufacturing facilities. An estimated 1.45 million metric tons of carbon are emitted annually as a result of compliance with existing environmental regulations, including effluent treatment and associated solid waste disposal activities, combustion source particulate controls, and kraft mill total reduced sulfur controls. Recently promulgated, proposed, and expected regulations are predicted to nearly double compliance-related emissions to 2.52 million metric tons of carbon annually. Cluster Rule effluent limits and emission standards account for about one-fifth of this total.

NCASI's estimate of the forest and paper industry's mid-1990s carbon emissions from all manufacturing activities is 30 million metric tons per year, which includes 10 million tons emitted by utility companies that generate the industry's purchased electrical power. Compliance with existing environmental regulations currently accounts for 4.9% of the industry's total emissions.

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December 1998

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ABSTRACT

An estimate of the total annual carbon dioxide (CO_2) emissions that result from compliance with current federal environmental regulations, and that would be expected to result from compliance with proposed and anticipated environmental rules, has been developed for the U.S. forest and paper industry. Energy use associated with existing and likely future emission control technologies was estimated for each regulation believed to result in significant energy consumption or savings. Control technologies were defined for each regulation, and the industry-wide electricity, steam, and fuel requirements were calculated. The calculations were based on information taken from industry databases, engineering calculations developed for typical mill installations, and the technical literature. The energy use values were then employed to estimate CO_2 emissions using industry-specific emission factors developed for purchased electricity, steam generated at mills, and fuel use.

The total carbon dioxide emissions resulting from compliance with the regulations identified in this report are estimated to be 2.52 million metric tons of carbon per year. Slightly more than one-half of this amount results from current effluent treatment and associated solid waste disposal activities, combustion source particulate controls, and kraft mill total reduced sulfur controls. Carbon dioxide emissions related to environmental compliance will almost double as the result of recently promulgated or expected regulations. About one-fifth of the total is carbon dioxide emissions expected to result from compliance with Cluster Rule effluent limits and emission standards. These amounts can be compared to the industry's mid-1990s carbon dioxide emissions of approximately 30 million metric tons of carbon equivalents, about two-thirds of which is emitted from the industry's manufacturing sites.

KEYWORDS

carbon emissions, environmental compliance, environmental controls, energy use, carbon dioxide, greenhouse gases, emissions factors, Cluster Rule

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ESTIMATED CO_2 EMISSIONS RESULTING FROM COMPLIANCE WITH U.S. FEDERAL ENVIRONMENTAL REGULATIONS IN THE FOREST PRODUCTS INDUSTRY

1.0 INTRODUCTION

Greenhouse gas emission reduction targets established by the Kyoto Protocol of the United Nations Framework Convention on Climate Change would, if ratified by the U.S. Senate, require that the U.S. reduce its emissions of greenhouse gases (primarily carbon dioxide) to 7% below 1990 levels.

Compliance with U.S. environmental regulations results in energy consumption to operate modified processes and pollution control equipment. In some instances, energy savings related to reduced process losses also occur. An estimate of the CO_2 emissions that result from environmental compliance was prepared to show the importance of balancing other environmental goals with the goal of meeting greenhouse gas emission reduction targets.

2.0 APPROACH

An estimate of the carbon dioxide emissions that result from energy consumed for controlling emissions to air and discharges to water from the forest and paper industry's primary manufacturing activities was developed. A list of existing, proposed, and expected environmental regulations was compiled, and each regulation was assessed for its potential to result in significant energy impacts. For those rules that were deemed to be significant, the existing or likely control technologies needed for compliance were identified, and an industry-wide estimate of the energy use associated with each control was developed. Energy use as electricity, steam, and fuel was calculated as appropriate for each technology. The calculations were based on information taken from industry databases, engineering calculations developed for typical mill installations, and the technical literature. An industry energy consultant, EKONO, Inc., was retained to develop many of the control technology energy use estimates. These estimates are included as Appendix A.

Energy use values were subsequently used to estimate CO_2 emissions, using emission factors developed specifically for the forest and paper industry for purchased electricity, steam generated at mills, and fuel use. Total CO_2 emissions are reported in metric tons of carbon per year, to allow direct comparison to other estimates of greenhouse gas emissions.

3.0 ENVIRONMENTAL REGULATIONS

The existing environmental regulations for which energy and carbon dioxide emissions were estimated include: (1) Clean Water Act provisions requiring control of biochemical oxygen demand (BOD) and suspended solids in the effluents discharged from all primary manufacturing facilities; (2) Clean Air Act provisions for controlling particulate matter (PM) from industry combustion sources and total reduced sulfur emissions from kraft mills; and (3) Cluster Rule effluent guidelines for bleached kraft and sulfite mills, Best Management Practices (BMPs), and Maximum Achievable Control Technology (MACT) standards for hazardous air pollutant (HAP) emissions from pulp and paper mill production sources (commonly known as MACT I).

The proposed or expected environmental regulations for which estimates were prepared include: (1) Cluster Rule hazardous air pollutants (HAP) standards for pulp and paper process combustion sources (commonly known as MACT II); (2) MACT emission standards for wood panel manufacturing plants; (3) the Industrial Combustion Coordinated Rulemaking (ICCR) standards for fine particulate air emissions; and (4) implementation of revised National Ambient Air Quality Standards for ozone. The regulations and their associated parameters and sources for which energy and carbon dioxide emissions were estimated are given in Table 1.

Table 1. Environmental Regulations and Associated Controls for Which CO_2 Emissions Were Estimated

Regulation	Parameters and Sources Controlled
Existing Water Rules	BOD and suspended solids from mill effluents
Existing Air Rules	particulate emissions from boilers, furnaces, lime kilns, and smelt dissolving tank vents; reduced sulfur compounds from kraft process vents
Cluster Rule Effluent Guidelines and Best Management Practices	chlorinated organic matter from kraft mill bleach plants; spent pulping liquor and liquor by-product losses from kraft mills
Cluster Rule Air Standards – MACT I	HAPs from kraft mill process vents and condensates
Cluster Rule Air Standards – MACT II	particulate HAPs from recovery furnaces, lime kilns, dissolving tank vents, and sulfite furnaces; particulate and gaseous organic HAPs from semi-chemical liquor combustion units
Wood Products MACT-based Air Standards	HAPs from medium density fiberboard (MDF), oriented strandboard (OSB), softwood veneer, fiberboard, and particleboard dryers, and MDF and OSB presses
Industrial Combustion Coordinated Rulemaking	fine particulate emissions from coal- and wood-fired boilers
Implementation of National Ambient Air Quality Standards for Ozone	oxides of nitrogen (NO_x) from all power boilers in the eastern U.S.; VOCs from black liquor oxidation vents in the eastern U.S.

Several other proposed or anticipated regulations were considered, but their impacts on CO_2 emissions are expected to be minimal because the associated energy use was deemed to be relatively low, or the anticipated controls were redundant to those associated with other regulations. A listing of expected rules with minimal CO_2 impacts can be found in Appendix B.

4.0 CALCULATION METHODS AND ASSUMPTIONS

Methods for calculating energy use varied depending on the availability of information. In some cases calculations were done by two or more methods to test the validity of the primary method and assumptions. A variety of information sources were used to calculate energy use, including NCASI databases of industry combustion sources, engineering calculations developed for typical mill installations, EPA documents, and other technical literature. The specific calculation methods and assumptions are described below. Detailed energy use calculations are included as Appendix C.

4.1 Existing Water Rules

Provisions in the Clean Water Act require mills to treat their waste waters to remove suspended solids and BOD prior to discharge to receiving streams. Estimates of electricity use for pumping wastewater and treatment plant residuals, primary clarification, secondary treatment aeration and mixing, and dewatering wastewater treatment residuals, as well as steam and fuel use for residuals dewatering and hauling to landfill (Weston 1977) were consolidated into five industry categories for which annual production statistics are available. These values were expressed on a per unit of production basis, and were multiplied by 1995 production figures (AF&PA 1997) to estimate total energy use by the industry for effluent treatment and disposal of residual solids.

A separate estimate of the electricity needed for secondary effluent treatment was calculated using average industry BOD loads, a widely accepted average power use factor for aeration (US EPA 1997), and total industry production. This second estimate of the power required for secondary treatment was within approximately 5% of the first estimate.

4.2 Existing Air Rules

Federal and state regulations imposed under the authority of the Clean Air Act require that all mills employ particulate matter (PM) controls on combustion source flue gases, and that kraft mills collect and incinerate concentrated sources of reduced sulfur compounds.

4.2.1 Particulate Matter Controls

Energy used to operate particulate control devices on recovery furnaces, lime kilns, smelt dissolving tanks, and power boilers was estimated. For each combustion source type (e.g., coal-fired boiler) the number of sources, the average capacity of those sources, and the numbers of each type of particulate control device were calculated from NCASI databases. Flue gas flow factors and scrubber and electrostatic precipitator (ESP) power use factors developed by EKONO for typical mill installations were applied to estimate the total energy use on an industry-wide basis. The few scrubbers used on furnaces were not included in the estimate. Energy requirements for the 197 wet scrubbers (US EPA 1998b) on smelt dissolving tanks were based on an estimate for a typical installation.

4.2.2 Total Reduced Sulfur Controls

An estimate of the steam required for ejectors to transport the low-volume, high-concentration (LVHC) non-condensable gases from their sources to their point of incineration was developed for a typical 1000-ton-per-day kraft mill. This value was scaled to an industry-wide estimate based on 1995 kraft pulp production. Incineration of the LVHC gases was assumed to require no additional fuel to support their combustion in kilns and boilers. Fuel used in stand-alone incinerators was estimated from a 1995 NCASI database.

Energy requirements for black liquor oxidation (BLO) units on direct contact recovery furnaces were also estimated for a typical 1000-ton-per-day kraft mill. The per-ton value was multiplied by the estimated total 1995 pulp production associated with direct contact recovery furnaces. The majority of the energy consumed is due to a reduction in heating value of the black liquor caused by partial oxidation of the liquor components, which reduces the amount of steam generated per mass of black liquor solids burned.

4.3 Cluster Rule Effluent Guidelines

4.3.1 ECF Bleaching

The recently promulgated Cluster Rule contains standards based on the performance of mills that bleach pulp using complete chlorine dioxide substitution (also known as elemental chlorine free or ECF bleaching). An estimate of the total amount of chlorine dioxide (ClO_2) associated with converting all U.S. bleached kraft mills to ECF bleaching was developed based on the following key assumptions:

- The "baseline" ClO_2 substitution levels are 15% for both softwood and hardwood bleaching. This level of substitution for chlorine is commonly used as a means to maximize pulp strength.
- Kappa numbers (lignin content) for softwood and hardwood pulps produced by conventional pulping processes are 30 and 20, respectively.
- Kappa numbers for softwood and hardwood pulps produced by extended and/or oxygen delignification processes are 17 and 12, respectively.
- Chlorine dioxide is applied at a kappa factor of 0.22 for softwoods and 0.18 for hardwoods.

Using these assumptions, 1995 production data, and cooking technology installation statistics generated by EPA (US EPA 1997), an estimated 425,000 additional short tons of chlorine dioxide per year will be required to move the entire U.S. bleached kraft sector from baseline to complete substitution levels. An independent estimate of the incremental chlorine dioxide consumption based on estimated industry chlorine use gave a value 21% greater than the primary estimate.

The incremental chlorine dioxide use value (425,000 short tons per year) was used to estimate the total energy consumed to manufacture the additional sodium chlorate (used as a feedstock at mills to generate chlorine dioxide) and the energy consumed to generate the additional chlorine dioxide at mills. A credit was taken for the amount of energy not used to manufacture the chlorine being replaced with chlorine dioxide. Values published by EPA (US EPA 1997) for energy use associated with chlorate and chlorine manufacturing were used in this analysis. It should be noted that the energy consumption and credit, while a direct result of achieving compliance with the Cluster Rule effluent guidelines, primarily occur "off-site" at chlorate and chlorine manufacturing plants.

4.3.2 Improved Washing and Best Management Practices

In addition to the change in bleaching chemicals, the Cluster Rule will also result in changes to pulp washing and spill control practices. Brown stock pulp washing improvements to achieve a washer loss of 10 kg saltcake or less per 1000 kg of pulp is a component of Best Available Technology (US EPA 1998a). Reductions in inadvertent black liquor losses through Best Management Practices (BMPs) are also part of the Cluster Rule (US EPA 1998a). Both of these control techniques would result in increased recovery of black liquor. This would result in reduced BOD loads to effluent treatment systems, increased steam generation from the recovered black liquor solids, and increased steam consumption to evaporate the water recovered with the liquor solids. A reduction in electricity for effluent treatment and a net increase in steam generated from improved washing and BMPs were calculated using average values for incremental evaporation load and solids recovery published by EPA (US EPA 1996a).

4.4 Cluster Rule MACT I

4.4.1 Collection and Incineration of HVLC gases

An estimate of the power required to collect and transport the high-volume, low-concentration (HVLC) kraft mill vent gases was developed for a typical 1000-ton-per-day kraft mill. Boiler energy balance calculations were made to determine the loss in steam generating efficiency in boilers in which these gases were assumed to be incinerated. The values were used to estimate annual energy use for the entire kraft sector based on 1995 production statistics.

4.4.2 Steam Stripping of Kraft Mill Condensates

Steam stripping of kraft mill condensates is one of the options to achieve compliance with the new MACT I HAP standards (US EPA 1998a). NCASI databases indicate that about one-third of kraft mills already have condensate strippers. The assumption was made that an additional one-third of mills will install this capability, and the other mills will opt for "hardpiping" of condensates directly to secondary treatment. Thus, about two-thirds of the total kraft production will ultimately incur energy impacts associated with steam stripping.

Electricity requirements for condensate pumping were developed by EKONO for a typical mill installation. Total steam requirements were estimated based on typical condensate flows, published values for steam use to achieve the required 92% efficiency (US EPA 1997), industry production statistics, and an assumption that 75% of the heat applied as steam would be recovered and used in the kraft process.

Stripping and incinerating the volatile organic compounds (primarily methanol) from the condensates reduces the BOD load to effluent treatment and reduces fossil fuel use where the stripper gases are incinerated in a lime kiln or power boiler. A credit was taken for reduced fuel use calculated from the total methanol expected to be recovered from both bleached and unbleached kraft mills, the heating value of methanol (9066 BTU/lb), and an estimation (from 1995 NCASI incinerator database) that 65% of kraft mills did not have stand-alone incinerators.

A factor of 1.08 kg of BOD per kilogram of methanol recovered (Barton et al. 1998) and a power application of 1.25 kWh/kg BOD (US EPA 1997) were used to estimate the reduction in electrical power required for effluent treatment due to steam stripping of condensates. No credit was taken for reduced generation of treatment plant residuals.

4.5 Cluster Rule MACT II

EPA has proposed standards on PM and gaseous organic HAP emissions from industry combustion sources, including kraft recovery furnaces, lime kilns, smelt dissolving tank vents, and sulfite and semi-chemical process liquor combustion units (US EPA 1998b). Kraft mill sources were assumed to require upgrades to existing PM controls, whereas sulfite and semi-chemical sources were assumed to require new control technologies, as specified in the proposed rule.

4.5.1 PM HAP Standards – Recovery Furnaces

EPA predicts that 52 of the 215 recovery furnaces will require additional particulate matter controls to meet proposed PM HAP standards (US EPA 1998b). It was assumed that the precipitators to be upgraded would require one-third more capacity, such that energy use would increase by 33% over the average energy requirements estimated for precipitators under existing air rules. This is a somewhat arbitrary number based on the assumption that an additional precipitator section would be added of the same size as three existing sections in order to simplify ducting modifications.

4.5.2 PM HAP Standards – Lime Kilns

EPA predicts that 60% of the lime kilns can now meet the proposed PM HAP standard (US EPA 1998b). Since the control technology upon which the standard is based is an ESP or high efficiency scrubber, it was assumed that 40% of the lime kiln scrubbers would require an upgrade to a high-efficiency device, a 20 psi pressure drop venturi scrubber. The energy consumption this represents was calculated from the energy use factors used to estimate the requirements under existing air rules, and an assumption that energy requirements are linearly proportional to the drop in pressure across the devices. Non-venturi scrubbers were assumed to be 2 psi devices, and the existing venturi units that would require upgrades were assumed to be 10 psi devices.

4.5.3 PM HAP Standards – Smelt Dissolving Tanks

EPA predicts that 75% of smelt dissolving tank vents can now meet the proposed standard for PM HAP (US EPA 1998b). The remaining 56 vents would require either that an existing demister unit be replaced with a wet scrubber or that a low efficiency scrubber be upgraded. Energy use was estimated for a typical (10 psi system pressure drop) installation using assumed exhaust fan and scrubbing liquid pump sizes, then multiplied by the number of affected units.

4.5.4 PM HAP Standards – Sulfite Liquor Combustion Units

To meet the proposed PM HAP standard, the proposed MACT floor for sulfite liquor combustion units is a fiber bed demister (US EPA 1998b). The proposed rule indicates that 13 of the 21 sulfite units already have this technology installed, and the other eight have some type of wet scrubber. It was assumed that conversion of these eight units to fiber bed demisters would result in no additional energy consumption.

4.5.5 PM and Gaseous Organic HAP Standards – Semi-chemical Liquor Combustion Units

Seven of the 14 units at stand-alone semi-chemical pulp mills are predicted to require upgrading to the proposed "beyond the floor" MACT, which is a wet ESP followed by a regenerative thermal oxidizer, or RTO (US EPA 1998b). Values for electricity use were taken from the literature for the wet ESP (Wark and Warner 1976) and from 1995 NCASI data compiled for RTOs deployed at oriented strandboard (OSB) facilities. Each of the seven units was assumed to have a flue gas flow rate of 100,000 actual cubic feet per minute (acfm). It was also assumed that auxiliary fuel would not be required to sustain oxidation in these units.

4.6 Wood Products Facilities MACT

It was assumed that most panel manufacturing plants would be required to install RTOs on their press and dryer exhaust gas streams to comply with expected gaseous organic HAP emissions standards. Factors for flue gas flow rates were calculated from measurements made by NCASI at many particleboard, medium density fiberboard (MDF) (NCASI 1995a), OSB, softwood plywood (NCASI 1995b), and fiberboard plants. For RTO systems used to control organic vapors, average natural gas use and purchased electricity (for exhaust fans) factors were developed based on actual energy use for RTOs in OSB plants. It was assumed that these energy use factors would be representative of RTOs on other types of panel plants. Industry-wide natural gas and electricity use values were calculated using the estimated flue gas flows, energy factors, and 1997 production figures (AFA 1997, APA 1997, CPA 1997).

4.7 Industrial Combustion Coordinated Rulemaking

This yet-to-be-proposed regulation is expected to require high-efficiency particulate control devices on all industry coal- and wood-fired power boilers. Average energy use calculations for venturi scrubbers and ESPs described in Section 4.2.1 were used as the basis for estimating the incremental power requirements for upgraded particulate control devices. For the potentially affected power boilers, all venturi scrubbers were assumed to already be high-efficiency (20 psi) units. Other wet scrubbers were assumed to be 2 psi devices requiring upgrading to 20 psi venturis. Energy use was assumed to be linearly proportional to pressure drop. All precipitators on potentially affected boilers were assumed to require one-third more capacity.

4.8 Implementation of National Ambient Air Quality Standards for Ozone

Implementation of the revised 1997 NAAQS for ozone (US EPA 1996b) will likely require advanced controls on many sources of oxides of nitrogen (NO_x) and VOCs, which are ground-level ozone precursors, in nonattainment areas. Energy use was estimated for collecting and incinerating all vent gases from atmospheric black liquor oxidation units located in the eastern U.S. Other sources of VOCs were assumed to be controlled to the degree feasible by the various MACT and other applicable standards. Energy impacts associated with transporting the vent gases and incinerating them in a boiler were estimated for a typical mill installation. These values were used to calculate an industry-wide total using 1995 production values for the affected facilities.

Energy use was also estimated for NO_x controls on all power boilers in the eastern U.S. Selective catalytic reduction (SCR) was assumed to be the required NO_x control technology. Energy use associated with NO_x control was estimated in two parts because it is uncertain how many sources will be affected by the proposed rule. One part includes only coal- and residual oil-fired power boilers larger than 250 million BTU per hour, the sources most likely to be affected. The second part provides an estimate for installing SCR technology on all other power boilers. Both parts are included in calculating the total energy and carbon dioxide emissions predicted as a result of this rule.

4.9 CO_2 Emission Factors

Carbon dioxide emissions were calculated using the energy use estimates for each regulation and the CO_2 emission factors listed in Table 2. The factors represent average or representative carbon dioxide emissions associated with an amount of energy consumed. For steam, an industry-specific emission factor was derived using estimated 1995 fossil fuel use data (AF&PA 1997), fuel-specific CO_2 emission factors (US DOE 1997), and typical fuel-to-steam boiler efficiencies. Biomass fuels (black liquor and wood waste) were not included in calculating the emission factor for steam. All the energy used for environmental controls is assumed to be supplied from sources "at the margin," which for steam are power boilers burning fossil fuels.

Similarly, the marginal source of electricity is assumed to be power purchased "from the grid." The emission factor for electricity used in this assessment is a national average value specific to the U.S. forest and paper industry. It represents an average of state CO_2 emissions factors for purchased electrical power weighted by the amount of industry production in each state. The state CO_2 factors were developed by the Department of Energy (DOE), and take into consideration the mix of fuels and methods (i.e., hydroelectric, coal-fired power boilers, etc.) used in each state to generate the electricity available on the grid (US DOE 1994).

The CO_2 emission factors for natural gas, coal, and oil used in this analysis are those published by DOE (US DOE 1997). The factors for coal and residual oil were used only in deriving the industry-specific emission factor for steam use. Diesel fuel was assumed to have the same emission factor as distillate oil.

Table 2. CO_2 Emission Factors

Energy Form	CO_2 as Equivalent Metric Tons Carbon	Basis
Electricity (purchased)	140.5	per 10^9 Wh generated
Steam (from fossil fuels)	23.70	per 10^9 BTU in steam
Natural Gas	14.47	per 10^9 BTU in fuel
Diesel	19.95	per 10^9 BTU in fuel
Coal	25.63	per 10^9 BTU in fuel
Residual Oil	21.49	per 10^9 BTU in fuel

5.0 RESULTS OF ENERGY USE CALCULATIONS

Estimates of electricity, steam, and fuel use for each regulation and associated controls covered by this assessment are listed in Table 3. Details of the calculations are given in Appendix C. Totals for each category can be found at the bottom of the table. The regulations resulting in the largest amounts of electricity consumed are the existing water and air rules and the Cluster Rule effluent guidelines. The existing air and MACT I rules result in the greatest amounts of steam use, and the expected wood products MACT rule fuel use estimate represents 96% of total fuel use.

Table 3. Estimated Energy Use Associated with Environmental Controls

Regulations and Controls	Energy Used for	Electricity 10^9 Wh/yr	Steam 10^9 BTU/yr	Fuel 10^9 BTU/yr
Existing Water Rules				
primary & secondary	pumping & residuals handling	4,289		
effluent treatment and	residuals dewatering		4,012	
solids disposal	residuals hauling			131
Existing Air Rules				
electrostatic precipitators	electrode charging	1,090		
wet scrubbers	fans & pumps	1,319		
concentrated TRS collection & incineration	steam ejectors		2,808	
	supplemental fuel			573
black liquor oxidation	blowers & pumps	266		
	liquor heating value loss		12,539	
Cluster Rule Effluent Guidelines				
ECF bleaching	incremental chlorate[a]	4,249		
	chlorine elimination[a, b]	(1,931)		
	ClO_2 generator pumps	77		
	ClO_2 generator ejectors & chillers		5,098	
improved pulp washing, BMPs	reduced secondary aeration	(296)		
	steam from recovered liquor		(6,913)	
	steam to evaporate water		799	
Cluster Rule – MACT I				
dilute HAP source incineration	HVLC transport fans	91		
	incineration in boilers		1,680	
foul condensate stripping	steam for stripping		7,733	
	condensate pumping	149		
	reduced secondary aeration	(222)		
	fuel value of methanol			(2,142)
Cluster Rule – MACT II				
upgrade kiln & vent scrubbers	fans & pumps	157		
upgrade furnace ESPs	electrode charging	50		
install wet ESP+RTO on semi-chem liquor combustion units	fans, ESP charging	33		

(Continued on next page. See notes at end of table.)

Table 3. (continued)

Regulations and Controls	Energy Used for	Electricity 10^9 Wh/yr	Steam 10^9 BTU/yr	Fuel 10^9 BTU/yr
Wood Products MACT Standards				
regenerative thermal oxidizers	thermal oxidation			15,409
	exhaust fans	751		
Industrial Combustion Coordinated Rulemaking				
high efficiency scrubbers	fans & pumps	464		
high efficiency ESPs	electrode charging	146		
NAAQS Implementation – Ozone				
collect & incinerate black liquor oxidation vent gases	cooling tower fans & pumps	30		
	transport fans		6	
	boiler efficiency reduction			188
install SCR units[c]				
coal & oil-fired boilers >250M lb/hr	fans	125		
	catalytic reactor sootblowing		303	
all other boilers	fans	670		
	catalytic reactor sootblowing		1,136	
TOTAL ENERGY USE		11,513	29,383	13,971

[a] This energy impact occurs “off-site” but is included to show the full impact of this regulation.

[b] Chlorine credit is likely overstated because chlor-alkali plants also supply mills with caustic, for which demand will not be reduced equivalently to chlorine.

[c] Assumes PM controls are adequate to prevent fouling of SCR units: coal- and wood-fired boilers upgraded under ICCR, no PM controls needed for oil- and gas-fired units.

6.0 RESULTS OF CO_2 EMISSIONS CALCULATIONS

Each energy use estimate listed in Table 3 was multiplied by the appropriate emission factor to determine the resulting CO_2 emissions expressed in metric tons of carbon per year. Table 4 summarizes CO_2 emissions associated with each regulation, total CO_2 emissions, and the percentage contributed by each regulation.

Table 4. Estimated Carbon Dioxide Emissions
Resulting from U.S. Federal Environmental Regulations

Regulation	Carbon Dioxide Emissions: Metric Tons Carbon/Yr	Carbon Dioxide Emissions: % of Total
Existing Water Rules	700,000	27.8
Existing Air Rules	748,000	29.7
Cluster Rule Effluent Guidelines & BMPs	271,000	10.8
Cluster Rule Air Standards – MACT I	195,000	7.7
Cluster Rule Air Standards – MACT II	34,000	1.4
Wood Products MACT-based Air Standards	328,000	13.0
Industrial Combustion Coordinated Rulemaking	86,000	3.4
Implementation of National Ambient Air Quality Standards for Ozone	156,000	6.2
TOTAL EMISSIONS	2,518,000	100

7.0 CONCLUSIONS

An estimate of the total carbon dioxide emissions resulting from the operation of environmental controls in the forest and paper industry was developed. Industry-wide energy use was estimated for each control used to comply with existing and proposed or expected regulations that were deemed to have significant energy impacts. Industry-specific emission factors were used to translate the energy use estimates to carbon dioxide emissions.

Total CO_2 emissions for the industry to comply with current and expected environmental regulations are estimated to be 2.5 million metric tons of carbon per year. Emissions due to the existing air and water regulations represent approximately 58% of this total. Cluster Rule effluent and air standards comprise another 20%, and the balance is primarily attributable to the proposed air standards for the wood products sector of the industry.

The forest and paper industry's CO_2 emissions attributable to compliance with U.S. federal environmental regulations are expected to approximately double as a result of the Cluster Rule and other regulations recently promulgated or expected to be promulgated in the near future. This increase will occur during a period when it would impact the ability of the industry to meet Kyoto Protocol targets.

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APPENDIX A

ENERGY USE ESTIMATES FOR ENVIRONMENTAL CONTROLS

A. ENERGY IMPACTS FROM EXISTING WATER RULES

Biological effluent treatment is already in place in practically all pulp and paper mills. Effluent treatment plants in pulp and paper mills typically require between 30 and 70 kWh/t product of electrical power. A small amount of steam is sometimes also used; for example, for sludge dewatering and pressing.

Table A1 summarizes the estimated energy use by effluent treatment systems in different mill categories. The breakdown of the energy use is based on the results of reference [1].

Table A1. Energy Requirements for Effluent Treatment

	Electrical Power, kWh/T product					Fuel, 10^6 Btu/T product	
	Pumping	Primary Treatment	Biological Treatment	Sludge Dewatering	Total	Heating, Dewatering	Sludge Trucking to Landfill (5 miles)
Bleached kraft	12	4	31	6	53	0.07	0.002
Linerboard	9	2	17	1	29	0.05	0.001
Newsprint – TMP	6	2	28	4	40	0.05	0.001
Fine papers							
integrated	15	4	32	6	57	0.07	0.002
non-integrated	5	2	32	2	41	0.05	0.001
SBS	12	4	31	6	53	0.07	0.002
Deinked tissue paper mill	15	11	85	3	114	0.1	0.003
Recycled board	9	6	23	1	39	0.05	0.001
LWC							
integrated	15	4	32	6	57	0.07	0.002
non-integrated	5	2	32	2	41	0.05	0.001
NSSC	5	4	29	1	39	0.07	0.001

B. ENERGY IMPACTS OF EXISTING AIR RULES

The existing air rules require control of particulate and TRS emissions. Air pollution control measures typically installed in pulp and paper mills include:

- electrostatic precipitators for flue gases
- scrubbers for flue gases and vent gases

- gas collection and incineration (NCG)
- black liquor oxidation systems for TRS control

Particulate Control

Table A2 illustrates the estimated power consumption by two common particulate control devices, a venturi scrubber and an electrostatic precipitator (ESP). The impact of three different size categories is shown for each device.

Table A2. Energy Use Impacts of Particulate Control Devices

Device: Size Category:	Unit	Venturi small	Venturi medium	Venturi large	ESP small	ESP medium	ESP large
Flue gas flow	1000 scf/min	27	54	107	134	267	401
Particulate control unit							
Flue gas temp.	°F	400	400	400	400	400	400
Flue gas flow	1000 acf/min	50	100	150	250	500	750
Impact on electrical energy							
dP over unit	psi	20.0	20.0	20.0			
Power cons., incl. circ. pumps	kWh/ 1000 acfm	8.5	7	6	1.4	1.3	1.2
	kWh/h	426	701	900	350	649	901

Typical flue gas flow rates for recovery furnaces, coal-fired boilers, and wood-fired boilers were developed from boiler heat balances. The values are given in Table A3. This information can be used to estimate the total flue gas flow rates so that total energy requirements can be estimated.

Table A3. Typical Flue Gas Flow Rates

Boiler Type	Flue gas temperature, °F	Flue gas flow (wet), acfm/lb steam/hr
Power boiler, coal-fired	400	0.50
Power boiler, wood-fired	400	0.92
Recovery furnace, DCE	400	0.84
Recovery furnace, NDCE (68% BLS)	400	0.60

Low-Volume High-Concentration (LVHC) Gases

LVHC gases normally originate from:

- batch digester blow heat recovery
- turpentine recovery

- continuous digester flash condensers
- evaporator hot wells

The blow tank vent from a continuous digester could be tied either to the LVHC or the high-volume low-concentration (HVLC) system.

In general, the LVHC gases contain enough energy that no major amount of support fuel is required. The main energy usage for the LVHC gases is the steam used in the ejectors that are normally used for transportation of the gases. The steam amount for a 1000 ADT/d kraft mill is typically 1500 to 2000 lb/h of 150 psig steam. Because no condensates are returned, the energy use is about 1.8 to 2.5 MBtu/h.

Black Liquor Oxidation

Black liquor oxidation is practiced in kraft mills that operate direct contact evaporators (DCE). Black liquor oxidation has a significant impact on kraft mill energy balances.

Power Consumption in Oxidation

The majority of the black liquor oxidation systems are operated by air blowers. Typical power consumption by the blowers and pumping system for strong black liquor oxidation is 0.4 to 0.8 kW/T of pulp per day [2]. This corresponds to 10 to 20 kWh/T of pulp.

Change in the Heating Value of Black Liquor Dry Solids

The heating value of black liquor solids will be reduced in the oxidation process for the following reasons:

- The inorganic reactions (conversion of sodium sulfide to thiosulfate and caustic) are exothermic reactions. The heat from the exothermic reactions is released in the oxidation process rather than in the boiler furnace.
- Some organic material is also oxidized in the oxidation process
- The oxidation reactions consume oxygen and some water. The amount of dry solids of the black liquor increases slightly due to the reactions. Accordingly, the heating value for a unit of dry solids is further reduced because of the increased dry substance amount.

The summary equation for the black liquor oxidation reaction (inorganic compounds only) can be written as [3]:

$$2\ Na_2S + 2\ O_2 + H_2O \rightarrow Na_2S_2O_3 + 2\ NaOH + 215\ \text{cal/g-mole}$$

In British units this would be:

$$2\ Na_2S + 2\ O_2 + H_2O \rightarrow Na_2S_2O_3 + 2\ NaOH + 387\ \text{kBtu/lb-mole}$$

It can be derived from the equation that each pound of sodium sulfide reacted will cause an increase of about 0.5 lb in the inorganic solids content of the black liquor. The Na_2S content of black liquor at

50% dry solids content is typically 2.5 lb/ft^3, and the liquor amount is 80 ft^3/ADT of pulp. The amount of sodium sulfide is thus about 200 lb/ADT. Accordingly, the increase of inorganic dry substance is 100 lb/ADT.

Based on the equation above and the amount of Na_2S in the liquor, heat released in the inorganic reaction is:

$$(200\ \text{lb/ADT})/(2 \times 78\ \text{lb/lb-mole}) \times (387\ \text{kBtu/lb-mole}) = 496\ \text{kBtu/ADT}$$

In order to be able to calculate the change in the heating value caused by the oxidation reaction, the following assumptions are made:

- dry solids amount before oxidation 3250 lb/ADT
- heating value before oxidation 6200 Btu/lb d.s.

The heating value after oxidation (taking into account only inorganic reactions) would be:

$$\frac{(6{,}200 \times 3{,}250 - 496{,}000)\ \text{Btu / ADT}}{(3{,}250 + 100)\ \text{lb d.s./ADT}} = 5{,}867\ \text{Btu / lb d.s.}$$

The reduction in the heating value due to the inorganic reactions is thus about 333 Btu/lb d.s. In practice, some organic material is oxidized as well. Typically, the actual reduction in the heating value is 20 to 30% higher than theoretical [4]. Thus, in the sample above, the actual drop in heating value would be 400 Btu/lb d.s. of original dry solids. Taking into account the increase in the dry solids because of oxidation of organic material, the actual heating value would be approximately 5800 Btu/lb and the dry solids amount would be 3370 lb/ADT.

Tables A3 and A4 show the recovery boiler energy balances for systems with and without black liquor oxidation, respectively. It has been assumed that the liquor dry solids concentration increases in the oxidation from 50% to 51.5% (typically 1 to 2% [4]) partly because of increased solids per ton of product, and partly because of evaporation that occurs in the oxidation process. The liquor temperature has been assumed to decrease by 20°F in the oxidation process (from 190 to 170°F). The kraft mill production has been assumed to be 1000 ADT/d, and dry solids before oxidation to be 3250 lb/ADT. As shown, the net steam available for processes decreases from 399.8 klb/h to 376.4 klb/h because of oxidation. This corresponds to 0.68 MBtu/ADT reduction in the steam generation from black liquor.

Table A3. Energy Balance for Recovery Boiler with DC Evaporator with Black Liquor Oxidation

Item	Btu/lb BLS	%
Heat Input		
heating value of BLS	5,800	92.2%
sensible heat in BL	200	3.2%
sensible heat in air	4	0.1%
heat to preheat air	239	3.8%
heat in sootblowing	31	0.5%
heat in blowdown	17	0.3%
Total Heat Input	6,290	100.0%
Heat Output		
dry flue gas loss	339	5.4%
loss from H_2 in BLS	379	6.0%
loss from H_2O in BL	1,071	17.0%
sensible heat in smelt	259	4.1%
heat to form sulfide	430	6.8%
sootblowing loss	227	3.6%
blowdown loss	52	0.8%
radiation loss	19	0.3%
unaccounted losses	189	3.0%
Total of Losses	2,965	47.1%
heat to steam	3,325	52.9%
Total Heat Output	6,290	100.0%

Assumptions and Factors		
dry solids to boiler	3.37	Mlb/d
excess air	20.00	%
flue gas temperature after DCE	360	°F
black liquor dry solids to boilers	3370.0	lb/ADT
pulp production	1000.0	ADT/d
black liquor to boiler	272.7	klb/hour
total steam generation excluding sootblowing	385.9	klb/hour

(Continued on next page.)

Table A3. Continued

Item		
steam to BL heating	9.5	klb/hour
steam to sootblowing	28.1	klb/hour
black liquor dry solids	51.5	%
flue gas temperature at boundary	360	°F
excess air at FD fan	15	%
heating value of BL dry solids	5800	Btu/lb
oxygen content of flue gases	3.54	%
net steam after sootblowing and liquor heating	376.4	klb/hour

Table A4. Energy Balances for Recovery Boiler with DC Evaporator Without Black Liquor Oxidation

Item	Btu/lb BLS	%
Heat Input		
heating value of BLS	6,200	92.4%
sensible heat in BL	206	3.1%
sensible heat in air	4	0.1%
heat to preheat air	248	3.7%
heat in sootblowing	31	0.5%
heat in blowdown	17	0.3%
Total Heat Input	6,706	100.0%
Heat Output		
dry flue gas loss	351	5.2%
loss from H_2 in BLS	379	5.6%
loss from H_2O in BL	1,137	17.0%
sensible heat in smelt	265	4.0%
heat to form sulfide	440	6.6%
sootblowing loss	227	3.4%
blowdown loss	52	0.8%
radiation loss	20	0.3%
unaccounted losses	201	3.0%
Total of Losses	3,074	45.8%
heat to steam	3,632	54.2%
Total Heat Output	6,706	100.0%

(Continued on next page.)

Table A4. Continued

Item		
Assumptions and Factors		
dry solids to boiler	3.25	Mlb/d
excess air	20.00	%
flue gas temperature after DCE	360	°F
black liquor dry solids to boilers	3250.0	lb/ADT
pulp production	1000.0	ADT/d
black liquor to boiler	270.8	klb/hour
total steam generation excluding sootblowing	406.5	klb/hour
steam to BL heating	6.8	klb/hour
steam to sootblowing	27.1	klb/hour
black liquor dry solids	50	%
flue gas temperature at boundary	360	°F
excess air at FD fan	15	%
heating value of BL dry solids	6200	Btu/lb
oxygen content of flue gases	3.55	%
net steam after sootblowing and liquor heating	399.8	klb/hour

C. ENERGY IMPACTS FROM MACT I REQUIREMENTS

The major changes resulting from the MACT I requirements are:

- treatment of foul condensates
- increased collection and incineration of low-volume high-concentration (LVHC) NCGs

Foul Condensate Treatment

EPA proposes several methods for treatment of foul condensates, including steam stripping and biological treatment. Steam stripping is generally considered to be energy intensive. By integrating the stripping system with other steam usage in the mill, the energy requirements can be substantially reduced.

To meet EPA's requirement for destruction of methanol in the foul condensates, a typical 1000 T/d kraft mill would have to treat 300 to 500 gpm of foul condensate (1.6 to 3 m^3/ADT of pulp). In a completely unintegrated system the steam demand for stripping would be 0.74 to 1.2 MBtu/ADT. However, by completely integrating the steam stripping, for example, between stages in the evaporation plant, the heat consumption would be only 0.1 to 0.2 MBtu/ADT.

By incinerating the recovered methanol in a unit equipped with heat recovery, the heat consumption of an integrated stripping system could be offset.

Collection and Incineration of HVLC gases

The sources for HVLC gases in a kraft mill are typically:

- chip bin (continuous digester)
- blow tank (continuous digester)
- knotter and knot tank vents
- foam tank vent
- washer filtrate tank vents
- washer hoods
- black liquor tanks

In some mills the black liquor oxidation system vent may also be tied to the HVLC system.

The volumetric flows of HVLC gases vary widely depending on the process equipment. The amount of HVLC gases from the brown stock washers, especially, can vary from practically zero to 30,000 to 40,000 Sft^3/min for one washer. With a reasonably tight hood construction on a vacuum washer, the gas volume can be brought to about 5000 Sft^3/min for a washer in a 1000 ADT/d kraft mill. The other sources can typically be limited to less than 5000 Sft^3/min in a 1000 ADT/d mill.

The main energy usage in the HVLC system is the power consumed for the transportation of the gases and the somewhat reduced boiler efficiency if the gases are incinerated in a power boiler or a recovery boiler. The following estimates assume that the HVLC gases are incinerated in a power boiler.

For the illustration of energy use, the following is assumed:

• pulp production washing	1,000 ADT/d
• four vacuum washers for brown stock	
• HVLC gas flow	25,000 Aft^3/min
• HVLC gas temperature	140°F
• pressure drop in the transportation system	15 in H_2O
• moisture content of the HVLC gases	0.04 lb H_2O/lb d.s.
• HVLC gases incinerated in power boiler	

The power consumption of the transportation fan is:

$$\frac{0.000157 \times (15 \text{ in } H_2 0) \times (25{,}000 \text{ A ft}^3 \text{ / min})}{0.65} = 90.6 \text{ HP or } 68.8 \text{ kW}$$

The boiler that incinerates the HVLC gases will experience a slight change in the efficiency, because:

- a somewhat higher amount of combustion air is required on average, because all HVLC gases have to be incinerated in all conditions
- the moisture content of the combustion air increases
- heat brought to the boiler with combustion air is somewhat increased because of the higher temperature and higher moisture content of the HVLC gases

For illustration, the following is assumed or calculated:

- oil-fired boiler, steam production 100,000 lb/h
- boiler combustion air requirement about 25,000 Sft^3/min (i.e., nearly all air is coming from HVLC)
- excess air without HVLC gases is 20% (flue gas O_2 content 3.3%)
- excess air with vent gases increases to 30% (flue gas O_2 content 4.5%)
- temperature of combustion air is 100°F and moisture content is 0.006 lb/lb of dry air
- HVLC gas humidity is 30% at 140°F

Almost all combustion air to the boiler comes from HVLC gases in the sample. It has also been assumed that the flue gas temperature is increased by 20°F to compensate for increased moisture and sulfur contents of the flue gases.

Based on boiler balance calculations (Appendices A.1 and A.2), it is estimated that incineration of the HVLC gases would reduce the amount of steam generated by 0.03 Mbtu/ADT.

D. POTENTIAL ENERGY IMPACTS OF IMPLEMENTATION OF NAAQS FOR OZONE

NO_x Control of Coal- and Residual Oil-Fired Boilers

Table A5 illustrates the energy consumption of NO_x control systems. The specific system that has been assumed in the calculations is the so-called "Selective Catalytic Reduction" (SCR) process using ammonia as the chemical. The main contribution to the energy consumption is power that is required to transfer the flue gases through the catalytic reactor. The other major factor is that the flue gas temperature has to be about 660°F (for a coal-fired boiler) when entering the SCR unit. Normally, however, air is preheated with flue gases after the SCR unit; therefore the flue gas exit temperature can be maintained at the same level as without an SCR system.

Table A5. Energy Impacts of NO_x Emission Control

Fuel	Unit	Coal-Fired Boiler	Residual Oil-Fired Boiler
Boiler size (fuel)	MBtu/h	350	350
Flue gas flow	Sft^3/1,000 Btu in fuel	11.8	11.9
	Aft^3/min	167,893	159,960
SCR process			
Flue gas temp. in SCR unit	°F	662	600
Flue gas flow in SCR unit	Aft^3/1,000 Btu in fuel	29	27
Impact on electrical energy			
Pressure drop over SCR unit and air heater	in H_2O	4.0	4.0
Fan hp	hp	162	116
Fan Motor horsepower	hp	203	145
Fan Motor horsepower	kWh/h	153	109
Ammonia supply system	kWh/h	30	30
Total power	kWh/h	183	139
Impact on heat to steam			
Flue gas exit temp.			
w/o SCR	°F	400	400
w SCR	°F	400	400
Sootblowing of catalytic bed and air heater[1]	MBtu/h	0.5	0.2

[1] Rough estimate

VOC Control of the Oxidation System Vent

VOC control of the vent from the black liquor oxidation plant can be accomplished by condensing the vapors and by using the vent gases as the air supply to a power boiler or a recovery boiler. Energy is consumed in this operation for:

- cooling tower operation
- transportation of gases to the boiler house
- reduction in the boiler efficiency due to reduced O_2 content of the vent gases as compared to fresh air

If all heat lost in the oxidation reactions escapes with the vent gases, the heat to be removed would be approximately:

$$1.2 \times 496 \text{ kBtu/ADT} = 595 \text{ kBtu/ADT}$$

The above figure includes the heat of reaction for inorganic reactions plus 20% additional to cover the oxidation of some organic compounds. For a 1000 ADT/d mill this would correspond to a heat load of:

$$(1{,}000 \text{ ADT/d}) \text{ x } (1 \text{ d/24h}) \text{ x } (595 \text{ kBtu/ADT}) = 24.8 \text{ MBtu/h}$$

The estimated power consumption of the cooling tower is 80 kW, and power consumption for pumping water to the condenser and back to the cooling tower is estimated to be 30 kW. The total power for heat removal is thus estimated to be 100 kWh/h.

The air requirement for the oxidation of strong black liquor is typically 20 Sft^3/min for one gpm of liquor feed. For a 1000 ADT/d kraft mill, the strong liquor flow at 50% dry solids content is typically 380 to 450 gpm. The air requirement would thus be about 9000 Sft^3/min for a 1000 ADT/d mill. For the estimation of the power requirement of the fan that would blow the vent gases (after the condenser) to the boiler air system, the following is assumed:

- air requirement 9,000 Sft^3/min
- vent gas temperature (after condenser) 120°F
- required head (condenser and ducts work) 12 in H_2O

The actual gas flow at 120°F is approximately 10,000 Aft^3/min. The power required to transfer the vent gases is estimated as follows:

$$\text{Power} = \frac{0.000157 \times (12 \text{ in } H_2 0) \times (10{,}000 \text{ A ft}^3 \text{ / min})}{0.65} = 29 \text{ HP or } 22 \text{ kW}$$

The boiler that incinerates the vent gases from the oxidation system will experience a slight change in the efficiency, because:

- a higher amount of combustion air is required because the vent gases contain reduced O_2
- the moisture content of the combustion air increases
- heat brought to the boiler with combustion air is somewhat increased because of higher temperature and higher moisture content of the vent gases

For illustration, the following is assumed or calculated:

- an oil-fired boiler, steam production is 100,000 lb/h
- excess air without vent gases is 20% (excess O_2 content 3.3%)
- excess air with vent gases increases to 26% (excess O_2 content 4.1%)
- temperature of combustion air is 100°F and moisture content is 0.006 lb/lb of dry air
- vent gases from oxidation are saturated at 120°F (0.08 lb H_2O/lb dry air)

Based on a comparison of energy balance calculations, a boiler burning the BLO vent gases would generate 0.016 Mbtu/ADT less than the same boiler without these gases. The balances are shown in Appendices A.1 and A.3.

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APPENDIX A.1

POWER BOILER ENERGY BALANCE - BASE CASE

Heating Value/Flue Gas Calculations

Fuel:	#6 oil	
Excess Air:	20%	
	3.3% O_2 content of dry flue gases	
Incombustible material (sand, rocks, etc.; dry basis)	0.0%	
Fuel moisture content	0.1%	
Combustible fuel elementary analysis (dry basis)		
Carbon	85.5%	
Hydrogen	11.2%	
Oxygen	0.7%	
Nitrogen	0.0%	
Sulfur	2.5%	
Ash/other	0.1%	
Total	100.0%	
Higher heating value (type “+HHV” to have it estimated)	18,520	Btu/lb d.s.

Wet fuel composition

Carbon	85.5	lb/100 lb dry fuel
Hydrogen	11.2	lb/100 lb dry fuel
Oxygen	0.8	lb/100 lb dry fuel
Nitrogen	0.0	lb/100 lb dry fuel
Sulfur	2.5	lb/100 lb dry fuel
Other	0.1	lb/100 lb dry fuel
TOTAL	100.1	lb/100 lb dry fuel

Theoretical air

Ambient air moisture content	0.006	lb/lb dry air
Oxygen	319.4	lb/100 lb dry fuel
Nitrogen	1,201.6	lb/100 lb dry fuel
Moisture	9.1	lb/100 lb dry fuel
TOTAL	1,530.1	lb/100 lb dry fuel

Flue gas

	lb/100lb	lbmol/100lb	vol%	vol% (dry basis)
Carbon dioxide	313.5	7.13	10.6%	11.7%
Oxygen	63.9	2.00	3.0%	3.3%
Nitrogen	1,441.9	51.50	77.0%	84.8%
Sulfur dioxide	5.0	0.08	0.1%	0.1%
TOTAL DRY	1,824.2	60.69	90.7%	100.0%
Water	111.9	6.21	9.3%	
TOTAL WET	1,936.1	66.91	100.0%	

Dry flue gas

Molecular weight	30.1	lb/lbmol
Volume @ 68°F, 1 atm	23,367	cu.ft./100 lb

Estimated higher heating value (HHV)	18,590	Btu/lb dry fuel
Lower heating value (LHV)	17,346	Btu/lb dry fuel

Stack test parameters

Flue gas oxygen content	3.29%	(by volume, dry basis)
Flue gas moisture	9.29%	(by volume)
Flue gas SO_2	1,287.2	ppmdv
Flue gas flowrate . . .	14.08	m^3/sec (dry basis, 20°C)
Flue gas SO_2 . . .	173.7	kg/hr
. . . at fuel consumption of	92.0	T/d (actual)

Adiabatic flame temperature

Assume all feeds enter at 77°F

	Mean Cp Btu/lb°F	Mass flow lb/lb dry fuel	Heat content Btu/lb dry fuel	
Carbon dioxide	0.2866	3.135	2,717.8	
Oxygen	0.2572	0.639	497.0	
Nitrogen	0.2798	14.419	12,202.1	
Sulfur dioxide	0.2011	0.050	30.4	
Water	0.5611	1.119	1,898.4	
TOTAL	0.2962	19.361	17,345.6	= LHV

Adiabatic flame temperature 3,101.6°F

Boiler heat balance

Ambient air temperature, °F	100
Flue gas temperature, °F	400
Feedwater temperature, °F	302
FW temp before heating, °F	100
Steam enthalpy, Btu/lb	1,441
Unburned combustible, %	0.4%
Unaccounted loss, %	1.5%
Radiation loss, %	0.8%

Heat inputs

	Btu/lb dry fuel	
Fuel heating value	18,520	98.8%
Combustion air	218	1.2%
TOTAL	18,738	100.0%

Heat outputs	Btu/lb dry fuel	
Flue gases, sensible heat	1,624	8.7%
Flue gases, latent heat	1,174	6.3%
Unburned combustible	74	0.4%
Unaccounted loss	281	1.5%
Radiation loss	150	0.8%
Heat to steam	15,434	82.4%
TOTAL	18,738	100.0%

CO_2 discharges	203.1	lb CO_2/MBtu in steam
SO_2 discharges	3.2	lb SO_2/MBtu in steam

Steam generation	lb/lb dry fuel	Mbtu/h	MBtu/ADT
Steam generated	13.20	118.3	2.840
LP steam required in FW heater	0.74		

APPENDIX A.2

POWER BOILER ENERGY BALANCE - WITH HVLC GASES

Heating Value/Flue Gas Calculations

Fuel:	#6 oil	
Excess Air:	30%	
	4.5% O_2 content of dry flue gases	
Incombustible material (sand, rocks, etc.; dry basis)	0.0%	
Fuel moisture content	0.1%	
Combustible fuel elementary analysis (dry basis)		
Carbon	85.5%	
Hydrogen	11.2%	
Oxygen	0.7%	
Nitrogen	0.0%	
Sulfur	2.5%	
Ash/other	0.1%	
Total	100.0%	
Higher heating value (type “+HHV” to have it estimated)	18,520	Btu/lb d.s.

Wet fuel composition

Carbon	85.5	lb/100 lb dry fuel
Hydrogen	11.2	lb/100 lb dry fuel
Oxygen	0.8	lb/100 lb dry fuel
Nitrogen	0.0	lb/100 lb dry fuel
Sulfur	2.5	lb/100 lb dry fuel
Other	0.1	lb/100 lb dry fuel
TOTAL	100.1	lb/100 lb dry fuel

Theoretical air

Ambient air moisture content	0.048	lb/lb dry air
Oxygen	319.4	lb/100 lb dry fuel
Nitrogen	1,201.6	lb/100 lb dry fuel
Moisture	73.0	lb/100 lb dry fuel
TOTAL	1,594.0	lb/100 lb dry fuel

Flue gas

	lb/100lb	lbmol/100lb	vol%	vol% (dry basis)
Carbon dioxide	313.5	7.13	9.3%	10.8%
Oxygen	95.8	2.99	3.9%	4.5%
Nitrogen	1,562.0	55.79	72.6%	84.5%
Sulfur dioxide	5.0	0.08	0.1%	0.1%
TOTAL DRY	1,976.3	65.98	85.8%	100.0%
Water	195.8	10.88	14.2%	
TOTAL WET	2,172.1	76.86	100.0%	

Dry flue gas

Molecular weight	30.0	lb/lbmol
Volume @ 68°F, 1 atm	25,404	cu.ft./100 lb

Estimated higher heating value (HHV)	18,590	Btu/lb dry fuel
Lower heating value (LHV)	16,464	Btu/lb dry fuel

Stack test parameters

Flue gas oxygen content	4.54%	(by volume, dry basis)
Flue gas moisture	14.15%	(by volume)
Flue gas dewpoint	127.64	°F
Flue gas SO_2	1,184.0	ppmdv
Flue gas flowrate . . .	15.30	m^3/sec (dry basis, 20°C)
Flue gas SO_2 . . .	173.7	kg/hr
. . . at fuel consumption of	92.0	T/d (actual)

Adiabatic flame temperature

Assume all feeds enter at 77°F

	Mean Cp Btu/lb°F	Mass flow lb/lb dry fuel	Heat content Btu/lb dry fuel	
Carbon dioxide	0.2789	3.135	2,218.3	
Oxygen	0.2526	0.958	614.2	
Nitrogen	0.2753	15.620	10,911.0	
Sulfur dioxide	0.1963	0.050	24.9	
Water	0.5426	1.958	2,695.6	
TOTAL	0.2988	21.721	16,464.0	= LHV

Adiabatic flame temperature 2,614.1°F

Boiler heat balance

Ambient air temperature, °F	140
Flue gas temperature, °F	420
Feedwater temperature, °F	302
FW temp before heating, °F	100
Steam enthalpy, Btu/lb	1,441
Unburned combustible, %	0.4%
Unaccounted loss, %	1.5%
Radiation loss, %	0.8%

Heat inputs

	Btu/lb dry fuel	
Fuel heating value	18,520	93.3%
Combustion air	1325	6.7%
TOTAL	19,845	100.0%

Heat outputs	Btu/lb dry fuel		
Flue gases, sensible heat	1,989	10.0%	
Flue gases, latent heat	2,056	10.4%	
Unburned combustible	74	0.4%	
Unaccounted loss	298	1.5%	
Radiation loss	159	0.8%	
Heat to steam	15,270	76.9%	
TOTAL	19,845	100.0%	
CO_2 discharges	205.3	lb CO_2/MBtu in steam	
SO_2 discharges	3.3	lb SO_2/MBtu in steam	
Steam generation	lb/lb dry fuel	Mbtu/h	MBtu/ADT
Steam generated	13.06	117.1	2.810
LP steam required in FW heater	0.74		

APPENDIX A.3

POWER BOILER ENERGY BALANCE - WITH BLACK LIQUOR OXIDATION GASES

Heating Value/Flue Gas Calculations

Fuel:	#6 oil	
Excess Air:	26%	
	4.1% O_2 content of dry flue gases	
Incombustible material (sand, rocks, etc.; dry basis)	0.0%	
Fuel moisture content	0.1%	
Combustible fuel elementary analysis (dry basis)		
Carbon	85.5%	
Hydrogen	11.2%	
Oxygen	0.7%	
Nitrogen	0.0%	
Sulfur	2.5%	
Ash/other	0.1%	
Total	100.0%	
Higher heating value (type “+HHV” to have it estimated)	18,520	Btu/lb d.s.

Wet fuel composition

Carbon	85.5	lb/100 lb dry fuel
Hydrogen	11.2	lb/100 lb dry fuel
Oxygen	0.8	lb/100 lb dry fuel
Nitrogen	0.0	lb/100 lb dry fuel
Sulfur	2.5	lb/100 lb dry fuel
Other	0.1	lb/100 lb dry fuel
TOTAL	100.1	lb/100 lb dry fuel

Theoretical air

Ambient air moisture content	0.023	lb/lb dry air
Oxygen	319.4	lb/100 lb dry fuel
Nitrogen	1,201.6	lb/100 lb dry fuel
Moisture	35.0	lb/100 lb dry fuel
TOTAL	1,555.9	lb/100 lb dry fuel

Flue gas

	lb/100lb	lbmol/100lb	vol%	vol% (dry basis)
Carbon dioxide	313.5	7.13	9.9%	11.2%
Oxygen	83.0	2.60	3.6%	4.1%
Nitrogen	1,514.0	54.07	75.2%	84.7%
Sulfur dioxide	5.0	0.08	0.1%	0.1%
TOTAL DRY	1,915.5	63.87	88.8%	100.0%
Water	145.0	8.05	11.2%	
TOTAL WET	2,060.5	71.92	100.0%	

Dry flue gas

Molecular weight	30.0	lb/lbmol
Volume @ 68°F, 1 atm	24,589	cu.ft./100 lb

Estimated higher heating value (HHV)	18,590	Btu/lb dry fuel
Lower heating value (LHV)	16,998	Btu/lb dry fuel

Stack test parameters

Flue gas oxygen content	4.06%	(by volume, dry basis)
Flue gas moisture	11.20%	(by volume)
Flue gas SO_2	1,223.2	ppmdv
Flue gas flowrate . . .	14.81	m^3/sec (dry basis, 20°C)
Flue gas SO_2 . . .	173.7	kg/hr
. . . at fuel consumption of	92.0	T/d (actual)

Adiabatic flame temperature

Assume all feeds enter at 77°F

	Mean Cp Btu/lb°F	Mass flow lb/lb dry fuel	Heat content Btu/lb dry fuel	
Carbon dioxide	0.2828	3.135	2,466.3	
Oxygen	0.2549	0.830	588.9	
Nitrogen	0.2776	15.140	11,689.2	
Sulfur dioxide	0.1987	0.050	27.6	
Water	0.5519	1.450	2,225.7	
TOTAL	0.2966	20.605	16,997.7	= LHV

Adiabatic flame temperature 2,858.6°F

Boiler heat balance

Ambient air temperature, °F	107
Flue gas temperature, °F	400
Feedwater temperature, °F	302
FW temp before heating, °F	100
Steam enthalpy, Btu/lb	1,441
Unburned combustible, %	0.4%
Unaccounted loss, %	1.5%
Radiation loss, %	0.8%

Heat inputs

	Btu/lb dry fuel	
Fuel heating value	18,520	96.8%
Combustion air	608	3.2%
TOTAL	19,128	100.0%

Heat outputs	Btu/lb dry fuel	
Flue gases, sensible heat	1,746	9.1%
Flue gases, latent heat	1,522	8.0%
Unburned combustible	74	0.4%
Unaccounted loss	287	1.5%
Radiation loss	153	0.8%
Heat to steam	15,346	80.2%
TOTAL	19,128	100.0%

CO_2 discharges	204.3	lb CO_2/MBtu in steam
SO_2 discharges	3.3	lb SO_2/MBtu in steam

Steam generation	lb/lb dry fuel	Mbtu/h	MBtu/ADT
Steam generated	13.13	117.7	2.824
LP steam required in FW heater	0.74		

APPENDIX B

ENVIRONMENTAL REGULATIONS FOR WHICH CO_2 IMPACTS ARE EXPECTED TO BE MINIMAL

Table B1. Environmental Regulations for Which CO_2 Impacts Are Expected to be Minimal

Regulation	Reasons for Excluding from Estimate
Paper Coating MACT	Number of new oxidizers for VOC control will probably be small
Panel Coating MACT	Number of plants affected is expected to be small
Subpart Db NO_x Revisions	Affects only new coal and oil (with or without wood) boilers constructed after 9/97 with input >100 million BTU/hr Most new units expected to be gas- or wood-fired
PM2.5 NAAQS	Primary fine particulate control estimated under ICCR for coal- and wood-fired boilers, and MACT II for recovery combustion sources Secondary PM precursor (VOC, CO, NO_x) control is assumed to be achieved via improved combustion control; SO_2 control by switching to gas
Regional Haze	This rule has large overlap with PM2.5 (and ICCR) Precursor NO_x control is estimated under Ozone NAAQS Implementation, SO_2 by switching to gas
Cluster Rule Effluent Guidelines for Other Industry Sectors	Impact is expected to be small

APPENDIX C

ENERGY USE CALCULATIONS

Existing Water Rules - primary & secondary treatment of mill effluent + sludge treatment and disposal

A. Estimate based on breakdown by sector and point of use [1]:

	Electrical Power, kWh/ton product					Fuel, MBTU/ton prod.	
Sector	Pumping	Primary	Secondary	Dewater'g	TOTAL	Dewater'g	Hauling
Bleached Kraft	13	4	31	6	54	0.070	0.002
Containerboard	7	3	23	1	34	0.060	0.001
On-site De-ink (tissue, fine)	15	11	85	3	114	0.100	0.003
Recycled Paperboard	9	6	23	1	39	0.050	0.001
All other	6	3	32	4	45	0.050	0.001

Sector	Production 10^6 tons/yr	**Total Electricity MWH/yr**	**Fuel converted to steam for dewatering (71% eff.) MBTU/yr**	**Total Diesel MBTU/yr**
Bleached Kraft	32	1,728,000	1,590,400	64,000
Containerboard	26	884,000	1,107,600	26,000
On-site De-ink (tissue, fine)	4	456,000	284,000	12,000
Recycled Paperboard	14	546,000	497,000	14,000
All other	15	675,000	532,500	15,000
TOTAL	91	**4,289,000**	**4,012,000**	**131,000**

B. Cross-check on power required for secondary treatment:

Average BOD5 to waste treatment in 1988 [8]	59	lb BOD5/Ton product
BOD5 reduction across primary treatment	15%	
BOD5 load to secondary treatment	50.2	lb BOD5/Ton product
average power applied	1.25	kWh/kg BOD5
total production in 1995	91,000,000	tons/yr
total power used for secondary treatment	**2,592,983**	**MWH/yr**

compare to estimate using values from reference [1]

Sector	Power for Sec. Trtmnt kWh/ton	Production 10^6 tons/yr	**Electrical Power MWH/yr**	
Bleached Kraft	31	*32*	**992,000**	
Containerboard	23	*26*	**598,000**	
On-site De-ink (tissue, fine)	85	*4*	**340,000**	
Recycled Paperboard	23	*14*	**322,000**	
All other	32	*15*	**480,000**	
TOTAL		*91*	**2,732,000**	**MWH/yr**

% difference from estimate using data from (A.) **-5.4%**

Existing Air Rules - particulate controls from combustion sources and TRS controls

A. Particulate emissions from boilers, furnaces, and vents

	[3] Avg. Size	[3] Units	[1] Flue gas factor, acfm	[1] Power factor	**Total Electrical Requirements** ESPs	Scrubbers	TOTAL
Power boilers	1000 lb stm/h	No.	/lb-stm/h	W/acfm	**MWh/yr**	**MWh/yr**	**MWh/yr**
ESPs - coal	236	86	0.50	1.3	116,000		116,000
ESPs - wood	358	87	0.92	1.3	326,000		326,000
Scrubbers - coal	130	23	0.50	7		92,000	92,000
Scrubbers - wood	269	89	0.92	7		1,351,000	1,351,000
Recovery Furnaces							
ESPs	375	215	0.68	1.3	624,000		624,000
Lime Kilns	tons CaO/d		acfm/tonCaO/d				
ESPs	380	28	200	1.3	24,000		24,000
Scrubbers	210	163	200	7		420,000	420,000
Total electricity required for furnace and boiler particulate controls					**1,090,000**	**1,863,000**	**2,953,000**

Note: calculation assumes that all wet scrubbers are 20 psi venturi units. See MACT II - B. lime kilns, and ICCR - A. venturi scrubber-equipped boilers, for estimates of power for other wet scrubbers after upgrading to 20 psi venturis

smelt dissolving tank vent scrubbers		
total no. of SDTs at 124 mills [10]	227	
no. with wet scrubbers (87%) [10]	197	
estimate of power requirements for wet scrubber on SDT		
typical flue gas flow rate [16]	15000	acfm
estimated system pressure drop	10	inches H20
fan power (assume 65% efficiency)	27	kWh/h/unit
assume scrubber is located 100 ft above SDT+100 ft of friction losses		
assume 100 gpm weak wash, centrifugal pump @50% efficiency, to scrubber		
pumping power =	7.5	kWh/h/unit
Total electricity required for smelt dissolving tank vent scrubbers	**60,000**	**MWh/yr**

Estimated flue gas flow factor for lime kilns:

Values used to estimate factor taken from example material & energy balance examples [20]

	kiln A	kiln B	units
Total exhaust gas flow rate	13,579	11,394	lb/ton CaO
- assumed avg mol wt. same as dry air			
Exhaust gas temperature	576	330	deg F
	1,036	790	deg R
Gas constant for air	53.35	53.35	ft-lbf/lbm-deg R
Pressure ambient	14.7	14.7	lb/in2
Estimated total gas flow, V=R(air)*T/P	355,000	227,000	ft3/ton CaO
	247	158	acfm/tonCaO/d
Average of two kilns	202		acfm/tonCaO/d
Value used in industry energy estimates	200		acfm/tonCaO/d

B. 1. TRS from concentrated sources - collection and incineration

a. collection and transport of LVHC sources to incineration:

for a 1000 ADTP/D kraft mill, average ejector steam use [1]	1750	lb/h @150psi
energy value of the steam	2.09	MBTU/h/1000ADTP/d
	50	MBTU/1000ADTP
total 1995 kraft production [13]	56,000	1000 ADTP/yr
annual energy use (steam)	**2,808,000**	**MBTU/yr**

b. incineration of LVHC sources in stand-alone incinerators
(assume no additional fuel required if LVHC gases combusted in kilns, boilers, etc.)

natural gas used in stand-alone incinerators in 1995 [2]	**573**	million ft3/yr
high heat value of gas (typical) [9]	**1,000**	BTU/ft3
annual energy use (fuel)	**573,000**	**MBTU/yr**

2. TRS from recovery furnaces with direct contact evaporators (black liquor oxidation)

a. Blowers and pumps:

average power required for air blowers & liquor pumps [1]	0.6	kW/ADTP/d
tons pulp produced with direct contact recovery furnaces [5]	18,440,000	ADTP/yr
annual energy use (electrical power)	**266,000**	**MWH/yr**

b. Loss in liquor heating value due to oxidation:

net reduction in steam generated from black liquor [1]	0.68	MBTU/ADTP
annual energy use (steam)	**12,539,000**	**MBTU/yr**

Cluster Rule Effluent Guidelines - conversion of all kraft bleached mills to ECF

A. Estimate of total ClO2 required to practice ECF bleaching

1. data and assumptions used:

1995 total bleached kraft production, tons/yr [13]	32,092,000
% of production softwood [13]	47%
% of production produced with oxygen delignification [7]	30%
% of production produced with extended delignification [7]	15%
assumed % produced with ED, OD, or ED+OD	40%
assumed % of ED, OD, ED+OD production on softwood	60%
assumed pre-ECF baseline % substitution for hardwood	15%
assumed pre-ECF baseline % substitution for softwood	15%

2. estimate of total chlorine dioxide used for delignification (Do stages)

	assumed average values			ECF	baseline
	kappa no.	kappa factor	tons pulp/yr	tons ClO2/yr	tons ClO2/yr
Softwood - conventional	30	0.22	7,413,252	186,036	27,905
Softwood - ED, OD, OD+ED	17	0.22	7,702,080	109,528	16,429
Hardwood - conventional	20	0.18	11,841,948	162,095	24,314
Hardwood - ED, OD, OD+ED	12	0.18	5,134,720	42,171	6,326
			32,092,000	499,830	74,974

estimated ClO2 to move all mills from baseline levels to ECF **424,855** **tons ClO2/yr**

On site electricity required [1]	**0.20**	**kWh/kgClO2**	**=**	**77,000**	**MWh/yr**
Off site electricity required [7]	**11**	**kWh/kgClO2**	**=**	**4,249,000**	**MWh/yr**
Chlorine elimination credit [7]	**5**	**kWh/kgClO2**	**=**	**(1,931,000)**	**MWh/yr**
Additional steam required [1]	**6000**	**BTU/lbClO2**	**=**	**5,098,000**	**MBTU/yr**

B. Second estimate of ClO2 required to convert all mills to ECF bleaching:

ClO2 to convert remaining mills to ECF, beyond 1995 installed capacity [6]	575	TPD ClO2
percentage of mills ECF as of 1995 [7]	33%	
Estimated total ClO2 to convert all mills to ECF	858	TPD ClO2
	313,000	**tons ClO2/yr**

% difference from estimate (A.) **-26.3%**

C. Third estimate of ClO2 required to convert all mills to ECF bleaching:

approximate 1992 chlorine consumption by the pulp/paper industry [13]	1,113,000	tons Cl2/yr
approximate 1997 chlorine consumption by the pulp/paper industry [12]	850,000	tons Cl2/yr
assuming linear decline, interpolated chlorine consumption for 1995	955,200	tons Cl2/yr
assumed percent of chlorine consumed used for bleaching kraft pulp	95%	
percentage of mills ECF as of 1995 [7]	33%	
ClO2 equivalent of 1995 estimated chlorine consumption	**515,000**	**tons ClO2/yr**
% difference from estimate (A.)	**21.2%**	

D. Power credit for BOD5 reduction due to recovery of black liquor solids

total estimated black liquor solids recovered by BAT, BMPs [7]	2,160,000	kg BLS/d
BOD5 content of black liquor solids [7]	0.3	kg BOD5/kg BLS
equivalent BOD5 removed from sewer	236,520,000	kg BOD5/yr
power application rate [7]	1.25	kWh/kg BOD5
Total power reduction	**(296,000)**	**MW/yr**

E. Net steam due to recovery of black liquor solids

1. steam generated from black liquor solids recovered		
total estimated black liquor solids recovered by BAT, BMPs [7]	2,160,000	kg BLS/d
average heating value of black liquor solids [14]	13,700	BTU/kg BLS
steam generation efficiency	0.64	BTUstm/BTUfuel
steam generated from recovered solids	**(6,913,000)**	**MBTU/yr**
2. steam to evaporate water recovered from BMPs		
estimated water reclaimed with black liquor solids [15]	0.025	m3/ADton pulp
1995 total kraft production	56,000,000	ADtons pulp/yr
total water to be evaporated	1,400,000	m3 water/yr
assumed multiple effect evaporator steam economy	4.5	lb water/lb stm
total steam required	343,000	tons steam/yr
equivalent energy	**799,000**	**MBTU/yr**
Net steam required for BAT & BMPs	**(6,114,000)**	**MBTU/yr**

MACT I - steam stripping of foul condensates and collection+incineration of HVLC gases

A. HVLC gas collection and incineration 1995 kraft production = 56,000,000 tons/yr

sources:

- brownstock & O2 delig. washer hoods
- brownstock & O2 delig. filtrate tank vents
- O2 delig blow tanks
- knotters & knotter tank vents
- black liquor tank vents
- chip bins (continuous digesters)
- blow tanks (continuous digesters)

1. Transportation

Assumptions [1]

mill production rate	1000	ADT/d
number of vacuum washers on brownstock	4	
HVLC gas flow - mill total	25000	acfm
HVLC gas temperature	140	deg F
pressure drop in ducts	15	in H20
fan efficiency factor	65%	
conversion: 1 in H20 =	5.20	lb/ft2
conversion: 1 hp =	33000	ft-lb/min
Power required =	91	hp/1000 ADT/d
	68	kW/1000 ADT/d
	1.63	kWh/ADT
Total power required for transport =	**91,000**	**MWh/yr**

2. Incineration

assume all HVLC gases burned in power or recovery boilers		
reduced boiler efficiency from boiler heat balance [1]	0.030	MBTU/ADT
Total reduction in steam generated	**1,680,000**	**MBTU/yr**

B. steam stripping of kraft condensates

assumed percentage of mills to employ stripping	67%	
power required for pumps, etc. [1]	4	kWh/ADT
Total power required	**149,000**	**MWh/yr**
total 1995 kraft pulp production	56,000,000	ADT/yr
average condensate volume [1]	1.6	m^3/ADT
steam required per volume condensate [7]	200	kg/m^3
total steam flow to stripper (65 psia)	320	kg/ADT
as heat (1178 BTU/lb steam)	0.83	MBTU/ADT
assumed percentage of heat recovered - average for all units	75%	
Total steam required	**7,733,000**	**MBTU/yr**

C. BOD load reduction due to steam stripping of condensates

for bleached production:		
pulp production	32,092,000	AD ton/yr
methanol removal requirement (10.2 lb/ODT)	9.2	lb MeOH/ADT
assume actual removal is 25% greater than required	11.5	lb MeOH/ADT
total methanol to be removed from effluent	245,258,296	lb MeOH/yr
for unbleached production:		
pulp production	23,908,000	AD ton/yr
methanol removal requirement (6.6 lb/ODT)	5.9	lb MeOH/ADT
assume actual removal is 25% greater than required	7.4	lb MeOH/ADT
total methanol to be removed from effluent	118,226,255	lb MeOH/yr
total methanol removed from effluent	363,484,552	lb MeOH/yr
BOD5 content of methanol [21]	1.08	lb BOD5/lb MeOH
equivalent BOD5 load reduction	391,109,378	lb BOD5/yr
power application rate [7]	1.25	kWh/kg BOD5
Total power reduction	**(222,000)**	**MWh/yr**

D. Fuel value of stripped methanol burned in lime kilns & power boilers

total methanol recovered	363,484,552	lb MeOH/yr
approximate % of mills burning stripper gas in kilns & boilers [2]	65%	
BTU value of methanol	9066	BTU/lb MeOH
Total fuel credit	**(2,142,000)**	**MBTU/yr**

MACT II - increased control of particulate matter from kraft recovery furnaces, lime kilns, smelt dissolving tanks, as well as sulfite and semi-chemical recovery furnaces.

	Sources		Flue gas	Power
	Avg. Size	Units	factor, acfm	factor
	1000 lb stm/h	No.	/lb-stm/h	W/acfm
Recovery Furnaces				
ESPs	375	215	0.68	1.3
Lime Kilns	tons CaO/d		acfm/tonCaO/d	
ESPs	380	28	200	1.3
Scrubbers	210	163	200	7

A. kraft furnaces

all ESPs upgraded to achieve 0.1 g PM/dscm (NSPS) [10]
52 units expected to require upgrading [10]
100 m2/m3/s specific collection area (SCA) typically required for NDCE, 90 for DCE
assume units to be upgraded are average in size
assume upgraded units require 33% more SCA

Power required = 50,000 MWh/yr

B. lime kilns

information from NCASI database [4]
192 units total
124 have venturi scrubbers
34 have other kinds of wet scrubbers
28 have ESP, or ESP+wet scrubber
6 are unknown

115 units can now meet the proposed MACT floor of 0.15 g/dscm [10]
assume that all the ESP, ESP+scrubbers, and most of the venturis comprise the 64%
77 units must be upgraded, assumed broken down as follows:
34 other wet scrubbers, assumed to be low pressure-drop devices, say 2psi [11]
6 unknown units, assumed to be 'other' wet scrubbers (2 psi devices)
37 venturis, assumed to need to increase from 10 to 20 psi
assume units to be upgraded are average in size

Power required = 140,000 MWh/yr
note - this amount subtracted out of 'Existing Air Regs' scrubber estimate

C. smelt dissolving tanks

data from EPA [10]
227 SDTs at 124 mills
87% have wet scrubbers
NSPS is 0.1 kg/Mg BLS fired
29% subject to, and 75% can now meet, NSPS
56 units need to be upgraded to meet NSPS [10]
proposed MACT floor for SDTs is 0.1 kg/Mg BLS fired (NSPS), achievable with wet scrubber
estimate of power requirements for wet scrubber on SDT

fan power = 27 kWh/h/unit
assume scrubber is located 100 ft above SDT+100 ft of friction losses
assume 100 gpm weak wash, centrifugal pump @50% efficiency, to scrubber
pumping power = 7.5 kWh/h/unit

Power required = 17,000 MWh/yr

D. sulfite liquor combustion units

data from EPA [10]

21	units total
13	have fiber bed demisters (FBD)
8	have venturi or packed bed scrubbers
	proposed MACT floor is fiber bed demister

assume no net increase in energy to convert scrubber to FBD

E. semi-chem liquor combustion units

14	units total at 13 stand-alone semi mills
	proposed "beyond the floor' MACT is wet ESP+RTO
7	units will need to be upgraded [10]
	assume each unit emits 100,000 acfm of flue gas
	for wet ESP use 0.35kW/1000 acfm total power requirements
	based on pilot unit on mag sulfite furnace flue gas [11, p.225]

Power required - wet ESPs 2,000 MWh/yr

for RTOs, assume no auxiliary fuel required to regenerate the oxidizer

Assume 0.005 kW/acfm required for fan power, based on data from wood products RTOs

Power required - fans 31,000 MWh/yr

Wood Products MACT - control of VOCs from dryers and presses

Wood Products Dryers

Product	Annual Production (1997) [17,18, 19]	Annual Production Unit	Annual Dryer Throughput	Dryer Throughput Unit	Exhaust Rate	Exhaust Rate Units	Industry Projected acfm	RTO Energy Use: Industry Projected MBtu/yr	RTO Energy Use: Industry Projected Electricity (MWh/yr)
Particleboard	4,530,671	MSF 3/4/yr	2,871,313	ODTs/yr	3,591	acfm/ODTH	1,177,042	914,575	51,554
OSB	10,534,000	MSF 3/8/yr	6,675,923	ODTs/yr	4,981	acfm/ODTH	3,796,073	2,949,594	166,268
MDF	1,385,119	MSF 3/4/yr	1,890,687	ODTs/yr	12,033	acfm/ODTH	2,597,105	2,017,982	113,753
Soft. Veneer	17,963,000	MSF 3/8/yr	17,963,000	MSF 3/8/yr	1,602	acfm/MSF3/8/hr	3,285,014	2,552,496	143,884
Fiberboard	1,052,791	MSF 1/2/yr	1,052,791	MSF 1/2/yr	1,400	acfm/MSF1/2/hr	168,254	130,736	7,370
			Dryer Totals--->					**8,565,000**	**483,000**

Wood Products Presses

Product	Number of Presses	acfm per press enclosure	Industry Projected acfm	Industry Projected MBtu/yr	Industry Projected Electricity (MWh/yr)
Particleboard	47	100,000	4,700,000	3,153,775	123,516
OSB	32	100,000	3,200,000	2,147,251	84,096
MDF	23	100,000	2,300,000	1,543,337	60,444
Press Totals--->				**6,844,000**	**268,000**
Industry Totals--->				**15,409,000**	**751,000**

RTO Energy Use Factors:

	Fuel, BTU/h/acfm	Electricity, kWh/acfm
dryers	88.7	0.005
presses	76.6	0.003

note: factors were developed for RTOs at OSB plants

ICCR - increased control of particulates from all industry coal and wood-fired power boilers

Power boilers	Avg. Size 1000 lb stm/h	Units No.	Flue gas factor, acfm /lb-stm/h	Power factor kW/1000acfm	
ESPs - coal	236	86	0.50	1.3	115,565
ESPs - wood	358	87	0.92	1.3	326,315
Non-venturi scrubbers-coal	130	15	0.50	7	59,787
Non-venturi scrubbers-wood	269	30	0.92	7	455,264

A. Venturi scrubber-equipped boilers:

Upgrade non-venturi scrubbers to 20 psi venturi units
Assume non-venturi scrubbers are 2 psi devices [11]
Assume power requirement linearly proportional to pressure drop

Power required = 464,000 MWh/yr

B. ESP-equipped boilers:

Assume that all ESPs will require 33% more specific collection area, and therefore will consume 33% more power.

Power required = 146,000 MWh/yr

Ozone NAAQS Implementation - NOx control on boilers and VOC control from BLO vents

A. Install selective catalytic reactor (SCR) for NOx control on all coal and residual oil-fired power boilers larger than 250 MBTU/hr located east of the Mississippi River

	coal-fired	oil-fired	
1. no. of units larger than 250 MBTU/h [3]	47	22	units
2. estimated requirements for a 350 MBTU/h boiler			
a. power required for fan to overcome SCR pressure drop [1]	183	139	kWh/h/unit
b. sootblowing steam for catalytic bed and air heater [1]	0.5	0.2	MBTU/h/unit
3. average size of boiler of those larger than 250 MBTU/h [3]	438	407	MBTU/h
Total power required =	**94,000**	**31,000**	**MWh/yr**
Total steam required =	**258,000**	**45,000**	**MBTU/yr**

4. SCR technology requires low PM levels to prevent fouling.
   Assume that PM controls added for coal boilers under ICCR would be adequate
   Assume no additional PM controls for oil--fired boilers

B. Install SCR for NOx control on all other boilers east of the Mississippi River

	coal/wood fired	residual oil-fired	dist. oil & gas-fired	
1. no. of units affected [3]	236	238	476	units
2. average size of boilers affected [3]	340	111	127	MBTU/h
3. energy required for SCR control of NOx [1]				
a. power required for fan to overcome SCR pressure drop [1]	0.523	0.397	0.397	kW/MBTU/h
Total power required =	**368,000**	**92,000**	**210,000**	**MWh/yr**
b. sootblowing steam for catalytic bed and air heater [1]	0.00143	0.00057	0.00000	BTU/BTUfuel
Total steam required =	**1,004,000**	**132,000**	**0**	**MBTU/yr**

4. SCR technology requires low PM levels to prevent fouling.
   Assume that PM controls added for coal and wood boilers under ICCR would be adequate
   Assume no additional PM controls for oil- or gas-fired boilers

C. Collect and incinerate BLO vent gases for VOC control for BLO systems east of the Mississippi River

1. energy for cooling vent gases to condense moisture			
a. heat to be removed from gas stream [1]		595	kBTU/ADT
b. estimated power required for cooling tower fan & water pump [1]		2.64	kWh/ADT
c. pulp produced with DCE furnaces east of the Mississippi River[3]		11,737,000	ADTP/yr
Total power required =		**30,000**	**MWh/yr**
2. energy to transport cooled gas stream to boiler			
a. flow rate of gases for 1000 ADT/d mill [1]		9000	scfm
		9721	acfm
b. gas temperature [1]		120	deg F
c. head loss through condenser & ductwork [1]		12	inches of H2O
d. fan efficiency factor		0.65	
e. conversions:	1 inch H20 =	5.20	lb/ft2
	1 hp =	33000	ft-lb/min
	1 kW =	1.34	hp
f. power required per 1000 ADT/d pulp produced		21.1	kW/1000ADT/d
Total power required =		**6,000**	**MWh/yr**
3. reduction in boiler efficiency due to reduced O2 content of vent gases used for combustion air as compared to fresh air			
a. boiler energy balance calculations [1]		0.016	MBTU/ADT
Total reduction in steam generated		**188,000**	**MBTU/yr**

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