Emissions from Wood-Fired Combustion Equipment

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EXECUTIVE SUMMARY

This report was prepared for the British Columbia Ministry of Environment (BCMOE) to provide a summary of the emission measurement data available from BC and other jurisdictions that are using wood as fuel –both for heat and electrical power generation. The emphasis of the report is on industrial applications; residential and institutional applications are mentioned where data was available, but were not further emphasized. The focus of this report is to provide guidance on currently economically achievable emission limits for new wood-fired boilers.

Summary Observations and Conclusions

- Biomass fuels can vary significantly in terms of ash content, chlorine, and moisture content, all having a bearing on flue gas composition. For non-wood biomass fuels, sulphur content may also be important.
- Different combustion technologies can result in very different particulate matter (PM) emission profiles (before flue gas treatment), with gasifiers currently producing the lowest uncontrolled emissions e.g., <70 mg/m^3 compared to levels of 300 to >540 mg/m^3 for direct combustion systems.
- Measured PM emissions of 152 industrial sized wood fired combustors operating with BCMOE permits ranged from 4 to 310 mg/m^3 with a median of 30 mg/m^3.
- PM emissions from greenhouse heater sized boilers ~8 MW equipped with either ESPs or baghouses ranged from 1 to 80 mg/m^3, with an average of 30 mg/m^3. Recent data by Metro Vancouver has indicated that with well operated systems this average can drop to 6 mg/m^3. The difference in average results (and the wide range) highlights the "real-world" variability in emissions from biomass system combustions systems that can result from changes in fuel, maintenance, or operating conditions.
- Combustion particulates are very fine with mean particle sizes of less than 1 μm; consequently, mechanical collectors such as cyclones cannot normally achieve emission levels less than 120 mg/m^3 for wood combustion (grate or suspension burners). Since the coarser particles are more easily collected, as the efficiency of air pollution collection (APC) equipment increases, the remaining (or penetrating) fraction becomes increasingly fine and even more difficult to collect. Thus the cost per unit of collected particles tends to rapidly increase as the required efficiency asymptotically approaches 100%. Based on manufacturer data, this area of rapid cost increases starts to occur at levels below about 30 mg/m^3 for ESPs. Smaller burners are especially sensitive to this increase since the ESP can contribute 50% or more to their capital cost.
- Typically, APC equipment manufacturers design systems to achieve significantly less emissions than the specified permit limit in order to guarantee the required performance even under worse than design conditions. For example, the average of all permits for wood combustors with ESPs in BC is about 100 mg/m^3, whereas the average of measurements on the same units was 60 mg/m^3 (40% less than the permitted level). Data from PPC Ltd., an ESP supplier, shows that for 12 of their installations the median of the guaranteed PM emissions was 52 mg/m^3, while the median of the actual measurements was 18 mg/m^3 (65% less than the guaranteed level). The lowest guaranteed emission installation from this supplier is currently 16 mg/m^3 using a 5 field (in series) ESP.

- Based on this supplier's data the actual performance of guaranteed systems was, on average, 40 to 65% less than design or permit. This implies that to guarantee more stringent emission limits (e.g., 25 mg/m^3) the equipment will likely have to be designed for levels of 12 to 15 mg/m^3 to meet the guarantee under the expected range of operating conditions, or conversely, the acceptable range of allowable operating conditions covered by the guarantee may be unduly restricted. Thus, although low emission levels are achievable they now are well within the asymptotic (rapidly escalating cost) portions of the cost-performance curves and may place significant restrictions on the range of normal (guaranteed) operating conditions (such as allowed variability in fuel moisture, ash or sizing).
- There is no existing BC or Canadian biomass fuel standard to ensure consistency of biomass fuel or to link combustor design to a given type of fuel. This can be especially important when trying to achieve very low emission limits where changes in fuel characteristics can impact emissions and for fuel derived from construction and/or demolition waste (CDW).
- European developments in wood fuel standard development are still underway and need to be monitored in order to assess the applicability of these standards to BC.
- For smaller combustion units the cost of (ESP or fabric filter) pollution control equipment can exceed the cost of the combustor. For example: at 1.5 MW the cost of the control equipment was 2.5 times that of the boiler, while at 5.5 MW the APC and combustor costs were comparable.
- The operation and fire hazard posed by unattended high-performance flue gas cleaning equipment, such as ESPs and fabric filters, appears to preclude its use for smaller applications, such as in the institutional sector, and where no full-time personnel is available to supervise the operation of such equipment.
- Current technologies are capable of reducing particulate emissions to extremely low levels (e.g. less than 10 mg/m^3 corrected to 8% oxygen). However, few suppliers have actually guaranteed such low emissions, due in part to the fact that the ongoing achievement of these low levels requires constant system optimization and maintenance of the system (including fuel) within close design tolerances. As allowable emission limits decrease, the importance of good controls with experienced operators, and proactive maintenance becomes very important, which is increasingly difficult to accommodate for smaller installations for cost reasons. At these low emission levels, not only changes in fuel characteristics, but even atmospheric temperature and moisture can effect ESP's performance.
- Pellets represent a special case: as long as costs remains close to that of natural gas, advanced APC equipment (e.g., beyond cyclones) is not economical for small units.
- The limited data available indicate that dioxins concentrations in the emissions from smaller boilers burning wood containing salt can be much higher than from large industrial boilers. If chlorine (sea salt or PVC) containing fuels are allowed to be burned in small boilers, more work needs to be done to measure dioxin emissions and determine appropriate control options. Restrictions on the use of salt laden wood in smaller boilers are recommended in order to prevent dioxin formation from those less controlled sources.

Tables ES1 and ES2 summarise the conclusions drawn from this report. Concentrations are reported as filterable PM (front-half catch) at dry, standard conditions and 8% oxygen.

Table ES 1: Achievable PM Emission Limits by Technology Size (Heat Boilers/Furnaces)

Boilers and Furnaces				
Heat Input	**40+ MW_{th}**	**3-39 MW_{th}**	**1-3 MW_{th}**	**<1 MW**
A.P. Controls	**ESP**	**ESP/fabric filter**	**ESP/fabric filter**	**Cyclone/ uncontrolled**
Current Range	3-47 mg/m^3		59-221 mg/m^3	216–5,000 mg/m^3
Economically Achievable Limit	20 mg/m^3	35 mg/m^3	50 mg/m^3	120* mg/m^3
Rationale for E. A. Limit	Large units are less sensitive to higher cleanup costs. Achievable with a 3-4 field ESP.	APC costs as much as boiler at about 5 MW size. Achievable 2-3 field ESP.	Can be achieved with cyclone and 1-2-field ESP, but APC costs my exceed combustor.	Feasible with cyclone or two-stage combustor.
Even lower limits	Technically feasible, but APC cost starts to increase sharply below this limit, especially for higher ash fuels such as hog.	Would require technology demanding constant supervision.	Would require technology demanding constant supervision.	Would discourage use of wood as a fuel. *If gasification technology or pellets are used then 70 mg/m^3 is achievable.

Note: Air pollution controls (APC) such as ESP and baghouses usually include cyclones as precollectors. The higher cost of pellet fuel relative to raw wood, reduces opportunity to fund enhanced APC (e.g., beyond cyclones) out of the fuel cost savings at current natural gas/pellet price differentials.

Key considerations in minimizing air emissions from biomass combustion are to use combustion and air pollution control systems designed for, and appropriate to, the specific fuel to be used. This should include taking into consideration the fuel's moisture, ash, and chlorine (and sulphur if used with an auxiliary fuel) contents as well as the fuel's physical characteristics (e.g., dry chips, sander dust, or wet hog fuel, species). Biomass is not as homogeneous or as predictable as fossil fuels, and may vary, perhaps due to poor quality control by the fuel supplier, changes in fuel availability (e.g., as sawmills may close) or swapping of fuel sources in response to price variations. Such changes can have an impact on burner operation and the pollution control equipment and may lead to increased emissions. Consequently, the achievement of very low emission levels requires ongoing and high levels of operational monitoring and control as well as ensuring that the fuel properties (sizing, moisture, ash and contaminant contents) are restricted (or linked) to the combustion and pollution control process.

Since the economics for power plants are different from those of heat boilers, different size thresholds were used for each. Currently, wood only costs about 25% of natural gas per unit of energy, leaving a fairly large margin to accommodate gas cleanup costs for heat boilers (as opposed to electrical power plants). For power plants, margins are very low at current electrical rates and even a small percentage increase in capital and operational costs due to flue gas cleanup can mean a project is no longer viable. This mainly applies to small and mid-sized projects where capital costs for flue gas cleanup are 5% or more. In addition, small power systems (under 10 MW_{el}) are likely to be supervised on a part-time basis only, which reduces the ability to operationally control emissions at all times.

Table ES 2: Achievable PM Emission Limits by Technology Size (Electrical Power Plants)

Electrical Power Plants			
Heat Input	**90+MW**	**45-89 MW_{th}**	**0.8-44 MW_{th}**
Power Output*	**25+ MW_{el}**	**10-25 MW_{el}***	**0.1-9 MW_{el}**
Technology	Steam	Steam	Non-steam
Economically Achievable Limit	20 mg/m^3	50 mg/m^3	120 mg/m^3
Rationale for E.A. Limit	Large units are less sensitive to higher cleanup costs. This can be achieved with a 3-4 field ESP	Achievable with 1-2 -field ESP while allowing fuel and operational flexibility.	Confidently achievable with cyclone while allowing fuel and operational flexibility.
Even lower limits	May require additional ESP fields and near the limit currently guaranteed by manufacturers. Requires constant system optimization. May limit the ash content in fuels (e.g., clean low ash wood).	Would increase ESP costs more than economics of small systems can tolerate.	Would require technology demanding constant supervision; increases capital costs by at least 5% (more for systems under 2 MW_{el}); would mandate fixed-bed gasification technology (which can achieve 70 mg/m^3, see previous table) and/or reduced fuel flexibility.

* MW_{el} output is derived from heat input using appropriate electric conversion efficiencies

In summary, it is technically possible to achieve very low emissions from wood combustion(e.g. <10 mg/m^3). However, the increased capital costs and the need for full-time supervision to continuously maintain these levels will have negative impacts on the use of wood as an energy source in BC (notably on smaller units). Lower limits may also restrict the use of higher ash woods species (biomass) or bark. The limits in the tables above are deemed economically achievable based on the analysis carried out for this report and with current technologies and costs. Both technologies and costs are subject to change. For example, steel cost have doubled in the past year Lower limits may be desirable for facilities sited in urban centres or sensitive air sheds, but such stringent requirements may ultimately deter the use of wood in these areas (or require public funding or other subsidies).

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1.0 INTRODUCTION AND BACKGROUND

British Columbia has a large forest fibre (biomass) resource. The BC government is looking at options to expand the amount of energy and heat generated from wood, including trees killed by the mountain pine beetle.

The use of biomass as a fuel offers three significant advantages:

- biomass is greenhouse gas neutral if harvested sustainably since the greenhouse gases (GHG, principally CO_2) released during combustion are recaptured in new forest growth;
- it is renewable if sustainably managed; and,
- is a readily available and proven fuel in BC, the use of which enhances local economic benefits while reducing energy imports.

Additional benefits in terms of reduced wildfire hazards and accelerated regrowth would come from harvesting low-value standing dead pine forests in BC. On the other hand, wood combustion releases air pollutants – sometimes close to or within urban areas - among which particulate matter is of the greatest concern. The most significant health risks related to air quality posed by wood combustion are associated with fine particulates, in particular "inhalable" particulates <10 µm in diameter and "respirable" particulates < 2.5 µm in diameter.

The 2007 BC Energy Plan identified bioenergy as a potential energy source as part of a clean renewable future along with geothermal, tidal, run-of-river and wind power. This was supported by carbon taxes included in the February 2008 provincial budget, which will make the utilization of fossil fuels more expensive, tending to reduce their consumption in BC and economically favouring the use of renewable or CO_2 neutral fuels, such as wood. BC Hydro has issued a call for independent power projects that focus on converting biomass to electricity. As of May 14, 2008, BC Hydro has 16 registered proponents for Phase I RFPs.[1] It is therefore important to establish emission limits that can be applied to projects that use wood for energy.

All references in this report to burner capacity (MW-Megawatt, GJ-Gigajoules, etc.) refer to the thermal or heat input, unless indicated otherwise.

[1] RFP = request for proposals; see http://www.bchydro.com/info/ipp/ipp956.html

2.0 PURPOSE AND TASKS

The purpose of this project is to investigate biomass combustion practices, and to produce a background report for government agency policy development. The lower cut-off level for regulating emissions is not clearly defined.[2] This report provides a summary of the publicly available information on emissions and control options for wood combustion systems with a rated capacity greater than 0.1 MW (excluding residential units and wood fired hydronic heaters which are typically in the size range of 10-15 kW_{th}) Specifically, the project reviewed biomass combustion practices from feedstock preparation to emission discharge to:

- compare air emission performance for various biomass combustion technologies (based on recent stack sampling data and other relevant sources), feedstocks and flue gas treatment for various rated sizes or capacities (greater than 0.1 MW), and for a variety of applications (e.g., process heat production, power generation, cogeneration, greenhouse heating);
- include an assessment of information from other jurisdictions, particularly information made available by Environment Canada, Natural Resources Canada, Metro Vancouver, and the BC Ministry of Environment;
- indicate the expected emissions from all wood biomass combustion / gasification systems and practices in use, in demonstration or in R&D domestically and internationally, including consideration for various feedstocks and exhaust gas after treatment options. For each, it notes the key characteristics which would affect the decision to choose that option;
- provide a comparison of air emissions from current biomass combustion and control technologies with non-biomass technologies (such as natural gas and oil combustion);
- indicate achievable emission levels for logical size categories (i.e., megawatts output) for biomass combustion units; and,
- include, for comparative purposes, relevant currently used or business-as-usual non-biomass technologies, and best available non-biomass technologies. For each, it includes the same key characteristics noted above.

[2] In some jurisdictions, regulated units start at around 50 kW. Small-scale wood combustion units exist today at the 100 kW size, such that this size could still be included in emissions regulations. For example an EnergyCabin heating system has been installed at a school in Nakusp; this unit provides solar power and heat from biomass and is available in sizes from 10 kW to 500 kW. The cabin uses pellets or chips for heating

3.0 OVERVIEW: BIOMASS WOOD FUEL AND CONTAMINANTS

3.1 CHARACTERISTICS OF WOOD FUEL

The composition of wood fuel varies depending on the tree species (with variation within species depending on the locale and the handling process). Typically, wood contains about 70% cellulosic material, ~25% aromatics (lignin that binds or glues the cellulose together) ~5% extractives (terpines, resin acids, fatty acids, and phenols), and between 0.2 to 3% ash.

For example, the elemental composition of typical BC wood and bark mix is shown in **Table 1.**

Table 1: Typical Wood Elemental Analyses

Element	Wood	Bark
Carbon	50.8%	52.8%
Hydrogen	5.9%	5.8%
Oxygen	41.2%	38.7%
Sulphur	0.0%	0.1 (0.0)%
Nitrogen	0.1%	0.1 (0.2)%
Chlorine	Variable - see 3.1.2 below	
Ash	<1	2.5%

Ref. #10

Four major compositional and physical factors affect the air emissions released from wood combustion. These are: ash (or incombustibles), chlorine (salt), moisture and the physical size or nature of the fuel. These are discussed below, followed by a discussion of the impacts of combustor and air pollution control (APC) equipment design, selection, and operation.

3.1.1 Ash

The ash content of typical BC wood ranges from 0.2 to 3.0% (See **Table 2**). However, bark (and hog fuel) can contain 3.5% or more ash depending on the wood species, the handling procedures, and the amount of dirt included. Some data has indicated up to 20% (e.g., Natural Resources Canada work in small biomass systems). Here it can be seen that lodge-pole pine and spruce have higher ash contents than Douglas fir, western hemlock or cedar (Ref. #10).

Table 2: Ash Contents of Various Woods

Species	Ash content, dry basis (%)	
	Wood	Bark
Douglas fir	0.1-0.8	1.2-2.2
Western hemlock	0.2-2.1	1.7-3.7
Ponderosa pine	0.2	0.7
Lodgepole pine	2.5	2.0
Spruce	3.0	3.8
Redwood	0.2	0.4-0.8
Cedar	0.2	0.2

Fuel made from construction and demolition waste (CDW) can be expected to contain more non-combustibles such as dirt, bits of drywall, plastic, and metals (e.g., nails). Painted or treated wood may cause additional toxic emissions, such as heavy metals. However, as recycling processing improves, the quality of the fuel produced can be expected to improve. For example, one company, Urban Wood Waste Recyclers in New Westminster currently produces about 180,000 tonnes per year of two types of fuel, primarily from construction (as opposed to demolition) waste. Based on interviews and an inspection of their operations, it was determined that their

- *White Wood Fuel* visually appears to be essentially high quality wood chips, which would be derived from untreated dimensional lumber, plywood, and oriented strand board used in construction.
- *Process Engineered Fuel* (PEF) or "Hog fuel" is less processed (separated) and therefore may contain more non-wood products such as and plastic, which Urban Recyclers states increase the fuel's specific energy content.

Fuel from demolition waste would be comparable to PEF, but can be anticipated to contain even more dirt, paint and treated wood, as well as other impurities, including nails, drywall, metals, and plastic. Interest in the combustion of refuse as refuse derived fuel (RDF) as an alternative to landfilling is also increasing.

Table 3 presents approximate analyses of two samples of the Urban Waste Wood Recyclers fuel. There is currently no detailed information on the chemical or physical composition (e.g., the percentage of plastic or polyvinyl chloride [PVC], sulphur, nitrogen, chlorine, or salt). In addition, there are currently no standards or specifications (at least from an air pollution or contaminant perspective) in BC on what constitutes an acceptable refuse derived fuel, and what would be an appropriate combustor air pollution control system for the various fuel types (See Section 3.1.5 for European biomass specifications).

Table 3: Urban Recyclers CDW Derived Fuel Analyses

Analysis	Unit	White Wood	PEF
Moisture content	%, as-rec'd	32.0	29.2
Ash @ 525°C	%, dry basis	0.71	4.70
Calorific value (HHV)	GJ/t, dry basis	18.96	18.85
Bulk density			
Uncompacted			
• green	kg/m^3	198	200
• oven dried	kg/m^3	136	141
Compacted			
• green	kg/m^3	220	260
• oven dried	kg/m^3	150	183

Ref: Information supplied by Urban Recyclers

3.1.2 Chlorine

Wood that has not been exposed to salt water typically contains less than 0.01% chlorine. If the wood has been ocean transported via log booms or otherwise exposed to marine salt water (primarily wood from BC's coastal forests), then the chlorine content of the now salt soaked hog can be in the range of 0.8% chlorine (Ref #16*).* The presence of chlorine is important for three main reasons.

1. It is a precursor to dioxin formation (dioxin formation is discussed in Section 4.2.2);
2. It often appears as a fume (very fine particulate) that is difficult to collect in electrostatic precipitators (EPS), and much of it may therefore pass right through and out the stack; and,
3. It creates a plume that can be visible some distance from the source. It is not uncommon on large combustors burning salt laden hog fuel for over 30 -65% of the particulate emissions to be salt (Ref. #16 and #21).

3.1.3 Moisture

The moisture content of wood depends on the type of wood and the amount of drying (both forced and natural air) prior to combustion. Typical values for moisture content (MC) include 60%+ for green wood; 55% for wet hog fuels; 30% for hogged scrap wood from sawmills; 10% for planer shavings and sawdust from dried wood (wood is typically planed after some or complete drying); and 4.5% for pellets. Note, all moisture contents (MC) referenced in this report are on a wet or green basis (wb –calculated as the percentage of water in relation to the total mass of wood and water combined). Moisture contents above 62% create combustion and energy recovery difficulties as there is barely enough heat to evaporate the water contained in the wood. This results in low flame temperatures and combustion instability. To maintain good combustion conditions with high moisture fuels, several coastal mills have used auxiliary (or supplementary) fuels, such as tire-derived fuel (TDF), PEF, coal, or some form of pre-drying, such as using flue-gas recirculation or hog presses. An advantage of hog presses is that they may also lower the chlorine content by squeezing out some of the sea water (salt). A test conducted at one of the west coast pulp mills determined that addition of 2–5% TDF by weight with an energy content of 33 GJ/tonne (as compared to 8 GJ/t for wet hog) increased the [fluidized] bed temperature by an average of 55°C, and stabilized and improved the combustion of low-quality hog fuel and high-moisture-content sludge (Ref. #25). In addition, the combustion equipment and processes must be specially designed to burn wet wood.

Conversations with gasifier designer Chris Krann of Krann Energy Systems indicated between 62 to 65% as the maximum feasible moisture content for an air fired gasifier as part of a two-stage combustor.

3.1.4 Fuel Physical Size or Nature

Wood fuel can range in size from solid (and moist) cord wood to very fine (and very dry) sander dust. Typically, combustors are designed to burn a specific type of wood fuel. For example, a combustion system designed for sander dust will not effectively (if at all) burn hog fuel. Also, a system designed for chips may find that the moisture or ash content changes seasonally or with the original residue source. For example, hogged pine beetle wood may have a moisture content of 20% versus 50% for fresher wood. The density and the energy content of the wood also varies with the wood species, with the denser woods having higher energy content per volume. So it is important that the combustor only be fed (or limited to) the type of fuel it was designed for, but also that it be able to respond to changes in quality in the design fuel. Frequent operational adjustments may be necessary to maintain low emission levels, which can be a challenge for small systems running without designated supervising personnel. Therefore, it may make sense to have one boiler operator supervise a number of smaller wood energy systems when facilities are located in close proximity to each other.

3.1.5 European Solid Biofuel Standards

Currently there are no generally accepted biomass fuel standards in Canada. To address the issue of biomass fuel quality, sampling, and fuel sources, the European Committee for Standardization, CEN (TC335) is currently preparing 30 technical specifications for solid biofuels (see **Appendix II**). The two most important technical specifications being developed deal with classification and specification (CEN/TS 14961) and quality assurance for solid biofuels (CEN/TS 15234). The committee is considering the physical and chemical characteristics of fuel, and also the source of the material. The fuel specifications and classes for all solid biofuels are set out in CEN/TS 14961:2005. The development of these standards should be followed to evaluate the applicability to the BC and Canadian situations.

3.1.6 Supply and Sources of Biomass

The supply of biomass has been covered in other studies (see Envirochem reports for Metro Vancouver, BC Ministry of Forests and Range, Alberta Government, and the Commission for Environmental Cooperation); therefore, it is not repeated in detail here, subject to presenting the data from a recent 2008 BIOCAP study, shown in Ref #23. It can be seen that the sustainable supply of biomass in BC can replace about 30% of BC current fossil fuel requirements. If the Mountain pine beetle wood is added (over a 20 year harvest cycle), this increases the supply to 517.4 PJ (517 x10^{15} Joules) - equivalent to about 56% of BC fossil fuel demand.

Table 4: Bioenergy Potential in BC

Bioenergy Potential of British Columbia

Biomass Feedstock	Resource Size (dry t/yr)	Bioenergy potential (PJ/yr)	% of Potential	% of total fossil energy
Municipal Solid Waste				
MSW	**948,450**	**15.2**	**2.9%**	**1.6%**
Sustainable Agriculture				
Crop residues	143,901	2.3	0.4%	0.3%
Livestock manure	388,426	6.1	1.2%	0.7%
Biomass Crops on summerfallow land	147,060	2.4	0.5%	0.3%
Biomass Crops on new /converted land	2,587,118	41.4	8.0%	4.5%
TOTAL SUSTAINABLE AGRICULTURE	**3,266,505**	**52.1**	**10.1%**	**5.7%**
Sustainable Forestry				
Forest residues	11,940,429	191.0	36.9%	20.8%
Enhanced silviculture for traditional forest products	1,194,043	19.1	3.7%	2.1%
Enhanced silviculture for bioenergy plantations	3,980,143	63.7	12.3%	6.9%
TOTAL SUSTAINABLE FORESTRY	**17,114,615**	**273.8**	**52.9%**	**29.8%**
Mountain Pine Beetle: A Temporary (20 yr) Resource				
to harvest dead pine (a)	2,353,882	37.7	7.3%	4.1%
Whole tree harvest of non-recoverable pine (b)	8,660,736	138.6	26.8%	15.1%
TOTAL MPB FOR	**11,014,618**	**176.2**	**34.1%**	**19.2%**
Total potential	**32,344,188**	**517.4**	**100%**	**56.2%**

NOTE: The current fossil energy demand in the province is 920 PJ/year

(a) *PJ/yr*.calculated as the residue left from the harvest of the recoverable MPB wood (417 Mm^3 or 224 Mt(dry)) assuming that 30% of the harvested biomass is forest residue and 70% of this can be removed sustainably. Finally, it was assumed that the resulting 47 Mt(dry) would be harvested over 20 years, resulting in 2.4 Mt(dry) per year.

(b) Calculated from BC government estimates for excess MPB wood of 358 Mm3 (about 193 Mt(dry)), where 90% of this could be harvested over a 20 year period to give an estimate of 8.7 Mt(dry) per year.

3.1.7 Current Burning Practices in BC

Since there is no clear definition of biomass fuel in BC, **Table 5** lists the fuels considered in this report and related current burning practices.

Table 5: Burning Practices for Different Biomass Fuels in BC

Fuel type	Burning Practices
Hog fuel	Beehive burners Pulp Power boilers
Salt-laden hog fuel	Pulp Mill Power boilers
Shavings & sawdust	Power and cogeneration
Pellets	Greenhouses and some residential heating
Puck fuel	Envisioned for greenhouse and other small manufacturing operations
RDF	Envisioned for power plants on Vancouver Island
PEF	Pulp Mill Power Boilers
Municpal Solid Waste (MSW)	Incinerator in Metro Vancouver

Puck fuel is compressed wood (or other combustible material, typically sawdust and shaving). It is similar to, but larger than pellets (i.e., puck sized). It is also not as hard as, and more difficult to transport than pellets, consequently pucks are usually used onsite for local energy (or material) recovery rather than for an export market like pellets. (See Ref. #20). Also the cost of equipment is typically much less than for manufacturing pellets.

4.0 EMISSIONS GENERATED BY WOOD COMBUSTION

The combustion of wood can result in number of potential pollutants depending on the contaminants in the fuel and the type and completeness of combustion process. The USEPA in AP-42 has identified 90 organic compounds (or groups of compounds), and 26 trace elements (metals) in the emissions from wood combustion. Washington State in 2005 developed emission factors for over ninety (90) chemicals (Ref. #32). Then it conducted a risk assessment, including air dispersion modelling, to determine "Candidate Pollutants of Concern" which, based on their analyses, represent the "*most significant emissions from wood-fired boilers*".

Table 6 lists these pollutants of concern. The table also lists the surrogate control options for the various pollutants. For example, volatile organic compounds (VOC) such as acetaldehyde are best controlled through maintaining good combustion conditions. Polyaromatic hydrocarbons are formed through incomplete combustion, and once formed can condense to collectable particulates. These are best controlled by a combination of good combustion to minimize formation, followed by back-end particulate controls to collect any particulates that were formed.

Table 6: Candidate Pollutants of Concern

Substance	Surrogate Controls*
Acetaldehyde	C
Alpha-pinene	C
Beta-pinene	C
Carbon monoxide (CO)	C
Formaldehyde	C
Methanol	C
Naphthalene	C
Toluene	C
Total phenols	C
Turpentine	C
PAHs	C/P
2,3,7,8 Tetrachlorodibenzo-p-dioxin (TCDD)	C/P
2,3,7,8-Tetrachlorodibenzo-p-furan	C/P
Hydrogen sulphide	C/S
Nitrogen oxides (NO_x)	N
Beryllium	P
Cadmium and compounds	P
Chromium (II) compounds, as Cr	P
Chromium (III) compounds, Cr	P
Chromium (metal)	P
Chromium (total)	P
Chromium, hexavalent metal and compounds	P
Cobalt as Co metal Dust and fume	P
Cobalt carbonyl as Co	P
Copper, Dusts and mists, as Cu[3]	P
Copper, Fume	P
Iron	P
Lead arsenate, as Pb_3 (A_2O_4)	P
Lead chromate, as Cr	P
Lead compounds	P

Substance	Surrogate Controls*
Magnesium	P
Manganese	P
Molybdenum	P
Nickel and compounds	P
Particulate matter (PM)	P
Phosphorus	P
Selenium	P
Silver	P
Thallium	P
Zinc	P
Arsenic and inorganic arsenic compounds	P/S
Mercury	P/S
Hydrochloric acid	S
Sulphuric acid	S
Sulphur dioxide (SO_2)	S
***Surrogate Controls Index** **C** - Carbon monoxide (good combustion practices & control) **P** - Particulate matter (cyclones, filters, ESP, …) **S** - Sulphur dioxide (acid gases - scrubbers) **N** - Nitrogen oxides (nitrogen in fuel and combustion modifications)	
Ref. #32: Washington State	

It should be noted that the list above does not include all of the substances that can be generated by wood combustion. For example, one of the factors limiting the ability to recirculate wood combustion products back into greenhouses to provide the carbon dioxide for growing, is the presence of trace quantities of ethylene, which is not included in either the USEPA or Washington State emission factors. Ethylene is a plant hormone that can affect greenhouse crops, such as tomatoes, in very low concentrations. So although ethylene may not be considered an "environmental concern" in the ambient air outside of a greenhouse, it can be inside; consequently, if wood flue gas is to be circulated within a greenhouse, the APC system will have to deal with this gas.

4.1 CRITERIA AIR CONTAMINANTS (CAC) AND CONTROLS

The primary or criteria air contaminants (commonly regulated or included in air discharge permits) are particulate matter (PM), oxides of nitrogen (NO_x), carbon monoxide (CO), and sulphur dioxide (SO_2). Depending on the source (or process), volatile organic compounds (VOC) and hazardous air pollutants including PAH, dioxins and furans may also be required to be monitored and controlled to specified levels. Each of these pollutants is briefly discussed below.

4.1.1 Particulates

The combustion of wood can form a variety of particulates that include:

- carbon particles and soot;
- unburned wood dust;
- polyaromatic hydrocarbons (PAH) compounds;
- semi-volatile organic compounds (e.g., tars and condensables); and,
- ash (minerals, metals, dirt).

As the efficiency of wood combustion equipment increases with improving technologies, the amount of larger particles (unburned fuel and wood dust, char and carbon) in the emissions will decrease. This will result in the emissions from modern high efficiency combustors not only being lower, but also of a smaller size fraction.

All PM data in this report are based on the filter catch portion of a sample (filterable PM) and where the base data were available, corrected to an 8% oxygen dry basis. The filterable PM includes the smaller PM_{10} and $PM_{2.5}$ fractions, but not condensable compounds that pass through the filter and are caught in the "back half" of the sampling train. Some jurisdictions (and permits) may include the back half, or condensable VOC in the total PM measurements; this is not normally the case in BC for combustion sources.

The condensable fraction of emissions may be significant for plywood, OSB and other wood dryers, but is not generally a significant portion of the uncontrolled filterable PM for combustion sources, assuming efficient combustion, as would be required to achieve low emission limits. For example, as shown on the last row of the USEPA, emission factors on **Table 12** the condensable fraction constitutes only about 3% of the uncontrolled emissions (18 of 577 mg/m^3). However as the PM control increases, for example if emissions were to drop to 18 mg/m3, and if there was no corresponding reduction in VOC, then the condensable portion would rise to be equal to, or greater than, the front half or filterable portion.

Combustion Particulate Sizing PM_{10} and $PM_{2.5}$

The size of the uncontrolled particles formed during efficient wood combustion is relatively small, with about:

- >90% less than 10 microns (µm) in diameter (PM_{10}) and therefore inhalable; and
- >75 % less than 2.5 microns in diameter ($PM_{2.5}$), which are capable of penetrating deep into the lungs. For this reason, fine particulate matter is commonly also considered a hazardous air pollutant. Health effects research has, however, shown that the composition of the particle may be as important as size (Ref. # 31).

Table 7 presents size information from small-scale wood combustion processes – but larger-scale combustion will produce very similar emission profiles. In all cases, 90% or more of the particles emitted are less than 10 microns in diameter (PM_{10}). Tests on smaller residential modern, high-performance wood boilers (Ref. #29) firing both split wood and pellets demonstrated that the particle size increases with decreasing combustion efficiency (in the same combustor). This is to be expected as the emissions from inefficient combustion would contain larger unburned fuel and agglomerated soot particles. Mean particle size increased from 0.06 to 0.1 μm as the efficiency dropped (emissions increased from ~80 mg/m^3 to ~ 400 to 800 mg/m^3). This data highlights the extremely small size of combustion particulates from efficient combustion as well as demonstrating the importance of maintaining good combustion conditions.

Table 7: Typical Particulate Matter Size Distribution of Emissions from Wood burning

Source	Sector	$PM_{2.5}$	PM_{10}	TSP
Dreiseidler, 1999	Domestic furnaces	n.d.	90.0%	100 %
	Wood pellets	84.4 %	94.6 %	100 %
EPA, 1998b[1)]	Residential wood -not pellet stoves	93.0 %	97.0 %	100 %
Baumbach, 1999	Domestic furnaces	96 .0%	99.7 %	100 %
UMEG, 1999	Small boilers	79.0 %	92.0 %	100 %

Ref. #9 (Table A1- 30)

4.1.2 Oxides of Nitrogen (NO_x)

Oxides of nitrogen (NO_x), primarily nitric oxide (NO) and nitrogen dioxide (NO_2), are formed by the oxidation of nitrogen, both in the fuel and in the air, with the fuel nitrogen being more reactive. Nitrous oxide (N_2O) is also present in lesser amounts and is important from a global warming perspective. NO_x emissions range from 303 mg/m^3 (95 g/GJ) for wet wood to 674 mg/m^3(211 g/GJ) for dry wood. The hotter burning dry wood can yield higher flame temperatures if not controlled (e.g., with overfire air or flue gas recirculation) and therefore, greater NO_x formation. Typically, NO_x controls are focused on reducing flame temperature without compromising combustion efficiency or heat transfer. Controls include staged combustion, where secondary air is introduced after the main combustion zone, and flue gas recirculation. Flue gas controls can also include selective catalytic reduction (SCR) but usually adequate NO_x reduction can be achieved through staged combustion or low-NO_x burners. Chemicals and effluent management make SCR inappropriate for non-industrial, smaller applications. BACT values are currently in the order of 320 mg/m^3 (100 g/GJ).
See **Appendix IV** for detailed BACT data.

4.1.3 Carbon Monoxide (CO) and Volatile Organic Compounds (VOC)

The presence of carbon monoxide (CO) and volatile organic compounds (VOC) indicates incomplete combustion. Formation of CO is caused by the incomplete combustion of the carbon atoms, while the presence of VOC indicates incomplete breakdown of the organic components. This latter effect is discussed in more detail in the following section on poly aromatic hydrocarbons (PAH).

The combustion of carbon compounds occurs in two stages: first the carbon is oxidized to carbon monoxide (CO), which is then further oxidized to CO_2. It is this latter step where most of the energy in carbon is released. Therefore, combustors are designed to maximize the oxidation of CO to CO_2. However, there are a variety of conditions that can lead to incomplete combustion and higher CO emissions. These include: lack of excess air, which is typically minimized to reduce both NO_x formation and to improve combustion efficiency; poor fuel-air contact; and, reduced temperatures in the combustion zone (possibly due to high moisture content biomass fuel). The controls typically include good combustor design (i.e., providing a sufficient amount of the 3Ts, time, temperature, and turbulence), fuel preparation (drying and/or sizing), good operation (such as adjusting both the combustor and the APC to changing conditions), and good air distribution. See **Appendix IV** for detailed BACT data.

4.1.4 Sulphur Oxides (SOx)

Wood is essentially a low-sulphur fuel with emissions of sulphur oxides (primarily sulphur dioxide) estimated at 10.8 g/GJ by the USEPA. Although it is possible to further reduce this with flue gas scrubbing, this process is almost never applied to wood fuel, and may be even counterproductive with the scrubbing energy costs offsetting potential reductions in SOx. Sulphur may, however, be present in larger quantities if wood is supplemented with other fuels such as TDF or fuel oils.

4.2 HAZARDOUS AIR POLLUTANTS (HAP)

4.2.1 Polyaromatic Hydrocarbons (PAH)

As discussed above, wood is composed of cross-linked aromatics —primarily phenyl propane terpines, resin acids, fatty acids, and phenols and cellulose (polysaccharides). If during the combustion process the lignin and/or extractives are incompletely oxidized, they can be partially broken down into products of incomplete combustion (PIC), such as PAH, which are usually two or three-ring aromatic compounds such as anthracene, benzaldehyde, benzo(a)pyrene, chrysene, ethylbenzene, fluoranthene, and many more compounds as shown in the AP-42 Wood Combustion Emission Factors. Operational controls are processes that favour complete combustion similar to those discussed above under carbon monoxide.

USEPA AP42 estimates Volatile Organic Compounds (VOC) emissions at 0.017 lb/MMBTU (7,300 mg/GJ) and total organic compounds (TOC) at 0.039 lb/MMBTU (16,800 mg/GJ), which includes the PAH, plus chlorinated and non-aromatic compounds, such as formaldehyde, acetone, and methane.

4.2.2 Dioxins / Furans Emissions

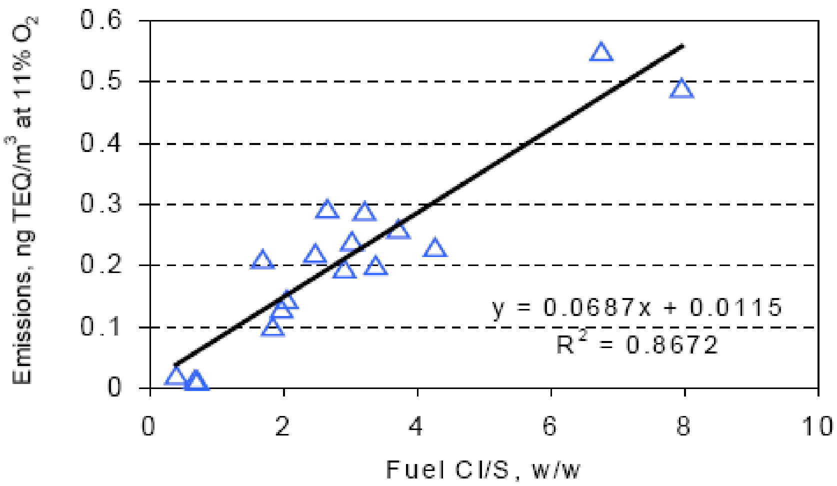
The nature of the fuel, combustion, and post-combustion conditions impact the formation of dioxins and furans. PAPRICAN has developed simplified mathematic relationships examining the impact of stack and fuel variables on dioxin emissions.

$$\boxed{Stack\ [TEQ] = A + B \cdot exp(-C/T\ stack\ ) + D \cdot [PAH] \ \cdot [NaCl]^2\ hog\ (1)}$$

The equation predicts that stack dioxin emissions increase linearly with decreasing electrostatic precipitator (ESP) efficiency or with increasing concentrations of precursor PAH compounds (e.g., poor combustion), exponentially with increasing ESP temperature, and to the second order with hog salt content (Ref. #16).

Other research (Ref. #25) has also shown that the presence of sulphur in the fuel can inhibit dioxin emissions. For example, data from Paprican on testing at a west coast pulp mill boiler burning TDG (rubber contains sulphur) shows that dioxin emissions were positively correlated to the chlorine-to-sulphur ratio in the fuel as shown **Figure 1** below. This indicates that with constant chlorine concentrations in the fuel, the presence of sulphur tends to reduce dioxin formation.

Figure 1: Graph of Dioxin versus Fuel Cl/S Ratio



There are Canada Wide Standards (CWS) for dioxin and furan for boilers burning more than 10,000 oven dry tonnes per year of hogged fuel generated from wood transported or stored in salt water. For new units (after 2006) this is 100 pg/m^3 while for existing units the limit is 500 pg/m^3 (Ref. #3).

Although there is a large volume of data on the emissions of dioxins from large hog fuel fired boilers such as in pulp mills, there is very little on the emissions from smaller boilers. Data is, however, available on a single test for an 8 MW (29 GJ/hr) greenhouse boiler located in the Lower Mainland. This test, shown in

Table 8, indicates that the emissions from smaller boilers burning wood containing salt, in this case about 2000 mg/kg , can have dioxin concentrations several orders of magnitude greater than large pulp mill boilers. This single test may not be representative and additional testing appears warranted.

It should also be noted that the USEPA requirements for Boilers and Heaters (40CFR60, Subpart DDDDD) consider PM a surrogate for hazardous metals (non-mercury metallic HAP), or selected total metallic HAP (arsenic, beryllium, cadmium, chromium, lead, manganese, nickel, selenium) and limit new solid fuel units to 25 mg/m^3 (0.025 lb/MMBtu) of PM, or hazardous metals to ~0.3 mg/m^3 (0.0003 lb/MMBtu).

Table 8: Dioxin and Furan Emissions Wood Waste Boilers

Details	Paprican's Canadian Data	Lower Mainland Greenhouse
# of Boilers Tested	5	1
# of Stack Tests	16	Single Test
Stack Dioxin Emissions, pg/m^3 TEQ*		
Range	0.8 - 86.5	
Average	20.2	3,380
Median	5.7	

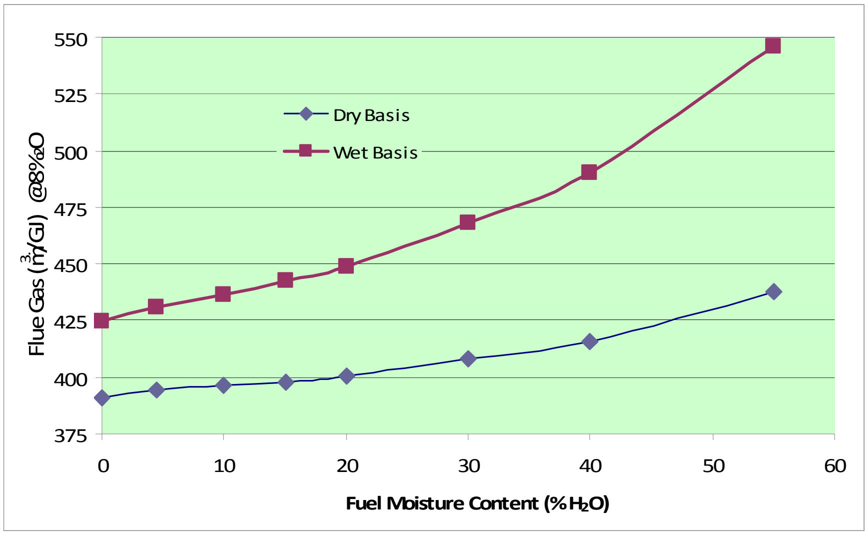
At 8 % O_2 for the Paprican data set Ref..#24 and #20

It should be noted that frequently smaller boilers used in greenhouses may not have been subject to the same rigorous dioxin minimization design considerations as the larger pulp mill boilers. For example, they do not generally have air pre-heaters like the larger boilers. An air pre-heater can quickly reduce the flue gas temperatures, which will in turn reduce the residence time and conditions favouring *de novo* dioxin formation. Consequently, it is not surprising that smaller combustors and boilers burning salt-laden hog can have higher dioxin concentrations in the emissions than larger-scale units. More work needs to be done to confirm dioxin emissions from small boilers burning fuel that may contain chlorine, e.g. salt or PVC, but restrictions on the use of such fuels for small boilers are recommended to prevent dioxin emissions from small, less controlled sources.

4.2.3 Conversion Factors for Emissions

Throughout this report it has been necessary to convert emission factors from a unit of energy basis (e.g., kg/GJ or in the USA lb/MMBTU) to an emission concentration (e.g., mg/m^3 at 8% oxygen [~12% CO_2]) dry, and at standard temperature and pressure) as is included in typical air emission discharge permits from BCMOE, Metro Vancouver and other jurisdictions. Envirochem conducted a series of material balances for various fuels at various moisture and ash contents to determine the quantities of flue gases that would be created. Based on this analysis, plus a review of other values in the literature, a value of 417 m^3 of flue gas (dry STP basis at 8% O_2) being formed per GJ of wood energy input has been used throughout this report. This is equivalent to wood moisture content of approximately 35% moisture content. **Figure 2** illustrates these findings showing the stack flow rates for both wet and dry basis. The two graphs are based on the initial moisture content of the fuel, but do not coincide at 0% due to the moisture formed from the hydrogen in the dry wood during combustion. Detailed conversion factors used throughout the report are shown in **Appendix III**.

Figure 2: Conversion Factors for Emissions at 8% Oxygen



The authors appreciate the mass of flue gas produced will of course depend on the nature of the fuel (e.g., its chemical, physical, and moisture content as discussed above). However, applying individual factors to all of the data collected was beyond the scope of this present study. In many cases, the literature or measurements available did not include details on the fuel that would allow site-specific corrections. The conversion is to a dry STP basis, which will tend to minimize the impact of differing fuel moisture and combustion conditions. **Table 9** summarizes the relationship (conversion factors) between emissions based heat input and the stack concentration.

Table 9: Approximate Conversions for Emissions of PM, NO_x, and CO

Emission	Stack concentration @ 12% CO2 dry	lb/MMBTU (Input)	kg/GJ (Input)
PM	125 mg/m^3	0.121	0.43
NO_x	125 ppmv (223 lb/hr)	0.24	0.10
CO	200 ppmv (217 lb/hr)	0.23	0.09

Ref. #22

One of the key considerations in minimizing air emissions from biomass combustion is to use a combustion system designed for, and appropriate to, the specific fuel to be used. This should include taking into consideration the fuel's moisture, ash, and chlorine contents as well as the fuel's physical size and characteristics (e.g., dry chips, sander dust or wet hog fuel).

Changing biomass fuel type or characteristics (perhaps due to poor quality control by the fuel supplier, changes in fuel availability or in response to price variations) without taking into consideration the impact that such changes will have on burner operation will frequently lead to increased emissions. Consequently, it is important to link (or restrict) the combustion and pollution control process to the type of fuel. As the limits get increasingly tight, good controls with experienced operators, and proactive maintenance becomes very important.

5.0 TYPES OF WOOD COMBUSTION EQUIPMENT, APPLICATIONS

5.1 INTRODUCTION

This section discusses grate burners, fluidized bed burners and gasifiers. More technologies exist, yet these appear to be the main ones currently in use, and proposed for British Columbia in connection with biomass feedstocks. Actual emissions measurement data is used whenever possible, and manufacturers' claims or guarantees are used where such data is not available. Note that all measurements are specific to feedstocks; for example, grass and straw have much higher ash content than woody biomass. Also, biomass is generally very low in sulphur content, but peat and some grass types have fairly high sulphur content.

Chlorine is present in straw and grass, as well as in wood that has been floating in salty water. Biomass is therefore not very homogeneous, and there are even differences between bark (hog fuel with high ash content up to 3%), white wood chips, and premium pellets (under 0.5% ash) in terms of their burning properties, and thus the emissions generated (see Chapter 3). This section concentrates on the impact of burning technology on emissions, rather than that of the feedstocks.

5.2 GRATE, PACKAGE OR STOKER SYSTEMS

These systems designed to burn pellets, wood chips, ground wood, or sawmill dust. There is usually no drying before combustion, but sorting may take place to remove impurities, metals or other contamination. Their uncontrolled emissions are high, as there is a lot of dust formation and incomplete combustion. Much of the total ash residue produced by a hog-fired grate equipped boiler is in the form of gas borne particulate, called fly ash or furnace carryover. Depending on the fuel used, such as pellets, emissions can be lower but in general the combustion process is not very well controlled.

The following figures show a large grate burner, a smaller European package boiler with built-in multi-cyclone dust collection system, as well as a typical stoker burner. It should be noted that many of the package boilers do not have any built-in control systems, and external controls are added downstream of the combustors.

Figure 3: Large Grate Burner

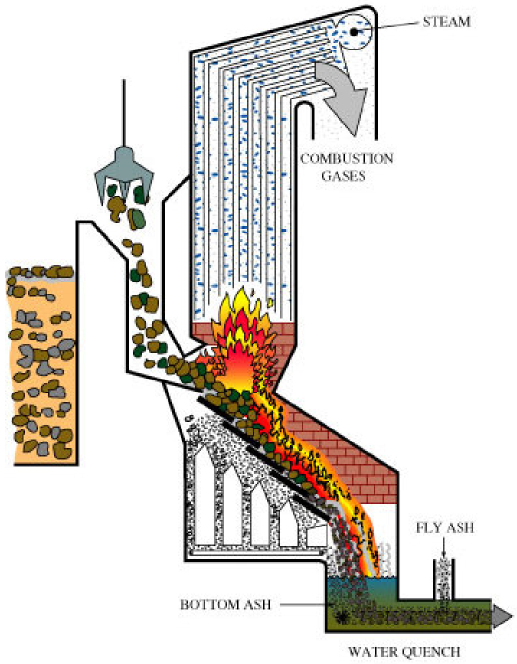
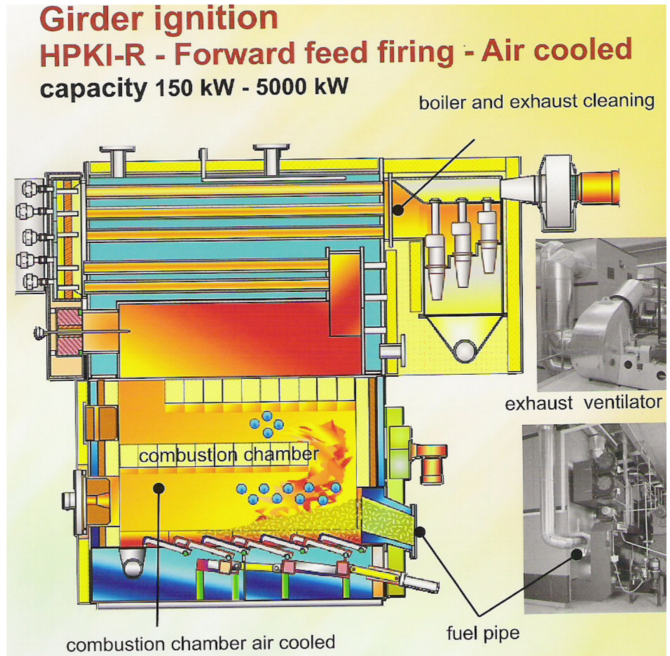


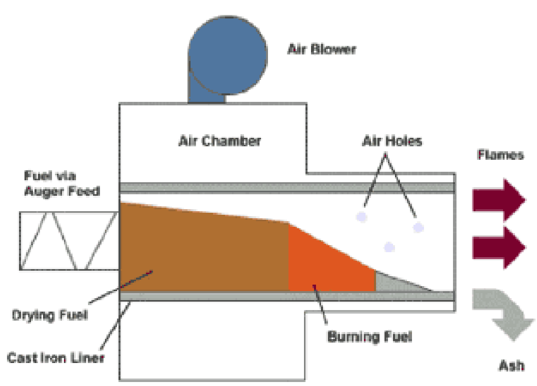
Figure 4: Package Boiler – Forward Feed Firing



Ref: http://www.energyanswers.com/

Stoker burners consist of (1) a fuel admission system, (2) a stationary or moving grate assembly that supports the burning fuel, and provides a pathway for the primary combustion air, (3) an overfire air (OFA) system that supplies additional air to complete combustion and minimize atmospheric emissions, and (4) an ash discharge system.

Figure 5: Stoker Burner



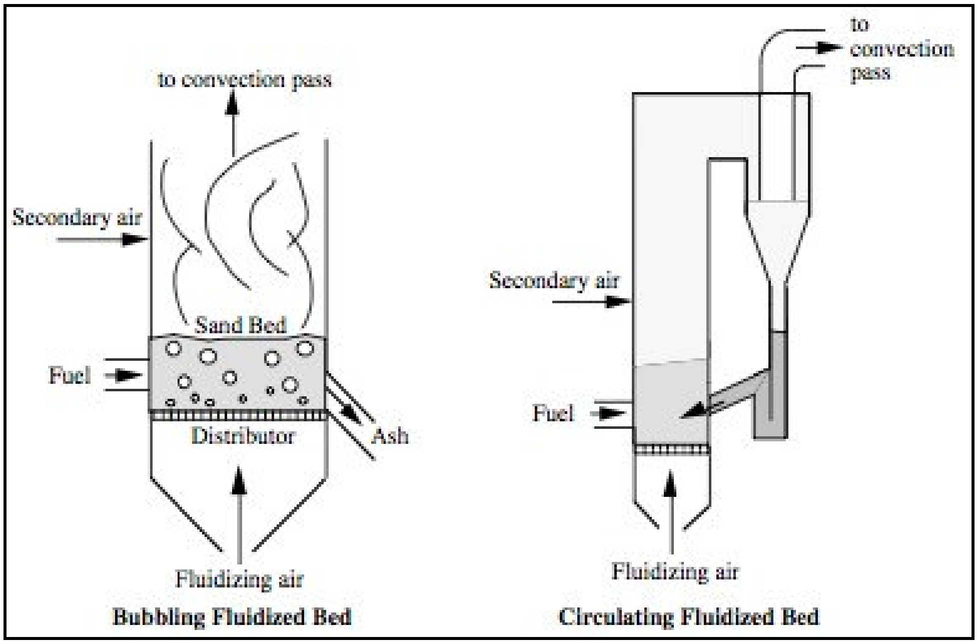
Stoker-firing systems (See **Figure 5**) are typically categorized as either underfeed or overfeed stokers. Underfeed stokers supply both fuel and primary combustion air from beneath the grate. Overfeed stokers let the fuel arrive in the grate from above, whereas primary combustion air flows upward from beneath the grate and through the burning bed of fuel.

Source: www.woodfuelwales.org.uk

5.3 FLUIDIZED BED BUBBLING / CIRCULATING SYSTEMS

In fluidized bed burners, the fuel is introduced into a bed of (usually) hot sand, which provides a very homogeneous temperature and improved combustion dynamics. Pumped combustion air fluidizes the bed and creates conditions for complete gasification and combustion of the fuel within the bed. The high heat transfer combined with high thermal inertia effect allows higher moisture wood and sludge fuels to maintain self-sustained combustion without adding fossil fuels (i.e., the technology offers good flexibility with respect to biomass fuel types and qualities). Burning at temperatures around 700-900°C, NO_x formation is lower than with grate burners. Due to the complexity of these systems, they are normally only used for large industrial/utility boilers. Bubbling bed technology is mainly used for smaller-scale applications with fuels of lower heat content such as sludge and wet wood waste fuels. Circulating fluidized beds are typically restricted to larger units and high heat content fuels.

Figure 6: Bubbling and Circulating Fluidized Bed Burners



Like grate burners, fluidized bed burners also combust the biomass (as opposed to gasification). However, the temperature in the combustion zone is a lot more homogeneous and the combustion process is better controlled, assuring a more complete burnout, which results in lower VOC emissions and ash carbon content as compared to grate burners. Considerably less ash is carried over into the flue gas than with a grate burner, because of much reduced char formation due to the higher combustion efficiency, although all ash leaves the furnace as carryover. The more complete burnout also increases boiler efficiency over that of a grate burner. Still, uncontrolled particulate emissions are considerable, and additional emissions are caused by the gradual disintegration of the material in the fluidized bed itself.

5.4 GASIFIERS OR TWO-STAGE COMBUSTORS

Figure 7: Nexterra Fixed Bed Gasifier

1 – Fuel feed system
2 – Gasifier
3 – Ash removal system
4 – Syngas

Gasification is employed in order to split up the combustion process, resulting in so-called two-stage combustion. By creating a syngas composed of all material in the biomass feedstock and leaving behind the ash, this technology promises better process control and lower particulate emissions. It is becoming more and more popular for new biomass energy installations, and several fixed bed gasifiers running on woody biomass are planned to be installed in BC by Nexterra / Pristine Power, for example.

Gasifiers are classified as fixed bed (downdraft and updraft), fluidized bed, and entrained flow. **Figure 7** shows the Nexterra fixed bed gasifier, and **Figure 8** compares the three main technologies and their plant capacity application ranges.

In an updraft (or "counterflow") gasifier, the biomass fuel enters the top of the reaction chamber while steam and air (or oxygen) enter from below a grate. The type of the gasifier, whether it is up-draft, down-draft, bubbling or fluidized bed, can have an impact on air emissions. Gas velocity through the bed and the ability to control the gasification process it is one of the key variables. In downdraft ("co-flow") gasifiers, both biomass and combustion air come from above. Downdraft versions have been shown to be the cleaner of the two varieties in terms of particulate and tar emissions in the product.

Fixed bed gasifiers are used in case of a well-defined feedstock and for smaller plant sizes (up to around 10 MW_{el} output). They are simpler in design, do not require secondary material, such as sand, and are less costly to purchase and operate than the other types.

Fluidized bed gasifiers, just like burners, use sand or a similar material to mix up biomass and air in a fluidized bed of a uniform temperature. They can be pressurized (larger systems) or at atmospheric pressure. The turbulence created through this process increases the tar content of the syngas compared to a fixed bed gasifier. In a bubbling fluidized bed gasifier, the bed material is agitated by gases flowing through it. Circulating fluidized bed gasifiers employ a system where the bed material circulates between the gasifier and a secondary vessel. Various designs are possible, with biomass fuels being fed into the top, bottom or middle of the moving bed. Syngas typically exits these systems at a high temperature, and has relatively high particulate contents due to the turbulence within the reactor. Due to the high temperatures involved, the syngas may also contain vaporized alkali salts. Tars will also be present in the gas in varying amounts depending on the specifics of the operation. Fluidized beds are more tolerant with respect to the feedstock and are available up to very large scale.

In an entrained bed gasifier, the solids are entrained in the gas flow at high velocities. This is a pressurized process with high capital and operating costs. Entrained flow gasifiers are being discussed for large-scale biomass conversion with syngas cleanup in a Fischer-Tropsch process, but are currently only used commercially for coal as a fuel. They can use different fuels, but may require additives for ash / slag management.

Figure 8: Gasification Technologies and their Size Applications [Ref. #4]

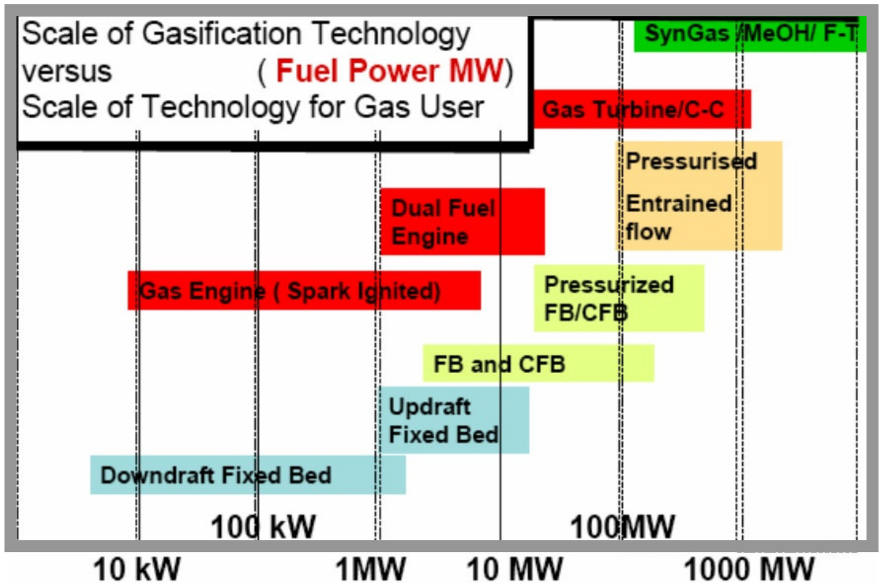


Table 10 compares three burner types and resulting boiler emissions without any flue gas cleaning equipment, based on measurements and manufacturer's guarantees (gasifier). It is obvious that the grate burner is most polluting, due to incomplete burnout and high ash content in the flue gas.

Table 10: Comparison of Uncontrolled Biomass Boiler Emissions

Emission	Grate burner	Fluidized bed	Two-Stage Combustor*
CO	1,746 mg/m^3 645 kg/GJ 1,500 ppmdv	175 mg/m^3 65 kg/GJ 150 ppmdv	NA
NO_x	226 mg/m^3 86 kg/GJ 118 ppmdv	182 mg/m^3 69 kg/GJ 95 ppmdv	NA
PM	USEPA AP-42: 540 - 330 mg/m^3 AB Kraft Mills 33.5 - 130 mg/m^3		50 -100 mg/m^3
VOC	77 ppmdv (7% O_2)	2 ppmdv (7% O_2)	
Source	Ref. #21	Ref. #21	Nexterra, Kraan
Type	Measured (average of several plants)	Measured (average of several plants)	Manufacturer guarantee

* Values for uncontrolled gasifiers emissions for systems in operation in BC are about 70 mg/m^3 for both, the Nexterra installations (at Hefley Creek), and the Kraan gasifier in the Lower Fraser Valley.

6.0 TYPES AND EFFECTIVENESS OF PM CONTROLS

There are five main types of air pollution control systems (APC) applied to the combustion of wood biomass as follows:

1. Cyclones and/or multi-cyclones
2. Electrostatic precipitators (typically dry ESPs are used for wood combustion. Wet ESPs –WESP are typically reserved for wood dyers or processes that generate higher VOC emissions, however they can also be used for combustion)
3. Fabric filters or baghouses
4. Scrubbers

The first key variable before any downstream pollution control equipment is to reduce the emissions leaving the combustion zone. This is achieved by good; design, fuel quality, equipment selection, operational controls, and ongoing maintenance. A well designed and operated combustor can (as discussed earlier in **Section 4.0**) reduce the amount of particulate VOC, PAH, NOx, CO and dioxins, in the raw flue gas, and consequently the loadings into, and the emissions out of the APC equipment.

The following sections briefly describe each of the air pollution control systems. The information in this section is taken form a variety of sources including "*Air Pollution Control Technologies for Small Wood-Fired Boilers*", a study completed by the Resource Systems Groups in 2001 for the New England states (Ref. #18). This study focused on units in the 3 to 10 MMBTU/hr (1 MW ~ 3.4 MMBTU/h) size range.

6.1 CYCLONES AND MULTICYCLONES

Cyclones and multicyclones are mechanical separators that use the centrifugal force in a rapidly rotating gas flow to separate particles. A multicyclone is essentially a series of cyclones operating in parallel; this reduces the size of the cyclone required as the flow can be split between several cyclones. Overall efficiency ranges from 65% to 95%, with multicyclones being more efficient than straight cyclones. Typical emission concentrations from wood and hog fuel fired grate systems equipped with cyclones are in the range of 100 to 200 mg/m^3. Cyclones are also used as a pre-cleaning stage before the flue gas passes an ESP or fabric filter.

6.2 ELECTROSTATIC PRECIPITATORS (ESP)

Electrostatic precipitators (ESPs) are widely used for the control of particulates from a variety of combustion sources, including wood combustion. An ESP is a particle control device that employs electric fields to charge and then collect particles from the gas stream on to collector plates from where they can be removed. There are a number of different designs that achieve very high overall control efficiencies.

Overall control efficiencies typically average over 98%, with control efficiencies almost as high for particle sizes of 1 micrometer or less. ESPs perform almost as well as the best fabric filters. The RACT/BACT/LAER Clearinghouse (RBLC) database reports several large wood-fired boilers with PM_{10} emission rates in the range of 20 to 30 mg/m^3 (0.02 to 0.03 lb/MMBtu).

Wet electrostatic precipitators use water to flush the captured particles from the collectors. The advantage of dry systems is that they may have a lower capital cost and reduced waste disposal problems. Wet systems are slightly more efficient at capturing very small particles that may include toxic metals.

A search of the RBLC (Ref. #18) reveals no ESP in use for wood-fired boilers in the 3 to 10 MMBTU size range. ESPs have been used on MSW incinerators where they are needed for toxic air pollutant control. Based on cost and lack of existing installations, ESPs are not considered to be feasible for wood-fired boilers in a size range less than 1-3 MW.

6.3 FABRIC FILTERS

Various types of fabric filters or baghouses have been successfully used for particulate control with solid and liquid fuels. With the correct design and choice of fabric, particulate control efficiencies of over 99% can be achieved even for very small particles (1 micrometer or less). The lowest emission rate for large wood-fired boilers controlled by fabric filters reported in the RBLC database is ~10 mg/m^3 (0.01 lb/MMBTU). This is consistent with expected control efficiencies close to 98%. Operating experience with baghouses on larger wood-fired boilers indicates that there is a fire risk, due to caking of the filters with unburned wood dust.

Although it is possible to control or manage this risk, it is less practical in small boilers. This is because small wood-fired boilers are used in small institutions such as schools and hospitals without full time boiler staff. In such situations the fire risk is unacceptable. A review of the RBLC database shows only two fabric filter systems on wood-fired boilers and none in this size range. Therefore fabric filters are not recommended for the control of particulates in small wood-fired boilers for safety reasons (Ref. *#18*). Fabric filters are, however, common for medium-sized systems. For example, Metro Vancouver's Waste-to-Energy facility, although not a biomass combustion system, uses a fabric filter to control PM emissions.

6.4 VENTURI AND WET SCRUBBERS

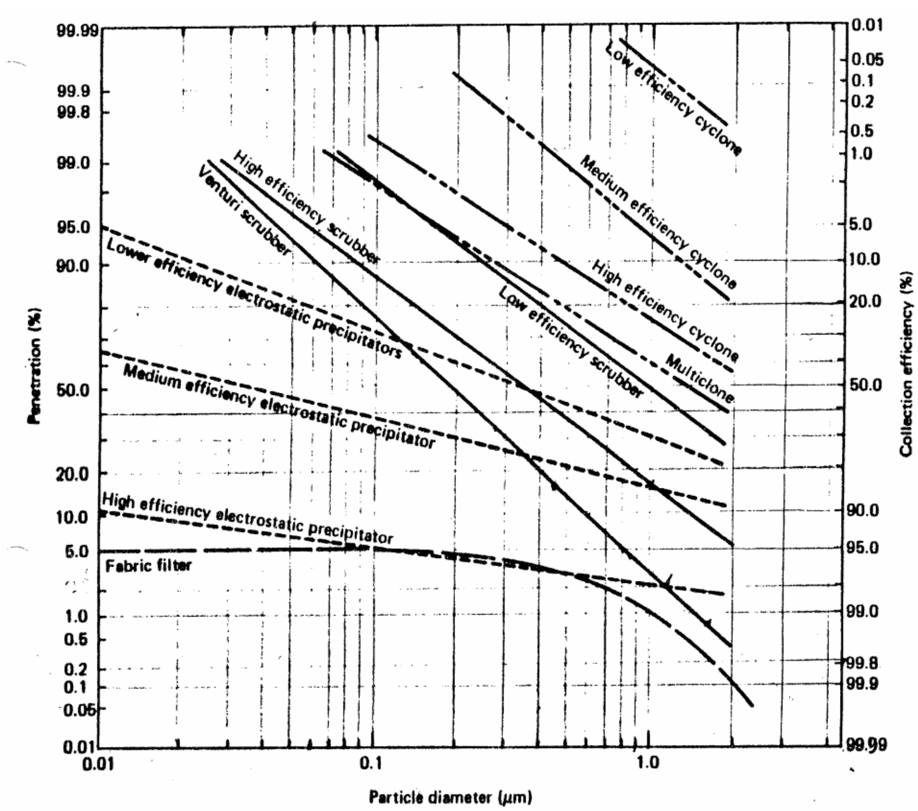
Venturi and other wet scrubbers are more efficient than multicyclones, especially in size fractions below 1 micrometer. The AP 42 indicates a control efficiency for wet scrubbers of 87% for PM_{10} on hog fuel. In a New England study no wet scrubbers were reported in use on wood-fired boilers in the size range of less than 1MW. A Venturi scrubber was installed on a 13.5 MMBTU wood-fired boiler in Hardwick, MA. This had a design emission rate at full capacity of ~130 mg/m^3 (0.13 lb/MMBTU). The best performing Venturi scrubber on a wood-fired boiler listed in the RBLC database had an emission rate of ~150 mg/m^3 (0.15 lb/MMBtu). Emissions are known to be less than that for some existing systems, however, these may not be in the RBLC database. For example, a combined cyclone plus wet scrubber system on a wood-fired boiler of 10 MW (35.5 MMBTU/hr) capacity at Northampton, MA had a design emission rate of ~100 mg/m^3 (0.1 lb/MMBTU). A combined multicyclone followed by a Fischer Klosterman Spray Scrubber installed on a pair of wood-fired boilers with a combined capacity of ~14 MW (49 MMBTU/hr) had a design emission rate of ~10 mg/m^3 (0.01 lb/MMBTU).

Wet scrubbers are problematic in the small size ranges (<3 MW) because many applications are likely to be in small institutional or commercial buildings where it would be difficult to handle the wastewater in an environmentally sound manner.

6.5 CONTROL TECHNOLOGY COMPARISON

Figure 9 summarize the range of emissions and efficiencies that can be achieved by various air pollution control systems. As can be seen, particle size is a very important parameter with the penetration increasing (efficiency dropping) as the particle size decreases. As discussed earlier (see **Table 7**) the particle size of combustion products is very small, with more than 90% being less than 10 microns with mean particle sizes near 0.1 μm. In addition, the smaller, more difficult to collect particles are frequently of the greatest health concern due both to their size, which are more readily respirable, as well as their composition, which can be formed from condensed metal fumes.

Figure 9: Extrapolated Pollution Control Efficiency



Ref: Stern Air Pollution Control Manual and Eisenmann Environmental

Table 11 summarizes the data from the above graph to more clearly show the impact of particle size on the performance of the various APC devices. The table also presents pressure drop data, which is directly related to the fan power requirements and consequently the long term operating costs. For example, even the cost of a Venturi scrubber may be much less (in some cases an order of magnitude) than an ESP but the high pressure drop and therefore ongoing operating costs can soon offset the original capital cost savings.

Table 11: Typical Control Equipment Efficiencies (%)

	Efficiency at Different Particle Sizes					Press. Drop
Control Technology	**10 µm**	**2 µm**	**1 µm**	**0.5 µm**	**0.1 µm**	**"H_20**
High Eff. Cyclone	90	40	30	10	1	2-8
Multi-Clone	95	60	50	20	1	2-8
Fabric Filter	99.9	99.9	99	97	95	4-10
Dry Precipitator	99.9	98	97.5	97	95	0.5-4
Venturi Scrubber	99.6	99.6	96	90	24	5-60

Ref: Stern Air Pollution Control Manual and Eisenmann Environmental

To provide some guidance to the values typically used where actual measurements are not available, the US-EPA emissions factors from AP42 are shown on **Table 12**. As discussed above in **Section 4.2.2**, 1 lb/MMBTU is equivalent to roughly 1031 mg/m^3 at 8% oxygen dry at STP. For example, 0.56 lb/MMBTU is equivalent to about 577 mg/m^3. Thus a pollution control system capable of a 90% reduction would reduce the concentration from 577 down to 58 mg/m^3.

Table 12: USEPA AP42 Emission Factors

Fuel	PM Control Device	Filterable PM		Filterable PM10		Filterable PM2.5	
		lb/MMbtu	**mg/m^3**	**lb/MMbtu**	**mg/m^3**	**lb/MMbtu**	**mg/m^3**
Wet Bark/Bark & wood	No control	0.56	577	0.5	516	0.43	443
Dry wood	No control	0.4	412	0.36	371	0.31	320
Wet wood	No control	0.33	340	0.29	299	0.25	258
Bark	Cyclone	0.54	557	0.49	505	0.29	299
Bark and wet wood	Cyclone	0.35	361	0.32	330	0.19	196
Dry wood	Cyclone	0.3	309	0.27	278	0.16	165
Wet wood	Cyclone	0.22	227	0.2	206	0.12	124
All fuels	Electrolyzed gravel bed	0.1	103	0.074	76	0.065	67
All fuels	Wet scrubber	0.066	68	0.065	67	0.065	67
All fuels	Fabric filter	0.1	103	0.074	76	0.065	67
All fuels	ESP	0.054	56	0.04	41	0.035	36
All fuels	All controls/no controls	0.017*	18	*Condensable Fraction Only			

Ref. #30

On larger units (>10 MW), the collection system usually includes multiple stages of control with a cyclone (or multi-cyclones) acting as a pre-collector to reduce the loadings to a subsequent filter, ESP or scrubber, which are usually much more capital and operational cost-intensive than a cyclone.

7.0 TYPICAL CURRENTLY MEASURED EMISSIONS

The following section summarizes the available emission data from a variety of sources and databases. These include information on BC and Metro Vancouver; US sources including USEPA, references to BACT, the New England studies and information from US suppliers (who also refer to some Canadian installations); European studies; and finally, some recent or proposed installations.

7.1 EMISSION DATA FOR BCMOE SOURCES

Table 13 and **Table 14** below summarize the particulate matter (PM) data collected from a total of 161 measurements taken from 23 individual facilities located throughout BC and which are of sufficient size to require a BCMOE emission permit. Most of these units are larger (>10 MW output) industrial boilers at sawmills and pulp mills.

Controlled total particulate emissions averaged 68 mg/m^3 (0.162 kg/GJ), including all of the BCMOE data collected. Based on 152 measurements, the average concentration of PM emitted from wood-fired boilers controlled by ESP was estimated to be 59 mg/m^3 (0.142 kg/GJ). From the same dataset, the average permit limits for these ESP controlled boilers was 100 mg/m^3. The average PM concentrations from boilers controlled by cyclones was 120 mg/m^3 (0.288 kg/GJ), while the average PM emitted from boilers controlled by baghouses was 62 mg/m^3 (0.149 kg/GJ). The raw data sources for **Tables 13, 14 and 17** are shown in **Appendix V.**

Table 13: BCMOE Particulate Matter Emission Data for Larger Industrial Sized Wood Fired Boilers

Ref #	Type of Combustion Unit	Air Pollution Control Method	Particulate Matter mg/m^3 @ 8%			Particulate Matter	Permit Limit mg/m^3	No. of Tests
			Average	Max	Min	kg/GJ		
1	Hog fired boiler	Five field ESP	27	42	17	0.011	115	2
2	Hog fired boiler	Five field ESP	12	17	8	0.005	115	2
3	Wood Fired Boiler	ESP	7	18	2	0.003	51	14
4	Power Boiler	Three field ESP	277	900	163	0.115	230	11
5	Power Boiler	Three field ESP	213	349	144	0.089	230	11
6	Two twin cell Salton Systems (1 wet, 1 dry) Energy System	Three field ESP	6	31	1	0.002	230	17
7	Power Boiler	ESP	85	335	14	0.035	50	16
8	Power Boiler	ESP	18	33	2	0.008	50	4
9	Power Boiler	ESP	11	30	2	0.005	50	21
10	Co-gen unit	ESP	24	37.2	17.4	0.010	70	4
11	Power Boiler	WESP	33	71.8	12.15	0.014	30	5
12	Power Boiler	ESP	45	274	13	0.019	45	11
13	Combined Power Boiler	ESP	70	127.6	35	0.029	120	12
14	Co-gen unit	ESP	121	201.1	56.9	0.050	120	7
15	Co-gen unit	ESP	47	56.3	42.1	0.020	120	7
16	Wood Fired Boiler	Filtration Baghouse	3	3	3	0.001		1
17	Wood waste Fired Boiler	Filtration Baghouse	122	214.78	28.54	0.051		2
18	Wood Fired Boiler	Cyclones	59	59	59	0.024		1
19	Wood waste Fired Boiler	Multi-cyclones & ESP	53	86.57	26	0.022		4
20	Wood waste Fired Boiler	Cyclones	221	239.93	202	0.092		2
21	Wood waste Fired Boiler	Multi-clone	81	87.07	75.04	0.034		3
22	Wood Fired Boiler	Cyclones & ESP	9.4	9.40	9.40	0.004		1
23	Hog Fuel Fired Boiler	Multi-clones & ESP	10.1	16.50	3.61	0.004		3

Table 14: Summary of PM Data for BC MOE Sources

BC Data Summary Wood Fired Systems	Particulate Matter mg/m^3 @ 8% and kg/GJ					Permit Limit	No. of Tests
	APC	Average	Max	Min	Median	mg/m^3	
mg/m^3	All	68	277	3	45	30-230	161
g/GJ (pg/J)	All	28	115	1	19		
mg/m^3	ESP	59	277	6	30	30-120	152
g/GJ (pg/J)	ESP	25	115	2	13		
mg/m^3	Cyclones	120	221	59	81		
g/GJ (pg/J)	Cyclones	50	92	24.4	34		6
mg/m^3	Baghouses	62	122	3	62		
g/GJ (pg/J)	Baghouses	26	51	nd	26		3

7.2 EMISSIONS FROM GREENHOUSES IN METRO VANCOUVER

There is an increasing volume of data available on greenhouse heaters in Metro Vancouver. This data has been discussed in earlier reports (See Ref. #20) and is summarized in **Table 15.**

Table 15: Emission Data for Greenhouses in Metro Vancouver

	Maximum		Minimum		Average		Comments
Control Devices	mg/sm^3	g/GJ	mg/sm^3	g/GJ	mg/sm^3	g/GJ	
Cyclone	275	86.1	58.6	18.4	178.5	55.9	Two Sources 3 measurements
Multi-clones	79.7	25.0	78.5	24.6	79.1	24.8	One Source 3 measurements
Cyclones & EPS	69	21.6	9.4	2.9	29.9	9.4	Three Sources 7 measurements
Baghouse	76	23.8	2.6	0.8	29.6	9.3	Two Sources 3 measurements

It should also be noted that Metro Vancouver (MV) reviewed the data on greenhouse heaters that formed the basis of **Table 15**, plus additional data they are continuing to collect on ESPs and baghouses. Their analysis concluded that under good operating conditions the total PM concentrations varied from 1 mg/m^3 to 13 mg/m^3, with an average result of 6 mg/m^3 (*Ref MV verbal communication*). For all conditions, there were 24 tests ranging from 1-76 mg/m^3, with an average of 12 mg/m^3. While the range in the Table is comparable with the recent MV data, the average is less than half of the values in the Table. This difference maybe due in part to the inclusion of newer, better performing units in the MV average, or that the Table data includes a larger number of tests where the control equipment or combustors were not operating at peak performance. In any event, the wide range of emissions (1 to 76 mg/m^3) highlights the fact that there can be significant differences in emissions from the same (or similar) systems, depending on operating conditions.

As emission limits tighten the importance of skilled operators that are able to respond to changes in fuel characteristics and operational upsets becomes increasingly important. Maintaining (and supporting) skilful operators is not usually a problem for larger facilities, such as a 50 MW_{el} power plant, but can be an issue on smaller institutional or greenhouse sized units. Here, operation of the combustion equipment may not be a full-time responsibility or hands-on position; consequently, responses to changes in fuel or equipment upsets may not be completed in a timely manner that minimizes emission excursions.

Based on an analysis of the available data, Metro Vancouver proposed a set of emissions limits for wood burning equipment as shown in **Table 16.** The table also shows the estimated number of units of each size in the Metro Vancouver area. Due to the differences in the distribution of commercial, institutional and industrial facilities between MV and the rest of BC, estimates of the number of similarly sized systems in BC could not reliably be extrapolated from the MV data.

Table 16: Proposed Metro Vancouver Emission Limits

Size / Capacity		**Example Uses**	**Estimated # of Units in MV**	**Limit**
MW & MMBTU/hr	**GJ/hr and Boiler HP**			**mg/m^3**
Large >50 MW >170 MMBTU/hr	>180GJ/hr >4100 B Hp	large industrial facility, large university utilities	0	15
Medium 3-50 MW 10 – 170 MMBTU/hr	11 – 180GJ/hr 250- 4100 B Hp	mid-sized hospital, large commercial operation, greenhouses mid-sized university, Community Cogen	25-35	15
Small <3 MW <10 MMBTU/hr	<11GJ/hr <250 B Hp	swimming pool ice rink, school, hotel, office building, small and large apartment building	1-10	15 (rural: 30)

Ref.: http://www.gvrd.bc.ca/growth/keyfacts/popest.htm

7.3 EMISSION DATA FOR USA SOURCES

Table 17 is a summary of a recent (February, 2008) search through the EPA's RACT/BACT/LAER databases for wood burning systems. **Appendix V** presents a summary of the Massachusetts emission criteria, which are believed to be the most stringent in the USA.

Table 17: USEPA BACT Data

Boiler Size		Boiler Type	Control Method	State	Permit Date	Particulate Matter				Est Eff (%)
MMBTU/hr	MW					lb/MM BTU	mg/m^3	kg/GJ	Grain/SCF	
1300	381.0	Boiler	Mechanical Dust Collector, ESP	ME	11/2001	0.03	34.14	0.01	0.01	99
631	184.9	Boiler, Bark	ESP	KY	02/2002	0.1	103.10	0.04	0.05	
600	175.8	Boiler- Wood-fired	Multicyclone and variable throat venturi type wet scrubber	NC	10/2001	0.250	257.75	0.11	0.11	
550	161.2	Boiler	Cyclone, ESP	MN	11/2001	0.03	30.93	0.01	0.01	99
315	92.3	Boiler #1	ESP Cyclone	ME	04/1999	0.036	37.31	0.02	0.02	93
310	90.8	Hog Fuel Boiler	ESP	WA	10/2002	0.15	154.65	0.06	0.07	
265.1	77.7	Boiler, Multi-Fuel	ESP and Wet Scrubber	GA	11/1998	0.10	103.10	0.04	0.05	99
230	67.4	Boiler, wood-fired	ESP	MN	06/2005	0.025	25.78	0.01	0.01	98
230	67.4	Boiler, wood-fired	ESP	MN	06/2005	0.025	25.78	0.01	0.01	98
120	35.2	Boilers, steam	Good Combustion Practices and CEM	VA	02/2002	0.150	154.65	0.06	0.07	98
77	22.6	Heat Energy Systems for Pellet Processing	Setting Chambers and Cyclones	VA	12/2005	0.09	103	0.04	0.04	90
43	12.6	Wood Thermal Oxidizers for Wood Pellet Process	Setting Chambers and Cyclones	VA	12//2005	0.09	93.51	0.04	0.04	99

(USEPA BACT LAER Website Data Shown in Appendix V)

Table 18 represents data from "Air Pollution Control Technologies for Small Wood-Fired Boilers", a study completed in 2001 (Ref. #18). Average PM estimated from four different boiler manufacturers was 116 mg/m^3 (0.05 kg/GJ), all using cyclones as emission control measures.

Table 18: Emissions from Small Wood-Fired Boilers

Heat Input		Type of Combustion Unit	Control Method	Particulate Matter		
MMBTU/hr	MW			lb/MMBTU	mg/m^3	kg/GJ
16.3	4.78	BCS	Multi-clones	0.113	117	0.05
6.0	1.76	KMW	Cyclone	0.12	124	0.05
2.8	0.82	Messersmith	None	0.12	124	0.05
2.2	0.64	Chiptec	Cyclone	0.097	100	0.04
			Averages	**0.113**	**116**	**0.05**

(Ref #18)

This report goes on to say that combustion particulate emissions could be substantially reduced by replacing old units with new, automatically operated small-scale biomass combustion devices or at least by improving the operation of old systems. The main constituents of aerosols from the newer modern systems with complete burnout of the biomass (with good operation and control) are volatile elements such as K, S, Cl, and heavy metals with low melting points (Ref. #19). The following **Table 19** provided by Hamon Research-Cottrell, an ESP supplier, summarizes the measured emissions from a variety of their ESPs operating in North America. Of the 28 installations, 16 have emissions less than 25 mg/m^3.

Table 19: Equipment Supplier Data from Hamon Research-Cottrell

CUSTOMER	LOCATION	Start up	Flue Gas Volume (acfm)	Estim. Size (MW)	Flue Gas Temp (F)	*Outlet mg/m^3*
St. Felician	Quebec, Canada	*2001*	173,258	196	320	*100*
Tasman Pulp #2	Kawerau, NZ	*1992*	115,590	131	415	*100*
Tasman Pulp #3	Kawerau, NZ.	*1992*	135,610	153	415	*100*
Alberta Pacific F.I.	Alberta, Canada	*1991*	464,040	525	338	*89*
Georgia Pacific	Palatka, FlA	*1987*	230,000	260	420	*75*
Avenor	Dalhouse, NB	*1998*	220,719	252	432	*50*
Ultrapower #3	Blue Lake, CA	*1986*	78,000	88	300	*46*
Celgar Pulp	Castlegar, BC	*1992*	148,300	168	374	*45*
Container Corp.	Fernandina B, FlA	*1987*	282,000	319	380	*39*
Willamette Ind.	Campti, LA	*1992*	392,750	445	350	*39*
Yanke Energy Inc.	Dinuba Station,CA.	*1986*	103,000	117	350	*34*
Georgia Pacific	Palatka, FlA	*1987*	230,000	260	420	*25*
Atlantic Gulf Co.	Martell, CA	*1987*	153,300	173	364	*23*
Honey Lake Power	Susanville, CA	*1990*	285,012	323	360	*23*
James River Corp.	Camas, WA	*1992*	202,000	229	350	*23*
S.D.Warren	Skowhegan, Maine	*1991*	310,730	352	350	*23*
Tracy Constructors	Tracy, CA	*1991*	140,000	158	320	*23*
Zurn/Nepco	New Bern, NC	*1991*	282,350	320	350	*23*
Alternative Energy	Livermore Falls, ME	*1993*	296,334	335	360	*21*
Alternative Energy	Cadillac, MI	*1994*	305,225	345	360	*21*
Alternative Energy	Ashland, Maine	*1994*	296,334	335	360	*21*
Greif Bros. Corp.	Riverville, VA	*2001*	110,000	124	350	*17*
Yanke Energy	North Fork, CA	*1989*	82,000	93	375	*16*

CUSTOMER	LOCATION	Start up	Flue Gas Volume (acfm)	Estim. Size (MW)	Flue Gas Temp (F)	*Outlet mg/m^3*
Yanke Energy Inc.	Soledad, CA	*1990*	100,000	113	350	*16*
Hemphill P&L	Springfield, NH	*1988*	95,390	108	315	*15*
Whitefield P&L	Whitefield, NH	*1988*	95,390	108	315	*15*
Gorbell P&L	Athens, Maine	*1988*	101,730	115	330	*15*
Average		**1991**	**201,076**	**228**	**360**	**38**
Maximum		**2001**	**464,040**	**525**	**432**	**100**
Minimum		**1986**	**78,000**	**88**	**300**	**15**
Median		**1991**	**173,258**	**196**	**350**	**23**

Table 20 presents emission data from another manufacturer, PCC Industries of Longview, Texas, who has several ESPs in operation in Canada. The data shows that the guaranteed performance averages about 70 mg/m^3, with the lowest guarantee being 37 mg/m^3. It is informative to note the difference between the guarantee and the actual measured average performance, which was 20 mg/m^3 or about 70% less than the guarantee. This compares to the BC data shown in **Table 14**, where the measured emission was about 40% less than the permit values.

Table 20: Equipment Supplier Data from PPC

ESP Location	Emission PM Conc.		Actual as % of Guarantee
	Guarantee mg/m^3	Actual mg/m^3	
Boise-Cascade / La Grande, Oregon	46	21	46%
Browning-Ferris / Bartow, Florida	46	8	18%
Canfor / Vancouver, B.C.	50	28	55%
Cochrane Power / Cochrane, Ontario	90	4	4%
Georgia-Pacific / Holly Hill S. Carolina	52	18	34%
International Paper / Sampit, S. Carolina	103	47	46%
Owens-Brockway / Oakland, California	37	6	16%
Plum Creek Manuf. / Pablo, Montana	103	3	3%
Timber Energy / Telogia, Florida	103	47	46%
Weyerhaeuser / Edson, Alberta	0.09 mg/kg	0.011 mg/kg	12%
Welborn Cabinets / Ashland, Alabama	5.7 lbs/hr	1.28 lbs/hr	4%
Deltic Timber / Waldo, Arkansas	4.8 lbs/hr	0.78 lbs/hr	16%
Average mg/m^3 or %	**70**	**20**	**30%**
Median mg/m^3 or %	**52**	**18**	**34%**
Maximum mg/m^3 or %	**103**	**47**	**55%**
Minimum mg/m^3 or %	**37**	**3**	**3%**

Ref. #1

7.4 RECENT INSTALLATIONS

Onsite Energy in Medford, Oregon, is a 25 MW_{el} Wood Fired Cogen Facility. They recently installed two 238,000 m^3 ESPs to replace two existing scrubbers. The permit PM limit is 14 mg/m^3 @ 8% O_2. The average test results on these two units were 4-5 mg/m^3 @ 8% O_2.

In December 2007, the emissions from a small (~6GJ/hr input) Decker greenhouse boiler burning pine pellets in Manitoba (see Figure **10**) were measured at 6.6 mg/m^3 at 8% O_2, with CO at 480 mg/m^3 (Ref. #26).

Figure 10: Decker Manufacturing Greenhouse Boilers

DBB Economizer.
Significantly increases boiler efficiency & traps particulates.

Hook up in series to meet any BTU requirement.

New large wood-fired pulp mill power boilers proposed for Uruguay and Tasmania are both proposed to be in the 25 to 30 mg/m^3 range (Ref. #21).

7.5 OTHER JURISDICTIONS

Representative emission factors and regulatory information from Europe and other jurisdictions are included in **Appendix V**. This table is for reference only, as many of the newer high performance wood combustors are made in Europe. This list is not intended to be a complete as such data is already available in other reports completed for BCMOE and MV (See Ref. #14).

Appendix V also contains the New German Boiler Emission Limits from the latest Emission (Immission) Ordinance. Current particulate limits are between 90 and 100 mg/m^3 for wood, and 60 mg for pellets. Future limits (after 2014) will be 20 mg/m^3 for all solid fuels.

8.0 ECONOMIC ANALYSIS OF WOOD COMBUSTOR AND CONTROL SYSTEMS

8.1 RELATIVE COSTS OF COMBUSTORS

The following tables show estimates of installed costs and operating costs for the three main combustion technologies –grate burners, fluidized beds, and two-stage combustors. For smaller systems around 100 tons per day (10 MW), grate burners and fixed-bed gasifiers are the most cost-effective technologies. For larger systems, fluidized bed technology (with or without gasification) becomes more attractive. This data is taken from a 2003 report, but its authors gauged it with manufacturers and experts for the 2007 *Biomass CHP Catalog of Technologies* (Ref. #7). Note that these costs do not include any power generation or gas cleanup equipment, but only represent plants delivering steam or syngas (two-stage combustor).

Table 21: Grate Boiler Steam Plant Costs in U.S. Dollars [Ref. #7]

	Size 1	Size 2	Size 3
Net capacity, MMBTU/hr	**35.4**	**297.5**	**446.3**
MW heat input	10	84	126
Tons fuel /day (as received)	100	600	900
Grate boiler equipment	$1,195,000	$7,980,000	$10,790,000
Installation and balance of plant	$795,000	$10,020,000	$12,460,000
Biomass prep-yard	$2,640,000	$5,430,000	$7,110,000
Installed Cost	**$4,630,000**	**$23,430,000**	**$30,360,000**
Prep-yard labour costs	$400,000	$320,000	$320,000
Boiler section O&M	$160,000	$1,095,000	$1,110,000
Total Annual O&M (to steam)	**$560,000**	**$1,415,000**	**$1,430,000**
Boiler O&M ($/1,000 lb steam)	$3.55	$1.09	$0.73

Table 22: Circulating Fluidized Bed Boiler Costs in U.S. Dollars [Ref. #7]

	Size 1	Size 2	Size 3
Net capacity, MMBTU/hr	**35.4**	**297.5**	**446.3**
MW heat input	10	84	126
Tons/day (as received)	100	600	900
Fluidized bed boiler equipment	$6,175,000	$14,490,000	$19,790,000
Installation and balance of plant	$795,000	$10,020,000	$12,460,000
Biomass prep-yard	$2,640,000	$5,430,000	$7,110,000
Installed Cost	**$9,610,000**	**$29,940,000**	**$39,360,000**
Prep-yard labour costs	$400,000	$320,000	$320,000
Boiler section O&M	$260,000	$1,190,000	$1,205,000
Total Annual O&M (to steam)	**$660,000**	**$1,510,000**	**$1,525,000**
Boiler O&M ($/1,000 lb steam)	$4.19	$1.09	$0.74

Table 23: Two-Stage Combustor Costs in U.S. Dollars (Ref. #7)

Gasifier type	Atmospheric Gasification	Atmospheric Gasification	Atmospheric Gasification	High-Pressure Gasifier
	Fixed	Fluidized	Fluidized	Fluidized / high-pressure
Net capacity, MMBTU/hr	35.2	90.8	159.1	382.6
MW heat input	10	32	63	170
Tons/day (as received)	100	260	450	1,200
Gasifier equipment	$1,225,000	$10,050,000	$15,158,000	$34,682,000
Installation	$612,000	$5,024,000	$7,578,000	$17,338,000
Biomass prep-yard	$2,639,700	$3,947,400	$4,972,000	$9,685,766
Installed Cost	**$4,476,700**	**$19,021,400**	**$27,708,000**	**$61,705,766**
Prep-yard labour costs	$400,000	$320,000	$320,000	$400,000
Gasifier section O&M	$502,000	$634,500	$789,500	$2,235,800
Total Annual O&M (to syngas)	**$902,000**	**$954,500**	**$1,109,500**	**$2,635,800**
Gasification O&M ($/GJ)	$3.43	$1.41	$0.93	$0.92
Estim. steam cost* ($/1000lb)	$4.16	$1.71	$1.13	$1.12

* Not given in original source. Assumed 1150 Btu (1213 kJ) per lb of steam.

Whereas the tables above deal with larger boilers, greenhouses will usually require boilers in the smaller size range between 2 and 40 MW (Size 1 in the tables above). The following graph presents the relative costs of natural gas, pellet, and wood chip (hog) fuel fired systems for greenhouse scale operations including pollution control system. It should be noted that greenhouses in BC require about 7,000 GJ/Acre/year (~2 MW). As shown on the NRC data in **Figure 11**, the raw material handling, combustion, and APC systems required for wood chips with their higher moisture contents, lower energy density, higher ash, and variable physical sizing are much more costly than pellet or gas systems.

Figure 11: Capital Cost of Energy Systems

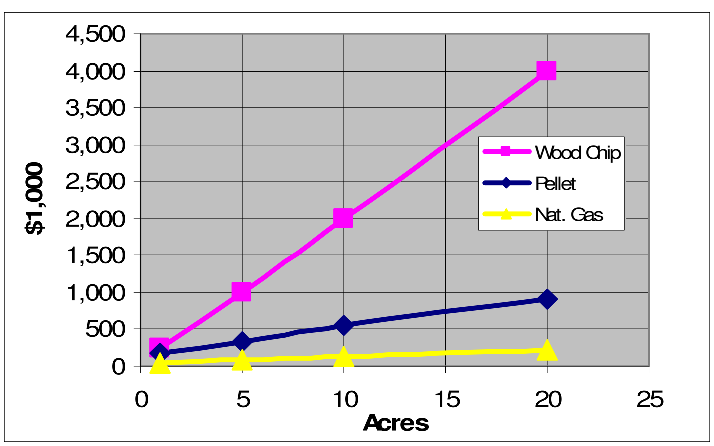


Table 24 presents the annual operating costs for various sized greenhouses for various fuels. The detailed data is based on pellet fuel, and on information provided by Natural Resources Canada (NRC).

Table 24: Annual Greenhouse Operating Costs (x 1000)

Green-house	Boiler size	Installed Cost – Pellets	Financing 5yr@ 6%	Nat. Gas for CO_2	Pellets $115/td	Lab our	Ash @ $40/t	Total Annual Cost (x$1000)		
								Pellets $115/td	Chips $40/td	N. Gas $9/GJ
Acres	MW	1,000$Can								
1	2	175	41.5	13.5	88.8	10	.74	154.5	–	135
2	4	175	41.5	27.0	117.6	10	1.5	257.6	–	270
3	6	250	53.4	40.5	266.4	10	2.2	372.5	–	405
4	8	325	77.2	54.0	355.1	15	3.0	504.3	–	540
5	10	325	77.2	67.5	444.0	15	3.7	607.3	493	675
10	20	550	130.6	135	888.0	30	7.4	1,191	986	1,350
15	30	875	207.8	202.5	1,332	45	11.1	1,782	1,479	2,025
20	40	1,000	260.0	270.0	1,776	60	14.8	2,382	1,912	2,700

td = tonne delivered; chips

It can be seen that at the energy costs shown for natural gas (e.g., $9.00/GJ), pellet and wood fuel are economic even for smaller greenhouses. However, the impediments to fuel switching (See ESI Report for MV), other than cost, will continue to constrain rapid or wholesale switching to wood fuel. It must be noted that the above NRC data includes data from other areas of Canada (e.g., Ontario) besides BC and the Lower Mainland, and therefore assumes a greater energy usage (~19,000 GJ/Acre versus 7,000 GJ/Acre) than the typical Lower Mainland greenhouse operation. However, the relative economic, capital and installed cost analysis still holds.

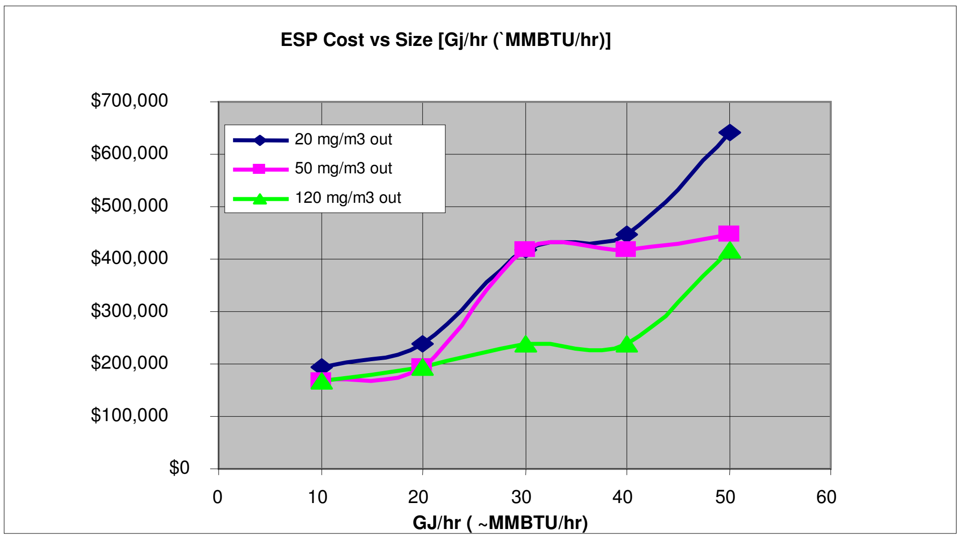
For additional information, reference should be made to the Natural Resources Canada, CANMET Energy Centre Ottawa, which has done a lot of research and developed good cost information on the relative capital and operating costs of solid waste combustion systems versus natural gas or liquid fuels (Ref. #6).

8.2 AIR POLLUTION CONTROL COSTS

The following graphs **Figure 12, Figure 13,** and **Figure 14** present the relative operational costs of pollution control systems necessary to meet specific limits. This data is supplied by PPC who has supplied several of the ESPs currently operating in BC. The cost information is current to 2007. The anomalies (curves) in the graphed data result from PPC's modular approach to ESP installation. Rather than custom-build each ESP, an approach that would result in more linear curves, they supply a series of modular units, thus they may overlap. For example, on the figures the same size unit is applied to both the 30 and 40 MMBTU/hr applications, thus resulting in plateaus on the curves over this range. According to PPC, this modular approach also allows it to provide lower-cost systems, since they do not have to repeat detailed engineering and design studies for each project.

The curves indicate that for the larger units (50 GJ/hr or 14 MW), to go from 50 mg/m^3 to 20 mg/m^3 (a 60% reduction in emissions) incurs a cost increase from \$430,000 to \$650,000, or about 50%. The cost of control is more closely related to the incremental reduction in emissions rather than just overall efficiency. For example, if the inlet loading to the collection system is about 500 mg/m^3 (similar ~0.50 lb/MMBTU values included in AP42), the reduction from 50 to 20 mg/m^3 implies that the control (or removal) efficiency increased from 90% to 96%, (i.e., by 6 %). This compares to the 60% reduction in emissions. Consequently, at high collection efficiencies it is the reduction, rather than just the total change in efficiency that informs the pollution control cost. Going from 50 to 15 mg/m^3 implies a 70% reduction in emissions and therefore implies an approximate 60% increase in cost (to about \$690,000) for the collection system based on the trend in the curve. These costs continue to increase as performance asymptotically approaches 100%.

Figure 12: ESP Size versus Cost



This trend for costs to rapidly increase at high control efficiencies is shown in Figure 13, where it can bee seen that the cost control curves start to rise steeply at concentrations below about 30- 40 mg/m^3.

Figure 13: ESP Cost versus Performance (Outlet Concentration)

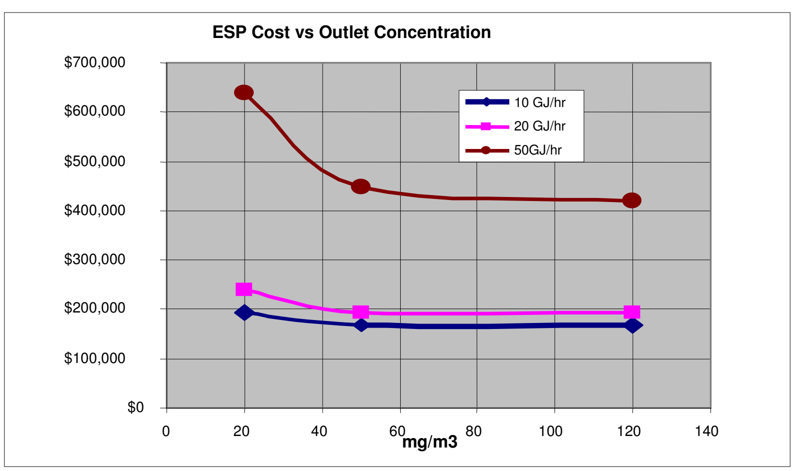


Table 25 presents cost and performance data for a 45 MW (163 GJ/hr) ESP. A fixed set of electrodes is called a field. An ESP consists of one or more such fields in series. The data indicates that for units of this size (and from this supplier) the incremental costs of removing the next tonne of particulates start to escalate rapidly below 22 mg/m^3 (Ref. #32). The outlet loading of course depends on a variety of factors including inlet loading, which for this case is assumed to be 550 mg/m^3 (near that of AP42). The costs shown are current, but include only the basic ESP. Installations are very case specific, and extra costs are not included but can be expected to add another 30-50%. The data also indicate that although a two-field system may achieve 22 mg/m^3 the supplier would likely install at least one extra field to be able to provide a guarantee and cover non-design conditions. Incremental costs describe the additional cost of reducing the next tonne of particulates to achieve a lower flue gas concentration than is possible with the previous number of fields. These costs increase sharply after the second field is added.

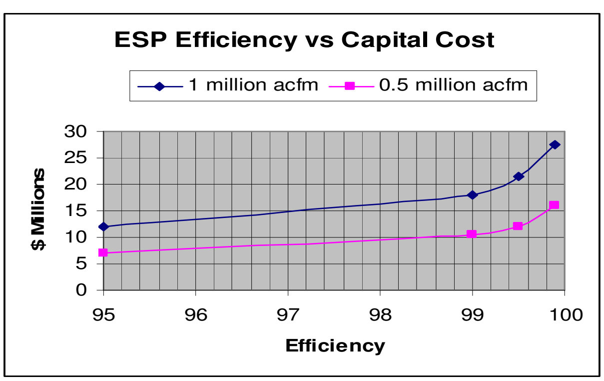
Table 25: 45 MW$_{th}$ ESP Cost Performance Data

ESP Description		Concentrations mg/m^3		Loadings tonnes/yr				Costs Capital	Collection Cost $/tonne collected/yr	
# of Fields	Efficiency	Inlet	Outlet	Inlet	Outlet	Removed	Change	ESP	Overall	Incremental
1	70.00%	550	165.0	327	98.17	229	229.07	500,000	2,183	2,183
2	94.00%	550	33.0	327	19.63	308	78.54	750,000	2,438	3,183
3	97.50%	550	13.8	327	8.18	319	11.45	1,000,000	3,134	21,828
4	99.00%	550	5.5	327	3.27	324	4.91	1,250,000	3,858	50,931
5	99.50%	550	2.8	327	1.64	326	1.64	1,500,000	4,607	152,794

From PPC Ref #1

Similar data from a 1996 USEPA (Ref. #28) study is shown in **Figure 14.** For this current report, the costs have been updated to BC 2007 costs using both the Vatavuc cost factors (Ref. #27) as well as the BC construction cost data shown in **Appendix VI.** The USEPA data, which are for much larger units (~1130 and 565 MW) show a similar trend for costs to rapidly rise once the level of control exceeds 99%. Care should be taken with this data, for in addition to the extrapolation of costs over time, the original data would be based on combustors that were not as efficient or clean as current technologies. Therefore, the PM loads into the APC equipment would have much been higher than current combustors. Consequently, the reported removal efficiencies in 1996 would be higher than with current combustors to achieve the same loading in the stack.

Figure 14: ESP Efficiency versus Capital Cost



From Fig 5.2-9, Ref. #28 USEPA 425 - Note: 0.5 million acfm ~ 566 MW

Additional information of equipment costs used in this report is available from the USEPA and Metro Vancouver (Ref. #5).

Table 26: Particulate Control Costs Analyses for ~2 MW (~7 GJ/hr) Boiler

Capital Cost	ESP Dry	ESP Wet	Core Separator	Multiclone	Cyclone
Equipment	$170,769	$183,386	$19,875	$18,315	$7,600
Site and Facilities	$13,969	$13,969	$2,000	$2,000	$2,000
Installation	$114,415	$122,868	$6,956	$7,365	$6,000
Total Direct Capital Cost	$299,153	$320,223	$28,831	$27,680	$15,600
Annual Cost					
Total Direct	$94,707	$58,534	$12,459	$9,641	$7,095
Capital recovery factor	0.15	0.15	0.15	0.15	0.15
Capital recovery	$44,574	$47,713	$4,296	$4,124	$2,324
Total Annual Cost	**$139,281**	**$106,247**	**$16,755**	**$13,765**	**$9,419**
PM10 Unit Cost of Control At 75%% Annual Capacity Factor					
Control Efficiency PM10	98.0%	98.0%	90.0%	73.0%	50.0%
Emission Rate PM10 uncontrolled lb/MM Btu	0.3	0.3	0.3	0.3	0.3
Emission Rate PM10 controlled lb/MM Btu	0.006	0.006	0.03	0.081	0.15
Annual Emissions PM10 uncontrolled tpy	7.391	7.391	7.391	7.391	7.391
Annual Emissions PM 10 after control tpy	0.148	0.148	0.739	1.996	3.696
Annual Emissions PM10 controlled tpy	7.243	7.243	6.652	5.396	3.696
Annual Cost per ton controlled	$19,228.58	$14,668.07	$2,518.78	$2,551.21	$2,548.80

Source: Ref. #18

Other studies (Ref. #18) have indicated that ESP control costs range from approximately $6,000 to $28,000 per ton [per year] controlled. For smaller units, costs per ton removed using ESPs far exceed the normal range of costs for PM_{10} control. For example, the capital and operating costs for a 2 MW combustor and particulate control system operating with a 75% annual load factor are shown in **Table 26**. The costs are based on an uncontrolled emission level of ~300 mg/m^3 leaving the combustor and before entering the APC system. This cost analysis also includes a "core separator", which is a high-performance mechanical collector similar to a cyclone

Table 27 presents a similar analysis for BC greenhouse boilers of various sizes (1.6 to 16 MW input). Here it can be seen that for the smaller units the cost of the APC system may exceed the cost of the combustor. For example, for the smaller 5 GJ/hr or 1.4 MW input system, the cost of the APC is over two times the cost of the combustions system. Thus, if an efficient low-emission combustion system is available that is capable of meeting acceptable criteria without add-on controls then the system capital and operating costs can be significantly reduced.

Tables 29-34 all assume a 98% reduction in particulate emissions, i.e., an ESP with two fields (or a normal fabric filter), which is the usual setup for this technology.

Table 27: Greenhouse Boilers Capital and Pollution Control Equipment Costs

Boiler Size (Input)		Equipment Cost ($1000s)				Capital Costs ($1000s)		O&M	Admin	Fuel Saving	ESP Cost as a % of	
MW	1000 lb/h steam	Boiler	Cyclone	ESP	Indirect	Total	Annual-ized	$1000/yr	$1000/yr	$/yr	Boiler Cost	Total Cap Cost
						Wood						
1.4	3.4	$78	$4	$190	$163	$491	$66	$20	$5	$71	245%	39%
5.6	14	$203	$13	$210	$256	$770	$103	$62	$15	$282	103%	27%
16.7	41	$535	$22	$230	$472	$1,423	$191	$161	$47	$847	43%	16%
						Natural Gas					LNB Cost as a % of	
		LNB									Boiler	Total Cap
1.4	3.4	$30	$6	$0	$22	$65	$9	$2	$0		20%	9%
5.6	14	$120	$9	$0	$77	$232	$31	$6	$0		7%	4%
16.7	41	$310	$40	$0	$210	$633	$85	$15	$0		13%	6%

Source: From Metro Vancouver and Envirochem (LNB: Low-NO_x burner; ESP: Electrostatic precipitator)

Tables 31 to 33 compare operating costs of biomass boilers with different flue gas cleaning equipment with that of using natural gas without special flue gas cleaning. Three different plant sizes are being compared, as is done in **Tables 24 and 25**. The basic operational costs were taken over from those tables, and specific clean-up costs were estimated from Table 27 above. The price of natural gas was assumed to be $8 per GJ, and that of wood as $30 per bone-dry tonne.

This may seem high for hog fuel, but given that very few mill residues remain for biomass energy projects in BC, this pricing level seems justified and would represent the economic circumstances of many current projects. For these assumptions, gas cleanup costs do not lead to higher costs than when natural gas is used as a heat source, although energy costs increase by up to 25%. When using cleaner-burning pellets, however, the fuel price (assumed to be $115/tonne) is already very close to that of natural gas when using a fabric filter (results for an ESP would be very similar). Requiring this type of flue gas treatment equipment for facilities using pellets would therefore likely discourage the use of pellets as a heat source in BC.

Table 28: Cost Comparison for Grate Burner

	10 MW	84 MW	126 MW
Basic annual operating costs ($)	**560,000**	**1,415,000**	**1,430,000**
Biomass cost ($30/bdt)	**431,961**	**3,630,179**	**5,445,878**
Natural gas cost	***2,114,345***	***17,768,864***	***26,656,282***
Multi-cyclones	75,000	480,000	750,000
Venturi scrubber	160,000	425,000	600,000
ESP	270,000	1,180,000	1,800,000
Fabric filter	200,000	940,000	1,420,000
Cost of steam in $/1,000 lb			
No treatment	6.37	3.85	3.50
Multi-cyclones	6.85	4.22	3.88
Venturi scrubber	7.40	4.18	3.81
ESP	8.10	4.76	4.42
Fabric filter	7.65	4.57	4.22
with natural gas ($8/GJ)	*17.17*	*22.08*	*14.30*
with pellets ($115/tonne, fabric filter)	15.51	12.43	12.08

Table 29: Cost Comparison for Fluidized Bed Burner

	10 MW	84 MW	126 MW
Basic annual operating costs ($)	**660,000**	**1,510,000**	**1,525,000**
Biomass cost ($30/bdt)	**431,961**	**3,630,179**	**5,445,878**
Natural gas cost	***2,114,345***	***17,768,864***	***26,656,282***
Multi-cyclones	75,000	480,000	750,000
Venturi scrubber	160,000	425,000	600,000
ESP	270,000	1,180,000	1,800,000
Fabric filter	200,000	940,000	1,420,000
Cost of steam in $/1,000 lb			
No treatment	7.01	3.93	3.55
Multi-cyclones	7.49	4.29	3.93
Venturi scrubber	8.04	4.25	3.86
ESP	8.74	4.83	4.47
Fabric filter	8.29	4.64	4.27
with natural gas ($8/GJ)	*17.81*	*22.19*	*14.35*
with pellets ($115/tonne, fabric filter)	16.15	12.50	12.13

For the gasifier section, the numbers from **Table 23** were adapted to reflect the BTU energy inputs of Sizes 1, 2 and 3 of **Tables 24 and 25**. The steam production part is not included in the original table, but O&M figures appear exaggerated for two-stage combustion, given that some companies, such as Nexterra, claim lower O&M costs than comparable technologies. The higher costs assumed for two-stage combustion technologies are therefore questionable, but overall results remain very similar for all technologies.

Table 30: Cost Comparison for Two-Stage Combustors

	10 MW	**84 MW**	**126 MW**
Gasifier type	**Fixed**	**Fluidized**	**Entrained**
Basic annual operating costs ($)	**902,000**	**2,074,646**	**3,074,641**
Biomass cost ($30/bdt)	**431,961**	**3,630,179**	**5,445,878**
Natural gas cost	***2,114,345***	***17,768,864***	***26,656,282***
Multi-cyclones	75,000	480,000	750,000
Venturi scrubber	160,000	425,000	600,000
ESP	270,000	1,180,000	1,800,000
Fabric filter	200,000	940,000	1,420,000
Cost of steam in $/1,000 lb			
No treatment	8.56	4.36	4.34
Multi-cyclones	9.05	4.72	4.72
Venturi scrubber	9.59	4.68	4.64
ESP	10.30	5.26	5.26
Fabric filter	9.85	5.08	5.06
With natural gas ($8/GJ)	*19.37*	*22.83*	*15.14*
With pellets ($115/tonne, fabric filter)	17.71	12.93	12.92

Table 31 describes the economics of power boilers in BC, which are quite different from those of heat boilers discussed above. The power price was set to levels between $110 and $140 per MW_{el}, plus the federal ecoENERGY incentive of $10 per MW_{el}. The 50 and 10 MW_{el} plants are supposed to be steam plants requiring at least three power engineers, whereas the smaller power plant is based on a non-steam system (Organic Rankine cycle or other) with fairly minimal maintenance and no need for a power engineer to supervise it. The necessary Return on Investment is assumed as 14%, using a mix of risk and bank financing. The cost parameters were adapted from Ref. #2 and are gauged against real examples of planned power plants in BC, although the economics may look somewhat different in each case.

A $30 cost per tonne for wood fuel was assumed here as well, although a higher price of $50 or more per dry tonne may apply, especially where mill residues are no longer available and more expensive fuels, such as roadside residue, is used. The operational costs for the different flue gas cleaning options were derived from Table 27, based on the assumed BTU inputs, which are in turn calculated assuming different power plant conversion efficiencies for each plant size. Capital costs for the flue gas cleaning system will roughly double when residual emissions are reduced by 50%, and operational costs for the flue gas cleaning section will increase by 40-50%, based on the information above. Although costs are high, ESP has been applied to units as small as 10 GJ/hr (3 MW_{th}) (Ref. #32).

Table 31: Cost Comparison for Power Production

	50 MW_{el}	10 MW_{el}	2 MW_{el}
Energy input, MMBTU/hr	*600*	*170*	*49*
Power price per MWh	*$120*	*$150*	*$150*
Capital cost	*170,000,000*	*40,000,000*	*7,000,000*
Salaries	1,890,000	900,000	12,500
Maintenance	6,800,000	1,400,000	350,000
Utilities, insurance etc.	400,000	40,000	20,000
Property tax	400,000	40,000	15,000
Property lease	0	60,000	20,000
Fuel pre-treatment	800,000	0	0
Wood fuel ($30/bdt)	9,000,000	3,000,000	900,000
Financing cost (14%)	23,800,000	5,600,000	840,000
Electricity sold	44,676,000	11,169,000	2,233,800
Balance	**1,586,000**	**129,000**	**76,300**
Multi-cyclone	1,000,000	280,000	95,000
Venturi scrubber	775,000	315,000	185,000
ESP	2,355,000	750,000	330,000
Fabric filter	1,870,000	630,000	240,000

As the table shows, flue gas cleaning is a fairly small part of the budget for a large 50 MW_{el} power plant (about 1%), but gains increasing importance as the plant size decreases. Current large-scale power plants are usually built using the most efficient flue gas cleaning equipment such as electrostatic precipitators (e.g., Mackenzie Green Energy). For a 10 MW_{el} power plant, adding a baghouse or ESP may mean the same as a $10 per MWh_{el} reduction in the price paid for the power it produces or a $5/bdt increase in fuel cost, which may make or break a project. For a 2 MW_{el} project, this difference is even $20 per MWh_{el} in the case of an ESP.

Any of the options would use up the remaining profit of a small project, and would thus reduce the gains available to lenders, possibly leading to the project not being realized. Whereas the economics modelled will not apply to each single project, biomass power projects are generally difficult to realize in BC due to the low value of electricity. This is important when comparing mandated emission levels to other projects in the Eastern US, for example, where power pricing is much higher (allowing for a larger investment in flue gas treatment). The rates paid to independent power producers used in **Table 31** are already optimistic in light of what BC Hydro was willing to pay in past years. On the other hand, combined heat and power projects will in many cases achieve better economics than shown here.

9.0 CONCLUSIONS

9.1 CONCLUSIONS ON GAS CLEANUP TECHNOLOGIES

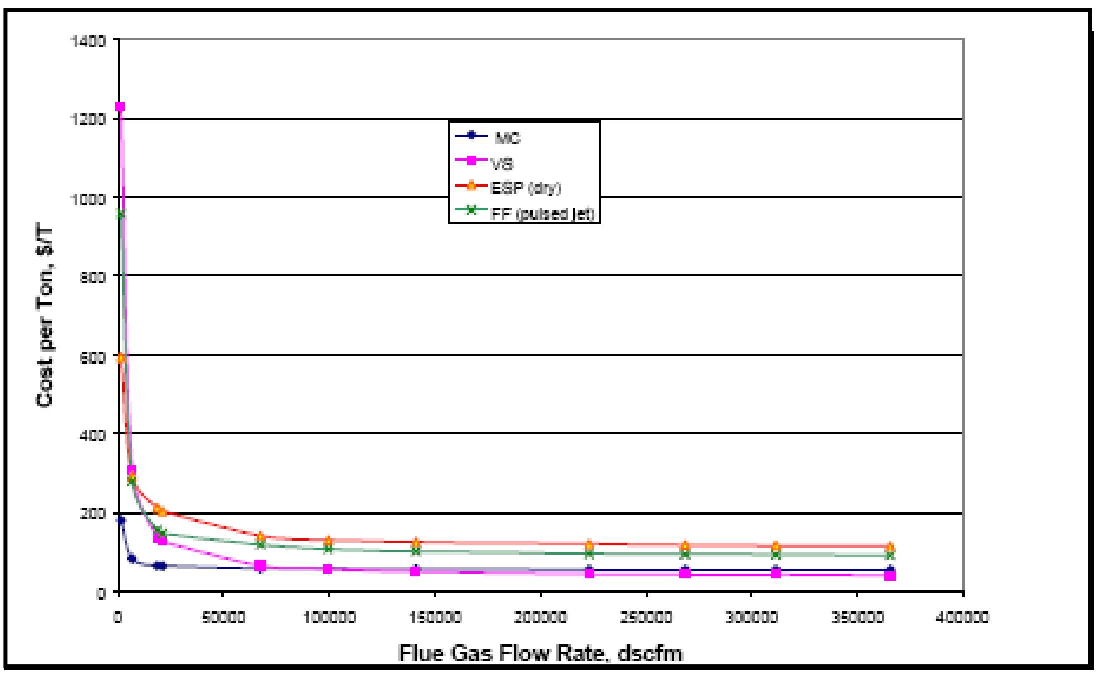
Table 32 summarizes the levels of emissions that can be achieved with current technologies and without consideration of costs for one-micron size particles. The overall removal efficiencies will depend on the size profile of the emissions leaving the combustion zone, which in turn will depend on the type and operation of the combustion equipment.

Table 32: Available Control Technology PM Removal for Five Technologies

Control System	Uncontrolled PM mg/m^3	Removal Efficiency % (for 1 μm Particles)	PM concentration mg/m^3 at stack
High Efficiency Cyclone	330	30-40	230-120
Multicyclone		50	165 -120
Venturi scrubber		96	15
Electrostatic precipitator		98	7-4
Baghouse		99	7-4

(After AP42 Wet Wood and Stern)

Figure 15: Cost-Effectiveness of PM Control Technologies



Ref. #32

Figure 15 shows the cost curves start to increase rapidly at a flue gas flow rate of about 20,000 cfm (34,000 m^3 per hour). Below this flow (~23 MW, or about 4.5 MW_{el} at 20% conversion efficiency), options other than cyclones become very expensive, although examples can be found where these are still used in this size range. Note, however, that power boilers are subjected to tighter economic circumstances than heat boilers – especially under 10 MW_{el}. Gas cleanup costs for new plants are moving down over time as the performance of flue gas cleaning technologies improves, and as the raw gas PM content is reduced due to improved combustion and gasification technology. In the same way, increasing power and natural gas pricing is likely to leave more room to accommodate the increased capital costs of better flue gas cleaning equipment in the future.

Key considerations in minimizing air emissions from biomass combustion are to use combustion and air pollution control systems designed for, and appropriate to, the specific fuel to be used. This should include taking into consideration the fuel's moisture, ash, and chlorine (and sulphur if used with an auxiliary fuel) contents, as well as the fuel's physical size and characteristics (e.g., dry chips, sander dust, or wet hog fuel). Changing biomass fuel type or characteristics, perhaps due to poor quality control by the fuel supplier, changes in fuel availability or in response to price variations, without taking into consideration the impact that such changes can have on burner operation and the pollution control equipment will frequently lead to increased emissions. Consequently, it is important to link (or restrict) the combustion and pollution control process to the type of fuel. In return, mandating strict emission levels may curtail a facility's ability to use a variety of fuels. This may reduce economic returns and fuel supply security of energy systems. The aim should be to allow for common wood fuels, including roadside residue with bark, whereas using fuels with high salt content may warrant specific restrictions due to dioxin emissions.

9.2 HEAT BOILERS/FURNACES

For boilers without power generation, wood represents a fairly inexpensive fuel as compared to natural gas, being about 70-80% cheaper on an energy unit basis. Project ROI to move from natural gas to wood is therefore attractive and allows for some gas cleanup equipment. The question of emission controls then becomes one of the relative cost of additional reductions, as well as the operation of emission control equipment. For example, institutional heat boiler applications using a baghouse may be inadequate due to the high maintenance requirements and the potential fire hazard. This suggests demanding no other technology than cyclones for those smaller applications, or not using biomass at all if particulate emissions are a major concern. Front-end combustion technology may then determine back-end emissions, i.e., two-stage combustors may allow for lower emissions than other technologies.

The economics of using wood as a heat source allow smaller heat boilers to still invest in high-performance cleanup equipment without losing the economic advantage of wood. Medium and large systems will be equipped with baghouses or ESP. Their usual performance can guarantee low levels of particulate emissions. Whereas lower limits are technically possible and may even be economically feasible, the per-tonne reduction costs become very high below a guaranteed emission level of 40-50 mg/m^3, and an ESP may cost as much or more than the heat boiler for sizes under 5 MW (See **Table 27**). A 50 mg/m^3 limit is equivalent to a two-field ESP working at a removal efficiency of 96-98% (See **Table 25**). At higher performance levels, the marginal reduction costs per tonne of particulates increases to more than $25,000 per year. This threshold should be reviewed over time as advances in technology may reduce this limit in the future.

Whereas the results of Metro Vancouver showed even lower average limits (e.g., the Interfor Hammond Mill, which is burning clean cedar shavings and sawdust show emissions are under 10 mg/m^3 for a 10 MW boiler, Ref. #33), the ability to consistently achieve such low limits was not confirmed in this present work. As an example, the Powell River power boiler meets a 20 mg/m^3 standard for particulates, whereas the Port Alberni unit fails to do so although it is very similar [Ref. #8]. This speaks to the difficultly in predicting operational performance, especially at these low emissions levels. A common ESP with one or two fields will only guarantee levels around 50 mg/m^3 (a number that is also deemed achievable by industry, see Ref. #8 and #34), and lower levels will require over-dimensioning, with associated higher costs.

The lowest levels manufacturers are likely to guarantee are 10-15 mg/m^3, but achieving these levels on an ongoing basis requires very good fuel quality control and close equipment surveillance in order to achieve maximum burnout and optimum ESP performance. PPC Ltd. installed an ESP guaranteeing 16 mg/m^3 in the U.S., however, this boiler was designed for a variety of fuels, including tire-derived and other higher ash fuels, such that a five-field ESP was necessary to achieve this performance level [Ref. #1]. Similar situations (e.g., the need for 5 field ESPs) may arise at BC facilities trying to use a variety of higher ash or moisture content fuels. The findings of this report, based on interviews with manufacturers, show that only larger facilities with full time staff dedicated to boiler operation can consistently achieve such low emissions. The lower-end measurements obtained by Metro Vancouver should therefore not be taken as proof that these levels can be achieved in all situations.

For smaller plants, however, requiring low emission levels appears to be equivalent to mandating specific combustion technology. Current permit levels of <120 mg/m^3 can be achieved with well designed combustion systems and a cyclone. Two-stage combustors may be able to achieve lower concentrations of 50 mg/m^3 (Nexterra's claim). These emissions may be able to be reduced even further with cyclones. Prediction of the improvement, however, would require information on particle sizing, which is currently not available.

Table 33 shows the results of the above research for power and heat applications using wood in BC.

Table 33: Achievable PM Emission Limits by Technology Size (Heat Boilers/Furnaces)

Boilers and Furnaces				
Heat Input	**40+ MW_{th}**	**3-39 MW_{th}**	**1-3 MW_{th}**	**<1 MW**
A. P. Controls	**ESP**	**ESP/fabric filter**	**ESP/fabric filter**	**Cyclones**
Current Range	3-47 mg/m^3		59-221 mg/m^3	216–5,000 mg/m^3
Economically Achievable Limit	20 mg/m^3	35 mg/m^3	50 mg/m^3	120* mg/m^3
Rationale for E. A. Limit	Large units are less sensitive to higher cleanup costs. Achievable with a 3-4 field ESP.	APC costs as much as boiler at about 5 MW size. Achievable 2-3 field ESP.	Can be achieved with cyclone and 1-2-field ESP, but APC costs my exceed combustor.	Feasible with cyclone or two-stage combustor.
Even lower limits	Technically feasible, but APC cost starts to increase sharply below this limit, especially for higher ash fuels such as hog.	Would require technology demanding constant supervision.	Would require technology demanding constant supervision.	Would discourage use of wood as a fuel. *If gasification technology or pellets are used then 70 mg/m^3 is achievable.

Note: Air pollution controls (APC) such as ESP and baghouses usually include cyclones as precollectors. The higher cost of pellet fuel relative to raw wood, reduces opportunity to fund enhanced APC (e.g., beyond cyclones) out of the fuel cost savings at current natural gas/pellet price differentials.

9.3 ELECTRICAL POWER BOILERS

Based on the calculations and other information above, larger power plants of 25 MW_{el} and more are relatively insensitive to both operational and capital costs incurred by emission reduction measures. Assuming a particulate concentration of 330 - 500 mg/m^3 in the raw flue gas, an electrostatic precipitator with 98% removal efficiency would be capable of reducing emissions to less than 10 mg/m^3. An average emission performance of 20 mg/m^3 is already envisaged by the Mackenzie Green Energy Centre (estimated based on the environmental assessment: 7 g PM/s and using 417 m^3 of flue gas per GJ), using an ESP. For actual performance data, it is important to note that equipment manufacturers usually only guarantee about twice the emission level their equipment can actually achieve, to reserve a safety margin. This is to allow for acceptable performance (emissions) when the actual operating conditions depart from the combustor or APC design conditions.

Power generation based on steam turbines requires the presence of two or more power engineers for the constant supervision of the power generation system. Smaller-scale power generation systems under 10 MW_{el} will likely be non-steam systems that are based on oil or other thermal fluids and which do not require the constant presence of an engineer or supervisor.
The BC Government is currently considering legislation to remove the need for a constant presence of two power engineers also for smaller-scale steam plants, such that smaller steam

plants might be built in the future. The main concern is, however, the ability of flue gas cleaning systems to function on their own without adding to the safety risk: incomplete burnout, which is also more likely in less controlled, smaller systems, may lead to a build up of carbonic matter on the fabric filter, which may be ignited by a spark from the boiler (fire hazard). Given very tight economics for biomass power plants in BC, emission control costs can curtail their development. The limits in **Table 34** therefore seem to be the minimum levels that can be achieved without unduly reducing a plant's ability to raise capital and use different fuel types. Note that setting a limit of 20 mg/m^3 implies that the manufacturer will typically design the unit for an average performance at about 50% of that level, i.e. around 10-15 mg/m^3. Thus it appears to be the current lower limit that can be achieved without having to spend undue efforts on controlling the combustion process.

The economics of electric power boilers are very different from those of heat boilers. The difficulty of securing large amounts of biomass leads to most biomass power plants being built in sizes between ten and fifty megawatts (electric), as opposed to more efficient coal and natural gas plants of several hundred megawatts. Electricity is only produced at an efficiency of around 30% or less (compared to a natural gas combined cycle plant that generates at 50% efficiency or more), and there are higher gas cleanup and fuel handling costs than for natural gas. Current pricing in BC is not advantageous for wood fuelled power plants in comparison to European countries, where power prices are higher and in addition certificate trading systems exist that sometimes double the value of the electricity sold. The industry, including the pellet sector, is able to pay up to $30 per dry tonne of wood, but most remaining resources, such as roadside residue, cost $50 per tonne or more. A power price of 10 cents per kWh is then no longer enough to profitably operate such a plant. Especially smaller power plants in the 10 MW_{el} range are therefore sensitive to increased flue gas treatment costs. A reduction to 25 mg/m^3 (from 50) could double the cost of an ESP, which translates into a 5% capital cost increase. Such an increase may, in combination with fuel price insecurity, lead to the abandonment of wood-based power projects in BC. For these reasons, emission levels for power plants are set slightly differently than for heat boilers. Cogeneration systems will generally have better economics than power-only systems due to the increased income from heat sales.

Table 34: Achievable PM Emission Limits by Technology Size (Electrical Power Plants)

Electrical Power Plants			
Heat Input	**90+MW**	**45-89 MW_{th}**	**0.8-44 MW_{th}**
Power Output*	**25+ MW_{el}**	**10-25 MW_{el}***	**0.1-9 MW_{el}**
Technology	Steam	Steam	Non-steam
Economically Achievable Limit	20 mg/m^3	50 mg/m^3	120 mg/m^3
Rationale for E.A. Limit	Large units are less sensitive to higher cleanup costs. This can be achieved with a 3-4 field ESP.	Achievable with cyclones and 1-2-field ESP while allowing fuel and operational flexibility.	Confidently achievable with cyclone while allowing fuel and operational flexibility.
Even lower limits	May require additional ESP fields and near the limit currently guaranteed by manufacturers. Requires constant system optimization. May limit the ash content in fuels (e.g., clean low ash wood).	Would increase ESP costs more than economics of small systems can tolerate.	Would require technology demanding constant supervision; increases capital costs by at least 5% (more for systems under 2 MW_{el}); would mandate fixed-bed gasification technology (which can achieve 70 mg/m^3, see previous table) and/or reduced fuel flexibility.

* MW_{el} output is derived from heat input using appropriate electric conversion efficiencies

9.4 PELLET FUELS

The use of pellets in itself can be viewed as an emission reduction measure, since pellets are of very consistent quality (relative to other wood fuels), burn very cleanly as they do not contain any bark (white premium pellets), thus have very low ash contents of around 0.5% with consistent and low moisture of about 8%. Their high delivered cost (around 72% the cost of natural gas on a per GJ basis); however, may preclude economically adding additional emission reduction measures.

Any demand on installing emission controls when using pellets will quickly shift the economic advantage towards natural gas as a fuel. Depending on the combustion technology, particulate emissions using pellets may be as low as 70 mg/ and small-scale two-stage combustors (gasifiers) with expected very low emissions 50-70 mg/m^3) are currently under development. Again, the argument that maintenance-intensive fabric filters and ESP will deter the use of wood as a fuel in many small-scale applications. Likewise, the potential fire hazard will preclude their use in small units without constant supervision (outside the common industrial sectors, such as pulp & paper).

9.5 COMPARISON TO OTHER JURISDICTIONS

The limit values identified as feasible in the preceding tables are more stringent than those currently used in other jurisdictions, such as Germany, Austria, or Switzerland (See **Appendix V**). Generally, 120 mg/m^3 can be achieved with most technologies using good combustion practices and a cyclone. Lower emission levels will require more sophisticated end-of-pipe treatment (fabric filter or ESP).

9.6 AIRSHED CONSIDERATIONS

Populated settings or sensitive air sheds may require special consideration. Thus, it may be necessary to require limits stricter than the proposed economically achievable levels, even for smaller units. In such cases the economics may then require subsidies, without which the wood-fired projects may be abandoned in these areas. Community resistance to wood burner emissions can be very strong (recent problems in realizing a district heating project in Prince George and in the Olympic Village in Vancouver). In Prince George, even though the average emissions of the proposed district heating system would have been in quite low (average of 15 mg/m^3), the system was still not accepted by the local community.

In such sensitive air shed cases it may be more informative to regulate the sources based on total mass emissions (loadings) to the local air shed, rather than just setting concentration criteria. Such an approach may present a clearer understanding of the impacts on (or relative addition to) the local air shed. This approach should also include consideration of the various size fractions in the emissions.

9.7 DIOXIN FORMATION CONSIDERATIONS

Due to the potential for dioxin formation from salt containing hog or wood fuel, the use of such fuels should be limited in smaller combustors that have not been specifically designed or demonstrated to minimize dioxin formation.

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Appendix II: European Biomass Standards CEN/TC 335

CEN/TC 335 is the technical committee developing the draft standard to describe all forms of solid biofuels within Europe, including wood chips, wood pellets and briquettes, logs, sawdust,and straw bales.

About CEN/TC 335

CEN/TC 335 allows all relevant properties of the fuel to be described, and includes both normative information that must be provided about the fuel, and informative information that can be included but is not required. As well as the physical and chemical characteristics of the fuel as it is, CEN/TC 335 also provides information on the source of the material.

Technical standards

For specified parameters to be relevant it is important that there is a standard way of measuring them to ensure that measurements are reproducible and unambiguous.

There are therefore, a list of technical standards that define terminology, measurement methods and sampling methods.

Published technical standards	
Standard reference	**Title**
CEN/TS 14588:2004	Solid biofuels - Terminology, definitions and descriptions
CEN/TS 14774-1:2004	Solid biofuels - Methods for determination of moisture content Oven dry method - Part 1: Total moisture - Reference method
CEN/TS 14774-2:2004	Solid biofuels - Methods for the determination of moisture content Oven dry method - Part 2: Total moisture - Simplified method
CEN/TS 14774-3:2004	Solid biofuels - Methods for the determination of moisture content Oven dry method - Part 3: Moisture in general analysis sample
CEN/TS 14775:2004	Solid biofuels - Method for the determination of ash content
CEN/TS 14778-1:2005	Solid biofuels - Sampling - Part 1: Methods for sampling
CEN/TS 14778-2:2005	Solid biofuels - Sampling - Part 2: Methods for sampling particulate material transported in lorries
CEN/TS 14779:2005	Solid biofuels - Sampling - Methods for preparing sampling plans and sampling certificates
CEN/TS 14780:2005	Solid biofuels - Methods for sample preparation
CEN/TS 14918:2005	Solid Biofuels - Method for the determination of calorific value
CEN/TS 14961:2005	Solid biofuels - Fuel specifications and classes
CEN/TS 15103:2005	Solid biofuels - Methods for the determination of bulk density
CEN/TS 15104:2005	Solid biofuels - Determination of total content of carbon, hydrogen and nitrogen - Instrumental methods
CEN/TS 15105:2005	Solid biofuels - Methods for determination of the water soluble content of chloride, sodium and potassium
CEN/TS 15148:2005	Solid biofuels - Method for the determination of the content of volatile matter
CEN/TS 15149-1:2006	Solid biofuels - Methods for the determination of particle size distribution - Part 1: Oscillating screen method using sieve

Published technical standards	
Standard reference	**Title**
	apertures of 3,15 mm and above
CEN/TS 15149-2:2006	Solid biofuels - Methods for the determination of particle size distribution - Part 2: Vibrating screen method using sieve apertures of 3,15 mm and below
CEN/TS 15149-3:2006	Solid biofuels - Methods for the determination of particle size distribution - Part 3: Rotary screen method
CEN/TS 15150:2005	Solid biofuels - Methods for the determination of particle density
CEN/TS 15210-1:2005	Solid biofuels - Methods for the determination of mechanical durability of pellets and briquettes - Part 1: Pellets
CEN/TS 15210-2:2005	Solid biofuels - Methods for the determination of mechanical durability of pellets and briquettes - Part 2: Briquettes
CEN/TS 15234:2006	Solid biofuels - Fuel quality assurance
CEN/TS 15289:2006	Solid Biofuels - Determination of total content of sulphur and chlorine
CEN/TS 15290:2006	Solid Biofuels - Determination of major elements
CEN/TS 15296:2006	Solid Biofuels - Calculation of analyses to different bases
CEN/TS 15297:2006	Solid Biofuels - Determination of minor elements
CEN/TS 15370-1:2006	Solid Biofuels - Method for the determination of ash melting behaviour - Part 1: Characteristic temperatures method

Appendix III: Useful Conversion Factors

Solid Wood Densities (kg/m3), Coastal Forest Mix, and Moisture Contents

	% Moisture Green		Density		Forest Mix	Weighted MC		Density Wted.	
Species	MC-db	MC-wb	Dry	Green		MC-db	MC-wb	Dry	Green
	%	%	kg/m3	kg/m3	%	%	%	kg/m3	kg/m3
Red Cedar	62%	38%	329	533	5%	3.10%	1.91%	16.45	26.65
Doug fir	45%	31%	450	652	45%	20.30%	13.97%	202.5	293.4
Balsam	12%	11%	335	730	20%	2.40%	2.11%	67	146
Hemlock	85%	46%	423	782	30%	25.50%	13.78%	126.9	234.6
Average	**51%**	**31%**	**384**	**674**	**100%**	**51.20%**	**31.80%**	**413**	**700.65**

From Forintek Conversion Factors

Gravity Packed Unit (GPU)	ft3	m3
1 unit	200	5.664
1 unit	200	5.664

Flue Gas Conversions	
1.0 GJ =	417 m3
0.948 MMBTU	417 m3
1MMBTU	440 m4
1.0 kg/GJ =	2398 mg/m3
1.0 lb/MMBTU =	0.43 kg/GJ
1.0 lb/MMBTU =	1031 mg/m3

Densities of Various Fuels		**kg/m3**			**m3 of SWE**	**Ratios to**	
Type of Residue		**low**	**high**	**Aver**	**/GPU**	**dry**	**Half Dry**
Solid wood	Dry			413		1	0.74
Solid wood	Green			701		1.7	1.26
Solid wood	Half dry			557		1.35	1
Pulp chips		256	320	288	2.16	0.7	0.52
Sawdust		288	352	320	2.27	0.78	0.57
bark		304	449	377	2.29	0.91	0.68
hog fuel		288	384	336	2.2	0.81	0.6
Planer shavings							
	green			64	0.48	0.16	0.11
	dry loose			88	1.04	0.21	0.16
	dry compacted			136	1.67	0.33	0.24

Trucking	
1 tandem truck	10 m^3
1 Large truck	45m3
1 chip Truck	(8 units)
Cost	$100 -$150.hr

Coastal Forest Mix (cf. Timber West-Van Isl)
5% western red cedar;
45% Douglas fir;
42% hemlock/balsam;
8% cypress, Sitka spruce and other species.

Energy units

* 1.0 joule (J) =	one Newton applied over a distance of one meter (= 1 kg m2/s2).		
* 1.0 joule =	0.239 calorie:	1.0 calorie =	4.187 J
* 1.0 GJ =	1000000000 J	10^9 Joules	
* 1.0 GJ =	0.948 MMBTU	1MMBTU =	1.055 GJ
* 1.0 GJ =	278 kWh		
1.0 BTU =	1055 J	1.055 kJ	
1. 0 Therm =	100000 BTU	100 scf Nat Gas	
1.0 Quad =	1 quadrillion Btu (1015 Btu) =	1.055 exajoules (EJ),	
1.0 Quad =	~ 172 million barrels of oil equivalent boe		
1000 Btu/lb =	2.33 GJ/Tonn	2.00 MM BTU/ton	
1 MMBTU/ton =	1.17 GJ/Tonne		
1000 Btu/US gallon =	0.279 megajoules per liter (MJ/l)		
1 BTU/HR =	0.2931 watts		

Orders of Magnitude (Size)

Expont.	Name	Abrev.	Description	Decimal	Example
10^{-2}	centi	c	Hundredth	0.01	cg/g
10^{-3}	milli	m	Thousandth	0.001	mg/g or g/kg
10^{-6}	micro	µ	Millionth	0.000 001	ug/g or ppm
10^{-9}	nano	n	Billionth	0.000 000 001	ng/g or ppb
10^{-12}	pico	p	Trillionth	0.000 000 000 001	pg/g
10^{-15}	femto	f	Quadrillionth	0.000 000 000 000 001	fg/g

Excess Air Oxygen Correction

Corrected Contaminant Concentration to Specifed O2 = (Measured Contaminant Concentration) * (0.21-Specified Standard O2Conc.) / (0.21-Measured O2 Conc)

	Example	Calculator	
Measured Contaminant Concentration	250	500	<--Enter
Measured O2 Concentration	13%	13%	<--Enter
Specified Standard O2 Concentrations	8%	8%	<--Enter
Corrected Contaminant Concentration to Specifed O2	**406.3**	**812.5**	<--Calculate (DO NOT enter values here)

Appendix IV: BCMOE and BACT Emission Data

Available Control Technology for Biomass Fired Boilers CO DATA

(100 - 750 MMBTU/hr size`range)

ENVIROCHEM SERVICES INC.

Facility Description	Boiler Size MMBtu/hr	Boiler Type	Primary Fuel	Facility Name	Facility State	Permit Date	Limit 1 lb/MMBtu	kg/GJ	Limit 1 Avg	Control Method (% removal)	Notes
Simpson mill manufactures bleached and unbleached kraft pulp and linerboard	595	Hog Fuel Boiler (Power Boiler #7)	Wood waste	Simpson Tacoma Kraft Company	WA	05/22/2007	0.35	0.15	30 day rolling avg	Combustion Controls with Overfire Air System	
Seven boilers purchased from an ethanol plant, permit is to retrofit these boilers to burn wood or wood waste to generate power	318	Wood Fired Boilers	Wood	South Point Biomass Generation	OH	4/4/2006	0.1	0.04		Oxidation Catalyst	
Designed to produce about 300 million board feet of lumber annually and run 430 MMBtu/hr waste wood fired boiler as a 30 MW cogen unit	430	Wood Fired Cogeneration Unit	Bark & Waste Wood	Skagit County Lumber Mill	WA	01/25/2006	0.93	0.39			
Manufacture of wood pellets-No Coatings	77	Heat Energy Systems for Pellet Processing	Wood / Wood Paste	International Biofuels. INC	VA	12/13/2005	0.19	0.08		Thermal Oxidizers and CEM System	
Manufacture of wood pellets-No Coatings	43	Wood Thermal Oxidizers for Wood Pellet Process	Wood / Wood Paste	International Biofuels. INC	VA	12/13/2005	0.38	0.16		Thermal Oxidizers and CEM System	
Wood fired cogeneration facility adjacent to an existing mill	403	Wood waste-Fired Boiler	Wood Waste	Darrington Energy Cogen Power Plant	WA	11/2/2005	0.35	0.15	24-Hour	Good Combustion Practices	
Pulp & Paper Mill. Project involves addition of 30 MMBTU/hr Natural Gas-Fired air heaters to the under grate air system of the No.12 Boiler, potentially allowing more steam to be produced on both a short and long term basis	787.5	No.12 Hogged Fuel Boiler	Bark	Bogalusa Mill	LA	11/23/2004	0.62	0.26	Hourly Max	Overfire Air System & Good Combustion Practices	
150 MW fossil fuel fired power plant consisting of three 50 MW units. Unit #5 is wood fired with coal as a back-up fuel.The two other units are coal fired.	720	Wood Fired Boiler, CFB Unit #5	Biomass	Schiller Station	NH	10/25/2004	0.10	0.04	24 Hour/Above 50% Load	Good Combustion Practices with the fluidized bed design	
The facility manufactures unbleached kraft linerboard	856	Boiler, Solid Fuel	Bark	Inland Paperboard and Packaging Inc - Rome Linerboard Mill	GA	10/13/2004	0.423	0.18		Staged combustion and good combustion practices	Emission limit as LB/MMBtu is not available
Sugar Mill and Refinery	936	External Combustion, Multiple Fuels	Bagasse	Clewiston Sugar Mill and Refinery	FL	11/18/2003	0.380	0.16	12 month rolling avg.	Good combustion and operating practices	12 month rolling avg avoids BACT
Vegetable Oil Plant	200	Boilers, 2 Wellons	Hulls	Archer Daniels Midland Co. - Northern Sun Veg. Oil	ND	9/7/1998	0.630	0.27			
Vegetable Oil Plant	280	Boiler, JTA	Hulls	Archer Daniels Midland Co. - Northern Sun Veg. Oil	ND	9/7/1998	0.630	0.27			
Turkey Manure and other biomass fueled power plant 50 MW output, 792 MMBtu/hr heat input	792	Boiler, Multi-Fuel	Manure	Fibrominn Biomass Power Plant	MN	10/23/2002	0.240	0.10	24-HR avg	Good Combustion Practices	
Hog fuel boiler will use SNCR for Nox control to 0.15 LB/MMBtu (24 Hr Avg) and 0.1 LB/MMBtu (Annual Avg), ESP for PM control to 0.02 LB/MMBtu (24 HR AVG) AND good combustion practice for CO control to 300 PPMDV (24 hr avg)	310	Hog Fuel Boiler	Waste Wood	Aberdeen Division	WA	10/17/2002	0.350	0.15		Good Combustion Practices	

Note: 0.17

Approximate unit conversions for Emissions of PM, Nox and CO — CO : 217 lb/hr = 0.23 lb/MMBTu = 4.3 lb/MWh

USEPA - BACT Data - NOx

Facility Description	Boiler Size MMBtu/hr	Boiler Size MW	Boiler Type	Primary Fuel	Facility Name	Facility State	Permit Date	Limit 1 lb/MMBtu	Limit 1 kg/GJ	Control Method	Estimated Efficiency (%)	Limit 1 Avg
Simpson mill manufactures bleached and unbleached kraft pulp and linerboard	595	174	Hog Fuel Boiler (Power Boiler #7)	Wood waste	Simpson Tacoma Kraft Company	WA	05/22/2007	0.2	0.08	Combustion Controls with Overfire Air System		30 day rolling avg
Seven boilers purchased from an ethanol plant, permit is to retrofit these boilers to burn wood or wood waste to generate power	318	93	Wood Fired Boilers	Wood	South Point Biomass Generation	OH	4/4/2006	0.087	0.04	Selective Catalytic Reduction	80	
Designed to produce about 300 million board feet of lumber annually and run 430 MMBtu/hr waste wood fired boiler as a 30 MW cogen unit	430	126	Wood Fired Cogeneration Unit	Bark & Waste Wood	Skagit County Lumber Mill	WA	01/25/2006	0.13	0.06	Selective Non-Catalytic Reduction (SNCR)	48	Calendar Day
Manufacture of wood pellets-No Coatings	77	23	Heat Energy Systems for Pellet Processing	Wood / Wood Paste	International Biofuels. INC	VA	12/13/2005	0.22	0.09	Thermal Oxidizers and CEM System	99	
Manufacture of wood pellets-No Coatings	43	13	Heat Energy Systems for Pellet Processing	Wood / Wood Paste	International Biofuels. INC	VA	12/13/2005	0.44	0.19	Thermal Oxidizers and CEM System	99	
Wood fired cogeneration facility adjacent to an existing mill	403	118	Wood waste-Fired Boiler	Wood Waste	Darrington Energy Cogen Power Plant	WA	11/2/2005	0.12	0.05	SNCR		24-Hour
Pulp & Paper Mill. Project involves addition of 30 MMBTU/hr Natural Gas-Fired air heaters to the under grate air system of the No.12 Boiler, potentially allowing more steam to be produced on both a short and long term basis	787.5	231	No.12 Hogged Fuel Boiler	Bark	Bogalusa Mill	LA	11/23/2004	0.45	0.19	Overfire air system with low Nox burners in the under grate air heater system & good combustion practices		Hourly Max
150 MW fossil fuel fired power plant consisting of three 50 MW units. Unit #5 is wood fired with coal as a back-up fuel.The two other units are coal fired.	720	211	Wood Fired Boiler, CFB Unit #5	Biomass	Schiller Station	NH	10/25/2004	0.08	0.03	SNCR	65	24 Hour Average
Hog fuel boiler will use SNCR for Nox control to 0.15 LB/MMBtu (24 Hr Avg) and 0.1 LB/MMBtu (Annual Avg), ESP for PM control to 0.02 LB/MMBtu (24 HR AVG) AND good combustion practice for CO control to 300 PPMDV (24 hr avg)	310	91	Hog Fuel Boiler	Waste Wood	Aberdeen Division	WA	10/17/2002	0.15	0.06	SNCR, Boiler Design		24 hr avg.
	230	67	spreader stoker	Waste Wood			6/30/2005	0.15	0.06	SNCR, Boiler Design	50.00	30 day avg.
	230	67	spreader stoker	Waste Wood			6/30/2005	0.15	0.06	SNCR, Boiler Design	50.00	30 day avg.
	175	51		Waste Wood			1/5/2004	0.44	0.19	SCR, Boiler Design	80.00	
	120	35		Waste Wood			2/15/2002	0.4	0.17	GCP		
	291	85	gasifier & combustor	Waste Wood			2/28/2003	0.3	0.13	GCP		
	600	176		Waste Wood			5/10/2001	0.25	0.11	GCP		
	Average NOx							**0.237**	**0.100**			
	Hi							**0.446**	**0.189**			
	Low							**0.075**	**0.032**			

Note:

Approximate unit conversions for Emissions of PM, Nox and CO | NOx : 223 lb/hr = 0.24 lb/MMBtu = 4.5 lb/MWh

Boiler Size MMBtu/hr	Boiler Size MW	Boiler Type	Primary Fuel	Facility Name	Facility State	Facility Description	Permit Date	Limit 1 lb/MMBtu	Limit 1 mg/m3	Limit 1 kg/GJ	Limit 1 Grain/SCF	Control Method	Estimated Efficiency (%)
77	22.6	Heat Energy Systems for Pellet Processing	Wood / Wood Paste	International Biofuels. INC	VA	Manufacture of wood pellets-No Coatings	12/13/2005	0.09	92.39	0.04	#REF!	Setting Chambers and Cyclones	90
43	12.6	Wood Thermal Oxidizers for Wood Pellet Process	Wood / Wood Paste	International Biofuels. INC	VA	Manufacture of wood pellets-No Coatings	12/13/2005	0.09	93.51	0.04	#REF!	Setting Chambers and Cyclones	99
310	90.8	Hog Fuel Boiler	Waste Wood	Aberdeen Division	WA	Hog fuel boiler will use SNCR for Nox control to 0.15 LB/MMBtu (24 Hr Avg) and 0.1 LB/MMBtu (Annual Avg), ESP for PM control to 0.02 LB/MMBtu (24 HR AVG) AND good combustion practice for CO control to 300 PPMDV (24 hr avg)	10/17/2002	0.15	154.65	0.06	#REF!	ESP	
631	184.9	Boiler, Bark	Bark	Meadwestvaco Kentucky, Inc / Wicklife	KY	Pulp and Paper Mill	02/27/2002	0.1	103.10	0.04	#REF!	ESP	
1300	381.0	Boiler	Wood Waste	S.D. Warren Co. - Skowhegan	ME	Kraft Pulp Mill	11/27/2001	0.03	34.14	0.01	#REF!	Mechanical Dust Collector,ESP	99
550	161.2	Boiler	Wood Waste	District Energy St. Paul Inc	MN	District Heating with Electricity Cogeneration	11/15/2001	0.03	30.93	0.01	#REF!	Cyclone, ESP	99
315	92.3	Boiler #1	Wood	Wheelabrator Sherman Energy Company	ME	Wood Fired Electric Generating Facility	04/0/1999	0.036	37.31	0.02	#REF!	ESP, Cyclone	93
265.1	77.7	Boiler, Multi-Fuel	Biomass	Tri-Gen Biopower	GA	Multi-fuel waste boiler and steam plant that combusts primarily woodwaste and papermill sludge from the adjacent durango-georgia paper company facility.	11/24/1998	0.10	103.10	0.04	#REF!	ESP and Wet Scrubber	99
230	67.4	Boiler, wood-fired	wood	Virginia Department of Public Utilities	MN		06/30/2005	0.025	25.78	0.01	#REF!	ESP	98
230	67.4	Boiler, wood-fired	Wood	Hibbing Public Utilities	MN		06/30/2005	0.025	25.78	0.01	#REF!	ESP	98
120	35.2	Boilers, steam	Wood	Thermal Ventures	VA	Seven boilers purchased from an ethanol plant, rebuilt to burn wood and to generate power, using wood waste	02/15/2002	0.150	154.65	0.06	#REF!	Good Combustion Practices and Continuous emission monitoring device	98
600	175.8	Boiler- Wood-fired	Wood waste	Riegel Wood Mill	NC		10/5/2001	0.250	257.75	0.11	#REF!	Multiclone and variable throat venturi type wet scrubber	
Average PM								**0.090**	**92.8**	**0.039**	**#REF!**		
HI								**0.250**	**258**	**0.107**	**#REF!**		
Low								**0.025**	**26**	**0.011**	**#REF!**		
Median								**0.090**	**93**	**0.039**	**#REF!**		

Note:
Approximate unit conversions for Emissions of PM
PM : 50 mg/m3 = 0.05 lb/MMBtu

USEPA BACT PM10 DATA

Facility Description	Boiler Size MMBtu/hr	Boiler Type	Primary Fuel	Facility Name	Facility State	SIC	NAICS	Permit Date	Limit 1 lb/MMBtu	Limit 1 mg/m3	Limit 1 kg/GJ	Limit 1 Avg	Limit 2 T/yr	Limit 2 Avg	Standard Emission Limit Lb/MMBTU	Standard Emission Limit GR/DSCF	Control Method	Estimated Efficiency (%)	Compliance Verified	Incremental Cost Effectiveness
Simpson mill manufactures bleached and unbleached kraft pulp and linerboard	595	Hog Fuel Boiler (Power Boiler #7)	Wood waste	Simpson Tacoma Kraft Company	WA	2611	322121	05/22/2007	0.02	20	0.05	Calendar day / Filterable	99	12 month rolling total			Electrostatic Precipitator (ESP)	99	Yes	
GHP is an existing PM with two paper machines.	379	Wood waste hog fuel boilers #6 and #8 & Gas fired boiler #9	Wood waste	Grays Harbour Paper LP	WA	2621	322121	11/17/2006	0.14	140	0.34	Calendar day / Filterable					Multiclone & Scrubber		Unknown	
GHP is an existing PM with two paper machines.	227	Wood waste hog fuel boilers #6 and #8 & Gas fired boiler #9	Wood waste	Grays Harbour Paper LP	WA	2621	322121	11/17/2006	0.34	340	0.82	Calendar day / Filterable					1.Multiclones - Western precipitation type 9VG, size 189-7, 2.Secondary multiclones 3.Secondary scrubber packed, wet venturi		Unknown	
Seven boilers purchased from an ethanol plant, permit is to retrofit these boilers to burn wood or wood waste to generate power	318	Wood Fired Boilers	Wood	South Point Biomass Generation	OH	4911	221119	4/4/2006	0.012	12	0.03		17.39	Per rolling 12 months		0.0064	Pulse Jet Baghouse		No	
Designed to produce about 300 million board feet of lumber annually and run 430 MMBtu/hr waste wood fired boiler as a 30 MW cogen unit	430	Wood Fired Cogeneration Unit	Bark & Waste Wood	Skagit County Lumber Mill	WA	831		01/25/2006	0.02	20	0.05	24-Hour	37.7	Per rolling 12 months	0.02			99	Unknown	
Manufacture of wood pellets-No Coatings	77	Heat Energy Systems for Pellet Processing	Wood / Wood Paste	International Biofuels. INC	VA	5211	321999	12/13/2005	0.08	81	0.19		25.4		Not Available		Setting Chambers and Cyclones	90	Unknown	
Manufacture of wood pellets-No Coatings	43	Wood Thermal Oxidizers for Wood Pellet Process	Wood / Wood Paste	International Biofuels. INC	VA	5211	321999	12/13/2005	0.08	79	0.19		14.2		Not Available		Setting Chambers and Cyclones	99	Unknown	
Wood fired cogeneration facility adjacent to an existing mill	403	Wood waste-Fired Boiler	Wood Waste	Darrington Energy Cogen Power Plant	WA	4911	221112	11/2/2005	0.02	20	0.05	24-Hour					Dry ESP		Unknown	
Pulp & Paper Mill. Project involves addition of 30 MMBTU/hr Natural Gas-Fired air heaters to the under grate air system of the No.12 Boiler, potentially allowing more steam to be produced on both a short and long term basis	787.5	No.12 Hogged Fuel Boiler	Bark	Bogalusa Mill	LA	2611	322110	11/23/2004	0.15	155	0.37	Hourly Max	357.97	Annual Max	0.15		Wet Scrubber	80	Unknown	
150 MW fossil fuel fired power plant consisting of three 50 MW units. Unit #5 is wood fired with coal as a back-up fuel.The two other units are coal fired.	720	Wood Fired Boiler, CFB Unit #5	Biomass	Schiller Station	NH	4911	221112	10/25/2004	0.03	25	0.06	No averaging period / MACT	0.04	24 hour average	0.03		Fabric Filter	99	Unknown	
The facility manufactures unbleached kraft linerboard	856	Boiler, Solid Fuel	Bark	Inland Paperboard and Packaging Inc - Rome Linerboard Mill	GA	2631	322130	10/13/2004	0.025	25	0.06				0.025		ESP		Unknown	
Turkey Manure and other biomass fueled power plant 50 MW output, 792 MMBtu/hr heat input	792	Boiler, Multi-Fuel	Manure	Fibrominn Biomass Power Plant	MN	4911	221119	10/23/2002	0.020	20	0.05	3-HR Test			0.02		Fabric Filter	99	Unknown	
Modification of existing Multi-fuel Boiler increasing the heat input rate from 265.1 to 302.2 MMBTu/hr. Multi-fuel waste boiler and steam plant that combusts primarily woodwaste and papermill sludge from the adjacent durango-georgia paper company facility	302.2	Boiler, Multi-Fuel	Wood Waste and papermill sludge	Tri-Gen Biopower	GA	4931	221119	05/24/2001	0.03	26	0.06				0.026		ESP and Wet Scrubber		Unknown	
Multi-fuel waste boiler and steam plant that combusts primarily woodwaste and papermill sludge from the adjacent durango-georgia paper company facility.	265.1	Boiler, Multi-Fuel	Biomass	Tri-Gen Biopower	GA	4931	221119	11/24/1998	0.03	30	0.07				0.03		ESP and Wet Scrubber	99	Unknown	
Facility produces plywood, dry veneer, chips, landscape timbers, and studs as products from southern pine.	225	Hogged Fuel Fired Boiler	Wood	Florien Plywood Plant	LA	2436	321212	07/18/2007	0.10	100	0.24	Hourly Max	98.55	Annual Max	0.1		Multiclones with a variable throat, venturi-type scrubber and good combustion practices		Unknown	
	230	Boiler, wood-fired	Wood	Virginia Department of Public Utilities	MN	4911	221119	06/30/2005	0.025	25	0.06	3-Hr Test			0.025		ESP	98	Unknown	
	230	Boiler, wood-fired	Wood	Hibbing Public Utilities	MN	4911	221119	06/30/2005	0.025	25	0.06	3-Hr Test			0.025		ESP	90	Unknown	
Seven boilers purchased from an ethanol plant, rebuilt to burn wood and to generate power, using wood waste	175	Boilers, wood-fired	Wood	Biomass Energy, LLC South Point Power	OH	4911	221119	5/1/2004	0.023	23	0.05		17.39	Per rolling 12 months	0.0125		Pulse Jet Baghouse, designed at 0.004 GR/CF	98	Unknown	
Seven boilers purchased from an ethanol plant, rebuilt to burn wood and to generate power, using wood waste	120	Boilers, steam	Wood	Thermal Ventures	VA	4961	221330	02/15/2002	0.140	140	0.34		73.60		0.14		Good Combustion Practices and Continuous emission monitoring device		Unknown	
	Average PM									69	0.16									
	HI									340	0.82									
	Low									12	0.03									
	Median									25	0									

USEPA - BACT Data - SOx

Facility Description	Boiler Size MMBtu/hr	Boiler Size MW	Boiler Type	Primary Fuel	Facility Name	Facility State	SIC	NAICS	Permit Date	Limit 1 lb/MMBtu	Limit 1 kg/GJ	Control Method	Estimated Efficiency (%)
Seven boilers purchased from an ethanol plant, permit is to retrofit these boilers to burn wood or wood waste to generate power	318	93	Wood Fired Boilers	Wood	South Point Biomass Generation	OH	4911	221119	4/4/2006	0.069	0.03	Spray Dryer Adsorber or dry sodium bicarbonate injection system	20
Designed to produce about 300 million board feet of lumber annually and run 430 MMBtu/hr waste wood fired boiler as a 30 MW cogen unit	430	126	Wood Fired Cogeneration Unit	Bark & Waste Wood	Skagit County Lumber Mill	WA	831		01/25/2006	0.025	0.01		
Manufacture of wood pellets-No Coatings	77	23	Heat Energy Systems for Pellet Processing	Wood / Wood Paste	International Biofuels. INC	VA	5211	321999	12/13/2005	0.05	0.02	Thermal Oxidizers and CEM System	99
Manufacture of wood pellets-No Coatings	43	13	Wood Thermal Oxidizers for Wood Pellet Process	Wood / Wood Paste	International Biofuels. INC	VA	5211	321999	12/13/2005	0.05	0.02	Setting Chambers and Cyclones	99
Pulp & Paper Mill. Project involves addition of 30 MMBTU/hr Natural Gas-Fired air heaters to the under grate air system of the No.12 Boiler, potentially allowing more steam to be produced on both a short and long term basis	787.5	231	No.12 Hogged Fuel Boiler	Bark	Bogalusa Mill	LA	2611	322110	11/23/2004	1.54	0.66	Limit annual fuel oil capacity factor to <=10%	
150 MW fossil fuel fired power plant consisting of three 50 MW units. Unit #5 is wood fired with coal as a back-up fuel.The two other units are coal fired.	720	211	Wood Fired Boiler, CFB Unit #5	Biomass	Schiller Station	NH	4911	221112	10/25/2004	0.02	0.01	Lime Injection	70
	Average SOx									**0.292**	**0.13**		
	Hi									**1.536**	**0.660**		
	Low									**0.020**	**0.009**		

USEAP BACT VOC DATA

Boiler Size MMBtu/hr	Boiler Type	Primary Fuel	Facility Description	Facility Name	Facility State	SIC	NAICS	Permit Date	Limit 1 lb/MMBtu	Limit 1 ppm	Limit 1 Avg	Limit 2 T/yr	Limit 2 Avg	Standard Emission Limit lb/MMBtu	Control Method	Estimated Efficiency (%)	Compliance Verified	Incremental Cost Effectiveness	Notes
318	Wood Fired Boilers	Wood	Seven boilers purchased from an ethanol plant, permit is to retrofit these boilers to burn wood or wood waste to generate power	South Point Biomass Generation	OH	4911	221119	4/4/2006	0.013			17.78	Per rolling 12 months	0.013	Good Combustion practices and use of oxidation catalyst		No		
430	Wood Fired Cogeneration Unit	Bark & Waste Wood	Designed to produce about 300 million board feet of lumber annually and run 430 MMBtu/hr waste wood fired boiler as a 30 MW cogen unit	Skagit County Lumber Mill	WA	831		01/25/2006	0.019		One Hour	35.8	Per rolling 12 months				Unknown		
720	Wood Fired Boiler, CFB Unit #5	Biomass	150 MW fossil fuel fired power plant consisting of three 50 MW units. Unit #5 is wood fired with coal as a back-up fuel.The two other units are coal fired.	Schiller Station	NH	4911	221112	10/25/2004	0.005		24 hour avg	14.30			Good Combustion practices	99	Unknown		
856	Boiler, Solid Fuel	Bark	The facility manufactures unbleached kraft linerboard	Inland Paperboard and Packaging Inc - Rome Linerboard Mill	GA	2631	322130	10/13/2004						0.05	Staged combustion and good combustion practices		Unknown		
936	External Combustion, Multiple Fuels	Bagasse	Sugar Mill and Refinery	Clewiston Sugar Mill and Refinery	FL	2061	311311	11/18/2003	1/0/1900			185.92	as propane	0.05	Good combustion and operating practices				VOC is defined as total hydrocarbons, less the sum of methane and ethane emissions

Appendix V: Emission Limits from Other Jurisdictions

Emission Limits for Wood Fueled Furnaces according to the German Emission Regulation ("1. BlmSchV")

fuel type	**furnace heating capacity, kW**	**max. emission, g per m³ of flue gas**	
		particulate matter	**CO**
pieces of untreated timber, incl. bark attached to it untreated wood in form of wood chips, sawdust, sanding dust and bark	≤ 50 kW	0.15	4.0
	50 – 150 kW	0.15	2.0
	150 – 500 kW	0.15	1.0
	> 500 kW	0.15	0.5

fuel type	**furnace heating capacity, kW**	**max. emission, g per m³ of flue gas**	
		particulate matter	**CO**
painted, varnished, coated wood, ply wood, OSB boards, press boards, and chunks or residue of the before mentioned not containing and halogen-organic coating or preservative chemicals Plywood, OSB boards, press boards or otherwise glued wood and residue thereof, as long as they have not been treated with preservatives and coatings that do not contain any halogen-organic chemicals	50 – 100 kW	0.15	2.0
	100 – 500 kW	0.15	1.0
	> 500 kW	0.15	0.5

fuel type	**furnace heating capacity, kW**	**max. emission, g per m³ of flue gas**	
		particulate matter	**CO**
straw and alike plant materials	≤ 50 kW	0.15	4.0
	50 – 100 kW	0.15	2.0

Comments:

- units with a capacity < 15 kW are not subject to mandatory emission testing

Further European Regulations on Wood Furnaces

Emission Limit Values – Austria (LRG-K)

Vol. % O2	Size	PM (mg/m^3)	CO (mg/m^3)	NOx (mg/m^3)
13%	< 2 MW	150	(no limit)	300
13%	2 - 5 MW	120	250	300
13%	> 5 MW	50	250	200-300

Emission Limit Values – Switzerland (LRV)

Vol. % O2	Size	PM (mg/m^3)	CO (mg/m^3)	NOx (mg/m^3)
13%	< 2 MW	150	500-4,000	250
13%	2 - 5 MW	50	250	250
13%	> 5 MW	50	250	250

Emission Limit Values Germany (TA-Luft)

Vol. % O2	Size	PM (mg/m^3)	CO (mg/m^3)	NOx (mg/m^3)
11%	≥ 5 MW	20	250	250
11%	2,5 - 5 MW	50	250	250
11%	< 2,5 MW	100	250	250

New German Emission Limits for Biomass Boilers

	Fuel	Size (kW)	Dust (mg/m^3)	CO (mg/m^3)
Installations starting operations after ordinance comes into force	Coal, char coal	4-500	90	1000
		>500	90	500
	Wood, bark	4-500	100	1000
		>500	100	500
	Pellets	4-500	60	800
		>500	60	500
	Treated wood, presswood	50-100	100	800
		>100-500	100	500
		>500	100	300
	Straw and other solid agricultural fuels	4-100	100	1000
Installations starting operations in 2015 or later	Coal, wood, pellets	>=4	20	400
	Treated wood	50-500	20	400
		>500	20	400
	Agric. fuels	4 < 100	20	400

Source: Novellierung der 1. BImSchV - Heizkessel

RAINS is the Regional Air Pollution Information and Simulation module developed by the Austrian International Institute for Applied Systems Analysis (IIASA) [RAINS 2008]. It is used to estimate emission reduction potentials and costs in Europe. The emission factors in the following table therefore represent levels that IIASA considers representative for European applications.

Particulate matter emission factors used in the RAINS model for wood burning

Sector	kg/GJ			mg/m^3
	$PM_{2.5}$	PM_{10}	TSP	TSP
Eastern Europe				
Fireplaces, stoves	0.279	0.288	0.3	719
Small domestic boilers	0.093 - 0.230	0.096 - 0.240	0.100 - 0.250	420
Large residential boilers	0.077 - 0.150	0.089 - 0.180	0.100 - 0.200	360
Industry [1)]	0.185	0.214	0.24	576
Western Europe				
Fireplaces, stoves	0.067 - 0.186	0.070 - 0.192	0.072 - 0.200	326
Small domestic boilers	0.060 - 0.167	0.062 - 0.172	0.065 - 0.180	294
Large residential boilers [1)]	0.050 - 0.120	0.060 - 0.134	0.065 - 0.150	258
Industry [1)]	0.185	0.214	0.24	576

(Europe as quoted in Klimont et al., 2002) (Ref #9)

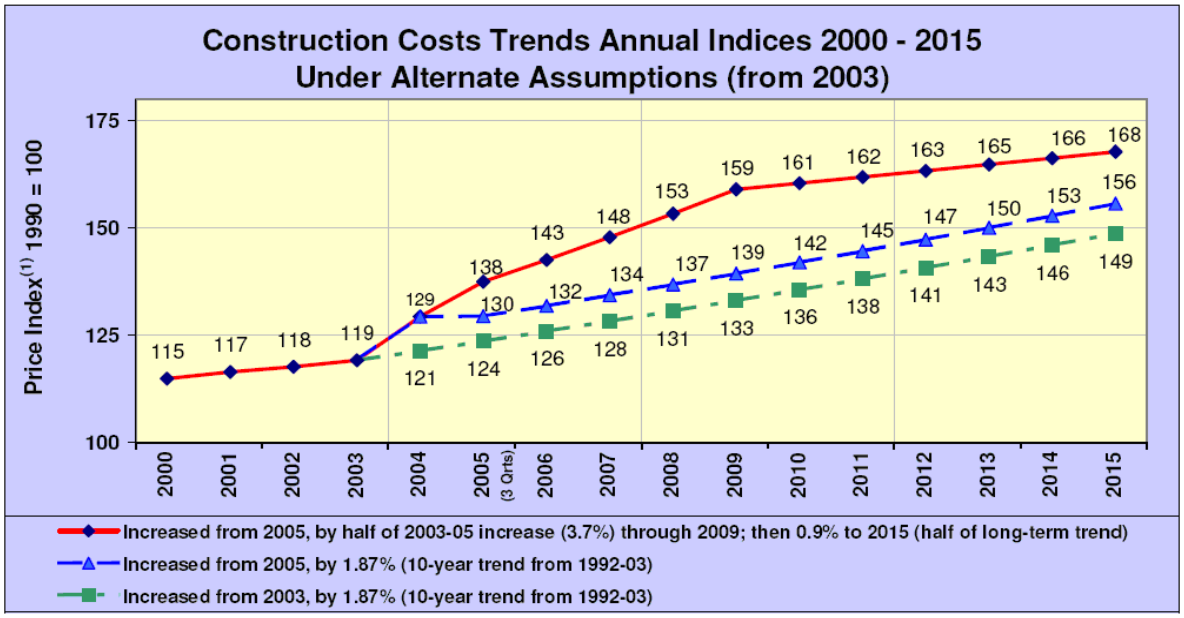
It should be noted that in AP42, the U.S. EPA's Emission Factors, PM_{10} is defined as less than 10 µm (i.e., including the $PM_{2.5}$ fraction), while more recent USEPA documents define PM_{10} as smaller than10 µm, but larger than 2.5µm.

Massachusetts Emission Guidelines

Contaminant	Units	
	lb/MMBTU or otherwise stated	mg/m^3
SO_2	0.02	20
NO_x	0.015	15
Ammonia	2 PPM @ 3%O_2	0.51
CO	0.01	10
PM	0.012	12
VOC	0.01	10
Opacity	5%	
HCl (biomass containing chlorinated compounds)	20 ppm @ 3% O_2	1.08
Toxics - arsenic, antimony, beryllium, cadmium, chromium III, chromium VI, copper, lead, mercury, nickel, and selenium (wood containing C&D wood)	85% removal of mercury and 99% removal of the other metals, or reduce emissions below the detection limit.	
Monitoring	CEMS - NO_x, Opacity, NH_3, SO_2 Annual PM. For, C&D, also metals testing.	
Reporting	Quarterly, annually	

Appendix VI: Cost Trend Information Used for Figure 14

Construction Cost Trends in BC



Ref. #31