LARGE SCALE POWER GENERATIONUSING FORESTRY AND WOOD INDUSTRY BY PRODUCTS

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Background to the Study

This study examines the potential for electricity generation from the by-products of the forestry and wood processing industries, and the possible reduction in greenhouse gas emissions that could result.

The study focuses on developed countries, as such nations have highly developed power distribution networks, so demand for electricity is unlikely to be a constraint on use of these fuels and there will be a wider choice in siting the plants. Developed countries also tend to have well developed, sustainably-managed forest resources, a critical prerequisite for the biomass to be regarded as a long term CO_2 neutral fuel. In future there may be scope for substantial use of forestry by-products for electricity generation in less developed countries, as more power grids are installed and further, sustainable forestry schemes are implemented.

The study was carried out for IEA GHG by a consortium headed by New Zealand Forest Research Institute, and including PB Power NZ Ltd, Coal Research Ltd NZ, and Mr John Irving (US engineering consultant). Members of the IEA Bioenergy Agreement Task 25 also provided input to the report.

Approach Adopted

Five developed countries were selected for detailed analysis: the USA, Canada, Sweden, Finland and New Zealand. The availability of forestry and wood industry by-products and the costs of collection in these countries were estimated in detail. Results were then extrapolated to four developed country regions: the former Soviet Union, North America, Europe, and developed Asia/Oceania. Power generation technologies suitable for forestry and wood industry by-products were reviewed and the costs and efficiencies of selected options were predicted. Finally, the costs of avoiding greenhouse gas emissions in each country were estimated by comparing the costs of power generation from by-products with the costs of generation from fossil fuels. Forestry and wood industry by-products were assumed to be zero net-emission fuels, except for the emissions produced during collection, transport and treating.

Results and Discussion

By-product Availabilities

Conventional forestry offers substantial opportunity for the recovery of biomass fuels. These by-products include thinnings, logging residues and other unmerchantable materials. By-products that could be used for power generation, such as bark, sawdust and panel trim, also arise from wood processing activities. Only a fraction of the total forestry by-product resource would be available for utilisation in power generation, for example due to the need to maintain forest nutrients, difficulties in by-product collection and differences in logging technologies in the different regions. Some of the available by-products are already used for heat and power production. The quantities of additional by-products predicted to be available for power generation in the year 2000 are shown in table 1. The quantities in table 1 are in addition to those that are already being used and those that cannot be recovered from the forests. The total energy content of the by-products in table 1 is about 2600 million GJ (lower heating value basis).

Table 1 Forestry and wood industry by-product availabilities

Regions	By-product availability, million m^3/y	
	Forestry	Wood industry
USSR (former)	42.7	13.5
North America	126.1	29.0
Europe	37.5	12.7
Developed Asia / Oceania	14.4	1.9
Total	**220.8**	**57.1**

Handling, pre-treatment and transport of forestry by-products

Another large source of wood-derived biomass that can be used for power generation is the residue from pulping, so-called black liquor. This contains the lignin, which accounts for about half of the total energy in the wood. Most black liquor is fed to ‘chemical recovery boilers’. The main purpose of these boilers is to recover the chemicals used in the pulping process but they also produce a large proportion of the energy used in the pulp mill. Recovery boilers were not included in this study because most of the potential is already used. The aim of this study is mainly to examine the scope for additional use of forestry and wood industry by-products. There is some scope to integrate the use of forestry by-products with steam and power systems in pulp mills based around recovery boilers. This was not examined in this study but some of the generic issues associated with co-use of forestry residues and fossil fuels, such as economies of scale and the scope for use of more efficient steam cycles, would also apply to integration with chemical recovery boilers.

Power Generation Options

A number of different technologies can be used to generate power from forestry and wood industry by-products. These technologies are described in detail in the main report. Combustion technologies for woody biomass are generally mature and well developed but the efficiency of power generation is limited by the high fuel moisture content and inherent features of the Rankine cycle. Biomass has a high reactivity, which means it can readily be converted to a gaseous fuel. The gaseous fuel can then be used in a high efficiency gas turbine combined cycle plant. Biomass gasification technology is still in the development and demonstration phase but has been included in this study because it is expected to become commercially mature for the size of power plants specified in this study within the next five to ten years.

There is significant potential to use forestry and wood industry by-products in existing fossil fuel power plants. By-products can be co-fired with fossil fuels in the same boiler, providing up to 10-15% of the heat input in a pulverised coal boiler. However, relatively high quality, low moisture content residues and modified feeding systems are required to enable high proportions of residues to be used. Advantages of co-firing with coal include lower capital costs and higher thermal efficiencies than a new biomass-only plant. There are also several potential disadvantages to co-firing including furnace fouling and contamination of the ash, which may eliminate the opportunity to utilise the ash. Some of the disadvantages can be overcome by parallel firing, i.e. feeding the by-products into a separate boiler with integration only of the steam systems. However, a new by-product fired boiler has to be built, so the capital cost in a retrofit is likely to be higher.

Selection of power generation options

Six by-product fired power generation technology options were selected for detailed evaluation.

1. Grate boiler
2. Bubbling fluidised bed boiler
3. Integrated gasification combined cycle
4. Co-firing by-products in an existing pulverised coal boiler

5. By-product fired grate boiler in parallel with an existing pulverised coal boiler
6. By-product fired grate boiler in parallel with an existing natural gas combined cycle

For each of the cases, 30 MWe was assumed to be produced from biomass. A sensitivity analysis was carried out to assess the effects of increasing the plant size to 60 MWe. This range of plant sizes was selected as optimum in a previous study of power generation using short rotation harvesting of biomass, carried out for IEA GHG[1]. The estimated efficiencies and capital costs of the by-product fired power generation plants and a reference 500 MW coal fired plant are summarised in table 2. The capital costs in the retrofit cases (cases 4-6) are the costs of modifying existing power stations.

Table 2 Thermal efficiencies and plant capital costs

Case number		Efficiency, % LHV	Capital cost, $/kWe
1	Grate boiler	27.7	2255
2	Fluid bed	28.9	2475
3	Gasification	36.8	3080
4	Coal co-fire	38.0	255
5	Existing coal (parallel fire)	30.9	726
6	Existing gas HRSG (parallel fire)	33.3	726
Base case	Pulverised coal-only	45.0	1300

The quantity of typical forestry by-product required to generate 30 MW of base load power ranges from 225 kt/y for coal co-firing (the most efficient option) to 308 kt/y for a grate boiler (the least efficient option).

Potential for Electricity Generation from By-products

The amount of electricity that could be generated from forestry and wood industry by-products is estimated by combining the data on by-product availabilities and power generation efficiencies. Table 3 shows data for the year 2000.

Table 3 Potential for electric power generation by various routes (TWh/y)

	Grate Boiler		**Fluid Bed**		**Gasification**		**Coal Co-Fire**		**Coal Parallel**		**Gas Parallel**	
Residue type	Proc.	All	Proc.	All	Proc.	All	Proc.	All	Proc.	All	Proc.	All
USSR (former)	9.7	39.4	10.1	41.0	13.1	52.2	13.5	54.0	10.8	43.9	11.7	47.3
North America	21.2	113.4	22.1	118.4	28.1	150.3	29.0	155.5	23.6	126.5	25.4	136.1
Europe	9.2	36.5	9.7	38.0	12.2	48.4	12.6	50.0	10.4	40.7	11.0	43.9
Dev Asia/Oceania	1.4	11.5	1.4	11.9	1.8	15.1	1.8	15.8	1.4	12.6	1.6	13.7
Total	**41.4**	**200.7**	**43.2**	**209.3**	**55.1**	**266.0**	**56.9**	**275.2**	**46.1**	**223.7**	**49.7**	**241.0**

Note: Proc = Processing residues, All = All residues, including forest and wood processing

The region with the greatest potential for power generation from forestry and wood industry by-products (without taking into account cost and existing infrastructure) is North America, particularly the USA. 56% of the global potential to generate electricity from by-products, in addition to that which is already being generated, is in North America. However, the potential in North America as a percentage of total electricity demand is relatively low: 3% of the total electricity demand in the USA and 4% in Canada. In New Zealand, Finland, and Sweden the proportions are much higher: 14, 9 and 8% of total electricity demand respectively.

[1] The Use of Biomass to Generate Electricity on a Large Scale, IEA Greenhouse Gas R&D Programme report number PH2/10, July 1997.

The greatest amount of power generation would result from application of the co-use technologies, because these have the highest thermal efficiencies. However, it is unlikely that some of the countries could utilise the full potential as there is insufficient existing coal fired plant capacity.

Avoidance of Greenhouse Gas Emissions

Use of forestry by-products for power generation avoids the need to generate power in other power stations. The net cost of greenhouse gas emissions avoidance is the cost of power generation using by-products minus the cost avoided, which in this study is calculated for a reference supercritical coal fired generating plant. The quantity of greenhouse gas emissions avoided is the emissions from the reference plant, including the emissions from fuel production and transport, minus the emissions from collection, transport and processing of forestry and wood industry by-products. The emissions from combustion of the by-products are ignored. It is assumed that if the by-products were not used for power generation they would naturally decompose to CO_2.

The quantity of emissions avoided depends on the type of fuel that is displaced and the efficiency of the displaced power stations. Further study would be required to investigate the types of plants that are most likely to be displaced in each of the study countries and the effects this would have on the costs and quantities of emissions avoided. If high efficiency gas fired plants were displaced, the greenhouse gas emissions benefits would be approximately halved compared to the coal fired reference plant in this study. If nuclear, hydro or wind power plants were displaced, use of forestry by-products for power generation would probably result in a net increase in greenhouse gas emissions, because of the emissions from transport and collection of by-products. If old, inefficient coal fired plants were displaced, the greenhouse gas emissions benefits would be higher than stated in this study. The effects on the net costs of greenhouse gas emissions avoidance is beyond the scope of this study.

The emissions from by-product collection, transport and processing can be significant. For a grate-boiler power plant using by-products, the greenhouse gas emissions from handling and processing the by-products, excluding transport, would be equivalent to about 8% of the emissions from the reference coal fired plant. This would rise to about 14% for a by-product haulage distance of 200 km.

The potential amount of greenhouse gas emissions avoided by use of by-products at a global scale ranges between 116 and 178 Million t/y of CO_2 depending on the technology used (table 4). The greatest potential for greenhouse gas emissions avoidance is in North America. The higher efficiency utilisation options have significantly greater potential for emissions avoidance.

Table 4 Avoided GHG emissions (Million tonnes CO_2 equivalent/year).

	Grate Boiler		**Fluid Bed**		**Gasification**		**Coal Co-Fire**		**Coal Parallel**		**Gas Parallel**	
Residue type	Proc.	All	Proc.	All	Proc.	All	Proc.	All	Proc.	All	Proc.	All
USSR (former)	7.2	25.3	7.6	26.7	9.9	35.8	10.3	37.3	8.1	28.9	8.8	31.6
North America	15.6	57.9	16.4	62.2	21.4	88.2	22.1	92.5	17.6	68.4	19.1	76.2
Europe	6.9	25.4	7.3	26.8	9.3	35.2	9.7	36.5	7.8	28.8	8.3	31.4
Dev Asia/Oceania	1.0	7.9	1.0	8.3	1.4	10.9	1.4	11.5	1.0	8.9	1.2	9.8
Total	**30.7**	**116.5**	**32.3**	**124.0**	**41.9**	**170.1**	**43.5**	**177.9**	**34.5**	**135.0**	**37.4**	**149.0**

Note: Proc = Processing residues, All = All residues, including forest and wood processing

Costs of electricity generation

The costs of electricity from forestry and wood industry by-products were estimated, taking into account the costs of by-product collection and transport and the costs at the power station. Three different collection and transport systems were evaluated in this study and the cheapest option for typical transport distances was used for subsequent analysis.

The costs of electricity generation from wood industry by-products for different power generation technologies are shown in table 5. Costs for the retrofit cases (cases 4-6) are based on the costs of modifications to cope with by-products, rather than total plant costs. Costs in table 5 relate to New Zealand; costs in the other study countries are broadly similar. Wood industry by-products are assumed to have only nominal handling and transport costs. Costs for using forestry by-products at various haulage distances are discussed below, in terms of costs of greenhouse gas emissions avoidance.

Table 5 Costs of electricity generation from wood industry by-products in New Zealand

Case number		US c/kWh
1	Grate boiler	5.97
2	Fluid bed boiler	6.50
3	Gasification	7.91
4	Coal co-fired	0.93
5	Coal parallel-fired	2.16
6	Gas parallel-fired	2.13
Base case	Pulverised coal-fired plant	4.14

Costs of greenhouse gas emissions avoidance

The costs of greenhouse gas emissions avoidance would depend on the power generation technology, the power plant size, the country, the by-product haulage distance and the type of power plant that is displaced. The relationship between power generation cost and haulage distance is illustrated in figure 1. This graph is based on costs in New Zealand but is typical of the 5 study countries. It also illustrates the range of costs of different power generation technologies. The cost of emissions avoidance in New Zealand (for a 30 MWe grate-boiler) would be about \$25/t CO_2 for wood industry by-products available at the power plant site and \$85/t CO_2 if the by-product haul distance was 200 km. For parallel firing of by-products in an existing coal fired plant there would be a net saving of about \$30/t CO_2 avoided for wood industry by-products at the site and a cost of about \$20/t CO_2 if the by-product haul distance was 200 km.

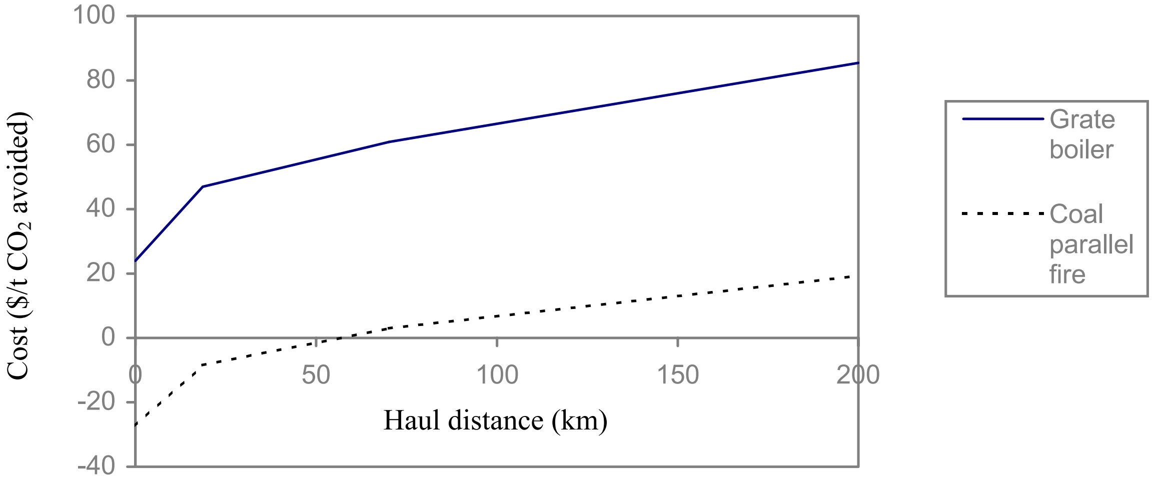

Figure 1 Sensitivity of GHG avoidance cost to by-product transport distance

There is uncertainty about how forestry by-product fired power stations would be distributed within the study countries. In one scenario the processing plants would be distributed throughout the countries according to by-product availability. In the regions that account for most of the by-products, the average haul distance for locally distributed 30 MWe grate fired plants using only forestry by-products would be about 70-100km. Costs corresponding to these haul distances are shown in figure 1. This estimate of haul distances assumes that the forests are evenly distributed throughout the regions. Haul distances would be less for power plants located close to wood processing plants or in areas of high forest density. In an alternative scenario, assessed in the main report, the study countries are divided into regions and it is assumed that by-products would be transported to central power plants within each region. Costs of GHG avoidance are predicted assuming that by-products are drawn from increasing radii around the central processing plants.

In practice it would not be possible to distribute by-product fired power plants within a country based solely on residue availability, because of constraints on power plant siting, such as availability of water, fuel and equipment transport. The location of existing fossil fuel power plants will be a constraint for co-fired plants and the average haul distances for such plants are likely to be higher than for plants fired solely on by-products. A more detailed, country-specific study would be needed to determine where actual power plants could be sited and the likely by-product transport distances and costs. An example of such a study is IEA GHG's study on short rotation biomass in Spain (PH2/10). However, it would be very expensive to carry out this type of detailed assessment for all of the large areas of commercial forestry land considered in this study.

As mentioned earlier, the cost of greenhouse gas emissions avoidance depends on the type of power plant that is displaced. In this study it was assumed that by-product fired power plants would displace new supercritical coal fired-fired plants. This is consistent with most of IEA GHG's other studies. The costs of generation in this type of plant in each of the study countries were estimated, based on typical coal costs in each country. Assessment of other reference plants was beyond the scope of this study.

Sensitivity to plant size

In IEA GHG's study on short rotation biomass in Spain, the optimum plant size was found to be 25-60 MWe, depending on location. The size of the base case by-product-fired power plant in this study was assumed to be 30 MWe. At some locations, e.g. large wood processing facilities, larger plant sizes may be viable. The effects of increasing the plant size to 60 MWe plants were therefore estimated. For a grate boiler plant using wood industry by-products, increasing the plant size to 60 MWe would reduce the cost of power by about 25%, because of economies of scale. As a result, the cost of CO_2 emissions avoidance would decrease to about \$5/t CO_2.

Other benefits

In this study it was assumed that the power would be fed into a national electricity supply grid. It is recognised that a number of other factors, such as localised supply arrangements and opportunities for co-production of heat may markedly improve the competitiveness of by-product fuelled power generating systems.

Forest sustainability and management

For biomass energy to contribute effectively to net GHG reduction, the material must be sourced from sustainably managed forests. Removal of logging residues for bio-energy purposes will inevitably reduce the nutrient levels on the site. Whether this is critical will depend on the intensity of the harvest and the nutrient status of the soil. Harvesting methods can be changed to reduce nutrient loss. For example if the residues are left to season for a period of weeks, most of the needles, which have high nutrient contents, will detach from the branches and will not be harvested. The removal of nutrients can be addressed by returning ash to the site and by addition of artificial fertilisers.

Removal of residues can cause soil compaction, which can reduce yields. This can be minimised by good equipment and practices. Removal of residues from steep terrain may increase erosion. However, most logging residue recovery operations will be carried out on flat to rolling terrain. This terrain is generally not at risk of severe erosion.

For this study it was assumed that forests would continue to be managed mainly for high value timber and pulp production. If by-products for power generation became a significant source of revenue, some changes may be made to forest management, such as rotations, thinning strategies and types of trees. Assessment of the impacts of these changes is beyond the scope of this study.

A further issue requiring consideration is the potential for forest by-products that remain in the forest to produce GHG emissions. If significant amounts of potent greenhouse gases such as CH_4 and N_2O are produced during decomposition, the benefits of using by-products for power generation would be greater than stated in this report. However, if this is not the case and a substantial proportion of the carbon in by-products is not converted to CO_2, then the benefits would be less than stated in this report. Assessment of this issue was not included in this study as no suitable information was available.

Expert Group Comments

The draft version of this report was sent to 10 members of the Programme's expert group, including members of the IEA Bioenergy Agreement. The general opinion was that it is a very detailed and informative study. Most of the comments were editorial, concerned with presentation of the large amount of information. Constructive comments were provided on the detailed assumptions used in the study, drawing on experience in the experts' own countries. Some reviewers thought that the assumptions regarding the fractions of by-products that would be available for new power generation were pessimistic. It was also suggested that the energy consumptions for by-product transport were rather high. The desirability of carrying out detailed country specific assessments to identify potential sites and determine by-product transport distances was also highlighted. This is covered in the recommendations for further work.

Major Conclusions

- Up to 178 Mt of annual CO_2 emissions could be avoided by using forestry and wood industry by-products in the developed countries. This is in addition to the by-products that are already used for power generation.

- The potential electricity production from these by-products would range from 3% of national electricity supply in the USA to 14% in New Zealand.

- The costs of greenhouse gas emissions avoidance would depend on the power generation technology, the power plant size, the country and the by-product haul distance. As an illustration, the cost of net emissions avoidance in New Zealand for a 30 MWe grate fired boiler would be about \$25/t CO_2 for wood industry by-products available at the power plant site and \$85/t CO_2 for a haul distance of 200 km.

- For parallel firing of by-products in an existing coal fired plant there would be a net saving of about \$30/t CO_2 avoided for wood industry by-products and a cost of about \$20/t CO_2 for a by-product haul distance of 200 km. The opportunities for co-use of by-products in existing fossil fuel fired plants will be limited by the availability of such plants.

- These costs and quantities of emissions avoided are in comparison to a coal fired reference plant. The quantities of emissions avoided would be lower if the reference plant was gas fired.

Recommendations

This study has identified further work that should be carried out on greenhouse gas abatement using forestry by-products and other sources of biomass. This work should be carried out by IEA GHG or others working in this field.

1. The quantities of greenhouse gas emissions that could be avoided by use of forestry by-products, and the associated costs, should be calculated in comparison to a gas-fired reference power plant, to complement the results presented here for a coal fired plant.

2. Greenhouse gas emissions from unused forestry by-products should be investigated, to determine the extent to which forestry by-products are zero-net emission fuels.

3. To make significant reductions in the uncertainties in these estimations it would be necessary to carry out detailed country-specific studies (as IEA GHG has done for purpose-grown biomass for power generation in Spain), although it would be too expensive for IEA GHG to carry out such studies for many countries. Country-specific study of forestry and wood industry by-products would identify possible locations for by-product fired power stations and determine optimum by-product transport distances and power plant sizes. This would reduce the uncertainties in the cost estimates for the country in question and might be used to extrapolate from this study to produce global results.

4. Studies should be carried out to assess power generation and greenhouse gas abatement based on other biomass by-products and wastes. Examples of materials that are available in large quantities are sugar cane bagasse, rice husks and straw. These studies should be carried out on a basis that is consistent with IEA GHG's studies of other abatement options.

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Prepared by
Forest Research
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Confidential report prepared for
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LARGE SCALE POWER GENERATION USING FORESTRY AND WOOD INDUSTRY BY-PRODUCTS STUDY REPORT

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EXECUTIVE SUMMARY

LARGE SCALE POWER GENERATION USING FORESTRY AND WOOD INDUSTRY BY-PRODUCTS

This study assessed the potential for new large scale (≥30MW) electricity production at a global scale using forest by-products in order to evaluate greenhouse gas (GHG) mitigation strategies. Only Developed Countries were considered as it was assumed that such nations would have highly developed power distribution networks and well developed sustainably managed forest resources, a key requisite for biomass energy to be regarded as a long term CO_2 neutral fuel for substituting for fossil fuels.

The key objectives of the study were to:

- assess the forestry and energy industries in five industrialised countries with significant forest resources;
- evaluate the potential to generate electricity in the five countries using forestry by-products;
- assess the environmental implications of using forestry by products;
- determine costs and CO_2 emissions arising from the use of forestry by-products to generate electricity and assess the influence of carbon tax on economics of using these bio-fuels;
- assess the technologies for utilising biomass to generate electricity;
- undertake a global assessment of the power generation and GHG mitigation potential using forestry by-products; and
- assess the potential of using forestry by-products in the future out to 2020 and consider key factors that may influence the implementation of biomass technologies.

Key Factors

Key factors included in the analysis are summarised in Table I.

Table I. Key factors included in the analysis.

Countries	Canada, Finland, New Zealand, Sweden and USA.
Global regions	USSR (former), North America, Europe and Developed Asia & Oceania
Background information	energy and forestry statistics, GHG emissions, residue collection and transport systems, biomass power generating systems, environmental issues
Power generation technologies evaluated	grate fired, fluidised bed; gasification; co-firing with coal; parallel powering with either existing or new coal; or existing or new combined cycle plants; and conventional coal fired (500MW) plant
Residue assessment	wood processing residues from sawmilling, pulp and paper and panel industries; forest residues from cutover and landings on different terrain using varying technologies. Benchmark year, 2000
GHG assessment	greenhouse gas emission arising from collection, transport, pre-treatment & conversion of forestry by-products to electricity; GHG emissions arising from coal mining, transport and use in coal fired power stations.
Financial assessment	financial assessment involved cost of residue collection, transport, and pre-treatment, and costs of power generation. Cost of generation for biomass were compared to a 500 MW coal fired plant. The levels of support analysed included \$0, \$20, \$100 & \$500 /t CO_2 avoided.

Key Findings

An estimated 200 TWh/y to 275 TWh/y of electric power could be produced from forest by-products assessed to be available in Developed Countries in the year 2000 (Table II). The region with the greatest potential is North America with a potential capacity of up to 155 TWh/year (56% of the global total) using Coal Co-Firing technologies.

Table II. Electric power generation potential (TWh/y) in Developed Countries.

	Grate Boiler		Fluid Bed		Gasification		Coal Co-Fire		Existing Coal		Existing HRSG	
Residue type	Proc.* residues	All** residues	Proc.* residues	All** residues	Proc.* residues	All** residues	Proc.* residues	All** residues	Proc.* residues	All** residues	Proc.* residues	All** residues
USSR (former)	9.7	39.4	10.1	41.0	13.1	52.2	13.5	54.0	10.8	43.9	11.7	47.3
North America	21.2	113.4	22.1	118.4	28.1	150.3	29.0	155.5	23.6	126.5	25.4	136.1
Europe	9.2	36.5	9.7	38.0	12.2	48.4	12.6	50.0	10.4	40.7	11.0	43.9
Dev Asia-Oceania	1.4	11.5	1.4	11.9	1.8	15.1	1.8	15.8	1.4	12.6	1.6	13.7
Total	**41.4**	**200.7**	**43.2**	**209.3**	**55.1**	**266.0**	**56.9**	**275.2**	**46.1**	**223.7**	**49.7**	**241.0**

*Proc. = Processing residues, **- All residues include both wood Processing and forest harvesting residues

The corresponding greenhouse gas (GHG) emissions (arising from residues collection, transport, pre-treatment and combustion processes) ranged between 43.7 and 45.1 million tonnes of CO_2 equivalent per year (Mt CO_2 e/y). Assuming that the power produced by using forest by-products substitutes for that sourced from coal fired plants (500 MWe generating capacity), estimates of the amounts of GHG avoided at a global scale range between 116 and 178 Mt CO_2 e/y (Table III). Coal Co-firing had the greatest GHG mitigation potential.

Table III. GHG mitigation potential in Developed Countries (M t CO_2 e/y).

	Grate Boiler		Fluid Bed		Gasification		Coal Co-Fire		Existing Coal		Existing HRSG	
Residue type	Proc.* residues	All** residues	Proc.* residues	All** residues	Proc.* residues	All** residues	Proc.* residues	All** residues	Proc.* residues	All** residues	Proc.* residues	All** residues
USSR (former)	7.2	25.3	7.6	26.7	9.9	35.8	10.3	37.3	8.1	28.9	8.8	31.6
North America	15.6	57.9	16.4	62.2	21.4	88.2	22.1	92.5	17.6	68.4	19.1	76.2
Europe	6.9	25.4	7.3	26.8	9.3	35.2	9.7	36.5	7.8	28.8	8.3	31.4
Dev Asia-Oceania	1.0	7.9	1.0	8.3	1.4	10.9	1.4	11.5	1.0	8.9	1.2	9.8
Total	**30.7**	**116.5**	**32.3**	**124.0**	**41.9**	**170.1**	**43.5**	**177.9**	**34.5**	**135.0**	**37.4**	**149.0**

*Proc. = Processing residues, **- All residues include both wood Processing and forest harvesting residues

Figures I and II provide country and global GHG emission avoidance cost curves. The $0 tax base case line illustrates the threshold costs of power production assuming no tax incentives from the conventional 500 MWe coal fired plant. The CO_2 (equivalent) cost supply curves are provided in Figures III and IV.

Both the tables (II & III) and figures (I – IV) put in perspective, (i) the potential GHG emissions in collection, transport, pre-treatment and conversion of forestry by-products to electric power; (ii) the maximum achievable levels of GHG mitigation by the use of forestry by-products in electric power production in the different countries / regions; and (iii) the impact of technology on power generation, GHG emission and GHG abatement using forestry by-products.

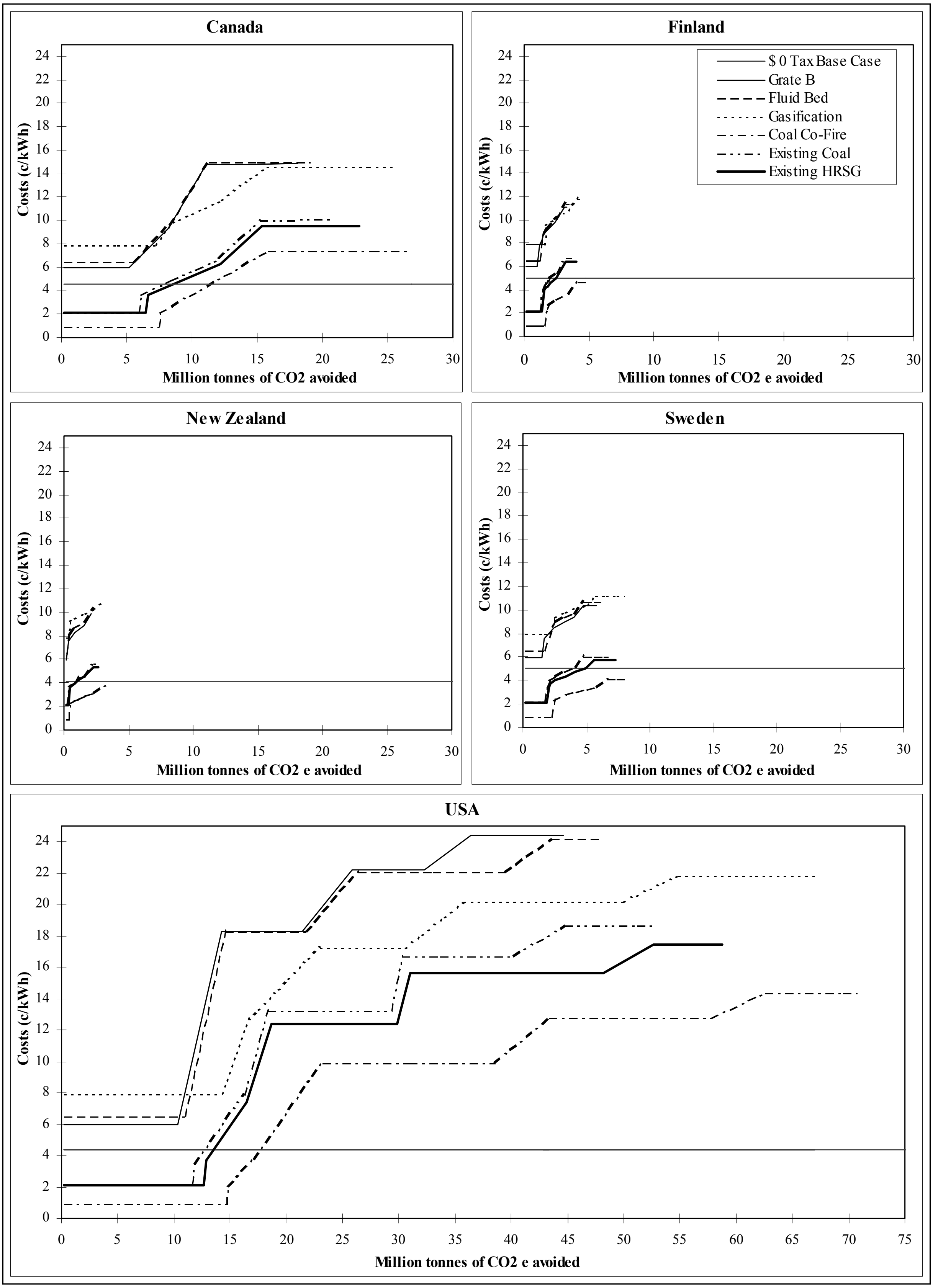

Figure I. Country GHG emission avoidance cost curves.

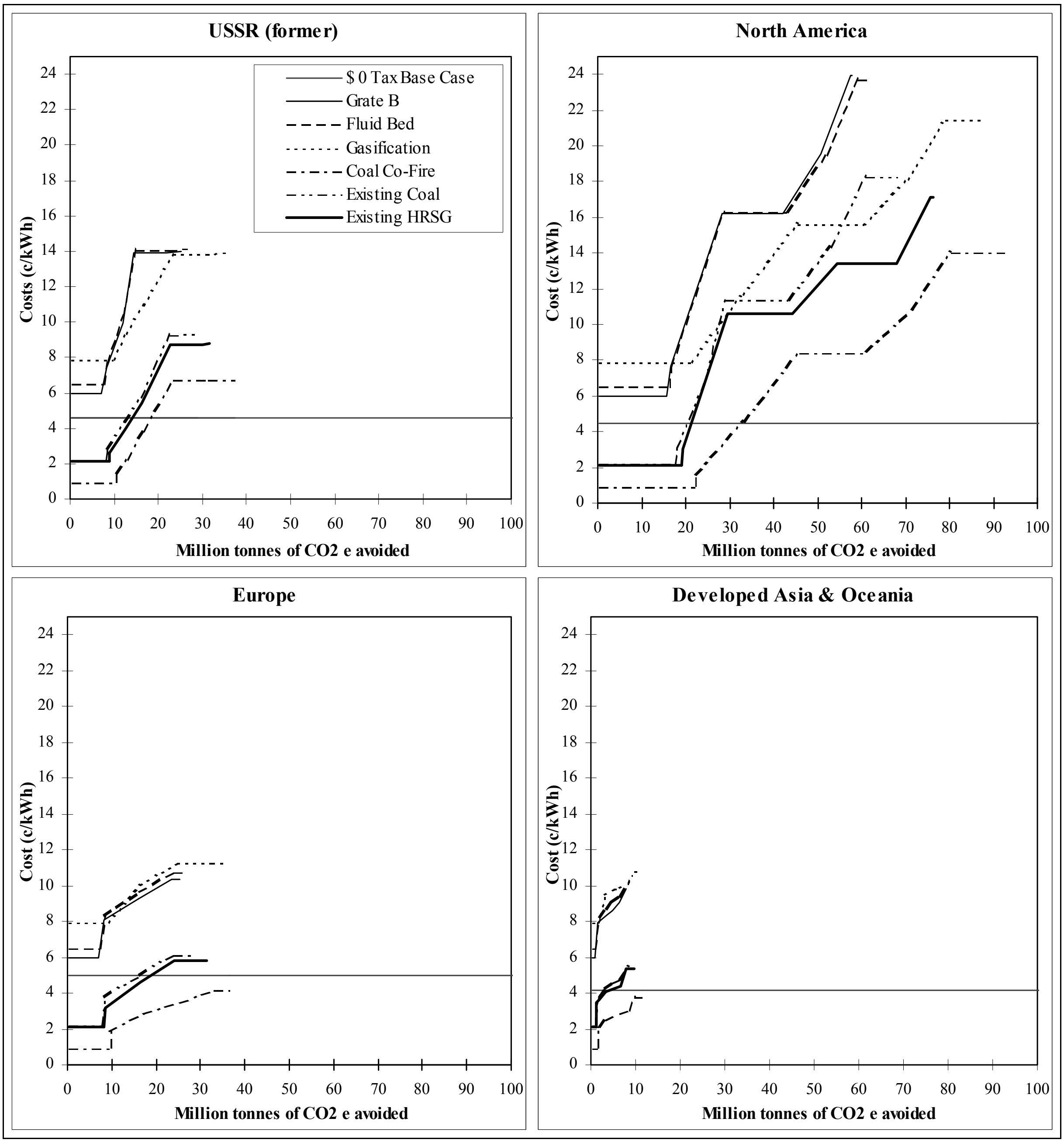

Figure II. GHG emission avoidance cost curves in developed countries.

The initially low costs of GHG mitigation for all technologies (horizontal portions of the curves) represent the use of wood processing residues. Variations in costs (c/kWh, Figures I and II, and \$/tonne of CO_2 avoided, Figures III and IV) reflect the effects of residues haul distance on the technical, economic and environmental viability of using forestry by-products in electric power production, and in energy related GHG mitigation strategies.

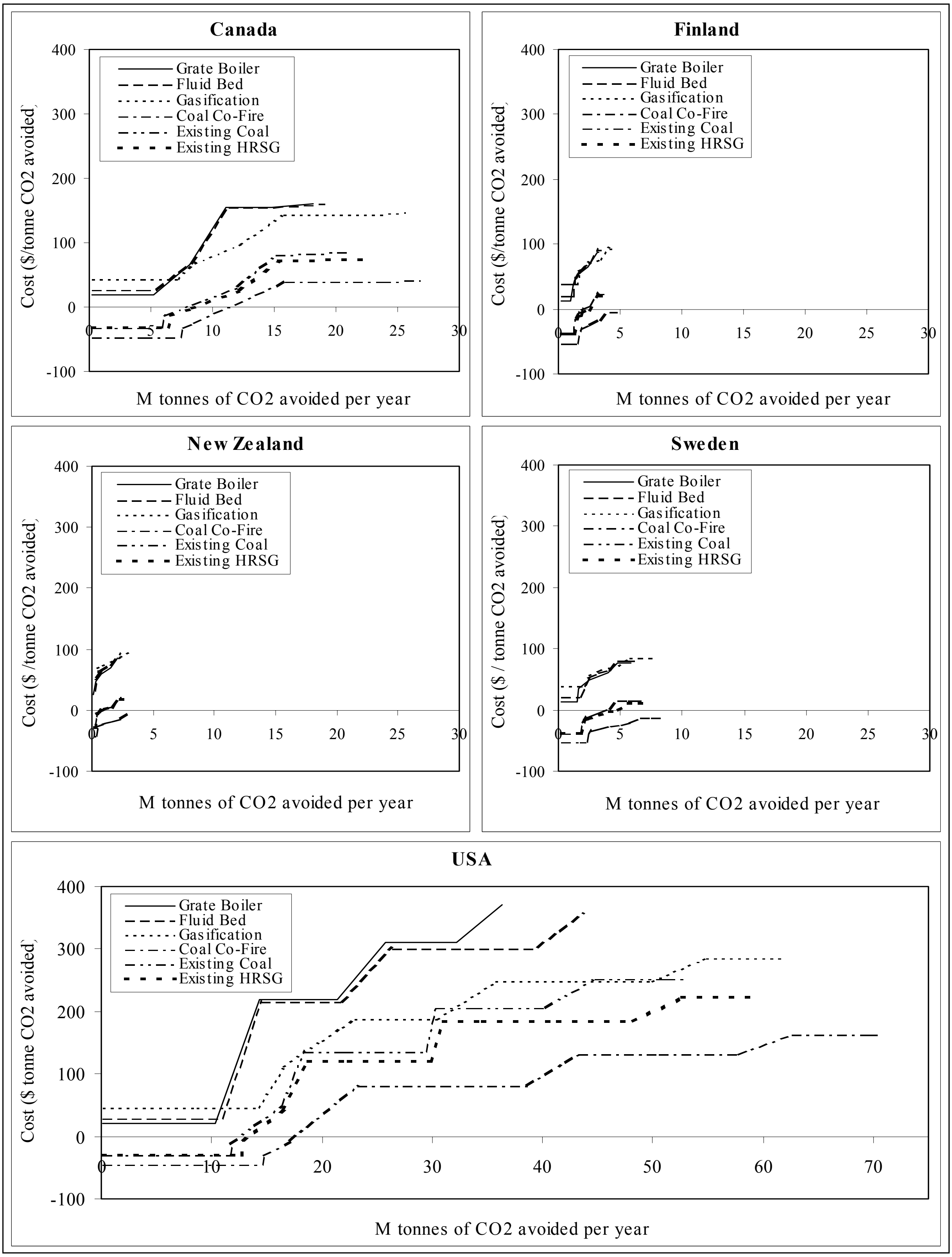

Figure III. CO_2 cost supply curves in the 5 study countries

Three technologies - Grate Boiler, Fluidised Bed and Gasification require initial tax incentives to be viable, even when utilising wood processing residues considered to be the cheapest. The cost of GHG avoidance using Coal Co-Fire, Existing Coal and Existing HRSG in all countries was lower than the conventional coal for all wood processing residues. The use of a proportion of forest residues applying coal co-fire, existing coal and existing HRSG was also below the threshold levels in Finland, Sweden, and New Zealand, but mostly exceeded the threshold with increasing forest residue haul distance in Canada and USA. Though not indicated in the curves, the bulk of costs of power generation (and hence GHG mitigation) from wood processing residues was capital expenditure, operation and maintenance. The lack of competitiveness for some of the residues was due to the high transport distances (up to 510 and 980 kilometres in Canada and USA, respectively).

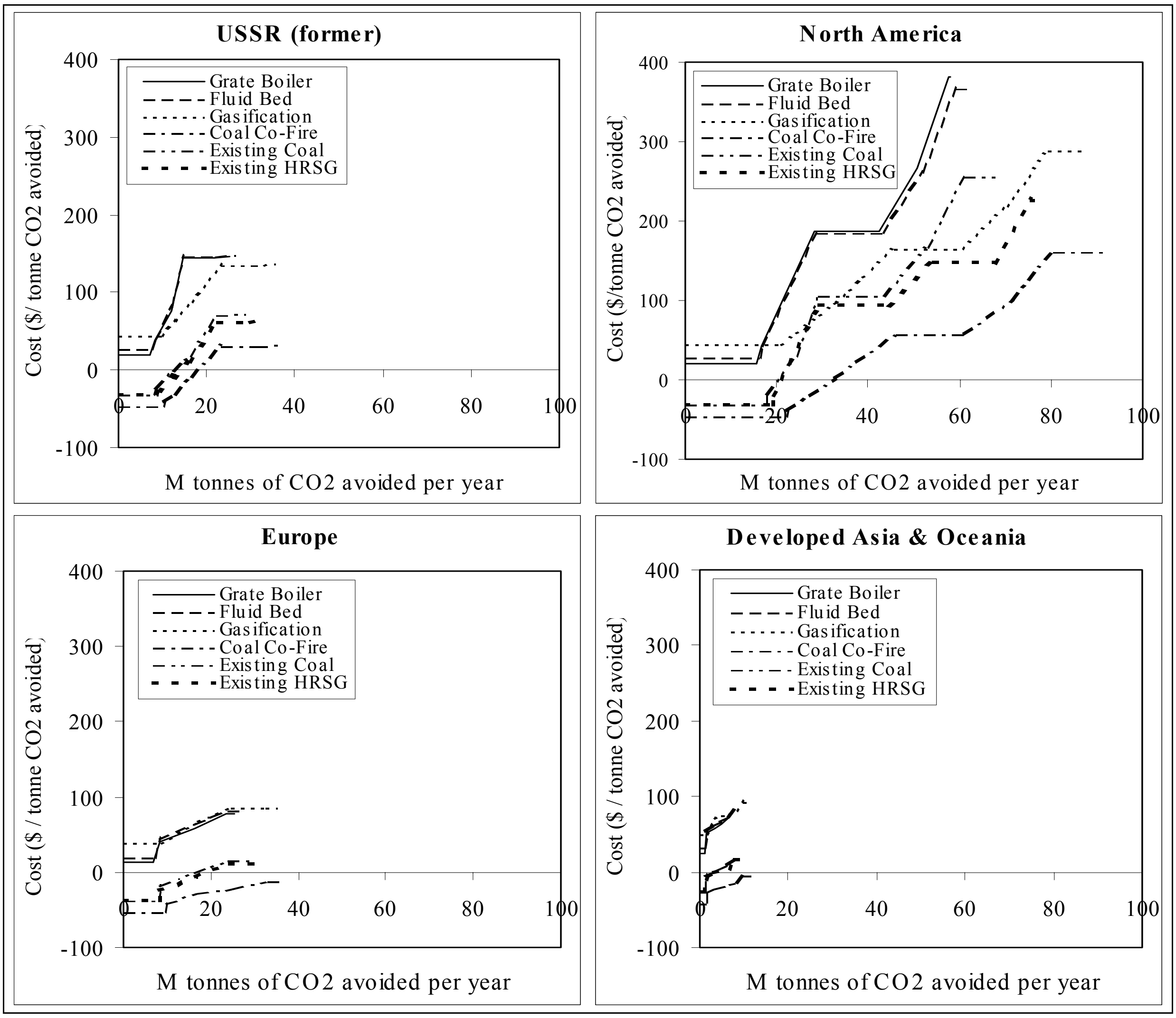

Figure IV. CO_2 cost supply curves in Developed countries

Further studies on the utilisation of forest by-products in the generation of power should also compare bioenergy schemes with gas technology in addition to coal incorporating detailed assessment of factors that influence the substitution of fossil fuels with biomass in specific countries. The analyses could match the utilisation of biomass with resource locations taking advantage of existing infrastructure such as existing coal fired plants, transport networks and electrical transmissions systems. Country specific studies could assess the effect of distributing biomass power plants to optimise locations with respect to resource quantities, infrastructure, costs, markets and CO_2 emissions as opposed to centralised plants which emphasised the effect of feedstock haul distances on both the costs of power production and CO_2 emissions.

IEA GHG Forestry By-Products Report
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LARGE SCALE POWER GENERATION USING FORESTRY AND WOOD INDUSTRY BY-PRODUCTS

CHAPTER 3

FORESTRY AND HARVESTING

CHAPTER 4

FORESTRY RESIDUES ASSESSMENT

CHAPTER 5

WOOD PROCESSING INDUSTRIES: RESIDUE ASSESSMENT

CHAPTER 6

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GLOSSARY

Power Generation

BFB	Bubbling fluidised bed boiler
CFB	Circulating fluidised bed boiler
Cl	Chlorine
O_2	Oxygen
CO	Carbon-monoxide
db.	Dry weight basis
DIN	Technical Standard of the German Industry (Deutsche Industrie Norm)
HHV	Higher Heating Value in MJ/kg or MJ/Nm^3
K	Potassium
kPag	Pressure in Kilopascal gauge
kW_e	Electric Power in Kilowatt
LHV	Lower Heating Value in MJ/kg or MJ/Nm^3
MCR	Maximum Capacity Rated
MJ/kg	Megajoule per kilogram
MJ/Nm^3	Megajoule per Normal cubic metre
MW_e	Electric Power in Megawatt
MW_{th}	Thermal Power in Megawatt
Na	Sodium
NCV	Net Calorific Value
NO_x	Nitrogen-oxides
PC	Pulverised Coal firing
O & M	Operation and Maintenance
SO_2	Sulphur dioxide
t/a	SI Tonnes per annum (not US short tons)

CHAPTER 1:

INTRODUCTION & STUDY OUTLINE

1.0 INTRODUCTION

Biomass offers considerable potential as a sustainable and renewable energy source and is rapidly gaining world wide attention. Advantages of biomass energy include its possible role in mitigating greenhouse gas emissions arising from the use of fossil fuels, diversifying the energy mix of countries and reducing dependence on imported oil supplies, and decreasing the rate of depletion of fossil fuel reserves.

Although numerous studies have indicated that biomass is potentially an important fuel for electricity generation (Easterly and Burnham 1996, McGowin 1996 and McGowin and Wiltsee 1996), the use of woody biomass materials for energy production in many industrialised nations is still mainly used for residential or process heating rather than as fuel for electric power generation. With the introduction of varying energy policies in different countries there has however been a significant increase in the amount of electricity power generated from biomass. For example in the US, electric generation capacity grew from about 200 MW in 1979 to about 6000 MW in 1992 (Turnbull 1996).

Disadvantages of biomass to electricity plants generally have been related to their inability to compete with alternative fuel supplies, in particular coal and natural gas. Biomass-fired plants are typically smaller than 50 MW_e, thermal efficiencies are low (25 percent or less) and delivered fuel prices are sometimes relatively high due to collection and transport logistics or competition from other wood processing plants. Within such an environment, as low natural gas prices, biomass waste fuels are often only competitive in certain circumstances such as when fuel is delivered at a marked discount compared to the costs of fossil fuels, or a tipping fee or subsidy is paid to the fuel user.

However, with growing concern over the potential for global warming and the role of carbon dioxide (CO_2) emissions along with other green house gases, the potential for biomass energy in the world environment and economy is continually being re-evaluated.

Biomass in contrast to other fossil fuels, that may be consumed for electricity production, has the advantage that the net CO_2 emissions are zero or relatively low per unit of electricity produced compared to alternative fossil fuels.

The aim of this study was to assess the potential for electricity generation from biomass based on the use of forestry and wood industry derived residues and the possible effects this would have on greenhouse gas emissions. The study includes schemes based solely on forest by-products and those where co-firing with coal or natural gas may be used. Forestry residues to be included in the investigation were harvesting residues (unmerchantable stem wood, branches, tree tops and foliage) as well as residual biomass products arising from processing logs into wood products such as sawn lumber, wood pulp and panel products (bark, sawdust, shavings, log yard waste and sander-dusts).

The study focuses on the potential for electricity generation in developed countries as it was assumed most likely that such nations have highly developed power distribution networks so demand for electricity was unlikely to be constrained. Developed countries also tend to have well developed sustainably managed forest resources, a critical prerequisite for the biomass to be regarded as a long term CO_2 neutral fuel. Developing countries were regarded to have low power demands in areas where forests are mostly located and limited power distribution systems.

1.1 OBJECTIVES

The objectives of this study were as follows:

- assess the forestry and energy industries in five industrialised countries with significant forest resources;
- evaluate the potential to generate electric power in the five countries based on using forestry by-products;
- assess the environmental implications of using forestry by products;
- determine the costs and CO_2 emissions arising from the use of forestry by-products and assess the influence of carbon tax on the economics of using these bio-fuels;
- assess technologies for converting biomass to electricity and the economics of different systems;
- based on the findings for five countries undertake a global assessment of the amount of power that could be generated using forestry by-products.
- assess the potential of using forestry by-products in the future out to 2020 and consider key factors that may influence the implementation of biomass technologies.

1.2 SCOPE OF STUDY

The scope for this study was prepared by the IEA Greenhouse Gas Research and Development Programme (IEA GHG) and included the following components:

- Obtain information on timber and pulp production and electricity consumption in different countries.
- In consultation with IEA GHG, select five countries with large timber/pulp productions and high levels of electricity consumption.
- Estimate the quantities of forestry and wood industry by-products which are produced in each of the five countries.
- Compare the power demands in areas of these countries where forestry and wood industry activities are carried out, and the amounts of power which could be generated using forestry and wood industry by-products to determine whether power demand and transmission will be a constraint on power generation.
- Assess the feasibility and costs of collecting and transporting forestry by-products to power generation plants.
- Assess the greenhouse gas emissions associated with collecting and transporting forestry by-products to power generating plants.
- Comment on the effects of using forestry by-products on the sustainability and yields of forests.

- Assess the greenhouse emissions resulting from not using forestry by-products in power stations, including parallel and co-use with coal and assess the advantages and disadvantages of the different options.
- Estimate the costs and performances of power stations based on the following schemes:

  – a stand-alone boiler using forestry and wood industry by-products.
  – a pulverised coal boiler generating high pressure and temperature steam and a parallel boiler using forestry and wood industry by-products generating lower quality stream.
  – a natural gas combined cycle plant and a parallel boiler using forestry and wood industry by-products, generating steam for use in the same steam cycle.
  – a plant co-firing by-products and coal or natural gas in the same boiler.
  – one of the above schemes, using gasification of by-products instead of combustion.

- The cost and performance estimates for the above plant configurations were to be undertaken using a standard set of assessment criteria supplied by IEA GHG.
- Estimates of the amounts of power which could be generated from forestry and wood industry by-products at different levels of financial support ($/tonne of carbon emissions avoided) in each of the countries.
- Carry out sensitivity studies to examine the effects of different discount cash flow rates.
- Extrapolate individual country results to estimate the amounts of power which could be generated from forestry and wood industry by-products world-wide at different costs of carbon avoided.

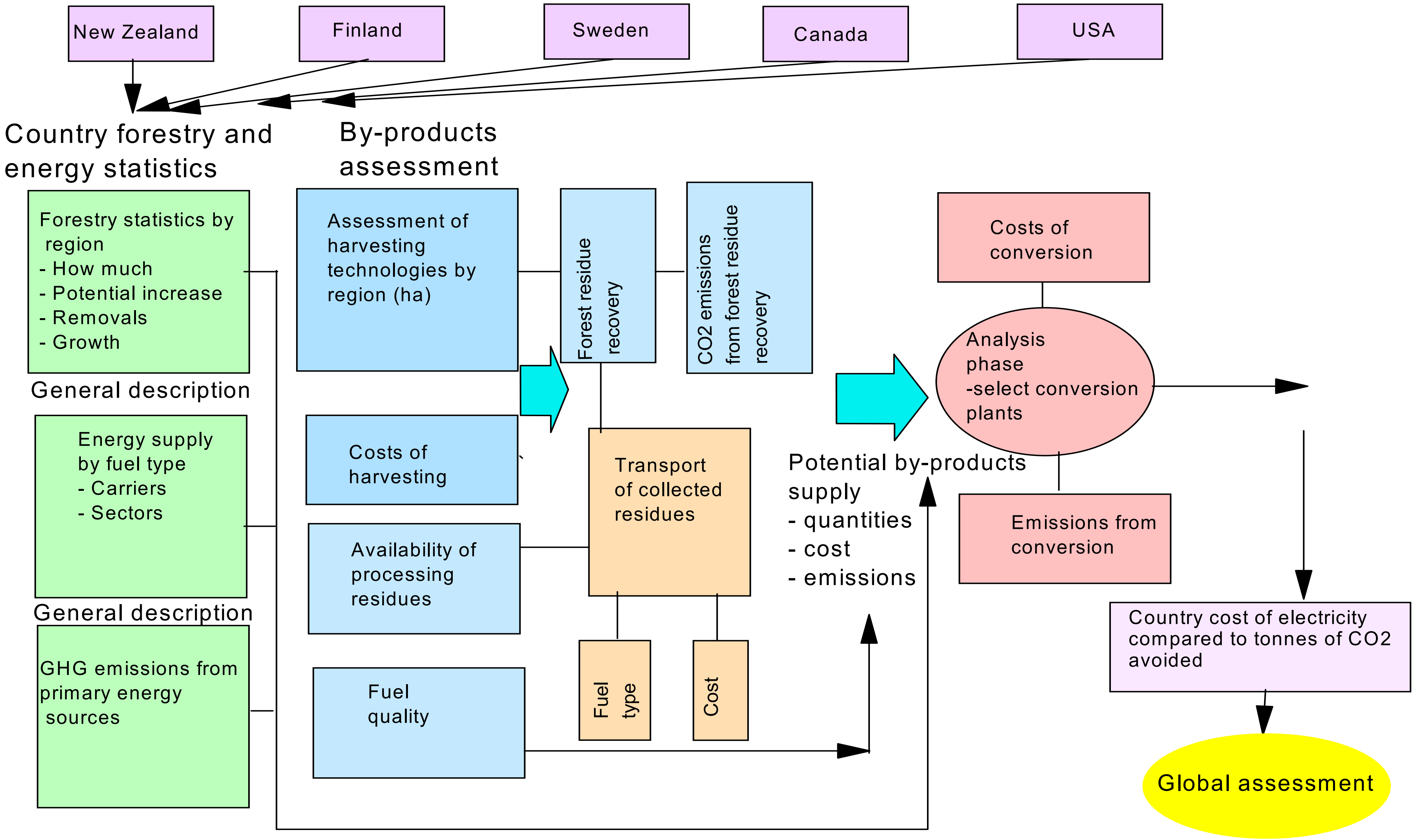
  - The lowest cost of abating CO_2 using this option
  - The quantities of CO_2 which could be abated at a net cost of :

    - zero
    - $20/tonnne of CO_2
    - $100/tonne of CO_2
    - $500/tonnne of CO_2

- The quantity of CO_2 which could be abated using this option, regardless of cost was to be estimated.
- Emissions of greenhouse gas other than CO_2 should be converted to a CO_2 equivalent using the relative global warming potentials using three time horizons 20, 100 and 500 years.

An overview of the study framework is presented in Figure 1-1.

Figure 1-1. Study framework



1.3 PRE-DETERMINED STUDY CONDITIONS

A number of key study conditions were defined at the outset of the study - these were presented in the tender document submitted by ***Forest Research***. These study conditions were developed and applied to restrict the study boundaries and provide clarification on the scope of the study as originally set out by IEA GHG.

The key pre-determined study conditions were as follows:

- Sustainable forests were assumed to be those managed to achieve continuous production and a balance between incremental growth and harvest.
- Consideration was limited to woody biomass derived from industrial plantations which are replanted or regenerated following harvest. In addition, residues from current and predicted future tree felling (thinnings and clearcut), where felling is conducted sustainably, were also to be considered.
- Processing residues included bark and other woody materials available for conversion to energy and which avoids landfilling or incineration.
- Costs and emissions arising from the collection and harvesting of biomass wastes were to include additional operations only, rather than attributing a proportion of existing forest operations to the potential fuel biomass stream.
- Biomass fuels were considered to be zero net carbon -emission fuels.
- In-country variation in relation to site and infrastructure was to be ignored.
- Energy substitution was to be projected based on future primary energy sources.
- Assumed no costs for connection to local power grids or other market related entry costs.

The five countries proposed and agreed to by IEA GHG for the study were:

- Canada
- Finland
- New Zealand
- Sweden and
- United States of America (USA).

These countries fulfilled the criteria outlined above.

For the global assessment, only developed countries were considered which included 48 countries broadly grouped under four regions according to FOA statistics as follows (FOA 1995):

i) USSR (former), comprising the 15 states of the former USSR, including Armenia, Azerbaijan, Belarus, Estonia, Georgia, Kazakhstan, Kyrgystan, Latvia, Lithuania, Republic of Moldova, Russian Federation, Tajikastan, Turmenistan, Ukraine, and Uzebekistan;

ii) North America, comprising two countries - Canada and USA;

iii) Europe including Albania, Austria, Belgium, Bulgaria, Cyprus, Czechoslovakia (former), Denmark, Finland, France, Germany, Greece, Hungary, Iceland, Ireland, Italy, Israel, Luxemburg, Netherlands, Norway, Poland, Portugal, Romania, Spain, Sweden, Switzerland, Turkey, United Kingdom, and Yugoslavia (former); and

iv) Developed Asia & Oceania, comprising 3 countries - New Zealand, Australia and Japan.

1.4 REPORT STRUCTURE

The report is divided into nine chapters as follows:

- Chapter 1 is the introduction to the report.

- Chapter 2 outlines the energy industries in each of the five countries and provides information on the total primary energy supply, energy demand, electricity production, future energy trends, energy policies and comments on the scale of bioenergy industries.

- Chapter 3 describes the forest and forestry industries in the various countries. Key focus is on amount of forest, growth rates, harvest rates, uses of forest products and the types of forests.

- Chapter 4 presents details of different harvesting and residue collection regimes and considers the key variables that influence the recovery and cost of forest residue collection. This chapter also outlines the methodology used to determine the quantities of forest residues available in each of the five countries, and their respective regions. A detailed assessment of costs for recovering these materials is also provided along with the data on forest residue yields.

- Chapter 5 considers the role of wood processing industries for the supply of woody biomass for power production. Details are provided on the nature and scale of processing industries in each of the five countries, typical residue yields for different wood processing sectors, factors affecting residue yields, and an indication of future influences on the supply of these materials. Data are also presented on the quantities of wood processing residues that may potentially be available.

- Chapter 6 considers in some detail the technologies that can be used for biomass conversion and considers the cost and feasibility of using six different power generating technologies/configurations. These were:

    - conventional grate fired boiler with a steam turbine (grate boiler)
    - fluidised bed boiler with steam turbine (fluidised bed)
    - biomass gasification with gas turbine combined cycle (gasification)
    - co-firing biomass in an existing pulverised coal fired boiler (coal co-fire)
    - installing a new biomass grate boiler to operate in parallel with an existing coal fired boiler (new coal)
    - installing a new biomass grate boiler to operate in parallel with an existing HRSG in a gas fired turbine combined cycle plant (new HRSG).

This chapter also considers the performance of these systems and provides detailed capital and operating costings. A review of air emissions is also included which provides input into the greenhouse gas analysis.

- Chapter 7 focuses on the integrated analysis which combines the costs and carbon dioxide equivalent data from residue collection and power generating systems to assess the benefits and potential disadvantages of using biomass power for the abatement of greenhouse gas emissions. A brief sensitivity assessment considering varying plant size and discount rates are also included in this Chapter.

- Chapter 8 discusses the environmental implications of sustainable forest harvesting for bioenergy.

- Chapter 9 presents the overall discussion of the study results.

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CHAPTER 2:

ENERGY OVERVIEW

2.0 INTRODUCTION

Energy is a critical resource for any developed country as its availability underpins economic activity. Energy has been identified as a significant contributor to the production of greenhouse gases. The likelihood that countries will deploy bioenergy as a means of mitigating greenhouse gases will largely depend on existing and future energy profiles of countries, as this will significantly influence cost, and feasibility of implementation. In this section of the report, the energy sectors in each of the five countries are overviewed with the discussion including information on the total primary energy supply, energy use, electricity production, future energy trends, energy policies and comments on the scale of bioenergy industries where appropriate information was available.

Information presented in this Section will ultimately be compared to the potential new power generation based on using forestry by-products.

Each country is considered separately.

2.1 CANADA

2.1.1 Primary Energy Supply

Canada has a land area of approximately 10 million square kilometres and has a population of around 29 million. Canada is one of the least densely populated countries in the world. It has strong seasonal changes and large regional variations in temperature. The rigorous climate, the energy intensive nature of the country's industries, and the large distances between population centres results in relatively high energy use per capita.

Canada is a highly urbanised country with urban areas accounting for roughly 0.2% of the country's total land area. In terms of population however, about 80% of the people live in urban areas and cities over half a million people attract 60% of the urban population.

The energy sector is an important part of Canada's economy. The energy sector employs more than 300,000 Canadians and accounts for 7.4% of GDP and 16.8% of investment in Canada. Canada's energy production and demand are dominated by fossil fuels. In 1995, over 50% of Canada's crude oil/liquefied petroleum gases and natural gas production was exported. Total exported energy in 1993 was 1603 TWh (WEC 1995).

The total energy supply in Canada is approximately 2,746 TWh and the predominant fuel supplies are oil and gas which comprise about 33 and 29% respectively. Other significant contributors are hydro (13%), coal (11%), and nuclear (10%) (Figure 2-1). Total indigenous energy production in 1993 was 3,680 TWh and over 60% of this production was accounted for by oil and gas (Figure 2-2).

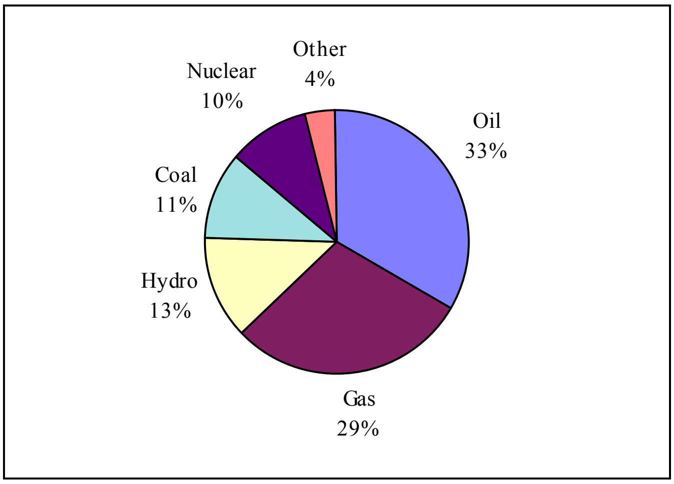

Figure 2-1. Total primary energy supply for Canada in 1996 by fuel type.
(Source: IEA 1998).

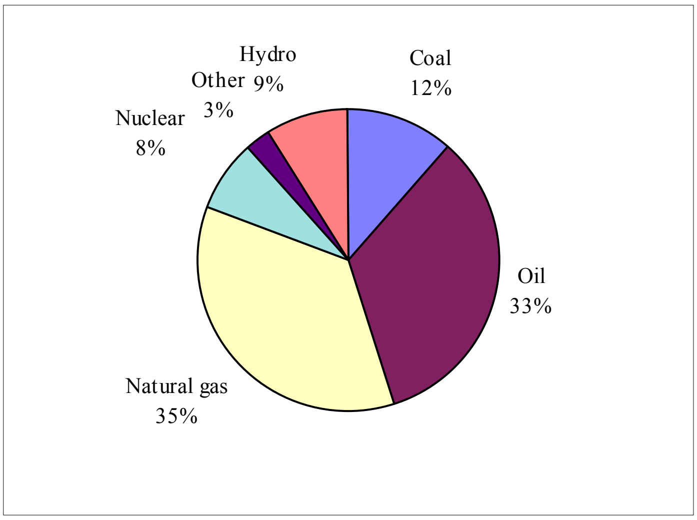

Figure 2-2. Indigenous energy production in Canada by fuel type in 1993.
(Source WEC 1995).

The Canadian oil industry is concentrated in the western part of the country. Over the past 20 years, crude oil production has been in the range of 500 to 700 million barrels per annum. The decline in the production of commercial light oil has been offset by oil sands production, which has doubled over the last decade. With a resource of 3 billion barrels of bitumen recoverable from Canada's oil sands, the prospects are for further increases in oil sands and heavy oil production (WEC 1995).

The provinces of Alberta, British Columbia and Saskatchewan supply all of Canada's natural gas with nearly 82% coming from Alberta. The availability of natural gas supplies from conventional fields continues to increase. Major gas fields have been discovered in the frontier and offshore regions, but there resources are not expected to be used in the near future (WEC 1995). Also, Canada has extensive bituminous coal reserves mostly found in the provinces of Alberta, British Columbia and Saskatchewan which account for over 94% of total coal production. The largest consumer of coal is the electricity sector.

2.1.2 Energy Demand

The most significant energy demand is for petroleum products and natural gas, as these two fuel supplies make up 63% of the total energy demand (Figure 2-3).

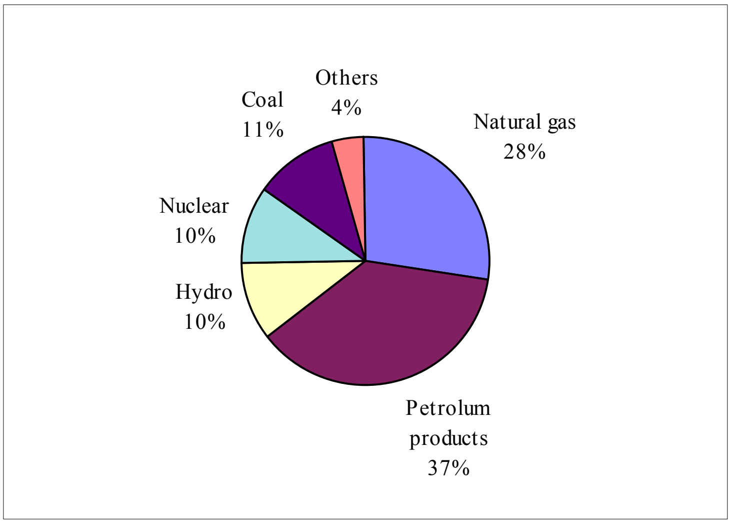

Figure 2-3. Canadian primary energy demand in 1995 by fuel type.
(Source: Environment Canada 1997).

Electricity is one of Canada's fastest growing energy sectors. In 1995, nuclear (320 TWh) and hydro power (298 TWh) were the largest domestic sources of electric energy, representing about 67% of the total electric supply (912 TWh). Other sources of electricity include oil, natural gas and renewables. Renewables currently make up something in the order of only 0.3% of the total supply.

Industry (39%) and transportation (27%) are the largest energy use sectors in Canada (Environment Canada 1997). The residential sector represents just over 21% of total end-use demand and the commercial sector is 13%. The industrial sector includes all manufacturing as well as forestry, construction and mining activities. Total energy demand by the industrial sector is around 351 TWh. For the industrial sector, natural gas and electricity are the major energy supplies. Renewables, mainly biomass used by the pulp and paper industry also represents a significant share. Six energy intensive industries - pulp and paper, iron and steel, smelting and refining, chemicals, petroleum refining and cement - make up about 60% of the total industrial energy demand even though their share of the total industrial production is approximately 15%.

2.2 FINLAND

2.2.1 Primary Energy Supply

Finland covers an area of 0.338 million square kilometers, which makes the country one of the largest in Europe. Finland's population is approximately 5.1 million and the average population density is 15 per square kilometer.

The high proportion of energy intensive processing industries and the high requirements for space heating make the total energy consumption per capita one of the highest of the OECD countries. The high energy consumption level with the absence of high grade fossil fuels has made Finland heavily dependent on imported energy, mainly oil and coal but also natural gas, electricity and nuclear fuel.

In 1996, the total primary energy supply was 366.1 TWh. The share of total primary energy supply by fuel type is shown in Figure 2-4.

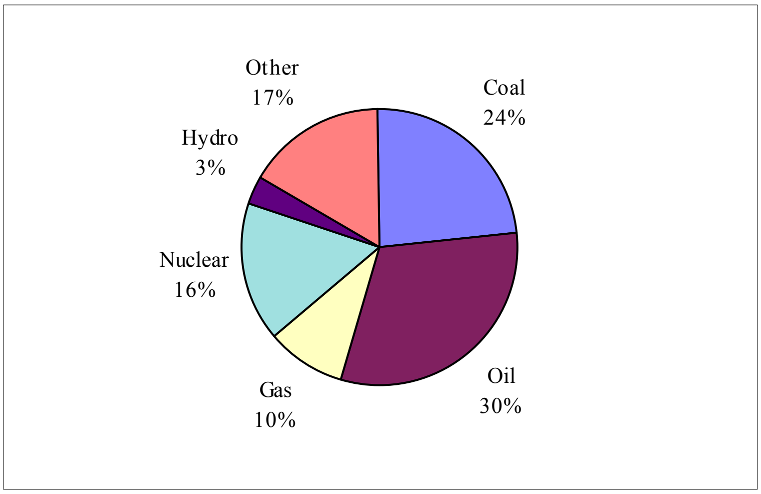

Figure 2-4. Total primary energy supply for Finland by fuel type in 1996.
(Source: IEA 1998).

Crude oil and oil products constitute the major part of the imported energy supply. Natural gas which accounted for about 9.5% of the country's energy needs is also imported.

The main domestic sources of energy in Finland are hydro power, wood, wood waste, pulping liquors and peat. Finnish peat reserves are among the worlds largest. Indigenous fuels comprise approximately 20%. Nuclear power is produced in four units, two 445 MW_e units in Loviisa and two 710 MW_e units in Olkiluoto.

2.2.2 Energy Demand

The total primary energy consumption by sector is given in Figure 2-5. Industry is the largest energy user group with the larger industries being relatively energy intensive and export orientated. The forest industries account for about 60% of the industrial energy demand. The utilisation of biomass in industry is high, accounting for 44% of its fuel consumption (98 TWh).

The Finnish electricity system includes about 370 power stations owned by 130 companies or municipalities. Many of the power plants are operated by small companies using either hydro or combined heat and power (CHP) plants. The total installed power capacity is about 14,570 MW of which CHP's make up about 34%, hydropower 19% and nuclear power about 16%.

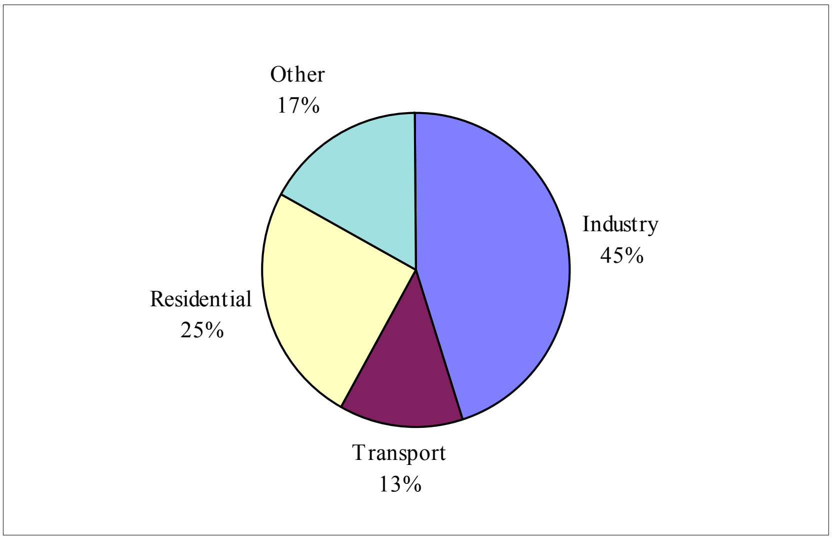

Figure 2-5. Total primary energy demand in Finland by sector (1996).
(Source: Energy Statistics 1996).

Electricity consumption has more than doubled since 1975. In 1975 electricity consumption was 29 TWh but by 1996 the electricity consumption had risen to 70 TWh. In 1997 electricity consumption further increased to 73.5 TWh. In 1996, CHP-based power production was 22.2 TWh, of which 56% arose from municipal district heating plants and 44% from industry co-generation.

Given that electricity demand is expected to increase markedly from around 70 TWh to 102 - 118 TWh by 2025, there are concerns over just how this future demand is going to be met. It is expected that part of the future capacity requirement will be met by industry and other small producers, but the source of most of the projected capacity is currently unknown, though a combination of both burning fossil and biomass fuels seems most likely. The primary energy sources used for electricity production are shown in Figure 2-6. The total installed power generation capacity where wood and wood derived fuels are important is about 1350 MW_e.

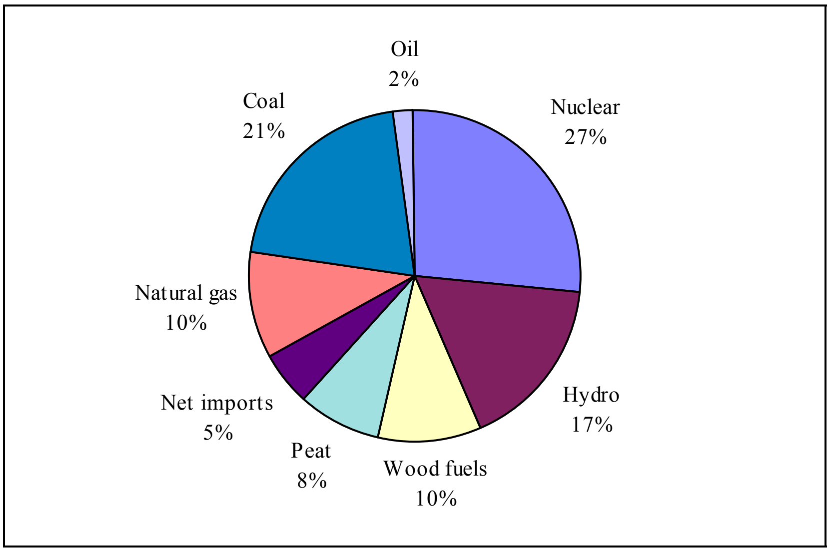

Figure 2-6. Primary energy source for electricity production for Finland in 1996.
(Source: Energy Statistics 1996).

Electricity consumption by sectors is given in Figure 2-7.

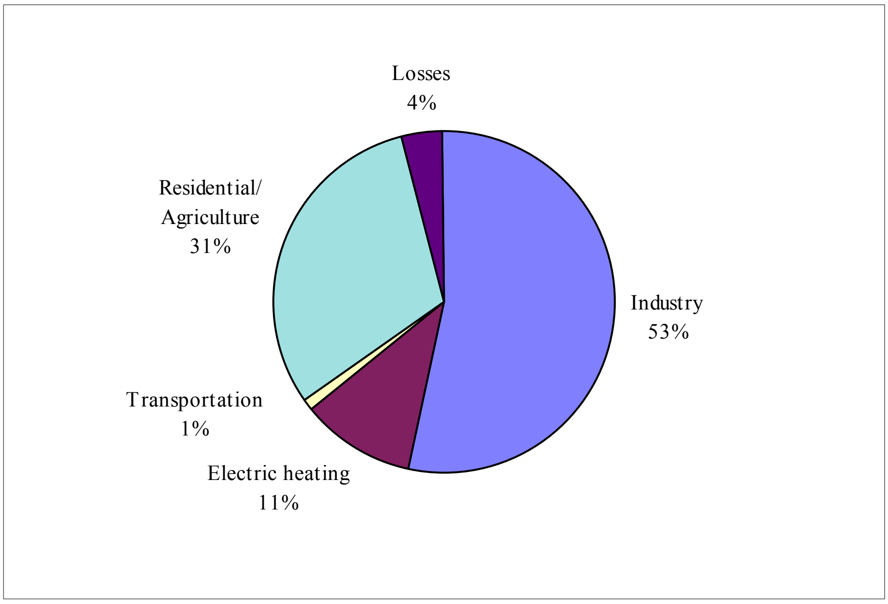

Figure 2-7. Electricity consumption in Finland by sector (1996).
(Source: Energy Statistics 1998).

Energy demand in the residential sector is 25% of the total energy supply. In this sector, district heating plays an important role as it is available in most cities and used by a million households and in most public buildings. District heating accounts for about 44% of the energy market, with more than 80% being used in large cities.

CHP-based heat production in 1996 was 27.6 TWh. Approximately 80% of Finland's district heat is produced in CHP plants. In both CHP and district heating, about 36% of the fuel used is coal, 25% is natural gas and 21% is peat, while fuel oil and other fuels like waste accounts for 9%. The share of wood fuels used for district heating is 6%. There are about 200 district heating utilities in Finland, serving approximately 250 municipalities.

2.3 NEW ZEALAND

2.3.1 Primary Energy Supply

New Zealand consists of two major islands and a number of smaller islands in the south west Pacific and has a total land area of 0.27 million square kilometres which makes it a similar size to the British Isles. The average population density is 13.5 individuals per square kilometre. The current land cover in New Zealand is 24% in natural forest, 52% in pasture and arable land, 5% in planted production forests and 19% in other land uses.

Current population is around 3.66 million and this is expected to increase to 3.75 million by 2000. In a further 20 years, population estimates are for 4.22 million. Eighty five percent of New Zealanders live in towns and almost a third of New Zealand's entire population lives in the northern half of the North Island.

New Zealand's economy is heavily dependent on its natural resources and exports. Agriculture, fishing and forestry provide the major basis for processing and manufacturing industries. Although generally regarded as an agricultural nation, New Zealand does have some heavy industry including two steel mills, an aluminium smelter, a synthetic petrol plant, cement works and pulp and paper mills. There are also dairy and meat processing plants spread throughout the country. New Zealand also has a sophisticated and diverse export-orientated manufacturing sector including plastics, packaging, whiteware and engineering.

New Zealand is self sufficient in electricity, gas and coal and was 36% self-sufficient in oil in 1996. Primary energy supply is provided by oil, gas, hydro, geothermal, coal and other renewables. The relative proportions of each of these are given in Figure 2-8.

The total primary energy supply has increased from 1980 to 1996 with quite a marked increase occurring from 1995 to 1996 when it grew by 4% to 193 TWh. This marked increase in total energy supply consisted of a 14% increase in the production of natural gas, a 5% increase in indigenous coal production and 19% increase in export coal (Ministry of Commerce 1998).

2.3.2 Energy Demand

The use of energy within New Zealand increased by 60% between 1974 and 1996, although over the same period the population rose by only 18%. This increase has been largely due to the development and expansion of a number of energy-intensive industries such as aluminium smelting and petrol-chemical industries. A break down of New Zealand's energy demand by fuel type is provided in Figure 2-9. The total energy demand was 117.6 TWh in 1996 and was dominated by oil (46.6%), with electricity (26.6%), coal (8.5%), gas (8.5%), with renewable such as geothermal, wastes and wood making up the remainder.

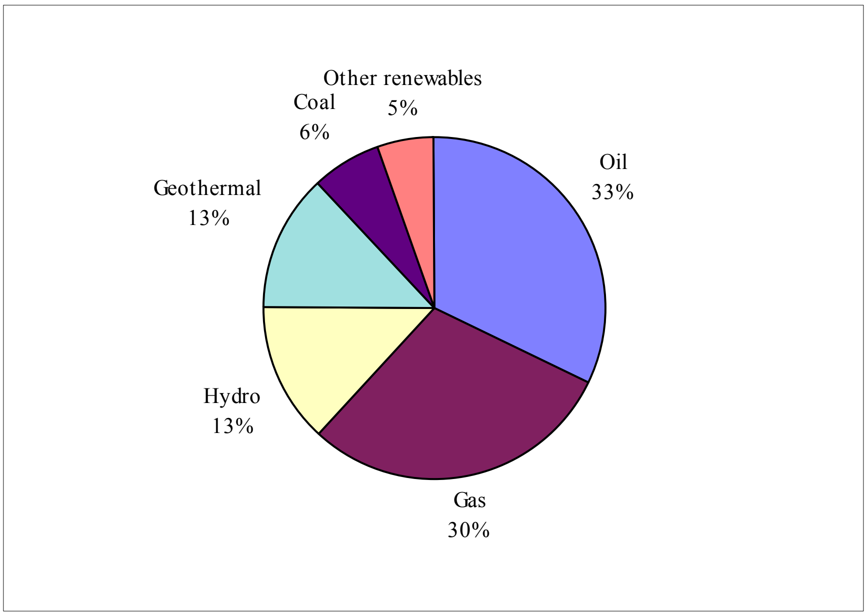

Figure 2-8. Total primary energy supply in New Zealand for 1996.
(Source: NZ. Ministry of Commerce 1998).

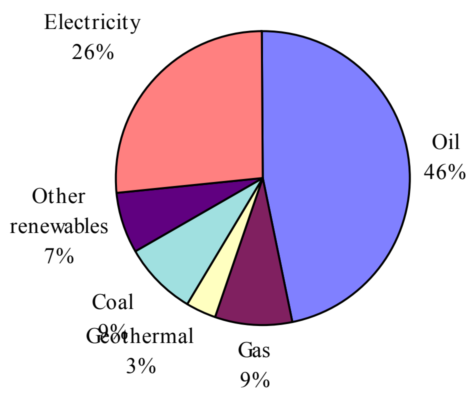

Figure 2-9. Total energy demand in New Zealand for 1996
(Source: NZ Ministry of Commerce 1998).

The major energy uses in New Zealand are domestic transport and industrial uses representing approximately 38.8 and 33.7% respectively. Residential makes up 13.3% of the total consumer energy supply and commercial and commercial and agriculture use 8.7 and 5.4% respectively (NZ Ministry of Commerce 1998).

2.3.3 Future Energy Demand

Energy consumer demand is projected to increase by 1.5% per annum to 2020, and includes 2.1% in the transport sector, 0.8% in the industrial sector and commercial sector, and 1.7% in the residential sector. Oil and electricity are projected to increase their fuel shares with a slight decline in fuel share for coal. A significant decline for gas's share is projected as yield from a major gas field declines.

New Zealand's electricity generation is dominated by renewable energy sources, with hydroelectric power producing around 70 -80% of the annual electricity needs, though this is dependent on rainfall. Geothermal power contributes another 6% with smaller contributions from other renewable sources such as wind and co-generation using wood. The balance is made up by fossil fuel generation, using mostly natural gas (Ministry for Environment 1997). Some 2,600 MW of additional electricity generation capacity is projected to be economic by 2020, with a natural gas combined cycle station as the single biggest addition to capacity prior to the year 2000.

2.4 SWEDEN

2.4.1 Primary Energy Supply

Sweden has a total land area of 0.42 million square kilometres with an average population density of 19 inhabitants per square kilometre and a total population of 8.8 million in 1996. Up to 85% of the population lived in urban areas. Transport needs are high in Sweden due to the low population density and long distances travelled. During a normal year in Sweden nuclear and hydro account for 90% of the total electricity generated.

The total energy supply in Sweden in 1996 was 485 TWh and compares with the average over the period 1970 to 1996 of around 440 TWh/a. Total energy use is projected to increase from now to 2010 (485-515 TWh) with much of the increase being used for transportation and industry. These values are based on the use of Swedish statistics which considers electrical output from nuclear plants rather than gross thermal output (NUTEK 1997).

The contribution of different fuel sources has changed markedly in Sweden over the last 25 years with the crude oil and oil products accounting for about 77% of the total energy supply in 1970, though by 1996 these same components represented only 45% of the total energy supply (Figure 2-10). Other significant changes during this period have been the introduction of nuclear power and an increase in the amount of hydropower. In 1996, nuclear accounted for approximately 72 TWh/an (16%) and hydropower 64 TWh (11%). The proportions of energy supplied by coke and coal was 6% and biofuels and peat was 18% (NUTEK 1997).

2.4.2. Energy Demand

Energy use in Sweden is divided into three major categories namely:

- total final energy use including residential/commercial, industry and domestic transport.
- energy losses which includes losses associated with supply of electricity, natural gas, town gas and blast furnace gas and district heating.
- other uses which includes bunker oil for shipping, coal and oil products used as raw materials and feedstocks for applications such as the plastics industry.

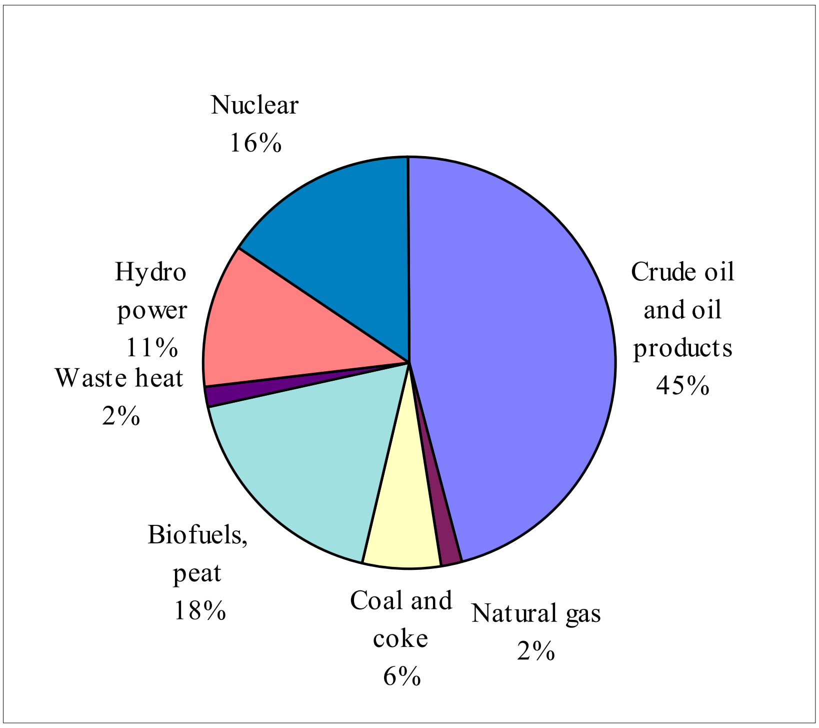

Figure 2-10. Total primary energy supply for Sweden in 1996 (Source: NUTEK 1997).

Within the total final use category, the use of energy within the residential/commercial and industry sectors has fallen relative to the use of energy for the domestic transport sector. The industry portion has fallen from 41% to 37% over the period 1970 to 1996 and the total energy use by the residential sector has reduced from 44% to 42% over the same period. In contrast, the domestic transport sector has increased its proportion from 15% to 21% between 1970 and 1996. The relative proportions of energy use in Sweden are summarised in Figure 2-11.

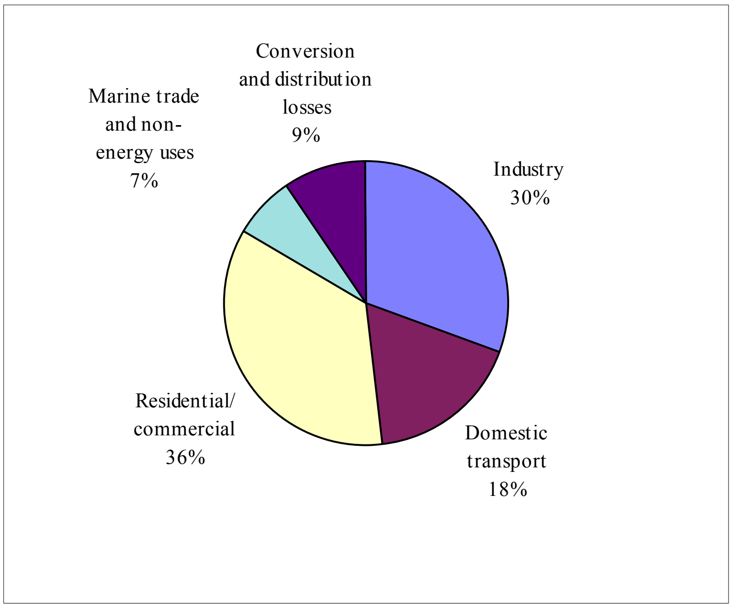

Figure 2-11. Relative proportion of energy used by various sectors in Sweden in 1996. (Source: NUTEK 1997).

Major factors affecting the annual total energy usage figures are economic and climatic conditions. In warmer years less energy is used by the residential/commercial sectors. The total final energy use in 1996 was approximately 400 TWh or 82% of the total supply. The residential/commercial sector used approx 170 TWh (42%) of the total final energy use with the largest proportion being used for space heating and hot water production in residential and commercial buildings (115 TWh). Other major uses included electricity for domestic purposes and for the operation of building service systems. A breakdown of the energy use by this sector by fuel type is given in Figure 2-12.

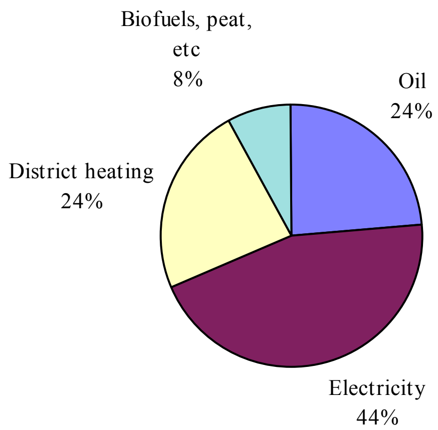

Figure 2-12. Usage of fuels by the residential, commercial and service sectors in Sweden for 1996. (Source: NUTEK 1997).

Changes in the relative use of oil and electricity have reflected a shift in the use of oil in houses for heating to electrical energy, whereas in apartment buildings there has been an increase in the use of district heating schemes. Both of these developments have led to improved energy efficiency due to reduced conversion losses.

In 1996, the use of energy by industry was approximately 147.2 TWh. This was made up of 27 TWh of oil products, 16.3 TWh of coal and coke, and 50 TWh of electricity. Supplies from natural gas and district heating schemes were 3.8 and 4.3 TWh respectively. Biomass fuels, peat etc contributed 48.7 TWh, of which about 78% were within the wood processing industries. The major energy user groups are the pulp and paper sector (45%), the iron and steel industry (15%) and chemical industries (6%). Major factors affecting the use of energy by industries are the level of industrial output, types of goods produced, technical developments, fuel substitution policy and energy prices (NUTEK 1997).

Over the period from 1970 to 1996 there has been a significant shift in the use of oil to the use of electricity where the use of electricity has increased from 21 to 34% over this period. Overall the use of energy by the industrial sector is expected to increase from 147 TWh to 165 TWh from 1996 to 2010.

Most of Sweden's electricity is produced by hydro power and nuclear power as these sources have the lowest production costs at present. Other sources of electricity production include back-pressure generation, combined heat and power generation, oil fired cold condensing plant, gas turbine or wind power (NUTEK 1997). In 1996, Sweden produced 136 TWh of electricity with hydro comprising 38% of production, nuclear 52%, oil -fired cold condensing power plants 3% and CHP 7%. Biofuels were used to produce some electricity, approximately 3 TWh. About 1 TWh was produced from wood fuels in CHP plants supplying district heating systems, 1 TWh was produced from wood fuels in industrial back-pressure plant and 1 TWh from digester liquors.

2.4.3 Energy Policy

Two important elements of Sweden's national energy policy are the phase out of nuclear power and consideration of environmental issues. Other initiatives include investment support for biofuel based CHP production, investment support for wind and solar energy, support funding for biofuel-based electricity production, development of programmes for energy efficiency and support for ethanol production.

The programme for the promotion of biofuel for electricity generation was established in 1992 as a result of the 1991 Energy Policy Bill. The purpose of the programme is to increase the efficiency and improve the environmental performance of biofuel-based electricity production and its emphasis is on development and demonstration of technology for electricity production based on biofuels (Second National Communication Document). The Swedish electricity market is being influenced by price trends on markets in neighbouring countries in the Nordic and Baltic Sea regions. In addition, the Swedish electricity market is being affected by an EU directive concerning an internal electricity market. Under this environment, it is expected that more customers will be able to purchase electric power in competition from foreign countries in addition to a more competitive local market.

Natural gas combined-cycle technology is currently regarded as the most advantageous alternative, based on fuel price assumptions. Given that some Nordic countries have supplies of natural gas, then it is envisaged that an increasing amount of energy for electricity in Sweden may be sourced from natural gas at plants in other neighbouring countries.

Greenhouse Gas Emissions

The net accumulation of carbon dioxide in Swedish forests has been estimated at 30 million tonnes per year. This corresponds to about half of the annual emissions of carbon dioxide from fossil fuel sources. The transport sector contributes approximately 33% of the total carbon dioxide (Sweden Second National Communication Document) .

In contrast to other countries, Sweden has very few options for reducing greenhouse emissions through changes in the electricity sector as less than 5% of the electricity generation is based on fossil fuels. In view of this, emphasis is on improving funding for renewable energy, energy saving and other supporting measures. Sweden also has an interest in joint implementation of greenhouse gas reduction with other countries. The cultivation of Salix is also seen as being important with the production of willow increasing over recent years to about 16,000 ha. The cultivation of Salix is seen as a way to further reduce carbon dioxide in the atmosphere and potentially be available for substituting for fossil fuels.

2.5 USA

2.5.1 Primary Energy Supply

The USA's energy resources are extensive and diverse. Coal, oil, natural gas and uranium are abundant and a variety of renewable resources are available in untapped quantities. Domestic oil production accounts for 22% of the USA energy production. Natural gas represents 27% of the total energy production and although it is produced in thirty three states, much of it is sourced from Texas, neighbouring states and the Gulf of Mexico. The USA was largely self sufficient in natural gas until the late 1980's, but since then consumption has outpaced production and now imports from Canada, Algeria (in liquefied form), Australia and United Arab Emirates have increased three fold. The total primary energy supply by fuel type is given in Figure 2-13 (EIA 1998).

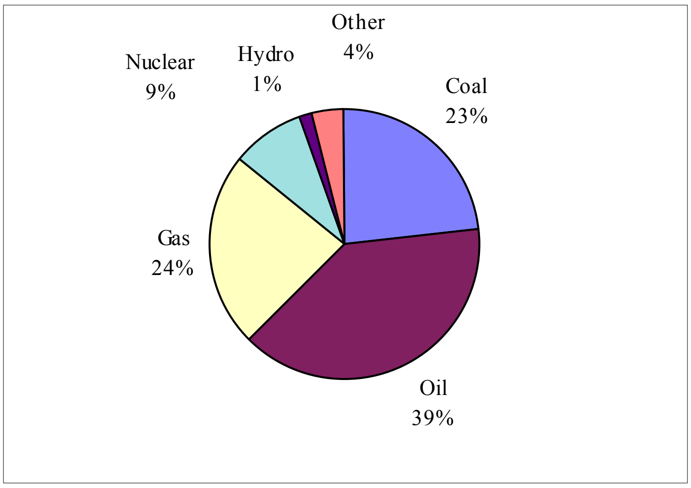

Figure 2-13. Total primary energy supply for the USA in 1996 (Source: IEA 1998).

Coal is a major resource and accounts for 31% of the nation's energy production. USA coal reserves are greater than any other nation. Of the billion tonnes of coal produced in the USA, something in the order of 90% is used for electrical generation. Coal-fired units accounted for 52% of the USA electricity generation in 1997.

Coal-fired electric generating units emit gases that are of significant environmental concern. In 1996 carbon dioxide emissions from the combustion of coal in the USA reached nearly half a billion metric tonnes of carbon, 36% of total carbon dioxide emitted from all fuel sources. Coal is the least expensive of the major fossil fuels in the USA.

Nuclear energy is the second major source of electricity generation after coal, approximately 20%. Renewable energy which includes hydropower, biomass, geothermal, wind and solar resources provide 10% of the USA primary energy production. Over 50% of renewable energy forms are used for electricity and the balance goes in transportation fuels (such as ethanol) and heating industrial processes (eg pulp and paper). Hydropower makes up 80% of all renewable energy forms used for electrical generation and it is 10% of the total electrical generation. The fuel sources for electricity production are given in Figure 2-14.

Electricity's usage in the USA in greatest in the residential sector, which is then followed by the industrial and commercial sectors. The nature of the electricity supply market is also rapidly changing in the USA with a greater proportion of electricity being generated by non-utility power producers (ie independent power producers and co-generators).

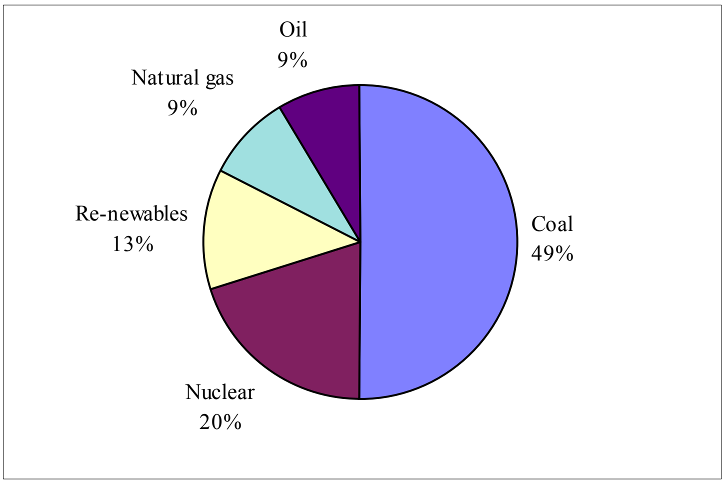

Figure 2-14. Sources for electrical production in the USA (Source: IEA 1998).

2.5.2 Energy Demand

Four major sectors make up the USA energy market; transportation industry, residential and commercial. Significant quantities of energy are used to produce electricity.

Transportation accounts for about 26% of the USA energy use and this sector accounts for about two thirds of all petroleum used. Industry accounts for approximately 37% of USA energy consumption with this sector relying on a mix of fuels. Petroleum and natural gas are the major industrial fuels and together they account for 70% of the direct consumption, much of which is used as a raw material or feedstock. About two thirds of the energy used by the industrial sector is for manufacturing. With the remainder going to mining, construction, agriculture, fisheries and forestry. The predominant end use activity for industry is process heating, followed by machine drive, facility heating, ventilation and air conditioning.

The residential sector uses about 21% of the total primary energy and 50% of this is used for heating, and electrical appliances use 17% of the total for this sector. Commercial activities consume 16% of the total primary energy consumption (EIA 1998).

2.5.3 Use of Biomass for Energy

Bio-power is the second largest source of renewable energy in the USA with about 10 GW of installed capacity. This installed capacity consists of about 7 GW which is derived from the forest products industries and agricultural residues. The balance of 2.5 GW is from municipal solid waste and 0.5 GW are from landfill gas. The growth in using biomass for electricity grew rapidly from 1978 after the introduction of the Public Utilities Regulatory Policy Act (PURPA 1978) which guaranteed small electricity producers that utilities would purchase their surplus electricity at a price equal to the utilities 'avoided cost of producing electricity. Following this regulation the capacity went from 200 MW in 1979 to 6 GW in 1989.

However, growth has slowed down substantially since 1989 due to low buyback rates and uncertainties within the industry (EIA 1998).

The 7 GW of installed biomass capacity represents about 1% of the total generating capacity and approximately 8% of all non-utility generating capacity. More than 500 plants around the USA are using wood or wood waste to generate electricity. The majority of the capacity is produced in Combined Heat and Power (CHP) facilities in the industrial sector primarily in the pulp and papermill and paperboard sectors. To generate electricity, the stand-alone power production facilities largely use non-captive residues including wood waste purchased from forest products industries and urban wood waste streams, used wood pallets, some wood waste from construction and demolition and some agricultural wastes from pruning, harvesting and processing.

All of today's capacity is based on mature, direct-combustion boiler/steam turbine technology. The average size of the bio-power plants is 20 MW (the largest approaches 75 MW) and the average biomass to electricity efficiency of the industry is 20%. These small plants lead to higher capital cost per kilowatt of installed capacity and to high operating costs as fewer kilowatt-hours are produced per employee. These factors, combined with low efficiencies which increase sensitivity to fluctuations in feedstock price, have led to electricity costs in the range of 8 - 12 cents per kilowatt range.

It is envisaged that the next generation of stand alone bio-power production will substantially reduce the high cost and efficiency disadvantages of today's industry. The industry is expected to dramatically improve process efficiency through the use of co-firing of biomass in existing coal-fired power stations, though the introduction of high efficiency gasification-combined-cycle systems, and through efficiency improvements in direct combustion systems made possible by the addition of fuel drying and higher performance steam cycles at larger scales of operation. Technologies presently at the research and development stage, such as Whole Tree Energy™ integrated gasification, fuel cell systems and modular systems, are expected to be competitive in the future.

2.5.4 Energy Policy Issues

Three major issues that underpin the development of energy policy in the USA are how to maintain energy security in global energy markets; how to successfully harness competition in the electricity markets and how to respond to the threat of climate change (US Department of Energy 1998).

Since 1980 there has been a significant increase in energy demand by developing countries which in part has been brought about by rapid economic growth in the same countries. USA policy makers see this as a potential threat to the security of oil supplies, especially since over 60% of the world oil reserves are confined to the Persian Gulf. Reliance on one geographic area to satisfy increased world demand for oil creates the potential for oil importing nations to be vulnerable to supply disruptions and price volatility. Policies will be developed which maintain and enhance the USA strategic petroleum reserves.

Following on from deregulation of the natural gas and oil industries, national policy changes are continuing to be made to deregulate the wholesale and retail electricity markets. While a few States with relatively high electricity rates have led the way in aggressively pursuing competition, most States have just begun to examine prospects for competition to encourage lower prices (US Department of Energy 1998).

The Kyoto Protocol to the United National Framework Convention on Climate Change, negotiated by the international community in December 1997, includes targets for developed countries to reduce GHG emissions. Given that more than 80% of man-made GHG emissions are energy related and that energy consumption continues to increase, energy policy has a new and demanding role. In the case of USA, the Kyoto Protocol calls for the USA to reduce its annual emissions to 7% below 1990 levels over the period 2008 - 2012 (measured net of baseline adjustments for hydrofluorocarbons, perfluorocarbons, sulphur hexafloride & carbon sequestration). This target entails significant emission reductions, though not all reductions will come from the energy sector. However, the USA will only ratify the Kyoto agreement if developing countries become key participants in addressing issue of climate change.

To address these issues and to provide a framework for the future co-ordination of energy developments a Comprehensive National Energy Strategy has been proposed which contains five key goals including (i) to improve the efficiency of the energy system; (ii) to ensure against energy disruptions; (iii) promote energy production and use in ways that respect health and environmental values; (iv) to expand future energy choices; and (v) to cooperate internationally on energy issues. These goals form a durable framework against which future energy initiatives will be judged to see if they are consistent with the national interest. Each of the goals are also supported by underlying objectives and strategy statements.

2.5.5 Energy Outlook Forecasts

Average world crude oil prices are projected not to increase markedly out to 2020. World wide demand for oil is expected to increase due to growth in economic activity. However, although Persian Gulf production may decease, it is expected that other recent oil discoveries will offset this decline. Recent discoveries include Nigeria, Algeria and it is envisaged that there will be capacity expansion in Venezuela. In addition, new fields in the North Sea slow projected production decline in that area, and production in central and south America is expected to increase, particularly in Mexico, Brazil, Columbia and Argentina. Oil production in the former Soviet Union is expected to increase through to 2020 largely due to the development of the Caspian Sea oil fields. Oil production in Canada and in the offshore areas of West Africa is also expected to increase (EIA 1998).

The total USA energy consumption is projected to increase from 27,572 to 34,788 TWh between 1996 and 2020 (26% increase). Energy consumption by the residential and commercial sectors will increase by 4% by 2015 due to projected decreases in electricity prices. Coal-fired generation is expected to lose market share, though the consumption of coal is expected to increase from 6,130 to 7509 TWh between 1996 and 2020 and average annual increase of 0.9%.

Renewable fuel use is expected to increase by 0.5% a year to 2020. In 2020, 59% will be for electricity generation and the rest for dispersed heating and cooling, industrial uses and blending in transport fuels. Growth in the use of biofuels may be constrained by low costs for other fuels.

Electricity consumption is projected to grow by 1.4% a year to 2020. Efficiency gains in electricity use partially offset the continued trend to electrification and the penetration of new electricity using equipment. Electricity generation from nuclear power is expected to decline significantly to 2020, with 101 GW of current capacity available in 1996 reducing to 49 GW due to retirement of plant. No new plants are expected to be constructed by 2020.

Generation from both natural gas and coal is projected to increase significantly through to 2020 to meet increased demand for electricity and off-set the decline in nuclear power. The coal share of generation declines due to the industry favouring the less capital intensive gas technologies for new capacity additions. Natural gas fired share of electricity generation is expected to more than triple from 9% to 30% between 1996 and 2020.

2.6 SUMMARY

The total energy supply and electricity consumption for 1996 in each of the five study countries is summarised in Table 2-1. The values include energy loses arising from the use of nuclear for electricity production. Primary energy sources as a proportion of total primary energy supply expressed as percentages are given in Table 2-2.

Table 2-1. Primary energy supply and electricity consumption for each country (1996).

Country	Total primary energy supply (TWh)	Total electricity consumption (TWh)
Canada	2,747	912
Finland	366	70
New Zealand	190	32
Sweden	611	136
USA	24,830	3,463

(Source: IEA, 1998).

Table 2-2. Primary energy sources as a proportion of total primary energy supply (%).

Energy source	Canada	Finland	New Zealand	Sweden	USA
Oil	33	30	33	45	39
Coal	11	24	6	6	23
Gas	29	10	30	2	24
Hydro	13	3	13	11	1
Nuclear	10	16	0	16	9
Other	4	17	18	20	4

Primary energy sources for electricity production are summarised in Table 2-3. Each of the five countries considered in this analysis has a distinct energy profile, with Canada, Finland and the USA being highly dependent on fossil fuels for both primary energy supply and electricity production. Sweden has a high dependence on nuclear power for electricity production and in New Zealand, hydropower is the predominant source of electricity. Finland currently has the highest use of biofuels for electricity production and both Finland and Sweden have well developed combined heat and power systems.

Table 2-3. Primary energy sources for electricity production in each country (%).

Energy source	Canada	Finland	New Zealand	Sweden	USA
Oil	2	2	<1	1	9
Coal	28	21	2		52
Gas	4	10	15	1	9
Hydro	32	17	75	38	6
Nuclear	31	27	0	52	18
Wood fuels	<1	10	<1	2	DNA
Peat	DNA	8	0	DNA	DNA
Wind	DNA	0	<1	DNA	DNA
Geothermal	DNA	0	6	DNA	DNA
Other (or non specified	2	5	1	6	6

DNA = data not available.

All countries are experiencing an increase in electricity demand which is largely being driven by increasing electrification and the use of electrical equipment. Natural gas appears to be the favoured form of fuel for future increases in electrical production for many of the countries.

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CHAPTER 3:

FORESTRY AND HARVESTING

3.0 INTRODUCTION

In 1995, it was estimated that productive forests (both natural, semi-natural, and planted) covered an area of 3,454 million hectares of land globally, equivalent to about 26.6% of the total world land mass excluding Greenland and Antarctica (FAO, 1997; WRI, 1994). In 1990, other wooded areas including bush, scrubland, heath and fallow land covered another 1,680 million hectares (Lanly, 1998). Of the total productive forests, approximately 1,961 million hectares (57% of the total) was found in developing countries (Figure 3-1). On a country basis, over 51% of the forests were in four countries - Russian Federation, 22.1%; Brazil, 15.9%, Canada, 7.1%, and USA, 6.2%.

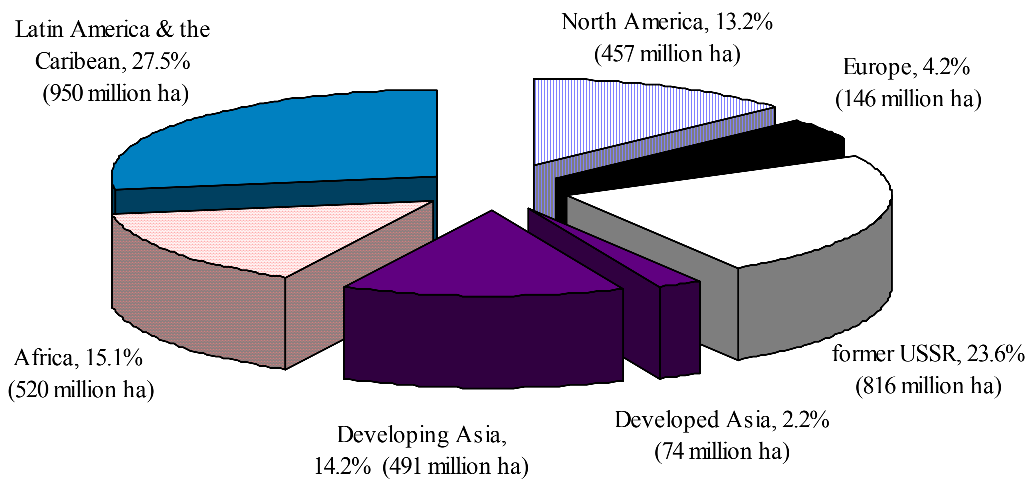

Figure 3-1. Global Forest Areas by Main Regions in 1995 (FAO, 1997).

The distribution of forest types, and also of species within the forests is highly variable. Natural forests cover a negligible area in Europe, significant areas in the rest of the developed world, and the majority of the humid tropical countries (Lanly, 1997). Plantation forests cover an estimated 80 - 100 million hectares in the developed countries, but only about 81 million hectares in the developing countries. Although natural forests continue to play a significant part in the world forest products industry, a base assumption was made to the effect that plantation forests will increasingly become important to the year 2020.

The five countries used in the analysis (Canada, Finland, New Zealand, Sweden, and the USA) constitute about 15% and 16% of the total and forest land areas of the world respectively, and contain about 14% of the total standing stock. According to the FAO Yearbook of Forest Statistics (FAO, 1996), slightly more than 1.5 billion cubic metres of industrial roundwood was harvested annually in the world for the years 1991-94 compared to about 960.3 million cubic metres harvested in 1995 in the five study countries. The following sections of the report provides an overview of the forest resource base in the five study countries.

Data for different countries was gathered from a variety of sources.

Canada:

i) Canadian Forest Inventory 1994, Natural Resources Canada, Web-site. (by Province); and
ii) National Forestry Database, Statistics Canada, 1995. This source includes data on fuel wood and fire wood.

These two sources provided historical data, covering the period 1970 to 1995 but did not provide information on future harvest volumes. The volume of harvests in each province were predicted based on the location of each province in relation to its annual allowable cut (AAC). When the province had reached its AAC, no further increase was allowed. If the province was below the AAC, then harvest volumes were predicted based on regressions derived from the historical data.

Finland:

i) Forestry Statistics Yearbook (Internet); and collated with
ii) Karjalainen and Lapveteläinen (Pers Comm) of the European Forest Institute, Finland who acted as the national contacts for the study.

New Zealand:

i) New Zealand Forestry Statistics (1997); and
ii) A National Exotic Forest Description (NEFD, Ministry of Forestry, 1997).

The New Zealand Forestry Statistics provided data on wood supply by region from 1995 to 2025 in groups of 5 years. The data assumes a base case scenario of 50,000 hectares per annum of new plantings, a clearfell age of 28 years with replanting in the year after harvest. The NEFD provides information on forest area by age class, which allowed prediction of waste thinning and production thinning volumes.

Sweden:

i) Statistical Yearbook of Forestry 1990-1997;
ii) Future production and utilisation of biomass in Sweden (1997);
iii) Sweden's Second National communication on climate change; and
iv) The HUGIN system/model (Internet).

The area of new plantings was assumed to be 2000 hectares per annum which will have minimal effect on the future volumes of roundwood harvest and therefore the associated residues production.

USA:

i) Forest Statistics of the United States (1987, 1994), USDA Forest Service;
ii) National communication on climate change (1997); and
iii) An analysis of the timber situation in the Unites States: 1989 -2040, USDA Forest Service

The analysis distinguished between total forest area, productive forest area, and reserved forest areas, but emphasised the productive forest areas, excluding reserves, scrubland etc. Thus, all data presented is limited to the productive forest land. The definitions and production levels of these forest categories differ between countries. Detailed country data for the periods 1990 and 1995 (real data), and for 2000 - 2020 (projected), on which the analysis of future residue resource availabilities was based, are provided in the Appendix. The 1995 data was used as the base scenario.

Global assessment:

Data for the global analysis were obtained from four main sources, though other data sources were used including internet sources:

i) FAO (1995). Forest resource assessment (1990). Global synthesis;
ii) FAO (1997). State of the World's Forests, 1997; FAO (1998);
iii) FAO Yearbook of Forest Products 1992-1996; and
iv) WRI (1994), World Resources (1994-95).

For the North American region, the data comprised the summation and or averages of data for both USA and Canada (see Chapters 3, 4, and 5; and the Appendix). Forest arisings and wood processing residues data for the other four regions were obtained by applying specific country factors (residue production, forest density and residues volumes factors, residue volume-transport distance model etc), to regional forestry data. The characteristics of forests in USSR (former) were considered to be similar to those of Canada, while those of New Zealand were considered to reflect the characteristics of the Developed Asia and Oceania. Europe was considered to be similar with Sweden.

Although some variation was noticed between the FAO data used, and some specific country documents, such variations were overlooked, taking the FAO data as the best available, and most consistent with time, and for country/regional comparisons.

3.1 FORESTRY IN CANADA

The productive forests of Canada comprise of a total of 219.6 million hectares (24% of total national land area). In addition, approximately 12 million hectares is reserved (land that is by law, not available for the harvesting of forest crops), and another 198 million hectares of non-commercial forest land made up of open forests comprising natural areas of small trees and shrubs. The productive forests are divided into twelve forest regions, with approximately 24% of the forests are found in the Quebec territory, 21% in British Columbia and 17% in Ontario (Table 3-1).

Table 3-1. Distribution of forests in Canada (1995).

	Unit	N'fland & L'ador	Prince Edward Is.	Nova Scotia	New Brunswick	Quebec	Ontario	Manitoba	S'chewan	Alberta	British Columbia	Yukon Territory	Northwest Territories	Whole Country
Land area	mill. ha	37.20	0.57	5.30	7.20	135.70	89.10	54.80	57.10	64.40	93.00	47.90	329.30	921.57
Productive forestland	mill. ha	10.26	0.28	3.28	5.89	46.65	37.55	13.22	10.60	20.90	44.98	6.49	13.72	213.83
Standing volume	mill. m3	527.00	26.00	254.00	646.00	4199.00	3626.00	903.00	826.00	2954.00	9936.00	633.00	439.00	24969.00
Annual increment	m^3/ha/y	1.70	2.10	1.30	1.80	1.60	1.80	1.30	2.10	2.00	1.90	1.00	0.60	1.81
Total harvest (area)	mill. ha	0.02	0.00	0.05	0.09	0.33	0.21	0.01	0.02	0.52	0.19	0.00	0.00	1.46
Total harvest (volume)	mill. m3	2.98	0.64	5.48	10.06	41.68	26.26	1.99	4.26	20.29	74.46	0.21	0.13	188.43

3.1.1 Silviculture and Forest Species Distribution

Of the total productive forest land, 119 million hectares are currently managed, but only 4 million hectares comprise of man-made forests. The rest of the forests have not been accessed or allocated for timber. An estimated 67% of all productive forests are softwoods, 15% are hardwoods, and the remainder 18% are mixed hardwoods. Planting and seeding programs concentrate on sites that have failed to regenerate several years after natural disturbances or harvesting, and they have been successful in reducing the backlog of understocked sites.

The forest management regimes emphasise the production of sawlogs, with forests being thinned 1-3 times from planting to maturity, depending on the products and markets targeted. Before the commercial thinning, it is estimated that up to 0.45 million hectares of juvenile forests are cleared every year once the trees reach a height of 2-3 meters.

Canada's forests can be divided into two categories - even-aged and uneven-aged stands although the even-aged forests dominate. Although clearcutting was the most widely used silvicultural system in Canada between 1975 and 1992, and it still continues to be the primary silvicultural system used in the prairie provinces and Newfoundland, the use of other systems including selection harvesting increased over that period in the major forestry regions. Although the use of different silvicultural systems within different regions, and also within the same regions will continue, clearcutting will remain predominant. In much of the area harvested since 1975, regeneration has been established, either through natural regeneration or planting or seeding. As a result, the area harvested since 1975 is distributed across a range of regeneration classifications.

3.1.2 Forest Inventory

The net volume of growing stock on productive forestland in Canada was estimated to be about 25 billion cubic meters of merchantable pulpwood (Lowe *et al,* 1994), mostly found in the British Columbia territory with up to 40% (nearly 10,000 million cubic meters, Mm^3 on about 21% of the productive forestland). Quebec's resource constituted about 17%, while Ontario had about 14%. Of the total standing volume, 18,000 Mm^3 (72%) is mature timber, the remainder being either immature and or in regenerated stands. An estimated 78% of the standing stock is from coniferous species dominated by Spruce (38%), Pines (22%), Fir

(15%) and Hemlock (9%). The broadleaved species are dominated by Poplar - aspen (55%) and Birch (20%).

The standing or growing stock varies between the site classes, forest types and territory. On a national basis, MAI (volume in merchantable pulp, inside bark) to maturity for all species has been estimated to be about 1.59 m^3/ha/y (Table 3-2). For all forests, the total MAI was about 364 Mm^3, while total MAI on productive timberland was about 229 Mm^3 (Lowe *et al*, 1994).

Table 3-2. **Forest type mean annual increments (m^3/ha/y)** (Lowe *et al.*, 1994).

Forest region	MAI to maturity (m^3/ha/y)
Boreal - predominantly forests	1.56
Boreal - forests and grasslands	1.82
Boreal - forests and barren	0.45
Subalpine	2.11
Montane	1.76
Coast	2.31
Columbia	2.11
Decidous	2.07
Great Lakes - St Lawrence	1.82
Acadian	1.55
Grassland	1.28
Tundra	0.79
Canada	1.59
National cummulative MAI (million m^3/y)	364

3.1.3 Harvesting / Logging

The total harvested area in 1995 was about 1.325 million hectares (0.6% of the total forestland area). Although Quebec region constitutes most of the forest land area, the territory of Alberta had a higher proportion of harvested land while British Columbia, with the highest standing volumes constituted about 14% of the harvest area. Approximately 19% and 18% of the national harvested areas were from Quebec and Ontario, respectively.

The annual total harvested volumes for 1995 was 188.4 Mm^3, less than 1% of the total standing volume. The bulk of the timber harvested (74.5 Mm^3, 40% of the national totals) was obtained from the British Columbia territory, while Quebec and Ontario provided 22% and 14% of the national total harvests (Figure 3-2). An estimated 39% of the harvest volumes were softwoods used by sawmills, 43% were mixed softwoods and hardwoods was converted to pulpwood, and only 4% of the harvest was directly used for firewood.

Overall, previous trends indicate that the size of the area harvested is growing, despite the economic downturn in 1976 and the recessions of 1982 and 1990. The area harvested increased from some 680 000 hectares in 1975 to over 1 million hectares in 1987. The harvested area peaked at 1.086 million hectares in 1988; since then the size of the area harvested has dropped to roughly mid-1980s levels.

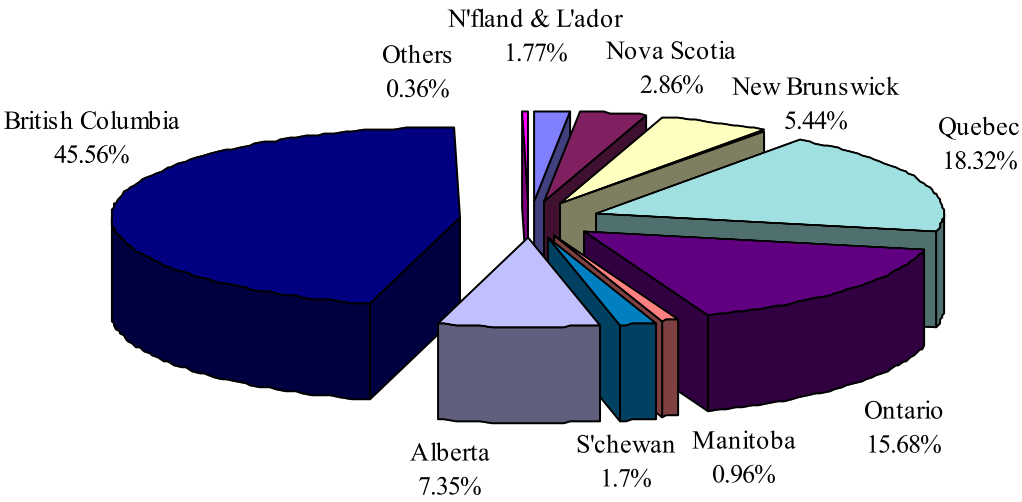

Figure 3-2. Forest harvest volumes (%) by territory in Canada (1990).

3.2 FORESTRY IN FINLAND

The forests of Finland comprise of a total of 26.4 million hectares, but only 19.5 million hectares are classified as productive (exploitable) forests, defined as sites with timber yields of more than 1.0 m^3/ha/y. The remainder is classified as scrubland (sites with timber yields of 0.1-1.0 m^3/ha/y), and wasteland (timber production of less than 0.1 m^3/ha/y). The productive forest region is distinguished into two - the North and South (Table 3-3), with 57.5% of all productive forestland area (about 11.5 million hectares) being located in the South. In addition, nearly 0.5 million hectares of productive forest land is under statutory protection (forest reserves).

Table 3-3. Forest distribution in Finland (1995).

	Unit	North	South	Whole country
Land area	mill. ha	14.8	16.1	30.9
Forest area	mill. ha	8.3	11.2	19.5
New planting area	mill. ha	0.0011	0.0079	0.0090
Standing volume	mill. m3	566.0	1357.4	1923.4
Annual increment	mill. m3	19.1	64.9	84.0
Total harvested area	mill. ha	0.082	0.202	0.284
Total harvested volume	mill. m3	12.3	31.8	44.1

3.2.1 Silviculture and Broad Forest Species Distribution

Although some 0.2 million hectares of forest land is targeted for either artificial or natural regeneration annually, only 9000 hectares, mostly in the South, is actually planted. These plantings however, coupled with improvements in overall forest management for higher productivity (eg drainage for forest land, and the application of fertilisers) has resulted in a general increase in the forest resource (see Appendix 1.2). Further, the total harvested area, plus natural losses is considerably less than the annual growth.

The management rotation periods range from 70 to 120 years. Before the commercial thinning, it is estimated that up to 0.2 million hectares of juvenile forests are cleared every year once the trees reach a height of 11-14 meters at the ages of 8 - 15 years. The management regimes emphasise the production of sawlogs, with commercial thinning being undertaken between the ages of 25-45 years (Mielikäinene and Hakkila, 1998), with up to 0.07 million hectares being thinned annually.

3.2.2 Forest Inventory

Of the total forests area of 19.5 million hectares, 90% are softwoods dominated by pines (65%) and spruce (25%). Hardwoods constitute only 8% while the remainder 2% of the total forest area is treeless.

The net volume of growing stock on productive forestland is estimated to be about 1923 million cubic meters (Mm^3) with 45% of this being pines, 37% spruce, and 18% are hardwoods. About 71% (1357 Mm^3) of the total standing stock is found in the Southern region with the remainder 566 Mm^3 being in the North. The mean annual increment (MAI, m^3/ha/y) also varies between the North and South regions, being higher in the South. In the base year, 1995, this resulted in a national annual increment of 84 Mm^3, again mostly concentrated in the South (64.9 Mm^3). Approximately 35% of the total timber growing stock is for logs, 56% for pulpwood, and the remainder 9% is categorised as waste wood.

3.2.3 Harvesting / Logging

The total harvested area annually for the base period 1995 was about 0.284 million hectares, or 1% of the total forest land area. Although the North region forests constitute about 42.5% of the forest land area, up to 71% of the area harvested was in the South. The roundwood volumes harvested for the base period was 44.1 Mm^3, with 31.8 Mm^3 (72% of the total) coming from the South. The total volume of national harvest was about 2.2% of the standing stock, and about 64% of the national annual increment. The Finnish Forest Association (1993) estimated that of the total growing stock of about 2000 Mm^3, and of the total annual growth of 85-88 Mm^3, the total drain from the forests (roundwood removals) is about 55 Mm^3 (roundwood). The harvesting was estimated to leave behind logging residues (forest arisings) of up to 6 Mm^3 (Figure 3-3). Of the total roundwood removed, 5 Mm^3 was used as fuelwood, 21 Mm^3 was used in the mechanical forest industry (sawmilling, panel products etc) resulting in about 7 Mm^3 of sawdust, chips etc which was recycled and used in the chemical forest industry consuming a total of 31 Mm^3.

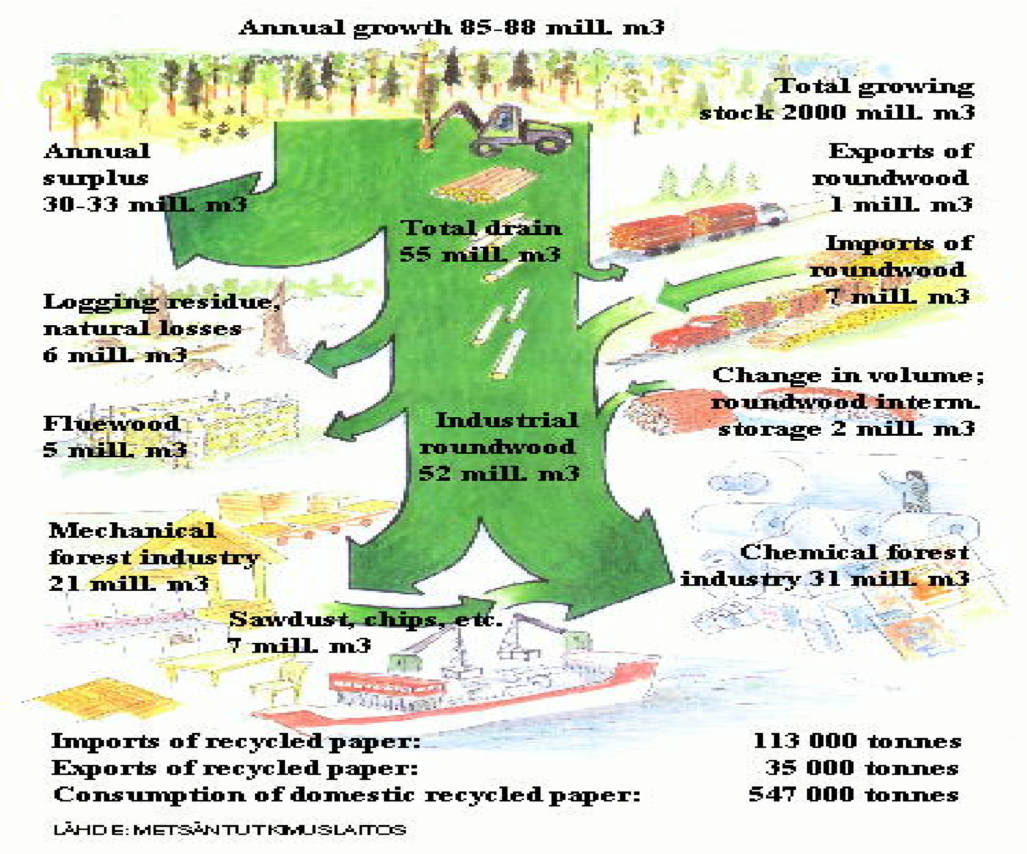

Figure 3-3. Wood flow in Finland (Finnish Forest Association, 1993).

3.3 FORESTRY IN NEW ZEALAND

The forests of New Zealand comprises of a total 7.9 million hectares (about 29% of the total land area). However, only 1.7 million hectares, (6.3% of the total land area) is classified as productive forestland, of which over 1.5 million hectares is planted forests. The remainder is natural forests, mostly in conservation estates (Murphy, 1998). The productive forestland is distinguished into three forest regions (Table 3-4).

Table 3-4. Forest distribution in New Zealand.

	Unit	North Island	Central North Is.	South Island	Whole Country
Land area	mill. ha	7.870	3.500	15.043	26.413
Forest area	mill. ha	0.640	0.553	0.482	1.675
Standing volume	mill. m^3	117.626	144.941	74.850	337.417
Annual increment	mill. m^3	12.800	11.060	9.640	33.500
Total harvested area	mill. ha	0.008	0.017	0.006	0.031
Total harvested volume	mill. m^3	4.649	10.259	3.880	18.788

In 1995, about 33% of the productive forest land area (0.55 million hectares) was located in the Central North Island, 38% in the rest of the North Island, and the remainder in the South Island. About 0.06 million hectares, distributed in the three forest regions is planted annually as new plantings in addition to the replanting in old harvested forests. The current planting rate indicates that planted forest resource will exceed 1.9 million hectares by the year 2010.

3.3.1 Forest Species Distribution and Silviculture

The plantation forests of New Zealand are dominated by softwoods with *Pinus radiata* accounting for about 91%, Douglas fir (*Pseudotsuga meniesii*) (4%), with the remainder being other softwoods (5%) and exotic hardwoods (2%). The natural forests on the other hand have a more heterogenous mix of species, even though some species dominate. In the South Island for instance, beech and podocarp species, principally rimu, are extensive, constituting nearly 80% of the indigenous forest area. Because most indigenous forests are reserved, they play an insignificant part in the forest products industry. Therefore, silvicultural practices are dominated by the silviculture of radiata pine - the most important plantation forestry species.

An estimated 74 thousand hectares of new forests, dominated by radiata pine and Douglas-fir, which account for about 97% of planted production forest area, were planted in 1995 (Ministry of Forestry, 1997). The plantings, mainly on previous pasture land coupled with improvements in overall forest management for higher productivity has resulted in a general increase in the projected forest resource (see Appendix 1-3).

Four broad classes of management have been described by the National Exotic Forest Description (Ministry of Forestry, 1995) - (i) Intensively tended with production thinning; (ii) Intensively tended without production thinning; (iii) Minimum tended with production thinning; and (iv) Minimum tended without production thinning. The management regimes emphasise the production of "direct saw logs", designed to produce a 5 metre pruned butt log for sawing or peeling, and allow quality top log which might be sawn for low quality uses, or be pulped. Nearly 69% of the radiata pine planted estate is, or is expected to be intensively tended (pruned to a height of at least four meres), and this proportion has been increasing, with higher proportions in the 1 to 20-year age classes than in the age classes older than 20 years (Ministry of Forestry, 1997). The management rotation periods range from 25 to 30 years, and therefore, little planted forests are more than 35 years old. Although these systems indicate large potential for the recovery of pre-commercial and part of the commercial thinning for energy purposes, there were no operations which were harvesting pre-commercial thinnings for wood fuel in New Zealand, at least in 1996.

3.3.2 Forest Inventory

The net volume of growing stock on productive forestland in New Zealand was estimated to be about 336 Mm^3 in 1995 with an average of 207 m^3/ha. Since no major changes in land-use proportions are anticipated in the next 20 years, planted forests are likely to continue to expand with planted forests covering more than 7% of New Zealand's land area by the year 2020. The overall standing stock is therefore expected to increase through this period.

The distribution of the forests over the three broad forest regions is provided in Table 3-4 which also shows that the mean annual increment (MAI, m^3/ha/y) also varies between the Central North Island and the rest of the country, being higher in the Central North Island. In the base year, 1995, the national annual increment was 33.5 Mm^3, mostly concentrated in the Central North Island (11.06 Mm^3) when considered in relation to the total forest land.

3.3.3 Harvesting / Logging

The total harvested area annually for the base period 1995 was 31,280 hectares, 1.9% of the total forestland area. Although the Central North Island region forests constitute only a third of the forest land area, it provided up to 54.7% of the harvested area, with a similar proportion of the harvested volumes. The roundwood volumes harvested for the base period was 18.788 Mm^3, with more than 10 Mm^3 (54.6% of the total) coming from the Central North Island. The total volume of national harvest was about 5.6% of the standing stock, and about 56% of the national annual increment. It is expected that roundwood removals in New Zealand will accelerate significantly in line with a maturing planted forest resource. Natural forest areas will generally remain static with harvesting remaining at negligible levels.

3.4 FORESTRY IN SWEDEN

The forests of Sweden comprise a total of 22.6 million hectares, about 55% of the total land area distinguished into four forest regions (Table 3-5). About 29.4% of the forestland area (about 6.65 million hectares) is located in Norra Norrland, 25.4% (5.74 million hectares) in South Norrland, 23% (5.24 million hectares) in Svealand, and the remainder (4.98 million hectares) in Goetaland. Annually, there are new plantings over an area of about 0.12 million hectares, proportionately divided among the four forest regions.

Table 3-5. Forest distribution in Sweden.

	Unit	Norra Norrland	Sodra Norrland	Svealand	Goetaland	Whole country
Land area	mill. ha	15.41	8.91	8.06	8.70	41.08
Forest area	mill. ha	6.65	5.74	5.24	5.01	22.64
New planting area	mill. ha	0.03	0.04	0.03	0.03	0.12
Standing volume	mill. m^3	598.40	746.20	710.80	873.70	2929.10
Annual increment	mill. m^3	16.47	22.10	24.94	32.21	95.72
Total harvested area	mill. ha	0.11	0.15	0.17	0.19	0.61
Total harvested volume	mill. m^3	9.90	15.50	14.30	22.30	62.00
Thinning/selective	mill. m^3	0.02	2.95	2.72	4.24	10.33
Final harvest	mill. m^3	8.02	12.56	11.58	18.06	41.31

3.4.1 Silviculture and Broad Forest Species Distribution

The rotation periods range from 70 to 110 years in Southern Sweden to 80 to 140 years in Northern Sweden. The forest management regimes emphasise the production of sawlogs, with forests being thinned 1-3 times from planting to maturity, depending on the products and markets targeted. Before the commercial thinning, it is estimated that up to 0.45 million hectares of juvenile forests are cleared every year once the trees reach a height of 2-3 meters. Of the total forests area of 22.6 million hectares, about 83% are coniferous species dominated with Pines and Spruce accounting for 37% and 46% respectively. Deciduous species account for only 15%, with the balance being dead trees or windfalls.

3.4.2 Forest Inventory

The net volume of growing stock on productive forestland is estimated to be about 2,797 million cubic meters (Mm^3) with about 30% being found in Goetaland, 24% in Svealand, 26.0% in South Norland, and the remainder 20% in North Norland. The mean annual increment (MAI, m^3/ha/y) also varies with regions, being higher in the Goetaland (6.5 m^3/ha/y) compared to only 2.3 m^3/ha/y in the North Norland. In 1995, this resulted in a national annual increment of 95.7 Mm^3, or 4.2 m^3/ha/y.

3.4.3 Harvesting / Logging

The total harvested area in 1995 was about 0.61 million hectares, 2.7% of the total forestland area. Approximately 30.4% of the area harvested was in the Goetaland region, 28% in Svealand, 24% in South Norland, and the remainder in North Norland region.

The total harvested volumes for the base period was 62 Mm^3, even though higher harvest values of 84 Mm^3 have been recorded for 1973-74, with nearly 22.3 Mm^3 (36% of the national totals) being obtained from the Goetaland region. Nationally, the total harvested volume was only 2.1% of the total standing stock, and 64.7% of the annual increment. Approximately 16% of the total volume harvested, equivalent to 10.8% of the total annual increment were either from thinnings, or from selective logging. Figure 3-4 illustrates the overall flow of wood in the Swedish forest industry including the quantities of exports, imports, stocks and that used as fuelwood.

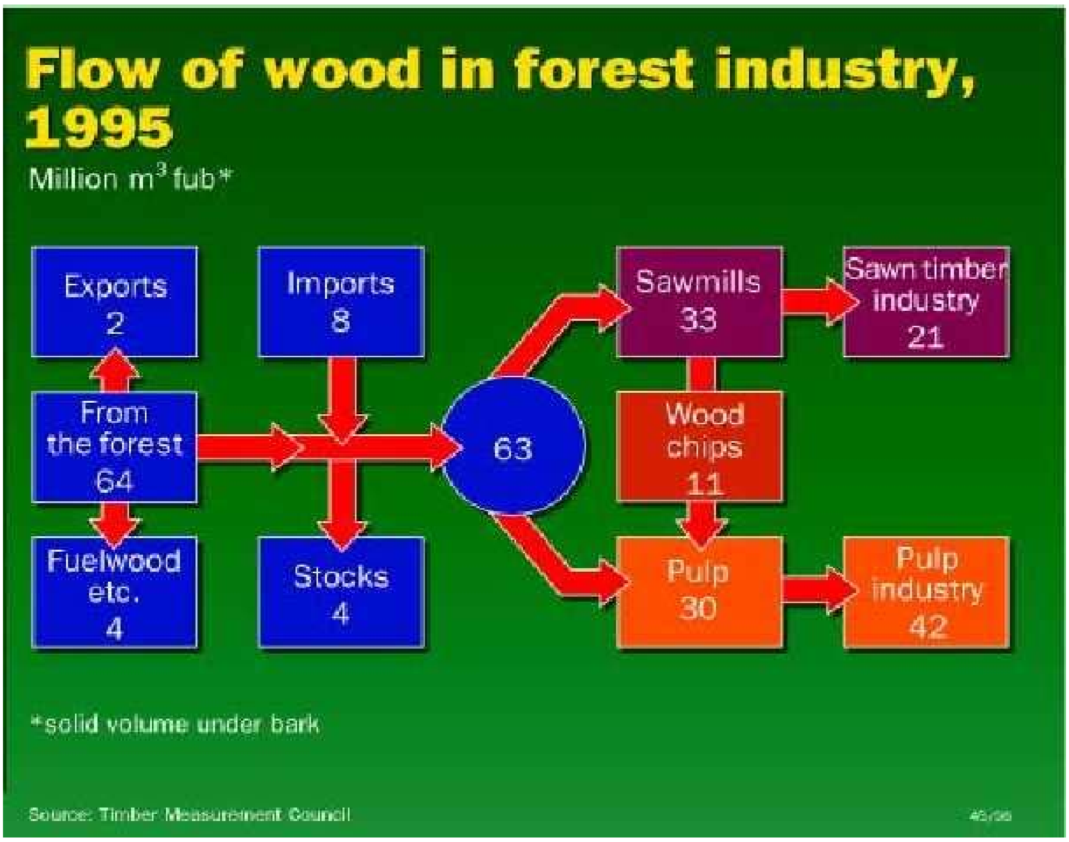

Figure 3-4. **Woodflow in the Swedish forest industry** (Timber Measurement Council).

Of the total industrial roundwood, more than 50%, mainly coniferous is used by sawmills, with the remainder, mainly mixed softwoods and hardwoods is converted to pulpwood and other panels products. About one third of sawmills intake comes out as woodchips and sawdust, which are either redirected into pulp and board industries or burnt as fuel.

3.5 FORESTRY IN THE UNITED STATES OF AMERICA

Forests cover some 295 million hectares, or approximately a third of the US land area. However, the productive forests (forests capable of producing more than 1.4 m^3/ha/y, and are available for timber production) comprises of a total of 195.6 million hectares, equivalent to about 21.4% of the total land area. These forests (productive) are distinguished into four forest regions (Table 3-6), with up to 40.4% of productive forest land area (about 79.1 million hectares) being located in the Southern region. Another 32% (62.6 million hectares) is in the Northern region while only 14.9% (29.2 million hectares) and 12.6% (24.7 million hectares) are located in the Pacific Coast and Rocky Mountains region respectively.

Table 3-6. Distribution of forests in the USA (1995).

	Unit	North	South	Rocky Mountains	Pacific Coast	Whole country
Land area	mill. ha	167.05	216.26	299.73	230.59	913.64
Forest area	mill. ha	62.60	79.07	24.74	29.18	195.59
Standing volume	mill. m3	6596	7780	3518	6375	24269
Annual increment	mill. m3	151.74	278.24	61.47	120.57	612.02
Total harvested volume	mill. m3	150.28	321.09	28.88	146.76	647.01

3.5.1 Forest Inventory

The net volume of growing stock on productive forestland is estimated to be about 24,269 million cubic meters (Mm^3). The total growing stock (excluding live cull, 1,576 Mm^3 and sound dead 460 Mm^3 from all timber) was estimated to be 22, 233 Mm^3, with 12,732 Mm^3 being softwoods, and the remainder, 9,501 Mm^3 being hardwoods. Approximately 32% of the total standing stock is found in the Southern region, 26% in the Pacific Coast region, 27% in Northern Region, and the remainder, 14.5% is in the Rocky Mountains region. The mean annual increment (MAI, m^3/h/ya) also varies with region, being higher in the Pacific Coast Region, 4.3 m^3/ha/y compared to only 2.4 m^3/ha/y in the Rocky Mountains region, 2.5 m^3/ha/y in the Northern region, and 3.7 m^3/ha/y in the Southern Region. In the base year, 1995, this resulted in a national annual increment of 637.94 Mm^3, or 3.26 m^3/ha/y.

3.5.2 Harvesting / Logging

The annual total harvested volumes for the base period was 647 Mm^3, mostly from the Southern region (321 Mm^3, 49.6% of the national totals), 23.2% from the Northern region, 22.8% from the Pacific Coast region, and the remainder, 4.5% from the Rocky Mountains region. Nationally, the total harvested volume was only 2.7% of the total standing stock, but exceeded the annual increment by nearly 3%.

The quantities of thinnings as a proportion of the total harvest or annual increment were not available but was thought to be significant given the high levels or silvicultural management in American plantation forests. Of the total forest harvested, 39% of the material, mainly coniferous was used by sawmills, while 43% (mixed softwoods and hardwoods) is converted to pulpwood. Only 4% of the harvest is directly used for firewood, with the remainder being used in the panels products industries.

3.6 FORESTRY IN DEVELOPED COUNTRIES

The four broad regions comprising the Developed countries (former USSR, North America, Europe, and Developed Asia & Oceania) contain about 1,451 million hectares of forest land covering approximately 27% of the world total land area (Table 3-7) (also see section 3.0, and Figure 3-1). However, only 898 million hectares (62% of the total forest area, or 17% of the total land area) was categorised as productive forest land. The growing stock in the productive forest land area for 1995 (the base period) was estimated to be about 159.3 billion m^3, with an annual increment of 2.1 billion m^3. The annual increment estimates exceeded the annual industrial roundwood removals estimated at 1.5 billion m^3.

On a regional level, countries of the former USSR, with a total forest and production forest land areas of 816 million hectares and 414 million hectares respectively, contained by far the largest forest estate, both in the developed world, and in the world at large. This was followed by North America and Europe, while the countries of Developed Asia and Oceania had the least coverage of forests. Like areas, the quantities of both the growing stock, and the annual increments were also highest in the former USSR (53% and 34% respectively of the totals). The total forest land area in these regions represents approximately 42% of the total world forest area, containing about 43% of the total growing stock.

Table 3-7. Distribution of forests in Developed countries (1995).

	Unit	USSR (former)	North America	Europe	Developed Asia & Oceania	Total
Land area	mill. ha	2194	1835	472	829	**5331**
Total Forest area	mill. ha	816	412	149	74	**1451**
Production forest (PF) area	mill. ha	414	308	133	43	**898**
Growing stock (PF)	mill. m^3	84234	49238	19264	6553	**159289**
Annual increment	mill. m^3	700	612	577	163	**2052**
Total harvested volume	mill. m^3	184	835	360	95	**1474**

3.7 FOREST DENSITIES

The distribution of forests within the countries, and also within the regions was assessed by analysing the forest densities, ie. the proportion of land covered by forests within specific regions, and incorporating the average rotation lengths within each country. In New Zealand, the average rotation length was taken as 28 years, in Finland and Sweden, it was taken as 60 years, in Canada, 80 years, while in the USA, it was 90. These rotation length values reflect national averages only.

Regional forest density values assume that forests are evenly distributed around a potential power generation site. Further, the harvest rates in the different regions and countries were assumed to be based on the different densities, and that they were sustainable. Typical forest density is 25% of the land area (ranging between 4% - 81%). The density adopted for Canada was 24%, 64% for Finland, 25% for New Zealand, 56% for Sweden, and 21% for USA.

3.7.1 Effect of Forest Density on Availability of Roundwood Material

Using the forest density and rotation length factors, the theoretical total roundwood harvestable to supply a centralised processing plant was determined (Table 3-8).

Table 3-8. Forest quantities (000 t) and the effect of forest density (%).

	New Zealand			Finland and Sweden			Canada			USA		
Radius	28 years rotation length			65 years rotation length			80 years rotation length			90 years rotation length		
(km)	80%	50%	20%	80%	50%	20%	80%	50%	20%	80%	50%	20%
10	157.1	98.2	39.3	52.4	32.7	13.1	31.4	19.6	7.9	27.9	17.5	7.0
20	628.3	392.7	157.1	209.4	130.9	52.4	125.7	78.5	31.4	111.7	69.8	27.9
30	1,413.7	883.6	353.4	471.2	294.5	117.8	282.7	176.7	70.7	251.3	157.1	62.8
40	2,513.3	1,570.8	628.3	837.8	523.6	209.4	502.7	314.2	125.7	446.8	279.3	111.7
50	3,927.0	2,454.4	981.8	1,309.0	818.1	327.3	785.4	490.9	196.4	698.1	436.3	174.5
60	5,654.9	3,534.3	1,413.7	1,885.0	1,178.1	471.2	1,131.0	706.9	282.7	1,005.3	628.3	251.3
70	7,696.9	4,810.6	1,924.2	2,565.6	1,603.5	641.4	1,539.4	962.1	384.8	1,368.3	855.2	342.1
80	10,053.1	6,283.2	2,513.3	3,351.0	2,094.4	837.8	2,010.6	1,256.6	502.7	1,787.2	1,117.0	446.8
90	12,723.5	7,952.2	3,180.9	4,241.2	2,650.7	1,060.3	2,544.7	1,590.4	636.2	2,262.0	1,413.7	565.5
100	15,708.0	9,817.5	3,927.0	5,236.0	3,272.5	1,309.0	3,141.6	1,963.5	785.4	2,792.5	1,745.3	698.1
110	19,006.7	11,879.2	4,751.7	6,335.6	3,959.7	1,583.9	3,801.3	2,375.8	950.3	3,379.0	2,111.9	844.7
120	22,619.5	14,137.2	5,654.9	7,539.8	4,712.4	1,885.0	4,523.9	2,827.4	1,131.0	4,021.2	2,513.3	1,005.3
130	26,546.5	16,591.6	6,636.6	8,848.8	5,530.5	2,212.2	5,309.3	3,318.3	1,327.3	4,719.4	2,949.6	1,179.8
140	30,787.7	19,242.3	7,696.9	10,262.6	6,414.1	2,565.6	6,157.5	3,848.5	1,539.4	5,473.4	3,420.9	1,368.3
150	35,343.0	22,089.4	8,835.8	11,781.0	7,363.1	2,945.3	7,068.6	4,417.9	1,767.2	6,283.2	3,927.0	1,570.8
160	40,212.5	25,132.8	10,053.1	13,404.2	8,377.6	3,351.0	8,042.5	5,026.6	2,010.6	7,148.9	4,468.1	1,787.2
170	45,396.1	28,372.6	11,349.0	15,132.0	9,457.5	3,783.0	9,079.2	5,674.5	2,269.8	8,070.4	5,044.0	2,017.6
180	50,893.9	31,808.7	12,723.5	16,964.6	10,602.9	4,241.2	10,178.8	6,361.7	2,544.7	9,047.8	5,654.9	2,262.0
190	56,705.9	35,441.2	14,176.5	18,902.0	11,813.7	4,725.5	11,341.2	7,088.2	2,835.3	10,081.0	6,300.7	2,520.3
200	62,832.0	39,270.0	15,708.0	20,944.0	13,090.0	5,236.0	12,566.4	7,854.0	3,141.6	11,170.1	6,981.3	2,792.5

For a specified radius, the quantity of harvestable roundwood increased with forest density, and was highest in New Zealand due to the higher growth rates. Although wide forest catchments translate into higher volumes for any plant, transport distances may determine the economic viability of bigger plants. Different regions operate on average haul distances for the forest industries. Such haul distances were assumed to apply to bioenergy power plants utilising forest harvesting residues, as it was considered unlikely that bioenergy industries will operate on longer distances than those of conventional forest products industries.

3.8 PROJECTIONS IN ROUNDWOOD VOLUMES

Table 3-9 provides a summary of roundwood volumes projected to the year 2020. All data for 1990 and 1995 were actual data recorded from different data sources (see Appendix) while the data for the years 2000 to 2020 were based on projections/predictions obtained from National statistical trends, or provided by respective country representatives. The projections were based on current plantings, changes in annual increments and planned harvest levels.

Table 3-9. Roundwood volumes to the year 2020 (million m^3).

	1990	1995	2000*	2005*	2010*	2015*	2020*
Canada							
Newfoundland & Labrador	2.9	2.9	2.9	2.9	2.9	2.9	2.9
Prince Edward Island	0.4	0.6	0.5	0.5	0.5	0.5	0.5
Nova Scotia	4.6	5.5	5.3	5.3	5.3	5.3	5.3
New Brunswick	8.8	10.1	10.8	10.9	10.9	10.9	10.9
Quebec	29.7	41.7	56.5	56.5	56.5	56.5	56.5
Ontario	25.4	26.3	27.7	29.4	31.1	32.7	34.4
Manitoba	1.6	2.0	2.4	2.9	3.4	3.9	4.4
Saskatchewan	2.8	4.3	4.4	4.7	5.1	5.5	5.9
Alberta	11.9	20.3	22.6	23.0	23.0	23.0	23.0
British Columbia	73.9	74.5	72.4	72.4	72.4	72.4	72.4
Yukon territory	0.1	0.2	0.0	0.0	0.0	0.0	0.0
Northwest Territories	0.0	0.1	0.1	0.1	0.1	0.1	0.1
Total	**162.1**	**188.4**	**205.6**	**208.7**	**211.3**	**213.9**	**216.4**
Finland							
North	12.3	12.3	12.3	12.3	12.3	12.3	12.3
South	31.7	31.8	31.8	31.8	31.8	31.8	31.8
Total	**44.0**	**44.1**	**44.1**	**44.1**	**44.1**	**44.1**	**44.0**
New Zealand							
North Island	4.6	4.6	10.0	11.5	11.5	12.7	12.7
Central North Island	10.3	10.3	10.9	11.5	11.5	11.5	11.5
South Island	3.9	3.9	5.8	6.1	6.4	6.7	6.9
Total	**18.8**	**18.8**	**26.6**	**29.1**	**29.4**	**30.9**	**31.1**
Sweden							
Norra Norland	9.5	9.9	13.7	13.7	14.5	14.5	14.6
Sodra Norland	16.8	15.5	22.9	22.9	24.1	24.1	24.3
Svealand	14.8	14.3	20.6	20.6	21.7	21.7	21.9
Goetaland	19.9	22.3	29.8	29.8	31.5	31.5	31.7
Total	**61.0**	**62.0**	**87.0**	**87.0**	**91.7**	**91.7**	**92.5**
USA							
North	147.2	150.3	147.2	146.8	146.5	145.6	144.6
South	316.2	321.1	308.9	307.8	306.8	305.7	304.5
Rocky Mountains	29.8	28.9	28.4	28.3	28.3	28.2	28.2
Pacific Coast	163.3	146.8	153.3	152.5	151.7	150.9	150.0
Total	**656.4**	**647.0**	**637.8**	**635.5**	**633.3**	**630.3**	**627.4**

* Projections of harvest volumes

This data shows the forest land area and growing stock distributions within the countries. The forest densities indicate the concentration of material within confined zones, and within the regions. Such differences influence the availability of roundwood to wood industries; will impact on the residues distribution and availability for use in power generation; and will influence the viability (and to a small extent greenhouse gas emissions) associated with collection and transport of feedstock to power plants (see Chapter 4).

A general increase in the volume of logs harvested is predicted for most regions. In New Zealand, the total harvested volume is predicted to increase by more than 65% between 1990 and 2020, while the volume harvested in the USA is expected to decline marginally in the same period. Although the forest resource in New Zealand is small when compared to the other four countries, the production forests are man made, and the rate at which they are expanding (more than 46,000 ha/y, equivalent to about 3% of the productive forest estate) has the potential to significantly affect future harvest volumes and operations. Although the overall growing stock in Finland is predicted to increase to the year 2020, harvesting is projected to remain at the 1995 levels (Karjalainen and Lapveteläinen, 1998). For other countries where forestry is based on a natural resource, and a considerable proportion of the land is already under forestry, new planting at current levels are unlikely to have a significant impact on future harvest volumes.

3.8.1 Roundwood volume production trends in Developed countries

Except for the countries of the former USSR which registered one of the lowest harvest volumes of 184 million m^3 in 1995, representing only 12.5% of the total harvests in Developed countries, the volumes of industrial roundwood harvested is expected to remain steady to the year 2020 (Table 3-10).

Table 3-10. Forest harvest volumes (million m^3) to the year 2020 in Developed countries.

	1990	1995	2000*	2005*	2010*	2015*	2020*
USSR (former)	386.4	183.5	285.0	234.2	259.6	246.9	253.2
North America	818.5	835.4	843.4	844.3	844.6	844.2	843.8
Europe	390.5	359.6	375.1	367.3	371.2	369.3	370.2
Developed Asia & Oceania	89.3	95.5	95.5	95.5	95.5	95.5	95.5
Total Developed Countries	**1684.7**	**1474.0**	**1598.9**	**1541.3**	**1570.8**	**1555.8**	**1562.7**

* Projections

Harvest in the former USSR was relatively lower than the other three regions, especially when the resource potential was considered. North America, with a harvest of up to 835 Mm^3 accounts for about 56.7% of the total harvest, Europe, 24.4%, and the Developed Asia & Oceania, 6.5% of the total. It was noted that the industrial roundwood harvests and removals from countries of the former USSR has declined significantly during the 1990's leading to the suppressed roundwood harvests in the Developed countries over the last decade. The decline not withstanding, the analyses and projections in the study assumed that the former USSR will recover to achieve higher harvest levels commensurate with the resource base. This assumption resulted in the gradual rise in industrial roundwood volumes after the year 1995, but remained below 1990 harvest volumes.

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CHAPTER 4:

FORESTRY RESIDUES ASSESSMENT

4.0 INTRODUCTION

Conventional forestry offers substantial opportunity for the recovery of biomass as renewable fuel. Such fuel sources will arise due to pre-commercial and early commercial thinning of young stands, residual stemwood and crown mass from regeneration cuttings, logging residues from clearfell cutover and at log landing sites, the dead, dying and decaying unmerchantable trees selectively removed to increase the productivity of forest stands, and in some countries poor quality, small sized deciduous trees from under-productive stands or plantation cleaning. Other conventional forest sources may include prunings as well, though to date such materials are not regarded as a viable residue source. Although forest arisings may include merchantable as well as non-merchantable tree components, only the non-merchantable components, with minimal competing uses in the forest products industry were considered in this study. In addition, large pieces of broken, rotten or unrecoverable material that fall outside the utilisation range were included.

The efficiency and effectiveness of biomass recovery from conventional forestry depends markedly on forest management regimes and harvesting methods, with efficiency considering not only low costs and high productivity, but also the enhancement of industrial wood production and employing environmentally sustainable forestry management practices. Where conventional forestry is to be used as a viable source of renewable energy, the production of high quality merchantable wood remains of first importance with renewable energy production being a by-product of the system.

Logging residues refer to the foliage, branches, stem wood and bark that is left behind in forest harvesting or stand cleaning operations. These materials may exist in varying proportions and piece size depending on forest type, forest management systems, harvesting techniques, tree species and terrain. This section of the report considers:

- an overview of forestry harvesting methods and how these may affect the recovery of forest residues from conventional sustainable forestry operations.
- the fuel characteristics of forest residues
- methods used to determine the potential quantities of forest residues that would be available from the five countries,
- methods used to determine the cost of forest residue recovery and transport
- methods used to assess the fossil fuel consumption and the amounts of greenhouse gases produced from collection and transport of forest residues.
- evaluation of factors that may affect the long term supply of forest residues

4.1 DATA SOURCES

The residues data were derived from the forestry and forest harvesting data outlined in section 3.0. Data from the New Zealand Forestry Statistics (1997) and from the National Exotic Forest Description (Ministry of Forestry, 1997) for New Zealand were combined with published data on logging residue volumes, as a % of harvest (Hall, 1994,1998); and also with unpublished data on the proportion of ground based and hauler logging (Hall, 1997). These sources were combined with various factors from actual studies carried out in New Zealand, and which describe the volume of logging residue left on the cut-over and at the log landing areas, and the survey of the logging industry which provided information on the proportion of ground based and cable logging on a regional basis. These provided the volumes of residue on the cut-over and at the landing by region.

4.2 HARVESTING SYSTEMS AND OPERATIONS

Throughout the world there is a trend towards using cut to length (CTL) harvesting systems whereby trees are felled delimbed and cut to length in one operation at the tree stump. Such practices have been common in Sweden and Finland for many years. There are also rapid changes occurring in Canada (Godin 1995) and the USA which indicate that CTL systems will be the predominant system in ground based logging in the future. However, cut to length systems are not common in New Zealand although, mechanised felling, delimbing and bunching at the stump are frequently used practices. New Zealand also differs from the other countries in the proportion of harvest on steep terrain requiring hauler (cable) logging. Currently cable logging represents approximately 40% of the total harvest and is likely to rise to 60% over the next 30 years. Cut to length is not used in New Zealand due to the average piece size of the clear-fell trees in New Zealand being large (2.2 m^3), which limits the use of this technology for steep slopes or large trees. Roadside processing of logs is still common in the USA and Canada but these operations are reducing in number.

Given the above situation, forest residues within New Zealand are distributed differently compared to the other nations as some is at landings or roadside in the form of logging residues and a substantial proportion is inaccessible on steep terrain cutover. However, much is still located on the flat terrain cutover due to breakage during felling and delimbing prior to extraction.

Although there are differences in harvesting operations between countries, the types of systems that exist or which might be developed for fuel-wood harvesting in Scandinavia could also be appropriate for New Zealand or North America. All harvesting methods leave residues which are of a variable nature, and scattered at relatively low densities throughout the cutover. The accumulation of large piles of residues is often necessary prior to transport of residues from forests or subsequent pre-treatment (such as chipping).

Forest management and harvesting systems for industrial wood and the potential for recovery of forest residues as a renewable fuel needs to be considered in an integrated manner.

For the purposes of this study, estimates of residue yields included material available both at cutover and at landings or roadside (eg. as shown in Figure 4-1), but excluded residues left in steep terrain clearfell sites (eg. as shown in Figure 4-2). Residues on steep terrain clearfell sites were assumed to be unavailable, partly due to the logistics and costs involved in their collection, and also for site, ecological, and environmental reasons. However, for cost and greenhouse gas emission assessments, only the cutover was considered as the quantities of residues available from the cutover are typically much greater than that from the landing or roadside.

Figure 4-1. **Logging residue from ground-based clearfelling**
(Such sites were considered suitable for residues recovery)

Figure 4-2. Steep terrain clearfell
(Residues on such sites were assumed to be unavailable)

4.3 ANALYSIS OF FOREST RESIDUE YIELDS

4.3.1 The Influence of Forest Density

The quantity of logging residues at specific sites could be estimated by i) the direct measurements of the weight of residues in sample plots, and extrapolating the results to reflect the whole region; and (ii) the line transect methods (Hakkila, 1989). The quantity of residues generated from a logging operation may be assumed to be directly proportional to the total roundwood removed. For specific forest densities assumed to supply a centralised processing plant (see section 3.7) it was assumed that (i) forests are evenly distributed around the plant; (ii) harvest rates are based on established forest densities; and (iii) harvests are sustainable.

Table 4-1 shows model variations in residue quantities over different radial distances for three forest density scenarios. The quantities are cumulative, ie, quantities at subsequent radial/haul distances are additive to quantities at shorter distances. It was assumed that residues from extended distances could only be utilised after those nearby the centralised processing plants, including forest residues are exhausted.

Table 4-1. Forest residue quantities (000 t) and the effect of forest density (%).

	New Zealand			Finland and Sweden			Canada			USA		
Radius	28 years rotation length			65 years rotation length			80 years rotation length			90 years rotation length		
(km)	80%	50%	20%	80%	50%	20%	80%	50%	20%	80%	50%	20%
10	22.4	14.0	5.6	7.9	4.9	2.0	4.7	2.9	1.2	4.2	2.6	1.0
20	89.8	56.1	22.4	31.4	19.6	7.9	18.8	11.8	4.7	16.8	10.5	4.2
30	202.0	126.2	50.5	70.7	44.2	17.7	42.4	26.5	10.6	37.7	23.6	9.4
40	359.0	224.4	89.8	125.7	78.5	31.4	75.4	47.1	18.8	67.0	41.9	16.8
50	561.0	350.6	140.3	196.4	122.7	49.1	117.8	73.6	29.5	104.7	65.5	26.2
60	807.8	504.9	202.0	282.7	176.7	70.7	169.6	106.0	42.4	150.8	94.2	37.7
70	1,099.6	687.2	274.9	384.8	240.5	96.2	230.9	144.3	57.7	205.3	128.3	51.3
80	1,436.2	897.6	359.0	502.7	314.2	125.7	301.6	188.5	75.4	268.1	167.6	67.0
90	1,817.6	1,136.0	454.4	636.2	397.6	159.0	381.7	238.6	95.4	339.3	212.1	84.8
100	2,244.0	1,402.5	561.0	785.4	490.9	196.4	471.2	294.5	117.8	418.9	261.8	104.7
110	2,715.2	1,697.0	678.8	950.3	594.0	237.6	570.2	356.4	142.6	506.8	316.8	126.7
120	3,231.4	2,019.6	807.8	1,131.0	706.9	282.7	678.6	424.1	169.6	603.2	377.0	150.8
130	3,792.4	2,370.2	948.1	1,327.3	829.6	331.8	796.4	497.7	199.1	707.9	442.4	177.0
140	4,398.2	2,748.9	1,099.6	1,539.4	962.1	384.8	923.6	577.3	230.9	821.0	513.1	205.3
150	5,049.0	3,155.6	1,262.3	1,767.2	1,104.5	441.8	1,060.3	662.7	265.1	942.5	589.1	235.6
160	5,744.6	3,590.4	1,436.2	2,010.6	1,256.6	502.7	1,206.4	754.0	301.6	1,072.3	670.2	268.1
170	6,485.2	4,053.2	1,621.3	2,269.8	1,418.6	567.5	1,361.9	851.2	340.5	1,210.6	756.6	302.6
180	7,270.6	4,544.1	1,817.6	2,544.7	1,590.4	636.2	1,526.8	954.3	381.7	1,357.2	848.2	339.3
190	8,100.8	5,063.0	2,025.2	2,835.3	1,772.1	708.8	1,701.2	1,063.2	425.3	1,512.2	945.1	378.0
200	8,976.0	5,610.0	2,244.0	3,141.6	1,963.5	785.4	1,885.0	1,178.1	471.2	1,675.5	1,047.2	418.9

The analysis assumed centralised processing where all materials were trucked to one point, resulting in different haul distances used in estimating the quantities, costs, and emissions (see Appendix). There is potential to (i) reduce haul/transport distances; (ii) reduce transport costs due to reduced haul distances; (iii) reduce emissions associated with transport and use of diesel; and consequently (iv) increase GHG abatement from a unit quantity of material. However, decentralised processing would compromise advantages of economies of scale operations and would have been difficult to consider within the scope of this analysis as site specific features would need to have been considered in more detail.

4.4 AVAILABILITY OF FOREST RESIDUES FOR POWER PRODUCTION

4.4.1 Assessment Methods

The general level of interest in recovering small trees and residues has been shown to be low except for a few areas where the bioenergy market has become established (Gingras, 1995). In many parts (eg. Canada), large quantities of mill residues are still unused and available. The availability of such mill residues reduce the viability of recovering logging residues. Although this analysis was based on the premise that forest residues are mainly unused in many parts of the world, it did not negate the possibilities of future competing markets. Thus, the quantities of harvesting residues were derived by applying a factor to recorded and or estimated logging rates, incorporating the availability of the residues which was determined by applying recoverable potential factors incorporating issues of terrain; the associated cost/economics of collection; the environmental effects of total recovery; and (also the possibilities of future utilisation from competing uses), to recorded forestry data in the different regions/countries including the productive land areas, inventory data, recorded annual increments, annual allowable cuts, forest harvesting and wood products processing and production data. Although the methodologies differed from those applied by McDaniels and Manning (1987) who utilised a series of factors including the annual allowable cut, harvest data, growth, density and decay to estimate the quantities of forestry and wood processing residues in British Columbia, the values obtained were comparable to many other studies, and reflected the current residue quantities.

Country estimates

Each country analysed was differentiated into regions, mainly from national forestry management blocks/subdivisions. The analysis differentiated between the different categories of forest lands - total forest land, productive forestland, reserved forest land etc. Reserved forests were considered to play no part in the forest products industry. All data was based on the productive forest resource base that is not reserved.

Although the different sites within countries have different productivities resulting in regional differences in tree forms, and tree components, calculations assumed that forest residue production was similar. Estimation of the available quantity of residues recognised the difficulties and differences in residues collection in different terrains, and also the differences in logging technologies applied in the different regions and countries. Only a proportion of this resource is available for potential utilisation in the production of power. The yield scenarios indicated by year represented judgements about the potential success of collection technologies. Where possible, the quantity values obtained were compared with national estimates of production, availability, and current usage.

Estimated quantities of the residues available by country for 1990 and 1995 (real harvest data), and for 2000 to 2020 based on projections from the 1990-95 data, planting rates, annual increments, annual allowable cuts etc (see chapter 3) are presented in Table 4-2. The residues available were over and above those which are already being used for bioenergy production.

Table 4-2. Trends in regional/country forest residues to the year 2020 (million m^3).

	1990	1995	2000*	2005*	2010*	2015*	2020*
Canada							
Newfoundland & Labrador	0.43	0.45	0.45	0.45	0.45	0.45	0.45
Prince Edward Island	0.07	0.10	0.08	0.08	0.08	0.08	0.08
Nova Scotia	0.70	0.82	0.80	0.80	0.80	0.80	0.80
New Brunswick	1.32	1.51	1.62	1.64	1.64	1.64	1.64
Quebec	4.45	6.25	8.48	8.48	8.48	8.48	8.48
Ontario	3.81	3.94	4.16	4.41	4.66	4.91	5.16
Manitoba	0.23	0.30	0.36	0.44	0.51	0.59	0.67
Saskatchewan	0.41	0.64	0.65	0.71	0.77	0.83	0.88
Alberta	1.79	3.04	3.38	3.45	3.45	3.45	3.45
British Columbia	11.08	11.17	10.86	10.86	10.86	10.86	10.86
Yukon territory	0.01	0.03	0.00	0.00	0.00	0.00	0.00
Northwest Territories	0.01	0.02	0.02	0.02	0.02	0.02	0.02
Total	**24.32**	**28.26**	**30.85**	**31.31**	**31.70**	**32.08**	**32.47**
Finland							
North	1.47	1.23	1.23	1.23	1.23	1.23	1.23
South	3.80	3.18	3.18	3.18	3.18	3.18	3.18
Total	**5.27**	**5.68**	**4.41**	**4.41**	**4.41**	**4.41**	**4.40**
New Zealand							
North Island	0.60	0.62	1.32	1.50	1.50	1.64	1.65
Central North Island	1.86	1.86	1.97	2.09	2.10	2.10	2.12
South Island	0.48	0.50	0.73	0.78	0.81	0.86	0.88
Total	**2.94**	**2.98**	**4.02**	**4.37**	**4.40**	**4.60**	**4.64**
Sweden							
Norra Norland	0.95	0.99	1.37	1.37	1.45	1.45	1.46
Sodra Norland	1.68	1.55	2.29	2.29	2.41	2.41	2.43
Svealand	1.48	1.43	2.06	2.06	2.17	2.17	2.19
Goetaland	1.99	2.23	2.98	2.98	3.15	3.15	3.17
Total	**6.10**	**6.20**	**8.70**	**8.70**	**9.17**	**9.17**	**9.25**
USA							
North	17.28	19.14	17.28	17.24	17.19	17.09	16.98
South	55.09	49.05	47.17	47.01	46.85	46.68	46.50
Rocky Mountains	2.74	2.18	2.14	2.14	2.13	2.13	2.13
Pacific Coast	35.70	27.47	28.69	28.55	28.40	28.24	28.08
Total	**110.81**	**97.83**	**95.28**	**94.93**	**94.58**	**94.13**	**93.69**

* Projections of residues availability

Volume predictions for the future were based on the assumption that available residues were equal to 10% of the roundwood volume harvested in Finland and Sweden. In Canada, it was assumed that that available residues were equal to 15% of the roundwood volume harvested, while the proportions varied with region in USA – 11.7% in the North, 15.27 in the South, 7.5% in the Rocky Mountains, and 18.7% in the Pacific Coast region. In New Zealand, volume of residues in the Central North Island varied between 18.1-18.4% of the total aboveground biomass, 12.9-13.3% in the rest of the North Island, and 12.3-12.8% in the South Island. The higher residues quantities in the Central North Island result from the higher proportions of ground based logging operations as opposed to predominantly hauler operations in the other regions. Other residues were assessed to be on steep terrain, or the extraction would impinge on site stability resulting in soil erosion etc. In Finland and Sweden, it was recognised that the proportion of 10% of total roundwood harvested is lower than in real practice, but it was considered feasible in view of the fact that these countries already harvest significant proportions of the residues. The 10% proportion represents residues judged to be over and above current utilisation volumes. Except for New Zealand, the area of new plantings was assumed to have minimal effect on the future volumes of roundwood harvest and therefore the associated residues production.

Estimates in Developed Countries

A distinction was made between fellings and removals, the difference being the volume of timber felled but not extracted form the forest (FAO, 1995). Such differences provide the basis for utilising forest residues for bioenergy, and formed the core of this study. The data presented for harvest volumes (Chapter 3) refers to the quantities actually removed and those that are projected to be removed for utilisation by the forest industry. Although technology of extraction, terrain and other site specific factors have a significant influence on harvesting operations, the quantity of harvesting residues generated tends to be in proportion to the harvest volumes. To estimate the volumes of residues that could be extracted for developed countries (Table 4-3), various factors were taken into consideration (see Section 4.3).

Table 4-3. Availability of forestry residues in Developed Countries (million m^3).

	1990	1995	2000*	2005*	2010*	2015*	2020*
USSR (former)	58.0	27.5	42.7	35.1	38.9	37.0	38.0
North America	135.1	126.1	126.1	126.2	126.3	126.2	126.2
Europe	39.1	36.0	37.5	36.7	37.1	36.9	37.0
Developed Asia & Oceania	14.0	15.1	14.4	14.3	14.3	14.2	14.2
Total Developed Countries	**246.1**	**204.7**	**220.8**	**212.4**	**216.6**	**214.4**	**215.4**

* Projections

4.4.2 Factors Affecting the Supply of Forest Residues

The total potential residues from a harvesting operation is dependent on the species or dominant species within the stand, silvicultural management history and the age/rotation factors of the stand, harvesting technology, application of the roundwood logs (sawmills, pulp and paper, panel products etc), and the minimum log diameter requirements. Further, the availability of biofuels from forests will vary depending on competing demand for sawn lumber, pulp and papermaking, and particle and fibre board products. For example, when pulp chip prices are low more stem wood will become available as fuel wood. When chip prices rise it will be more attractive to sell for the higher price, and fuel wood operations may become uncompetitive. Pulp chip prices have a history of long term rises and falls. Availability of residues needs to be viewed in relation to the chip price at the time.

Given the number of variables which may potentially effect forest residue recovery, decisions regarding the most optimum system need to take an integrated approach and consider the entire supply chain from forest to power generation. Such analyses are often complex and are most appropriately dealt with on a site specific basis. In order to simplify the process for this study, various assumptions on the harvesting and transport systems were made. Some aspects of New Zealand forestry are worth noting:

i) New Zealand differs from the other countries included in the study as the forests being harvested were plantations, and the New Zealand resource in comparison to the other countries is small. All the production forests included are man made, and the rate of new forest plantings has a significant potential to effect future harvest volumes. This contrasts with the other four study countries where forestry is based on a natural resource, of a very large scale. In these other countries therefore, new forestry plantings are likely to have a limited effect on the future volumes of wood being harvested, at least to the year 2020.

ii) Plantation forests in New Zealand are often located on steep land where hauler harvesting is required. How much is on steep land varies by region but currently averages 40 percent of the resource. It could be generalised that up to 40% of the harvest is on steepland, and that such areas were assessed to be unsuitable for forest residues harvesting. Information on the proportion of forests on steep terrain in other countries was not available. Data on residues from these countries was either supplied, or estimated from harvest figures.

iii) Residues that occur at log processing landings were assumed to be available and those at the stump unavailable due to cost and environmental reasons. New Zealand's trees are large and tall (40m+) at clearfell, frequently they break when felled, with the crown breaking into several small pieces which are unmerchantable as conventional products. This material is not extracted to roadside.

For other countries included in the study, the issue of steep land and its effects were uncertain. The proportion of steep land which has productive forest was assumed to be much lower, with variation by region. These are often much smaller than those in New Zealand with a different branching habit, resulting in less felling breakage and more residues produced at roadside. In the absence of better information where residues were deemed to be available as presented in the literature, it was assumed to be at roadside or on flat terrain.

4.5 WOOD FUEL PRODUCTION TECHNOLOGIES

Many systems may be used in the production of fuel chips from logging residues - Chipping at roadside; Chipharvester; and Chipping and transport. In this analysis, the system adopted involved the collection of slash into heaps in conjunction with processing with one-grip harvesters and haulage to the roadside with conventional forwarders with enlarged load space.

4.6 HANDLING AND PRETREAMENT OF FOREST RESIDUES

Biomass fuel handling systems have been developed for processing fuels to different specifications depending on the conversion technologies including (i) pulverised fuel combustion; (ii) grate combustion; (iii) fluidised-bed combustion; and (iv) gasification/gas combustion. The study recognised that the technology applied may be reliant on the nature of the material, and the extent of processing. Similarly, the nature of material desired, and requiring different levels of processing/handling may be dictated by the conversion system. Thus, feedstock requirements for gasification, especially fluidised bed systems would require more pre-treatment than feedstock for a grate fired boiler, involving particle size reduction (comminution) and moisture content adjustments. In spite of this recognition, the study assumed that residue processing would be required for hogging (comminuting wood waste to fuel by high speed fixed/swing hammer device in a rotating drum with rows of hammers attached), and or chipping only, and to a limited extent, reductions in moisture content. Power generating plants would further process the material to suite plant requirements.

Options for reducing forest residues to a form suitable for an in-feed supply to a power station include (i) the collection and size reduction on the cutover using a chipper forwarder or trailer chipper (Figure 4.3); (ii) chipping at landing or roadside with a trailer chipper (Figure 4.4); and (iii) collection of residues from cutover or landing and transported to a centralised chipping plant (Figure 4.5).

Figure 4-3. Chipper forwarder for residue recovery on flat terrain or at roadside.

In some countries (Finland) specialist machines have been developed for fuel wood recovery from pre-commercial thinning operations. Such machines (small feller-chipper-forwarders) produce whole tree chips in a one pass operation. However, harvesting of pre-commercial thinnings as bio-energy is dependent on finding an efficient low cost harvesting system as the piece size (tree size) is typically small and the density of material per hectare is low. Although this material is generally of low priority for recovery due to its high costs, it should not be ignored as it is a substantial resource in numerous countries and use of small volumes may be viable to supplement other fuel sources to achieve an appropriate supply volume.

Figure 4-4. Large mobile hog for processing landing or roadside residues.

Figure 4-5. Centralised chipping plant for processing conventional pulp chip or residues.

Harvesting of full sized trees with landing or roadside log making can produce significant piles of woody residue. If left in the forest such piles my pose a potential fire risk, encourage pests or disease and occupy valuable space. Thus, the use of these materials as a renewable fuel source both minimises these problems, while providing energy. Where such piles of residues are produced large chippers can be used to process materials directly into chip trucks.

Perhaps more critical in the decision making process is where and when the comminution should take place. Chipper forwarders have low production rates and hence high chipping costs (Brunberg, 1994, Brunberg 1995). Large trailer mounted chippers and hogs are more productive but costs are highly sensitive to utilisation and they can have logistical difficulties, especially with truck supply (Table 4-4).

Table 4-4. Production rates and costs for mobile pre-treatment systems.

	Production rates (Green tonnes/hour)	Production costs ($/green tonne)
Chipper forwarder	8 - 14	15 - 30
Trailer chipper	20 - 50	8 - 15

Source: Desrochers *et al*., (1995)

Large fixed installation chippers are often the most productive and have lower fuel costs in comparison with the other options. However, centralised chipping installations require that the residues be transported over considerable distances in an unprocessed form, resulting in significantly higher costs especially if trucks are not running at close to the their maximum payload and gross vehicle weights (GVWs), over long haul distances. This limitation not withstanding in this study, all forest residues were assumed to be pre-treated at a centralised site to take advantage of the higher production rates and lower production costs. This option was considered the lowest cost option and would allow for the plant to be operated at full capacity. Where roadside and cutover residues are used, then site preparation requirements and costs along with silvicultural treatment costs can be reduced (Zundel *et al.*1997).

In order to minimise unit costs and maximise production large, trailer mounted chippers need to be operated at full capacity and therefore typically require large volumes of residues as feedstock and an unrestricted supply of trucks to transport chipped material to a large market or user. The chipper capacity needs to be matched to the available fuel supply (Stuart *et al.*, 1981; Desrochers *et al.* 1995), which together with residue availability / density per unit area, and the wood content or composition / moisture content determines the chipper productivity.

The integration of residue harvesting with conventional logging is attractive, but the residue operation must not interfere with the production of industrial wood products or increase their costs. This is difficult to achieve in many situations. It has been found that the inclusion of small piece size material with the full tree harvest tends to increase the unit cost of logs (McMahon *et al.* 1998). Several residue harvesting systems which are effectively separate to the log harvesting operation have been developed, particularly for conventional ground based and CTL operations. Although the accumulation of residue material can cause storage problems and interfere with the efficient operation of landings in conventional landing based or roadside operations, whole tree harvesting with roadside processing into logs/fuelwood generally give cheaper fuelwood than a CTL harvesting system with the subsequent residue recovery from the cutover. Besides, the problems associated with such accumulation can be overcome by chipping the material and transporting it to a potential user.

In New Zealand, Canada and the USA, centralised processing yards (CPY's) are frequently used for log making (Figure 4.6). These yards take full sized trees or more commonly tree length stem wood and process them into log products. Associated with this processing is the production of stem wood and bark wastes. The waste material produced is frequently landfilled, as it occurs in large volumes (2% to 4% of the processed stem volume). The CPYs are often in remote locations and transport distances to potential biomass fuel users are high. However, utilisation of this material for bio-fuel is attractive as it has already incurred costs by the time it is delivered to the log processing site.

Figure 4-6. Accumulation of processing residues at a small central processing landing.

4.6.1 Compaction of Residues

Neither baling nor full load compaction were considered in this study as the two systems are not currently used widely for recovering forest residues. However, it was recognised that the technologies have high potential for future bioenergy systems, and were therefore mentioned.

Baling

There have been numerous attempts to bale forest residues with very limited success, partly due to the high costs of the technology, reaching up to US$10.00 per green tonne (Andersson

1995a,1995b, Andersson and Hudson 1997, Brunberg and Andersson, 1996). A significant problem is that residues are not homogenous, mainly consisting of a mixture of stem, branch and often leaf material. Although the branches are relatively easy to handle, the stem material is often unsuitable for baling requiring pre-sorting of stem and branch material, which is not cost effective. Since baling technology is still being developed, future potential resulting from increased productivity and marked reductions in cost may make it an attractive option. Besides, baling of residues may be more cost effective over longer haul distances and where high truck gross vehicle weights are allowed, as it can reduce transport costs by up to US$10.00 per green tonne over a 100 kilometre haul distance.

Full load compaction

Compaction of forest residue for transport is desirable in many situations. Full load compaction can be achieved by, ratchet tie downs or machine assisted tie downs (Hankin and Mitchell, 1994). These approaches are low cost compared to baling.

4.6.2 Transport of Forest Residues

The most appropriate transport system for forest residues should be considered on a case by case basis with the preferred system often depending on the distance between the forest and market (eg an electric power generation plant). In addition, whether the roads are publicly or private may also be an important factor.

Over short distances (< 50 kilometres) it is likely that the use of trucks will be the main transport method. However, over longer haul distances (150 kilometres plus) other transport systems may be used, such as truck and rail, truck and barge or off-highway and on-highway trucks. Truck and trailer transport is often preferred due to its flexibility, cost effectiveness and can easily be matched with scale of harvesting operation. In general, road transport contributes a substantial proportion of the delivered cost of fuel (30% - 70% depending on haul distance). Similarly, the number of loads per day that can be carried by a given truck will vary with the haul distance.

Transport systems and truck designs are becoming more sophisticated and specialised. What is highly efficient on-highway may be inappropriate or unusable for in-forest situations and vice versa. For instance, although a number of sophisticated high volume B train chip van designs, with walking floors in the bins (Figure 4-7), have been developed, they are often unsuitable for in-forest transport as they are designed for highway use and perform poorly off-highway, particularly on adverse grades when the truck is empty. More commonly simple semi-trailers or truck and trailers (Figure 4-8) are used in-forest due to the uneven conditions encountered. Trucks will also be frequently used as the infrastructure for roads and expertise has been developed for the transport of industrial wood p products. In Finland for example, 80% of the roundwood harvest is taken to the mill by truck.

Figure 4-7. High volume B-train chip transporter.

Residues can be transported in 3 different forms (i) uncomminuted residues (ie. Non-chipped); (ii) chipped or hogged; and (iii) compacted or baled. On the other hand, unloading of residues from trucks can either be by (i) hydraulic self-tipping trailers; (ii) hydraulic ramps which rise and tip the entire truck; (iii) walking floor trailers which self empty; (iv) bottom dumpers; (v) crane and grapple; and (vi) removable containers. Regardless of the product, a key component of efficient transport is to maximise the truck payload and to reach the maximum permissible gross vehicle weight (GVW) for the truck configuration being used.

Figure 4-8. Truck and trailer for residue transport.

There are substantial differences in the maximum GVWs allowed in the different countries, with the highest being Sweden with 60 tonnes compared to only 36 tonnes in the USA. The differences in the five countries are summarised in Table 4-5, which also indicates the potential payloads, and the average haul distances. For countries which allow high GVWs it is sometimes difficult to achieve the maximum permitted GVW with unchipped or uncompacted residues due to the high bulk volume of chips. In countries that permit lower GVWs and trucks of a similar size and cargo volume, it is possible to get to the maximum GVW with unchipped residues compacted into the truck with a loader.

Table 4-5. Vehicle characteristics, transport distances and potential payloads (t).

	Canada	Finland	New Zealand	Sweden	USA
Max GVW (t)	53.5	56	44	60	36
Load space (m^3)	130	135	110	135	110
Mean haul distance (km)	100	130	65	120	100
Potential payloads (t)					
Residue	30	29	24	30	24
Bales	39	36	29	40	25
Chip	33	30	29	33	24

Uncompacted residues have a density of 15 percent to 20 percent compared to the original material (Figure 4-9). However, careful loading and compaction with loaders and tie downs can significantly increase this to 35 percent. Loader compaction can increase density by 20 percent and compaction devices such as cables pulled by the loader can increase density by 200 percent (Hankin and Mitchell 1994). Figure 4-9 is an illustration of different load densities for uncompacted forestry material, while Figure 4-10 illustrates the simple means of compacting the material to optimise on gross vehicle weights, and therefore the payloads.

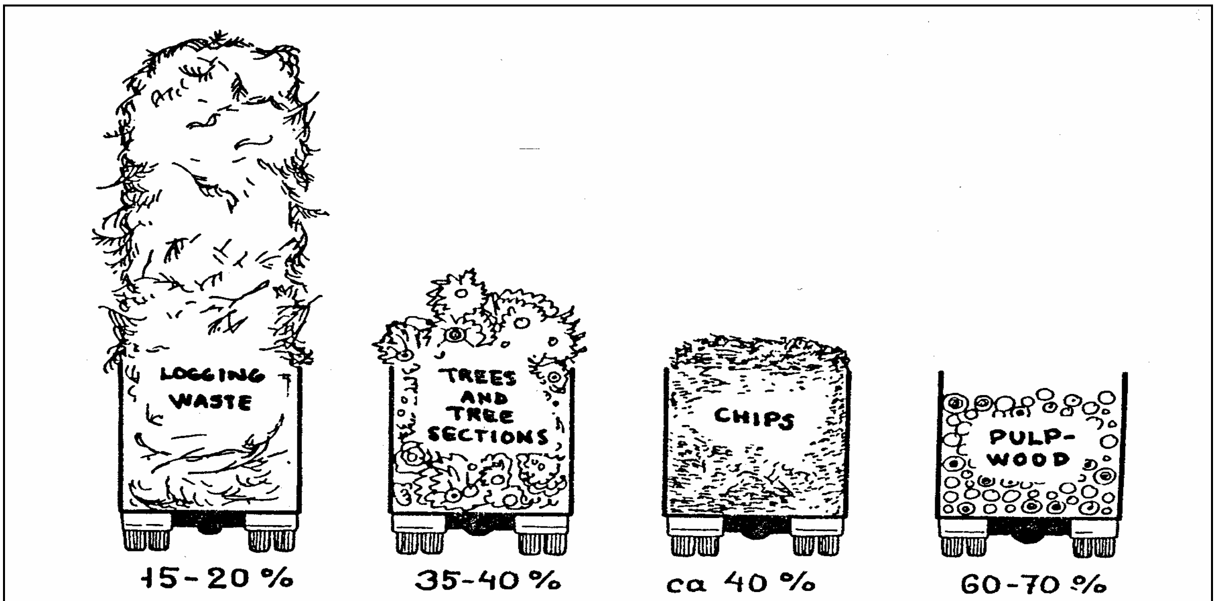

Figure 4-9. Typical load density for uncompacted material (Source: Nilson 1983).

In-forest chipping allows load densities of 40 percent to be achieved. However, such chippers are expensive to run in comparison to fixed chipper installations. System choice in any given case will depend on balancing a number of parameters such as transport distance, local vehicle regulations and the type of residue being produced within the catchment area for the fuel supply. For example, residues in New Zealand will have a higher proportion of large diameter stem wood than Scandinavian countries due to local crop type, processing systems and minimum log specifications. These conditions will dictate the use of different fuel transport systems between countries and possibly regions within countries.

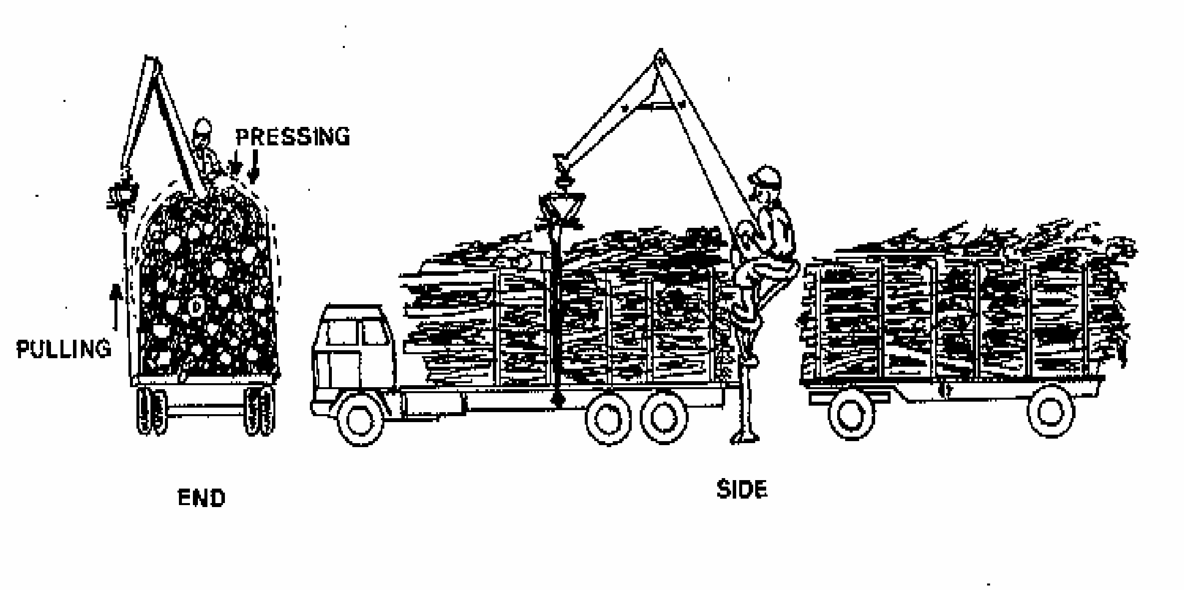

Figure 4-10. Simple means of compacting unprocessed residues (Source: Silversides & Moodie, 1985).

It has been estimated that a density of 220 kg/m³ is necessary to achieve maximum weight load capacity (Bronson 1994). Whether this can be achieved will depend on the moisture content of the material. If the residue is transported green (45 percent to 55 percent moisture content) then maximum payloads will readily be achieved. If the residue has been stored in the forest during summer then the moisture content may drop markedly (to 20 - 25 percent). The same solid volume of wood will weigh less but have a higher net energy content (on a volume basis).

Air or transpirational drying can reduce the moisture content of woody fuels if stored without size reduction (Alexander 1995, Jirgis 1995, Nurmi 1995). The same volume of wood therefore weighs less but has a higher fuel value. In the case of pine residues it has been found that they can reduce from 50 percent moisture content to 35 percent (wet basis) in 30 days (Nurmi, 1995). Air drying can be effective depending on species, climate and residue composition. In addition, air drying tends to be cheaper than alternative drying methods.

4.6.3 Storage of Residues

Storing chipped residue for long periods (6 to 8 weeks) may lead to problems with fungal growth, heat build up, spontaneous combustion within chip piles, dry matter loss and subsequent energy loss (Jirgis 1995). Since these problems do not occur with unprocessed residues, it is often preferable to keep residue in an unprocessed form for as long as possible during the collection and transport phase and chip just prior to use in the conversion plant.

4.7 FUEL QUALITY

The variability in characteristics of residues is well recognised - variable particle size, ranging from 1.5 meter lengths to sawdust; component composition (logs, bark, slabs, sawdust, cones, branches and tops); and the variability in the moisture content ranging from green (as received) to air dry. The variability in the energy characteristics - ash contents and heating values can also be significant. Overall, the properties vary with the nature of the residues (logging residues, thinning residues etc); season of harvest and collection; period between harvest and collection, and whether this allows for air drying; and the level of processing. Representative characteristics are presented in Table 4-6, which should be regarded as broadly indicative for pre-treated / processed material, and the suitability of the residues will depend on the technology adopted. For purposes of determining transport requirement, it was assumed that 1 m^3 of green wastes (forest residues) would be equivalent to 1 tonne.

Table 4-6. Typical properties of different types of solid wood fuels chips (VTT, 1998**)**

Characteristic	Unit	Logging residue	Whole tree	Log	Stump	Soft-wood	hard-wood	Wood residues	Saw residues	Sawdust	Cutter	Plywood residues	Uncovered wood
Moisture content	w-, %	50-60	45-55	40-45	30-50	50-56	45-55	10-50	45-60	45-60	5-15	5-15	15-30
Net calorific value	Dry, MJ/kg	18.5-20	18.5-20	18.5-20	18.5-20	18.5-20	21-23	18.5-20	18.5-20	19-19.2	19-19.2	19-19.2	18-19
Net calorific value	AR*, MJ/kg	6.0-9.0	6.0-9.0	6.0-10.0	6.0-11.0	6.0-9.0	7.0-11.0	6.0-15.0	6.0-10.0	6.0-10.0	13.0-16.0	15.0-17.0	12-15
Bulk density	AR*, kg/m^3	250-400	250-350	250-350	200-300	250-350	300-400	150-300	250-350	250-350	80-120	100-150	150-250
Energy density	MWh/m^3 **	0.7-0.9	0.7-0.9	0.7-0.9	0.8-1.0	0.5-0.7	0.6-0.8	0.7-0.9	0.5-0.8	0.45-0.7	0.45-0.55	0.5-0.65	0.65-0.8
Ash content	Dry wt, %	1.0-3.0	1.0-2.0	0.5-2.0	1.0-3.0	1.0-3.0	1.0-3.0	0.4-1.0	0.5-2.0	0.4-0.5	0.4-0.5	0.4-0.8	1-5
Hydrogen content	Dry wt., %	6.0-6.2	5.4-6.0	5.4-6.0	5.4-6.0	5.7-5.9	6.2-6.8	5.4-6.4	5.4-6.4	6.2-6.4	6.2-6.4	6.2-6.4	6-6.4
Sulphur content	Dry wt., %	<0.05	<0.05	<0.05	<0.05	<0.05	<0.05	<0.05	<0.05	<0.05	<0.05	<0.05	<0.1
Nitrogen content	Dry wt., %	0.3-0.5	0.3-0.5	0.3-0.5	0.3-0.5	0.3-0.5	0.5-0.8	0.1-0.5	0.1-0.5	0.1-0.5	0.1-0.5	0.1-0.5	0.1-0.5

4.8 FUEL USE IN RESIDUE COLLECTION, TRANSPORT AND PROCESSING

Diesel was assumed to be the primary fuel for machinery used to collect and transport residues. The forwarder was assumed to have a 210 kW engine, and the loaders 145 kW. Trucks were assumed to be 350 kW. Fuel consumption was assumed to be 0.16 litres per kW per hour while the oil consumption was assumed to be 0.08% of the diesel consumption. The amount of fuel used per green tonne produced was related to the hours worked and the volume collected. Productivity figures were based on average figures derived from a review of available studies on residue harvesting.

The chipper at the central power plant was assumed to be electric powered and was the same in all cases. It was assumed to have a 750 kW motor, working at 80% capacity for 22 hours per day, with a production rate of 100 green tonnes per hour. Once the electricity consumption had been calculated the green house gas emissions associated with the production of the electricity were determined on a country by country basis. Electricity consumption was assumed to be 6 kWh per green tonne. The estimated amounts of fuel used to collect forest residues from forest cutovers are provided in Table 4-7.

Table 4-7. Estimated fuel consumption (l/green tonne of residues collected).

		Canada	Finland	New Zealand	Sweden	USA
Forward (l/green tonne)		1.46	1.46	1.46	1.46	1.46
Load (l/green tonne)		0.309	0.309	0.309	0.309	0.309
Pay load (tonnes)		30	29	24	30	24
Transport (km, no of trips)	25 (8)	2.1	2.2	2.6	2.1	2.6
	50 (6)	2.8	2.9	3.5	2.8	3.5
	100 (3)	5.6	5.8	7.0	5.6	7.0
	150 (2)	8.4	8.7	10.5	8.4	10.5
	200 (2)	11.2	11.6	14.0	11.2	14.0
Unload (l/green tonne)		0.309	0.309	0.309	0.309	0.309
Infeed (l/green tonne)		0.309	0.309	0.309	0.309	0.309
Screen (l/green tonne)		0.035	0.035	0.035	0.035	0.035
Mean haul distance (mhd, km)		100	130	65	120	100
Transport fuel @ mhd (l/green tonne)		8.0	10.7	6.1	9.6	9.4
Fuel (l/green tonne) for mhd at infeed		10.4	13.1	8.5	12.0	11.8

Like the effect of haul distance on transport cost ($/green tonne), the effect of haul distance on transport fuel consumption was derived from regressions of distance against the overall fuel used for the five study countries. The regressions are provided in Table 4-8.

Table 4-8. Effect of haul distance on transport fuel consumption - regressions.

New Zealand	litres/green tonne	=	(0.0635 * hd) + 0.5273
USA	litres/green tonne	=	(0.0666 * hd) + 0.5335
Canada	litres/green tonne	=	(0.0522 * hd) + 0.4175
Finland	litres/green tonne	=	(0.0551 * hd) + 0.4433
Sweden	litres/green tonne	=	(0.0533 * hd) + 0.4268

hd = haul distance in kilometres

4.9 RESIDUES COLLECTION, TRANSPORT AND PROCESSING COSTS

Systems are available which can take whole tree or residue chips and sort them into pulp chip and fuel components. In large scale operations, with large supplies of residue at a central point, "upgrading" some of the incoming residue to a higher value product may be viable depending on the relative prices for component products.

Logging residues currently have no value or price in many areas, and may even have other associated costs in the form of site preparation for regeneration planting. However, as systems which use the residues are installed there will inevitably be demand and competition for the material and therefore it will have a price or value. However, what this price may be difficult to predict. For the purposes of this study it has been assumed that the arisings are available at the cutover or landing at no direct cost and that no greenhouse gas emissions apply (ie it has been assumed that costs and emissions arising from the production of residues, by conventional forestry, only includes additional operations, rather than attributing a portion of the industrial wood product operations to the potential biofuel stream).

Costs were derived for residue collection and transport systems using detailed costing templates (Riddle 1994). Such costing templates are used by the New Zealand Logging Industry Research Organisation, though similar systems are used in other countries. The templates incorporate costs for all labour, operating supplies, overheads, vehicles and machine operation. An example of the breakdown of costs involved in collecting residues at the cutover and the relative proportions of the cost items is shown in Table 4-9. This table is for a one machine operation with a capacity of about 185 green tonnes per day. Where available and appropriate, country specific fuel and labour costs were used.

Table 4-9. Distribution of cost items in the collection of residues at the cutover.

	Cost (US$ / day)	Proportion (%)
Labour	134.36	20
Operating supplies	6.98	1
Overheads	26.44	4
Chainsaw	4.85	1
Operator Transport	26.12	4
Forwarder (Fuel)	397.37 (74.99)	61 (11)
Profit	59.61	9
Total	**655.71**	**100**

4.9.1 Fuel Costs

The price of fuel and electricity (US $) used for each country, and at the four different CO_2 tax regimes ($0; $20; $100; and $500) is provided in Table 4-10. For comparative purposes, this table also indicates possible fuel prices given different GHG emission tax levels. Although it was realised that some of the study countries already incorporate an element of CO_2 tax (eg. Sweden), the $0/$CO_2$ tax regime assumed the present (1998) fuel prices.

Full fuel cycle analysis was used to determine combined greenhouse gas emission factors (CO2, methane and nitrous oxide) for diesel, gasoline, wood waste combustion and the reference 500MW coal plant (which included coal mining, transport and combustion). For the purpose of comparison, the CO_2 tax regimes were assumed to apply to equivalent methane and nitrous oxide emissions using 100 year Global Warming Potentials based on emission factors from the Revised 1996 IPCC Guidelines for National Greenhouse Gas Inventories (IPCC, 1996) and from IEA Coal Research's Greenhouse Gas Emission Factors for Coal (IEA CR/98: Smith, 1997).

All data (Table 4-10) are in US dollars exclusive of refundable value added taxes and estimated from IEA Energy Prices and Taxes 1st Quarter 1998 data. It is noted that value added taxes (VAT) appear to be refundable in NZ, Sweden and Finland but not US or Canada.

Table 4-10. Estimated fuels prices at different tax levels (US$).

	A $0/tCO2	B $20/tCO2	C $100/tCO2	D $500/tCO2
NZ				
electricity delivered to industrial consumers ($/MWh)	$40.40	$48.48	$60.60	$80.80
using the following factors compared with no tax		1.20	1.50	2.00
steam coal for electricity generation ($/net GJ) #	$1.01	$2.94	$10.68	$49.34
consequent 500MW coal station power costs ($/MWh) ##	$40.12	$57.97	$129.34	$486.22
diesel for commercial use ($/net GJ)	$8.17	$9.66	$15.61	$45.37
diesel for commercial use ($/litre)	$0.29	$0.35	$0.56	$1.63
premium unleaded gasoline ($/net GJ)	$17.28	$18.68	$24.28	$52.28
premium unleaded gasoline ($/litre)	$0.57	$0.61	$0.79	$1.71
US				
electricity delivered to industrial consumers ($/MWh)	$43.80	$61.32	$78.84	$87.60
using the following factors compared with no tax		1.40	1.80	2.00
steam coal for electricity generation ($/net GJ) #	$1.26	$3.16	$10.78	$48.84
consequent 500MW coal station power costs ($/MWh) ##	$42.43	$60.00	$130.27	$481.61
diesel for commercial use ($/net GJ)	$8.61	$10.10	$16.05	$45.81
diesel for commercial use ($/litre)	$0.31	$0.36	$0.58	$1.64
premium unleaded gasoline ($/net GJ)	$11.50	$12.90	$18.50	$46.50
premium unleaded gasoline ($/litre)	$0.38	$0.42	$0.60	$1.52
Canada				
electricity delivered to industrial consumers ($/MWh)	$38.80	$50.44	$62.08	$69.84
using the following factors compared with no tax		1.30	1.60	1.80
steam coal for electricity generation ($/net GJ) #	$1.47	$3.37	$10.99	$49.05
consequent 500MW coal station power costs ($/MWh) ##	$44.37	$61.94	$132.20	$483.55
diesel for commercial use ($/net GJ)	$11.51	$13.00	$18.95	$48.71
diesel for commercial use ($/litre)	$0.41	$0.47	$0.68	$1.75
premium unleaded gasoline ($/net GJ)	$13.36	$14.76	$20.36	$48.36
premium unleaded gasoline ($/litre)	$0.44	$0.48	$0.67	$1.58
Sweden				
electricity delivered to industrial consumers ($/MWh)	$34.20	$37.62	$44.46	$51.30
using the following factors compared with no tax		1.10	1.30	1.50
steam coal for electricity generation ($/net GJ) #	$2.18	$4.08	$11.70	$49.76
consequent 500MW coal station power costs ($/MWh) ##	$50.14	$65.89	$128.89	$443.89
diesel for commercial use ($/net GJ)	$20.03	$20.35	$26.30	$56.06
diesel for commercial use ($/litre)	$0.72	$0.73	$0.94	$2.01
premium unleaded gasoline ($/net GJ)	$26.47	$24.87	$30.47	$58.48
premium unleaded gasoline ($/litre)	$0.87	$0.81	$1.00	$1.91
Finland				
electricity delivered to industrial consumers ($/MWh)	$55.30	$66.36	$71.89	$82.95
using the following factors compared with no tax		1.20	1.30	1.50
steam coal for electricity generation ($/net GJ) #	$2.18	$4.08	$11.70	$49.76
consequent 500MW coal station power costs ($/MWh) ##	$50.14	$65.89	$128.89	$443.89
diesel for commercial use ($/net GJ)	$17.19	$18.26	$24.21	$53.97
diesel for commercial use ($/litre)	$0.62	$0.66	$0.87	$1.94
premium unleaded gasoline ($/net GJ)	$26.78	$27.75	$33.35	$61.35
premium unleaded gasoline ($/litre)	$0.88	$0.91	$1.09	$2.01
wood tax for combustion CH4 and N2O ($/tonne)	$0.00	$0.56	$2.81	$14.03

Extrapolation of coal prices from data as far back as 1989 was necessary for some countries.
Assuming for NZ, US and Canada sub-critical (39%LHV) capex + O & M=3.08c/kWh and for Sweden and Finland super-critical (43.5%LHV) capex+O&M=3.21c/kWh

The price increases for industrial electricity consumers were estimated from the assumed coal, gas and oil fired proportions of electricity which are based on 1992-1996 proportions and intuitive changes resulting from the various tax levels and increased imports from low cost generation countries. Taxes were assumed to have been in place for a while so there were no considerations for transition from fossil fuelled plants. The overall assumption was that increases were limited to a doubling effect before nuclear, renewables and imports could become competitive.

The \$500/t CO_2 tax was assumed to eliminate all fossil fuels, while the \$100/t CO_2 tax would allow only a small proportion of gas combined cycle in NZ, US and Finland. The \$20/t CO_2 tax was assumed to almost eliminate coal stations from NZ, Canada and Sweden and to switch most of the current high coal share to gas in US and Finland. US and Finland's current dependence on fossil fuel power were assumed to be offset by imports from Canada and Sweden, limiting their price increases. Sweden's almost total lack of fossil fuels would lead to low increases from tax, but export demand for this power would increase the local price. The impact of GHG tax on the relative economics of fuel usage are likely to be complex.

For the purposes of the integrated analysis presented in Chapter 7, only the cost provided for \$0/tCO_2 and the 500MW coal station were used. Notable features of these prices, which influenced the overall structure of the costs of residues include (i) the very high cost of diesel in Sweden, and to a lesser extent in Finland; and (ii) the high cost of electricity in Finland.

4.9.2 Effect of Haul Distance

The effect of haul distance on transport cost (\$/green tonne) was derived from regressions of distance against the overall cost for the five study countries (Table 4-11). The transport costs obtained from the regressions in the table represents an aggregation of many of the factors including labour, overheads and truck operating costs in different proportions.

Table 4-11. Transport cost regression models.

Canada	\$/green tonne	=	(0.1608 * hd) + 2.2442
Finland	\$/green tonne	=	(0.1787 * hd) + 2.3232
New Zealand	\$/green tonne	=	(0.1960 * hd) + 2.8000
Sweden	\$/green tonne	=	(0.1720 * hd) + 0.8049
USA	\$/green tonne	=	(0.1980 * hd) + 2.8613

hd = haul distance in kilometres

The distribution of the cost items derived in Table 4-11, for New Zealand, is provided in Table 4-12. The values in Table 4-12 presupposes a specific average haul distance which was assumed to be 65 kilometres for New Zealand. The costs incorporated the cost of the truck (capital, labour, fuel, etc) converted into the cost for a tonne of residues per kilometre by estimating the production at given distances ie., \$/t at 25, 50, 100, 150 and 200 kilometres which were used in the regressions. The higher payload advantage in Sweden is reflected in the lower non-transport costs of the residues in the regressions.

Table 4-12. Breakdown of the transport costs.

	Costs (US $/y)	Proportion (%)
Labour	39,676	23.32
Overheads	6,350	3.73
Profit	15,468	9.09
Truck	90,966	53.46
Fuel (for the trucks)	17,690	10.40
Total	170,150	**100**

4.9.3 Residue Collection Costs

Three different forest residue collection systems were evaluated. This included (i) Cut-over residue forwarding with centralised chipping at power generation plant; (ii) Bale and load with chipping at a centralised at power generation plant; and (iii) Cut-over residue forwarding with roadside chipping, were costed, with the location of size reduction being the major variable. The result of the analysis of the three regimes is presented in Table 4-13 which shows the costs ($/green tonne) for collecting residues from the cutover areas only, and utilised national average haul distances for each country. Details of the average haul distances from the power plants, and taking into account the regional differences in forest densities are provided in the Appendix.

Table 4-13. Collection and transport costs for three different regimes (US $/tonne)

	Forwarding at cutover and chipping at a centralised plant	Baling at cutover and chipping at a centralised plant	Forwarding to roadside and chipping at landing or at the roadside
Canada	28.13	34.83	36.93
Finland	36.94	44.57	50.84
New Zealand	23.45	32.03	33.45
Sweden	30.54	41.94	47.10
USA	31.80	41.60	44.25

The analysis indicated that the collection of residues at cutover, transport to a centralised chipping facility and chipping at the power plant provided the least cost option (Table 4-13). This collection and fuel pre-treatment system was therefore used as a base case scenario for subsequent analysis, with the system choice being underpinned by the assumption that unchipped residues can be transported at optimum payload (maximum gross vehicle weights in all countries) without the need for expensive baling. Some compaction of the residue was assumed to be possible using loaders and tie-downs, which was deemed to be sufficient to achieve the necessary density of about 26 percent to optimise payloads.

The costs of collecting forest residues and transporting them to power generation plants (as used in the integrated analysis (see Chapter 7) for each of the countries is summarised in Table 4-14. These costs are for collection from the cutover and transport by truck to a centralised chipping plant at a power generation facility only, and are for average haul distances. These costs were used to assess total costs for electricity generation using biomass as they were the minimum costs. In the case of forest thinnings, the costs of material harvested would be expected to be similar to those from clearfelling since similar harvest systems could be applied. Although a number of machines for the extraction of early thinnings (eg. Chipharvesters in Finland) have been developed, none of the machines on the market, with productivities of up to 15 m^3/h, at an estimated costs of about $24/$m^3$, will cost less than the clear felled material. Thus, the same cost, which assumed that whole tree extraction and transport un-comminuted to a central processing yard was used. Biofuels collected using other regimes would be more expensive.

The costs and fuel consumption per green tonne were assumed not to change over time. Fuel use was assumed to be constant as the same harvesting system was used for different years. The main variable that does change with time is the available volume, although this varied by country.

Table 4-14. Forest residues collection and transport costs (US$/tonne).

		Canada	Finland	New Zealand	Sweden	USA
Forwarding		3.85	4.25	3.10	4.40	2.75
Load		1.10	1.12	1.10	1.13	1.10
Transport distance (km)	25	6.00	6.55	7.40	6.45	7.40
	50	9.50	10.40	11.60	8.60	11.70
	100	18.95	20.85	23.15	17.25	23.75
	150	28.40	31.25	34.75	25.85	35.00
	200	32.80	36.40	40.00	36.20	40.40
Unload		1.10	1.12	1.10	1.13	1.10
Infeed		1.10	1.12	1.10	1.13	1.10
Chip		1.95	2.10	1.95	1.95	1.95
Screen		0.08	0.12	0.05	0.10	0.05
Mean haul distance (km)		100	130	65	120	100
Mean haul distance costs (US $)		18.95	27.11	15.05	20.70	23.75
Costs at infeed (@mean haul distances, US$)		28.13	36.94	23.45	30.54	31.80

4.9.4 Base Case Scenario: Residue Collection and Transport

The residue was recovered from the cut-over, including the landings and roadsides with a large forwarder with a modified bunk. The forwarder collected the residue and subsequently unloaded at a central point in the forest. The residues may then be stored and left to air dry.

The bulk of log harvesting operations was assumed to take place on terrain which could be traversed by ground based machinery such as forwarders. In areas where cable logging operations take place, the residue which occurred on the cut-over were assumed to be inaccessible due to high recovery costs. However, cable harvesting operations often produce piles of residue at landings and road sides which can be collected using systems as described for flat terrain cutover. The residue was then collected by large volume trucks with an independent loader (hydraulic grapple) used for loading and compacting the residue. Multiple tie-downs were used to contain and compress the load.

The cost of taking residues from flat terrain to roadside was calculated to be approximately US$3 to $5 per green tonne. To get residues from steep terrain to roadside is likely to cost US$15 to $20 per green tonne. This would mean that the delivered cost of fuel from steep terrain in New Zealand at the average haul distance of 65 kilometres would be $37.20 per green tonne as opposed to US$23.45 per green tonne for flat terrain, an increase of 58 percent.

In addition to cost, collecting forest residues off step terrain also has environmental implications such as increased risk of soil erosion due to soil disturbance and exposure. Currently steep land harvesting operations are under intense scrutiny from environmental agencies. Regulatory authorities may not allow increased harvest intensity on steep terrain. Given that most countries have truck dimensions that allow load spaces well in excess of 100 m^3, a density of 26 percent would give a payload of 26 tonnes or greater if permissible under the relevant gross vehicle weight rules. The residues were then transported to a central point for size reduction.

The average haul distances for forest residues were assumed to be the same as for round wood products for each country. It is unlikely that the average haul distance will exceed 150 kilometres, as the cost of transport beyond this distance would be prohibitive (unless a high carbon tax regime prevailed). The trucks at the power generation plant were assumed to be unloaded by hydraulic grapples. The residue is then fed into a large fixed-installation electric chipper (probably of a drum design). The residue is then screened to remove fines, oversize components (which can be re-chipped) and other contaminants.

4.9.5 Effect of Radial Distance on Fuel Usage and Costs in the Supply of Forest Residues

The radial distances between the power generation plant and the forest resource is a key factor influencing the quantity and availability of residues, the quantity of fuel used in the collection, and the overall costs of supplying forest residues, and therefore has a direct effect on the economics of collecting more forest residues to match a larger, potentially more cost efficient power plant. The actual volumes of residues in the different regions, taking into account the actual regional forest densities may be derived from the haul distance regressions, presented in Table 4-15, which also shows the regional variations in forest densities.

4.10 EMISSIONS IN RESIDUES COLLECTION, TRANSPORT AND PROCESSING

Section 4.5 provided an assessment of appropriate forest residues collection, handling and pre-treatment systems, based on operation costs which were dependent on the capital expenses, operation and maintenance, labour and quantity of fuel used per unit of residue collected. Section 4.7 provided an evaluation of systems for residues collection, transport and handling between the roadside to the power plant, and showed that the system involving the collection of residues at the cutover, transport to a centralised chipping facility at a power plant provided the least cost option (see Table 4-12). The assessments assumed that machinery fuel consumption was the same in all five countries. Thus, variability in costs was based on differences in the prices of fuel in the different countries (Table 4-10).

Tables 4-7 to 4-9, and 4-12 to 4-14 provided a breakdown in the quantities of fuel used and costs of residues collection and handling. Table 4-8 provided regression lines defining the influence of haul distance on fuel consumption, while Table 4-14 provided regression lines defining the quantities of residues at varying distances. The regressions were used to derive the quantities of residue at varying distances and the diesel quantity used at varying distances.

Table 4-15. Forest density and volume available by distance regressions.

Country	Region	Forest density (% of land area)	Volume - distance regressions
Canada		**24**	
	NorthWest Territories	4	-
	Yukon	13	Vol. m^3 = $(0.0098 * hd)^{2.0082}$
	British Columbia	48	Vol. m^3 = $(0.0346 * hd)^{2.0211}$
	Alberta	32	Vol. m^3 = $(0.0250 * hd)^{2.0015}$
	Saskatchewan	18	-
	Manitoba	24	-
	Ontario	42	Vol. m^3 = $(0.0347 * hd)^{2.0047}$
	Quebec	38	Vol. m^3 = $(0.0312 * hd)^{2.0047}$
	New Brunswick	81	Vol. m^3 = $(0.0690 * hd)^{1.9998}$
	Nova Scotia	62	Vol. m^3 = $(0.0519 * hd)^{2.0011}$
	Prince Edward Island	49	-
	Newfoundland	27	-
Finland		**64**	
	North	57	Vol. m^3 = $(0.0467 * hd)^{2.0083}$
	South	76	Vol. m^3 = $(0.0690 * hd)^{2.0021}$
New Zealand		**25**	
	North Island	15	Vol. m^3 = $(0.0330 * hd)^{1.9984}$
	Central North Island	35	Vol. m^3 = $(0.2984 * hd)^{2.0008}$
	South Island	15	Vol. m^3 = $(0.0160 * hd)^{2.0039}$
Sweden		**56**	
	Goetaland	57	Vol. m^3 = $(0.0560 * hd)^{1.9999}$
	Svealand	65	Vol. m^3 = $(0.0630 * hd)^{2.003}$
	Sodra Norland	65	Vol. m^3 = $(0.0606 * hd)^{2.0137}$
	Norra Norland	44	Vol. m^3 = $(0.0426 * hd)^{2.0017}$
USA		**21**	
	Pacific Coast	12	Vol. m^3 = $(0.0029 * hd)^{2.3170}$
	Rocky Mountains	8	Vol. m^3 = $(0.0010 * hd)^{2.0072}$
	South	36	Vol. m^3 = $(0.0321 * hd)^{2.0812}$
	North	37	Vol. m^3 = $(0.0480 * hd)^{2.0016}$

hd = haul distance in kilometres

Greenhouse gas (GHG) emissions from the collection, transport and processing of residues was derived by multiplying the quantities of fuel and or electricity used (see Section 4.7; and also the Appendix) with IEA factors for different gases associated with the use of specific quantities of the different fuels and corrected to CO_2 equivalents using the global warming potential factors (CO_2, 1; CH_4, 21 and N_2O, 310) over a 100 year time horizon. The use of one litre of diesel was assumed to result in the emission of 2.59686 kg of CO_2, 0.00053 kg of CH_4, 0.00012 kg N_2O, 0.02858 kg NOx, and 0.01928 kg of CO (non-full fuel cycle basis).

Although gases including NOx, CO and SO_2 are generated in the use of fossil fuels, there is no agreed method to estimate their contributions to climate change (IPCC, 1996). Although gases including NOx, CO and SO_2 are generated in the use of fossil fuels, there is no agreed method to estimate their contributions to climate change (IPCC, 1996).

GHG emissions in the use of electricity (for chipping) was based on the proportion of electricity generated from different sources (hydro, fossil fuels, nuclear etc, see Chapter 2), providing CO_2 equivalence factors for different countries. Although post-1990 GHG emissions from power generation in New Zealand has been based on the marginal rate for a gas fired power station (Huntly) with a value of 624 g CO_2/kWh, a 1990 value of 140 g CO_2 / kWh based on the different sources of power was adopted because marginal values aim to show potential GHG mitigation potential from new power plants. The value for Finland was 260 g CO_2 equivalent per kWh (Orn and Kariniemi, 1997) even though Sipilä *et al.* (1993) utilised a value of 60 g CO_2/MJ, equivalent to about 215 tonnes CO_2/GWh. A value of 500 g CO_2/kWh was assumed for Canada and Sweden, while for USA, a value of 750 gCO_2/kWh was assumed given the proportion of electricity generated from coal powered plants. Table 4-16 provides a summary of the results of the analysis of GHG emissions in collection, transport and pre-treatment. Between 69% and 92% of the emission would be associated with residues collection and transport, and emissions increase with increasing haul distance.

Table 4-16. GHG emission in residue collection, transport and pre-treatment (000 tonnes).

		Processing residues	All residues*
	Collection	0	362.25
Canada	Transport	0	2604.59
	Pre-treatment	29.24	119.72
	Total	29.24	3115.80
	Collection	0	40.55
Finland	Transport	0	181.91
	Pre-treatment	3.28	6.88
	Total	3.28	232.62
	Collection	0	36.27
New Zealand	Transport	0	129.57
	Pre-treatment	0.44	4.93
	Total	0.44	188.99
	Collection	0	79.40
Sweden	Transport	0	273.84
	Pre-treatment	8.87	25.92
	Total	8.87	388.04
	Collection	0	865.90
USA	Transport	0	15968.93
	Pre-treatment	86.69	423.98
	Total	86.69	17345.50

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CHAPTER 5:

WOOD PROCESSING INDUSTRIES: RESIDUE ASSESSMENT

5.0 INTRODUCTION

Much of the world's roundwood harvest is used to produce lumber, pulp and paper or panel products. In the five study countries, the volumes of roundwood harvested, and the products distribution is presented in Table 5-1. In the process of conversion of logs into these products a substantial amount of wood processing residues/wastes is produced. Such residues typically consist of bark, log off-cuts, chipper-fines, sawdust, shavings, product off-cuts and sander dusts. Other potential residues streams are log-yard waste and reject product.

Table 5-1. Roundwood volumes and products distribution (FAO, 1995).

Country	Roundwood volumes (million m^3/y)				Products quantities		
	Total harvest	Sawmilling & veneer production	Pulp & paper production	Panels production	Sawn lumber and plywood (million m^3/y)	Pulp & Paper (Air dry tonnes/y)	Panels (million m^3/y)
Canada	188	146	62	31.0	25.0	3.2	6.5
Finland	57	22	10	23.0	10.0	0.3	0.7
New Zealand	19	5.1	3	4.2	1.4	0.5	0.9
Sweden	62	33	15	21.0	11.0	0.3	0.9
USA	647	243	123	150.0	61.0	11.0	20.0

This section of the report considers:

- sources of residues from different wood processing activities.
- fuel characteristics of processing residue materials.
- methods used to determine the total quantities of wood processing residues produced.
- estimates of the quantities of wood processing residues produced in the five countries.
- evaluation of factors likely to influence the longterm supply of residues.
- cost of supplying processing residues for power generation.

5.1 SOURCES OF WOOD PROCESSING RESIDUES

Sawmilling, pulp and paper making, and panel manufacturing make up the major primary wood processing industries and are major contributors of residues for bioenergy production.

5.1.1 Sawmilling

Typical residue streams produced at sawmills are bark, sawdust, shavings, lumber off-cuts, and sander dusts (Figure 5-1). Other residue streams are sawdust and chips from resaw. Some sawmills may also produce chip fines where chip screening is undertaken on site.

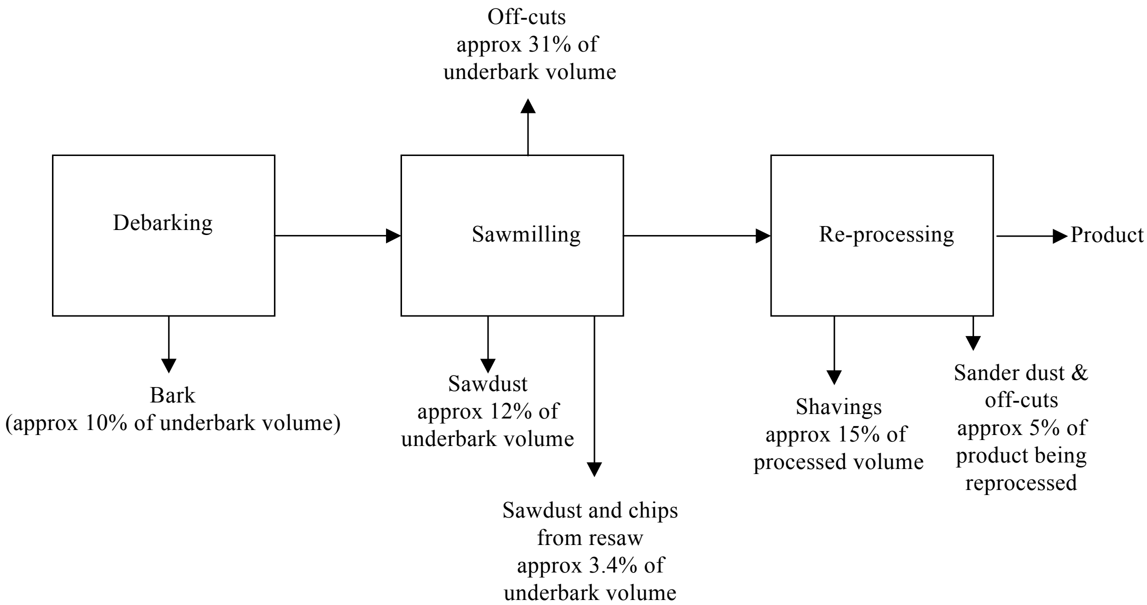

Figure 5-1. Typical residue streams arising from sawmilling.

Bark and sawdust are the most significant streams, often totalling approximately 22 percent of the total under bark roundwood volume entering a sawmill. Log off-cuts produced during the primary log breakdown are generally chipped and used for other wood processing activities such as pulp and paper or panel production. Bark yields are dependent on the diameter of stems, species being debarked, method of debarking and time of the year. Small diameter stems have a high bark to wood ratio compared to smaller diameter logs. Surveys of bark yield at wood processing sites in New Zealand have shown that lower yields occur during spring compared to summer and winter due to a higher proportion of bark dropping of the stem during spring. Such effects are attributed to changes in the nature of the cambium layer at times of rapid spring growth.

Bark is removed from logs at sawmills using either ring de-barkers or rosser heads. For a ring debarker, the log is held between spiked rollers and moved longitudinally through a debarking ring. The ring consists of blunt pivoted knives which press against the logs and which shear the bark off at the cambium. Ring de-barkers can typically handle logs from 650 to 1000 mm at feed speeds ranging from 0.25 to 1.0 metre per second.

Rosserhead de-barkers consist of cutter heads which are lowered onto logs while rotating, this results in the bark being removed in a helical fashion. Such debarking systems have a lower feed rates compared to ring de-barkers and are typically employed at small sawmills. The advantages of rosserheads are that they can handle unusually shaped logs or logs that are too big for ring debarkers.

The costs and emissions associated with debarking were not included in the analysis as this activity occurs as part of the normal production of industrial wood.

Sawdust is produced during the log reduction stages. Sawmills use a variety of saws to progressively cut logs into lumber of desired dimensions. Typical sawing configurations consist of a headrig and resaws. The choice of saws used at a mill is influenced by the log resource (quality, size and volume), markets and product mix, and capital investment. The sawing configuration and type of equipment used can markedly influence sawdust yields, for example band saws (ie those consisting of an endless steel band) can be made of thin gauge steel to produce a saw kerf of about 4mm. Circular saws, on the other hand, are made of thicker steel and thus produce a thicker kerf.

Shavings are produced during the planing of lumber. Planing results in smooth sided boards of given dimensions. Planers remove the surface layers of boards using rotating knives. The amounts of shavings produced during lumber processing depend on the accuracy of the sawing system used, type of planer and species of wood being processed.

Lumber off-cuts and sander dusts are produced at the time of cutting stick lumber to length or final finishing and are typically in relatively low quantities. Shavings sander dusts and product off-cuts were not included in the analysis as such residue streams are dependent on level of processing being undertaken at a particular sawmill site and are site specific.

5.1.2 Pulp and Paper

For pulp and paper industries, bark and wood preparation yard waste are the main sources of potential biomass fuel supplies (Figure 5-2). The bark must be removed from tree stems prior to chipping to ensure that the final pulp is free of bark and dirt. Commonly used debarkers are dry drum systems where logs are feed into one end of a drum, which has slots along its entire length, these allow the bark to pass out. The bark is removed by the drum rotating and log/log and log/drum impact and abrasion knocks the bark off stems. Other types of debarkers are wet drum and hydraulic jet systems. The wet drum debarker operates in a similar way to the dry drum except that water is added at the in-feed end to help loosen bark and flush loose dirt off stem surfaces. Hydraulic jet debarkers are frequently used for large logs and operate by directing high pressure (>7 MPa) jets of water against logs to dislodge the bark. Disadvantages of wet debarking systems are that significant effluent volumes are produced and the residual material is wet and may require drying before being suitable for combustion.

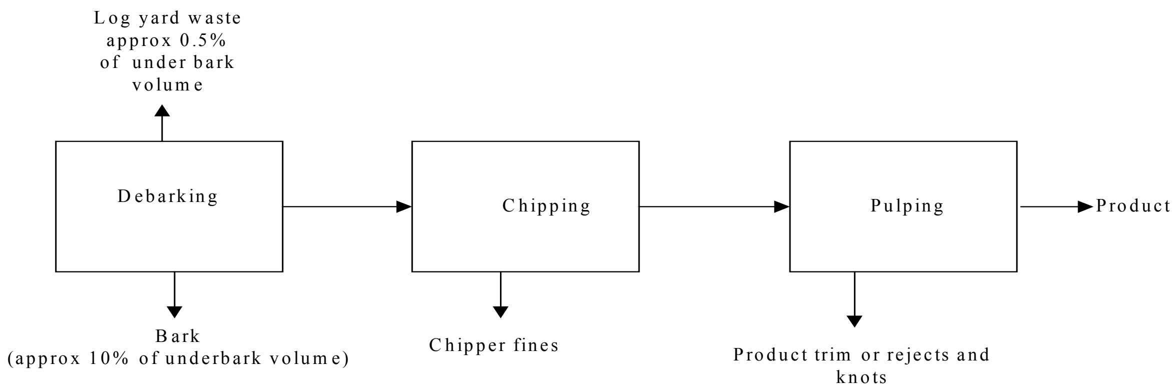

Figure 5-2. Residues from pulp and paper mills.

Factors influencing bark yields at pulp and paper mills are similar to those discussed above for sawmilling. Log yard waste at pulp and paper mills was estimated to be 0.5 percent of the total underbark volume of wood passing through the site. Such material will consist of broken pieces of stem wood, bark, and in some cases trim from debarker in-feeds. Additional sources of woody derived residues arising from pulp and paper manufacturing are chipper fines, knots, and reject product. These sources were not included in the analysis.

Pulping yields are markedly affected by the type of pulping processes used. Chemical pulp yields are typically around 50% based on the amount of chipwood used resulting in the production of an equal weight of black liquor, dry basis. However, the present analysis assumes that all black liquor produced in all five study countries is currently used in steam generation within the pulp mills and therefore not available to new bioenergy plants. In future, black liquor may be recovered and used in higher efficiency technologies such as gasification.

5.1.3 Panel Production

Wood based panel production refers to plywood, particle board and fibre board.

Plywood is manufactured by gluing together a number of veneers with the grain of alternative layers being arranged to cross at right angles. In the case of particle and fibre boards, wood particles or wood fibres are blended with synthetic resin adhesive and formed into sheets prior to pressing and resin curring under heat and pressure. Particle and fibre boards are used for a variety of construction and furniture applications. Wood materials frequently used for particle or fibre board manufacture are low quality roundwood or wood processing white wood residues (ie chips, shavings and sawdust). Such white wood residues are sourced from sawmills. For the analysis of residues produced at panel plants, it was assumed that 50 percent of the wood/fibre input was from reusable white wood sourced from other wood processing facilities such as sawmills. Typical waste streams arising from panel production are bark, log-off cuts, chipper fines, veneer trim, product trim and sander dusts (Figure 5-3). Debarking facilities used at panel mills are similar to those at pulp and paper mills.

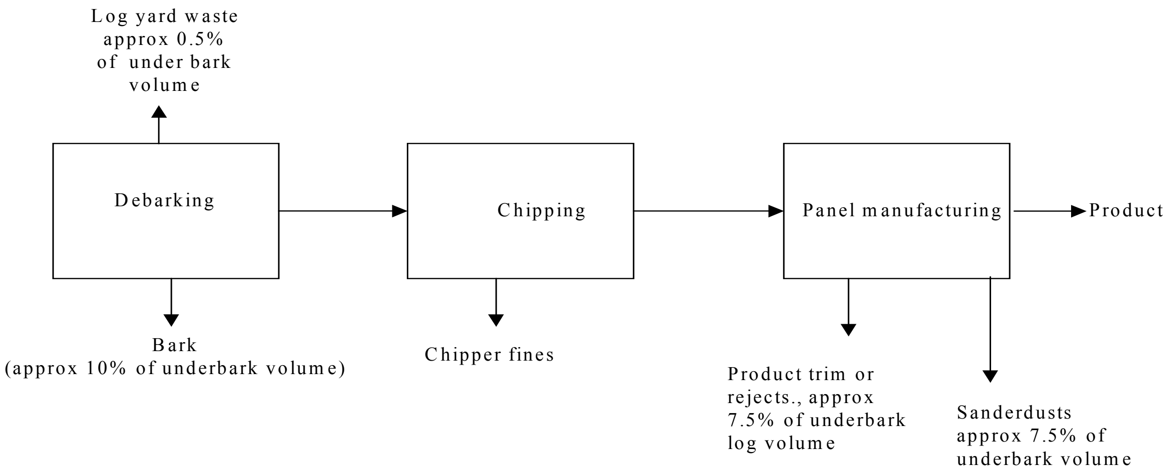

Figure 5-3. Typical residue streams arising from panel production.

For the assessment of woody residues available from panel manufacturing it was assumed that the major residue streams would be bark, log yard waste, product trim and sander dust.

Chipper fines were not included as this source can be highly variable dependent on the nature of the chipping systems and the type of products being produced at the mill. Some panel manufactures can use high proportions of sawdust and chip particles.

5.1.4 Other Wood Processing Residues

Other materials that may be available as woody derived biofuel are primary sludges, wooden packaging materials, log peelings (produced when rounding poles), and historic landfill material. These residue/waste streams were not included in the analysis.

5.2 FUEL QUALITY OF WOOD PROCESSING RESIDUES

The fuel quality of wood processing residues can be variable depending on such factors as age and species of trees being processed, season when trees are milled, type of debarking facilities used, the nature of material handling systems, relative composition of bark and wood, degree of contamination with soil and dirt, and level of contamination with other substances (eg resins from panel waste). Table 5.2 shows the ypical quality of residues.

Table 5-2. Fuel quality characteristics of wood processing residues.

Fuel type and source		Energy density	Moisture content	Particle size range	Net CV (dry)	Net CV (as received)	Ash content	Reference
		MWh/m3 (bulk volume basis)	% W/W	<mm	MJ/kg	MJ/kg	% dry weight	
Finland								
	Wood residue chip	0.7 - 0.9	10 - 50.	30 - 100	18.5 - 20	6 - 15.	0.4 - 1	1
	Saw residue chip	0.5 - 0.8	45 - 60	NA	18.5 - 20	6 - 10	0.5 - 2	
	Sawdust	0.45 - 0.7	45 - 60	5 - 30.	19 - 19.2	6 - 10.	0.4 - 0.5	
	Sanderdust	0.5 - 0.65	5 - 15.	NA	19 - 19.2	15 - 17	6.2 - 6.4	
	Bark (softwood)	0.5 - 0.7	50 - 60	40 - 65	18.5 - 20	6 - 9.	1 - 3.	
New Zealand	Bark (softwood)	NA	30 - 67	3 - 100	20	NA	3 - 10.	2
	Log yard residues	NA	40	NA	15	NA	17 - 40	
	Veneer plant residues	NA	3 - 5.	NA	19 - 20	NA	0.4 - 0.5	

References: 1: Bioenergy in Finland: Review 1998. 2: Gifford *et al.* pers com.

5.3 ANALYSIS OF WOOD PROCESSING RESIDUE YIELDS

The steps used to estimate the quantities of wood processing residues that may be available as biofuel for large scale power generation are shown in Figure 5-4. The analysis involved:

- an evaluation of the total country production of sawn lumber, pulp and panel products. Sawn lumber production included veneer and plywood and panel production included particle and fibre boards [1] [2] .
- an assessment of the total roundwood used to produce these products
- an assessment of typical residue yields for sawmilling, pulping and panel manufacturing

[1] Plywood production was combined with sawn lumber production since log statistics were for sawlogs and veneer logs combined.
[2] All data were based on FAO forest product statistics (FOA 1995, 1997)

- an assessment of potential wood processing residue yields by region based on predicted changes in total forest harvest for each region. (It was assumed that there was no change in the relative quantities of wood being used for lumber, pulp and panel production for each region, and that the proportion of wood being used for lumber, pulp and panel production was similar between regions).

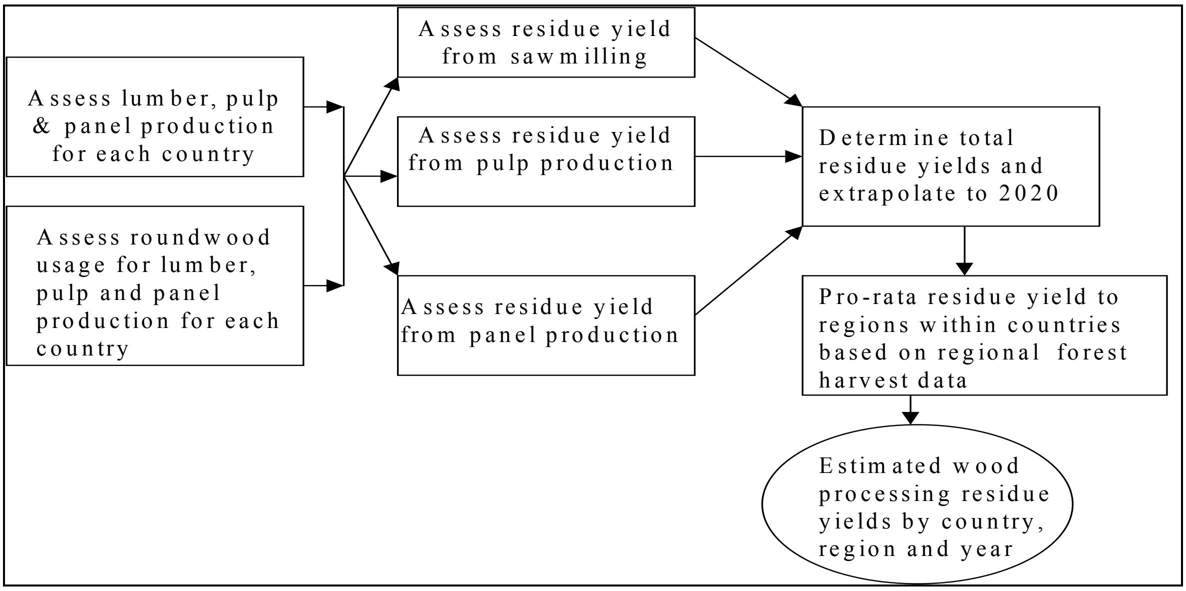

Figure 5-4. Determination of wood processing residue yields.

5.3.1 Lumber, Wood Pulp and Panel Production

The estimated production of forest products for each country by year is given in Table 5-3.

Table 5-3. Wood products produced in the study countries.

Country		Sawn lumber & plywood (million m3/an)	Pulp (million ADT/an)	Panel (million m3/an)
Canada	1990	56.9	23.0	4.3
	1994	63.5	24.7	5.8
	1995	62.3	25.4	6.5
Finland	1990	8.1	8.8	0.7
	1994	10.5	10.5	0.6
	1995	10.3	10.2	0.7
New Zealand	1990	2.2	1.2	0.6
	1994	2.9	1.4	0.9
	1995	3.1	1.4	0.9
Sweden	1990	12.1	10.2	1.2
	1994	13.9	10.4	0.8
	1995	15.1	10.5	0.9
USA	1990	128.6	57.2	13.3
	1994	111.6	59.8	14.5
	1995	122.5	60.9	20.0

These production figures were compared to estimated roundwood volumes required to produce these quantities of product in order to verify that the log volume estimates obtained from FAO statistics, fairly reflected the volumes of lumber likely to be used for processing into wood products. Generally, the conversion yields were consistent with typical industry estimates (Table 5-4). The log volume estimates were used to calculate likely residues yields.

Table 5-4. Estimated roundwood volumes and conversion ratios in forest industries.

Country		Roundwood for sawn lumber & plywood (million m3/yr)	Conversion ratio for sawmilling (lumber out/ roundwood in)	Roundwood for pulp (million m3/yr)	Conversion ratio for pulping (wood pulp out/roundwood in)	Roundwood for panel (million m3/yr)	Conversion ration for panel (panel out/roundwood in)
Canada	1990	123.6	0.46	41.7	0.6	2.2	1.95
	1994	139.8	0.45	35.7	0.7	2.9	2.00
	1995	146.2	0.43	31.1	0.8	3.2	2.03
Finland	1990	18.2	0.45	21.2	0.4	0.3	2.33
	1994	20.8	0.50	21	0.5	0.3	2.00
	1995	21.9	0.47	22.9	0.4	0.3	2.33
New Zealand	1990	4.7	0.47	4.6	0.3	0.3	2.00
	1994	5.9	0.49	4.7	0.3	0.4	2.25
	1995	5.1	0.61	4.2	0.3	0.5	1.80
Sweden	1990	23.7	0.51	24.1	0.4	0.4	3.00
	1994	27.6	0.50	32.8	0.3	0.3	2.67
	1995	32.7	0.46	20.9	0.5	0.3	3.00
USA	1990	272.4	0.47	140.5	0.4	6.6	2.02
	1994	233.5	0.48	151.5	0.4	7.2	2.01
	1995	242.9	0.50	150.0	0.4	10.5	1.90

5.3.2 Residue Yields from Wood Processing

To convert roundwood estimates to potential residue yields for the different types of wood processing operations, the conversion factors for each the relevant stages of the processing chain as presented in Figures 5-1 to 5-3 were used. An example of these conversions is provided in Figure 5-5 for New Zealand (1995 data, 000m^3). Slabwood and chips arising from sawmilling was assumed to used for other wood processing activities and was not available as bio-fuel. Only 50% of the sawdust from sawmilling was assumed to be available.

Sawmill model			
Log input (under bark volume)	5123		Residue available
Bark	10%	512.3	
Sawdust	12%	614.8	
Slabwood	31%	1588.1	
Sawdust from resaw	0.60%	30.7	
Chip from resaw	2.80%	143.4	850.4

Pulp mill model			
Log input (under bark volume)	4156		Residue available
Bark	10%	415.6	
Log yard waste	0.5%	20.8	436.4

Panel mill model			
Log in put (underbark)	464		Residue available
Bark	10%	46.4	
Log yard waste	0.50%	2.3	
Sander dust	7.50%	34.8	
Trim	7.50%	34.8	118.3

Figure 5-5. Example of conversion models for estimating residue yields.

Wood processing residue yield estimates for 2000, 2010 and 2020 were determined by regression analysis using the production data obtained for 1990, 1994, 1995 (Table 5-4). To apportion the amount of residues that were likely to be produced in each region of the countries, estimates of the total country wood processing residue volumes were pro-rated based on the relative proportion of total forest harvest for the particular region. The results are presented in Table 5-5. The quantities of processing residues that could be used for new or additional power generation were assumed to be 25% of the total amount calculated to be available, as existing uses of residues were estimated at 75%. The average basic density of processing residues was assumed to be 500 kg/m^3 when converting dry tonnes to m^3 available.

Table 5-5. Estimated wood processing residues production to the year 2020 (000 tonnes)

		1990	1995	2000	2005	2010	2015	2020
Canada	New foundland and Lab	282.5	280.6	284.3	305.9	327.7	349.1	369.8
	PrinceEdward Island	44.0	60.0	47.4	51.0	54.6	58.2	61.6
	Nova Scotia	438.5	515.7	502.3	540.5	579.0	616.7	653.3
	New Brunswick	866.8	945.8	1024.2	1111.6	1190.8	1268.3	1343.5
	Quebec	2917.4	3920.5	5355.2	5762.0	6172.5	6574.2	6964.2
	Ontario	2497.1	2470.1	2626.1	2996.2	3392.6	3808.1	4240.1
	Mannitoba	153.5	186.9	226.8	296.4	373.4	453.8	547.5
	Saskatchewan	270.9	400.5	412.9	483.2	559.3	640.1	725.1
	Alberta	1170.0	1908.2	2138.1	2345.6	2512.7	2676.2	2835.0
	British Columbia	7255.5	7003.9	6862.2	7383.5	7909.5	8424.3	8924.0
	Yukon	8.1	20.1	0.9	1.0	1.1	1.2	1.2
	North west territories	4.5	11.9	10.4	11.2	12.0	12.8	13.6
	Total	15908.9	17724.4	19491.0	21288.2	23085.3	24882.9	26679.0
Finland								
	North	928.7	1066.1	1170.3	1293.6	1417.0	1540.6	1663.9
	South	2406.0	2762.9	3032.7	3352.4	3672.0	3992.4	4312.1
	Total	3334.7	3829.0	4203.0	4646.0	5089.0	5533.0	5976.0
NZ								
	North Island	206.1	217.3	388.0	446.2	477.9	540.3	574.7
	Central North Island	454.9	479.5	423.0	446.2	477.9	489.3	520.4
	south Island	172.0	181.4	225.1	236.7	266.0	285.0	312.3
	Total	833.1	878.2	1036.1	1129.0	1221.8	1314.6	1407.4
Sweden								
	North	643.8	778.4	931.4	1068.2	1208.6	1345.9	1481.9
	South	1138.6	1218.7	1556.9	1785.6	2008.9	2237.0	2466.5
	Svealand	1003.0	1124.3	1400.6	1606.2	1808.8	2014.2	2222.9
	Gotland	1348.7	1753.3	2026.1	2323.6	2625.7	2923.9	3217.6
	Total	4134.2	4874.7	5915.0	6783.6	7652.0	8521.0	9389.0
USA								
	North	8640.6	8550.8	8893.6	9173.0	9456.8	9715.1	9973.1
	South	18567.0	18206.6	18660.5	19236.3	19809.5	20401.8	20994.7
	Rocky Mountain	1746.8	1637.8	1714.9	1770.9	1826.8	1885.3	1944.2
	Pacific Coast	9588.5	8321.5	9258.5	9529.2	9797.2	10069.1	10341.1
	Total	38542.8	36716.7	38527.6	39709.4	40890.3	42071.2	43253.1

5.4 FACTORS AFFECTING SUPPLY OF WOOD PROCESSING RESIDUES

Significant factors that may affect the long-term supply of wood processing residues for biofuel include:

- With the modernisation of wood processing technologies, the conversion efficiencies of mills is increasing. Therefore, more wood will be converted to product and less residue will be produced. Modernisation of wood processing technologies is also allowing high quality wood products to be produced from lower quality wood or fibre. For example, more sawdust and low quality wood chip can be used for fibre board manufacturing due to improvements in fibre refining and adhesive technologies.

- Some sectors of the wood processing industry have an increasing demand for heat for on-site processing. In New Zealand over recent years, the quantity of sawn lumber dried has increased significantly which has led to a marked increase in the number of timber drying kilns and heat plant facilities using biofuel.
- Over recent years substantial research has been carried out on extracting high value chemicals from bark residues. Although such processes have proved uneconomical to date, in future years competition for bark for other uses may well increase. Other competing uses for bark could be landscaping applications, animal bedding and horticultural mulch.
- Quantities of residues produced in particular countries will also be affected by the relative quantities of wood processed on-shore compared to that exported.

For the global assessment, the available wood processing residues (Table 5-6) was estimated based on the proportion of the actual quantities generated (see Sections 5.3 & 5.4). Global availability values represent only 25% of the actual processing residues production.

Table 5-6. Wood processing residues availability in Developed Countries (million m^3).

	1990	1995	2000*	2005*	2010*	2015*	2020*
USSR (former)	19.0	8.6	13.5	11.9	14.2	14.4	15.6
North America	27.2	27.2	29.0	30.5	32.0	33.5	35.0
Europe	13.2	14.1	12.7	14.3	15.5	17.2	18.8
Developed Asia & Oceania	2.0	2.2	1.9	1.9	2.0	2.0	2.2
Total Developed Countries	**61.4**	**52.2**	**57.1**	**58.6**	**63.6**	**67.0**	**71.5**

* Projections of harvests based on harvest volumes

5.5 COST OF WOOD PROCESSING RESIDUES

Costs for supplying wood processing residues to a large scale power generation plant were assigned a nominal value of US$ 2/m^3. This low cost factor was applied as typically any costs that may be attributed to transporting or handling are likely to be off-set by costs of disposal. Disposal costs for wood waste are highly variable between countries as they are markedly influenced by the availability of land, environmental legislation and monitoring requirements.

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CHAPTER 6:

POWER GENERATION

6.0 INTRODUCTION

Biomass can be used in a number of different technologies (such as combustion, gasification and pyrolysis) for power or steam generation. This section of the report presents the following:

- A review of the technologies available for power generation using woody biomass fuels;
- The criteria used to select the power generation technologies, configurations and capacities used for this study;
- An assessment of plant performance and operation for the power plant configurations and capacities selected;
- An assessment of the costs to generate electricity using the power plant configurations and capacities selected;
- An assessment of the greenhouse gas emissions arising from power generation using the power plant configurations and capacities selected.

6.1 TECHNOLOGY REVIEW

6.1.1 Introduction

This technology review focuses on combustion and gasification technologies and their current status internationally. Technologies associated with pyrolysis, or any biomass power generation technology other than combustion and gasification, have not been included. The joint report of the IEA Bioenergy Programme and the IEA CADDET Renewable Energy Technologies Programme, "Advanced Thermal Conversion Technologies for Energy from Solid Waste", August 1998, although dealing with the pyrolysis and gasification of municipal and industrial waste, contains descriptions of thermal conversion technologies that may also be used for power generation using biomass.

Combustion technologies are generally mature and well developed but conversion efficiency is limited by high fuel moisture and inherent features of the Rankine cycle. Thermal gasification of biomass offers high conversion efficiencies through the use of combined cycle plant, where biomass syn-gas is used to fuel the gas turbine, but is still very much in the development phase. Gasification technology has been included because it is expected to become commercially mature within the next five to ten years.

6.1.2 Combustion Technologies - General

Combustion technologies can be generally classified according to the use of fixed bed, fluid bed or suspension firing technologies. Such classification is not precise as spreader stokers feeding bulk fuel material to a fixed bed grate typically result in the finer fraction burning in suspension, giving rise to the term "semi-suspension firing". Table 6-1 shows examples of fuel delivery systems and furnace technologies employed according to the form and size distribution of the biomass fuel.

Except for the case of co-firing biomass in small ratios with coal in a pulverised coal fired boiler, suspension firing, as typified by the many pulverised coal fired boilers throughout the world, has not been considered. This is because suspension firing generally requires a high degree of fuel preparation to produce the fine particle size necessary for its success. This is readily achieved for a friable material such as coal but size reduction of tough, woody materials is more difficult and energy intensive. Sander dust, a wood industry by-product, is an exception because it is already suitably sized for suspension firing and no preparation is needed. Biomass (typically woodwaste) fired boilers, burning a portion of their fuel in suspension, where there is a separate sander dust source, are not uncommon.

The choice of combustion technology is an economic function of boiler size, where the operating cost savings owing to improved efficiency associated with suspension firing increasingly weigh against the capital cost of fuel preparation equipment as the boiler size increases. For example, small coal fired boilers are typically fixed bed, stoker fired owing to the lower cost of fuel preparation equipment. There is an efficiency penalty associated with this combustion technology as result of its higher excess air requirements and higher carbon-in-ash losses. However, the cost of the efficiency penalty is typically insufficient to justify the higher cost of suspension firing fuel preparation equipment. Large coal fired boilers, on the other hand, are typically suspension fired (pulverised coal fired) because this technology is more efficient as a result of its lower excess air requirements and lower carbon-in-ash losses. Here, with the larger size, the cost of the efficiency penalty of not suspension firing is sufficient to justify the higher cost of the suspension firing fuel preparation equipment. There is presently no demand for biomass boilers large enough to consider choosing pulverised fuel/suspension firing instead of fixed bed, stoker firing.

Table 6-1. Fuel delivery systems & furnace technology.

Fuel Form	Maximum Particle Size	Delivery System Most Appropriate	Furnace Technology Utilised
Bulk Material	<5 mm	Direct injection, Pneumatic conveyors	Direct fired (semi-suspension), Cyclone burners, CFB
Bulk Material	<50 mm	Screw Conveyors Belt Conveyors	Underfeed stokers, Grate fired BFB, CFB
Bulk Material	<100 mm	Vibroconveyors, Troughed chain conveyors	Grate fired, BFB
Bulk Material	<500 mm	Flight conveyors, Lumber wood conveyors	Grate fired, BFB
Shredded or Cut Bales	<50 mm	Cutters / shredders followed by pneumatic or screw conveyors	Direct fired, Grate fired, BFB, CFB
Bales, Sliced Bales	Whole bales	Hydraulic feeders	Grate fired, Cigar burners
Pellets	<30 mm	Screw conveyors	Underfeed stokers, BFB, CFB
Briquettes	<120 mm	Sliding bar conveyors, Lumber wood conveyors	Grate fired, CFB

(Source: Obernberger, 1997).

6.1.3 Fixed Bed Combustion

Fixed bed combustion uses air or mechanical devices to feed solid fuels on to a bed at the bottom of a furnace. The fuel is burnt on a grate through which a major portion of the air required for combustion passes. The airflow through the bed of fuel particles is low, so that the fuel remains in contact with the grate and tends to resist movement.

Fixed bed combustion systems typically require minimal fuel preparation and can handle a range of fuel size. This reduces the cost of fuel preparation compared to suspension firing.

Fixed bed combustion systems can be further classified according to the fuel feeding system and the grate system. Both can be applied in different combinations.

Fuel Feeding Systems

The fuel feeding systems, also called stokers, are classified according to the way the fuel is fed onto the grate: overfeed and spreader stoker, or underfeed stoker.

<u>Overfeed Stoker</u>

Overfeed stokers are divided into mass feed stokers and spreader stokers.

The fuel in mass feed stokers is fed by gravity at one end of the grate surface. The depth of the incoming bed is typically adjusted by a gate, under which the fuel passes before entering the furnace. The fuel is transported by means of the grate away from the feed end and through the furnace. Combustion takes place in the bed as air fed under the grate passes through the bed. The ash is continuously discharged at the opposite end of the grate from the fuel feed.

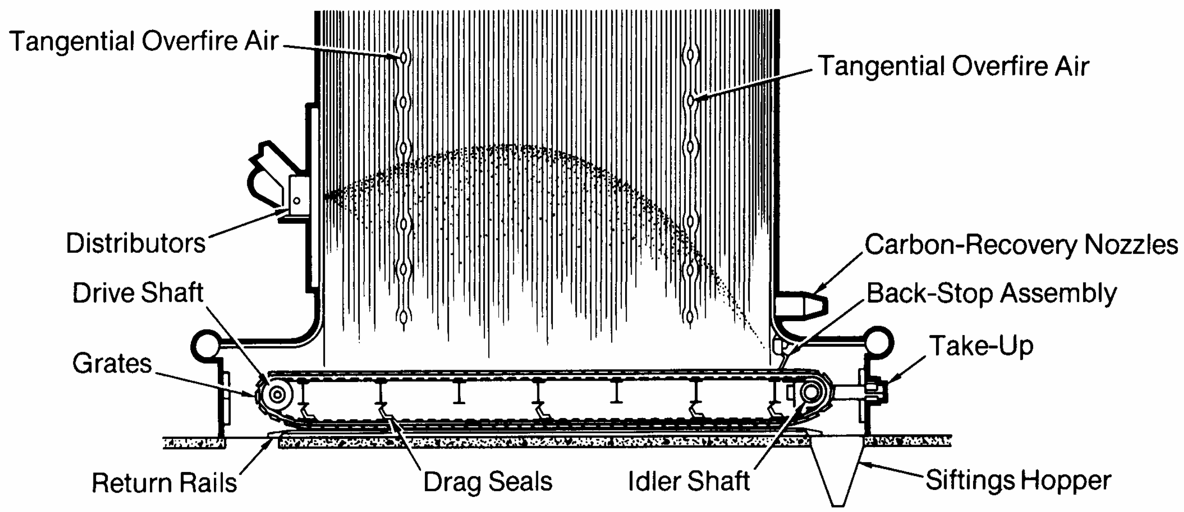

Figure 6-1. Diagram showing an overfeed spreader stoker and travelling grate.
(Source: Combustion, Fossil Power, 4th Edition. Combustion Engineering Inc. (1991)

Spreader stokers are characterised by fuel distributors, which continuously throw fuel into the furnace above an ignited fuel bed on the grate (Figure 6-1). Mechanical throwers are installed for coal distribution, and pneumatic throwers for biomass distribution. The fine particles are burned in suspension while larger particles fall and burn on the grate. Because the firing is based partly on suspension firing, the method works best with rather dry fuels (below 50% moisture content). When fuels with higher moisture content are to be fired, auxiliary firing with oil or gas is often required unless the boiler is designed for a higher combustion air temperature, to pre-dry the higher moisture content fuel. Appropriate fuel sizing is very important, as spreader stoker firing is based partly on suspension firing.

An advantage of the spreader stokers in comparison with mass-feed stokers is the quick response to changes in boiler capacity demand. However, a high proportion of unburned carbon in the flue gas is often apparent, which results in a lower boiler efficiency owing to combustion losses.

Underfeed stoker

In underfeed stokers, the incoming fuel is pushed through one or more openings located below the burning fuel bed and air ports. Figure 6-2 shows a typical arrangement. If the fuel ash content is too high, as is the case for bark, cereals and straw, then these systems are unsuitable. Because underfeed stoker systems are usually suitable for small-scale systems, up to a nominal size of 6 MW_{th}, they are not considered further in this study.

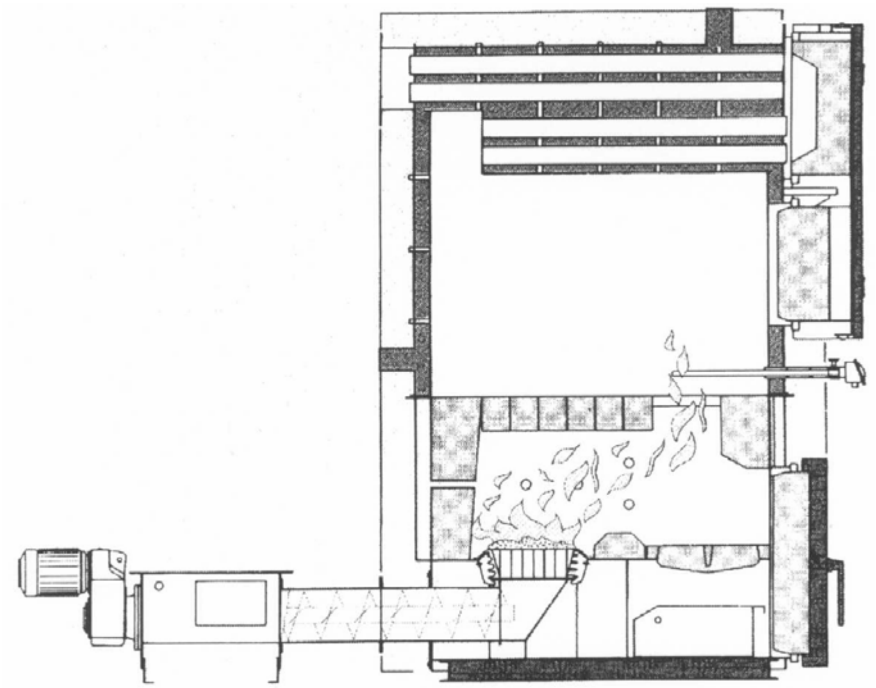

Figure 6-2. Boiler with underfeed stoker. (Source: Obernberger, 1997)

Grate Systems (over feed stokers)

Grate systems are suitable for biomass combustion devices greater than 1 MW_{th}. The grate system supports the fuel while combustion takes place, provides access to the fuel for air, and provides a means of removing the ash. A grate typically transports the fuel across the furnace to provide for a steady and even heat release and complete burn-out before the ash is discharged into the disposal system. It facilitates combustion control through bed depth, residence time and air flow rate.

Grate systems can be broadly classified according to the bed transport methods: travelling grate, a vibrating/reciprocating grate, or sloping stationary grate. The different grate systems can be combined with different overfeed stoker systems. Typical combinations of overfeed stoker and grate systems are shown in Table 6-2.

Table 6-2. Over feed stoker and grate systems.

Stoker type	Grate Type
Mass feed stoker	Vibrating: water-cooled
	Travelling grate
	Reciprocating
Spreader stoker	Vibrating: water-cooled
	Vibrating: air-cooled
	Travelling grate

Travelling grate

The travelling grate is a mechanical or hydraulic driven moving chain (referred to as a chain grate), which transports the fuel horizontally across the bottom of the furnace. The fuel is fed onto the grate by means of either a spreader stoker or a mass feed stoker (Figures 6-3 and 6-4).

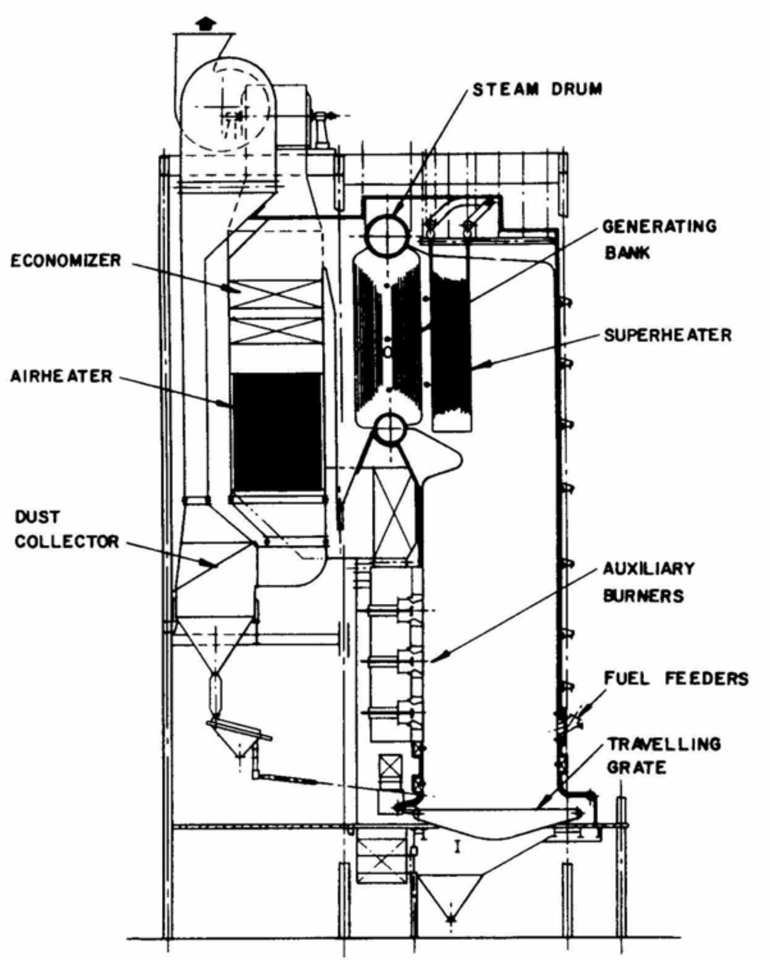

Figure 6-3. Boiler with travelling grate. (Source: Unknown)

The design is essentially an air-cooled grate; therefore it is important to retain a layer of ash on the grate to shield the grate bars from furnace radiation and resulting thermal degradation. When biomass with a low ash content is fired, it is common to operate the grates intermittently, so a layer of ash can build-up and be retained on the grate. The abrasive nature of biomass ash (i.e. silica content), in combination with high temperature grate bar exposure can result in high maintenance requirements.

If high moisture fuels are to be burned, such as biomass with 45% to 60% moisture content, a primary air temperature of 400 – 500°C is required to evaporate the water in the fuel prior to its combustion. Since the travelling grate is not water-cooled, the combustion air temperature is limited to an under-grate air temperature of 290°C, requiring fuels with a moisture content of 55% or less. Although the travelling grate is a durable and a proven design, it has many moving parts resulting in higher maintenance costs than alternative grate systems.

Travelling grates were originally designed for coal combustion. If a high proportion of coal has to be fired on the grate of a biomass boiler, manufacturers typically offer this grate design. Disadvantages of biomass combustion in boilers fitted with travelling grates include (i) high maintenance cost; and (ii) limited combustion air temperature resulting in reduced capacity to use high moisture fuels.

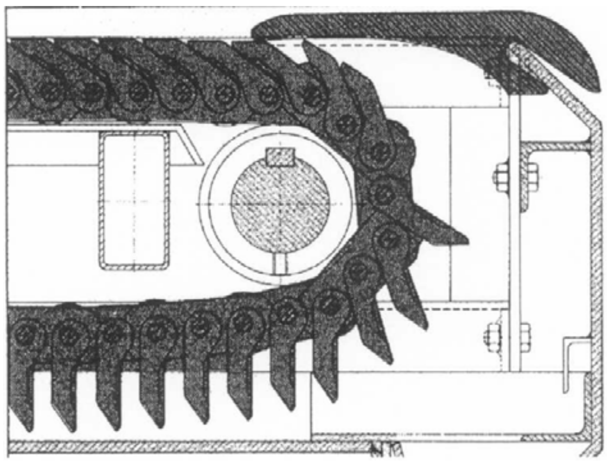

Figure 6-4. Close-up of one end of a travelling grate (Source: Obernberger, 1997).

Vibrating or Reciprocating grates

Vibrating or reciprocating grates are installed on a slope. Fuel 'flows' down the slope during combustion owing to their vibrating movement. They can be fed by means of a mass feed stoker or a spreader stoker. These grates are either air or water-cooled. The water-cooled grates can tolerate a higher temperature primary combustion air, which is required for high moisture fuels. These grates are suitable for coal co-firing to up to 20% or 30% maximum capacity rating (MCR) on the grate, or with pulverised coal burners, up to 100% MCR.

Sloping/Reciprocating grate

The sloping/reciprocating grate is another commonly used grate system in fixed bed biomass boilers. This grate is a combination of a sloping grate for pre-drying of the biomass and a reciprocating grate on which combustion takes place (Figure 6-5 and 6-6). These grate types are typically either water or air-cooled which eliminates the need for a protective layer of ash, making them suitable for low ash biomass combustion. This grate system is unsuitable for the combustion of large proportions of coal on the grate (coal feed to grate is limited to 20% to 30% MCR). Coal can be co-fired if a coal mill is installed and the coal suspension fired via pulverised coal burners. However, while this enables the combustion of a high proportion of coal in the biomass boiler (up to 100% MCR), the capital cost is increased.

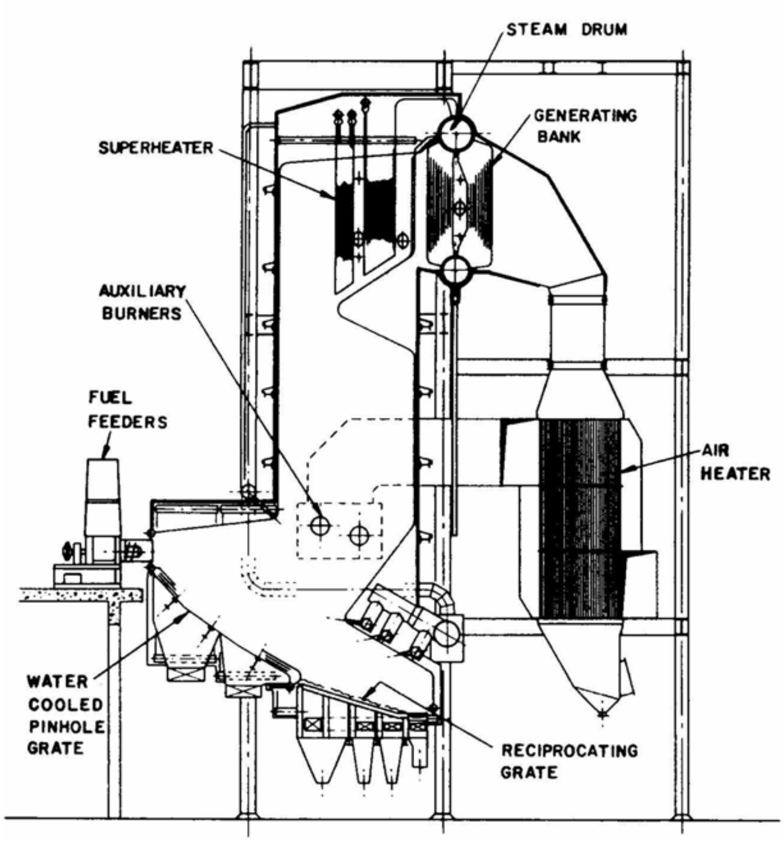

Figure 6-5. Boiler with sloping/reciprocating grate (Source: Unknown).

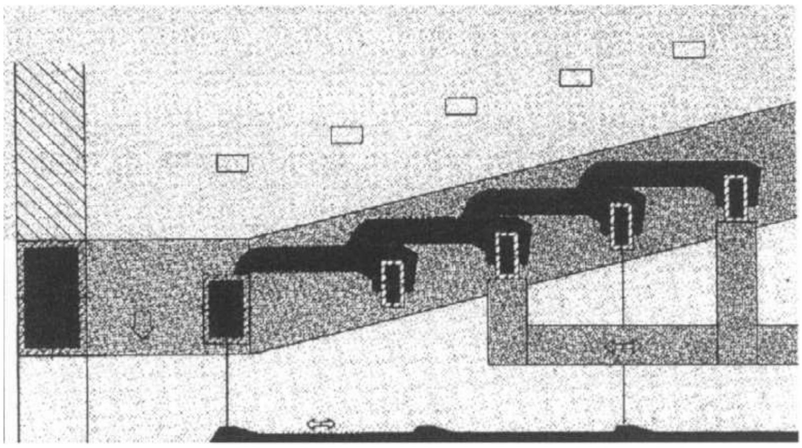

Figure 6-6. Close-up of part of a reciprocating grate (Source: Obernberger, 1997).

Comparison of Grate Designs

Table 6-3 compares the characteristics of the grate designs discussed in the previous sections.

Table 6-3. Qualitative comparison of grates for biomass boiler.

Characteristics	**Sloping / reciprocating grate**	**Vibrating grate**	**Travelling grate**
Moisture content (>45–60%)	++	++	-
Ash (highly abrasive)	+	+	-
Grate Coal co-firing (high proportion)	+	+	++
Pulverised Coal co-firing (high proportion)	+	+	++
Combustion efficiency (high)	+	+	-
Capital cost (high)	-	-	+
O&M cost (low)	-	++	-
Overall rating for biomass combustion	++	+	**-**
Note: - = poor, + = good, ++ = best			

Decisions on which grate to be used for the combustion of a defined biomass fuel depends on:

- Moisture content of the fuel (>45-60% ⇨ reciprocating/vibrating grate);
- Ash characteristics (if highly abrasive ash ⇨ reciprocating/vibrating grate);
- Proportion of coal firing on the grate (> 20-30% MCR ⇨ travelling grate).

The sloping/reciprocating grate is normally the preferred system for biomass combustion.

6.1.4 Fluidised Bed Combustion

The fluidised bed can be described as a large vessel filled with coarse silica sand, through which air passes upward, and into which the fuel is introduced. The upward flow of fluidising air converts the bed of solid particles into an expanded, suspended mass that has many properties of a liquid. The resulting mass has zero angle of repose, seeks its own level, and assumes the shape of the containing vessel. The sand has two main purposes (i) t mix the fuel and the combustion air thoroughly; and (ii) to increase the heat transfer to the fuel, for quick drying and ignition.

Unlike fixed bed combustion, the solid material in fluidised beds has a fluid-like, free flowing behaviour due to the velocity of the air and combustion gas passing upward through the bed of solid particles. Fluidisation occurs when the gas flow reaches a point at which the forces on the particles are just sufficient to cause separation ('Minimum fluidisation velocity'). The transition from fixed bed to fluid bed is dependent on the gas velocity and the pressure drop through the bed (Figure 6-7). However, increasing velocity does not significantly increase the separation distance, but the excess gas volume forms bubbles in the bed. This bubble formation provides a lower resistance path for the gas flow. The size, shape and growth of the bubbles significantly affect the bed performance. The bubbles are very important for the mixing in the bed. However, the combustion takes only place in the lower part of the boiler.

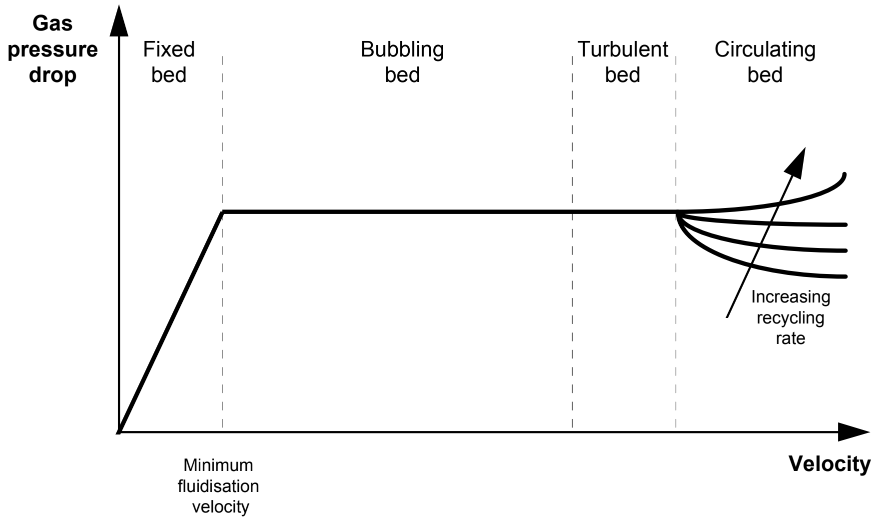

Figure 6-7. Gas pressure drop through a fluidised bed versus gas velocity.
Source: Combustion, Fossil Power, 4th Edition, Combustion Engineering, Inc., (1991)

The bed particle size is an important value for the fluidisation in a fluidised-bed boiler.

The major advantages of fluidised bed combustion compared with fixed bed combustion are:

- **The ability to burn low-grade fuels:** the high inertia of the bed provides conditions for a stable ignition of very low grade fuels with high ash and/or moisture content like biomass.
- **The fuel flexibility:** the combustion bed temperature is lower than a conventional combustion system, therefore fluidised bed boilers are not as sensitive to characteristics of the fuel and ash. A wide range of fuels with varying ash content and properties can be burned in a single boiler. In a conventional grate or suspension fired boiler, furnace exit

gas temperatures that exceed the ash fusion temperature of the fuel utilised can cause slagging problems.

- **Low nitrogen-oxide (NO_x) production: -** NO_x emissions in the furnace originate from the oxidation of nitrogen in the combustion air (thermal NO_x) and nitrogen components in the fuel (fuel-NO_x). Due to the relatively low combustion temperatures in the fluidised bed, the thermal NO_x is very low and appropriate design of the fluidised bed can significantly reduce the fuel-NO_x levels.
- **In-situ capture of sulphur dioxide (SO_2)**: - if fuels with high sulphur content are used, the SO_2 emissions can be controlled by addition of sulphur capture material into the fluid bed, such as limestone ($CaCO_3$).

Fluidised bed combustion technologies have two primary subdivisions: Bubbling Fluidised Bed Combustion (BFB) and Circulating Fluidised Bed Combustion (CFB).

Bubbling Fluidised Bed Boiler (BFB)

Bubbling fluidised bed boilers tend to be of interest for plants with a nominal boiler capacity greater than 10 MW_{th}. The BFB boiler is characterised by a lower gas velocity in the boiler compared with the CFB boiler. At the minimum fluidisation velocity (Figure 6-7), a cushion of gas separates the bed particles from one another. Primary air is provided through fluidising air nozzles at the bottom of the bed with secondary air fed to the furnace above the bed. The bed temperature is held below ash softening temperature by controlling the ratio of primary to secondary air. A certain amount of flue gas can be recirculated for controlling the bed temperature when dry fuels are used. If different fuels are fired together in the same boiler it is important to check that the ash mixture will not form an eutectic mixture with an ash fusion temperature considerably lower than the ash fusion temperature of either of the two ashes before mixing. This may happen if an alkaline ash is mixed with an acidic ash.

Fine ash and fuel particulate material may become entrained in the exhaust gases leaving the bed. Such material is normally captured in multi-cyclone mechanical dust collectors and returned to the bed. Recycle of entrained material to the bed improves carbon burnout and sulphur absorbent utilisation. Given the fineness of the entrained material and the multi-cyclone collection efficiency, optimum recycle ratios are in the range of 1:1 to 5:1.

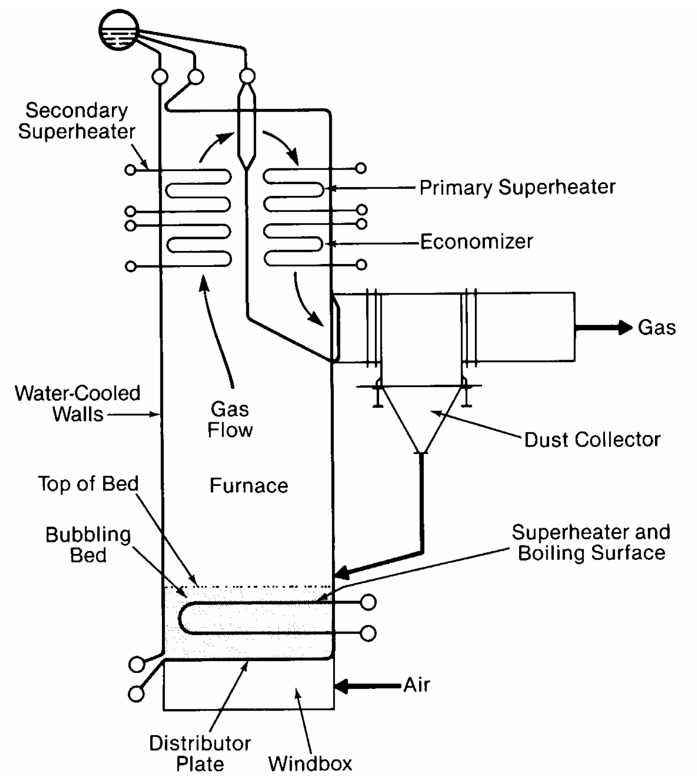

Figure 6-8. Bubbling fluidised bed boiler (BFB).
Source: Steam, its generation and use. 40th Edition, Babcock & Wilcox, (1992)

Circulating Fluidised Bed Boiler (CFB)

The basic design of the circulating fluidised bed (CFB) boiler is similar to the BFB boiler design but has a higher gas velocity through the boiler. As a result, the CFB has no distinct bed surface but the bed density is considerably higher at the bottom than at the top of the furnace.

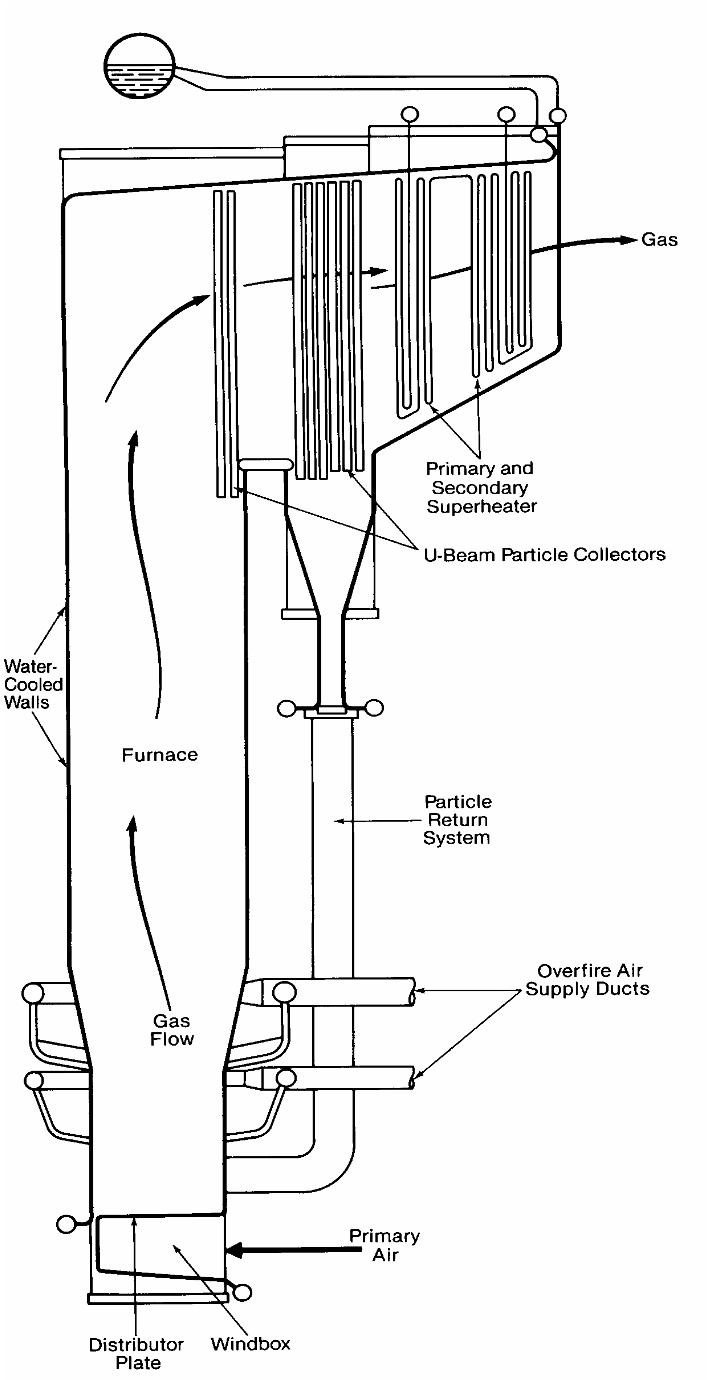

Figure 6-9. Circulating fluidised bed boiler (CFB).
Source: Steam, its generation and use. 40th Edition, Babcock & Wilcox, (1992)

Primary air is supplied in the bottom of the furnace through an air distributor, with secondary air fed through one or more elevations of ports in the lower part of the furnace. Consequently, combustion takes place throughout the entire furnace. The flue gas and entrained solids leave the furnace and enter one or more cyclones where the solids are separated out. The recycling ratio in a CFB boiler is typically in the range of 10:1 to 100:1. By increasing and reducing the sand recirculation, it is possible to fire both high calorific fuels (i.e. coal) and low calorific fuels (i.e. wet bark) in the same bed as this controls the bed temperature. CFB boilers are more complicated than grate boilers and have higher capital and maintenance costs compared with BFB or grate boilers. Some of the advantages of these systems include (i) ability for co-firing of a high proportion of coal (up to 100% MCR); and (ii) reduced emission levels compared to grate or BFB boilers. Due to their high specific heat transfer capacity, CFB boilers tend to be only of interest for plants over 30 MW_{th}.

Compact Circulating Fluidised Bed Boilers

Current development effort on CFB boilers centres on reducing the physical size of the CFB boiler. Two manufacturers, Foster Wheeler and Kvaerner Pulping, have developed their own versions of a compact CFB. Foster Wheeler's compact CFB boiler replaces the conventional round cyclone with a square one and this centrifugal separator is joined to the furnace without any expansion joints (Figure 6-10). The new design has lower investment, operating and maintenance costs. It is also claimed to reduce implementation schedules and to be suited for retrofitting into existing facilities.

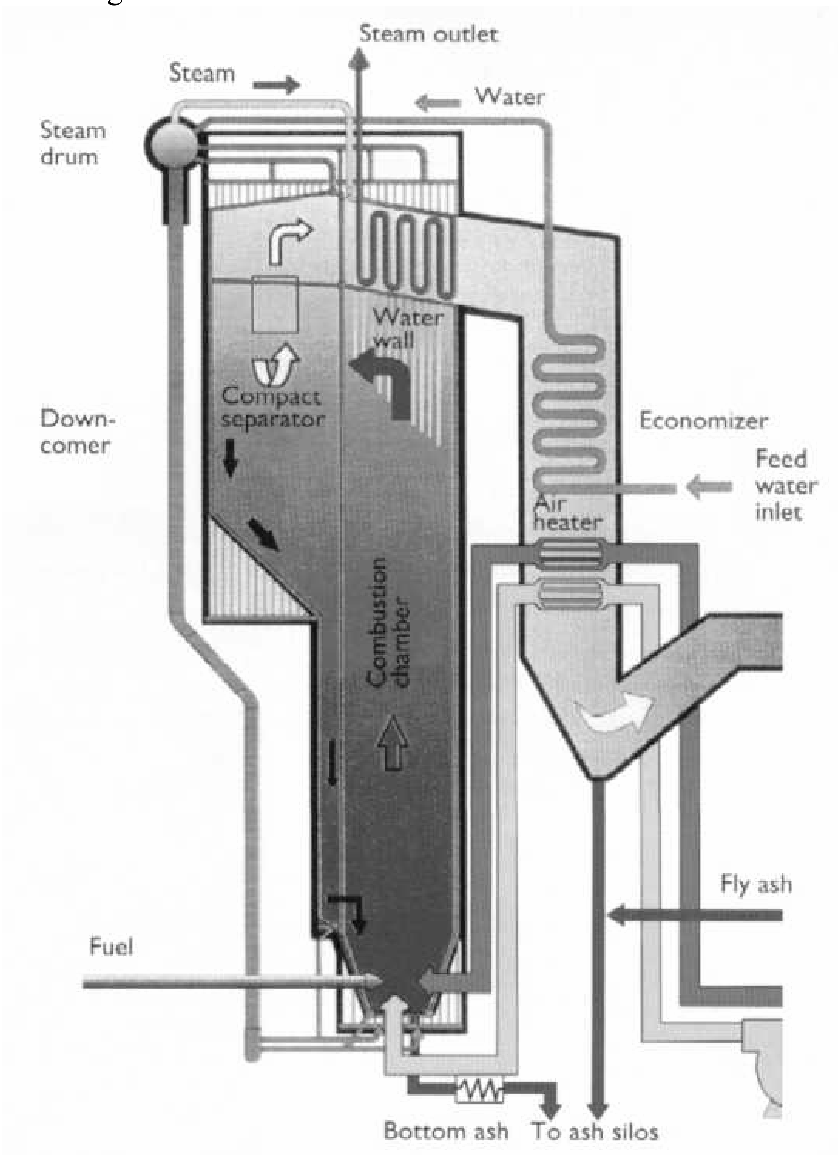

Figure 6-10. Foster Wheeler Compact CFB boiler (Foster Wheeler Information Brochure)

Kvaerner Pulping's CYMIC®(Cylindrical Multi-Inlet Cyclone) CFB boiler differs from others due to the water-cooled cyclone situated within the furnace. This saves space, increases heat delivery surface and reduces the amount of refractory required. Figure 6-11 shows a diagram of a 160 MW_{th} boiler that has been installed in an existing building at a paper mill in Finland.

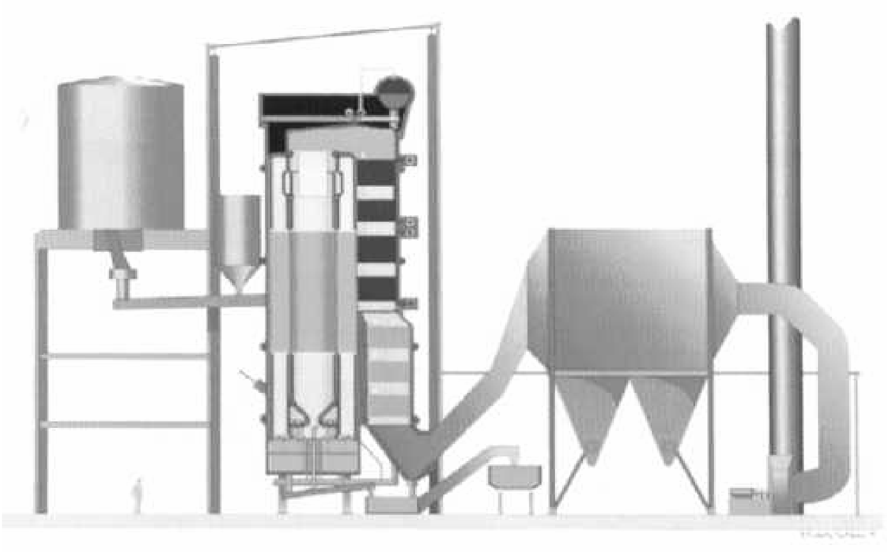

Figure 6-11. Kvaerner Pulping's CYMIC® CFB boiler (Kvaerner Information Brochure)

The totally water-cooled construction ensures that the furnace and the cyclone are at the same temperature. This ensures that there is no thermal movement between the furnace and the cyclone, which simplifies operation and maintenance and shortens the boiler start-up and shutdown times. Even during partial load the CYMIC® boiler can provide full superheating. Figure 6-12 shows a cut-away diagram of the boiler.

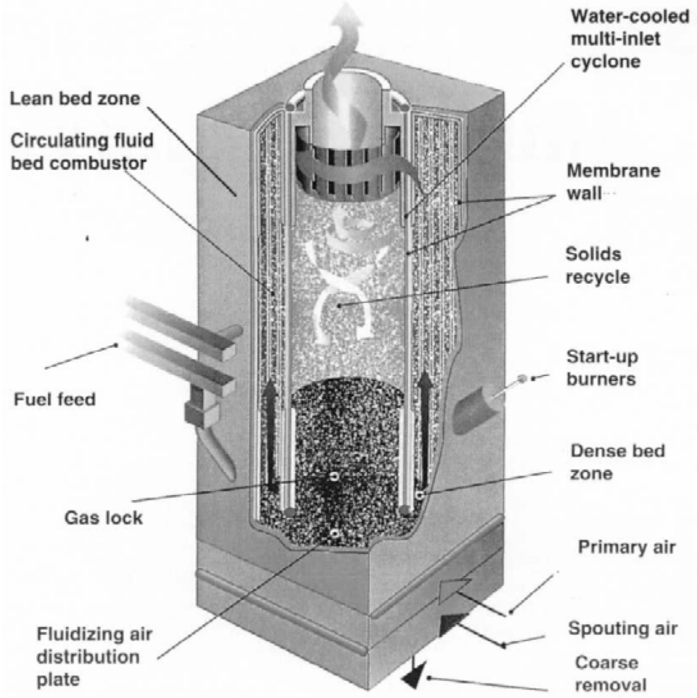

Figure 6-12. Cut-away diagram of CYMIC® CFB boiler (Kvaerner Information Brochure)

6.1.5 Comparison of Combustion Technologies

The following section compares the characteristics of fixed bed sloping and vibrating grate firing systems with bubbling fluidised bed (BFB) and circulating fluidised bed (CFB) combustion systems. Table 6-4 provides a qualitative comparison of the grate types and fluidised bed combustion options.

Table 6-4. Grate type versus fluidised bed combustion.

Characteristics	**Sloping Grate**	**Vibrating Grate**	**BFB**	**CFB**
Boiler efficiency		+	++	++
Internal electricity consumption	++	++		
Availability		++	+	+
Need of service	•	+	•	•
Excess air			++	++
Fuel flexibility			+	++
Demand for homogeneous fuel	+			
Tolerance towards fuel moisture	++	+		
Tolerance towards variation in fuel moisture			+	+
Stop in fuel feed	++	+		
Load change rate		+	++	++
Need of soot blowing	•	•	•	•
Need of dust collection	•	•	•	•
Emissions to air		+	+	++
Capital cost	++	++		
Note: + = better • = about equal				

Table 6-4 shows that a grate boiler would be preferred if the wood waste contained significant large particles and stones, and high moisture. A grate boiler also has a lower auxiliary power consumption than BFB or CFB boilers. Table 6-4 also shows that CFB boilers provide the best boiler efficiency, highest fuel flexibility, best load change capability, and lowest emissions of the technologies compared. Recent experience in Europe with CFB boilers has been very favourable and capital costs have been extremely competitive. This has not proven to be the case in the United States where higher installation cost and poor reliability has been demonstrated.

A review of industry practice indicates that coal co-combustion on inclined grates is not typical but BFB boilers are capable of burning about 20 to 25% of the fuel input as coal. The presence of potassium (K) and chlorine (Cl) in the fuel could create fouling and slagging problems in fluidised bed boilers.

Table 6-5 lists the advantages and disadvantages of the different conventional combustion systems available.

Table 6-5. Advantages and disadvantages of combustion technologies.

Grate Boilers	
Advantages	***Disadvantages***
Low investment costs for plants <10MW$_{th}$ Low operating costs Low dust load in flue gas Good burn-out of fly-ash particles Good operation at partial load possible Less sensitive to slagging than BFB and CFB boilers	No mixtures of wood and straw/cereals possible Efficient NOx reduction requires special technology Combustion conditions not as homogeneous as in BFB and CFB furnaces Higher oxygen access decreases the efficiency
Bubbling Fluid Bed Boilers	
Advantages	***Disadvantages***
Low investment costs for plants >10MW$_{th}$ No moving parts in the hot combustion chamber NOx reduction by air staging works well High flexibility concerning particle size, moisture content, and mixtures of biomass fuels Lower excess oxygen raises the efficiency	High operating costs Higher dust load in the flue gas than grate furnaces Good operation at partial load requires special technology Medium sensitivity to ash slagging Medium erosion of heat exchanger tubes
Circulating Fluid Bed Boilers	
Advantages	***Disadvantages***
No moving parts in the hot combustion chamber NOx reduction by air staging works well High flexibility concerning moisture content and mixtures of biomass fuels Homogeneous combustion conditions in furnace if several fuel injectors are used High specific heat transfer capacity due to high turbulence Addition of additives easy Efficient S fixation in the ash if enough Ca available	High investment costs (interesting only for plants > 30MW$_{th}$) High dust load in the flue gas Partial load operation requires a second bed Loss of bed material with the ash High sensitivity concerning ash slagging Medium erosion of heat exchanger tubes Low flexibility concerning particle size of the fuel High Auxiliary Power Requirement High Maintenance Cost

(Source: Obernberger, 1998)

In terms of emissions from biomass boilers, BFB and CFB boilers normally show lower CO and NOx emissions due to the homogeneous nature of fluid beds and controllable combustion conditions. On the other hand a grate boiler would be expected to emit less particulate and show a better burnout of carbon in the fly-ash.

6.1.6 Gasification Technologies

Biomass Gasification can be defined as a process by which biomass is converted primarily to a combustible fuel gas. The fuel gas can then be used in a number of different combustion/generation technologies that can use a low/medium calorific value gas. Proximate analysis of typical biomass indicates that about 70% of the biomass (on a dry basis) is volatile matter. This volatile matter can be converted to a gas primarily by heating. Biomass naturally has a high reactivity, which means it can readily be converted to a gas.

There are many advantages to gasification compared to direct combustion.

- Gasification takes place at lower temperatures than combustion, allowing the utilisation of fuels with lower ash fusion temperatures without extensive slagging or fouling;

- Gasification can be used to facilitate the use of biomass fuels in an existing coal, oil or gas fired plant. Gas from a biomass gasifier can be ducted into an existing boiler and co-fired or fired exclusively without requiring the need to install a new steam generator or balance of plant equipment;
- Gasification can be used to convert biomass into a gaseous fuel, which can then be used in a high efficiency gas turbine combined cycle power plant. While not the best available technology, large biomass combustion plants representative of existing units in the US at present have net operating efficiencies of 25% on a higher heating value (HHV) basis., or 30% on a lower heating value (LHV) basis. When a biomass gasifier is combined with a high efficiency combined cycle plant, the theoretical efficiency approaches 50% according to technology developers. Plant efficiencies in this report reflect units designed for power generation only. The efficiency of a CHP (combined heat and power) plant will be higher as the condensing losses are less or may be eliminated altogether. It is not practicable to compare CHP plants with varying heat/power ratios, with power generation only plants.

Biomass Gasification Technologies can be categorised into (i) Updraft Gasifiers; (ii) Downdraft Gasifier; (iii) Stirred Bed Gasifiers; and (iv) Fluid Bed Gasifiers. Figure 6-13 illustrates three of these biomass gasification technologies.

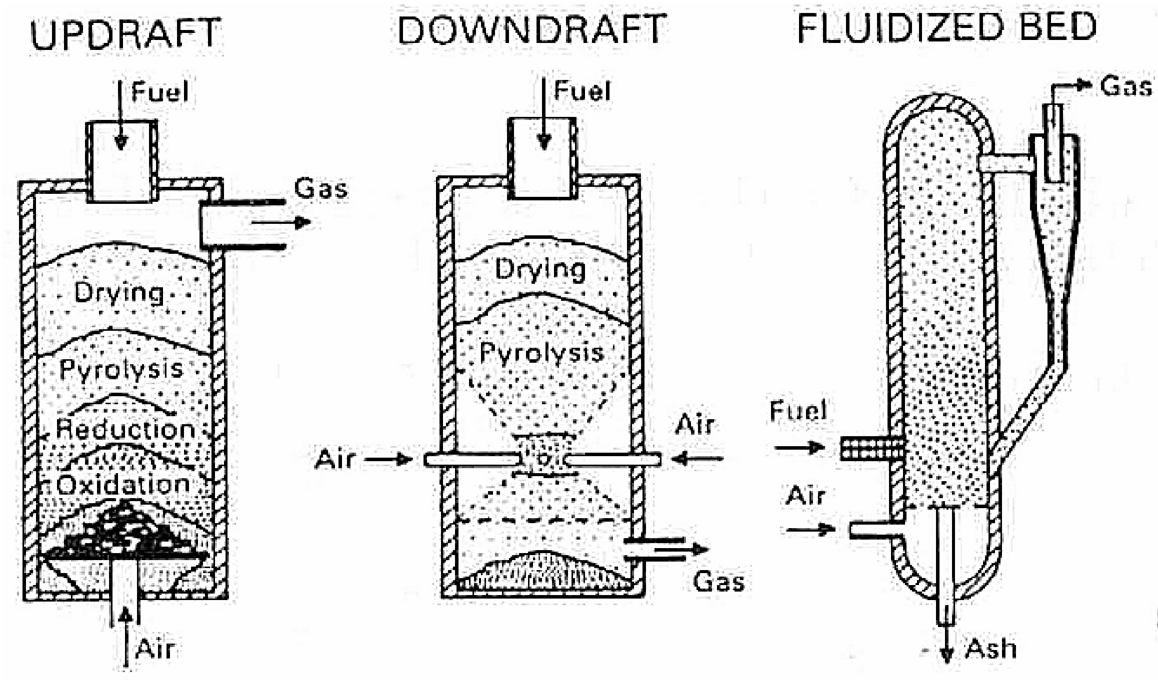

Figure 6-13. Different biomass gasifier technologies (Source: Kurkela et al, 1993).

Updraft Gasifiers

In an updraft gasifier, wood is fed into the top of the gasifier vessel, and ash is removed from the bottom. The four stages of gasification in an updraft gasifier are drying, pyrolysis, reduction and combustion. The heat necessary to provide energy in the pyrolysis and reduction stages is provided by the combustion stage. Product gas leaves the vessel from the top, where it has a high tar content due to the exposure to the cool moist incoming biomass feedstock just prior to exiting the gasifier.

Because of the high tar content of the product gas from an updraft gasifier, this process is used primarily for producing heat or for providing combustible gas for use in a boiler. Units of this type have been installed with heat output of over 20 GJ/h and gasification energy conversion efficiencies of up to 95% (LHV). This does not take into account the efficiency of the boiler or balance of plant equipment.

The fuel requirements for an updraft gasifier allow up to 50% moisture content, and particles up to 100 mm in length. The resulting product gas typically has a calorific value in the range of 4.2 to 5.6 MJ/m^3 (LHV).

Downdraft Gasifiers

In a downdraft gasifier, wood is fed into the top of the gasifier vessel, and ash is removed from the bottom. A restriction is placed above the grate, which allows for the reduction in fuel volume as it is gasified. Air enters the vessel above the throat, and the product gas leaves the vessel below the throat. The four stages of gasification in a downdraft gasifier are the same as in the Updraft Gasifier; drying, pyrolysis, combustion and reduction. In downdraft gasifier, the combustion stage takes place above the throat prior to the reduction stage.

Product gas from a downdraft gasifier has a much lower tar and oil content due to the location in the gasifier from which the product gas is extracted. Downdraft gasifiers are used to provide gaseous fuel for diesel and spark ignited internal combustion engines. The Imbert Gasifiers popular in the Second World War for fuelling mobile vehicles, were downdraft gasifiers.

Downdraft gasifiers are generally limited in size to less than 10 GJ/h. When used as a source of heat or fuel to a boiler, a downdraft gasifier has gasification energy conversion efficiencies of up to 95% (LHV). A gasifier providing fuel gas for a gas turbine or reciprocating engine is often evaluated based on cold gas efficiency. This is the ratio of chemical heat in the product gas compared to the heat in the fuel input. Downdraft gasifiers have a cold gas efficiency of up to 75%.

Fuel requirements for a downdraft gasifier limit the moisture content of the fuel to less than 30% by weight. The size requirements are for particles between 25 and 150 mm. The resulting product gas typically has a calorific value in the range of 4.4 to 5.5 MJ/m^3 (LHV).

Stirred Bed Gasifiers

Some gasifier designs rely on mechanical stirring of the fuel bed, and are classified as stirred bed gasifiers. The presence of mechanical agitators makes these gasifiers more vulnerable to solid flow problems as well as failures of the stirring equipment due to high abrasion and high operating temperatures.

There are several specific designs that fall in this category, some of which could be categorised as updraft gasifiers and some as downdraft gasifiers. The largest installed unit produces 21 GJ/h of energy, and has a product gas with a calorific value of 4.7 MJ/m^3 (LHV). The fuel requirements allow up to 40% moisture content, and particle sizes up to 50 mm.

Fluid Bed Gasifiers

Two fluidised bed gasification approaches are being pursued for commercial development at present:

- Low heating value gas production through air gasification;
- Medium heating value gas production by means of indirect heating or nitrogen free gasification using oxygen.

If the product gas is to be used in a combustion turbine, it must be compressed to the pressure required by the combustor of the turbine. This is typically between 10 and 30 bar. The power required to compress the large volumes of product gas from a low heating value gasifier provides a significant incentive to operate the low heating value gasifier as a pressurised unit. This gives rise to two types of air gasifier: atmospheric and pressurised.

Low Heating Value Atmospheric Gasifiers

Atmospheric gasifiers produce a product gas at or near atmospheric pressure. This gas must be compressed for use in a gas turbine. If the gas heating value is low, larger quantities of product gas must be compressed for a given heat supply, resulting in large auxiliary power requirements for fuel compression. Low heating value gasifiers typically produce product gas with a calorific value in the range of 6 to 8 MJ/Nm^3 (LHV). Examples of low heating value atmospheric gasifiers currently under development or operating are listed below.

EPI

Energy Products of Idaho installed a 25 MW$_{th}$ atmospheric pressure, fluidised bed gasifier in 1985 at North Powder Oregon, USA. This gasifier utilises wood waste, which has been dried to 25% moisture content. The wood is gasified to product gas with a calorific value of approximately 5.9 MJ/ Nm^3 (LHV). The gas is burned directly in a boiler, producing steam, which drives a 6 MW$_e$ turbine.

Foster Wheeler

Foster Wheeler supplied four atmospheric circulating fluidised bed gasifiers in the mid 1980's for use in the pulp and paper industry. The sizes of these units ranged from 17 to 35 MW$_{th}$. These gasifiers utilise dried waste wood as feedstock, and produce hot product gas, which is used to fuel lime kilns. All of these units are still in operation today. Because the gas is used as fuel for combustion, product gas cleanup is not necessary.

Foster Wheeler supplied a 50 MW$_{th}$ atmospheric pressure fluidised bed gasifier supplying hot gas to a 350 MW$_{th}$ coal/gas fired boiler at the Kymijarvi Power Station. This plant is used to provide electricity and district heating for the City of Lahti, Finland. The project first started up in January 1998, and operated for the balance of the 1998 district heating season, until June 1998.

The major difference between the gasifier at Kymijarvi and those installed previously by Foster Wheeler at the pulp mills is the Kymijarvi gasifier utilises wet wood and recycled fuel (REF). Approximately 30% of the fuel for the Kymijarvi gasifier is REF consisting of plastics, paper, cardboard and wood. The average moisture content of the fuel is 30%, but may be as high as 55%. This design can handle fuel moisture content of up to 60% by weight.

Biomass and REF is mixed after sorting and shredding. The fuel enters the refractory lined steel vessel. Gas is produced at about 850 ^{o}C. When utilising fuel at 50% moisture content, the calorific value of the gas is about 2.2 MJ/kg (LHV).

Detailed gas characteristics were not available, however the total SOx emission from the boiler were reduced by 20 mg/MJ owing to the absence of sulphur in the wood fuel. The NOx emissions were reduced by 10 mg/MJ presumably owing to the lower nitrogen in the wood compared to coal and the lower flame temperature of the biomass gas firing. There was also a reduced oxygen content in the furnace in the area of the coal burners, which are directly above the biomass burners. The reduced flame temperature and the reduced oxygen content would reduce the amount of thermal NOx generated (by thermally combining the nitrogen and oxygen in the air). The HCl content increased by 10 mg/m^3 presumably owing to the chlorine content in the REF fuel. The CO emissions while operating the gasifier were the same as without the gasifier, 10 - 20 mg/MJ.

Lurgi

The Lurgi Biomass Gasifier is an atmospheric, air-blown circulating fluidised bed gasifier. A unit of this design is currently proposed for the Thermie Energy Farm, near Pisa Italy. This project has been delayed due to changes in Italian law, but earthwork was expected to begin in late 1998. The project includes a 10.9 MW_e gas turbine supplied by Nuovo Pignone and a 5 MW_e steam turbine. The net plant output is expected to be 12.1 MW_e, operating at a net thermal efficiency of 31.7% based on lower heating value (LHV).

The fuel for this project will include short rotation forestry as well as forestry and agricultural residues. The agricultural residues will include olive stones and grapeseed flour while the forestry species will include poplar, robinia, willow and chestnut.

The biomass fuel will be chipped and then dried in a dryer which will utilise exhaust gases from the gas turbine, after they are cooled in the heat recovery steam generator. The dried fuel will be fed to an atmospheric gasifier, which will convert the fuel to a product gas with the following characteristics:

H_2	$16\%_v$
CO	$22\%_v$
CH_4	$5\%_v$
N_2	$44\%_v$
CO_2	$13\%_v$
LHV	7.35 MJ/Nm^3

The gas is cooled in a heat exchanger, which preheats the gasification air, and steam will be produced in a cooler. The cooled gas will be cleaned in a scrubber before being compressed and delivered to the gas turbine.

Termiska Processer AB

Termiska Processer AB, (TPS) was formerly a part of Studsvik AB. The TPS gasifier design incorporates an air blown, atmospheric pressure, fluidised bed gasifier producing a low energy product gas with a calorific value of 4-7 MJ/Nm^3. There is one operating facility with this technology, known as the Greve-in-Chianti Waste Gasification Plant in Florence, Italy.

Greve-in-Chianti is a 200 tonne per day plant with two 15 MW_{th} gasifiers utilising pelletised refuse derived fuel (RDF). The product gas is used in a boiler and as fuel for cement kilns, so extensive gas cleanup is not necessary. There are two stages of solids separation for the product gas after leaving the gasifier. Steam from the boiler drives a 6.7 MW_e condensing steam turbine.

Product gas from the Greve-in Chianti plant has the following characteristics based on operating data. This data is presented on a dry basis. The moisture content of the gas is 9.5%.

H_2	$7.79\%_v$
CO	$7.95\%_v$
CH_4	$5.89\%_v$
N_2	$41.48\%_v$
CO_2	$14.16\%_v$
CxHy	$4.42\%_v$
LHV	7.43 MJ/Nm^3

The TPS technology is also being used in the 8 MW_e ARBRE plant currently under construction at Eggborough, North Yorkshire, England, and it is planned for use in the 30 MW_e Brazilian BIG-CC plant sponsored by the United Nations Global Environment Facility. A TPS gasifier is under consideration for the 30 MW_e Noord-Holland project, which may or may not proceed at this point. TPS also has a 2 MW_{th} pilot plant that is used for process development and the testing of specific fuels for proposed projects.

The ARBRE facility will utilise short rotation forestry as the feedstock. Start-up was scheduled for 1999.

The prepared fuel will be dried utilising exhaust gases from the heat recovery steam generator, and fed into the fluidised bed gasifier. Product gas from the gasifier will be directed to a tar cracker, which utilises dolomite to reduce the tar content of the gas to levels below 65 mg/ Nm^3. The gas will then be cooled, filtered, scrubbed and compressed prior to entering the combustor for a 4.75 MW_e gas turbine. Gas turbine exhaust gases will be directed to a heat recovery steam generator, producing steam for the 5.25 MW_e steam turbine. The net output of the plant is expected to be 8 MW_e, at an operating efficiency of 30% (LHV).

Expected emissions for the plant are as follows:

CO	10-20 ppm
Total hydrocarbons	2-5 ppm
NOx	10-30 ppm
Particulates	5-10 mg/ Nm^3

Low Heating Value Pressurised Gasifiers

Examples of low heating value pressurised gasifiers are as follows.

<u>Carbona</u>

Carbona Corporation licensed the RENEWGAS gasification technology from the Institute of Gas Technology in Chicago (IGT). Carbona was previously known as Enviropower, which was a joint venture of Tampella Power, a major Finnish boiler manufacturer and Vattenfall AB, a large Swedish utility.

Carbona has a 15 MW_{th} pilot plant in Tampere, Finland. The heat from the pilot plant can be used in the Tampere district heating system or it can be diverted to a flare. This pilot plant is used to test various fuels for applications considering the Carbona gasifier. It operates at 30 bar, and is complete with hot gas cleanup. Since 1993, this plant has tested over 4,000 tons of biomass fuels for gasification including wood chips, forest residues, straw, paper mill waste and alfalfa. There is also a 2 MW_{th} pilot plant based on the IGT RENEWGAS technology in Chicago Illinois.

A 20 MW_{th} demonstration project utilising the IGT (Carbona) technology was installed in Hawaii, utilising bagasse or woodchips for feedstock. The gasifier could be operated as either an air blown gasifier or an oxygen blown gasifier, at pressures up to 20.4 bar. Gasification temperatures were typically in the 850°C to 900°C range. A slipstream hot gas cleanup system was installed and tested.

The Carbona technology is planned for a 75 MW_e alfalfa stem fuelled plant, scheduled for construction in Minnesota USA. This project is known as the Minnesota Agri-Power Project, (MAP). The Minnesota Valley Alfalfa Producers Co-operative (MnVAP), will produce 640,000 tonnes of alfalfa per year, which will be processed into 320,000 tonnes of animal feed and 320,000 tonnes of dried pelletised stems for fuel in the power plant.

Approximately 1,000 t/day of pelletised alfalfa stems will be delivered to the storage silos at the plant. The fuel will then be weighed and fed through three lockhoppers before entering the gasifier. The gasifier will operate at 20 bar, and at 700°C. It is important to keep the gasification temperature below 750°C due to the low sintering temperature of the ash.

The calorific value of the product gas is expected to be 5-6 MJ/Nm^3 (LHV) based on data from the pilot plant studies. The product gas is cooled, and then cleaned in a ceramic filter before entering the combustor for the 50.9 MW_e gas turbine. A portion of the gas turbine compressor flow is diverted to a booster compressor, to provide air for the gasification.

The exhaust gases from the gas turbine enter a heat recovery steam generator. Steam is produced which drives a 28.3 MW_e steam turbine, as well as providing the steam necessary for gasification. The expected station service requirement is 4.3 MW_e, resulting in a net output of 74.9 MW_e. The expected efficiency of the plant is 40.2% (LHV).

Foster Wheeler

Foster Wheeler Energy International and Sydkraft AB have built the first complete biomass fuelled Integrated Gasification/Combined Cycle (IGCC) power plant in Varnamo Sweden. This technology is also known as the Bioflow Energy System. It was developed by the Ahlstrom Corp., which was purchased by Foster Wheeler Energy International.

The Commissioning of the Varnamo plant started in late 1992 and the first gasification of wood chips occurred in June 1993. The start-up phase was completed in the spring of 1996. The plant has had 950 operating hours as a fully integrated plant as of March 1997.

Biomass fuel is dried from moisture content of about 50%, to approximately 10-20% in a dryer. The dryer can either use heat from the exhaust gases from the heat recovery steam generator, from low-pressure steam from the steam system, or the wood can be dried in an external drying facility. The dried and crushed wood is fed through lock hoppers to the gasifier.

The gasifier operates at approximately 20 bar, and between 950°C and 1,000°C. The bed material may consist of sand, dolomite or limestone. The wood is gasified, and the product gas exits the gasifier along with the bed material into the separator. The bed material is removed in the separator, and returned to the gasifier. The product gas is then cooled prior to entering the hot gas cleaning system. The cleaned gas then goes to the combustor of the 4 MW_e gas turbine. Approximately 10% of the gas turbine compressor flow is diverted to a booster compressor and used for gasification air.

The exhaust from the gas turbine goes to a heat recovery steam generator, where steam is produced for the steam turbine. The exhaust steam from the steam turbine provides 9 MW_{th} of district heating energy for the village of Varnamo.

Typical characteristics of the product gas are as follows:

H_2	9.5-12.0$\%_v$
CO	14.4-17.5$\%_v$
CH_4	5.8-7.5$\%_v$
N_2	48-52$\%_v$
CO_2	16-19$\%_v$
LHV	5.3-6.3 MJ/Nm^3

Figure 6-14 shows the schematic for the Varnamo biomass gasification plant.

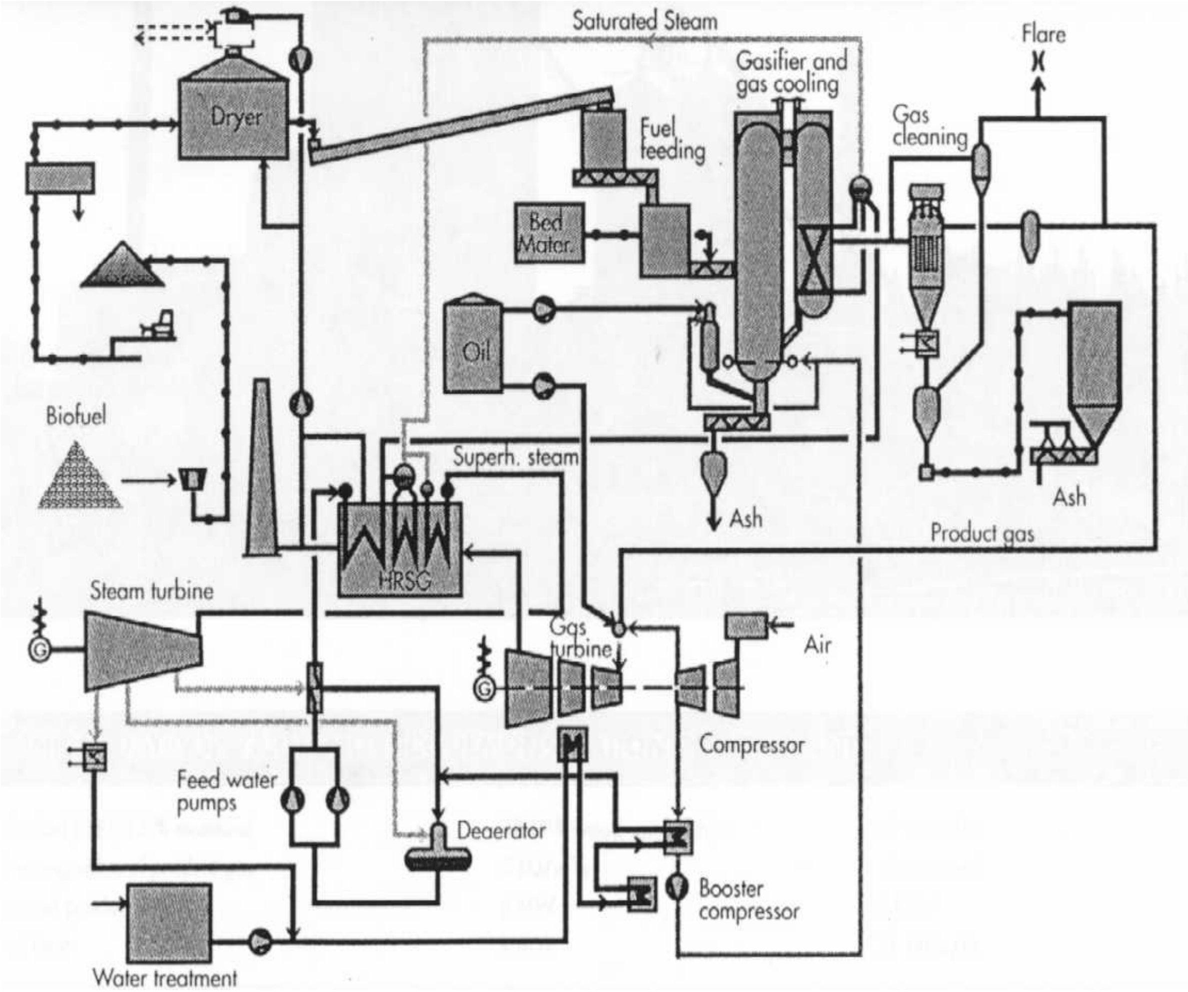

Figure 6-14. Schematic of the Varnamo plant (Alstom Information Brochure)

Medium Heating Value Gasifiers

An example of a medium heating value gasifier is as follows.

<u>*Battelle/Ferco Indirectly Heated Gasification*</u>

In the Battelle/Ferco Indirectly Heated Gasifier, a medium heating value product gas is obtained by anaerobic gasification which avoids the problem with diluting the product gas with nitrogen. Battelle Memorial Laboratory in Columbus Ohio developed the process. Future Energy Resources Corporation (FERCO) purchased the rights to the technology in North America. The gasification takes place using hot sand that is heated in a separate vessel, thereby allowing the gasification to take place in the absence of air.

The process schematic in Figure 6-15 shows the Battelle/Ferco process. Two physically separate reactors are utilised, a gasifier and a combustor. In the gasifier, the biomass is converted into a medium energy gas and residual char. In the combustor, the residual char is burned as a source of heat for warming up the sand bed material. The bed material transfers the heat from the combustor to the gasifier.

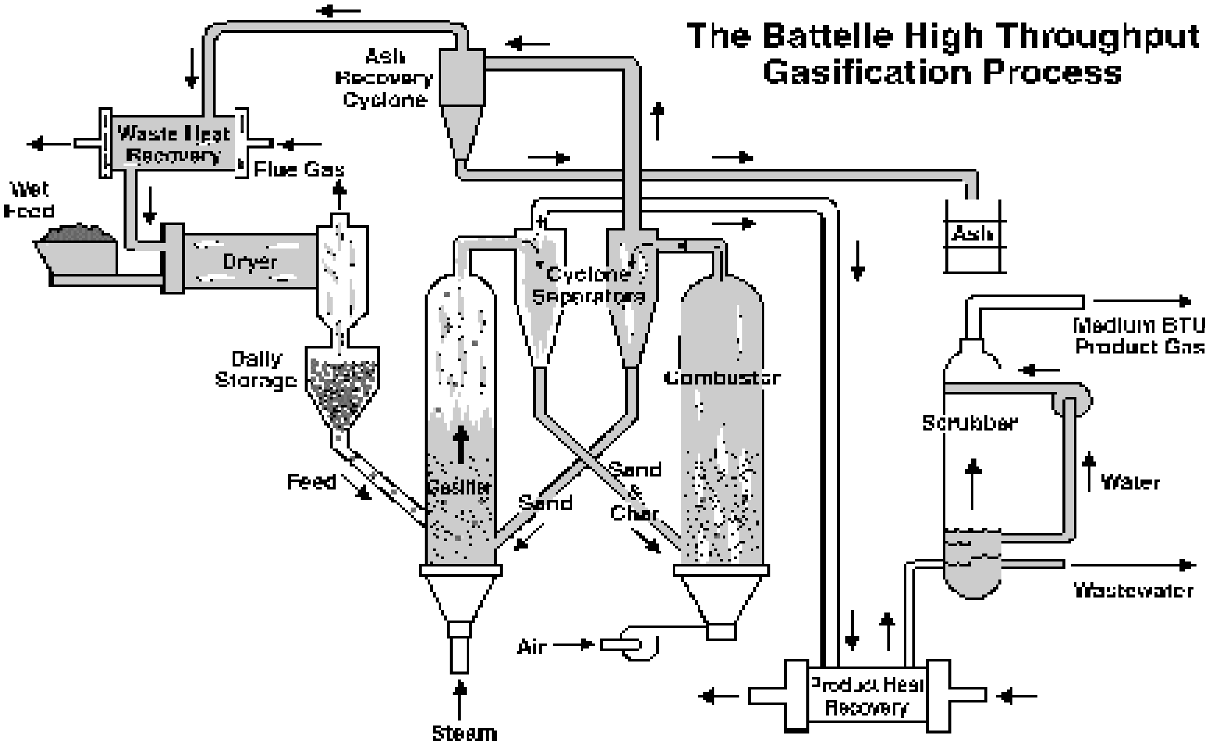

Figure 6-15. Schematic of the Battelle gasifier (US DOE BioPower Program Internet Site)

Dried biomass enters the gasifier through a series of lockhoppers. The gasifier operates at approximately 1.36 bar. Sand that has been heated to 980°C enters the gasifier and volatilises about 70% of the biomass. Steam is added to the gasifier primarily as a propellant. The mixture of sand, product gas and char exit the gasifier and enter a primary cyclone. The cyclone separates the product gas, at which point it is cooled and cleaned in a scrubber. The char and sand are separated, and flow to the combustor. The char is burned in the combustor by adding air, and the reheated sand returns to the gasifier again.

A 2 MW_{th} pilot plant has been operating in Columbus Ohio for about 15 years using this technology. This plant was used for process development and for testing various fuels. To date, this facility has operated for over 10,000 hours. A 200 kW_e gas turbine has been added, and operated successfully.

A 40 MW_{th} facility using the Battelle/Ferco process has been constructed in Burlington Vermont USA and is currently in the process of start-up. Initially, this gasifier is providing product gas to an existing 50 MW_e wood fired generating station. Once the testing is complete in this mode, the intent is to add a gas turbine and operate as an integrated system. Product gas has been successfully produced during the start-up, but not for prolonged periods of time.

A summary of fluidised bed gasification technologies is presented in Table 6-6.

Table 6-6. Gasification technologies summary.

Manufacturer	**Energy Product of Idaho**	**Foster Wheeler**	**Lurgi**	**TPS**	**Carbona**	**Foster Wheeler**	**Battelle/ FERCO**
Gasification Pressure (bar)	1.3	1.3	1.3	1.3	30	20	1.3
Gas calorific value (LHV, MJ/m^3)	5.9	2.2	7.4	7.4	6	6	12
Installations							
Location	North Powder, Or. USA	Kymijarvi, Finland	Frankfurt, Germany	Greve in Chianti, Italy	Hawaii, USA	Varnamo, Sweden	Vermont, USA
Size, MW_{th}	25	50	3	30	20	18	40
Installation Date	1985	1987		1992	1996	1992	1998
Gas Use	Boiler Fuel		Pilot Plant	Boiler Fuel	Flare	Gas Turbine	Boiler Fuel
Status	Discontinued	Operational	Testing	Operational	Test Completed	Operational	Startup

6.1.7 Co-Firing Of Biomass In Existing Boilers

Co-firing is the combustion of two or more fuels simultaneously in a single process. There is significant potential for cofiring of biomass in fossil boiler power plants already built world-wide. Biomass has been successfully co-fired with coal, natural gas, or oil, or with a combination of these three. Combusting biomass directly in a furnace designed for gas or oil may cause serious problems with fouling or ash removal, and each application must be evaluated for this purpose. Biomass has been successfully co-fired with coal in pulverised coal boilers, cyclone boilers, stoker fired boilers, bubbling fluidised bed boilers and circulating fluidised bed boilers.

It is important to note that co-firing results in the substitution of an existing energy source, not the addition of an energy source. In a coal fired boiler co-fired with biomass, the biomass is simply displacing the coal that would have been burned in the same boiler.

Biomass can be co-fired in existing boilers in a number of ways:

Coal Fired Boiler

The biomass can be mixed directly with the coal prior to entering the mills in a pulverised coal plant. Best results have been attained when the wood moisture content is less than 25%, and if the energy input from the wood is less than 5% of the total. A higher moisture content and heat input is possible with coal burned on a grate or in a cyclone burner. Heat input ratios of 10-15% are possible in a pulverised coal burner by reducing the biomass particle size to less than 6 mm, and firing it in separate burners.

The biomass component of the energy results in lower SO_2 emissions owing to the absence of sulphur in the biomass. In most cases, the NO_x emissions are also lower owing to the reduced nitrogen content in the fuel, and lower flame temperatures owing to the higher moisture content in the wood. The lower flame temperature results in lower "thermal NOx" (which results from oxidation of the atmospheric nitrogen with oxygen under high temperature conditions). There may also be reduced NOx due to a reburning effect, depending on furnace configuration.

There are several advantages to co-firing biomass with coal in an existing boiler:

- The modifications required to adapt a coal fired boiler to co-firing biomass are typically much less costly than building a new biomass facility;
- The plant staff and support facilities are already in place, significantly reducing the operating costs as well;
- Thermal generating facilities generally are more efficient on a larger scale. A larger plant can usually justify more stages of feedwater heating, and a larger turbine generator is more efficient due to the utilization of a reheat cycle and other thermodynamic improvements. Co-firing biomass in an existing coal plant therefore allows a higher conversion efficiency at a lower cost than a new biomass only plant;
- There can also be significant air emission reductions by co-firing wood with coal as explained in Section 6.6 below.

There are several potential disadvantages to cofiring biomass with coal:

- Furnace fouling can be a problem if cofiring high alkali agricultural residues is done in a furnace designed for coal with a high ash fusion temperatures. In general, the ash fusion temperature of coal ash is significantly lower than most biomass fuels, so this is not a problem[1].

- Another potential problem with cofiring biomass with coal, is the inability to market the resulting ash. Ash from coal fired boilers is often utilised as an additive to cement and concrete building materials. Wood ash has significantly different characteristics compared to coal ash, and the mixture may not be suitable for the intended service of the coal ash.

- Wood ash is often utilised as a soil amendment. A primary ingredient to wood ash is calcium oxide, and the ash is quite basic in pH. Many areas use wood ash to augment or as a substitute for limestone or lime to raise the pH of acidic soil to better meet the needs of the intended crop. Contaminating the wood ash with coal ash may eliminate the opportunity to utilise the ash as a soil amendment. The combined ash may still be used as an ingredient in road construction, fill material, or may have to be landfilled. The options available will depend on the ratio of biomass to coal, the type of coal and biomass fuels utilised, and the relevant regulations in the country where the plant is installed.

[1] Note that the ash fusion temperature is the temperature at which the ash starts to become molten. A properly designed coal furnace reduces the temperature of the combustion gases to below the ash fusion temperature for the particular coal fuel to be utilised, before the gases exit the furnace and encounter the first convection pass tubes (typically superheater tubes). If the ash is still in the molten state when it reaches these tubes, it will deposit on the cooler tubes, solidify, and cause a fouling problem. This deposit cannot be removed by ordinary sootblowing equipment and, in this event, the boiler must be shut down, and physically cleaned.

- Co-firing biomass in an existing coal boiler may jeopardize the reliability of the coal boiler. One of the lowest capital cost means to cofire wood, is to feed the wood directly into a coal mill in a pulverised coal boiler. If the wood contains contaminants or excessive moisture, this may reduce the reliability of the coal mill, resulting in lost production for the plant.

Biomass Boilers

Biomass boilers may burn alternate fuels simultaneously with the biomass. Existing grate boilers have added the capability to use natural gas and/or oil simultaneously with biomass, by adding fossil fuel burners. A given boiler will typically be most efficient on oil, somewhat less efficient on gas, and least efficient on wood.

The capability of a biomass boiler to utilise alternate fuels will depend on the design. An air-cooled travelling grate depends on combustion air for grate cooling, as well as a layer of ash to protect the grate from radiant heat. If the fossil fuel burners are close to the grate, it may be necessary to use higher levels of combustion air through the grate for cooling.

Gasification

Biomass may be gasified for co-firing in an existing boiler. The low or medium energy gas may then be burned directly in the furnace of a fossil fuel fired boiler. Kymijarvi Power Station, Lahti, Finland recently installed a 50 MW_{th} gasifier, fuelled with biomass and REF, for co-firing in a 350 MW_{th} coal fired boiler. Co-firing in this manner would allow a much higher percentage of heat input by biomass since the co-firing fuel is a gas. The heat input by the biomass would only be limited basically by the turndown capability of the alternate fuel. Gasification would also allow the use of biomass fuels with higher alkali content, without risk of furnace fouling.

Pyrolysis

Biomass may also be pyrolysed into a liquid fuel, and used in the fossil fuel burners in an existing boiler. Pyrolysis has the advantage that the energy can be more easily stored and transported in the form of oil than as biomass. Pyrolysis oils can also be burned in existing oil, gas or coal fired boilers with minimal modifications. Pyrolysis oils may have storage limitations, which require special design considerations or inventory control requirements. It may also be necessary to heat the oil to provide the proper viscosity for the liquid fuel burners.

The solid residue remaining after pyrolysis, comprising char and ash, could be used as a solid fuel or disposed of. If the pyrolysis plant is associated with a coal fired plant then the pyrolysis residue could be co-fired with the coal.

6.1.8 Chemical recovery boilers

While not strictly a technology for power generation using woody biomass fuel, chemical recovery boilers in the Pulp and Paper Industry collectively convert the largest quantity of forest biomass to energy worldwide. In Canada alone, chemical recovery boilers provide over

200 million GJ per year of energy compared to approximately 40 million GJ per year from direct combustion of biomass fuels.

The purpose of recovery boilers is primarily to recover chemicals from the pulping process to reduce makeup chemical requirements and reduce losses. An additional benefit is the supply of approximately 1/3 of all the energy requirements for the pulp and paper industry and as much as 60% of the requirements at an individual pulp mill. The majority of the chemical recovery boilers in operation today are associated with the "Kraft" pulping process. Recovery boilers are also used on "Sulphite" pulping processes, but to a lesser degree. Figure 6-16 below is a simplified process diagram of the Kraft recovery process.

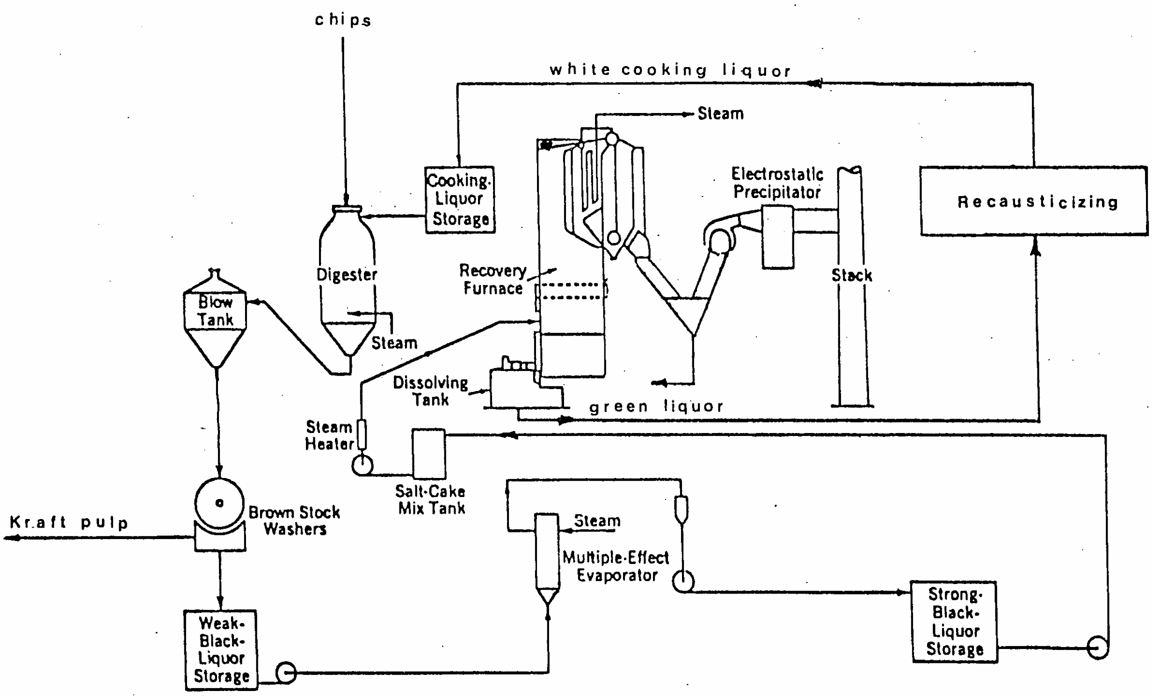

Figure 6-16. Kraft Recovery Process Diagram
Source: A Comparative Assessment of Forest Biomass Conversion to Energy Forms, Simons Resource Consultants and B H Levelton & Associates Ltd, (1983)

During the pulping process, the lignin in the wood is captured in the spent cooking liquid after the wood has been processed in the digester. The lignin contains approximately one half of the total energy in the wood on a dry basis. The spent cooking liquid is typically less than 20% solid content. After reducing the moisture content in the spent cooking liquids, the black liquor is then combusted in a recovery boiler. Na_2CO_3 and Na_2S are accumulated in a smelt bed at the bottom of the furnace. These chemicals leave the recovery boiler as "green liquor", and are introduced back into the pulping process.

Figure 6-17 below illustrates a modern Babcock and Wilcox Recovery Boiler.

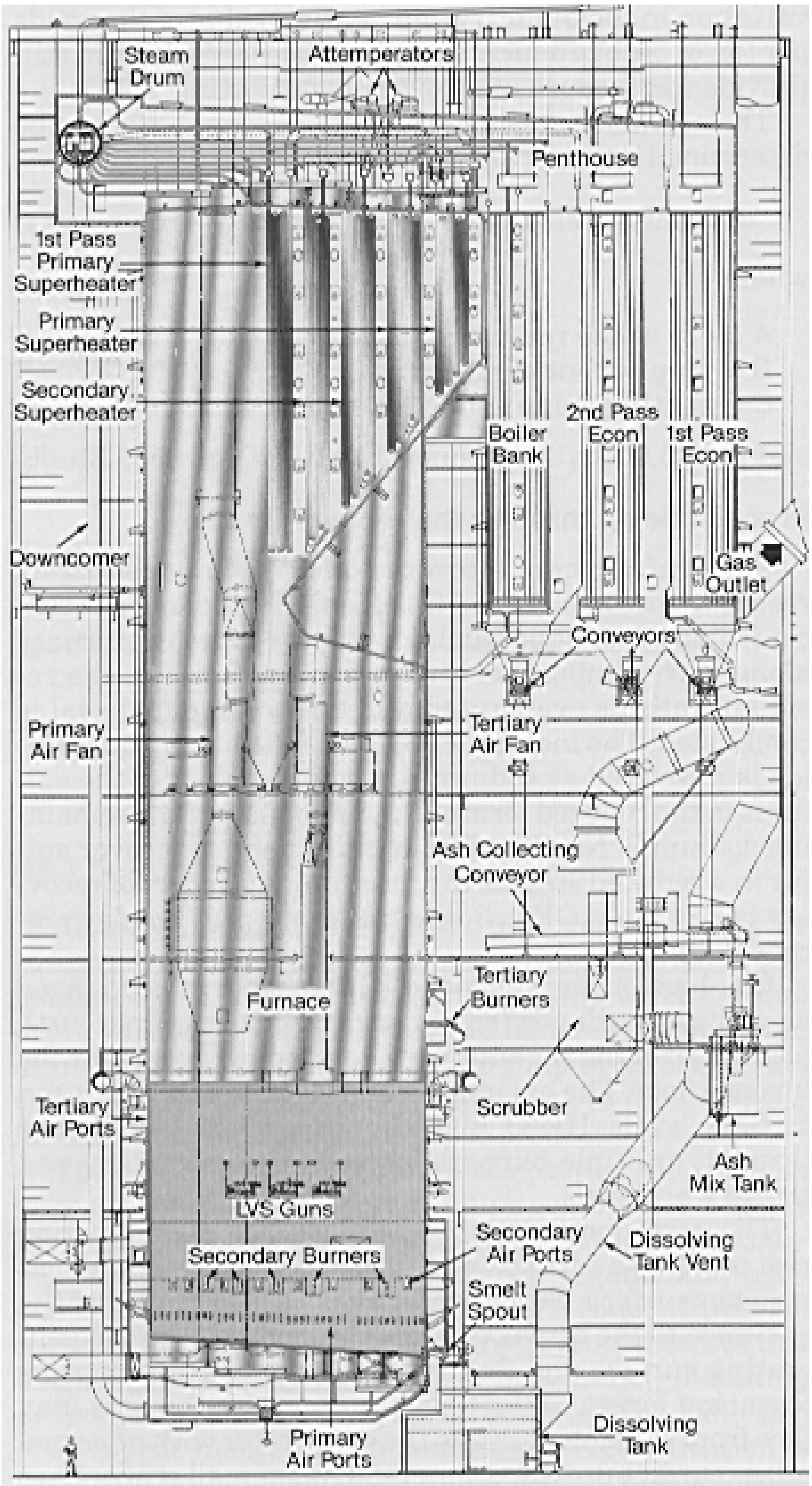

Figure 6-17. Babcock and Wilcox Kraft Recovery Boiler
Source: Steam, Its Generation and Use, 40th Edition, Babcock & Wilcox, (1992)

The installation of recovery boilers is primarily driven by the existence of a pulp and paper mill, and the desire to reduce the operating costs of makeup chemicals. Increasing the efficiency of recovery boilers will allow better utilisation of biomass resources. A typical recovery boiler operates at an efficiency of 70% on a HHV basis when utilising black liquor at 70% solids concentration. This corresponds to 83% efficiency LHV basis.

Gasification technology may have great potential in the black liquor boiler industry. In many cases, the capacity of a pulp mill is limited by the capacity of the existing recovery boiler(s). Installing incremental capacity of recovery boiler(s) is quite expensive. Gasifiers have been utilised to provide this incremental recovery capacity at significantly lower installed cost. Chemical recovery gasifiers may also replace existing recovery boiler capacity if the operating efficiency proves to be significantly higher than the boilers.

Chemical recovery gasifiers are relatively new and there is not sufficient operational data to determine the reliability and viability of this concept. It does not appear that this technology is a significant means of increasing the utilisation of biomass as most pulp mills already have recovery boilers in operation.

6.2 TECHNOLOGY SELECTION

6.2.1 Introduction

Forestry and wood industry by-products can be burned directly in conventional Rankine cycle plant, to generate steam for use in steam turbines. New technologies are also being developed which involve gasification of these by-products to produce low to medium calorific value fuel gas. The cleaned product gas may be used in a higher efficiency gas turbine combined cycle power plant, reciprocating engines, or direct fired in boiler plant. When fully developed and proven, these technologies may become more competitive and attractive than Rankine cycle plant, which is the preferred technology at present.

In some circumstances, it may be advantageous to locate a boiler or gasifier, which uses forestry and wood industry by-products, on the same site as a power station using fossil fuels. The biomass plant would supply steam or fuel respectively to the fossil fuelled plant. This 'parallel powering' approach can give:

- Economies of scale in the steam turbine and ancillaries;
- Improved efficiency as the larger turbines and ancillaries tend to be more efficient.

An alternative approach is to feed the by-product biomass into the same boiler or gasifier as fossil fuels. This can give greater economies of scale and can help smooth out any variability in the quantity and quality of the by-products. However, such a plant may not be optimal for either the biomass or the fossil fuel.

In order to assess the comparative merits of the various technologies, both developed and still developing, this study sought to estimate the cost and performance of large scale power generation using the following schemes:

- A stand-alone boiler using forestry and wood industry by-products;
- A plant co-firing forestry and wood industry by-products <u>and</u> coal or natural gas in the same boiler;

- Parallel powering options, comprising:

  - A pulverised coal boiler generating high pressure and temperature steam, and a parallel boiler using forestry and wood industry by-products and generating lower quality steam for use in the same steam cycle;

  - A natural gas combined cycle plant, and a parallel boiler using forestry and wood industry by-products and generating steam for use in the same steam cycle;

- One of the above schemes, using gasification of the by-products instead of conventional combustion.

In addition, a sixth scheme was included to provide a reference case for comparative purposes. This scheme was a:

- Conventional pulverised coal fired Rankine cycle boiler with a steam turbine.

This section of the report considers the selection of the configuration and capacity options for the above schemes for subsequent analysis, and presents the rationale for making these selections.

6.2.2 Stand Alone Boiler Systems

The Technology Review presented in Section 6.1 noted that suspension firing was not being considered for this study due to the high degree of fuel preparation required to produce fine particle sized fuel necessary. Of the remaining fixed bed and fluid bed combustion technologies, fixed bed or grate systems are well developed and common place. Fluid bed technologies, while not so well developed as grate systems, are increasingly becoming the preferred technology in some countries.

Two stand-alone boiler technology options were selected for analysis as follows.

Conventional Grate Boiler Technology

The grate technology option assumed a conventional grate fired boiler plant of 30 MW_e net size. This technology was selected as it has been used for over 50 years for biomass fuels, and is still the predominant technology used, particularly in the USA.

The design conditions assumed were single pressure, superheated, non-reheat Rankine cycle with boiler final steam conditions of 87 bar (8720 kPa) and 510^oC. It was considered unusual for a 30 MW_e biomass unit to have a reheat cycle, primarily owing to the high cost of steam turbines with reheat in this size range. It is not generally economically justified to incur the higher capital cost associated with a non-standard steam turbine for the marginally increased cycle efficiency.

The capital cost estimates for this option included the following:

- utilising either a travelling grate water-cooled vibrating grate, or a stationary grate boiler;
- installing a multi-celled cooling tower;
- utilising well water for makeup water requirements;
- gas cleanup equipment suitable for meeting the emission limits (Emissions are considered in more detail in Section 6.6).
- an allowance for land;
- switchyard at the site for a local transmission connection;
- environmental permitting.

Fluidised Bed Boiler Technology

The fluidized bed technology option was based on a bubbling bed boiler plant of 30 MW_e net size. This technology was selected because it represented a viable option for utilising biomass fuels based on many successful installations.

The design conditions assumed were single pressure, superheated, non-reheat Rankine cycle with boiler final steam of nominally 87 bar (8720 kPa) and 510°C.

The capital cost estimates for this option allowed for the following:

- utilizing either a bubbling or circulating fluidized bed boiler;
- installing a multi-celled cooling tower;
- utilizing well water for makeup water requirements;
- gas cleanup equipment suitable for meeting the emission limits;
- an allowance for land;
- switchyard at the site for a local transmission connection;
- environmental permitting.

6.2.3 Gasification Technology

The gasification option assumed the use of the biomass integrated gasification combined cycle (BIGCC) technology. This essentially permits the forestry and wood industry by-products to be burned in a modern, high efficiency gas turbine combined cycle plant. This achieves the maximum energy conversion efficiency.

This option therefore assumed a state of the art biomass gasifier with a gas turbine and combined cycle plant of 30 MW_e net size. This may consist of a directly heated atmospheric pressure gasifier, a directly heated pressurized gasifier or an indirectly heated gasifier.

This technology is currently being developed and no plants of this type are operating commercially at present. As a result, it is very difficult to determine the capital cost or reliability of the various gasification technologies. In all probability, it is considered that the atmospheric gasifier designs will be less costly to build, but more costly to operate than the pressurised designs. A study recently completed by the US National Renewable Energy Laboratory concluded that the indirectly heated gasifier coupled with an advanced utility gas turbine would have a lower installed cost than either a pressurised gasifier with an aero-derivative gas turbine, or a pressurised gasifier with an advanced utility gas turbine, or an atmospheric gasifier with an advanced utility gas turbine. Cost estimates used in this study would allow for any of these technologies.

The performance assumptions for gasification technologies in this study are similarly very conservative. All current gasification technologies discussed would have overall efficiencies greater than or equal to the assumed performance.

The capital cost estimated for this option included the following:

- fuel handling and storage facilities;
- biomass dryer;
- utilizing either a directly heated atmospheric pressure gasifier, a directly heated pressurized gasifier or an indirectly heated gasifier;
- installing a multi-celled cooling tower;
- utilizing well water for makeup water requirements;
- gas cleanup equipment suitable for meeting the emission limits;
- an allowance for land;
- switchyard at the site for a local transmission connection;
- environmental permitting.

6.2.4 Co-Firing Technology

In a biomass co-firing installation, the biomass is combusted directly in the furnace of an existing pulverised coal boiler. Operating examples to date have shown that this can be done successfully where biomass provides 5 - 15% of the total heat input.

Existing biomass co-firing installations have followed basically three approaches:

- The biomass fuel is sized to particles less than 25 mm. The biomass is fed directly with the coal to the existing coal mills. The existing mills thus receive a mixture of the two fuels, there is no separation downstream of the mills, and the resulting pulverised fuel mixture is fed to the existing burners. This generally precludes the use of low quality bark (large particle size, high dirt or stone content, and possibly high moisture content), and limits the proportion of heat input by biomass to less than 10%. This limitation reflects the capacity of the existing coal pulverising plant to handle non-friable, fibrous material.
- An existing coal bunker, feeder, mill and associated burner group is dedicated solely for biomass firing. This approach requires a dryer source of biomass, such as planer shavings, sander dusts and dry timber processing sawdust, and may require modifications to the existing mill. This approach may allow for the proportion of heat input by the biomass to exceed 10%.

- The biomass fuel is ground to a much smaller particle size, less than 1.5 mm. The biomass is prepared and combusted separately using dedicated plant retrofitted to the existing pulverised coal furnace. This requires additional investment in, and the greater auxillary power consumption by, biomass fuel preparation equipment, including drying facilities, but overcomes the limitations imposed by the existing coal pulverising plant.

The co-firing option in this study therefore assumed that a 300 MW_e pulverized coal fired boiler is co-fired with forestry and wood industry wood products. Assuming a 10% biomass component, 30 MW_e net of coal fired power would be replaced by 30 MW_e of biomass power. The design conditions assumed for the existing coal fired boiler were superheated, single reheat Rankine cycle with final steam conditions of 165 bar and 540°C.

For this option it is also necessary to provide separate unloading, storage, screening and processing facilities for coal fired plants co-firing forestry and wood industry by-products.

The capital cost estimated for this option conservatively allowed for the most expensive fine grinding approach. The cost estimate also allowed for:

- installing separate biomass unloading, storage, screening and processing facilities;
- gas cleanup equipment modification or retrofit suitable for meeting the emission limits;
- environmental permitting.

6.2.5 Parallel Powering

Parallel powering comprises a steam turbine which is supplied with steam from two separate and independent sources. The primary source is usually a conventional fossil fuelled boiler but could be the heat recovery steam generator (HRSG) of a combined cycle plant. The secondary source is usually the HRSG of a gas turbine but, with respect to this study, could also be a forestry and wood industry by-products fired boiler. Parallel powering thus links a secondary steam source with a conventional steam cycle through a common steam turbine. To avoid operational difficulties, the secondary steam source should be designed for the same steam conditions to the steam turbine as the primary source, particularly if there is a reheat cycle.

The advantages of parallel powering with respect to this study were:

- versatility of design. The design of both steam raising systems can be fuel specific and avoid the necessary design compromises that must be made for dual fuel firing capability of a single boiler;
- versatility of fuelling. Both natural gas or coal, and forestry and wood industry by-products can be burned at the same site;
- versatility of operation. The ratio of gas or coal to forestry and wood industry by-products can be freely varied. The loss of one fuel or steam raising system does not result in a complete loss of generation capability;
- economies of scale in the steam turbine and auxiliaries;

- improved efficiency due to the use of larger turbines and auxiliaries.

The disadvantages of parallel powering with respect to this study were:

- two completely separate fuel reception, handling, storage and preparation plants would be required to service each steam raising system;
- two steam raising systems with associated auxiliaries would be required instead of one;
- two completely separate exhaust gas cleaning systems may be needed.

In addition to parallel powering, which comprises the use of new plant, the study also considered parallel repowering which is based on using existing plant.

Parallel repowering is a subset of parallel powering and comprises a new source of steam to supplement the steam supply from an existing steam raising system to an existing steam turbine. The existing steam raising system is usually a conventional coal fired boiler but could also be the heat recovery steam generator (HRSG) of a combined cycle plant. The new source is usually the HRSG of a gas turbine but, with respect to this study, could also be a forestry and wood industry by-products fired boiler. Parallel repowering thus links a new steam source with an existing conventional steam cycle through an existing common steam turbine. The existing boiler or HRSG continues to be used, possibly in modified form and at reduced thermal power.

Parallel repowering requires space for the forestry and wood industry by-products fuel reception, handling, storage and preparation plant, and the new boiler. Parallel repowering is particularly attractive where the primary fuel cost is significantly higher than forestry and wood industry by-products and where the existing steam turbine already has the swallowing capacity to accept a significant amount of additional steam. The latter is not unusual; the 250 MW units at Huntly Power Station in New Zealand have a continuous overload rating of 275 MW. Where this is not the case, the existing steam raising system should be operated at reduced thermal load. As for parallel powering, the secondary steam source for parallel repowering must be designed for the same steam conditions to the steam turbine as the existing primary source, particularly if the existing cycle is a reheat cycle.

The advantages of parallel repowering with respect to this study were:

- versatility of fuel supply; both natural gas or coal, and forestry and wood industry by-products can be burned at the same site;
- versatility of operation; the ratio of gas or coal to forestry and wood industry by-products can be freely varied. The loss of one fuel or steam raising system does not result in a complete loss of generation capability;
- a new steam turbine, condenser, and cooling water system is not required. The existing steam turbine can be utilised;
- the life of an existing boiler may be extended. Steam boilers generally have a shorter operating lifetime than the steam turbines they supply. In many cases their useful life can be extended by operation at lower superheater outlet conditions, thereby reducing the duty on the high pressure, high temperature components;

- the generation capacity of an existing plant may be restored. The steam generating capacity of a boiler can sometimes be reduced as a result of a previous fuel conversion (e.g. from oil to coal). In such cases, the reduction in the existing boiler's thermal output can be offset by parallel repowering.

- The disadvantages of parallel repowering with respect to this study were:

- a new completely separate fuel reception, handling, storage and preparation plant would be required to service the new forestry and wood industry by-products boiler;
- steam raising system auxiliaries would be duplicated;
- two completely separate exhaust gas cleaning systems would be required;
- if the existing steam turbine does not have significant additional swallowing capacity and the existing steam raising plant thermal output is reduced, the efficiency of the existing steam raising system will be reduced. This will be more pronounced for an existing gas turbine combined cycle plant than for an existing coal fired boiler plant.

While parallel repowering is generically a practical option, it is, like co-firing, a very site specific option. Assessment of such options in other than very generic terms would require country specific, individual plant technical analysis. There are also issues of existing plant residual life, condition and capital value.

This study has therefore considered both parallel powering and repowering with respect to performance, cost, electricity price and emissions estimates. However, only the parallel repowering options were carried through to the subsequent integrated analysis and were assessed in terms of different plant scales (10 and 60 MW).

Parallel Powering

Two parallel powering options were selected for analysis as follows.

Biomass Grate Boiler In Parallel With Coal Fired Boiler

This option assumed a nominal 150 MW_e net output, twin boiler and single steam turbine plant. Although the standard size plant for IEA GHG assessment is usually 500 MW, the impact of adding only 30 MW of parallel power to a 500 MW plant would be considered insignificant. A 150 MW plant was therefore selected with the coal boiler sized to produce about 120 MW_e of electricity and the forestry and wood industry by-products boiler the remaining 30 MW_e. This size of forestry and wood industry by-products boiler is consistent with the Stand-alone options.

Both boilers produce steam at the same pressure and temperature of nominally 87 bar and 540°C. A non-reheat cycle has been assumed. The boilers share a common deaerator and common boiler feedwater pumps.

The capital cost estimated for this option included the following:

- installing separate coal and biomass unloading, storage, screening and processing facilities;
- utilising either a travelling grate, water-cooled vibrating grate, or a stationary grate type of boiler;
- installing a multi-celled cooling tower;
- utilizing well water for makeup water requirements;
- gas cleanup equipment suitable for meeting the emission limits;
- an allowance for land;
- switchyard at the site for a local transmission connection;
- environmental permitting.

Biomass Grate Boiler In Parallel With Combined Cycle Plant

This option is based on the standard GE106FA gas turbine combined cycle (a nominal 110 MW_e). A parallel forestry and wood industry by-products boiler was added to the cycle producing about 30 MW_e of extra power from the steam turbine, giving a total net capacity of 140 MW_e. This size of forestry and wood industry by-products boiler was consistent with the Stand-alone options.

The boiler steam conditions are lower, at 20 bar and 495°C, than the stand-alone conventional grate or fluidised bed boiler options. This is because the plant is configured with the boiler steam joining the hot reheat steam from the HRSG and going to the inlet to the IP cylinder of the steam turbine. The non-reheat configuration for the biomass boiler was consistent with the stand-alone option and was also generally consistent with industry practice for that boiler size. Given a non-reheat boiler, the secondary steam source is constrained by IP cylinder conditions. The gas turbine HRSG and the boiler share a common deaerator and common boiler feedwater pumps.

The capital cost estimated for this option included the following:

- installing biomass unloading, storage, screening and processing facilities;
- utilising either a travelling grate, water-cooled vibrating grate, or a stationary grate type of boiler;
- installing a multi-celled cooling tower;
- utilizing well water for makeup water requirements;
- gas cleanup equipment suitable for meeting the emission limits;
- an allowance for land;
- switchyard at the site for a local transmission connection;
- environmental permitting.

Parallel Repowering

Two parallel repowering options were selected for analysis as follows.

<u>Biomass Grate boiler in Parallel with Existing Coal Fired Boiler</u>

The study assumed that the existing coal fired boiler was a pulverised coal (PC) fired boiler with subcritical steam conditions. This was, and still is, the most common technology over all the five countries under consideration. With respect to unit size, in the last decade PC boilers have been built to match steam turbines with outputs between 50 and 1,300 MW_e, however most are rated at between 300 and 700 MW_e. It was considered for this study that parallel repowering would likely be more attractive for the smaller, and possibly older, units in the 50 to 300 MW_e size range. The study therefore assumed a 150 MW_e unit size, consistent with the equivalent parallel powering option.

Steam conditions for the existing 150 MW_e subcritical PC boiler were assumed to be 125 bar and 510°C and it was considered likely that the boiler would have a single stage of reheat.

The requirements for matched steam conditions for successful parallel repowering can be accomplished in either of two ways:

- Assuming the relatively small (30 MW_e) biomass would have single reheat. This would be a departure from the assumptions made for the Stand-alone options which were for a non-reheat cycle; and
- Assuming substantial practicable modifications could be made to the existing coal fired boiler to enable it to reheat more steam than it generates. This assumes that the biomass boiler has no reheat and generates superheated steam which is mixed with the coal fired boiler main steam and passed to the HP cylinder of the existing steam turbine. It is also assumed that the existing reheat steam turbine was originally well matched with the existing boiler and has little additional swallowing capacity. The existing coal fired boiler would therefore be required to reheat more steam than it generated. This would likely require a reduction in radiant furnace tube surface area, a reduction in superheater tube surface area, and an increase in reheater tube surface area; a substantial rebalancing of mass and energy flows through the boiler.

The study assumed that both boilers would have final steam conditions of 125 bar and 510°C and with reheat to 510°C. The biomass boiler would therefore have reheat. While it is quite unusual for a 30 MWe biomass unit to have a reheat cycle (see Section 6.2.2), in a parallel repowering option with an existing turbine generator, reheat is not only feasible but quite likely. The cost estimated assumed that no changes were required to the existing boiler heating surface.

The heat input to the existing coal fired boiler would be reduced after the biomass boiler repowering addition, to allow 120 MW_e of net power output attributable to the coal. The biomass boiler would provide 30 MW_e of net power from the unit. Both boilers would share common feedwater heaters, boiler feed pumps, condenser, and the existing reheat steam turbine.

The capital cost estimated for this option included the following:

- installation of a separate biomass unloading, storage, screening and processing facilities independent of the existing coal handling facilities;
- installation of a 30 MW_e, 125 bar/510°C/510°C reheat biomass boiler of either a travelling grate, water cooled vibrating grate, or stationary grate design;
- installation of a multi-celled mechanical draft cooling tower;
- flue gas cleanup equipment suitable for meeting typical emission standards for biomass boilers;
- environmental permitting costs.

No costs were allocated for transmission, land, control room, office facilities, or support facilities such as maintenance shops, as those were assumed to be at the existing site.

Biomass Grate Boiler In Parallel With Existing Combined Cycle Plant

This option assumed modification to an existing combined cycle gas turbine (CCGT) plant by adding a biomass fuelled boiler in parallel to augment the steam from the existing heat recovery steam generator.

A CCGT power plant is typically a closely balanced system. The fuel is burned in a gas turbine, which powers a generator. The exhaust gases from the gas turbine are directed to a heat recover steam generator (HRSG), which produces steam for a steam turbine generator. This option comprises adding a biomass fired boiler, which displaces steam from the HRSG.

With respect to the biomass boiler, to be consistent with the Stand-alone options and the other parallel powering and repowering options, the study assumed a 30 MW_e biomass boiler.

With respect to the CCGT plant, it was not practicable to be consistent with the equivalent parallel powering option which was based on a standard GE106FA GTCC plant (a nominal 110 MW). The steam turbine capacity of a typical CCGT is approximately 1/3 of the total plant output, with the gas turbine providing the remaining 2/3. A reduction in HRSG steam output can only be accomplished by reducing the heat from the gas turbine, which means reducing the power generation from the gas turbine.

As gas turbine efficiency is reduced at lower loads, more heat is exhausted per MW produced than at rated load. The equivalent gas turbine reduction per biomass MW_e is therefore greater and the efficiency of the gas fired component of energy from the plant is compromised in this arrangement. Parallel repowering therefore requires the existing plant to significantly reduce load to accommodate the new plant biomass capacity.

For a 110 MW_e CCGT the reduction in gas turbine output, and corresponding loss of efficiency, to accommodate the biomass boiler was considered excessive. This suggests that a larger gas turbine combined cycle host is therefore required for parallel repowering with a 30 MW_e biomass boiler. Potential candidates of around 300 to 500 MW_e were sought and the GE model S109FA gas turbine combined cycle, producing nominally 376 MW_e (net, at ISO conditions) was selected. While the standard GE configuration uses a three-pressure HRSG with reheat, this plant was assumed to be configured as a two-pressure (HP & LP), reheat steam cycle with steam conditions of 100 bar and 540°C/540°C (HP/Reheat) and 5.5 bar/305°C (LP). This results in a slight reduction in output and efficiency.

As noted for the coal fired boiler repowering option, the need for matched steam conditions for successful parallel repowering requires the parallel biomass boiler to have the same steam conditions and reheat configuration as the combined cycle HRSG, 100 bar and 540°C/540°C. However, a single pressure boiler was assumed as dual pressure with reheat was considered impracticable for a 30 MW_e biomass boiler.

The impact of adding a 30 MW_e forestry and wood industry by-products boiler to the existing combined cycle was to reduce the gas turbine output so that, in turn, the HRSG output was reduced to accommodate the steam addition from the biomass boiler. The reduction in HRSG output results in a reduction in steam turbine output owing to the reduced contribution from the second, LP pressure circuit of the HRSG. The gas turbine HRSG and the boiler share a common deaerator and common boiler feedwater pumps.

The capital cost estimated for this option included the following:

- installation of a separate biomass unloading, storage, screening and processing facilities independent of the existing coal handling facilities;
- installation of a 30 MW_e, 100 bar/540°C/540°C reheat biomass boiler of either a travelling grate, water cooled vibrating grate, or stationary grate design;
- installation of a multi-celled mechanical draft cooling tower;
- flue gas cleanup equipment suitable for meeting typical emission standards for biomass boilers;
- environmental permitting costs.

No costs were allocated for transmission, land, control room, office facilities, or support facilities such as maintenance shops, as those were assumed to be at the existing site.

6.2.6 Conventional Pulverised Coal Fired Boiler

The conventional pulverised coal fired boiler technology proposed to provide a reference, or base case, against which to compare the biomass technologies was a supercritical boiler, operating at a pressure of 240 – 250 bar, where the maximum practical thermal efficiency achievable in new plant is limited to 45%. A plant size of 500 MW was selected comprising either a single 500 MW unit or two 250 MW units. This technology and plant set was selected to be consistent with previous IEA GHG studies.

Summary

The following options are therefore carried forward for performance, cost and emissions analysis. The names in brackets are the short titles used for financial analysis.

1. Conventional grate fired boiler with steam turbine ("Grate Boiler");
2. Fluidized bed boiler with steam turbine ("Fluid Bed");
3. Biomass gasification with gas turbine combined cycle ("Gasification");
4. Cofiring biomass in an existing pulverised coal fired boiler ("Coal Cofire");
5. Parallel powering comprising a new biomass grate boiler to operate in parallel with a new coal fired boiler ("New Coal");
6. Parallel powering comprising a new biomass grate boiler to operate in parallel with a new HRSG in a gas fired gas turbine combined cycle plant ("New HRSG");
7. Parallel repowering comprising a new biomass grate boiler to operate in parallel with an existing coal fired boiler ("Exist Coal");
8. Parallel repowering comprising a new biomass grate boiler to operate in parallel with an existing HRSG in a gas fired gas turbine combined cycle plant ("Exist HRSG");
9. A conventional pulverised coal fired boiler and steam turbine ('500 Mw SUP').

6.3 PERFORMANCE

6.3.1 Introduction

The performance of power generation technologies is dependent upon a number of factors. The key factors are as follows:

- Fuel type, which in turn determines the choice of thermodynamic conversion cycle. The high efficiency gas turbine combined cycle (i.e. Brayton and Rankine cycles combined) requires a clean burning gas or liquid fuel. Solid fuels and contaminated liquids and gases are restricted to Rankine cycle plant.
- The thermodynamic conversion cycle temperature limits. The upper temperature limit is set by metallurgical and cost limitations relating to the handling of fluids at high temperatures. The lower limit is the heat rejection temperature which is set by the environment and the availability of a suitable heat sink;
- The thermodynamic conversion cycle configuration. This includes the choice of steam pressure and the degree of superheat, the use of reheat, the use of economisers, the use of recuperative air heating, the use of intercooling (Brayton gas turbine cycle only), and the use of regenerative feedwater heating;
- Fuel moisture. Unless a condensing economiser is employed, the energy required to evaporate fuel moisture is lost to the gas exhaust;

- Exhaust gas exit temperature. The energy required to raise the temperature of the inert nitrogen in the combustion air from ambient to the gas exit temperature is also lost to the gas exhaust;
- Excess air ratio. Excess air is required to ensure complete combustion but the requirement can be reduced by ensuring efficient combustion.

With all attempts to secure the highest energy conversion efficiency there is a trade-off between the costs involved (both capital and operating), the technical risk (e.g. of using exotic materials) and the amount of additional energy recovered.

This section describes the assumed performance from the eight biomass power generation technology options and the conventional pulverised coal fired reference case.

6.3.2 Conventional Grate Boiler Technology

The net plant efficiency of the 30 MW_e (net) conventional grate boiler option was assumed to be 27.7% (LHV). This corresponds to 23% efficiency (HHV) assuming 50% moisture fuel and hydrogen content in the fuel of 2.75% on a wet basis.

A sensitivity analysis showed that a 10 MW_e net plant would operate at 24.2% efficiency (LHV), and a 60 MW_e plant would operate at 30.2% efficiency (LHV).

Plant operation was based on 7,500 hours per year at rated output, or a capacity factor of 85%. This is a reasonable figure for this technology based on existing plant performance.

6.3.3 Fluidized Bed Boiler Technology

The net plant efficiency of the 30 MW_e (net) fluidised bed boiler option was assumed to be 28.9% (LHV). This corresponds to 24% efficiency (HHV) assuming 50% moisture fuel and a hydrogen content in the fuel of 2.75% on a wet basis.

A sensitivity analysis showed that a 10 MW_e net plant would operate at 25.4 % efficiency (LHV), and a 60 MW_e plant would operate at 31.4 % efficiency (LHV).

Plant operation was based on 7,500 hours per year at rated output, or a capacity factor of 85%. This is a reasonable figure for this technology based on existing plant performance.

6.3.4 Biomass Integrated Gasification Technology

The net plant efficiency for the 30 MW_e (net) integrated gasification option was assumed to be 36.8 % (LHV). This corresponds to 30.5% efficiency (HHV) assuming 50% moisture fuel and hydrogen content in the fuel of 2.75% on a wet basis.

The sensitivity analysis showed that a 10 MW_e net plant would operate at 36.2 % efficiency (LHV), and a 60 MW_e plant would operate at 38 % efficiency (LHV).

Plant operation was based on 7,500 hours per year at rated output, or a capacity factor of 85%. This has not been demonstrated as achievable with this technology to date as it is still in the development stage. It is assumed that it will be possible in the future when the technology matures.

6.3.5 Co-Firing Biomass with Pulverised Coal

The net efficiency of a pulverised coal plant co-firing biomass will vary significantly depending on the type of plant being considered. A typical 300 MW_e coal fired plant would have an efficiency of approximately 38% (LHV).

The actual efficiency is not critical in this particular case. Operating installations of pulverised coal co-firing wood indicate that the boiler efficiency from the biomass fuel is essentially the same as the coal component, particularly on a lower heating value basis. This means that the biomass energy is a direct substitution for the coal on a $/GJ basis. This simplifies the analysis of comparing the biomass energy with the 500 MW_e coal fired plant.

Quantifying the number of pulverised coal plants that are converted to biomass co-firing is dependent on the number of plants in each country considered, or those having transmission access to those countries.

6.3.6 Biomass Grate Boiler in Parallel with Coal Fired Boiler

New coal fired boiler

The net plant efficiency of the conventional biomass grate boiler in parallel with a conventional pulverised coal fired boiler was calculated to be 36.9% (LHV), based on a net power output of 150 MW_e.

The net plant efficiency of the 28.6 MW_e biomass grate boiler contribution was calculated to be 31.0% (LHV) based on a net power output of 28.6 MW. This assumed a biomass boiler efficiency of 88% (LHV). This corresponds to 25.7% efficiency (HHV) assuming 50% moisture fuel and hydrogen content in the fuel of 2.75% on a wet basis. The net plant efficiency of the 121.5 MW_e conventional pulverised coal fired boiler contribution was calculated to be 38.6% (LHV) based on a net power output of 121.5 MW_e. This assumed a coal boiler efficiency of 95% (LHV).

The net plant efficiency of the biomass grate boiler contribution, at 31% (LHV), is higher than the stand-alone Conventional Grate Boiler Technology (27.7%) or Fluidised Bed Boiler Technology (28.9 %) owing to the higher efficiency of the larger steam turbine. This is despite the assumption that although both boilers produce steam at the same pressure and temperature of 88 bar and 538°C, and share a common deaerator and common boiler feedwater pumps, the feedwater for the biomass boiler comes directly from the feedwater pumps at 122°C. The coal fired boiler was modelled with two HP feedwater heating stages, using steam extractions from the steam turbine, giving a feedwater temperature of 210°C.

No sensitivity analysis was carried out to test the effect of smaller or larger plant sizes on efficiency.

Plant operation was based on 7,500 hours per year at rated output, or a capacity factor of 85%. This is a reasonable figure for this technology based on existing plant performance. Conventional coal fired plant is capable of achieving higher capacity factors.

Existing coal fired boiler

The overall net plant efficiency of a conventional biomass grate boiler in parallel with an existing conventional pulverised coal fired boiler was calculated to be 33.5 % (LHV).

It was assumed the plant originally had a net output of 150 MW_e, and a station auxiliary requirement when operating at full load on coal of 7%. The smaller biomass boiler was expected to have a slightly higher station auxiliary requirement of 10%. Assuming that the plant was operating at the maximum gross generator output, the parallel repowered operation would result in a slightly lower net output, 148.4 MW_e (net) compared to the 150 MW_e (net) of the original coal fired plant.

The net plant efficiency of the 27 MW_e (net) biomass grate boiler contribution was calculated to be 30.9% (LHV). This assumed a biomass boiler efficiency of 88% (LHV). This corresponds to an efficiency of 25.7% (HHV). This assumes 50% moisture content wood fuel, and a hydrogen content of 2.75%.The net plant efficiency of the 121.4 MW_e (net) coal fired contribution was calculated to be 34.1% (LHV), which is essentially the same efficiency as the coal fired plant prior to modification. This assumed a coal boiler efficiency of 95% (LHV).

The net plant efficiency of the biomass grate boiler contribution, at 30.9% (LHV), is higher than the stand-alone Conventional Grate Boiler Technology (27.7%) or Fluidised Bed Boiler Technology (28.9%) owing to the higher efficiency of the larger steam turbine and the use of reheat. Both boilers produce steam at the same pressure and temperature of 125 bar and 510°C, with reheat to 510°C, and share a common deaerator and common boiler feedwater pumps. Both boilers also benefit from feedwater heating, using steam extractions from the steam turbine. Additional operating and maintenance personnel would be required to operate the biomass equipment.

No sensitivity analysis was carried out to test the effect of smaller or larger plant sizes on efficiency.

Plant operation was based on 7,500 hours per year at rated output, or a capacity factor of 85%. This is a reasonable figure for this technology based on existing plant performance. Conventional coal fired plant is capable of achieving higher capacity factors.

6.3.7 Biomass Grate Boiler in Parallel with Combined Cycle Plant

New combined cycle plant

The overall net plant efficiency of the conventional biomass grate boiler in parallel with a combined cycle plant option was calculated to be 43.3% (LHV), and based on a net power output of 140 MW_e.

The net plant efficiency of the 33.5 MW_e biomass grate boiler contribution was calculated to be 28.6% (LHV) based on a net power output of 33.5 MW_e. This assumed a biomass boiler efficiency of 88% (LHV). This corresponds to 23.7% efficiency (HHV) assuming 50% moisture fuel and hydrogen content in the fuel of 2.75% on a wet basis. The net plant efficiency of the 106.5 MW_e gas turbine combined cycle plant contribution was calculated to be 51.7% (LHV) based on a net power output of 106.5 MW_e.

The net plant efficiency of the biomass grate boiler contribution, at 28.6% (LHV), is higher than the stand-alone Conventional Grate Boiler Technology (27.8%) owing to the higher efficiency of the larger steam turbine. This is despite the lower boiler steam conditions assumed (20 bar, 494°C compared to 87 bar, 510°C). The efficiency of the biomass grate boiler contribution is lower than the Fluidised Bed Boiler Technology (29%) owing to the lower steam conditions selected.

No sensitivity analysis was carried out to test the effect of smaller or larger plant sizes on efficiency.

Plant operation was based on 7,500 hours per year at rated output, or a capacity factor of 85%. This is a reasonable figure for this technology based on existing plant performance. Gas turbine combined cycle plant is capable of achieving higher capacity factors.

Existing combined cycle

The existing GE model S109FA gas fired combined cycle power plant was assumed to have operated at an efficiency of 55% (LHV), while producing a net power output of 372 MW_e. After the repowering addition of a 30 MW_e reheat biomass boiler, providing steam to displace or augment HRSG steam production, the overall plant efficiency was calculated to be 45% (LHV). With the limiting factor being the swalloing capacity of the existing steam turbine, the gas turbine is operated at part load to reduce HRSG steam production in favour of steam production by the biomass boiler. The net plant output after the repowering modifications was calculated to be 278 MW_e, or 75% of the original plant output.

The net plant efficiency of the 27 MW_e net biomass plant portion of the output was calculated to be 33.3% (LHV). This is based on a biomass boiler efficiency of 88%. This corresponds to an efficiency of 27.6% (HHV), assuming a 73% (HHV) boiler efficiency, 50% moisture fuel and 2.75% hydrogen content in the fuel. The net plant efficiency of the 251 MW_e (net) gas fired portion of the plant output was calculated to be 48.1% (LHV).

The net plant efficiency of the biomass grate boiler contribution, at 33.3% (LHV), is higher than the stand-alone Conventional Grate Boiler Technology (27.7%) or Fluidised Bed Boiler Technology (28.9%) owing to the higher efficiency of the larger steam turbine and the use of reheat. Both the HRSG and biomass boiler produce steam at the same pressure and temperature of 100 bar and 540°C, with reheat to 540°C, and share a common deaerator and common boiler feedwater pumps.

It was considered unlikely that a CCGT plant would be converted to allow biomass generation in this configuration owing to the very significant output reduction. However, there may be individual situations where plants have been designed with excess steam turbine capacity, which may require significantly less plant derating to accomplish successful biomass utilisation. This study has not considered the country specific issue of CCGT plant type and size potentially available for repowering with biomass grate boiler technology.

No sensitivity analyses were performed to test the effect of smaller or larger plant sizes on efficiency.

Plant operation was based on 7,500 hours per year at rated output or a capacity factor of 85%. This is a reasonable figure for this technology based on existing plant performance. Gas turbine combined cycle plants are capable of achieving higher capacity factors.

6.3.8 Conventional Pulverised Coal Fired Boiler

The net plant efficiency of the 500 MW conventional pulverised coal fired plant was assumed to be, 45%, (LHV). No sensitivity analysis was carried out to determine efficiencies for smaller or larger unit sizes.

Plant operation was based on 7,500 hours per year at rated output or a capacity factor of 85%. This is a reasonable figure for this technology based on existing plant performance as capacity ratings are typically higher than this.

6.4 CAPITAL COSTS OF POWER GENERATION PLANTS

6.4.1 Introduction

This section sets out the estimated costs (capital and operating) of eight biomass power generation technologies and two conventional pulverised coal fired reference cases, and describes the basis for the estimates. Costs have been estimated at ±30% accuracy, depending on site-specific requirements. This is considered reasonable as the cost estimate information in this study is intended to be used only for comparison with alternative technologies. Plant pricing was based on the scope previously described. Cost estimates include gas cleanup equipment suitable for meeting typical emission standards for biomass boilers, as well as an allowance for land, switchyard at the site for a local transmission connection, and permitting.

6.4.2 Conventional Grate Boiler Technology

The estimated capital cost for a 30 MW_e net biomass fired generating station with a grate fired boiler was \$2,255/net kW_e or \$67,650,000 in 1998 US Dollars including a 10% contingency factor. Estimated costs were based on five plants built over the past 15 years as well as data from two studies and one budget estimate. Historical data was corrected to 1998 US Dollars assuming a 2.5% escalation factor. There were regional disparities in cost information between countries, and often within regions in a country. A sensitivity analysis showed that a 60 MW_e plant would cost \$1650/kW_e, and a 10 MW_e plant would cost \$3080/kW_e.

6.4.3 Fluidized Bed Boiler Technology

The estimated capital cost for a 30 MW_e net biomass fired generating station with a fluidized bed boiler was \$2475/net kW_e, or \$74,250,000 in 1998 US Dollars including a 10% contingency factor. Estimated costs were based on plant built over the past 5 years as well as data from studies and proposal information. Historical data was corrected to 1998 US Dollars assuming a 2.5% escalation factor. Coat data from fluid bed plants built recently in Europe are significantly lower and may reflect regional or market driven disparities.

A sensitivity analysis showed that a 60 MW_e plant would cost \$2310/kW_e, and a 10 MW_e plant would cost \$2640/kW_e.

6.4.4 Biomass Integrated Gasification Technology

The estimated capital cost for a 30 MW_e net biomass fueled generating station with a gasifier/gas turbine were \$3,080/net kW_e, or \$92,400,000 in 1998 US Dollars including a 10% contingency factor. Estimated costs were based on information from developers of this technology. Four independent studies have been completed to estimate the cost of IGCC plants. When adjusted to 1998 US Dollars, and including a 10% contingency, the results of these studies were as follows, for plants in the 60 MW_e range:

Study performed by	Installed cost, \$/kw	
EPRI	\$4,030	
Tecogen	\$2,480	
Ebasco	\$2,290	
NREL 1	\$2,130	Based on HP air-blown gasif. with aero-derivative GT
NREL 2	\$1,480	Based on LP indirect heated gasifier with utility GT
NREL 3	\$1,810	Based on LP air-blown gasifier with utility GT

The highest three values above were selected and the mean of these, \$2,933/kW_e, was increased by 5% to give an estimated specific capital cost for a 30 MW plant of \$3,080/kW_e. A sensitivity analysis showed that a 60 Mw_e plant would cost \$ 2750/kW_e, and a 10 Mw_e plant would cost \$ 3520/kW_e.

This technology is presently in the development stage, and there are no commercially operating plants of this type. Costs should be more competitive in the future as plant designs are optimized.

6.4.5 Co-Firing Biomass with Pulverised Coal

The estimated capital cost of modifying an existing pulverised coal furnace for biomass co-firing was 255 \$/kW_e for a 30 MW_e addition. This may vary greatly depending on site-specific conditions however, if properly sited, co-firing requires the lowest capital investment of any of the options considered, on a \$/kW_e basis.

A 60 MW_e addition was estimated to cost \$220/kW_e and a 10 MW_e was estimated at \$300/kW_e. Estimated costs were based on EPRI and US DOE (Department of Energy) data. The US DOE report looked at 25 facilities ranging from 17 to 560 MW_e total plant size and reported costs ranging from \$50 to \$700/kW of wood energy. A lower mid-range value was chosen for this study. It is important to note that the electrical generating capacity of the existing plant will not change significantly, as the steam turbine generator capacity remains the same.

The greatest variable in the cost of modifying a pulverized coal boiler to biomass co-firing was the particulate emission requirements. Emissions from the wood will be significantly lower than the coal component for SO_2, NO_x, and CO_2, but higher for particulate emissions.

6.4.6 Biomass Grate Boiler In Parallel With Coal Fired Boiler

New Coal Fired Boiler

The estimated capital cost of installing a 150 MW_e net generating station comprising a 30 MW net grate fired biomass boiler in parallel with a 120 MW net pulverised coal fired boiler, was \$1490/net kW_e or \$223,560,000 in 1998 US Dollars. This estimate was based on the general understanding that conventional pulverised coal fired plant would be priced in the range of \$850 - \$900/kW_e gross. This is an EPC (Engineering, Procurement and Construction) contract cost to which must be added 30 – 40% to cover "soft" or Owner's costs.

Two coal fired options were costed: a 120 MW_e net option at the upper specific EPC cost of \$900/kW_e gross, and 150 MW_e net option at \$896/kW_e gross. The 30 MW_e net conventional biomass grate boiler technology cost at \$2255/kW_e net was used for the biomass boiler. The EPC costs were broken down according to Table 10 of the IEA Coal Research report, "OECD Coal-fired Power Generation – Trends in the 1990s", adjusted where appropriate to reflect the relatively higher cost of a biomass boiler and the deletion of deNOx and FGD. The steam turbine and cooling water costs from the 150 MW_e option were then added into the remaining plant costs calculated by summing the 120 MW_e coal and 30 MW_e biomass options. 35% was then added to the resulting EPC cost for "soft" costs.

No sensitivity analysis was carried out.

Existing Coal Fired Boiler

The capital cost of installing a 30 MW_e net grate fired biomass boiler in parallel with an existing coal fired generating station's pulverised coal fired unit, was estimated to range between \$726 and 1500/net kW_e (\$21,780,000 - 45,000,000) in 1998 US Dollars including a 10% contingency factor. The application of this technology option was considered to be site specific. The lower limit of the estimated specific capital cost range was based on the conventional grate boiler technology cost of \$2,255/net kW_e and is the cost of the boiler only calculated at 1/3 (33%) of the grate boiler technology option cost. Based on a cost breakdown for an existing plant, the boiler was estimated to comprise 1/3 (33%) of the total plant cost. This was considered to be the lowest possible cost for the most synergetic existing site.

It was considered more probable that most existing sites would be less synergetic and would result in at least the following additional cost items being required:

- the installation of a separate biomass unloading, storage, screening and processing facility;
- additional costs of providing for reheat in the biomass boiler;

- cost of interconnecting main steam and reheat steam pipework, control vales, and control and instrumentation hardware and software;
- additional costs of engineering the parallel repowering configuration;

The need for these additional items will be highly site specific and depend on the nature of the existing coal fired plant and the specific nature of the biomass to be used. It was estimated that these items may add a further 1/3 (33%) to the above, thus providing the upper limit to the estimated specific capital cost range.

It is important to note that the electrical generating capacity of the existing plant may be reduced owing to the higher percentage of station auxiliary power requirements for a small biomass boiler compared to a large coal fired plant. However, this assumes that the existing coal fired plant is generating at the maximum gross generator output, a condition that may vary widely at various sites throughout the countries under consideration.

A sensitivity analysis showed that a 60 MW_e installation would cost \$660 - \$1100/kW_e, and a 10 MW_e installation would cost \$935 - \$2050/kW_e. Note that the lower figures of the above specific capital cost ranges were selected for subsequent economic analysis and inclusion in the integrated analysis.

6.4.7 Biomass Grate Boiler In Parallel With Combined Cycle Plant

New Combined Cycle Plant

The estimated capital cost of installing a 140 MW_e net generating station comprising a 33 MW_e net grate fired biomass boiler in parallel with a 107 MW net combined cycle plant was \$1370/net kW_e or \$191,740,000 in 1998 US Dollars. This estimate was based on the EPC or turnkey gas turbine combined cycle price published in Gas Turbine World 1997 Handbook which indicated a specific capital EPC cost of \$741/net kW_e for the combined cycle plant. This price was escalated at 2.5%/year to bring it to present day terms and a 10% contingency allowance was added. The calculated EPC price was then broken down according to a breakdown given in Gas Turbine World 1997 Handbook for a 107 MW_e combined cycle cogeneration facility, adjusted where appropriate to reflect the deletion of cogeneration features.

The 30 MW_e net conventional biomass grate boiler technology cost at \$2255/kW_e net was used for the biomass boiler. The EPC costs were broken down according to Table 10 of the IEA Coal Research report, "OECD Coal-fired Power Generation – Trends in the 1990s", adjusted where appropriate to reflect the relatively higher cost of a biomass boiler and the deletion of deNOx and FGD. The combined cycle and biomass boiler costs, excluding the steam turbine were then summed and an estimated cost for a 76 MW_e net steam turbine generator was added in. 35% was then added to the resulting EPC cost for "soft" costs.

No sensitivity analysis was carried out.

Existing Combined Cycle Plant

The estimated capital cost of installing a 30 MW_e net grate fired biomass boiler in parallel with an existing gas fired combined cycle generating station was estimated to vary from $726 - $1650/net kW_e ($21,780,000 - $49,000.000) in 1998 US Dollars including a 10% contingency factor.

Comments made above in relation to the cost estimates for the "*Existing Coal Fired Boiler*" option apply to this option. In this case, the lower bound is similar to that for biomass grate boiler in parallel with existing coal fired boiler, a cost of $726/net kW_e. The upper bound is based on that for biomass grate boiler in parallel with an existing coal fired boiler. However, a 10% has been added to cover the cost of additional engineering for parallel repowering configuration where the complexity of an existing 2 or 3 pressure HRSG must be taken into account. It is important to note that the electrical generating capacity of the existing plant may be reduced owing to (i) the increased station service requirements of biomass handling facilities at a plant where the existing turbine generators are operating at the maximum electrical output; and (ii) the reduced gas turbine output as a result of reducing the HRSG steam load to permit the biomass boiler contribution to be added to the inlet to the steam turbine generator without overheating the HRSG or venting gas turbine exhaust gas directly to the atmosphere. The existing gas turbine generator and steam turbine generator otherwise remain the same for this option.

A sensitivity analysis showed that a 60 MW installation would cost $660 - $1210/kW, and a 10 MW installation would cost $935 - $2250/kW. Again as for the *"Existing Coal Fired Boiler"* option, the lower figures of the above specific capital cost ranges were selected for subsequent economic analysis and inclusion in the integrated analysis.

6.4.8 Conventional Pulverised Coal Fired Boiler

Two conventional pulverised coal fired reference cases were costed for comparison: a subcritical case and a supercritical case.

The estimated capital cost for a 500 MW_e net conventional coal fired generating station with a subcritical pulverised coal fired boiler was $1250/net kW_e or $624,000,000 in 1998 US Dollars. This estimate was based on the understanding that conventional pulverised coal fired plant would be priced in the range of $850 - $900/kW gross. This is an EPC (Engineering, Procurement and Construction) contract cost to which must be added 30 – 40% to cover "soft" or Owner's costs. The lower specific EPC cost of $850/kW gross was chosen, to which was added 35% for "soft" costs.

The estimated capital cost for a 500 MW_e net conventional coal fired generating station with a supercritical pulverised coal fired was $1300/net kW_e or $653,000,000 in 1998 US Dollars. This estimate is based on the IEA Coal Research report, "OECD Coal-fired Power Generation – Trends in the 1990s" where it is estimated that the capital cost of a supercritical unit would be about 3 – 5% higher than for a subcritical unit. As the estimates are for comparative purposes, the 5% figure has been chosen and, on that and the above basis, the supercritical pulverised coal fired plant would be priced at $890/kW gross. As above, 35% has been added for "soft" costs. No sensitivity analysis was carried out for larger or smaller plant sizes.

Only the supercritical option was used in the integrated analysis as this was considered current state of the art technology.

6.5 COST OF POWER

This section describes the financial analysis carried out on, and reports the results for, eight biomass power generation technologies and one conventional coal fired reference case selected for this study. Capital costs estimated for each technology, and the reference case, are recorded in Section 6.4. The selection of the various technologies, and their expected performance, is described in sections 6.2 and 6.3 respectively. Capital costs include the turn-key or EPC (Engineering, Procurement & Construction) cost and the "soft" or owner's costs for the fully installed and commissioned plant.

Operating costs in all cases were assumed at 2%/year of the total installed cost in accordance with the financial criteria used in IEA/CON/96/11 (IEA, 1997). It is noted that the present IEA GHG assessment criteria for 500 MW plants requires the estimation of direct operating labour costs in terms of number of staff and annual cost per staff. To this, a further 20% and 60% is added to cover supervision and, administration and general overheads respectively.

Maintenance costs were assumed at 4%/year including labour, materials, and contract maintenance in accordance with the present IEA GHG assessment criteria for 500 MW plants. The annual cost of insurance and taxes were assumed to be 2%/year of the total installed cost.

The percentage figures above for operating, maintenance and insurance costs were reviewed against actual cost data for operating plants and verified as appropriate. Operating costs therefore include the cost of operating and maintaining the assumed plants but exclude the cost of either the coal or forestry and wood industry by-product fuel.

Fuel exclusive electricity prices in US cents/kWh were calculated using a financial model designed specifically for commercial evaluation of Independent Power Producer (IPP) project developments and verified against other international IPP financial models. The following assumptions were made in setting up the financial models for analysis.

- Plant size. The plant size for the stand-alone forestry and wood industry by-products plants was assumed to be 30 MW_e with sensitivity analysis for 10 and 60 MW_e plants.

  The co-firing plant was assumed to comprise an existing 300 MW_e conventional coal fired unit, co-fired with the equivalent of 30 MW_e of forestry and wood industry by-products on a coal replacement basis. Sensitivity analysis was carried out for 10 and 60 MW_e options.

  The parallel powering options were assumed to be nominally 140 - 150 MW_e in overall capacity with a 30 MW_e contribution from forestry and wood industry by-products. No sensitivity analysis was carried out for 10 and 60 MW_e options. The parallel repowering options were assumed to provide a 30 MW_e contribution from forestry and wood industry by-products. The capacity for the existing plant being repowered was 150 MW_e for the existing coal fired boiler and 372 MW_e for the existing combined cycle plant. Sensitivity analysis was carried out for 10 and 60 MW options.

  The conventional coal fired reference case was a 500 MW plant. No sensitivity analysis was carried out on plant sizing for this case.

- Plant Life. Twenty-five (25) years. Where, for technical reasons, this is regarded as excessive, provision can be made for the cost of any major maintenance or refurbishment.
- Capacity Factor. The capacity factor was assumed to be 85%, which corresponds to 7,500 hours per year throughout the lifetime of the plant. It was assumed that plant costs make sufficient allowance for installed duplicate/spare capacity to meet the required load factor taking into account maintenance requirements and reliability. An allowance for decline as plant ages was not included.
- Cost of Debt. All capital requirements were treated as debt. Loan interest rate was considered to be zero. The IDC (Interest During Construction) was calculated on the basis of an interest rate as of the applied target discount rate and a loan period of 20 years. No allowance for grants, cheap loans etc. was made.
- Capital Charges. Discounted cash flow calculations were expressed at a discount rate of 10% and, to illustrate sensitivity, at 5% for the primary options. All annual expenditures have been assumed to occur at the end of the year.
- Inflation. The inflation rate was assumed to be zero. No allowance was made for escalation of labour or other costs relative to each other.
- Currency. The results of the studies are expressed in 1998 US$. Data obtained in other currencies was converted to US$.
- Construction and Commissioning. A two (2) year construction period was assumed. Commissioning was assumed be included in the two year construction period.
- Decommissioning. It was assumed that the revenue from the salvage of the plant at the end of the life-time is equivalent to the decommissioning cost.
- Taxation. Taxation on profits was not included in the assessments.
- Insurance and other fees. All other ‘soft’ costs (eg specific services such as local rates, insurance and other development fees) were assumed included in the capital cost estimate.
- Contingencies. Project contingency costs were assumed included in the plant capital costs. All plants were assumed to be built on a turnkey basis, ie the cost of risk would be built into the contractor’s fees.
- Maintenance. Routine and breakdown maintenance was calculated at 4% per year of the installed plant cost on an overnight build basis.
- Maintenance Labour. The cost of maintenance labour was assumed covered by the above 4% for maintenance.
- Operating Labour. The cost of operating labour was assumed to be 2% per year of the installed plant cost on an overnight build basis.

The calculated non-fuel cost of generating electricity, for each of the plant options is summarised in Table 6-7.

Table 6-7 Cost analysis for generating electricity

INPUT

Option	Year (Size)	Capacity	2000		2010		2020	
	Size	MW net	30 MW		30 MW		30 MW	
			$/kWe	M$	$/kWe	M$	$/kWe	M$
1	Grate Boiler	30	2,255	67.65				
2	Fluid Bed	30	2,475	74.25				
3	Gasification	30	3,080	92.40	2,640	79.20	1,870	56.10
4	Coal Cofire	30	255	7.65				
5	New Coal	150	1,490	223.50				
6	New HRSG	140	1,370	191.80				
7	Exist Coal	30	726	21.78				
8	Exist HRSG	30	726	21.78				
9A	500MW SUB	500	1,250	625.00				
9B	500MW SUP	500	1,300	650.00				

OUTPUT

			2000				2010				2020			
			5% Discount Rate (Nominal Post-Tax)				5% Discount Rate (Nominal Post-Tax)				5% Discount Rate (Nominal Post-Tax)			
30 MW			Capex	O&M	Tax	Total	Capex	O&M	Tax	Total	Capex	O&M	Tax	Total
Option			c/kWh	c/kWh	c/kWh	c/kWh	c/kWh	c/kWh	c/kWh	c/kWh	c/kWh	c/kWh	c/kWh	c/kWh
1	Grate Boiler	30	2.27	1.80	-	**4.08**								
2	Fluid Bed	30	2.50	1.98	-	**4.48**								
3	Gasification	30	3.11	2.46	-	**5.57**	2.66	2.11	-	**4.77**	1.89	1.50	-	**3.38**
4	Coal Cofire	30	0.26	0.20	-	**0.46**								
5	New Coal	150	1.50	1.19	-	**2.70**								
6	New HRSG	140	1.61	1.28	-	**2.89**								
7	Exist Coal	30	0.73	0.58	-	**1.31**								
8	Exist HRSG	30	0.73	0.58	-	**1.31**								
9A	500MW SUB	500	1.26	1.00	-	**2.26**								
9B	500MW SUP	500	1.31	1.04	-	**2.35**								

			10% Discount Rate (Nominal Post-Tax)				10% Discount Rate (Nominal Post-Tax)				10% Discount Rate (Nominal Post-Tax)			
30 MW			Capex	O&M	Tax	Total	Capex	O&M	Tax	Total	Capex	O&M	Tax	Total
Option			c/kWh	c/kWh	c/kWh	c/kWh	c/kWh	c/kWh	c/kWh	c/kWh	c/kWh	c/kWh	c/kWh	c/kWh
1	Grate Boiler	30	3.76	1.80	-	**5.56**								
2	Fluid Bed	30	4.13	1.98	-	**6.11**								
3	Gasification	30	5.13	2.46	-	**7.60**	4.40	2.11	-	**6.51**	3.12	1.50	-	**4.61**
4	Coal Cofire	30	0.43	0.20	-	**0.63**								
5	New Coal	150	2.48	1.19	-	**3.68**								
6	New HRSG	140	2.28	1.10	-	**3.38**								
7	Exist Coal	30	1.21	0.58	-	**1.79**								
8	Exist HRSG	30	1.21	0.58	-	**1.79**								
9A	500MW SUB	500	2.08	1.00	-	**3.08**								
9B	500MW SUP	500	2.17	1.04	-	**3.21**								

INPUT

Option	Year		2000		2010		2020	
	Size		10 MW		10 MW		10 MW	
			$/kWe	M$	$/kWe	M$	$/kWe	M$
1	Grate Boiler	10	3,080	30.80				
2	Fluid Bed	10	2,640	26.40				
3	Gasification	10	3,520	35.20	2,970	29.70	2,090	20.90
4	Coal Cofire	10	300	3.00				
7	Exist Coal	10	935	9.35				
8	Exist HRSG	10	935	9.35				

			10% Discount Rate (Nominal Post-Tax)				10% Discount Rate (Nominal Post-Tax)				10% Discount Rate (Nominal Post-Tax)			
10 MW			Capex	O&M	Tax	Total	Capex	O&M	Tax	Total	Capex	O&M	Tax	Total
Option			c/kWh	c/kWh	c/kWh	c/kWh	c/kWh	c/kWh	c/kWh	c/kWh	c/kWh	c/kWh	c/kWh	c/kWh
1	Grate Boiler	10	5.13	2.46	-	**7.60**								
2	Fluid Bed	10	4.48	2.11	-	**6.59**								
3	Gasification	10	5.87	2.82	-	**8.68**	4.95	2.38	-	**7.32**	3.48	1.67	-	**5.15**
4	Coal Cofire	10	0.50	0.24	-	**0.74**								
7	Exist Coal	10	1.56	0.75	-	**2.31**								
8	Exist HRSG	10	1.56	0.75	-	**2.31**								

INPUT

Option	Year		2000		2010		2020	
	Size		60 MW		60 MW		60 MW	
			$/kWe	M$	$/kWe	M$	$/kWe	M$
1	Grate Boiler	60	1,650	99.00				
2	Fluid Bed	60	2,310	138.60				
3	Gasification	60	2,750	165.00	2,420	145.20	1,650	99.00
4	Coal Cofire	60	220	13.20				
7	Exist Coal	60	660	39.60				
8	Exist HRSG	60	660	39.60				

			10% Discount Rate (Nominal Post-Tax)				10% Discount Rate (Nominal Post-Tax)				10% Discount Rate (Nominal Post-Tax)			
60 MW			Capex	O&M	Tax	Total	Capex	O&M	Tax	Total	Capex	O&M	Tax	Total
Option			c/kWh	c/kWh	c/kWh	c/kWh	c/kWh	c/kWh	c/kWh	c/kWh	c/kWh	c/kWh	c/kWh	c/kWh
1	Grate Boiler	60	2.75	1.32	-	**4.07**								
2	Fluid Bed	60	3.85	1.85	-	**5.70**								
3	Gasification	60	4.58	2.20	-	**6.78**	4.03	1.94	-	**5.97**	2.75	1.32	-	**4.07**
4	Coal Cofire	60	0.37	0.18	-	**0.54**								
7	Exist Coal	60	1.10	0.53	-	**1.63**								
8	Exist HRSG	60	1.10	0.53	-	**1.63**								

Although the above financial analysis considered eight biomass power generating technologies, the integrated analysis only considered six options. The new parallel powering options were not included in the integrated analysis as it was considered more likely that any repowering using biomass would focus first on existing plant. Although included in the analysis, the subcritical conventional pulverised coal fired reference case was not included in the integrated analysis.

6.6 AIR EMISSIONS

6.6.1 Introduction

This section describes the expected emissions from the eight biomass power generation technologies and the conventional pulverised coal fired reference case.

In general terms, it was assumed that the plants would operate at the level of emissions permitted by the relevant process discharge licencing authorities in the countries under consideration. However, country specific standards are not quoted as these were found to vary from country to country and between regions/states within countries. The expected emissions described below are therefore typical values based on current practice across all countries. Consistent with this approach, the capital cost estimates in Section 6.4 include gas cleanup equipment suitable for meeting typical emission standards for biomass boilers.

The study examined emissions of carbon dioxide, (CO_2), methane (CH_4), nitrous oxide (N_2O), oxides of nitrogen (NO_x), carbon monoxide (CO), non-methane volatile organic compounds (NMVOCs), particulate matter (PM), and sulphur dioxide (SO_2). The emission figures selected were derived from a variety of sources. NO_x, CO, PM and SO_2 were derived largely from operational plant data and verified against the Australian National Greenhouse Gas Inventory (NGGI) Committee's Workbook. Fuel Combustion Activities (Stationary Sources). CH4, N2O, and NMVOCs were derived from data in the NGGI Workbook. Note that the units used, mg/MJ are equivalent to: tonnes (Mg)/PJ or g/GJ.

6.6.2 Conventional Grate Boiler Technology

Conventional grate boiler technology burning forestry and wood industry by-products was assumed to have emission control equipment for PM only. The predominant PM control technology was electrostatic precipitators (ESP), as baghouses tend to burn out as a result of carbon carryover in the flyash. There was normally no NO_x control on biomass boilers other than what may be provided for in the furnace design. Emissions for this technology were assumed as follows:

CO_2	0 mg/MJ	owing to use of biomass fuel
CH_4	4.2 mg/MJ	
N_2O	4.1 mg/MJ	
NO_x	100 mg/MJ	
CO	180 mg/MJ	
NMVOC	6.8 mg/MJ	
PM	10 mg/MJ	using ESP
SO_2	15 mg/MJ	sulphur in biomass is typically very low

6.6.3 Fluidized Bed Boiler Technology

Fluidised bed boiler technology burning forestry and wood industry by-products was assumed to have emission control equipment for PM only. The predominant PM control technology was electrostatic precipitators (ESP), as baghouses tend to burn out as a result of carbon carryover in the flyash.. There was normally no NO_x control on biomass boilers. Emissions for this technology were assumed as follows:

CO_2	0 mg/MJ	owing to use of biomass fuel
CH_4	2.3 mg/MJ	
N_2O	4.1 mg/MJ	
NO_x	100 mg/MJ	
CO	100 mg/MJ	
NMVOC	3.8 mg/MJ	
PM	40 mg/MJ	using ESP
SO_2	15 mg/MJ	sulphur in biomass is typically very low

Emissions of CH_4, CO and NMVOC's were reduced for the fluidized bed boiler owing to more efficient combustion and more complete burn-out of the fuel. PM emissions were increased to reflect the higher PM loading in the flue gas owing to the higher gas velocity through the fuel bed. NO_x and N_2O emissions were maintained at the same level as N_2O is thought to be formed from NO_x downstream of the combustion process.

6.6.4 Biomass Integrated Gasification Technology

As noted in Section 6.2, biomass integrated gasification combined cycle (BIGCC) technology is still being developed and no commercial plants are operating at present. Emissions estimated below were therefore based on reasonable expectations for the technology and verified against the results of the US DOE National Renewable Laboratory (NREL) Life Cycle Assessment of a Biomass Gasification Combined-Cycle System.

BIGCC is characterised by the production of a clean fuel gas for presentation to the gas turbine; such clean fuel is an absolute requirement for gas turbines. Gas cleaning is therefore required and scrubbing was assumed for this case. The effect of the gas cleaning process on emissions was considered to be that PM emissions would be negligible and no PM control would be required. Emissions for this technology were assumed as follows:

CO_2	0 mg/MJ	owing to use of biomass fuel
CH_4	1.2 mg/MJ	
N_2O	3.4 mg/MJ	
NO_x	80 mg/MJ	
CO	50 mg/MJ	
NMVOC	1.9 mg/MJ	
PM	7 mg/MJ	
SO_2	10 mg/MJ	

Emissions of CH_4, CO and NMVOC's were reduced in comparison to both the conventional grate boiler and fluidized bed boiler for the BIGCC owing to the higher excess air characteristic of gas turbines, the more efficient combustion, and resulting more complete burn-out of the fuel. NO_x and N_2O emissions were reduced to reflect the advances being made in low NO_x combustion in gas turbines. PM emissions were reduced to reflect the cleaner fuel. SO_2 emissions were reduced to reflect the removal of some of the sulphur from the fuel gas during the scrubbing process.

6.6.5 Co-Firing Biomass with Pulverised Coal

The greatest variable in the cost of modifying a pulverized coal boiler to biomass co-firing was expected to be the dust emission requirements. Generally, emissions from the wood will be significantly lower than the coal component for SO_2, NO_x, and CO_2, but not necessarily for PM emissions. Emissions for this technology, contributed by the biomass were assumed to be:

CO_2	0 mg/MJ	owing to use of biomass fuel
CH_4	2.3 mg/MJ	
N_2O	4.1 mg/MJ	
NO_x	100 mg/MJ	
CO	100 mg/MJ	
NMVOC	3.8 mg/MJ	
PM	40 mg/MJ	using ESP
SO_2	15 mg/MJ	

The predominant emission control used by pulverised coal plants for dust removal is ESP. The design for an ESP for firing biomass is quite different than for a pulverised coal boiler. Because of the extremely low density of biomass flyash compared to coal flyash, (300 kg/m^3 vs. 1000 kg/m^3) the gas velocities in a biomass precipitator must be significantly lower (1 m/sec. vs. 2 m/sec.) to reduce re-entrainment of the collected ash. Wood ash has significantly different resistivity characteristics, requiring different precipitator design parameters. If a pulverised coal boiler with a marginally sized electrostatic precipitator is modified for biomass co-firing, the capital cost to modify the entire precipitator could be significant, particularly when it is only to accommodate a small portion of the total energy input.

6.6.6 Biomass Grate Boiler in Parallel with Coal Fired Boiler

New and Existing Coal Fired Boiler

Emissions for the new biomass grate boiler were expected to be the same as for the Conventional Grate Boiler Technology in Section 6.6.2 above:

CO_2	0 mg/MJ	owing to use of biomass fuel
CH_4	4.2 mg/MJ	
N_2O	4.1 mg/MJ	
NO_x	100 mg/MJ	
CO	180 mg/MJ	
NMVOC	6.8 mg/MJ	
PM	10 mg/MJ	using ESP
SO_2	15 mg/MJ	

Emissions for the existing pulverised coal fired boiler associated with this option would, in practice, be country, location and age specific. In the absence of site specific emission data the emissions for the conventional pulverised coal fired reference case were assumed to be:

CO_2	91,500 mg/MJ	(use of coal as per IEA specification)
CH_4	1.9 mg/MJ	
N_2O	5.9 mg/MJ	
NO_x	260 mg/MJ	(750 mg/Nm^3)
CO	80 mg/MJ	
NMVOC	3.0 mg/MJ	
PM	18 mg/MJ	(50 mg/Nm^3) using ESP
SO_2	700 mg/MJ	(2000 mg/Nm^3)

6.6.7 Biomass Grate Boiler in Parallel with Combined Cycle Plant

Both New and Existing Combined Cycle Plant

Emissions for the new biomass grate boiler were expected to be the same as for the Conventional Grate Boiler Technology in Section 6.6.2 above. Emissions for this technology were assumed as follows:

CO_2	0 mg/MJ	owing to use of biomass fuel
CH_4	4.2 mg/MJ	
N_2O	4.1 mg/MJ	
NO_x	100 mg/MJ	
CO	180 mg/MJ	
NMVOC	6.8 mg/MJ	
PM	10 mg/MJ	using ESP
SO_2	15 mg/MJ	

Emissions for the gas fired gas turbine combined cycle plant were assumed the same as the BIGCC plant in Section 6.6.4 above, except for CO_2. Emissions for this technology were assumed as follows:

CO_2	50,000 mg/MJ	owing to the use of natural gas fuel
CH_4	1.2 mg/MJ	
N_2O	3.4 mg/MJ	
NO_x	80 mg/MJ	
CO	50 mg/MJ	
NMVOC	1.9 mg/MJ	
PM	7 mg/MJ	
SO_2	10 mg/MJ	depending upon the sulphur in the gas

6.6.8 Conventional Pulverised Coal Fired Boiler

New coal fired plant would be expected to be required to at least meet the World Bank Group's emission guidelines, as set out in their "Pollution Prevention and Abatement Handbook – Part III, Thermal Power – Guidelines for New Plant". On that basis, expected emissions from a new conventional pulverised coal fired boiler were assumed to be:

CO_2	91,500 mg/MJ	(use of coal as per IEA specification)
CH_4	1.9 mg/MJ	
N_2O	5.9 mg/MJ	
NO_x	260 mg/MJ	(750 mg/Nm^3)
CO	80 mg/MJ	
NMVOC	3.0 mg/MJ	
PM	18 mg/MJ	(50 mg/Nm^3) using ESP
SO_2	700 mg/MJ	(2000 mg/Nm^3)

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CHAPTER 7:

INTEGRATED ANALYSIS

7.0 INTRODUCTION

Chapter 3 outlined features of the forest resources in the five study countries projected to the year 2020. Chapters 4 and 5 outlined the features of residue quantities and availability, and provided details of factors affecting the collection of forest by-products. These chapters also examined the costs of collecting woody residues for bio-fuel, assessed quantities of residues that may be available in the five countries and 25 different regions (within these countries), and evaluated greenhouse gas emissions arising from residues collection and transport. Chapter 6 considered in detail power production systems including their costs, suitability and emissions. Although technologies exist for co-generation systems, the study emphasised power production only, as electricity was considered to be the major product.

In order to assess the amounts of power that could be generated from forestry by-products in the five countries, and also in the four regions defined for Developed countries, and to determine the amounts of CO_2 that could be avoided at different levels of financial support (ie \$/tonne of CO_2 emissions avoided), an integrated analysis spreadsheet was developed. The spreadsheet determined both the quantity of power that could be generated, the amounts of CO_2 and the costs (c/kWh) associated with the power produced by optimising both the costs and emissions through an integrated approach. Although it is advantageous to locate power plants closer to biomass resources to minimise transport costs, and also to minimise emissions associated with the transport of resources to processing plants, the analysis assumed a centralised processing structure (see Section 4.9.3). This section of the report describes the analysis approach used and presents the key results of the integrated analysis.

7.1 INTEGRATED ANALYSIS METHODOLOGY

The integrated analysis consisted of eight key modules:

- **Module 1**: Assessment of resources available. These data are presented in the Appendix, being country, region, and year specific. The data are cumulative volumes in concentric rings of specified distances from assumed centralised processing plants. The resource availability data included forest arisings and wood processing residues assessed in Chapters 3, 4 and 5. Year 2000 was considered as the base case, being the earliest time that any of the technologies considered could be implemented. The resource availability module, which applies the concentric rings concept, takes into account the effect of haul distance on access to residues and includes data on the amounts of CO_2 that would be produced during the collection and pre-treatment. Judgement was made regarding the viability of collecting residues from some regions, especially the isolated regions of Prince Edward Islands, Yukon and Northwest Territories of Canada. As a consequence, the total residue quantities utilisable (Appendix) was less than the quantities assessed to be available (Table 4.2).

- **Module 2**: Assessment of the costs of delivered biomass fuel to a power generating facility. This data is presented as the $ per delivered wet tonne of fuel. The analysis assumed that 1m^3 is equivalent to 1 metric tonne of wet fuel (see section 4.7).

- **Module 3**: Assessment of delivered fuel costs for different technologies. The power generating technology used influenced the amount of fuel required. Conversion efficiency of the technology was also accounted for in the assessment.

- **Module 4**: Assessment of the amount of electricity that may be generated based on a selected technology for a given haul distance. The calculation of this value was dependent on the number of plants that would be required to process the quantity of fuel available.

- **Module 5**: Assessment of the greenhouse gas emissions (expressed as CO_2 equivalents) for the particular technology option. The greenhouse gas emission data is based on emission factors presented in Chapters 4 and 6.

- **Module 6**: Assessment of the costs of producing power using the 6 selected technologies. The costs are based on the data for power generation presented in Section 6.4. A discount rate of 10% was used as the base case with a discount rate of 5% being used in the sensitivity analysis to demonstrate the effect of interest rates on the competitiveness of using forestry by-products.

- **Module 7**: Summarises the data output for a specific scenario (ie country/region, year, haul distance, power generation technology, plant size and plant discount rate). The key outputs are quantities of residue available; amount of fuel required; total electricity output; total cost of generating electricity (including residue collection costs, fuel pre-treatment costs and power generation costs); total greenhouse gas emissions; and GHG mitigation.

- **Module 8**: Assessment of the costs and emissions arising from using coal (500MW plant) to produce electricity. The costs of electricity produced by the coal fired plant were adjusted depending on the level of financial support / tax for CO_2 avoided or emitted.

The integrated model selection option and output sheet are shown in Figure 7-1. The model, under the eight modules, utilises data on different variables and variable combinations including the resource availabilities and the collection and transport requirements incorporating specific Country/regional inputs (Chapter 4 and Chapter 5); and technology variations, requirements, plant capacities (MW), outputs, emissions, and the limitations and costs of the different plant configurations (Chapter 6). Besides the resource quantities, the different modules incorporate geographical distribution and transport/haul distances in relation to centralised processing facilities, and also the resource types.

For the year 2000, different combination of variables were considered independently:

- Five countries (Canada, Finland, New Zealand, Sweden and USA), and four regions (former USSR, North America, Europe, and Developed Asia & Oceania);
- Six technologies (Grate Boiler, Fluid Bed, Gasification, Coal Co-fire, Existing Coal, and Existing HRSG);
- Four plant sizes (10, 30, 60 and 150 MW); and

- Four levels of support (tax regimes) - \$0/t CO_2, \$20/t CO_2, \$100/t CO_2, and \$500/t CO_2.

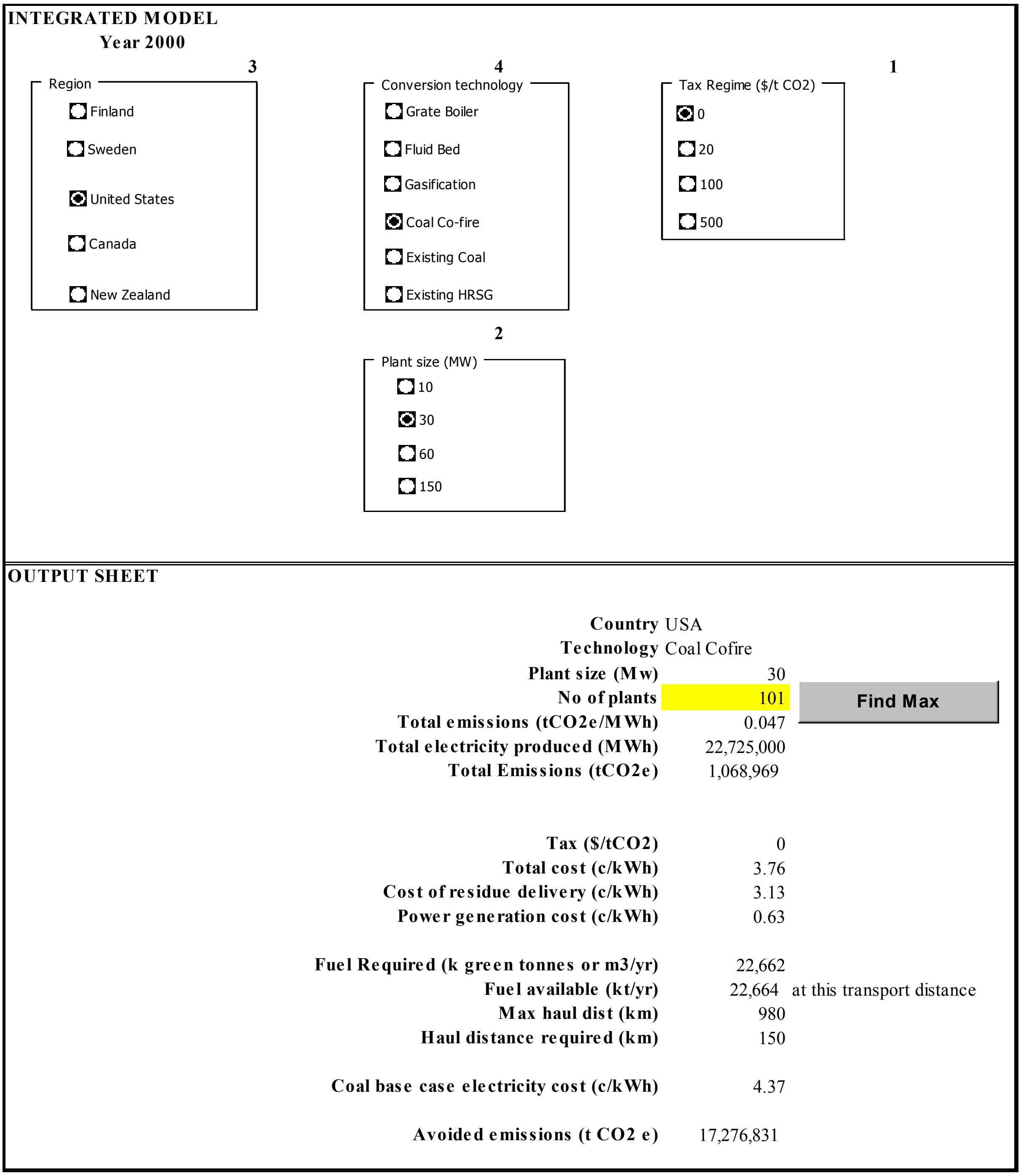

Figure 7-1. Integrated analysis model

The model analyses the combinations from the specified inputs (Country/region, conversion technology, plant size, and tax regime) and specifies the optimum operation levels given the resource availability and cost constraints under different levels of financial support in the form of tax regimes (\$/t CO_2 avoided). For Global assessment, the five countries listed in Figure 7-1 were replaced by the four regions describing Developed countries - USSR (former), North America, Europe, and Developed Asia and Oceania. Table 7-1 provides a summary of technology efficiencies and capital costs of different plants compared with the supercritical 500 MWe conventional coal plant. Technical and economic details for selection and sizing of technologies and plants are provided in Chapter 6.

Table 7-1. Technology efficiencies (%) and plant capital costs ($/kWhe)

	30 MWe plant efficiency		60 MWe plant efficiency		Capital costs ($/kWhe)	
	HHV	LHV	HHV	LHV	30 MW	60 MW
Grate Boiler	23.0%	27.7%	25.0%	30.1%	2,255	1,650
Fluid Bed	24.0%	28.9%	26.0%	31.3%	2,475	2,310
Gasification	30.5%	36.8%	31.5%	38.0%	3,080	2,750
Coal Cofire	31.5%	38.0%	33.1%	39.9%	255	220
Existing Coal	25.6%	30.9%	26.9%	32.4%	726	660
Existing HRSG	27.6%	33.3%	29.0%	35.0%	726	660
500 MW conventional Coal*	45.0%	45.0%	45.0%	45.0%	1,300	1,300

* Supercritical

7.2. MODEL OUTPUTS

In the sample output sheet (Figure 7-1), the model analyses the viability of a 30 MWe capacity coal co-firing technology in the United States of America, at zero level of support (ie. at $ 0/t CO_2 avoided) for residues assessed to be available within a radius of 150 kilometres (Appendix). The model specifies the maximum number of plants that could be installed (101), the total amount of electric power that could be generated (22.725 TWh/y), the fuel requirements and availability (22.662 and 22.664 million tonnes, respectively), and the haul distance required (150 kilometres). The model also shows the maximum possible haul distance for any specific country (see the Appendix). Further, the model gives the emission rates (0.047 t CO_2/MWh, equivalent to a total of 1.069 M t of CO_2). Given the emission levels, the model provides the overall CO_2 emissions avoided by the use of forestry residues (17.28 M t). Finally, the model compares the overall costs of electricity production using forestry by-products (3.76 c/kWh), with those of a 500 MWe Coal base case (4.37 c/kWh).

Table 7-2 shows the maximum number of plants that could be operated on either wood processing residues (involving no transport distance), and by utilising all residues including both wood processing and forestry residues at the maximum haul distances for both 30 and 60 MW plants. In New Zealand, processing residues available are not adequate for operation of 60 MW Grate Boiler and Fluid Bed plants, even if all the residues were located at one place.

By varying the number of plants for all technologies from one plant to the maximum given the residues available (see Chapters 4 and 5, and the Appendix), variations in electricity generation potential, costs, GHG emissions, GHG avoidance, and the viability of the plants when compared with the base case 500 MWe coal plants were determined. Sections 7.3 to 7.6 highlight the variation in power generation potential, GHG emissions and avoidance (tonnes of CO_2 equivalent), and the overall costs of both power generation (c/kWh) and of GHG emission avoidance both at country and global levels using 30 MWe plants. Section 7.7 considers the sensitivity (influence) of the various options on the competitiveness of power generation from forestry by-products. The assessments distinguish between generation, emissions, emission avoidance and costs associated with the use of wood processing residues and all residues including forest residues.

Table 7-2. Maximum number of plants that could be operated on different residues.

Technology	Capacity	Residue type	Canada	Finland	New Zealand	Sweden	USA
Grate Boiler	30 MW	Processing residues	31	6	1	9	62
		All residues*	126	21	14	37	368
	60 MW	Processing residues	17	3	0	5	34
		All residues*	68	11	7	20	200
Fluid Bed	30 MW	Processing residues	33	7	1	10	65
		All residues*	131	22	15	39	384
	60 MW	Processing residues	17	3	0	5	35
		All residues*	71	11	8	21	208
Gasification	30 MW	Processing residues	42	9	2	12	83
		All residues*	167	28	19	49	489
	60 MW	Processing residues	21	4	1	6	42
		All residues*	86	14	9	25	252
Coal Co-Fire	30 MW	Processing residues	43	9	2	13	85
		All residues*	173	29	20	50	509
	60 MW	Processing residues	22	4	1	6	45
		All residues*	91	15	10	27	267
Existing Coal	30 MW	Processing residues	35	7	1	10	69
		All residues*	141	23	16	42	414
	60 MW	Processing residues	18	3	1	5	36
		All residues*	74	12	8	22	217
Existing HRSG	30 MW	Processing residues	38	8	2	11	75
		All residues*	152	25	17	45	446
	60 MW	Processing residues	19	4	1	6	39
		All residues*	80	13	9	23	234

* All residues refer to both wood processing and forest residues inclusive

7.3. ELECTRIC POWER GENERATION POTENTIAL

The potential electric power generation from forestry by-products varied with Country (and region), and also with the choice of technology (Tables 7-3 and 7-4). On a country level, the highest potential was in the USA followed by Canada, while New Zealand had the least potential. The potential was a factor of both the extent of forests, and the overall size of the forestry and wood processing industries (see Chapter 3). Although both New Zealand, Finland and Sweden have a highly developed forest industry, and a large per capita wood processing capacity, the overall resource base is an order of magnitude lower than those of both Canada and the USA which respectively account for 7.1% and 6.2% of the Global forestry resources (FAO, 1997).

Table 7-3. Electric power generation potential (TWh/y).

	Grate Boiler		Fluid Bed		Gasification		Coal Co-Fire		Existing Coal		Existing HRSG	
Residue type	Proc.* residues	All** residues	Proc.* residues	All** residues	Proc.* residues	All** residues	Proc.* residues	All** residues	Proc.* residues	All** residues	Proc.* residues	All** residues
Canada	6.98	28.35	7.43	29.48	9.45	37.58	9.68	38.93	7.88	31.73	8.55	34.20
Finland	1.35	4.73	1.58	4.95	2.03	6.30	2.03	6.53	1.58	5.18	1.80	5.63
New Zealand	0.23	3.15	0.23	3.38	0.45	4.28	0.45	4.50	0.45	3.60	0.45	3.83
Sweden	2.03	8.33	2.25	8.78	2.70	11.03	2.93	11.25	2.25	9.45	2.48	10.13
USA	13.95	82.80	14.63	86.40	18.68	110.03	19.13	114.53	15.53	93.15	16.88	100.35

*Proc. = Processing residues, **- All residues include both wood Processing and forest harvesting residues

The potential from forest and wood by-products assessed to be available is less than target bioenergy potential for respective countries which often includes ongoing utilisation of biomass (eg black liquor) and purpose grown crops such as short rotation forest crops. It is emphasised that this is the potential from forest and wood processing residues assessed to be over and above current levels of bioenergy utilisation and does not include the use of purpose grown crops.

On a global scale, the North American region had the highest electric power potential exceeding the combined totals for all other Developed countries ie. former USSR, Europe and Developed Asia and Oceania (Table 7-4). Although the countries of the former USSR possess nearly a quarter of the world forest resources, nearly double that of North America (FAO, 1997; WRI, 1994), the wood processing industry is less developed. Further, the 1990's was a lean period for the forest products industry of the former Soviet Union countries, when forest production and wood processing declined significantly before starting to rise.

Table 7-4. Electric power generation potential (TWh/y) in Developed Countries.

	Grate Boiler		Fluid Bed		Gasification		Coal Co-Fire		Existing Coal		Existing HRSG	
Residue type	Proc.* residues	All** residues	Proc.* residues	All** residues	Proc.* residues	All** residues	Proc.* residues	All** residues	Proc.* residues	All** residues	Proc.* residues	All** residues
USSR (former)	9.7	39.4	10.1	41.0	13.1	52.2	13.5	54.0	10.8	43.9	11.7	47.3
North America	21.2	113.4	22.1	118.4	28.1	150.3	29.0	155.5	23.6	126.5	25.4	136.1
Europe	9.2	36.5	9.7	38.0	12.2	48.4	12.6	50.0	10.4	40.7	11.0	43.9
Dev Asia-Oceania	1.4	11.5	1.4	11.9	1.8	15.1	1.8	15.8	1.4	12.6	1.6	13.7
Total	**41.4**	**200.7**	**43.2**	**209.3**	**55.1**	**266.0**	**56.9**	**275.2**	**46.1**	**223.7**	**49.7**	**241.0**

*Proc. = Processing residues, **- All residues include both wood Processing and forest harvesting residues

The potential power generated was dependent on the technology (see Chapter 6), and the extent of residues use, ie. whether both forest harvesting and wood processing residues are used. In all countries and regions, the highest potential would be realised by utilising coal co-fire technologies. The total potential of electric power from wood processing residues ranged from 41 TWh/y to 57 TWh/y while the total from all residues estimated to be potentially available, excluding quantities in isolated regions of Canada ranged from 200 - 275 TWh/y.

The relatively higher potential in the use of Coal Co-fire over other technologies was a result of the higher efficiencies - 38% (LHV basis for 30 MW plants) compared to 27.7% for Grate Boiler, 28.9% for Fluid Bed, 36.8% for Gasification, 30.9% for Existing Coal, and 33.3% for Existing HRSG (see section 6.3, and also table 7-1). The resultant differences in technology efficiencies also resulted in a higher number of plants for Coal Co-fire over other technologies (Table 7-2), hence the proportionately higher power production potential (Tables 7-3 and 7-4).

7.4. GHG EMISSIONS ARISING FROM THE USE OF FORESTRY BY-PRODUCTS

Emissions in the use of forestry by-products result from (i) gas emissions in the use of fossil fuels in the collection, transportation and pre-treatment of residues (see Section 4.10 and Table 4.16); and (ii) the conversion of the residues at the power plants (see Section 6.6). The Appendix demonstrated the variation in GHG emissions (t CO_2 equivalent) with increasing residue transport / haul distance. The residues volume and the emission levels for any one country were such that for a given quantity of residues, GHG emissions were similar. There were differences in emission levels associated with the use of different technologies. These differences are linked to the efficiencies of specific technologies, also resulting in differences in the quantity of electric power that could potentially be generated from a unit of resource.

Tables 7-5 and 7-6 present the GHG emissions (million tonnes of CO_2 equivalent) associated with the use of the different technologies, in both the five countries and for the four regions of the developed countries.

Table 7-5. GHG emissions (M t CO_2 e/y) arising from the use of forest and wood processing residues.

	Grate Boiler		Fluid Bed		Gasification		Coal Co-Fire		Existing Coal		Existing HRSG	
Residue type	Proc.* residues	All** residues	Proc.* residues	All** residues	Proc.* residues	All** residues	Proc.* residues	All** residues	Proc.* residues	All** residues	Proc.* residues	All** residues
Canada	0.44	4.78	0.43	4.67	0.41	4.63	0.40	4.58	0.45	4.79	0.45	4.79
Finland	0.08	0.51	0.09	0.50	0.09	0.49	0.08	0.48	0.09	0.50	0.09	0.50
New Zealand	0.01	0.37	0.01	0.37	0.02	0.36	0.02	0.36	0.02	0.37	0.02	0.37
Sweden	0.13	0.87	0.13	0.85	0.12	0.83	0.12	0.80	0.13	0.89	0.13	0.88
USA	0.91	22.19	0.87	21.93	0.85	21.81	0.81	21.68	0.91	22.27	0.91	22.27

*Proc. = Processing residues, **- All residues include both wood Processing and forest harvesting residues

For any one country or region, the quantity of GHG emissions from the use of wood processing residues as a proportion of the total emissions declined with increasing transport/residues haul distance. As in the case of the quantity of electric power potential (Section 7.3), GHG emissions were dependent on the resource quantities, and also on the extent of forest utilisation and development. Thus, the USA, with the biggest forest products industry had the largest residues resource, involved higher transport distances, and had the highest GHG emission levels. It should be noted that values for North America are not simple additions of values for Canada and USA as the analysis utilised the total additive resource quantities independently applied to the model. This resulted in higher values resulting from a higher number of plants and reduced "assumed" wastage associated with individual countries. The location of the residues was however assumed to remain the same.

Table 7-6. GHG emissions (Mt CO_2 e/y) in the use of forest and wood processing residues in Developed Countries

	Grate Boiler		Fluid Bed		Gasification		Coal Co-Fire		Existing Coal		Existing HRSG	
Residue type	Proc.* residues	All** residues	Proc.* residues	All** residues	Proc.* residues	All** residues	Proc.* residues	All** residues	Proc.* residues	All** residues	Proc.* residues	All** residues
USSR (former)	0.6	6.4	0.6	6.2	0.6	6.2	0.6	6.1	0.6	6.4	0.6	6.4
North America	1.4	33.3	1.3	33.0	1.3	32.7	1.2	32.5	1.4	33.3	1.4	33.3
Europe	0.6	4.0	0.6	3.9	0.5	3.9	0.5	3.8	0.6	4.1	0.6	4.1
Dev Asia-Oceania	0.1	1.3	0.1	1.3	0.1	1.3	0.1	1.2	0.1	1.3	0.1	1.3
Total	**2.6**	**45.1**	**2.5**	**44.4**	**2.4**	**44.1**	**2.4**	**43.7**	**2.6**	**45.1**	**2.6**	**45.1**

*Proc. = Processing residues, **- All residues include both wood Processing and forest harvesting residues

Of particular interest is the maximum emission levels associated with complete utilisation of the residues assessed to be potentially available, and involving the longest transport distances.

Taking the case of Developed countries, only 2.4 Mt CO_2 - 2.6 Mt CO_2 equivalent was assessed to be produced by utilising wood processing residues compared to 43.7 Mt CO_2 - 45.1 Mt CO_2 from utilising all forest and wood processing residues.

7.5. AVOIDED GHG EMISSIONS IN USING FORESTRY RESIDUES

Total emissions in Tables 7-5 and 7-6 were compared with baseline coal emissions derived from the 1995 IPCC Guidelines for National Greenhouse Gas Inventories (IPCC, 1995). The difference between emissions from conventional coal fired plants for a similar electric potential, and those from the use of forestry by-products (Tables 7-5 and 7-6) constituted the avoided emissions (Table 7-7 and Table 7-8).

Table 7-7. Avoided GHG emissions (M t CO_2 e/y).

	Grate Boiler		Fluid Bed		Gasification		Coal Co-Fire		Existing Coal		Existing HRSG	
Residue type	Proc.* residues	All** residues	Proc.* residues	All** residues	Proc.* residues	All** residues	Proc.* residues	All** residues	Proc.* residues	All** residues	Proc.* residues	All** residues
Canada	5.19	18.11	5.57	19.12	7.22	25.70	7.42	26.85	5.91	20.83	6.45	22.82
Finland	1.00	3.29	1.18	3.49	1.54	4.58	1.55	4.77	1.18	3.66	1.36	4.02
New Zealand	0.16	2.11	0.16	2.28	0.33	3.00	0.34	3.17	0.33	2.45	0.33	2.63
Sweden	1.50	5.83	1.68	6.20	2.05	8.04	2.23	8.25	1.68	6.71	1.86	7.26
USA	10.35	44.66	10.94	47.82	14.23	67.01	14.63	70.77	11.63	52.93	12.71	58.75

*Proc. = Processing residues, **- All residues include both wood Processing and forest harvesting residues

The trends in total emissions and in plant conversion efficiencies (see Chapter 6; and also Table 7-1) were reflected in the overall avoided emissions. Technologies with high efficiencies (Coal Co-Fire and Gasification) had lower emissions resulting in the highest avoided GHG emissions.

Table 7-8. Avoided GHG emissions (M t CO_2 e/y) in Developed Countries.

	Grate Boiler		Fluid Bed		Gasification		Coal Co-Fire		Existing Coal		Existing HRSG	
Residue type	Proc.* residues	All** residues	Proc.* residues	All** residues	Proc.* residues	All** residues	Proc.* residues	All** residues	Proc.* residues	All** residues	Proc.* residues	All** residues
USSR (former)	7.2	25.3	7.6	26.7	9.9	35.8	10.3	37.3	8.1	28.9	8.8	31.6
North America	15.6	57.9	16.4	62.2	21.4	88.2	22.1	92.5	17.6	68.4	19.1	76.2
Europe	6.9	25.4	7.3	26.8	9.3	35.2	9.7	36.5	7.8	28.8	8.3	31.4
Dev Asia-Oceania	1.0	7.9	1.0	8.3	1.4	10.9	1.4	11.5	1.0	8.9	1.2	9.8
Total	**30.7**	**116.5**	**32.3**	**124.0**	**41.9**	**170.1**	**43.5**	**177.9**	**34.5**	**135.0**	**37.4**	**149.0**

*Proc. = Processing residues, **- All residues include both wood Processing and forest harvesting residues

On a country basis, the USA had the most amounts of GHG emissions avoidance, followed by Canada, mainly due to the higher residue resources available. Globally, there is potential to mitigate between 30 – 43.5 M t CO_2 e/y by utilising wood industry processing residues in developed countries alone. When all forestry by-products (forestry and processing residues) are used, the potential rises to 116 – 177.9 Mt CO_2 equivalent per year. The variation in potential is dependent on the choice of technology and on intensity of residue use (Table 7-8).

7.6. COSTS IN THE USE OF FORESTRY BY-PRODUCTS

Costs in the use of forestry by-products for electric power production include the costs of residues collection, transport and pre-treatment (see Sections 4.9 and 5.5; and also the Appendix for detailed residues costs); and conversion incorporating capital expenditure, operating, and maintenance (Section 6.5). Therefore, costs for the different countries/regions, and also for different technologies and residues show the sum of costs associated with the collection, transport and processing of the quantity of residues required for generating a given quantity of power (c/kWh).

7.6.1. Costs of Power Production in the use of Forest and Wood Processing Residues

Table 7.9 presents a summary of the costs of electric power generation using the six technologies evaluated in the five study countries. Since representative country factors were used in the derivation of Developed Country regions potential, a similar table to depict costs at the global scale was not generated. The cost of power production from the 500 MW Coal base case at different carbon tax regimes ($0, $20, $100, and $500 /t CO_2 avoided) is also provided in the table for comparison, and to indicate the competitiveness of biomass plants. The table distinguishes between the costs of generation from processing residues, from the first plant utilising forest residues in addition to any wood processing residues (ie. after all processing residues are exhausted), and from the maximum quantity of residues (as assessed to be potentially available).

There are significant differences in costs of generation from different technologies for any one country. Coal Co-Fire provided the lowest cost power generating option with costs lower than 1 c/kWh for wood processing residues in all countries. Gasification technologies had the highest costs reflecting the high capital, operating and maintenance costs compared to those of Coal Co-Fire and other technologies (see Section 6.5, and Tables 6-7 and 7-1). It is noted that while the costs for base case coal e.g. for Finland, 5 c/kWh appear very high, those for electricity from biofuel especially in coal co-firing, 0.95 c/kWh appear very low. The cost for base coal generation comprise the costs for the capex and O&M component of the electricity cost (Sections 6.4 – 6.5), plus the local cost of coal. Country specific cases were not analysed, essentially producing one "number" for the 500 MWe coal base case. Any variation in electricity cost between countries must therefore be owing to local cost of the fuel.

The cost of electricity from co-fired plant is very low and in reality may be even lower. The analysis, which produced the capex and O&M component of the electricity cost treated the co-firing option as if it were a new 30 MW biomass fired power plant costing $225/kW or $7.65 million, where the capex is simply the cost of providing biomass reception and preparation plant, and any modifications to the boiler plant and its auxiliaries. The same approach and the same financial model were used for all options and the basic inputs were MW capacity and capex. O&M was calculated internally as per the description in Section 6.5.

Table 7-9. Costs¶ of electric power production (c/kWh) using different technologies.

	Grate Boiler			Fluid Bed			Gasification			Coal Co-Fire			Existing Coal			Existing HRSG			500 MW Coal base case			
Residues	Proc.*	All** residues		Proc.*	All** residues		Proc.*	All** residues		Proc.*	All** residues		Proc.*	All** residues		Proc.*	All** residues		Tax regime ($/t CO_2 e)			
type	residues	Min.	Max	residues	Min.	Max	residues	Min.	Max	residues	Min.	Max	residues	Min.	Max	residues	Min.	Max	0	20	100	500
Canada	5.98	7.43	14.86	6.50	8.18	15.02	7.91	9.12	14.61	0.93	2.10	7.42	2.16	3.60	10.14	2.14	3.59	9.54	4.57	6.43	13.88	51.14
Finland	6.00	7.80	11.07	6.52	8.55	11.38	7.93	9.52	11.75	0.95	2.38	4.64	2.18	3.94	6.73	2.15	3.92	6.37	5.01	6.68	13.34	46.63
New Zealand	5.97	7.56	9.85	6.50	8.02	10.26	7.91	9.24	10.87	0.93	2.22	3.79	2.16	3.40	5.62	2.13	3.61	5.35	4.14	5.95	13.20	49.45
Sweden	5.99	7.58	10.36	6.52	8.92	10.71	7.92	9.35	11.22	0.94	2.10	4.13	2.18	3.46	6.10	2.15	3.47	5.79	5.01	6.68	13.34	46.63
USA	5.97	18.30	24.40	6.50	8.32	24.16	7.90	9.34	21.80	0.93	2.02	14.37	2.16	3.50	18.68	2.13	3.71	17.47	4.37	6.24	13.69	50.95

¶ Costs for all residues including forest residues are cumulative weighted costs for all fuel required

* Proc. = Processing

** All residues include both wood Processing and forest harvesting residues

Min. - Costs for "All** residues" refer to costs of production from the first plant utilising all processing residues and forest residues inclusive

Max. "All** residues" refer to all processing residues plus the maximum possible quantity of forest residues

In broad terms:

- Coal Co-Fire - In Finland, New Zealand and Sweden, all processing and forest residues assessed to be available can competitively be used for power production without the need for tax incentives. In Canada, all residues use become competitive at \$100 CO_2 tax while in the USA, some of the residues only become competitive within the \$500 /t CO tax regime.

- Existing Coal and Existing HRSG - All processing residues are competitive without the need for tax incentives. In Canada, Finland, New Zealand and Sweden, all residues are competitive at \$100 /t CO_2 tax regime, unlike in the USA where the use of some of the forest residues is only economical at \$500 /t CO_2 tax regime.

- Grate Boiler and Fluid Bed - Processing residues are competitive at \$20 /t CO_2 tax regime, while all residues are competitive at \$100 /t CO_2 tax regime in Finland, New Zealand and Sweden. In Canada and USA, all residues are competitive at the \$500/t CO_2 tax

- Gasification – A tax regime of at least \$ 100/t of CO_2 emitted is required to make use of forestry by-products competitive, when all residues in Finland, New Zealand and Sweden would be utilised. In Canada and USA, some of the residues would require a higher tax (\$500/t CO_2) to become competitive.

The lack of competitiveness for some of the residues is due to the high transport distances (up to 510 and 980 kilometres in Canada and USA, respectively). Differences in costs for any one residue category between countries reflect the differences in fuel/electricity costs for collection, transport and processing (Table 4.10). On the other hand, differences in costs between different residue types reflect the costs of collection and transport over different haul distances (see Section 4.9). Some differences between countries were associated with transport vehicle characteristics, and the localised costs of labour.

7.6.2 Costs of GHG Emission Avoidance in the use of Forestry By-products

The costs of electric power production in Section 7.6.1 above were multiplied by the total potential of electricity generated (TWh/y) and divided by the associated GHG emission avoided (M t CO_2 e, Section 7.5) and plotted against specific levels of CO_2 avoided per year (M t/y). In order to develop the supply cost curves, arbitrary decisions about the number of scenarios and therefore the number of plants were made. Although many more scenarios could have been run, sufficient outputs were generated to determine the shape and trend of the curves based on the minimum and maximum number of plants indicated in table 7.2.

Figures 7-2 and 7-3 illustrate the variation in costs of GHG mitigation (Cost of power production, c/kWh, versus CO_2 avoided) for different countries, different technologies, and also over different amounts of CO_2 avoidance. The results could also be presented as CO_2 cost supply curves, ie. cost (\$/tonne of CO_2 avoided) versus the quantity of CO_2 avoided (Figures 7.4 and 7.5). The \$0 tax reference case line (Figures 7-2 and 7-3) illustrates the threshold costs of power production without any tax incentives. Besides the costs of power generation and GHG mitigation using different technologies, the cost curves also put in perspective, the maximum amounts of GHG emissions that could be abated by the use of forestry by-products.

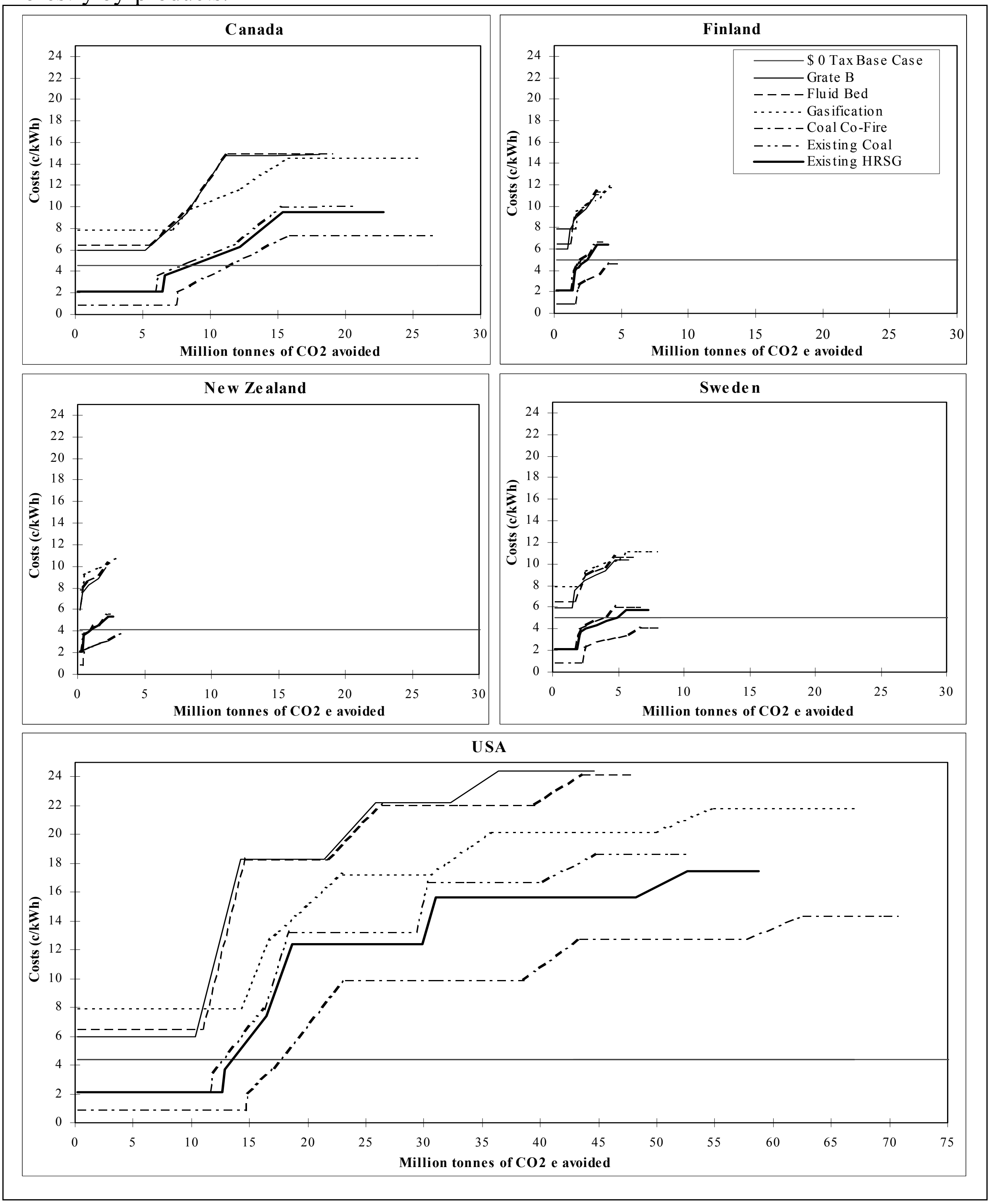

Figure 7-2. Country GHG emission avoidance cost curves.

The initially low costs of power production and GHG mitigation for all technologies (horizontal portions of the curves) represent the use of wood processing residues. Wood processing residues with a token value of $ 1/tonne, with a minimal processing fee averaging $2/tonne, were assumed to be available at the point of use and therefore involved no transport (see chapters 4 and 5). The greater proportion of the cost of power generation from wood processing residues comprises capital expenditure, operation and maintenance costs.

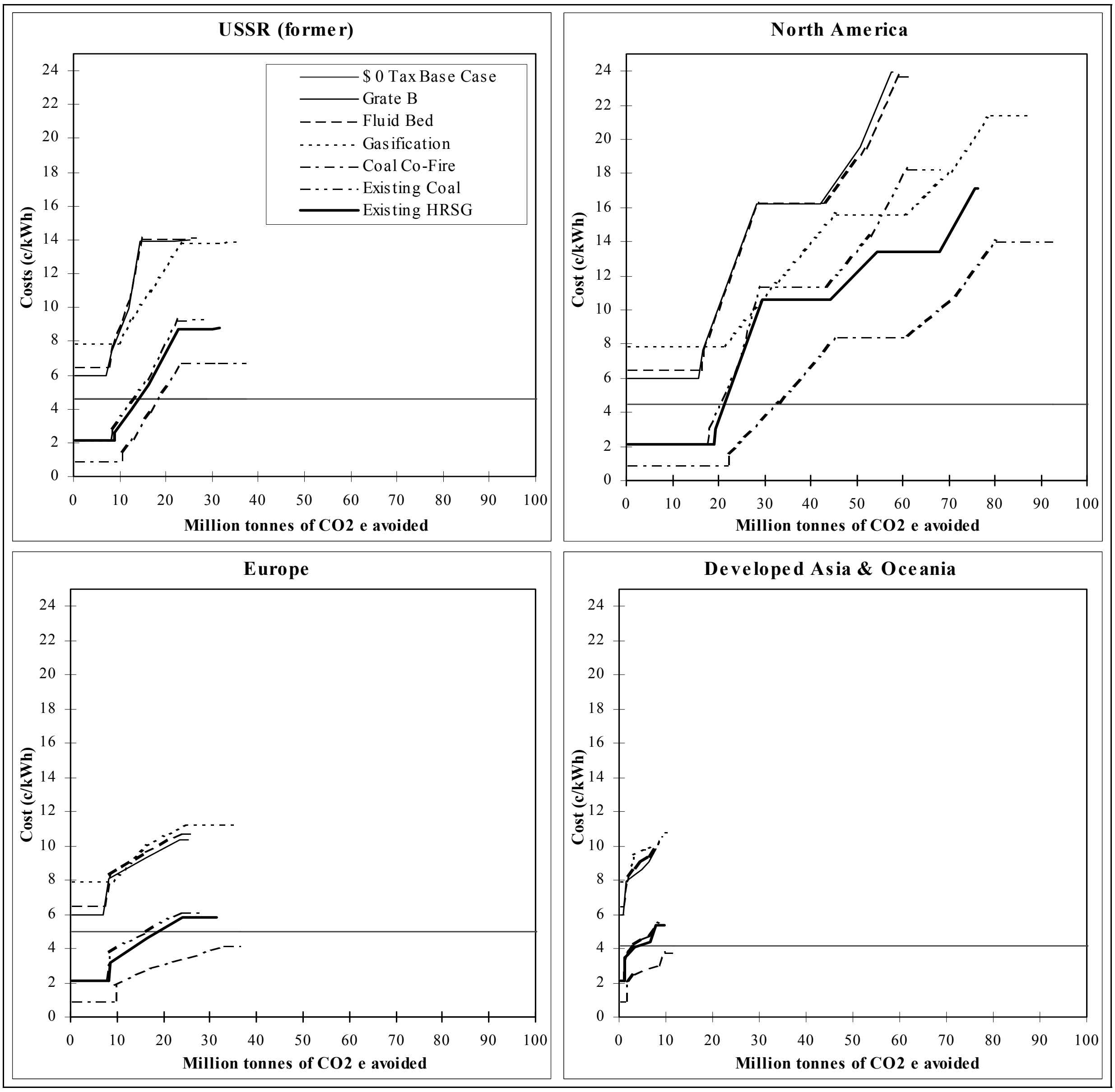

Figure 7-3. GHG emission avoidance cost curves in developed countries.

Because wood processing residues were low cost, it was assumed that all plants would aim to exhaust this material before starting to utilise the more expensive forest harvesting residues. The changes in both costs and GHG emissions are in progressive steps, initially resulting from radial distances defined from respective forest densities (see chapters 3 & 4; and also the Appendix). The jump in cost for all technologies following the initially low costs reflects the point at which the plants start utilising the more expensive forest residues which incur collection, transport (depending on haul distance) and processing costs. Thus, increasing costs reflect the effect of haul distance on both the costs of power production and of GHG mitigation. The higher transport distances increase the delivered costs of residues beyond certain haul distances.

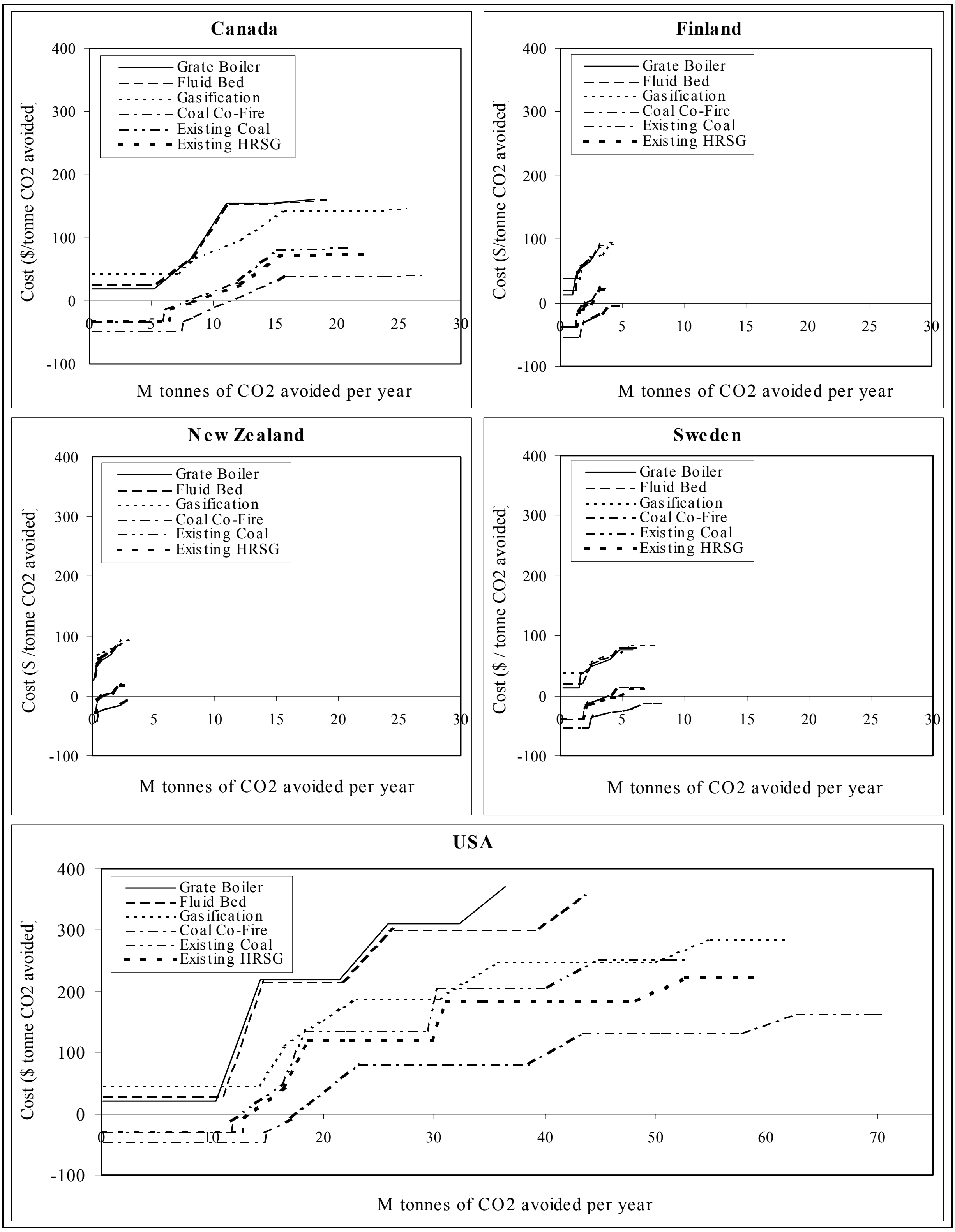

Figure 7-4. Co_2 cost supply curves in the 5 study countries

In all countries, Grate Boiler, Fluidised Bed and Gasification require initial tax incentives to be viable. The cost of power generation using wood processing residues in Coal Co-Fire, Existing Coal and Existing HRSG technologies was lower than the cost of power generation using conventional coal. The use of a proportion of forest residues applying coal co-fire, existing coal and existing HRSG was also below the threshold levels in Finland, Sweden, and New Zealand, but mostly exceeded the threshold with increasing forest residue haul distance in Canada and USA.

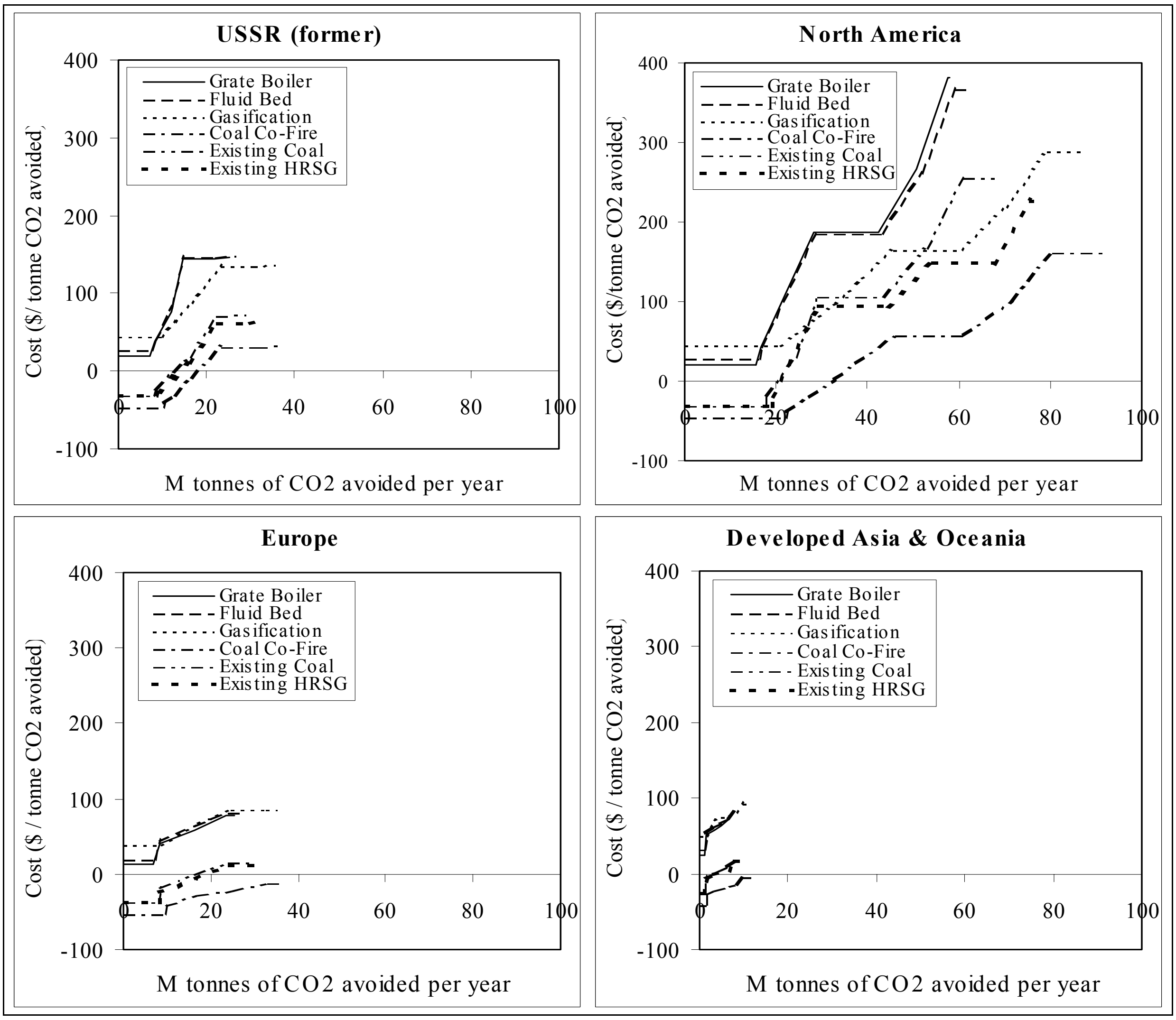

Figure 7-5. CO_2 cost supply curves in developed countries

7.7 SENSITIVITY ANALYSIS

This section of the report illustrates the effect of different options on the overall economic competitiveness / viability of utilising forestry by-products for electric power generation, and therefore on GHG mitigation. Five options were analysed - technology; tax regime; plant capacity (see Figure 7-1); discount rate applied in the economic assessment; and the fuel type (incorporating the fuel spread / distribution and haul distance).

7.7.1 Fuel Type and Haul Distance

Differences in costs of residue types were associated with the transport distances involved in their delivery (Chapter 4). The residue costs differences were reflected as residue delivery costs (Appendix) resulting in differences in costs of power generation from wood processing and from forest harvesting residues (Table 7-9). The lower costs of generating power from processing residues (relative to forest residues) illustrates the economic advantages of utilising residues with minimal transport distances. Although increasing haul distances increased the feedstock catchment for any one plant, thus raising the potential for power generation, it (i) increased the costs of generation; (ii) increased GHG emissions (t CO_2 equivalent, Tables 7-4 and 7-5), (iii) reduced potential GHG mitigation (Tables 7-7 and 7-8), and (iv) increased costs of GHG emission abatement (Figures 7-2 - 7-5).

7.7.2 Technology

The importance of appropriate technology choice has been illustrated by the differences in (i) electric power generation potential (Tables 7-3 and 7-4); (ii) GHG emissions (Tables 7-5 and 7-6); (iii) levels of GHG emission avoidance (Tables 7-7 and 7-8); and (iii) costs of generation and GHG emission abatement (Table 7-9; and Figures 7-2 to 7-5). Coal Co-Fire provided the most efficient technology resulting in the greatest power potential (275 TWh/y globally), had the lowest cost options, had the lowest emissions (43.7 Mt CO_2 /y globally), and resulted in the highest GHG abatement potential (up to 177.9 Mt/y globally). Grate Boiler on the other hand provided the least efficient technology. Gasification, Fluid Bed and Grate Boiler provided the most expensive technology options for utilising forestry by-products.

7.7.3 Tax regimes

The four tax regimes assessed resulted in different costs in the five countries (Table 7-9). Figures 7-2 to 7-5 illustrate the costs of CO_2 avoidance from forestry by-products, and show the points at which different technologies become uncompetitive with conventional coal fired plants. All technologies utilising all residues available would be competitive with conventional coal plants at the \$500 /t CO_2 regime. Except in Canada and USA, with haul distances of up to 510 and 980 kilometres respectively, all technologies were viable at the \$100 /t CO_2 tax regime. In all countries, coal Co-Fire, Existing Coal and Existing HRSG could be employed to utilise all wood processing residues and a proportion of forest residues without any tax interventions. Gasification could be competitive only when a tax of \$100/t CO_2 (and above) is applied.

7.7.4 Plant Size

The analysis employed 30 MW plants even though four plant sizes were evaluated in Chapter 6. The effect of plant size undertaken for USA alone is demonstrated in Figure 7-6 comparing the 60 MW and 30 MW plants for the six technologies. Overall, the 60 MW plants (i) resulted in higher power generating potential; (ii) had lower GHG emissions providing higher potential for GHG abatement from conventional coal fired plants; and (iii) resulted in marginally lower generating costs resulting from the better economies of scale and superior efficiencies.

GHG avoided directly reflects the potential power production for both the 30 MW and 60 MW plants. Higher power generating potential and increased GHG abatement for the bigger 60 MW plants using similar quantities of residues was due to higher efficiencies of the bigger plants resulting in lower emissions. Lower emissions result in higher GHG abatement per unit of power produced. The marginally lower costs for the 60 MW plants is a reflection of the better economies of scale compared to the smaller 30 MW plants.

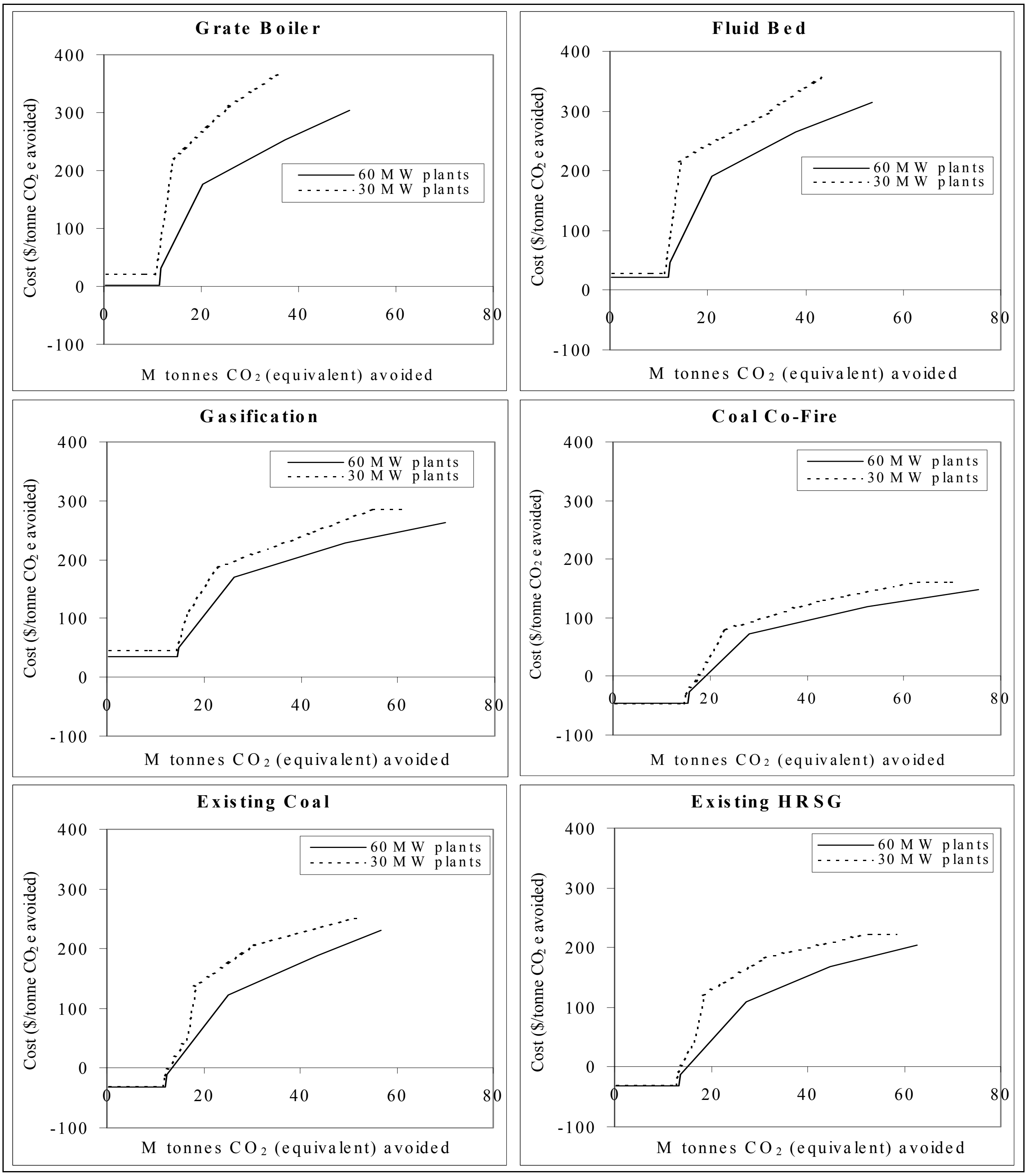

Figure 7-6. Effect of plant size on the cost of CO_2 avoidance in the USA.

7.7.5 Discount Rates

The sensitivity of both costs of power generation and of GHG abatement to discount rates was analysed by comparing results of 30 MW plants commissioned at discount rates of 10% and

5% in North America. The higher discount rate of 10% resulted in higher relative costs of power generation, and therefore higher costs of GHG abatement.

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CHAPTER 8:

ENVIRONMENTAL IMPLICATIONS OF USING FORESTRY BY-PRODUCTS

8.0 INTRODUCTION

Issues arising from intensive harvesting, the removal of forest arisings and long-term forest sustainability may include the (i) risks of erosion; (ii) water quality - sediment loadings, nutrient leaching and the run-off of chemical residues; (iii) nutrient removal; (iv) site productivity changes; (v) biodiversity; (vi) site establishment practices; and (vii) the application of wastes (ash, sludges or other materials) to maintain site productivity.

A review of the long-term productivity of forest plantations undertaken by Evans (1990) concluded that declining yields with successive forest plantations were the exception though the number of detailed studies were limited. In situations where declining yields had been observed, key factors were:

- failure to conserve organic matter between rotations;
- physical damage to the site through harvesting practices;
- failure to address weed problems as site conditions changed between rotations and competition has increased; and
- identifiable nutrient depletion.

However, there are also cases of yield increases between rotations. Factors contributing to this may include (i) management of the site has changed its potential eg drainage or addition of a limiting nutrient eg phosphate or boron. In Britain, second rotation spruce does not require the addition of phosphate like the first rotation. The one application for the first crop is sufficient and carried over into the next; and (ii) tree improvement may also contribute to productivity gains.

8.1 NUTRIENT REMOVAL

The limbs and needles of trees hold a greater concentration of important nutrients (N, P, K) than the stem wood. In conventional harvesting operations typically this material is left on the ground and decays, releasing the nutrients, some of these are available for the next crop, and some leach out of the soil.

If these residues are collected immediately after logging then the bulk of the needles will be removed as well, along with the nutrients they contain. The needles can contain 25% of the N and P in the above ground biomass of a tree. If the residues are left to season for a period of weeks, then the bulk of the needles will have detached from the branches and will have fallen to the forest floor. They will not be harvested.

The removal of the merchantable stem wood with the bark attached (conventional logging practice) is likely to be taking 45% to 50% of the N, P and K from the site. The residues harvested will contain stem and branch material, if it is assumed that 20% of the branch material is left behind with all the needles, then 30% of the nutrients are being left on the site with a further 20% to 25% going out in the residue harvest.

Removal of logging residues for bio-energy purposes will inevitably reduce the nutrient levels on the site. Whether this is critical will depend on the intensity of the harvest and the nutrient status of the soil, and possibly other factors such as acid rain (southern Sweden). In Finland it has been found that residue removals in Scots pine stands have had no significant effect on tree growth, up to 15 years after harvest (Kukkola & Malkonen, 1997). In some situations the residue was being concentrated at roadside and abandoned to decay. Harvesting this material for bio-energy reduces in-forest problems and costs.

In New Zealand, three trials at age 10 showed no significant effect on tree growth from removal of thinning slash (Hunter-Smith et al. 1998). Nutritional differences and productivity losses were predicted for three trials, based on biomass removal and existing soil nutrient status (Smith *et al.*, 1997).

Removal of logging residues, in Sweden, was found to reduce the number of many soil animals, although diversity was not affected. The reduced fauna was deemed to have only a small impact on nitrogen mineralisation (Bengtsson *et al.*, 1997). Where logging residue was left to decay after harvest, NO_3-N concentrations in stream water increased 6 fold. Where the residue was removed by burning the increase was 4 fold. The harvesting operation increased suspended sediment in the stream (Harr and Frederiksen, 1988).

Residue harvesting at two sites in Sweden had no effect on soil water chemistry 5 years after harvesting. There were no differences between treatments, with nutrient levels approaching normal. At 4 sites in Sweden the intensive harvesting of residue had no effect on total pools of nitrogen or carbon in the soil. However clear felling resulted in reductions of C and N in the humus layer. Other evidence of nutrient depletion were changes in vegetation cover (by treatment) and the C/N ratio in the soil after slash removal. The removal of the slash reduced the diversity of plot species (Olsson, 1995).

8.2 ADDITION OF WASTES TO MAINTAIN SITE PRODUCTIVITY

The removal of the nutrients can be partially addressed by returning ash to the site at a cost estimated at between $0.25 to $2.00 per green tonne. The return of the ash will not address the nitrogen removals, which could be replaced by artificial fertilisers at a cost estimated at between $3 to $10 per green tonne (Zundel *et al.* 1997).

The natural fertility of the site should be considered when planning residue harvesting, along with the cost of spreading ash and artificial fertilisers. It may be worthwhile to remove the residue and add fertiliser to compensate for nutrient loss.

8.3 SOIL QUALITY AND SITE PRODUCTIVITY

Any harvesting system will cause some soil disturbance and all ground based logging operations (skidders/forwarders) cause some soil compaction. Soil compaction can cause reduced tree growth if it is excessive. Soil compaction can be minimised by using well designed equipment in an organised manner.

Where extra machine passes over the cutover are being considered (for residue recovery) they should be carried out with low ground pressure machines using the tracks created by the previous stem harvesting operations where possible. Rehabilitation of extraction tracks has been shown to be viable in terms of tree growth and cost. Ripping and fertilising is a simple and effective method of rehabilitating extraction tracks (Hall, 1995).

8.4 RISKS OF EROSION

Most logging residue recovery operations will be carried out on flat to rolling terrain. This terrain is not generally at risk of severe erosion. Removal of moderate amounts of residue from the cut-over is not likely to significantly alter this. Steep terrain where erosion is a problem is not suited to residue recovery from the cutover as ground based machines cannot be used. It is unlikely that anyone will consider the removal of logging residue from steep terrain cut-over due to cost constraints. Environmental restrictions due to erosion risk are also likely to limit the removal of residues from steep terrain.

Residue recovery from cable logging landings is environmentally desirable. The residue that builds up at cable landings is often pushed off the landings to maintain operating space. These piles can be large and are often placed on steep unstable soil. As they decay they can become unstable and slip down hill (Figure 8-1). Often these slips are linked to heavy rainfall events. Removal of these residues and avoiding the pile build ups is likely to reduce mass soil slippage which is often associated with large piles of logging debris on steep slopes (Hall, 1997).

In any residue recovery operation it is unlikely that all the residue will be removed due to constraints of equipment and costs. Some of the residue will always remain. It is also possible to specify that a certain percentage of, or volume per hectare of, residue be left on the cut-over in order to maintain nutrients on site and to provide habitat for flora and fauna. The level at which this is set will be a trade off between getting maximum harvesting density and maintaining the environmental values.

Figure 8.1. Mass slump of soil and logging debris from a hauler landing.

8.5 DEVELOPMENT OF GUIDELINES TO MINIMISE ENVIRONMENTAL IMPACTS OF HARVESTING AND RESIDUE COLLECTION

There is a consensus amongst developed countries (Helsinki and Montreal Process's) that forest resources should be managed sustainably. Key issues are soil and land productivity and bio-diversity.

Forest operations are under increasing scrutiny and pressure, particularly those in natural resource forests, although plantation forests are not exempt. Guidelines for sustainable bio-energy production systems must have both local and international applicability, relevance to major issues and recognise ongoing developments in industry and government. They should also allow for incorporation of new information.

A proposed framework for guidelines (Smith and McMahon, 1997) uses a plan to check review cycle with 6 components including (i) setting management goals; (ii) planning; (iii) implementation and operation; (iv) monitoring; (v) review; and (vi) research programme. This approach would enable managers to plan for information acquisition to close knowledge gaps and reduce risks associated with making decisions based on limited information.

8.6 MONITORING OF SITE SUSTAINABILITY

Monitoring will be critical to ensure that forestry management practices maintain a sustainable system. In bioenergy production systems monitoring is required for silvicultural and operational performance measures. Silvicultural monitoring may include repeated measures of tree nutrition and growth rates on permanent sample plots - such practices are routinely carried out by many forest managers.

There is also a significant amount of research being conducted by industrialised nations to identify, test and apply system and forest specific indicators for sustainable management. A bio-centric approach towards monitoring sustainability is recommended, that recognises the need to first maintain the ecological viability of the forests before imposing economic and social expectations (Burger, 1997).

Forest site and soil specific indicators are needed for all biological and physical criteria that are sensitive enough to show significant change. These indicators also need to be easy and cost effective to measure or calculate and calibrated against system change.

Development and monitoring of meaningful indicators is essential.

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CHAPTER 9:

DISCUSSION

By assessing the potential quantities of forestry by-products (wood processing industry and forest residues) available in developed countries with major forest industries that are potentially available for new large scale power generation, it has been estimated that something in the order of 200 - 275 TWh/y (depending on power generation technology) could be produced in Developed Countries. These estimates were based on predicted sustainable forest harvest yields in the year 2000. The region with the greatest potential is North America which may produce up to 155 TWh/year (56% of the global total).

In producing this quantity of electricity, GHG emissions will arise primarily during the collection, transport, pre-treatment (ie chipping) of forestry by-products and power generation systems which inevitably utilise external energy (fossil fuel) resulting in GHG emissions. The emissions may arise during power production, but for purposes of this study, it was assumed that biomass was a zero net carbon emission fuel and that all costs, masses and energy flows, and therefore emissions in the 'production' of the residues are allocated to the main products (timber, pulp, and panel products). The quantity of GHG emissions were estimated to vary between 43-45 Mt CO_2 equivalent per year. The emissions would be influenced by power generating technology with the utilisation of coal co-firing producing less GHG emissions compared to the other biomass to power generation options.

Assuming that the power produced by using forest by-products substitutes for that sourced from coal fired power plants (500 MWe generating capacity), estimates of the amounts of GHG avoided at a global scale range between 30 Mt and 43.5 Mt CO_2 equivalent per year from wood processing residues alone, to 116 - 178 Mt CO_2 equivalent per year from all residues assessed to be potentially available. The variation in potential was dependent on the choice of technology, and on intensity of residues use. The power generating technology with the greatest CO_2 avoided potential was coal co-firing.

Estimates were also made of the potential costs for utilising forest by-products to produce electricity. The cost assessments were only undertaken at a specific country or aggregated regional level as an average global cost was considered unrealistic as the cost of building and operating a biomass electricity generating plant will be determined by the economics of the country or region where the plant is to be constructed and the nature of the biomass resource to be utilised. The estimated costs varied markedly (approximately 0.93 – 24.4 c/kWh, based on a 10% discount rate) depending on the nature of residue source (wood processing or forestry residues), the power generating technology and country. The cheapest power generating technology was the coal co-firing option and the cheapest fuel was wood processing residues, as these materials have minimal collection and handling costs. Using forest residues was shown to add approximately 10 - 50% additional cost to producing electricity depending on both haul distance and power generating technology. This variation in cost arises from the relative cost of collecting residues compared to the capital costs for different power generating options varying markedly.

The relative costs of GHG mitigation between (i) different technologies, (ii) different countries, (iii) different residues types, and (iv) over different haul distances reflected the costs of electricity production.

In order to assess the relative competitiveness of biomass generated electricity, the costs of electricity production based on biomass technologies was compared to price of power from coal fired plant for the different countries. Where no carbon tax or level of support exists for carbon avoided, the price of coal generated electricity varied between 4.14 - 5.01 c/kWh for the different countries. Based on these assessments, electricity generated using biomass was competitive when using coal co-firing or parallel powering options based on either an existing coal plant or combined cycle plant. Stand alone biomass power generating plants (grate or fluidised bed boiler & gasification technology) were generally non-competitive with coal. If stand alone biomass systems were to be competitive, then a level of tax or financial support over \$20/tonne of CO_2 avoided would be required. At a \$100/tonne of CO_2 avoided all biomass technologies would be competitive, except where haul distances are exceptionally large as in Canada (510 kilometres) and USA (980 kilometres).

In presenting this economic assessment, it was assumed that the power would be fed into a national electricity supply grid. It was not possible to take into account site or country specific conditions or difference in country infrastructure. However, it is recognised that a number of other factors, such as localised supply arrangements, may markedly improve the competitiveness of biomass generating systems.

Although the study has indicated the potential quantities of power, costs and CO_2 emissions associated with using forest by-products at both specific country level and a global scale, there are many issues that will influence the level of biomass substitution for fossil fuels for power generation to off-set CO_2 emissions. In Chapters 2, an overview of each country's energy industry was provided. Each country was shown to have a markedly different energy profile (ie fuel sources for total primary energy supply, energy demand, and energy imports or exports). There was marked variation in the relative proportions of energy used in each country which was already sourced from woody biomass. In order to assess the relative contribution that electricity derived from forestry by-products may have in the five countries, a comparison with total energy supply and electricity supply is provided in Table 9-1.

Table 9-1. Comparison of total energy supply and total electricity supply in each country with potential new electricity production based on the study findings.

Country	Total primary energy supply (TWh)	Total electricity consumption (TWh)	Potential electricity production using wood processing industry residues (TWh/y)	Potential electricity production using forestry and wood processing industry residues (TWh/y)	Percentage (Electricity production from using all residues / Total electricity consumption)
Canada	2,747	912	9.68	38.93	4%
Finland	366	70	2.03	6.53	9%
New Zealand	190	32	0.45	4.50	14%
Sweden	611	136	2.93	11.25	8%
USA	24,830	3,463	19.13	114.53	3%

Energy supply values are based on predicted data for 2000. Potential electricity production values are for coal co-firing only as this was the maximum amount of energy able to be produced. The percentage electricity relates to the relative quantity of new electrical power that may be generated using forestry by products compared to predicted total electrical energy supply in 2000.

Countries with the greatest potential for substitution (regardless of cost, and existing infrastructure) are New Zealand, Finland, and Sweden with the proportion of new electrical energy representing 9-14% of the existing total electrical supply. However, it is unlikely that these countries could utilise this full potential as there is insufficient existing coal fired plant capacity. In New Zealand there is only one large coal fired power station. Although data for the USA indicate that the proportion of new biomass derived electricity production based on forestry by-products relative to predicted total electricity supply is low (3%), given the fact that 52% of USA's electricity is currently generated by coal plants, then there may be significant opportunity to adopt coal co-firing systems.

A comparison of current electricity generated from woody biomass to that which may potentially be produced is provided in Table 9-2. Potential additional electricity is based on coal co-firing option and assumes that all potential forest and wood industry by products are used for electrical production. The current electricity values are based on 1996 data.

Table 9-2. Comparison of current electricity production from wood fuels and potential from new electricity production using forest by-products (%).

Country	Current electricity production from woodfuels	Potential additional electricity production from woodfuels
Canada	<1	4%
Finland	10	9%
New Zealand	<1	14%
Sweden	2	8%
USA	DNA	3%

New Zealand shows a marked increase in the percentage of potential total electricity supply based on forestry by products due to large increase in the amount of forestry residues that will become available from an increasing forest harvest.

In addition to comparing potential energy production based on using forestry by-products, it is also useful to consider the effect of collecting, transporting and using forestry by-products may have on total energy derived GHG emissions. Table 9-3 indicates the relative proportion of GHG emissions that may arise from using forest by-products for a coal co-firing regime (and utilising all potentially available residues) compared to current total energy derived GHG emissions.

Table 9-3. GHG emissions from total energy production, and arising from the use of wood processing or all forest by-product residues.

Country	Total energy derived CO_2 emissions (Mt CO_2 e/y, 1995)	Potential CO_2 emissions using wood processing residues (Mt CO_2 e/y)	Potential CO_2 emissions using all residues (processing & forest, Mt CO_2 e/y)	Biofuel CO_2 emission as a percentage of total energy derived CO_2 emisions
Canada	491	0.40	4.58	0.9%
Finland	79	0.08	0.48	0.6%
New Zealand	26	0.02	0.36	1.4%
Sweden	55	0.12	0.80	1.5%
USA	4,960	0.81	21.68	0.4%

Potential CO_2 emission data is based on the coal co-firing option and all forest by-products being utilised.

Generally, utilising forest by-products will contribute relatively low amounts of GHG emissions compared to existing total energy emissions.

Another important energy issue which will influence the uptake of biomass power generation systems is future fuel supplies. From the analysis of each country's energy environment, the competitiveness and utility of natural gas for future electricity production appeared important. Should natural gas supplies increase and international markets develop for electricity based on this resource, then future electricity prices may well decrease and alter the relative competitiveness of electricity derived from fossil fuel sources.

In providing this analysis of the potential amounts of electricity that may be produced using forestry by-products, it was generally assumed that efficient and effective forest residue recovery was practiced. However, such practices are dependent on using appropriate forest silvicultural regimes and harvesting methods; optimising industrial wood production; and employing sustainable forestry management systems. In this assessment it was assumed that the production of high quality merchantable wood remained first priority for utilising the forest resource and that biomass for energy production was a by-product of the system. With this in mind, it should be remembered that the availability of forestry by-products for energy will depend to a certain extent on the competing demand for wood for forest products. With increasing wood prices for forestry wood products, then the cost of residue collection may rise and fuel wood collection operations may become uncompetitive. The costings provided in this assessment were based on current harvesting practices and their existing cost structures. How these will be influenced in the future, remains to be seen.

For biomass energy to effectively contribute to net GHG reduction, the material must be sourced from sustainably managed forests. Although current evidence indicates that long term productivity declines may occur due to loss of organic matter, physical damage to sites, poor weed control or nutrient depletion, such trends tend to be the exception. To ensure collection of forest by-products do not influence the long term viability of bioenergy schemes, ongoing monitoring of forest productivity and health will be critical. A further environmental issue requiring consideration is the potential for forest residues which remain in the forest to produce GHG emissions. Assessment of this issue was not included in this study as no suitable information was available.

Recommendations for further investigations

Further studies on the utilisation of forest by-products should include the following key issues:

- Comparison of bioenergy schemes with gas technology as opposed to coal as was undertaken in this study.

- Detailed assessment of factors influencing the substitution of fossil fuels with biomass in specific countries, in particular analyses to match the utilisation of biomass with resource location within country regions to the effective use of existing infrastructure such as existing coal fired plants, transport networks and electrical transmissions systems.

- Undertake country specific studies to assess the effect of distributing biomass power plants to optimal locations. A key issue that arose during this study was weather plants should be distributed or centralised for the purposes of determining potential power costs and CO_2 emissions. In this report, a centralised approach was adopted to emphasis the impact of fuel haul distance on power costs and CO_2 emissions. An alternative option would have been to distribute the power plants over the country, but this would have resulted in using a fixed fuel haul distance as it was outside the scope of this study to undertake detailed regional assessments to select optimum plant locations. This in turn would have fixed the delivered cost of fuel.

The authors suggest that at least two countries should now be investigated in detail to optimise power plant locations within them and the power costs and CO_2 emissions compared for the centralised and distributed scenarios.

Appendix

Country Data (Year 2000)

1. **Canada**
2. **Finland**
3. **New Zealand**
4. **Sweden**
5. **USA**

a) Residues distribution from centralised processing plants

b) Cost of collection, transport and pre-treatment

c) GHG emissions in collection, transport and pre-treatment