CALCULATION TOOL FOR DIRECT EMISSIONS FROM STATIONARY COMBUSTION

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A WRI/ WBCSD Tool

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GHG PROTOCOL GUIDANCE
DIRECT EMISSIONS FROM STATIONARY COMBUSTION[1]

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[11] This document also addresses emissions from select non-combustion process related to the production of energy (i.e., use of sorbents in emissions control, geothermal energy production, use of fossil fuels as reducing agents, and fossil fuel reforming for fuel cells).

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1 Introduction

The objective of this document is to provide guidance on the estimation of direct (i.e., see box below on Scope 1) greenhouse gas emissions from stationary combustion processes that is in keeping with the principles of the GHG Protocol. Specific guidance is provided on the selection and implementation of emission estimation methodologies, data collection, documentation, and quality management. Methodological and data collection options are described so that different users of this tool may match the rigor and detail of their emission inventory to their needs or goals. This guidance, along with its companion Excel worksheet tool, may be used by companies for internal or public reporting needs, or to participate in a GHG program. Likewise GHG programs, including voluntary or mandatory programs and emission trading schemes, may also customize this tool for their program's needs.[2]

GHG Protocol Scope 1: Direct greenhouse gas emissions

Direct greenhouse gas emissions occur from sources that are owned or controlled by the company, for example, emissions from combustion in owned or controlled boilers, furnaces, vehicles, etc.; emissions from chemical production in owned or controlled process equipment. Direct CO_2 emissions from the combustion of biomass shall not be included in scope 1 but reported separately. Greenhouse gas emissions not covered by the Kyoto Protocol (e.g. CFCs, NO_x, etc.) shall not be included in scope 1, but may be reported separately.

The combustion of fuels produces emissions of the following greenhouse gases: carbon dioxide (CO_2), methane (CH_4) and nitrous oxide (N_2O). The focus of this guidance is on direct emissions of CO_2 from fossil fuel combustion.[3] Carbon dioxide accounts for the majority of greenhouse gas emissions from most stationary combustion units. When weighted by their Global Warming Potentials (GWPs), CO_2 typically represent over 99 percent of the greenhouse gas emissions from the stationary combustion of fossil fuels.[4] Therefore, only basic guidance is provided on the estimation of CH_4 and N_2O emissions from the stationary combustion; however readers are directed to other references for more detailed guidance.

This guidance applies to all sectors and companies whose operations involve stationary combustion of fuels and should be used in conjunction with the following two items:

- GHG Protocol Corporate Reporting Standard and Guidance (revised edition)[5]
- Calculation tool – Calculating CO_2, CH_4, and N_2O direct emissions from stationary combustion of fuels[6]

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[2] Companies participating in a particular GHG program should first check whether specific guidance is available from the program.

[3] Guidance on indirect (e.g., Scope 2) greenhouse gas emissions such as those from the use of electricity are addressed in a separate calculation tool. See <www.ghgprotocol.org/standard/tools.htm>

[4] Potential exceptions include CH_4 from open burning processes and N_2O from some engines with catalytic NOx emissions controls.

[5] See <www.ghgprotocol.org/standard>

[6] See <www.ghgprotocol.org/standard/tools.htm>

This guidance does not address greenhouse gas emissions from transport-related combustion of fuels (i.e., mobile sources).[7] It also does not address indirect greenhouse gas emissions attributable to the consumption of purchased electricity and/or steam.[8] Stationary combustion facilities may also emit greenhouse gases from a variety of other sources such as fugitive emissions of methane from fossil fuel (i.e., natural gas, oil, or coal) handling or storage and SF_6 emissions from electrical transmission and distribution equipment. GHG Protocol guidance on these source categories is upcoming.

Although they are not truly combustion sources, this document does provide a brief discussion on emissions from the use of sorbent materials, such as limestone, in pollution control devices, the use of fossil fuels as reducing agents in industrial processes and a source of hydrogen for fuel cells.

This guidance document is composed of three general segments. The first third of the document provides the core guidance on estimating greenhouse gas emissions. The second third of the document provides annex with default factors and references to available technical standards. The final third contains a detailed glossary of terms relevant to stationary combustion emissions. Figure 1 (below) provides a quick reference for locating the appropriate section of the document to address certain questions.

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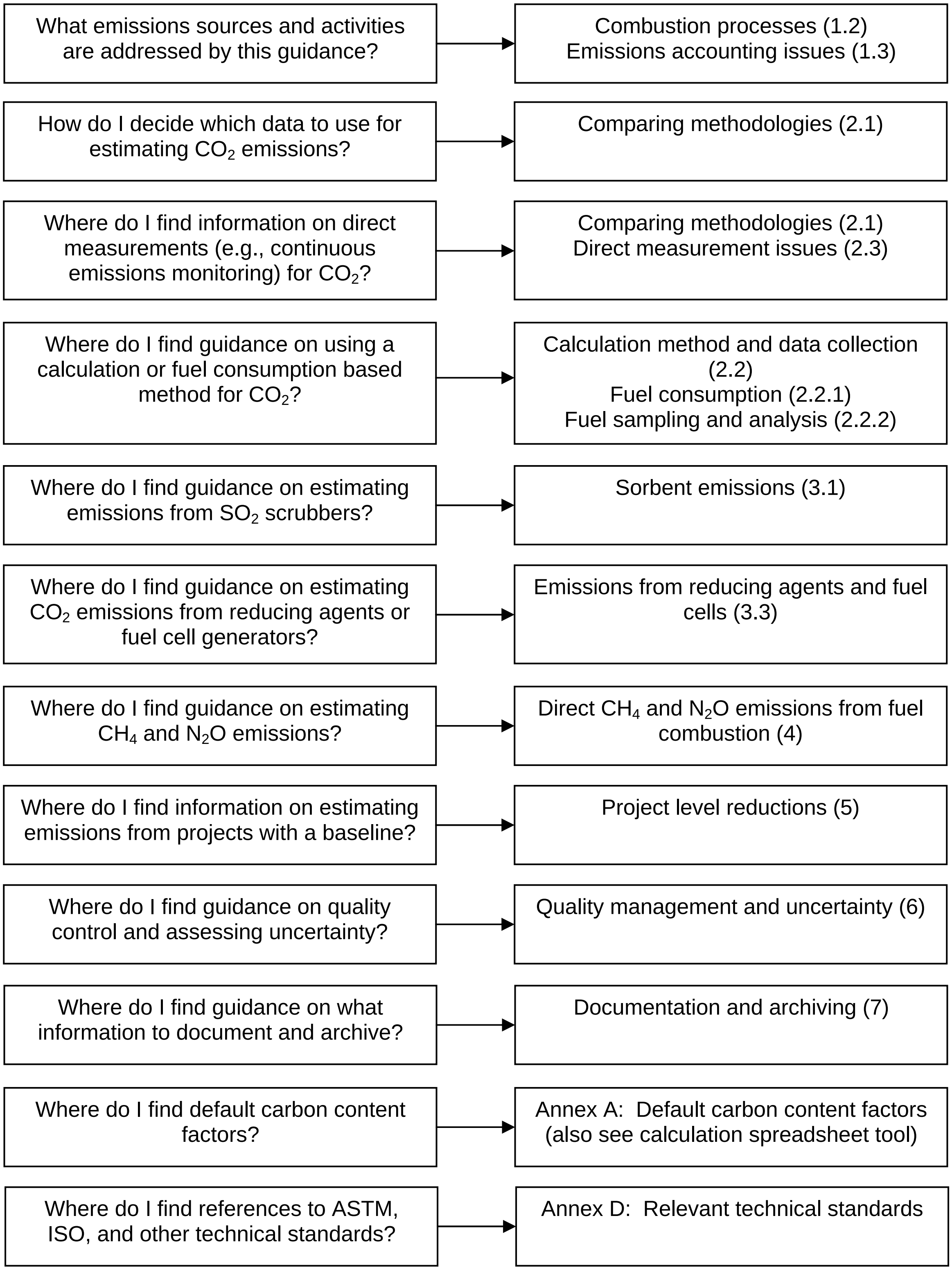
[7] Mobile sources is a term used to describe a wide variety of vehicles, engines, and equipment that generate air pollution and that move, or can be moved, from place to place. It includes vehicles used on roads for transportation of passengers or freight as well as off-road vehicles, engines, and equipment used for construction, agriculture, transportation, recreation, and many other purposes. By definition, other combustion sources are considered to be stationary.

[8] For guidance on accounting for CHP emissions and well as on optional reporting of electricity sales, see <www.ghgprotocol.org/standard/tools.htm>

Figure 1: Users guide to document



1.1 Organizational and operational boundaries

Companies and other users of this guidance should first review the *GHG Protocol Corporate Reporting Standard*[9] before proceeding further. The *GHG Protocol Corporate Reporting Standard* provides in depth detail on defining operational and organizational boundaries, including for complex company structures using an equity share or control approach. The *Corporate Standard* also has chapters on principles, managing inventory quality, public reporting, etc.

For direct greenhouse gas emissions from stationary combustion, any approach to defining organization boundaries will involve identifying individual facility locations where fuel combustion activities occur. Emissions from these facilities may be apportioned on an equity share basis or assigned solely on an operational control basis. Within each facility, multiple combustion units may be operated. Emissions from all combustion units located at a facility should be included in a corporate GHG inventory (e.g., emissions from auxiliary boilers at power plant facility should be included along with emissions from main boilers).

Definitions

A **facility** includes all buildings, equipment, structures, and other stationary items which are located on a single site or on contiguous or adjacent sites and which are owned or operated by the same person or entity (or by any person or entity which controls, is controlled by, or is under common control, with such person or entity). Facilities are also referred to as **installations**. Several distinct types of business activities may occur at a single facility, each of which may operate one or more combustion units. A **combustion unit** is an individual fuel-fired combustion device (e.g., boiler).

For example, a facility owned and operated by an electric power company can house two business activities. The primary activity will likely be electricity generation and may include several combustion units (as well as generators, pollution control equipment, etc.). The same facility could also contain a maintenance shop for the company's transmission line equipment, which may be classified as a separate business activity. The maintenance shop may itself include a combustion unit such as an emergency diesel generator or compressor engine.

Note: Based on definitions from U.S. EPA Emergency Planning and Community Right-to-Know Act (EPCRA), Toxic Chemical Release Inventory (TRI) guidance. The specific legal definition of facility or installation may differ across jurisdictions. The definitions provided above are meant to be instructive for the purpose of this guidance document only and may not represent applicable legal definitions for all companies or organizations.

The calculation tool worksheets associated with this guidance document allow the user to estimate the CO_2, CH_4, and N_2O emissions from any number of combustion units within their organizational boundaries. For the purpose of this guidance document, operational boundaries are restricted to Scope 1 (direct) emissions, as defined in the *GHG Protocol Corporate Reporting Standard*.

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[9] http://www.ghgprotocol.org/standard/GHGProtocolCorporateStandard_RevisedEdition.pdf

1.2 Combustion processes

The combustion process is defined by the rapid oxidation of substances (i.e., fuels) with the release of thermal energy (i.e., heat). During the combustion process greenhouse gases are formed and—unless capture or controlled—emitted.

The energy content of a fuel is an inherent chemical property that is a function of the number and types of chemical bonds in the fuel. The carbon content of a fuel (i.e., the fraction or mass of carbon atoms relative to the total mass or number of atoms in the fuel) is also an inherent chemical property. The vast majority of the energy released during combustion results from the breaking of chemical bonds between carbon and hydrogen atoms and the formation of a double bond between those same carbon atoms and oxygen atoms in the ambient air. Therefore both the amount of heat released from the combustion process and the amount of CO_2 produced are functions of the amount of carbon in the fuel. A small fraction of the carbon in the fuel can escape oxidation and remain as a solid after combustion in the form of soot or ash. The nature of the combustion process allows CO_2 emissions to be estimated based on a simple mass balance approach that accounts for the mass of carbon entering the combustion process in the form of fuel and the amount of carbon exiting the process in the form of CO_2, other carbon containing gases, soot, or ash.[10]

Carbon containing gases other than CO_2 that are also emitted from combustion processes, including methane (CH_4), carbon monoxide (CO), and non-methane volatile organic compounds (NMVOCs). Once in the atmosphere, though, these other gases are naturally oxidized to CO_2 within a few days to 12 years, and therefore are treated as part of the net addition of CO_2 to the atmosphere from fuel combustion.[11] For typical stationary combustion processes, the total amount of carbon in CH_4, CO, and NMVOC emissions is much less than 1 percent of that contained in the CO_2 that is initially emitted, and in most processes—except where combustion occurs extremely inefficiently—less than 0.1 percent. When CO_2 emission estimates are calculated using the amount of fuel combusted and its carbon content, all the carbon in the fuel—minus the fraction remaining unoxidized as soot or ash—is assumed to be oxidized to CO_2 in the long-run.

When emissions are based on direct measurements of CO_2 concentration and exhaust gas flow rate, the carbon in these other gases is not captured because the amount of CO_2 emitted is measured before the carbon in the CH_4, CO, and NMVOC molecules have been oxidized in the atmosphere to CO_2. However, direct measurements will capture non-combustion CO_2 emissions that calculation methods based on fuel consumption do not, such as those produced from limestone and other sorbent material that are used to control emissions of sulphur-containing pollutants in some large combustion units. When using calculation methods, these non-combustion emissions can be estimated separately.

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[10] Theoretically, the carbon in the CO_2 present in the ambient air could also factor into a mass balance approach. Although it is growing at roughly 0.4 percent a year, the concentration of carbon in ambient air is only 0.057 percent on a mass basis. Therefore, the error introduced by ignoring ambient CO_2 is insignificant.

[11] The global warming potential of CH_4 does not include the radiative forcing effect of the indirect CO_2 resulting from the atmospheric oxidation of methane emitted from fossil fuel sources of carbon.

The approach used to estimate CO_2 emissions varies significantly from that required to estimate CH_4 and N_2O emissions. Methane and N_2O emissions depend not only upon fuel characteristics, but also on the combustion technology type, conditions within the combustion chamber, usage of pollution control equipment, and ambient environmental conditions. Emissions of these gases also vary with the size, efficiency, and vintage of the combustion technology, as well as maintenance and operational practices. Due to this added complexity, a greater effort is required to accurately estimate CH_4 and N_2O emissions from stationary combustion sources than it is to estimate carbon dioxide emissions.[12]

Most stationary combustion devices can be classified into one of the following categories:

- Boilers
- Burners
- Turbines
- Heaters
- Furnaces, including blast furnaces
- Incinerators
- Kilns
- Ovens
- Dryers
- Internal combustion engines
- Thermal oxidizers
- Open burning (e.g., fireplaces)
- Flares
- Any other equipment or machinery that combusts carbon bearing fuels or waste streams.

This tool focuses on the combustion of fuels to produce electricity, heat or steam. Some industrial activities, however, involve a close integration of fuel combustion and non-combustion processes, such as iron and steel, cement, and petrochemical production. For processes such as these, it may be difficult to clearly separate between emissions related to combustion of fuels for energy and the oxidation of carbon in fossil fuel feedstocks that are used for non-energy purposes. Additional guidance on these three industrial processes is available in other GHG Protocol tools.[13]

Carbon dioxide emissions from flares are a special category of stationary combustion because flares are typically not operated for the purpose of producing useful energy. They also tend to function at lower combustion efficiencies than other devices (i.e., they allow a larger percentage of the fuel to pass unburnt). However, for the purpose of estimating CO_2 emissions from flares, the methods and data collection approaches are no different than for other combustion units. More attention to fuel composition analysis will likely be required, given the highly variable nature of waste gas streams that are flared. Additional detailed guidance on estimating emissions

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[12] The method provided in this guidance document and calculation tool does not account for the majority of these complexities, and therefore provides only a crude estimate of CH_4 and N_2O emissions from stationary combustion. References are provided for users wishing to use more accurate methods.

[13] See http://www.ghgprotocol.org/standard/tools.htm

from flares is provided in the SANGEA™ Emissions Estimation System for the oil and gas industry[14] and the Pulp and Paper tool.[15]

Stationary combustion emissions also include those from emergency equipment that may rarely be used, from unit startup, and from compressor stations used in the operation of pipelines. Some combustion units may use fuels different than the primary fuel type for start-up or burner ignition. Depending upon the frequency of unit startups, this quantity of fuel could become significant. A complete corporate GHG inventory should include emissions from all combustion sources even if infrequently used.

1.3 Special emissions accounting issues

There are several important accounting issues that are related to the estimation of greenhouse emissions from stationary combustion of fuels. These include the treatment of biomass fuels and fuels from waste materials, the transfer or storage of post-combustion CO_2, and non-combustion process emissions.

1.3.1 Biomass

In addition to fossil fuels such as coal, petroleum (i.e., oil), and natural gas, fuels can also be produced from biomass or plant materials (e.g., wood, crop residues and plant starches). The ultimate chemical composition of and fundamental combustion process for biomass fuels are similar to that of fossil fuels. However, the origin of the carbon in the two types of fuels is different. The carbon in biomass is of a biogenic origin—meaning that it was recently contained in living and breathing tissues—while the carbon in fossil fuels has been trapped in geologic formations for millennia. Because of their biogenic origin, CO_2 emissions from biomass fuels are treated differently from fossil fuel combustion emissions.[16]

For national inventories it is standard practice to report estimates of CO_2 emissions from the combustion of biomass for informational purposes, but not include them in national totals. Any net additions of CO_2 to the atmosphere resulting from biomass combustion should be captured by analyzing national land-use and land-use change activities and their associated effects on terrestrial biomass carbon stocks. If, at the national level, biomass harvests exceed growth and regeneration, the resultant depletion of national biomass stocks result in a net “emission” (flux to the atmosphere)[17]. In the case of corporate-level greenhouse gas inventories, the accounting of terrestrial carbon stock changes associated with the harvesting and combustion of biomass may fall outside the organizational boundaries of a company.[18] Recognizing this situation, the *GHG*

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[14] See http://projects.battelle.org/sangea/home.asp

[15] See http://www.ghgprotocol.org/standard/tools.htm

[16] Intergovernmental Panel on Climate Change (IPCC). 1997. *Revised 1996 IPCC guidelines for national greenhouse gas inventories: Reference manual (Vol 3)*. Section 1.4.1. IPCC National Greenhouse Gas Inventory Program.

[17] Intergovernmental Panel on Climate Change (IPCC). 1997. *Revised 1996 IPCC guidelines for national greenhouse gas inventories: Reference manual (Vol 3)*. Section 5.1.1. IPCC National Greenhouse Gas Inventory Program.

[18] In some cases, such as project level activities, a separate analysis of the impacts of using biomass fuels upon biological carbon stocks may be called for to determine if a net loss of carbon to the atmosphere has occurred.

Protocol Corporate Reporting Standard requires that CO_2 emissions from biomass combustion be reported separately from the other scopes.[19]

Unlike CO_2 emissions, the combustion of biomass does in all cases result in net additions of CH_4 and N_2O to the atmosphere, and therefore emissions of these two greenhouse gases as a result of biomass combustion should be accounted for in emission inventories under Scope 1.

Table 1 lists typical biomass materials that can be combusted for energy. Some of the materials listed in this table may have a fossil fuel component in addition to the biomass component (e.g., municipal waste). The components of waste materials that are of fossil origin should be treated as a fossil fuel, and reported as a Scope 1 emission. In keeping with the guidance from the Intergovernmental Panel on Climate Change (IPCC), the carbon dioxide emissions from the combustion of peat are considered to be of fossil fuel origin and should also be reported with Scope 1 emissions.

Table 1: Typical types of biomass materials used as fuels

Plants and parts of plants • Straw • Hay and grass • Leaves, wood, roots, stumps, bark • Crops (e.g. maize and triticale)
Biomass wastes, products, and by-products • Industrial waste wood (waste wood from woodworking and wood processing operations and waste wood from operations in the wood materials industry) • Used wood (used products made from wood, wood materials) and products and by-products from wood processing operations • Wood-based waste from the pulp and paper industries (e.g. black liquor) • Forestry residues • Animal, fish and food meal, fat, oil and tallow • Primary residues from the food and beverage production • Manure • Agricultural plant residues • Sewage sludge • Biogas produced by digestion, fermentation or gasification of biomass • Harbor sludge and other waterbody sludges and sediments • Turpentine and other biomass based solvents • Landfill gas
Biomass fractions of mixed materials • Biomass fraction of flotsam from waterbody management • Biomass fraction of mixed residues from food and beverage production • Biomass fraction of composites containing wood • Biomass fraction of textile wastes • Biomass fraction of paper, cardboard, pasteboard • Biomass fraction of municipal and industrial waste • Biomass fraction of processed municipal and industrial wastes
Fuels whose components and intermediate products have all been produced from biomass • Bioethanol • Biodiesel

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[19] See Chapter 9 on "Reporting GHG Emissions" in the revised standard.

- Etherised bioethanol
- Biomethanol
- Biodimethylether
- Bio-oil (a pyrolysis oil fuel) and bio-gas

Note: Taken from EU-ETS monitoring and reporting guideline

Additional guidance on the estimation of the combustion of biomass from the pulp and paper industry is available in the GHG Protocol calculation tool on Calculating GHG emissions from pulp and paper mills.[20]

1.3.2 Waste fuels

Waste products in solid, liquid, and gaseous form may also be combusted for energy. For emission inventory purposes, waste fuels are treated no differently than other types of fuels. Carbon dioxide emissions from the fraction of waste fuels of fossil origin should be accounted for, while the fraction of CO_2 emission resulting from carbon of a biogenic origin should be estimated and reported separately.[21]

Typical waste products of a fossil origin include, but are not limited to: plastics, synthetic textiles and rubber, liquid solvents, used tires, used motor oils, municipal solid waste, hazardous waste, and by-product gases. Typical waste products of a biogenic origin include, but are not limited to: yard waste, paper products, natural rubber, and landfill gas. Landfill gas is typically assumed to be entirely of a biogenic origin, although an extremely small fraction of carbon in landfill gas may result from the decomposition of organic material of fossil origin.

1.3.3 Transferred CO_2

If CO_2 resulting from the combustion of fossil fuels is captured and transferred outside the organizational boundaries of a company, then it can be subtracted from the company's direct (Scope 1) emissions, although it may be reported under Scope 3 or under optional information depending upon the whether the CO_2 is eventually emitted and the nature of the emission. Such transfers may occur when CO_2 gas is sold as an industrial feedstock. Some of the potential uses of transferred CO_2 are:

- Enhanced oil recovery
- Carbonated beverages
- Dry ice
- Fire extinguishing agents
- Refrigerant
- Laboratory gas
- Grain infestation treatment
- Solvents
- As a constituent of a by-product fuel that is exported
- As a feedstock to other chemical or industrial processes

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[20] See http://www.ghgprotocol.org/standard/tools.htm

[21] In calculating emissions, care should be taken that all data in calculations are on a consistent wet or dry basis.

Companies should document the quantities of CO_2 transferred outside of its organizational boundaries and the relevant organization and/or facility to which the gas was transferred to.

1.3.4 CO_2 capture and storage

It is possible for CO_2 to be captured (i.e., scrubbed) from the exhaust gas produced from stationary combustion units, and it is currently an active area of research and development. Once captured, CO_2 can be injected into geologic formations that may permanently—or for a long time—store the gas, thereby preventing it from entering the atmosphere. Since international consensus on accounting for geologic storage (i.e., geologic sequestration) of CO_2 is still emerging; companies should transparently document how they treat the quantities of CO_2 injected into geologic formations in their corporate inventory, pending future guidance.[22]

1.3.5 Non-combustion processes

Several non-combustion processes that are in some way related to stationary combustion activities generate CO_2 emissions. These processes include:

- The calcination of limestone used as sorbents in flue gas desulphurization systems and fluidized bed combustion boilers
- The reforming of fossil fuels to produce hydrogen for use in fuel cells
- The use of fossil carbon materials as reducing agents in metal production and other processes

Guidance on estimating emissions from these processes is provided in Section 3 "Direct CO_2 emissions from other processes." Emissions from other sources (e.g., SF_6 from electrical equipment leaks) are not addressed by this guidance document.

2 Direct CO_2 emissions from fuel combustion

There are two basic approaches for estimating direct (Scope 1) CO_2 emissions from stationary combustion: 1) direct measurement of the mass of CO_2 in the exhaust gas and 2) the calculation of CO_2 emissions based on proxy (i.e., activity) data. This section discusses the selection and application methods for the estimation of a company's CO_2 emissions and the collection of data necessary to apply each method.

2.1 Comparing methodologies

Both direct measurement and calculation-based approaches are acceptable ways to estimate CO_2 emissions from stationary combustion. Direct measurement methods usually take the form of a continuous emissions monitoring (CEM) system that records the total flow rate and CO_2 concentration of exhaust gases in a stack or duct, although they can also take the form of discontinuous measurements made for verification or calibration purposes. Calculation based methods usually involve the monitoring of fuel consumption rates, fuel composition, and adjustments for the fraction of carbon that remains unoxidized.

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[22] For additional information on the capture and geologic sequestration of CO_2 see:
<www.co2captureandstorage.info>
<www.netl.doe.gov/coal/CarbonSequestration/index.html>
<www.co2captureproject.com/Phase2Index.htm>

In principle, one would expect the direct measurement of greenhouse gas emissions to be the preferred method for stationary combustion sources.[23] However, in practice it can be both expensive and difficult to accurately measure exhaust gas concentrations and flow rates at combustion facilities. To ensure accurate results, CEM or other direct measurement systems require rigorous calibration and verification procedures. In contrast, calculation methods for CO_2 benefit from the close relationship between the carbon content of fuels and emissions and can generally be implemented at lower costs. Therefore, CEM systems are not necessarily more accurate than calculation based methods for estimating CO_2 emissions, although in most cases they will be more expensive to install and operate.

The relative accuracy of an emissions estimation approach strongly depends on the quality of the data collected and the rigor of quality control measures. Given similar levels of data quality and quality control both direct measurement and calculation based approaches are capable of producing accurate CO_2 emission estimates. However, the extra cost of a direct measurement approaches such as CEM systems typically cannot be justified for the purpose of estimating CO_2 emissions alone. If CEM systems are installed for the purpose of monitoring emissions of other pollutants, however, they can provide an excellent source of real time data that can be used to verify or be verified by fuel based emission estimates. The same conclusion was reached by the Intergovernmental Panel on Climate Change (IPCC):

> "Although continuous monitoring is generally recommended because of its high accuracy, it cannot be justified for CO_2 alone because of its comparatively high costs and because it does not improve accuracy for CO_2. It could, however, be undertaken when monitors are installed for measurements of other pollutants such as SO_2 or NO_x where CO_2 is monitored as the diluent gas in the monitoring system."
>
> - IPCC (2000) *Good Practice Guidance and Uncertainty Management in National Greenhouse Gas Inventories*, p 2.8

For cost and practicality reasons this guidance recommends the use of a calculation based method for estimating CO_2 emissions from stationary combustion sources. The companion spreadsheet tool to this guidance also focuses on the use of a calculation based approach. In cases where direct measurement methods are used for CO_2 emissions, users should demonstrate that the CEM based emission estimates are comparable in terms of quality and accuracy to emission estimates based on fuel consumption and carbon content factors. Companies using CEM systems for certain combustion units may also choose to estimate emissions from other units using a calculation based method.

Most companies with large stationary combustion units already collect emissions-related data and some of that data is already reported to national or other governmental agencies. Companies should strive to maintain consistency in their greenhouse gas inventory with data reported to government agencies. Companies are also encouraged to apply best engineering practices in collecting data, which can often be achieved by applying broadly accepted technical standards (e.g., ISO, CEN, ASTM, NIST, etc.)[24]

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[23] In some cases calculation-based methods for CO_2 emissions are used to check or calibrate exhaust flow rate measurement data of continuous emission monitoring. In such cases, direct measurement emission estimates are no longer fully independent of calculation-based emission estimates.

[24] See Annex D.

U.S. Acid Rain Program[25]

Carbon dioxide emissions are reported under the U.S. Environmental Protection Agency's (EPA) Acid Rain Program, which caps sulphur dioxide (SO_2) and nitrogen oxide (NO_x) emissions from large electric utility and industrial combustion units and allows the trading of emission allowances. The program also requires the reporting of CO_2 emissions from these units. The methods for monitoring and/or estimating CO_2 emissions are based on 40 CFR Part 75, which lists three approaches for determining CO_2 emissions:

- A CO_2 continuous emissions monitoring (CEM) system for measuring CO_2 concentration, volumetric gas flow, and CO_2 mass emissions
- Based on the measured carbon content of the fuel
- A CEM that uses O_2 concentration to determine CO_2 emissions

About 40 percent of the 3,100 units in the program use CEM systems to monitor their CO_2 emissions. These units tend to be larger and account for about 88 percent of the total CO_2 emissions from all affected units. The other 60 percent of combustion units in the program determine their CO_2 emissions by fuel sampling and analysis (Part 75, Appendix G) or by applying default factors. The fuel sampling methodology is based on the type of fuel, the fuel's gross calorific value, and ASTM standards. Upon receipt, EPA applies a series of data quality checking algorithms to reported hourly emissions data before it is formally accepted. Because of the legal compliance nature of all data reported to EPA, affected units in the program will likely utilize their Acid Rain Program CO_2 emissions data for reporting to greenhouse gas programs.

The U.S. Clean Air Act's New Source Performance Standards (NSPS) and other existing regulations also contain provisions regarding CEM systems.

The following section provides detailed guidance on calculation methodologies and data collection for estimating CO_2 emissions. Steps for improving the quality of the data collected for emission estimates are also described. In general, the collection and measurement of more facility and fuel-specific data—as discussed in section 2.2—should increase the quality of emission estimates. However, companies should ensure that differences between facility and fuel-specific data and typical default values are both reasonable and justifiable. Section 2.3 introduces the basic methodology and discusses issues related to the use of direct measurement (e.g., CEM) systems for estimating CO_2 emissions. However, any company that chooses to use a direct measurement methodology will also need to consult more detailed regulatory or GHG program guidelines.

2.2 Calculation method and data collection

Calculation based methods typically entail the collection of a) activity data, in the form of the quantity of fuel consumed for combustion purposes, and b) emission factor data, in the form of information on the characteristics of the fuel combusted and the efficiency of the oxidation process.

In order to calculate CO_2 emissions using fuel consumption and emission factor data, the following equations can be applied:

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[25] 40 CFR.Part 75 <www.epa.gov/airmarkt/monitoring/index.html>

Equation 1: Calculation based method for CO_2 emissions

$$E = A_{f,v} \cdot F_{c,v} \cdot F_{ox} \cdot (44/12) \quad \text{or} \quad E = A_{f,m} \cdot F_{c,m} \cdot F_{ox} \cdot (44/12) \quad \text{or} \quad E = A_{f,h} \cdot F_{c,h} \cdot F_{ox} \cdot (44/12)$$

Where,
E = Mass emissions of CO_2 (short tons or metric tons)
$A_{f,v}$ = Volume of fuel consumed (e.g., L, gallons, ft^3, m^3)
$A_{f,m}$ = Mass of fuel consumed (e.g., short tons or metric tons)
$A_{f,h}$ = Heat content of fuel consumed (GJ or million Btu)
$F_{c,v}$ = Carbon content of fuel on a volume basis (e.g., short tons C/gallon or metric tons C/m^3)
$F_{c,m}$ = Carbon content of fuel on a mass basis (e.g., short tons C/short ton or metric tons C/metric ton)
$F_{c,h}$ = Carbon content of fuel on a heating value basis (e.g., short tons C/million Btu or metric tons C/GJ)
F_{ox} = Oxidation factor to account for fraction of carbon in fuel that remains as soot or ash
(44/12) = The ratio of the molecular weight of CO_2 to that of carbon

Note: Activity data and carbon content factors should be in the same basis (i.e., volume, mass, or energy). For gaseous fuel quantities in terms of volume, care should be taken to ensure all data are on a consistent temperature and pressure basis.

Equation 2: Calculation of heat content of fuel consumed

$$A_{f,h} = A_{f,v}\, H_v \quad \text{or} \quad A_{f,h} = A_{f,m}\, H_m$$

Where,
$A_{f,h}$ = Heat content of fuel consumed (GJ or million Btu)
$A_{f,v}$ = Volume of fuel consumed (e.g., L, gallons, ft^3, m^3)
$A_{f,m}$ = Mass of fuel consumed (e.g., short tons or metric tons)
H_v = Calorific value (i.e., heat content) of fuel on a volume basis (e.g., million Btu/ft^3 or GJ/L)
H_m = Calorific value (i.e., heat content) of fuel on a mass basis (e.g., million Btu/short ton or GJ/metric ton)

Note: For gaseous fuel quantities in terms of volume, care should be taken to ensure all data are on a consistent temperature and pressure basis.

To apply the equations above using the GHG Protocol stationary combustion spreadsheet tool, or any other customized tool, the following steps should be taken:

Step 1

Collect data on the quantity of fuel combusted on a volume, mass, or energy basis. These data can be based on fuel receipts, purchase records, or metering of the amount of fuel entering the combustion device. The values used should account for the appropriate equity/control share. (See section 2.2.1)

Step 2

If necessary, collect data on the fuel's density and/or calorific/heating value and convert fuel data to a common volume, mass, or energy content basis. The fuel consumption data from Step 1 and the carbon content data from Step 2 should be on a common basis before calculating emissions. (See section 2.2.2.1)

Step 3

Estimate carbon content of each of the fuels combusted. Carbon content values can be based on laboratory fuel analysis, data provided by fuel suppliers, or default factors. (See section 2.2.2.2)

Step 4

Collect data to determine oxidation fraction. These data can be based on any combination of analyses of the carbon content of residual solids (i.e., bottom ash, fly ash, and soot), expert judgment, and default factors. (See section 2.2.3)

Step 5

Check to ensure that all units are consistent and converted correctly across parameters and facilities.

Step 6

Estimate CO_2 emissions by applying Equation 1.[26]

Some methods for estimating CO_2 emissions from fuel combustion simply apply a CO_2 emissions factor to fuel consumption data. These methods may or may not incorporate a fraction oxidized variable into the emission factor. The method presented in this guidance is based on parameters that users can explicitly measure and vary based on their specific circumstances and accuracy requirements.

A company's choice of data collection approaches will depend upon the intended application for their greenhouse gas inventory data and the resources available for inventory preparation. It may also depend on the relative significance of the emissions from a particular business unit, facility, or combustion unit.

If a company is collecting their data to report to a specific GHG program, the program may specify that only a certain approach, or even one or two of the options within an approach is acceptable. The user should adhere to all program specifications. These specification may include the method by which fuel consumption data is collected (hourly, daily monthly, yearly), or when a default emission factor is acceptable, etc.

The first step in applying a calculation based method is to prepare a monitoring plan. This plan should utilize and reference existing international and national technical standards where available (i.e., ISO, CEN, ASTM, NIST, U.S. EPA, etc.). Annex D provides a list of relevant technical standards. The monitoring plan should address the following three issues:

Missing data

There may be occasions when fuel flow rate monitors are not in operation because of maintenance or failure or results from fuel analysis samples are erroneous or lost. Procedures for substituting for missing data are an essential part of any calculation based methodology. Typically, data substitution is based on averages for the period before and/or after the equipment outage, preferably supported by operational data such as energy output (e.g., MWh). In some situations, regulators or companies themselves may choose to provide an incentive to avoid excessive monitoring equipment outages by specifying conservative substitution procedures or minimum data capture levels. A combination approach can be used that specifies the use of average substitution values for short duration and infrequent outages, but then directs the use of more conservative adjustment factors or default

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[26] U.S. EPA describes an analogous method for calculating CO_2 emissions in Appendix G to 40 CFR Part 75.

substitution values when the duration of outages exceeds a particular threshold or the number of outages in a year exceeds a particular number.

Biomass

In cases where combustion units are co-fired with a mix of fossil and biomass fuels, the biomass and fossil fuel components of the CO_2 emissions should be calculated separately, using carbon content and oxidation factors related to the specific fuels. The resulting emissions from biogenic carbon should be reported separately.

Calibration and testing

Fuel flow monitors, scales, or other techniques for measuring fuel consumption require careful calibration and testing procedures to ensure that the data collected is unbiased. Likewise, fuel sampling procedures and fuel analysis testing should be conducted so as to provide representative results and avoid contamination.

2.2.1 Fuel consumption (Activity data)

Data on the quantity of fuel consumed in stationary combustion units can be collected using a number of approaches. The following three are the most common and are presented in order of preference according their likely accuracy:

- On-site metering (i.e., flow meters or scales) of the mass or volume flow of fuel at the input point to one or more combustion units.
- Purchase or delivery records of the mass or volume of fuel entering facility. This mass balance approach should also account for inventory stock changes.
- Fuel expenditure data on the amount of fuel purchased in monetary units that is then converted to physical units (i.e., mass, volume, or energy content) based on average prices. This approach should also account for inventory stock changes.

On-site metering

The most direct and potentially the most accurate method for determining quantities of fuel combusted is to measure it as it enters the combustion unit or facility.[27] These data will be in the form of physical units (i.e., mass or volume) and can be gathered using a variety of different types of measurement equipment such as scales or flow meters. A list of common measurement equipment or approaches is presented in Table 2. Fuel metering equipment and readings are subject to biases, like any other measurement. Therefore calibration and testing should be performed to ensure their accuracy and adequate precision. Fuel meter data can also be compared with purchase records for quality control purposes. Fuel consumption monitoring data should be collected using applicable national or international technical standards (e.g., ASTM or ISO).[28]

Table 2: Common fuel consumption metering devices or approaches

Metering equipment or approach	**Media**	**Application**
Orifice plate meter	Gas	Various gaseous fuels
Nozzle meter	Gas	Various gaseous fuels

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[27] Two or more combustion units can be can be supplied by gas, oil, or coal from a common pipe or belt.

[28] See Annex D.

Venturi tube meter	Gas	Various gaseous fuels
Ultra sonic flow meter	Gas	Natural gas and miscellaneous gases
Rotary meter	Gas	Natural gas and miscellaneous gases
Turbine meter	Gas	Natural gas and miscellaneous gases
Ultra sonic flow meter	Liquid	Various liquid fuels
Coriolis flow meter	Liquid	Various liquid fuels
Turbine meter	Liquid	Various liquid fuels
Tank volume differences	Liquid	Various liquid fuels
Truck scale	Solid	Various solid fuels
Rail scales (moving train)	Solid	Coal
Rail scales (single car)	Solid	Coal
Ship displacement	Solid	Coal
Belt scale with integrator	Solid	Coal

Note: Based on EU-ETS M&V guidelines, modified.

Purchase or delivery records

In some cases fuel purchase or delivery records may provide adequate accuracy and precision, given that CO_2 emission estimate are more likely to be needed on annual than a continuous basis. To increase the certainty of the activity data being used, companies may want to determine how fuel suppliers measure their fuel deliveries and whether their procedure and measurement equipment is consistent with the company's data quality needs, as per the previous section. In some GHG Programs, such as the EU Emissions Trading Scheme, such determinations are recommended to ensure the quality of the data.

Equation 3: Accounting for changes in fuel stocks

$$Fuel_B = Fuel_P + (Fuel_{ST} - Fuel_{SE})$$

Where,

$Fuel_B$ = Fuel combusted during period

$Fuel_P$ = Fuel purchased or delivered during period

$Fuel_{ST}$ = Fuel stock at beginning of period

$Fuel_{SE}$ = Fuel stock at end of period

Issues with determining annual fuel consumption

Determining coal, and to a lesser extent oil and natural gas, consumption can problematic. Coal scales used for fuel metering are often imprecise. It may also be necessary to estimate the amount of coal in storage piles (or oil and natural gas in storage tanks) at the beginning of the year and at the end of the year is to determine stock changes. Using purchase and delivery records can also be problematic, as fuel from one delivery may not be used up before the end of the year. For these reasons, a combination of fuel metering and purchase and delivery records may be needed to ensure their estimation of the amount of fuel consumed each year is complete and consistent over time.

Fuel expenditure records

In cases where it is not practical or possible to obtain fuel meter or purchase data, expenditure data can be used to estimate the quantity of fuel purchased. Companies should endeavor to obtain data on the specific price paid for fuels from suppliers if it is not internally available. If specific price data is not available, then average or likely prices will have to be assumed. The basis for these price assumptions should be documented.

> Variations in price over the time period that emissions are being estimated should also be considered.
>
> *Accounting for Inventory Stock Changes*
>
> In cases where fuel is stored at a facility after it is delivered, it is important to address stock changes and any fugitive losses or spills. Purchases or deliveries may not be equivalent to the amount of fuel actually combusted during a period when fuel stocks have increased or decreased, especially when deliveries occur near the end of a reporting period (see Equation 3). Fuel losses can result form leaking valves or pipes supplying gaseous or liquid fuels. Releases of methane in gaseous fuels should be accounted for separately as fugitive emissions (see SANGEA™ Emissions Estimation System for the oil and gas industry[29]). In all cases the assumptions and calculations made to adjust fuel purchase and delivery data should be documented.

At some facilities, fossil fuels are used not only as a source of energy, but also as feedstocks for manufacturing processes or products. Some of these processes may result in the carbon in the fossil fuels not being oxidized, but instead converted into a product or by-product that is exported out of the company's organizational boundaries (e.g., the manufacture of plastics at a petrochemical facility). This unoxidized carbon that ends up in products or by-products should be subtracted from the quantity of carbon associated with previously estimated fuel consumption data. Equivalent measurement standards should be applied to estimating the quantity of carbon in products or by-products as is used to estimate fuel consumption and carbon content values.

Activity data, in the form of fuel consumption, is the key input parameter to calculation-based methods. It is the one data variable that is completely dependent on companies to collect because no default values are possible. Fuel consumption data are also likely to be the largest source of uncertainty for many companies.

2.2.2 Fuel sampling and analysis (Factors)

Fuel sampling and analysis is performed to determine the heating or calorific value (i.e., energy content) and carbon content of the fuels consumed in stationary combustion units. In some cases it may also be necessary to determine the moisture content of fuels and the density of gaseous fuels in order to convert volumetric fuel flow meter data to units of mass. This section provides specific guidance on carbon content and calorific values. Companies should refer to the Annex D for references on technical standards for measuring fuel density and moisture values.

Fuels may be sampled and analyzed by any combination of facility operators, fuel suppliers, or outside laboratories. The following are typical fuel sampling options in order of preference:

- As-fired[30] via a pipeline or belt feed
- As-delivered (e.g., ship load, truck load, rail load, discrete purchase through pipeline)
- From storage tank after each fuel addition

A fuel's heating value and carbon content may be measured on an a) as-received basis or b) moisture free basis and mineral matter-free basis. It is important that all fuel consumption data

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[29] See http://projects.battelle.org/sangea/home.asp

[30] As fired means taking a fuel sample just prior to its introduction into a combustion unit.

and factors applied in calculating CO_2 emissions are on an equivalent moisture and mineral-matter basis. If calculations are done on a wet basis but the moisture content of activity data and factors are different, then data should be adjusted to an equivalent moisture content.[31]

The frequency at which fuel analyses are performed will be dependent upon the consistency of the fuel's characteristics. The frequency of fuel sampling should be greater for more variable or heterogeneous fuels (i.e., municipal solid waste) and less frequent for highly homogeneous and invariant fuels (e.g., pure propane). In cases where there is some uncertainty as to the consistency of a fuel's characteristics, fuel sampling can initially be conducted at a high frequency (e.g., daily) and then after a period be conducted at a frequency that better matches the observed variation in the fuel. In such cases, though, sampling should continue to be repeated immediately following any change in the fuels characteristics (e.g., change in supplier).

Fuel analysis data should be collected and analyzed using applicable national or international technical standards (e.g., ASTM or ISO)[32] that address issues of sampling frequency, procedures, and preparation.

2.2.2.1 Heating (Calorific) values

The heating or calorific value of a fuel is a measure of the quantity of heat liberated during combustion of the fuel. The dominant source of heat during combustion processes results from the oxidation of the carbon in hydrocarbons.

Net calorific values (NCVs) are a measure of the quantity of heat liberated assuming that the water in the combustion exhaust gas remains as a vapor (i.e., the heat contained in the water vapor is not recovered). Gross calorific values (GCVs) are larger in magnitude because they assume that the heat in this water vapor is recovered. Net calorific values are also referred to as lower heating values (LHVs) and gross calorific values are also referred to as higher heating values (HHV). When calculating CO_2 emissions, it is critical that all fuel consumption data and factors are on the same heating value basis.

Fuel consumption can be converted from a GCV to NCV basis, or vice versa, using the following "rule of thumb."

Equation 4: "Rule of thumb" conversion between LHV and HHV

$$Y_{GCV} = Y_{NCV} / x \quad \text{or} \quad Y_{NCV} = Y_{GCV} \cdot x$$

Where,

Y = Fuel consumption data on an energy content basis (e.g., MJ)

x = 0.95 for solid and liquid fossil fuels and 0.90 for gaseous fossil fuels

In reality, however, the conversion between GCV and NCV based values is partly dependent upon the actual moisture content of the fuel, which can vary significantly. These "rule of thumb" values are based on assumed typical moisture contents and can be especially inaccurate for coal

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[31] For cases where fuels are assumed have air-dried, atmospheric moisture content (i.e., humidity) averages 1 to 2 percent by mass. However, the moisture content of solid fuels is often significantly higher than 2 percent.

[32] See Annex D.

and biomass fuels. Additional guidance on converting between GCV and NCV values is provided in Annex B.

The preferred approach for determining a fuel's heating value is to sample the fuel being combusted and complete a chemical analysis of it.[33] These analyses can be performed by outside laboratories or analogous data may be available from fuel suppliers. While it is not common for fuel suppliers to be able to provide carbon content factors, most suppliers should be able to provide information on their fuel's heating value on a volume or mass basis.

If it is not practical to conduct fuel analyses or otherwise obtain data that is specific to the exact fuel being combusted, then default heating values are available for standard fuel types. Default heating values for some specialty fuels or fuels derived from waste materials may not be available. The various IPCC guidelines reports provide information on default heating values for a variety of standard fuel types.[34] Table 1-13 in the Revised 1996 IPCC Guidelines provides default moisture and calorific values for various biomass fuels.[35] Information on the range of likely calorific values for major fuel categories and suggested default values are provided in the calculation tool that accompanies this guidance.

2.2.2.2 Carbon content factors

Carbon content factors are a measure of the potential CO_2 emissions from the combustion of a fossil fuel because they are a measure of the total carbon in the fuel. The fundamental chemistry of each type of fossil fuel results in physical limits in the variability of their carbon contents. However, even when precisely classified by fuel type (e.g., bituminous coal) there still exists variability in carbon contents across samples.

The preferred approach for determining a fuel's carbon content is to sample the fuel being combusted and complete a chemical analysis of it. These analyses can be performed by outside laboratories or analogous data may be available from fuel suppliers. In the determination of a fuel's carbon content it is important to consider any CO_2 that may be entrained, especially for gaseous fuels such as coke oven or blast furnace gas.

If it is not practical to conduct fuel analyses or otherwise obtain data that is specific to the exact fuel being combusted, then default carbon content factors are available for standard fuel types. Numerous sources for default carbon content factors are available. When choosing a default value, the inventory manager should try to pick the carbon content factor most likely to represent the fuel being used. For example, rather than using a coal carbon content factor based on an IPCC default, there may be national or even basin-specific values available. Default carbon content factors for some specialty fuels or fuels derived from waste materials may not be available. Annex A provides detailed information on default carbon content values for a variety of standard fuel types.

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[33] For the U.S. Acid Rain Program, guidance on determining heating values is provided in Appendix F of 40 CFR Part 75.

[34] See Table 2.4 at http://www.ipcc-nggip.iges.or.jp/public/gp/english/2_Energy.pdf

[35] See Table 1-13 at http://www.ipcc-nggip.iges.or.jp/public/gl/invs6a.htm

The IPCC and other international organizations typically provide carbon content factors expressed on an energy content basis (e.g., kg carbon/MJ). The justification for this recommendation is that within a specific fuel type, carbon contents exhibit less variability when expressed on an energy content basis rather than a volume or mass basis due to the close correlation between heating values and carbon content factors. In cases where default carbon content factors are being used, as-received or as-fired heating values should be used to convert fuel consumption data to an energy basis. In general, default carbon content factors should only be used on an energy basis.

However, in cases where fuel inputs to a combustion unit is measured on a volume or mass basis and an as-received or as-fired fuel analysis has been conducted using the same basis, then it is more practical and may be more accurate to apply carbon content factors on the same basis, rather than first convert the fuel to an energy basis. Utilizing factors on a mass or volume basis also allows adjustments to be made for variations in moisture content more easily.[36]

The IPCC and other international organizations also typically provide heating values on a NCV (i.e., LHV) basis. However, when default carbon content factors on an energy basis are used, there is a good argument for the use of data on a GCV (i.e., HHV) basis instead of a NCV (i.e., LHV) basis. The reason being that the relationship between carbon content and heating value is more direct when expressed on a GCV basis. When expressed on a NCV basis, the relationship is also a function of the moisture content of the fuel, which itself can be vary significantly.

If more than one type of fuel is combusted (i.e., mixed fuel) then a weighted average carbon content factor can be used or the CO_2 emissions from each type of fuel input should be calculated separately.[37]

Information on the range of likely carbon content values for major fuel categories and suggested default values are provided in the calculation tool that accompanies this guidance. Further information on default factors can be found in the various IPCC guidelines reports[38] and in the IPCC Emission Factor Database.[39]

Coal

Coal includes a wide diversity of fossilized solid materials derived from plants. The distinguishing characteristics of different coals are their heating value, carbon content, ash content, and content of sulfur and other impurities. Coal is classified into four general categories, or ranks. They range from lignite through subbituminous and bituminous to anthracite, reflecting the progressive response of individual deposits of coal to increasing heat and pressure. The carbon content of coal supplies most of its heating value, but other factors also influence the amount of energy it contains per unit of mass.

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[36] EU ETS monitoring and reporting guidelines require that reporting organizations justify the use of mass or volume based carbon content factors over energy content based factors in terms of their accuracy. In either case reporting organizations must still report the energy content of fuels combusted for quality control purposes.

[37] If a weighted average carbon content factor is used then the oxidation factor used should be representative of the total fuel mixture. The use of a weighted average carbon content factor would not be appropriate in cases where biomass fuels are used, as CO_2 emissions from biomass fuel combustion are to be reported separately.

[38] See http://www.ipcc.ch/pub/guide.htm

[39] See http://www.ipcc-nggip.iges.or.jp/EFDB/main.php

An important constituent of coals is ash, which is not a function of the coal's rank but is measured for determination of its grade when sold. Ash is the primarily inorganic (i.e., mineral) residue remaining after the combustion of coal and can vary between 1 and 30 percent by mass. The fraction of carbon remaining in residual bottom and fly ash is the major determinant of the oxidation factor for coal combustion.

For the purpose of interpreting fuel analysis results, it may be important to differentiate between the total carbon content of coals and the fixed carbon content. Fixed carbon is the solid residue remaining after the volatile matter has been liberated from coal. It is the total carbon content value of the fuel that should be used for the purpose of estimating CO_2 emissions.

A coal's heating value, carbon content, and fixed carbon content can be measured on an as-received basis, moisture free basis, or dry mineral matter-free basis. Most coal consumption data will likely be on an as-received basis. It is important that all factors applied in calculating CO_2 emissions are on an equivalent basis.

Coke is solid carbonaceous residue that is typically derived from low-ash, low-sulfur bituminous coal from which the volatile constituents have been driven off in an oven so that the fixed carbon and residual ash are fused together. Coke is used as a fuel for some stationary combustion purposes and both as a fuel and reducing agent in smelting iron ore in a blast furnace. Coke from coal typically has a heating value of around 29 MJ/kg. Coke can also be made from petroleum.

Coal ranks and composition[40]

Lignite. Lignite is generally the youngest of the coal ranks and is sometimes referred to as brown coal. It is a coal in the process of transformation from peat to sub-bituminous. The moisture content varies significantly, but is often high (up to 45 percent by mass). Lignite coals typically have a low heating value, from about 8 to 21 MJ/kg, and a high oxygen content compared with bituminous coals. They also tend to have lower carbon content than bituminous coals, varying between 26 to 50 percent by mass. The ash content can be highly variable from a few percent to as much as 50 percent. There is no universally accepted definition of lignite, which can create confusion when comparing lignite data from one country to another. One notable characteristic of lignite is its marked variability in quality. Even within a single deposit variation of ash, moisture, volatile matter and sulphur is generally much greater than is normally observed in hard black coal deposits. Some of this variability can be attributed to the generally young age of the lignite deposits.

Subbituminous. Subbituminous coals represent the next stage in the coalification process from lignite and are sometimes referred to as "black lignite." The main feature of subbituminous coals compared with lignite is the significantly lower levels of moisture. Subbituminous coals typically have a heat value from about 12 to 28 MJ/kg and carbon content between 35 and 65 percent by mass. Production of subbituminous coals is not reported consistently in all countries, lower rank subbituminous coals often get lumped in with lignite and higher rank subbituminous coals are frequently reported with bituminous.

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[40] The definitions of coal ranks in this box are meant to be instructive. More specific definitions may apply for regulatory purposes within specific jurisdictions.

Bituminous. Bituminous coals occur as a later stage of development in the coalification process and are typically lower in moisture than lignite or subbituminous ranks. They generally have a heating value from 20 to 38 MJ/kg and carbon content between 54 to 86 percent by mass.

Anthracite. Anthracite represents the highest rank of coal found in nature. The main characteristics of anthracite are the very low levels of moisture and volatile matter as a result of intense coalification. This coal rank is sometimes subdivided into three groups based on decreasing fixed carbon and increasing volatile matter content: meta-anthracite, anthracite, and semianthracite. Anthracite coals typically have a heat value from about 22 to 33 MJ/kg and carbon content between 60 and 94 percent by mass. Semi-anthracite coals typically have a carbon content of 58 to 84 percent by mass.

Natural gas

Natural gas is predominantly composed of methane (CH_4), but it may also contain many other compounds that can lower or raise its overall carbon content. These other compounds may be divided into two categories: 1) natural gas liquids (NGLs), and 2) non-hydrocarbon gases.

The most common NGLs are ethane (C_2H_6), propane (C_3H_8), butane (C_4H_{10}), and, to a lesser extent, pentane (C_5H_{12}) and hexane (C_6H_{14}). Because the components of NGLs have more carbon atoms than methane, their occurrence increases the overall carbon content of natural gas. Natural gas liquids typically also have a commercial value greater than that of methane, and therefore are often separated from raw natural gas at gas processing plants and sold as separate products. Ethane is typically used as a petrochemical feedstock, propane and butane have a variety of uses, and natural gasoline[41] is used make a variety of gasoline and naphtha products.

Raw natural gas also contains varying amounts of non-hydrocarbon gases, such as carbon dioxide, nitrogen, helium, other noble gases, and hydrogen sulfide. The share of non-hydrocarbon gases in raw natural gas is usually less than 5 percent by mass, but the share can be much larger. Hydrogen sulfide is normally removed from the gas during processing. Inert gases are typically removed if their presence is substantial enough to reduce the energy content of the gas below pipeline or market specifications.

Natural gas suppliers may achieve the same energy content with a wide variety of methane, higher hydrocarbon, and non-hydrocarbon gas combinations. Therefore, while the heating value of natural gas has some predictive value, knowing it does not substantially improve the accuracy of carbon content factors. The carbon content factors for typical pipeline grade natural gas in the United States range between 15.2 to 15.8 kg C/GJ. The carbon content of pure methane on mass basis is 75 percent, while that of higher gaseous hydrocarbons is limited to about 82 percent. On a volume basis at standard conditions, the carbon content of pure methane is about 0.51 kg C/m^3, while that of butane is about 2.1 kg C/m^3. The minimum carbon content value of any gaseous hydrocarbon fuel, however, can be significantly reduced by increased concentrations of inert gases.

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[41] A term used in the gas processing industry to refer to a mixture of liquid hydrocarbons (mostly pentanes and heavier hydrocarbons) extracted from natural gas.

Raw natural gas, which is usually flared, contains greater percentages of NGLs and carbon dioxide and therefore will typically have a higher overall carbon content on an energy basis than gas that has been processed and moved to end-use customers via transmission and distribution pipelines.

Petroleum

Crude oil and petroleum products can contain mixtures of several hundred distinct chemical compounds, but are predominantly composed of hydrocarbons. All hydrocarbons contain hydrogen and carbon in various proportions. When crude oil is distilled into petroleum products, it is sorted into fractions by the increasing boiling temperature of organic molecules of increasing size. Petroleum products consisting of relatively simple molecules and few carbon atoms have low boiling temperatures, while larger molecules with more carbon atoms have higher boiling temperatures. Petroleum products with higher carbon contents, in general, are denser and have lower energy content per unit mass and higher energy content per unit volume than products with lower carbon contents. Hydrocarbon molecules containing 2 to 4 carbon atoms are all natural gas liquids; hydrocarbons with 5 to 10 carbon atoms are predominantly found in naphtha and gasoline; and hydrocarbon compounds with 12 to 20 carbons comprise "middle distillates," which are used to make diesel fuel, kerosene and jet fuel. Larger molecules are generally used as lubricants, waxes, and residual fuel oil.

Petroleum products range in density from 60 to 150 kilograms per barrel, or ±50 percent. The variation in carbon content, however, is much smaller (±7 percent). Ethane is 80 percent carbon by mass, while petroleum coke can range from 75 to 95 percent carbon by mass. The narrow range of carbon contents can be explained by the fundamental nature of petroleum chemistry. On average, crude oils are around 85 percent carbon by mass.

Major petroleum chemical classes[42]

Petroleum based hydrocarbons can be divided into five general classes, each with a particular physical properties, including density and carbon content. Refiners control the mix of hydrocarbon types in particular products in order to give petroleum products distinct properties. The main classes of hydrocarbons are described below:

Paraffins. Paraffins are the most common constituent of crude oil, usually comprising 60 percent by mass. Paraffins are straight-chain hydrocarbons with the general formula C_nH_{2n+2}. Paraffins include ethane (C_2H_6), propane (C_3H_8), butane (C_4H_{10}), and octane (C_8H_{18}). As the chemical formula suggests, the carbon content of the paraffins increases with their carbon number: ethane is 80 percent carbon by weight, octane 84 percent. As the size of paraffin molecules increases, the carbon content approaches the limiting value of 85.7 percent asymptotically.

Cycloparaffins. Cycloparaffins are similar to paraffins, except that the carbon molecules form ring structures rather than straight chains, and consequently require two fewer hydrogen molecules than paraffins. Cycloparaffins always have the general formula C_nH_{2n} and are 85.7 percent carbon by mass, regardless of molecular size.

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[42] The definitions of petroleum classes in this box are meant to be instructive. More specific definitions may apply for regulatory purposes within specific jurisdictions.

Olefins. Olefins are a reactive and unstable form of paraffin: a straight chain with the two hydrogen atoms at each end of the chain missing. They are never found in crude oil but are created in moderate quantities by the refining process. Thus, gasoline, for example, may contain 2 percent olefins. They also have the general formula C_nH_{2n}, and hence are also always 85.7 percent carbon by weight. Propylene (C_3H_6), a common intermediate petrochemical product, is an olefin.

Aromatics. Aromatics are very reactive hydrocarbons that are relatively uncommon in crude oil (10 percent or less). Light aromatics increase the octane level in gasoline, and consequently are deliberately created by steam reforming of naphtha. Aromatics also take the form of ring structures with some double bonds between carbon atoms. The most common aromatics are benzene (C_6H_6), toluene (C_7H_8), and xylene (C_8H_{10}). The general formula for aromatics is C_nH_{2n-6}. Benzene is 92 percent carbon by mass, while xylene is 90.6 percent carbon by mass. Unlike the other hydrocarbon families, the carbon content of aromatics declines asymptotically toward 85.7 percent with increasing carbon number and density.

Polynuclear Aromatics. Polynuclear aromatics are large molecules with a multiple ring structure and few hydrogen atoms, such as naphthalene ($C_{10}H_2$ and 94.4 percent carbon by mass) and anthracene ($C_{14}H_4$ and 97.7 percent carbon by mass). They are relatively rare but do appear in heavier petroleum products.

Note: Taken from *Inventory of U.S. Greenhouse Gas Emissions and Sinks*

Non-standard and biomass fuels

Not all stationary combustion devices burn standard fuels. For example stationary combustion units can use waste fuels, such as wood residuals or municipal solid waste, and flares and thermal oxidizers can burn waste gas streams. Because of their variability, there are few reliable default carbon content factors for specific waste or biomass fuels. Therefore analyses of the fuel's fossil carbon content may be required.[43] Additional information on the carbon contents of biomass fuels is available in the GHG Protocol's pulp and paper industry calculation tool[44] or in the IPCC Emission Factor Database.[45]

2.2.3 Oxidation factors

Oxidation factors account for the fraction of carbon in a fuel that remains unoxidized and in solid form following the combustion process. Although most stationary combustion processes will result in the majority of the carbon in a fuel being emitted in gaseous form, either as CO_2 or as carbon containing molecules that will later oxidize to CO_2 in the atmosphere (e.g., CO, CH_4, or NMVOCs), a small fraction will be converted to residual ash, soot, or solid particulates. For the purpose of estimating combustion emissions of CO_2, it is assumed that this post-combustion residual carbon is stored indefinitely.[46] The amount of unoxidized (i.e., unburnt) carbon is a function of several factors, including: fuel type, combustion technology, equipment age, and operating practices. These factors can also vary over time even for an individual combustion unit.

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[43] In cases where a fuel stream is composed of a mix of fossil and biomass components, more rigorous analysis may be required to measure the exact composition of the two components separately.

[44] See http://www.ghgprotocol.org/standard/tools.htm

[45] See http://www.ipcc-nggip.iges.or.jp/EFDB/main.php

[46] Alternatively, any CO_2 emissions associated with oxidation of residual solid carbon may be accounted for under emissions from some other source category (e.g., energy recovery from high carbon fly ash).

Some of original work on oxidation factors for estimating CO_2 emissions from combustion processes was done by Marland and Rotty (1984) (see Table 3). The IPCC provides default values based on Marland and Rotty's work (see Table 4). Although widely used, the IPCC values are meant as global averages for national scale emission inventories. These default values may not be appropriate for a particular combustion unit. In general, the variability in oxidation factors for gaseous and liquid fuels across most combustion technologies is low. However, for solid fuels such as coal, oxidation factors can vary more significantly (see Table 4).

The preferred approach for determining an oxidation factor or factors is to measure the quantity of residual solid by-products of the combustion process and analyze their carbon content. If it is not practical to quantify and analyze post-combustion residual carbon solids then default oxidation factors can be used. The most conservative approach to selecting an oxidation factor would be to use 100 percent unless data is collected to demonstrate otherwise.

Table 3: Unoxidized fraction assumptions by Marland & Rotty (1984)

Fuel type	Assumption
Natural gas	Less than 1 percent of carbon in the fuel is left unoxidized as soot in the burner, stack, or in the form of particulate emissions.
Oil (petroleum)	1.5 +/-1 percent of the carbon in oil products is left unoxidized as soot or particulate matter
Coal	1 +/-1 percent of the carbon in coal that is combusted in furnaces remains in the residual ash

Note: As reported in IPCC (1997).

Table 4: IPCC national average default values for oxidation factor values (percent)

Fuel type	IPCC default value	Range of likely values
Coal	98[b]	91 to 100
Oil and oil products	99	97.5 to 100
Gas[a]	99.5	99 to 100
Peat	99 for electricity generation <99 for residential and commercial use	91 to 100

[a] Including natural gas, biogas, and other gaseous fuels.

[b] The default value for the U.S. greenhouse gas inventory and Acid Rain Program is 99 percent.

For gaseous and liquid fuels the oxidation factor will be dominated by carbon buildup and particulate emissions. More recent research has found that for modern gas-fired boilers and turbines and gasoline-fired internal combustion engines, that operate efficiently, the fraction of carbon oxidized can be assumed to be 100 percent. For diesel-fired engines with significant particulate emissions, oxidation factors can be towards the lower end of the range for oil.

For solid fuels, especially coal, the oxidation factor will be dominated by carbon remaining in ash. In boilers most of the carbon will be contained in fly ash instead of bottom ash or boiler slag. The ash content of typical coals range between 1 to 30 percent, but more typically ranges from 3 to 15 percent by mass. The carbon content of post-combustion fly ash can also vary between almost 0 up to 25 percent by mass (see Table 5). Specifically, stoker boilers have been found to produce higher unoxidized carbon fractions ranging up to 12 percent by mass of total fuel consumption. Coal combusted in small residential or commercial furnaces can leave up to 5 to 10 percent of carbon unoxidized.

Table 5: Typical carbon content range in fly ash by coal rank (percent by mass)

Coal rank	**Typical carbon content of fly ash**
Bituminous	0 to 15
Subbituminous	0 to 3
Lignite	0 to 5

Note: In cases of inefficient coal crushing leading to large particle sizes, ash carbon contents can be up to 25 percent by mass.

Emission estimates of CO_2 should also be adjusted for the carbon contained in any other unoxidized liquid or solid effluents or waste by-products containing carbon originating from the fossil fuel being consumed.

2.3 Direct measurement issues

This section introduces the basic methodology and discusses issues related to the use of direct measurement (e.g., CEM) systems for estimating CO_2 emissions. Companies and other interested in implementing a rigorous direct measurement methodology should also consult more detailed technical standards[47] and/or applicable regulatory or GHG program guidelines.[48]

Direct measurement of emissions typically entails the use of some type of CEM system, although it may also involve the use of intermittent sampling of stack gas flow rates and composition for verification or calibration purposes. The fundamental components of most direct measurement systems include:

- A CO_2 gas concentration monitor[49]
- A stack or flue volumetric flow rate (i.e., velocity) monitor
- Temperature monitor at the same location as monitoring probes to determine the density of the exhaust gas
- An automated data acquisition and handling system for recording and calculating emissions data

Oxygen (O_2) monitors are used in some systems as a proxy to estimate CO_2 concentration; however, this approach is not likely to be as accurate as directly measuring CO_2. Some systems may also require a stack exhaust gas moisture (H_2O) concentration monitor to adjust gas concentration data so that it is on a common wet basis with exhaust gas flow rate data.

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[47] See Annex D.

[48] For example see U.S. Acid Rain Program's 40 CFR Part 75 guidelines. <www.epa.gov/airmarkt/monitoring/index.html>

[49] CO_2 concentration is typically measured with the use of an infrared gas analyzer and a reference or calibration gas.

Like calculation-based methods, the first step in applying a direct measurement method is to prepare a monitoring plan, including the selection of suitable measurement equipment. This plan should utilize and reference existing international and national technical standards where available (i.e., ISO, CEN, ASTM, NIST, U.S. EPA, etc.). Annex D provides a list of relevant technical standards. The monitoring plan should also address the following issues:

> *Sample rate and data summation*
>
> The frequency at which the equipment samples the exhaust gas flow rate must be selected. In reality, CEM systems do not continuously monitor emissions, but instead sample the exhaust gas produced by combustion units at a high frequency. A typical sample rate for both exhaust gas flow rate and concentration is every 15 minutes. CEM systems must also specify an averaging time for the samples taken. Once averaged, emissions are calculated and then summed to produce longer term emission estimates. Standard practice in the United States is to average four 15 minute samples and then estimate emissions hourly. These hourly estimates can then be summed to produce annual estimates. For partial operating hours (i.e., combustion unit operates for less than four 15 minute intervals) hourly emissions data can be prorated or a full hours operation can be assumed to provided a more conservative estimate.[50]
>
> *Missing data*
>
> There will likely be occasions when particular components of a CEM system will not be operating because of maintenance or failure. Procedures for substituting for missing data are an essential part of any direct measurement methodology. Typically, data substitution is based on averages for the period before and/or after the equipment outage, preferably supported by emission estimates using fuel consumption data. In some situations regulators or companies themselves may choose to provide an incentive to avoid excessive monitoring equipment outages by specifying conservative substitution procedures or minimum data capture levels. A combination approach can be used that specifies the use of average substitution values for short duration and infrequent outages, but then directs the use of more conservative adjustment factors or default substitution values when the duration of outages exceeds a particular threshold or the number of outages in a year exceeds a particular number.[51]
>
> *Shared ducts and stacks*
>
> At some stationary combustion facilities the logical location for monitoring probes will be in a duct or stack shared by two or more combustion units. In such cases, fuel use data can be used to allocate directly monitored emissions to individual combustion units, or if acceptable, emissions can simply be estimated at the facility level.

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[50] The U.S. EPA specifies that emissions from partial hours of operation are to be reported as full hours for compliance purposes.

[51] The U.S. EPA's Acid Rain Program specifies that if an outage is less than 24 hours then average substitution values are to be used from hours before and after the outage. If missing data exceeds 24 hours, then a more conservative estimate must be applied (e.g., 90th percentile value from the last 30 days).

Biomass

CEM systems cannot distinguish between CO_2 produced from the combustion of biomass materials and that produced from fossil fuels. Therefore in cases where combustion units are co-fired with a mix of fossil and biomass fuels, the fraction of CO_2 emissions resulting from biogenic carbon must be subtracted from the final emission estimates and reported separately. In order to determine the fraction of biogenic carbon in mixed fuels, fuel consumption and composition data must be collected for use in a calculation methodology (see section 2.2).

Calibration and testing

The difficulties in accurately measuring exhaust gas flow rates and gas concentrations necessitates a rigorous and frequent process of calibration and testing to ensure that the data collected is as unbiased as possible. It is standard practice to require CEM systems to undergo a formal calibration and certification process before data are accepted for regulatory purposes. Such regulations will also typically specify the minimum frequency for specific calibration and testing activities. Typical calibration and testing procedures include:

- Calibration testing relative to a reference value
- Cycle/response time tests
- Linearity (i.e., sensitivity) checks at various levels (e.g., loads or gas concentrations)
- Interference tests on the presence and absence of likely contaminants or constituent gases
- Zero and span drift tests

Calibration and linearity checks should be made at regularly spaced intervals across the measurement span and care should be taken to ensure that monitoring data and calibration tests are done on a consistent moisture, pressure, and temperature basis. Procedures must also be put in place to prevent contamination of samples with ambient air.[52]

Probe location and settings

Monitoring probes should be positioned in a location where the samples taken are representative of the overall exhaust gas flow and composition (e.g., avoiding bends, areas of laminar flow or air leaks). They should also be located and designed to avoid effects from condensation, corrosion, or vibration. Visual inspection of probe orifices and nozzles are important to detect any damage or corrosion. The measurement range (i.e., span) of probes should be set such that measurements will not exceed the design range of the monitor.

Bias adjustments

Following calibration, significant biases may be observed between monitoring data and reference values. In some cases it will be possible to apply bias adjustment to direct measurements when the magnitude of systematic errors has been well characterized.

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[52] See 40 CRF Part 75 for example <www.epa.gov/airmarkt/monitoring/index.html>

However, it is preferable and encouraged that, where possible, the cause of significant biases be identified, documented, and corrected instead of the application of bias adjustment factors.

Data anomaly checks

Once recorded, the raw high frequency CEM data should be subject to automated data quality checks to search for outliers or other statistical anomalies before emissions data are finalized.

In order to calculate CO_2 emissions using flow rate and concentration data from CEM systems, the following equations can be applied:

Equation 5: Direct measurement when CO_2 concentration is on wet basis

$$E = D \cdot C_{CO2} \cdot Q$$

Where,

E = Mass emissions of CO_2 (short tons/hour or metric tons/hour)
D_{CO2} = Density of CO_2 (e.g.,1.87 kg/m^3 at 1.013 bar and 15°C) at standard temperature and pressure
C_{CO2} = Average concentration of CO_2 in exhaust gas on a wet basis (fraction by volume)
Q = Average volumetric flow rate on a wet basis and at standard temperature and pressure (ft^3/hour or m^3/hour)

Equation 6: Direct measurement when CO_2 concentration is on a dry basis

$$E = D_{CO2} \cdot C_{CO2} \cdot Q \cdot (1 - C_{H2O})$$

Where,

E = Mass emissions of CO_2 (short tons/hour or metric tons/hour)
D_{CO2} = Density of CO_2 (e.g., 1.87 kg/m^3 at 1.013 bar and 15°C) at standard temperature and pressure
C_{CO2} = Average concentration of CO_2 in exhaust gas on a dry basis (fraction by volume)
Q = Average volumetric flow rate as measured on a wet basis and at standard temperature and pressure (ft^3/hour or m^3/hour)
C_{H2O} = Average stack moisture content (fraction by volume)

Some units under the U.S. Acid Rain program monitor O_2 concentration of their exhaust gases and use it to estimate CO_2 concentration using the following equation:

Equation 7: Direct measurement when O_2 concentration is used as a proxy for CO_2

$$C_{CO2} = ((0.209 - C_{O2}) / 0.209) \cdot F_{CO2} / F_{exhaust}$$

Where,

C_{CO2} = Average concentration of CO_2 in exhaust gas on a dry basis (fraction by volume)
C_{O2} = Average concentration of O_2 in exhaust gas on a dry basis (fraction by volume)
0.209 = Fraction of O_2 in ambient air by volume
F_{CO2} = Ratio of the volume of CO_2 generated, on a dry basis and at standard temperature and pressure, to the gross calorific value of the fuel combusted (ft^3/million Btu or m^3/kJ)
$F_{exhaust}$ = Ratio of the volume of total exhaust gases generated, on a dry basis and at standard temperature and pressure, to the gross calorific value of the fuel combusted (ft^3/million Btu or m^3/kJ)

Note: See Annex C for U.S. EPA default F_{CO2} and $F_{exhaust}$ values.

The following equation can be used to convert gas volume values (as part of a density value) and actual exhaust gas volumetric flow rate measurements to standard temperature and pressure conditions:

Equation 8: Standard temperature and pressure conversion for flow rates.

$$Q_{STP} = Q_{Actual} \cdot (T_{STP} / T_{exhaust}) \cdot (P_{exhaust} / P_{STP})$$

Where,

Q_{STP} = Exhaust gas volumetric flow rate at standard temperature and pressure
Q_{Actual} = Exhaust gas volumetric flow rate at the actual temperature and pressure
T_{STP} = Standard temperature
$T_{exhaust}$ = Exhaust gas temperature at monitor location
$P_{exhaust}$ = Exhaust gas pressure at monitor location (absolute)
P_{STP} = Standard pressure (absolute)

2.3.1 Flow rate

Continuous measurements of the volumetric flow of exhaust gases are typically calculated by multiplying the average stack gas flow velocity by the stack cross sectional area. Exhaust gas flow rates are typically determined using type “S” pitot tubes, which are essentially pressure sensors. The accuracy of pitot tubes is sensitive to how well they are positioned, aligned, calibrated, and maintained. Pitot tubes or other types of flow monitors (e.g., ultrasonic) should be positioned such that they provide a representative sample of the average exhaust gas velocity over the cross-section of the stack or duct (e.g., avoiding bends, areas of laminar flow or air leaks).

One of the most common sources of bias in CEM and other direct measurement systems is associated with stratification in the stack or duct that causes the location(s) of the flow monitor probe(s) to not produce representative results. Special cases of stratification are cyclonic (i.e., swirling) and non-axial flow (i.e., yaw or pitch angle in the gas flow).[53] Stacks will generally have a particular stratification profile across the cross section both in terms of the gas concentration and exhaust gas velocity. The situation is further complicated when the gas concentration and velocity profiles are significantly different over the cross-section. Flowing exhaust gases are generally well-mixed, but stratification of gas concentrations can exist when the temperature of the gas is not uniform, after different gas streams intersect, structures or struts cause eddies to form, or when air is allowed to leak into a duct. Accurate monitoring of the overall mass rate of emissions under such conditions with CEM systems can be difficult.

These problems, however, can be addressed through stratification tests across the cross section of the stack or duct to fully characterize the flow profile of the stratification. Once the profile has been characterized, multiple probes (e.g., an array of point probes or multiple passes with path probes) can be used to account for the stratification. Probes may also be able to be placed in areas of the stack or duct where cyclonic (i.e., swirling) or other types of stratified flow are not present. In some cases problems can be mitigated through measures to normalize the flow (e.g., straightening vanes in the stack). It is important to recognize that stratification may vary with load or other process changes. Therefore stratification tests should be done under various loads to determine its sensitivity to other parameters.[54]

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[53] Yaw or pitch characterizes the degree to which the gas flow is not parallel to the stack wall.

[54] The U.S. EPA has provided methodological options for combustion units under the Acid Rain Program to better account for the impact of yaw, pitch, and wall effects on flow rate measurements (i.e., EPA Methods 2F, 2G, and 2H). http://www.epa.gov/ttn/emc/promgate.html

Other important exhaust flow monitoring issues include:

- Probes should also be subject to interference tests to ensure that flow monitors are not affected by the moisture content of exhaust gases.
- Probes should be inspected to ensure that they have not become plugged or partially plugged by accumulated materials.
- Flow monitoring probes should be located so as to capture sample data from an area of the stack or duct that is adequately away from the stack wall to avoid wall effects. Wall effects can cause the velocity of the gas flow to decrease near the stack wall.

CEM systems require temperature measurements to calculate gas density, which is used to convert the volumetric flow data to mass flow of exhaust gases. Like flow velocity, temperature stratification can also exist in the stack or duct. Other potential causes of biased temperature readings include: 1) the collection of moisture on temperature probes thereby causing evaporative cooling and 2) particulate buildup on temperature sensors thereby insulating them from temperature shifts and reducing response time.

As an alternative to flow velocity probes or to verify their performance, the volumetric flow of exhaust gas can be determined using oxygen concentration data, tracer gases, heat input data, and fuel factors for the ratio of the gas volume of combustion products to the heat content of the fuel. These fuel factors are based on a fuel sample analysis or default factors.[55] Estimates based on this method, however, cannot be treated as independent of fuel-based methodologies for estimating CO_2 emissions.

Overall, the largest uncertainty in the direct measurement of CO_2 emissions from stationary combustion will typically be associated with measurement of exhaust gas velocity. Therefore, it is important to consider potential sources of bias in flow measurements and apply applicable international and/or national technical standards.[56]

2.3.2 Gas concentration

To determine the mass emissions of CO_2 from a stack using direct measurement, data on the concentration of CO_2 in the exhaust gas are also required. There are two general types of continuous monitoring approaches for gas concentration:

- In-situ (i.e., in-line) monitoring that locates a probe in the stack or duct and does not require withdrawing in order to take readings or analyze results.
- Extractive (i.e., on-line) monitoring removes a sample of the exhaust gas from the flow that is then taken to a separate analysis location. Care must be taken in this approach not to contaminate the sample.

In-situ monitors tend to be used to take fairly continuous samples, and therefore can provide greater temporal resolution. However, the accuracy of in-situ concentration monitors can be lower than a laboratory gas analysis. In cases where gas concentrations are relatively stable, the extra resolution of continuous monitoring may provide little benefit.

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[55] See 40 CFR Part 75 and EIIP guidance for more information.

[56] See Annex D.

An alternative to in-situ or continuous gas concentration monitoring is a stack sampling approach, which could be used in cases where the input fuel is generally known to be homogeneous. The frequency of sampling would need to address any changes in fuel characteristics or operating parameters of the unit.

The moisture concentration of the exhaust gas may also require monitoring in some CEM systems in order to convert other concentration measurements from a dry to a wet basis.

As introduced above, the concentration of O_2 in the exhaust gas can be used as a proxy for determining CO_2 concentration. This approach assumes that the decrease in oxygen concentration in the exhaust gas is attributed to the oxidation of carbon in the fuel during combustion and is likely to produce less accurate emission results than either a direct measurement approach using a CO_2 concentration monitor or a calculation-based approach using fuel consumption data.

Like flow monitors, gas concentration monitors should be designed and installed in a location such that measurements will be representative of the overall exhaust gas, taking into account any stratification across the stack or duct. Concentration measurements should also be made at locations where the temperature of the exhaust gas is above the dew point temperature in order to avoid measurement errors associated with moisture accumulation.

Because these measurements of CO_2 concentration sample the exhaust gas in the stack or duct immediately after the gas exists the combustion chamber, they do not capture the delayed CO_2 emissions from the oxidation of CH_4, CO and NMVOCs in the atmosphere. These delayed CO_2 emissions are accounted for by fuel based calculation methods. This omission will lead to an underestimate in CO_2 emissions, although a minor one.[57] Gas concentration monitors, however, will capture the CO_2 produced by the use of limestone sorbents.

3 Direct CH_4 and N_2O emissions from fuel combustion

Other than CO_2, pollutants emitted from stationary combustion activities include the direct greenhouse gases CH_4 and N_2O and the ambient air pollutants NO_x, CO, NMVOCs, and SO_2. Emissions of these gases from stationary combustion sources depend upon fuel characteristics, size and vintage, along with combustion technology, pollution control equipment, and ambient environmental conditions. Emissions also vary with operation and maintenance practices. This guidance only addresses direct (i.e., Scope 1) emissions of the greenhouse gases CH_4 and N_2O.

Fuel characteristics (e.g., calorific value), the type of technology (e.g., combustion, operating and maintenance regime, the size and the vintage of the equipment), and emission controls, are major factors determining rates of emissions of CH_4 and N_2O gases from stationary sources. Specifically, N_2O emissions are closely related to air-fuel mixes and combustion temperatures, as well as the composition and operating temperature of any catalytic emission control equipment employed. Methane emissions from stationary combustion are primarily a function of the CH_4 content of the fuel and combustion efficiency.

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[57] The magnitude of the error for typical ranges of CH_4, CO, and NMVOC emissions is on the order of 0.1 percent or less.

Unlike for CO_2, the emissions of CH_4 and N_2O from the combustion of biomass fuels should be included with emissions from the combustion of fossil fuels.

Given their dependence on specific combustion conditions and other characteristics, the preferred approach for estimating CH_4 and N_2O emissions is to use a method based on combustion unit-specific data (see Table 6**Error! Reference source not found.** and Equation 9**Error! Reference source not found.**). The preferred method generally calls for the use of detailed activity data and emissions factors that account for these characteristics. Facility specific emission factors may be based on direct measurements, in which case the general guidance in section 2.3 should be followed.

Further information on more technology and fuel-specific emission factors can be found in the various IPCC guidelines reports,[58] the IPCC Emission Factor Database,[59] U.S. EPA's AP-42,[60] and the European Environment Agency's EMEP/Corinair Emission Inventory Guidebook.[61] A control efficiency/utilization factor can be included to account for emission control equipment downtime or partial failures.

The *IPCC Guidelines* provide default stationary combustion emission factors—which assume no emission controls are in place—for five sectors (i.e., Energy and Manufacturing Industries, the Commercial/Institutional Sector, the Residential Sector and Agriculture/Forestry/Fishing sources). These default emission factors are provided in the calculation tool that accompanies this guidance for use with a Tier 1 method. Emissions estimated using these general default factors will have a high degree of uncertainty associated with them.

Table 6: Methods for estimating CH_4 and N_2O emissions from stationary combustion

Rank	Description	Resolution
Preferred	Calculation based on fuel consumption data (or other activity data) disaggregated by specific fuel types and combined with site or equipment-specific emission and control efficiency/utilization factors	Combustion unit
Default	Calculation based on aggregate fuel consumption data (or other activity data) combined with generic default emission	Corporate or business unit

Equation 9: Equation for estimating CH_4 and N_2O emissions from stationary combustion

$$E = A \cdot EF \cdot (1 - C / 100)$$

Where,

E = Emissions (kg)

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[58] See http://www.ipcc.ch/pub/guide.htm

[59] See http://www.ipcc-nggip.iges.or.jp/EFDB/main.php

[60] U.S. EPA Compilation of Air Pollutant Emission Factors, Vol. 1: Stationary Point and Areas Sources. http://www.epa.gov/ttn/chief/ap42/index.html

[61] EMEP/CORINAIR Emission Inventory Guidebook - 3rd edition September 2004. http://reports.eea.eu.int/EMEPCORINAIR4/en

A = Activity level (e.g., GJ of fuel combusted)
EF = Emission factor (kg of pollutant/GJ of fuel combusted)
C = Control efficiency/utilization of any emission control equipment (percent)

Emissions of CH_4 and N_2O from stationary combustion are generally minor, on a GWP-weighted basis, compared to CO_2. Emissions can be more significant in cases of highly inefficient combustion (CH_4) such as open burning or where catalytic emission controls are used to reduce NO_x emissions (N_2O). In such cases companies are encouraged to apply a more rigorous method.

Emission factors for biomass fuels are not as well developed as those for fossil fuels. Research has shown that emission factors for small biomass devices and charcoal production are different from the IPCC defaults. Companies are directed to the references provided above for emission factors for the most up to date information.

Companies also have the option for using a direct measurement approach for estimating CH_4 and N_2O emissions from stationary combustion units. The IPCC provides the following guidance on the use of direct measurement for these gases:

> “Although continuous measurement of emissions is also consistent with *good practice*, continuous measurements of CH_4 and N_2O alone are not justified because of their comparatively high cost and because practical continuous monitoring systems are not easily available. Sufficiently accurate results may be obtained by using periodic measurements for CH_4 and N_2O. These measurements would help to improve emission factors. If monitors are already installed to measure other pollutants, they may deliver some useful parameters such as fluxes.”
>
> - IPCC (2000) *Good Practice Guidance and Uncertainty Management in National Greenhouse Gas Inventories*, p 2.37

4 Direct CO_2 emissions from other processes associated with stationary combustion facilities

Although not directly the result of the combustion of fuels for energy, CO_2 emissions also result from several other processes that may be related to stationary energy production activities. These processes include:

- The calcination of limestone used as sorbents in flue gas desulphurization systems and fluidized bed combustion boilers
- The reforming of fossil fuels to produce hydrogen for use in fuel cells
- The use of fossil carbon materials as reducing agents in metal production and other processes

A basic discussion of these source categories is provided below. Emissions from other sources of greenhouse gas emissions such as SF_6 from electrical equipment leaks or fugitive releases of CH_4 during fuel handling and processing are not addressed by this guidance document.

Additional guidance on these and other source categories can be found in other GHG Protocol calculation tools[62] and from the IPCC.[63]

4.1 Sorbent emissions

Limestone ($CaCO_3$) and dolomite ($CaCO_3MgCO_3$)[64] are basic raw materials used by a wide variety of industries, including as a sorbent in flue gas desulphurization (FGD) systems and fluidized bed boilers at electric utility and industrial plants. For example, wet limestone "scrubbers" use limestone slurries—mixtures of water and very finely crushed limestone—to prevent sulfur dioxide from passing through smokestacks. A rapid chemical reaction between sulfur dioxide gas and crushed limestone combines the gas, with calcium and oxygen, into a removable solid waste. During this reaction the limestone is heated and CO_2 is generated as a by-product.

Carbon dioxide emissions associated with the use of limestone as a sorbent material can be calculated by multiplying the quantity of limestone or dolomite consumed by its average carbon content, approximately 12.0 percent by mass for limestone and 13.0 percent for dolomite (based on stoichiometry). This approach assumes that all carbon in the mineral is oxidized and released and that impurities constitute a minor fraction of the material. Converting these percentages to a mass ratio of CO_2 to limestone using a molecular weight ratio produces emission factors of 0.440 ton CO_2/ton and 0.447 ton CO_2/ton of limestone and dolomite, respectively. The quantity of limestone consumed can be estimated based on purchase records or metered data (e.g., scales).

In cases where CEM systems or other direct monitoring approaches are used to estimate combustion emissions, the fraction of CO_2 in the exhaust gas resulting from the calcination of limestone should be estimated based on the quantity of limestone consumed and documented separately. If limestone-related CO_2 emissions are not estimated separately, then companies should document that their direct measurement data includes both fuel combustion and sorbent emissions.

The limestone used for industrial purposes is often a combination of pure limestone, dolomite, and minor impurities (e.g., magnesia, silica, and sulfur). Uncertainties in estimates of CO_2 emissions from limestone used as sorbents are due, in part, to variations in the chemical composition of limestone.

Although less common, other types of desulphurization scrubbers are operated by some facilities that use sorbents other than limestone. These other sorbents include i) lime (CaO) in dry scrubbers, ii) hydrated lime [$Ca(OH)_2$] in circulating fluid bed absorbers, and iii) sodium carbonate ($NaCO_3$). The first two of these sorbents can potentially absorb some CO_2 from the flue gas, while the third, like limestone, will likely produce additional CO_2 emissions. Companies using these other sorbents are encouraged to consult plant engineers before developing emission estimates.

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[62] See <www.ghgprotocol.org/standard/tools.htm>

[63] See <http://www.ipcc.ch/pub/guide.htm>

[64] Limestone and dolomite are collectively referred to as limestone by the industry, and intermediate varieties are seldom distinguished.

4.2 Emissions from reducing agents and fuel cells

The coke used in the production of pig iron and steel and other blast furnace applications typically functions as both a reducing agent and fuel within the process. The associated CO_2 emissions can be estimated based on the amount of carbon in the coke. Because carbon plays the dual role of a fuel and a reducing agent in these processes, it is important not to double-count the carbon from the oxidation of coke, if this is already accounted for elsewhere. More detailed guidance is available in the *GHG Protocol* tool on "Calculating CO_2 emissions from the production of iron and steel."[65]

Fossil fuels, such as natural gas or methanol, can be employed as a source of hydrogen for use in fuel cells. The hydrogen is removed from the hydrocarbons in these fuels and CO_2 is typically emitted as a by-product of the reforming process. The quantity of CO_2 emitted can typically be estimated based on the carbon content of the feedstock fuels.

5 Project level reductions

The *GHG Protocol Corporate Standard*, which this tool complements, focuses on accounting and reporting of greenhouse gas emissions at the company or organizational level. Reductions in corporate emissions are calculated by comparing changes in the company's actual emissions inventory over time and relative to a base year.

In addition to corporate accounting, the *GHG Protocol* is developing a project accounting and reporting module, which focuses on the quantification of greenhouse gas emission reductions, storage, or removals from mitigation projects that could be used as offsets. Offsets are discrete greenhouse gas reductions used to compensate for emissions elsewhere. Offsets are calculated relative to a baseline scenario that represents what emissions would have been in absence of the project activity, assuming the project activity would not have happened anyway.

This guidance and associated spreadsheet tool can be utilized by companies for calculating combustion emissions from stationary sources in the baseline scenario and for the project activity. For example, if a project activity were developed to install an energy efficient natural gas boiler, and the baseline scenario—determined using the *GHG Protocol* project accounting and reporting module— was the use of a coal boiler, the emissions from each of these boilers could be calculated using this tool.

This tool, however, does not provide all the emissions information required to complete the quantification of the GHG reduction, as it may not calculate unintended changes in upstream or downstream emissions caused by a project activity (i.e., secondary effects such as changes in the market due to the implementation of the project activity). Tools for these calculations may be found in the tool for indirect emissions from Stationary Combustion (to come) or certain sector specific tools, such as the Cement tool.

For more information on project quantification, see Chapter 8 of the *GHG Protocol* Corporate Accounting and Reporting Standard, or check on-line at www.ghgprotocol.org for the latest version of the Project Accounting Standard.

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[65] See http://www.ghgprotocol.org/standard/tools.htm

6 Quality management and uncertainty

Quality management procedures should be focused on reducing the uncertainty in data and emission estimates and increasing the transparency of documentation. General guidance on quality management for corporate greenhouse gas inventories is provided in Chapter 7 of the Revised Edition of the *GHG Protocol* Corporate Standard.[66] In addition to this general guidance, the following stationary combustion specific quality management procedures should be considered:

- Preparation of a quality management plan. Monitoring and quality management plans should be updated to reflect any changes in monitoring equipment or procedures that have the potential to effect the quality of emissions data.
- Compare emissions or emissions rate data between combustion units or facilities. Differences should be able to be explained by reasonable changes in operations.
- Compare emissions or emissions rate data at an individual combustion unit or facility other time. Changes or trends, especially significant single year changes (e.g., greater than 10 percent) should be able to be justified by reasonable changes in operations.
- Compare measured heating values, carbon content factors, and oxidation factors to available default values.
- Compare measured heating values and carbon content factors with values provided by fuel suppliers when collected separately.
- Compare emissions data from CEM systems or other intermittent direct measurements of emissions to emissions estimated using fuel consumption data.[67] It may only be necessary to occasionally compare limited samples of emission estimates using these two methods (i.e., once a month) to achieve the intended verification results.
- Compare fuel consumption data to that used to estimate other energy or emissions data (e.g., CO, NO_x, NMVOCs, HAPs[68], etc.). Fuel data should be consistent.
- Ensure that adequate quality management procedures are being employed by other parties to which any fuel analysis or other data collection functions that have been outsourced.
- Compare facility level fuel meter data to fuel purchase or receipt data, taking into account changes in fuel stocks.
- Regularly calibrate and test all measurement equipment.

Applicable national or international technical standards should be applied for all measurements (e.g., ASTM, ISO).[69] For CEM systems, an example of rigorous and detailed quality management procedures are described in 40 CFR Part 75.59.

In general, a quality management plan should address the following issues:

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[66] See (http://www.ghgprotocol.org/standard/GHGProtocolCorporateStandard_RevisedEdition.pdf).

[67] Comparing CO_2 emissions data from CEM systems with fuel based emission calculations can be more instructive for assessing the accuracy of CEM data than other quality control checks because of the independent nature of comparison.

[68] Hazardous air pollutants.

[69] See Annex D.

Time series consistency

Changes in data quality, the characteristics of data, or methods for estimating emissions can lead to problems with time series consistency. These changes include cases when improvements have been intentionally made to the data collected or methods used. Guidance on maintaining time series consistency is available from the IPCC.[70]

Completeness

In keeping with the GHG Protocol, estimates should include emissions from all fuels consumed in all combustion units within the company's organizational boundary over the reporting period.[71] Where it is not practical to include all emissions or combustion units, then exclusions should be documented and explained. The completeness of a corporate inventory can be checked by comparing the list of facilities used to estimate greenhouse gas emissions to lists compiled for other reporting purposes, such as environmental reporting, financial reporting, or other corporate wide reports. In cases where data is missing for entire facilities or portions of the company then, as a preliminary measure, proxy data such as equipment counts and assumed utilization levels can be used to estimate emissions.

Uncertainty

Guidance on assessing uncertainty in the data associated with greenhouse gas emission estimates is provided in the GHG Protocol tool, Calculating Measurement and Estimation Uncertainty for GHG Emissions (http://www.ghgprotocol.org/standard/tools.htm). Where measurement equipment is used, results from calibration tests and original equipment manufacture (OEM) precision information can be used as inputs to assessing data uncertainty. Companies should attempt to identify likely causes of uncertainty in emission estimates and make efforts to reduce those uncertainties.

7 Documentation and archiving

In order to ensure that estimates are transparent and verifiable, information and data should be documented. All raw data used to estimate emissions should also be archived for a reasonable period of time.[72] The following information is recommended to be documented for stationary combustion emission estimates:

- Description of facilities or installations and type of combustion activities carried out that result in greenhouse gas emissions
- Description of fuel and material inputs to and outputs from each activity related to greenhouse gas emissions
- Description of the methods applied to estimate emissions for each activity, facility, or combustion unit
- Description and list of metering or monitoring devices for each source or facility
- Description of the approach used for fuel sampling and the analytical approaches for the determination of calorific values, carbon contents, oxidation factors, emission factors or other factors (e.g., fraction of biomass in co-firing units)

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[70] See (http://www.ipcc-nggip.iges.or.jp/public/gp/english/7_Methodological.pdf).

[71] See Chapter 1 of the Revised Edition of the GHG Protocol Corporate Standard (http://www.ghgprotocol.org/standard/GHGProtocolCorporateStandard_RevisedEdition.pdf)

[72] The U.S. Acid Rain Program requires data to be archived for 3 years.

- Fuel sampling procedures and results. These records may include identification of organization conducting testing, analysis methods and standards applied (e.g., ASTM), sample contamination safeguards employed, sampling procedures, and procedure for transmitting sample to the laboratory.
- A description of any CEM or other direct measurement system used (e.g., the points and frequency of measurement, equipment used, calibration procedures, and data handing systems)
- CEM or other direct measurement inspection and maintenance procedures, repair activities, bias adjustments, and calibration test results
- A description of any cases of missing data for CEM or fuel based methods and what measures were taken to approximate and/or replace missing data
- A description of quality management procedures implemented
- A discussion of any changes that may have affected the accuracy, time series consistency, or completeness of the emission estimates
- Changes to monitoring equipment or procedures that have the potential to have an effect on data collection
- Any subtraction of emissions from the storage of CO_2 in geologic or other formations or transfer of CO_2
- Estimate of biomass-related CO_2 emissions
- Fraction of biomass fuels subtracted from mixed fuels
- A discussion of the likely causes of uncertainty (statistical and systematic bias) and available data on the precision of measurement instrumentation or calibration errors.
- Description of steps taken to deal with confidential business information
- Electricity generation data, where applicable.

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10 Revision history

This guidance and its companion worksheets will be updated on an intermittent basis to incorporate emerging best practices and state of art guidance on quantification methodologies and emission factors.

Comments and suggestions for this guidance are welcome. Comments should be sent to:
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February 2005: New guidance was developed incorporating a more detailed calculation method and a discussion of direct measurement based methods for CO_2. Only simple calculation method is provided for CH_4 and N_2O. The new guidance and spreadsheet now only addresses direct (Scope 1) emissions of CO_2, CH_4, and N_2O. The guidance and worksheets for indirect (Scope 2) emissions, combined heat and power (CHP) related emissions, and optional reporting options for the sale of electricity are now included in a separate calculation tool.

11 Annex A: Background on carbon content factors

General guidance on determining the carbon of fuels is presented in section 2.2.2.2 "Carbon content factors" in this document. This annex provides some default carbon content factor values for cases where data from specific fuel analyses is not available. Default carbon content factors should generally be used with fuel data that is on an energy content basis (versus on a physical unit basis). Calorific values (i.e., heating values) should be based on fuel specific data such as a fuel analysis performed by a fuel supplier. Default calorific values are provided in Annex B for cases where accurate values are not available.

Default carbon content factors are from the following organizations are presented:

- Intergovernmental Panel on Climate Change (IPCC)
- U.S. Environmental Protection Agency[73]
- European Union Emissions Trading Scheme (EU-ETS)
- Based on API gravity and sulfur content data for crude oil

Information on the variability of U.S. carbon content factors is also provided.

Companies are encouraged to consult fuel suppliers or technical experts before selecting a particular default value to apply.

11.1 Intergovernmental Panel on Climate Change (IPCC)

The IPCC has made publicly available an on-line searchable database of emission factors and other relevant data, including carbon content factors. This database can be accessed at: http://www.ipcc-nggip.iges.or.jp/EFDB/main.php

11.2 U.S. Environmental Protection Agency

Table 7 presents the national average carbon content factors (on an GCV basis) used for the U.S. greenhouse gas inventory.

Table 7: National average carbon content factors for the United States

Fuel Type	kg C/million Btu	kg C/GJ
Coal Rank		
Anthracite	28.26	26.79
Bituminous	25.49	24.16
Sub-bituminous	26.48	25.10
Lignite	26.30	24.93
Natural Gas	14.47	13.71
Petroleum		
Asphalt and road oil	20.62	19.54
Aviation gasoline	18.87	17.89
Distillate fuel oil	19.95	18.91

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[73] These values are based on research performed by the U.S. Energy Information Administration.

Jet fuel*	19.33	18.32
Kerosene	19.72	18.69
LPG*	16.99	16.10
Lubricants	20.24	19.18
Motor gasoline*	19.34	18.33
Residual fuel	21.49	20.37
Other Petroleum		
Crude oil	20.29	19.23
Naphtha (<401 deg. F)	18.14	17.19
Other oil (>401 deg. F)	19.95	18.91
Pentanes plus	18.24	17.29
Petroleum coke	27.85	26.40
Still gas	17.51	16.60
Special naphtha	19.86	18.82
Unfinished oils	20.29	19.23
Waxes	19.81	18.78

*Carbon contents vary annually based on changes in fuel composition. From 1990 to 2000, carbon factors have ranged as follows: Jet fuel between 19.33 and 19.40, LPG between 16.97 and 17.01, Motor gasoline between 19.33 and 19.41

Note: All coefficients based on a GCV (HHV) basis.[74]

11.2.1 Variability and uncertainty in U.S. coal carbon content factors

Table 8 provides data on average carbon content factors for various coal ranks for each U.S. State. These data illustrate some of the variability that can exist in carbon contents even on an energy basis. Because each of these values are regional averages themselves, the variability in individual coal batches can be even greater.

Table 8: Variability in average U.S. State carbon content by coal rank (kg C/million Btu)

State	Number of Samples	Bituminous	Subbituminous	Anthracite	Lignite
Alabama	946	25.32	-	-	27.03
Alaska	90	26.82	26.76	-	26.91
Arizona	11	-	26.60	-	-
Arkansas	70	26.32	-	-	25.90
Colorado	292	25.74	26.31	-	26.31
Georgia	35	25.92	-	-	-
Idaho	1	-	25.88	-	-
Illinois	16	25.46	-	-	-
Indiana	125	25.27	-	-	-
Iowa	89	25.07	-	-	-
Kansas	28	24.80	-	-	-
Kentucky	870	25.25	-	-	-

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[74] Higher heating value (gross heating value) is the total amount of heat released when a fuel is burned. Coal, crude oil, and natural gas all include chemical compounds of carbon and hydrogen. When those fuels are burned, the carbon and hydrogen combine with oxygen in the air to produce carbon dioxide and water. Some of the energy released in burning goes into transforming the water into steam and is usually lost. The amount of heat spent in transforming the water into steam is counted as part of gross heat content. Lower heating value (net heating value), in contrast, does not include the heat spent in transforming the water into steam. Using a simplified methodology based on International Energy Agency defaults, higher heating value can be converted to lower heating value for coal and petroleum products by multiplying by 0.95 and for natural gas by multiplying by 0.90.

Louisiana	1	-	-	-	26.19
Maryland	46	25.73	-	-	-
Massachusetts	3	-	-	31.31	-
Michigan	3	25.32	-	-	-
Mississippi	8	-	-	-	26.78
Missouri	91	25.05	-	-	-
Montana	301	28.70	26.66	28.25	27.10
Nevada	2	25.74	-	-	27.23
New Mexico	167	25.98	25.88	28.34	-
North Dakota	186	-	-	-	27.15
Ohio	646	25.05	-	-	-
Oklahoma	46	25.27	-	-	-
Pennsylvania	739	25.47	-	28.27	-
Tennessee	58	25.31	-	-	-
Texas	48	-	-	-	25.84
Utah	152	26.20	24.90	-	-
Virginia	456	25.51	-	26.87	-
Washington	14	26.02	26.91	27.96	29.06
West Virginia	566	25.61	-	-	-
Wyoming	476	25.82	26.51	-	-

- No Sample Data Available
Reference: Inventory of U.S. Greenhouse Gas Emissions and Sinks.
http://yosemite.epa.gov/oar/globalwarming.nsf/content/ResourceCenterPublicationsGHGEmissions.html
Note: All coefficients based on a GCV (HHV) basis.

11.2.2 Variability and uncertainty in U.S natural gas carbon content factors

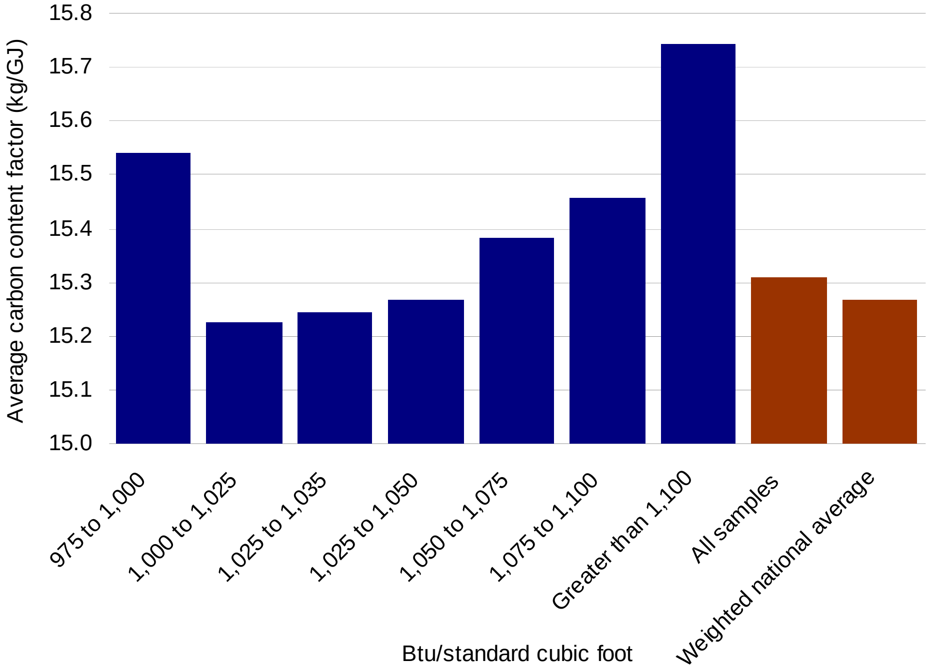
Table 9 and Figure 2 illustrates some of the variability in carbon content factors for natural gas in the United States. As can be seen, even though natural gas supplies in the United States are strictly regulated, there is still some variability across samples.

Table 9: Average composition of natural gas in the United States (percent by mass, except where noted)

Compound	**Average**	**Median**	**Carbon content**	**kg C/ million Btu**
Methane (CH_4)	93.07	95.00	75.0	14.2
Ethane (C_2H_6)	3.21	2.79	80.0	16.25
Propane (C_3H_8)	0.59	0.48	81.8	17.20
Higher hydrocarbons	0.32	0.30	-	-
Non-hydrocarbons	2.81	1.43	-	-
Higher heating value (Btu/ft^3)	1,027	1,032	-	-

Reference: Inventory of U.S. Greenhouse Gas Emissions and Sinks.
http://yosemite.epa.gov/oar/globalwarming.nsf/content/ResourceCenterPublicationsGHGEmissions.html
Note: All coefficients based on a GCV (HHV) basis.

Figure 2: Average carbon content of pipeline-quality natural gas by energy content in the United States



Reference: Inventory of U.S. Greenhouse Gas Emissions and Sinks. http://yosemite.epa.gov/oar/globalwarming.nsf/content/ResourceCenterPublicationsGHGEmissions.html
Note: All coefficients based on a GCV (HHV) basis. Natural gas samples were obtained from the Gas Technology Institute (formerly Gas Research Institute) database (1992) as documented in W.E. Liss, W.H. Thrasher, G.F. Steinmetz, P. Chowdiah, and A. Atari, *Variability of Natural Gas Composition in Select Major Metropolitan Areas of the United States*. Full sample (N=6,743). Data on the average heat content consumed, on a state-by-state basis, was obtained from the U.S. Department of Energy, U.S. Energy Information Administration, *State Energy Data Report 1999*, Tables 1 and 2 (2001c). See: www.eia.doe.gov/emeu/sedr/contents.html#PDF%20Files

11.2.3 Variability and uncertainty in U.S. petroleum product carbon content factors

Table 10 provides information on the assumed uncertainty and variability in the national average carbon content factors (on an energy basis). Because these are national averages, the actual variability in individual batches of fuel combusted by a particular facility may be greater. Table 11 through Table 13 provide detailed information on the assumed carbon contents of various fossil fuel additives and non-energy products in the United States.

Table 10: Uncertainty and variability in U.S. average carbon content factors for petroleum products

Gasoline	The amount of variation is limited by the compounds in the fuel to ± 4 percent.
Jet fuel	Variability in jet fuel is relatively small with the average carbon content of kerosene-based jet fuel on an energy basis varying by less than ± 1 percent and the density varying by ± 1 percent.
Fuel oil	Samples No.1 fuel oil contained an average of 86.01 percent carbon by mass compared to the 86.34 percent contained in samples of No.2 fuel oil. A carbon content coefficient based on No.1 fuel oil would equal 19.72 kg/million Btu rather than the 19.95 kg/million Btu for No.2 fuel oil.
Residual fuel oil	Overall, the uncertainty associated with the carbon content of residual fuel is probably ± 1 percent.
LPG	Because LPG consists of pure paraffinic compounds whose density, heat content and carbon content

	are physical constrained, there is limited uncertainty associated with the carbon content coefficient for this petroleum product (about ± 3 percent).
Aviation gas	Given the requirements for safe operation of piston-powered aircraft the composition of aviation gas is limited and the uncertainty of the carbon content coefficient is likely to be ± 5 percent.
Asphalt	The share of carbon in asphalt ranges from 79 to 88 percent by mass. Also present in the mixture are hydrogen and sulfur, with shares by mass ranging from seven to 13 percent for hydrogen, and from trace levels to 8 percent for sulfur.
Lubricants	Because lubricants may be produced from either the distillate or residual fractions, the likely range of carbon content coefficients range from just under 20.0 to about 21.5 kg/million Btu
Kerosene	If kerosene is more like kerosene-based jet fuel, the true carbon content coefficient is likely to be some 2 percent lower. If kerosene is more aptly compared to No. 2 fuel oil, then the true carbon content coefficient is likely to be about 1 percent higher.
Petroleum coke	Uncertainty is estimated to be as much as ± 6 percent.
Special Naphtha	The overall uncertainty is bounded on the low end by the carbon content of hexane and on the upper end by the carbon content of high solvency mineral spirits. This implies an uncertainty band of –15 percent to + 6 percent.
Waxes	The quantitative variation in the carbon contents for all waxes is limited to ± 1 percent because of the nearly uniform relationship between carbon and other elements in petroleum waxes broadly defined.
Crude oil	The uncertainty of applying a crude oil carbon content is likely to be bounded by the range of petroleum products (± 10 percent).

Reference: Inventory of U.S. Greenhouse Gas Emissions and Sinks.
http://yosemite.epa.gov/oar/globalwarming.nsf/content/ResourceCenterPublicationsGHGEmissions.html

Table 11: Characteristics of major reformulated fuel additives

Additive	**Density (degrees API)**	**Carbon content (percent)**	**Carbon content (kg C/ million Btu)**
MTBE	59.1	68.2	16.92
ETBE	59.1	70.5	17.07
TAME	52.8	70.5	17.00

Reference: Inventory of U.S. Greenhouse Gas Emissions and Sinks.
http://yosemite.epa.gov/oar/globalwarming.nsf/content/ResourceCenterPublicationsGHGEmissions.html
Note: All coefficients based on a GCV (HHV) basis.

Table 12: Assigned carbon contents of plastic resins (percent by mass)

Resin type	**Carbon content**	**Assumptions**
Epoxy	76	Typical epoxy resin made from epichlorhydrin and bisphenol A
Polyester (unsaturated)	63	Poly (ethylene terepthalate) (PET)
Urea	34	50% carbamal, 50% N-(hydroxymethyl) urea *
Melamine	29	Trimethylol melamine*
Phenolic	77	Phenol
Low-density polyethylene (LDPE)	86	Polyethylene
Linear low-density polyethylene (LLDPE)	86	Polyethylene
High density polyethylene (HDPE)	86	Polyethylene
Polypropylene (PP)	86	Polypropylene
Acrylonitrile-butadiene-styrene (ABS)	85	50% styrene, 25% acrylonitrile, 25% butadiene
Styrene-acrylonitrile (SAN)	80	50% styrene, 50% acrylonitrile
Other styrenics	92	Polystyrene
Polystyrene (PS)	92	Polystyrene

Polyvinyl chloride (PVC)	38	Polyvinyl chloride
Thermoplastic polyester	63	Polyethylene terephthalate
Nylon 6	64	-
Nylon 6,6	64	-
Nylon 4	52	-
Nylon 6,10	68	-
Nylon 6,11	69	-
Nylon 6,12	70	-
Nylon 11	72	-

*Does not include alcoholic hydrogens.
Reference: Inventory of U.S. Greenhouse Gas Emissions and Sinks.
http://yosemite.epa.gov/oar/globalwarming.nsf/content/ResourceCenterPublicationsGHGEmissions.html

Table 13: Synthetic rubber carbon content (percent by mass)

Elastomer type	**Carbon content**
SBR solid	91
Polybutadiene	89
Ethylene propylene	86
Polychloroprene	59
NBR solid	77
Polyisoprene	88

Reference: Inventory of U.S. Greenhouse Gas Emissions and Sinks.
http://yosemite.epa.gov/oar/globalwarming.nsf/content/ResourceCenterPublicationsGHGEmissions.html

11.3 European Union Emission Trading Scheme

The European Union’s Emissions Trading Scheme has published default carbon content factors, based primarily on IPCC defaults (see Table 14).

Table 14: European Emissions Trading System (EU ETS) default carbon content factors for fuel combustion

Fuel	**Carbon content factor (ton C/TJ)**	**Reference**
Liquid fossil		
Primary fuels		
Crude oil	20.0	IPCC, 1996[a]
Orimulsion	22.0	IPCC, 1996
Natural gas liquids	17.2	IPCC, 1996
Secondary fuels/products		
Gasoline	18.9	IPCC, 1996
Kerosene[b]	19.6	IPCC, 1996
Shale oil	21.1	National Communication Estonia, 2002
Gas / diesel oil	20.2	IPCC, 1996
Residual fuel oil	21.1	IPCC, 1996
Liquid petroleum gas	17.2	IPCC, 1996
Ethane	16.8	IPCC, 1996
Naphtha	20.0	IPCC, 1996
Bitumen	22.0	IPCC, 1996
Lubricants	20.0	IPCC, 1996
Petroleum coke	27.5	IPCC, 1996
Refinery feedstocks	20.0	IPCC, 1996

Other oil	20.0	IPCC, 1996
Solid fossil		
Primary fuels		
Anthracite	26.8	IPCC, 1996
Coking coal	25.8	IPCC, 1996
Other bitumen Coal	25.8	IPCC, 1996
Sub-bitumen Coal	26.2	IPCC, 1996
Lignite	27.6	IPCC, 1996
Oil shale	29.1	IPCC, 1996
Peat	28.9	IPCC, 1996
Secondary fuels		
BKB & patent fuel	25.8	IPCC, 1996
Coke oven / gas coke	29.5	IPCC, 1996
Gaseous fossil		
Carbon monoxide	42.3	Based on 10.12 TJ/ t[c]
Natural gas (dry)	15.3	IPCC, 1996
Methane	15.0	Based on 50.01 TJ/ t[d]
Hydrogen	0	Carbon free substance

Reference: EU ETS M&R guidelines (Table 4).
http://europa.eu.int/comm/environment/climat/pdf/c2004_130_en.pdf
Note: Based on NCV (LHV), excludes oxidation factor
[a] *Revised 1996 IPCC Guidelines for National Greenhouse Gas Inventories*: Reference Manual, 1.13.
[b] Kerosene, other than Jet Kerosene.
[c] J. Falbe and M. Regitz, Römpp Chemie Lexikon, Stuttgart, 1995.
[d] J. Falbe and M. Regitz, Römpp Chemie Lexikon, Stuttgart, 1995.

11.4 Estimating carbon content from API gravity and sulfur content data[75]

API gravity is an arbitrary scale expressing the specific gravity (i.e., the ratio of the mass of a substance to the mass of an equal volume of water) of liquid petroleum products, as established by the American Petroleum Institute (API). The higher the API gravity, the lighter the compound. Petroleum products vary between 5.6 degrees API gravity (i.e., dense products such as asphalt and road oil) and 247 degrees (i.e., ethane).[76] Light crude oils generally exceed 38 degrees API and heavy crude oils are all crude oils with an API gravity of 22 degrees or below. Intermediate crude oils fall in the range of 22 degrees to 38 degrees API gravity. Because the volume of a liquid is slightly affected by temperature and pressure, these parameters must be specified with the API gravity value. The standard temperature and pressure for U.S. API values is generally 60 degrees F (16 degrees C) and one atmosphere (101.3 kPa). At standard temperature and pressure, there are 62.36 pounds of water per cubic foot, or 8.337 pounds water per gallon.

Degrees API = (141.5 / specific gravity at 60 degrees F) – 131.5

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[75] Adapted from the IPCC (2001) and Encyclopedia Britannica.
[76]

The degrees API scale has the advantage of allowing hydrometers, which measure specific gravity, to be calibrated linearly. The Baumé scale is still used in parts of Europe, but considered to be slightly less accurate.

Degrees Baumé = (140 / specific gravity at 60 degrees F) - 130

The U.S. Energy Information Agency analyzed 182 crude oil samples and developed the following formula to estimate the carbon content (as a percent by mass) of crude oil based on its specific gravity and sulfur content:

Carbon content = $76.99 + (10.19 \times S_{oil}) - (0.76 \times F_{sulfur})$

S_{oil} : specific gravity of the oil sample
F_{sulfur} : sulfur content as a percentage by mass

Tables 2.2 and 2.3 in the IPCC Good Practice Guidance lists carbon and sulfur contents derived from this formula for crude oil samples from most countries in the world and for various crude oil grades and categories. (http://www.ipcc-nggip.iges.or.jp/public/gp/english/2_Energy.pdf)

12 Annex B: Background on calorific/heating values

Some countries measure fuel according to its gross calorific value (GCV) or higher heating value (HHV), while other countries use net calorific value (NCV) or lower heating value (LHV). The distinction between GCV and NCV arises from the different physical states (liquid or gaseous) water may be in following combustion. The GCV includes the latent energy of condensation of water following combustion. The NCV is computed for product water in the gaseous state (i.e., not condensed). The latent energy of vaporization of water is deducted from the GCV. When a moist fuel is combusted, two sources of product water exist – the moisture present in the fuel and the water formed from the hydrogen in the fuel during combustion.

The NCV of a fuel at any moisture content can be determined as[77]:

$$NCV = (1 - M_{wet})[GCV_{solids} - \lambda(M_{dry} + 9H)] \qquad \text{(Eq. 1)}$$

Where,
NCV is the net calorific value at any moisture content
GCV_{solids} is the gross calorific value of dry fuel (zero moisture content)
λ is the latent heat of vaporization of water (2.31 MJ/kg at 25°C)
M_{wet} is the moisture content of fuel on a wet basis (expressed as a fraction)
M_{dry} is the moisture content of fuel on a dry basis (expressed as a fraction)
H is the mass fraction of hydrogen in dry fuel (expressed as a fraction)

If the NCV is to be expressed in terms of dry fuel (e.g., corresponding to the dry solids in the fuel) it can be determined from the GCV of the dry fuel (GCV_{solids}):

$$NCV_{solids} = GCV_{solids} - 9\lambda H \qquad \text{(Eq. 2)}$$

Where,
NCV_{solids} is the net calorific value of dry fuel (zero moisture content)

A commonly accepted approximation is that NCV is 95% of GCV for coal and oil and 90% of GCV for natural gas[78]. IPCC does not provide a relationship between NCV and GCV for biomass fuels, presumably because the moisture content of biomass fuels can vary extensively. However, in most instances the forest products industry characterizes the energy content of biomass fuels (e.g., spent pulping liquors, hogged fuels, etc.) in terms of the energy in the dry solids of the biomass. Therefore, Equation 2 above can be used to develop a relationship between NCV and GCV for biomass fuels on a dry basis. A hydrogen content value

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[77] Biomass Handbook. Osama Kitana and Carl W. Hall eds. Gordon and Breach Science Publishers. New York. 1989. page 883

[78] Intergovernmental Panel on Climate Change (IPCC). 1997c. Revised 1996 IPCC Guidelines For National Greenhouse Gas Inventories: Reference manual (Vol 3). IPCC National Greenhouse Gas Inventory Program. Table 1-6, page 1.29

representative of many wood species is approximately 6 percent[79] (based on dry wood, expressed as the fraction 0.06). A typical $\text{NCV}_{\text{solids}}$ value for wood is 20 MJ/kg. Therefore:

$$\begin{aligned} NCV_{solids} &= 20\,\text{MJ/kg dry wood} = GCV_{solids} - 9\times(2.31\,\text{MJ/kg water})\times(0.06) \\ \therefore\ GCV_{solids} &= 20\,\text{MJ/kg dry wood} + 9\times(2.31\,\text{MJ/kg water})\times(0.06) \\ &= 21.25\,\text{MJ/kg dry wood} \end{aligned} \qquad \textit{(Eq. 3)}$$

An approximate relationship between $\text{NCV}_{\text{solids}}$ and $\text{GCV}_{\text{solids}}$ can be developed using this result:

$$\therefore \frac{NCV_{solids}}{GCV_{solids}} = \frac{20}{21.25} = 0.94 \cong 0.95 \qquad \textit{(Eq. 4)}$$

It is important to realize that the relation above is only valid when the energy content (in terms of both GCV and NCV) is expressed in terms of the dry fuel (i.e., energy expressed in terms of biomass solids, such as 20 GJ NCV per tonne dry wood).

The spreadsheet calculation tool companion to this guidance document provides ranges for the likely heating/calorific values of major fuel type and suggested values for cases where fuel analysis data is not available. Companies are encouraged to consult fuel suppliers or technical experts before selecting a particular default value to apply.

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[79] The Chemistry of Wood. B.L. Browning ed. Robert E. Krieger Publishing Company. New York. 1975. Table VI, page 74

13 Annex C: U.S. Acid Rain Program (40 CRF Part 75) default factors[80]

This annex presents the default values used in the U.S. Acid Rain Program (i.e., SO_2 and NO_x allowance trading) for the estimation of CO_2 emissions. Default data for carbon contents, heating values, specific gravity, density, moisture contents, and *F* factors are presented in Table 15 through Table 21. Some of these values are intentionally chosen to be "conservative" to provide an incentive for combustion unit operators to collect accurate fuel-specific data.

Readers are directed to Section 2 "Direct CO_2 emissions from fuel combustion" in this guidance document for more information on the application and selection of specific factors.

Table 15: Default factors for acid rain low mass emission units: Default CO_2 emission factor for natural gas and oil

Fuel type	CO_2 emission factor	
Pipeline grade natural gas	0.059 short ton/10^6 Btu	0.0507 metric ton/GJ
Oil	0.081 short ton/10^6 Btu	0.0696 metric ton/GJ

Note: Factor incorporates oxidation factor

Table 16: U.S. Acid Rain Program default heating/calorific values

Fuel type	HHV / GVC	
Pipeline grade natural gas	1050 Btu/ ft^3	39.12 MJ/m^3
Other natural gas	1100 Btu/ ft^3	40.99 MJ/m^3
Residual oil	19,700 Btu/lb or	45,831 kJ/kg
	167,500 Btu/gallon	46,686 kJ/L
Diesel Fuel	20,500 Btu/lb or	47,692 kJ/kg
	151,700 Btu/gallon	42,282 kJ/L

Note: Volume data at standard temperature and pressure conditions

Table 17: U.S. Acid Rain Program default specific gravity values

Fuel type	Specific gravity	
Residual oil	8.5 lb/gal	1.02 kg/L
Diesel Fuel	7.4 lb/gal	0.89 kg/L

Note: Volume data at standard temperature and pressure conditions

Table 18: U.S. acid rain conservative substitution HHV/GCV values

Fuel type	Conservative value	
Residual oil	19,500 Btu/lb	45,366 kJ/kg
Diesel oil	20,000 Btu/lb	46,529 kJ/kg
Natural gas or landfill gas	1,100 Btu/ft^3	40,986 kJ/m^3
Butane or refinery gas	1,500 Btu/ft^3	55,890 kJ/m^3

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[80] For more information on these factors and the U.S. Acid Rain Program see http://www.epa.gov/airmarkt/monitoring/index.html

Propane or other gaseous fuel	2,100 Btu/ft^3	78,246 kJ/m^3

Table 19: U.S. Acid Rain program default carbon content values on a mass basis for data substitution

Fuel type	**Carbon content** (percent by mass)
Anthracite	90
Bituminous	85
Subbituminous	75
Lignite	75
Oil	90
Natural gas	75
Other gaseous fuels	90

Table 20: U.S. Acid Rain Program default "*F*" factors for use in Equation 7.

Fuel type	$F_{exhaust}$		F_{CO2}	
	(ft^3/10^6 Btu)	(m^3/GJ)	(ft^3/10^6 Btu)	(m^3/GJ)
Anthracite	10,100	271.1	1,970	52.87
Bituminous & subbituminous	9,780	262.5	1,800	48.31
Lignite	9,860	264.6	1,910	51.26
Oil (crude, residual, or distillate)	9,190	246.6	1,420	38.11
Natural gas	8,710	233.8	1,040	27.91
Propane	8,710	233.8	1,190	31.94
Butane	8,710	233.8	1,250	33.55

Note: At dry standard temperature and pressure conditions (20°C and 760mm Hg)

Table 21: U.S. Acid Rain Program default correction for moisture content to correct when CO_2 concentration (by mass) is measured on a dry basis

Fuel type	**Moisture content** (percent by mass)
Anthracite	3
Bituminous	6
Subbituminous	8
Lignite	11
Wood	13

14 Annex D: Relevant technical standards

A listing of potentially applicable technical standards from the following national or international organizations are presented:

- American Society of Testing and Materials (ASTM)
- U.S. Environmental Protection Agency (EPA)
- American Society of Mechanical Engineers (ASME)
- American National Standards Institute (ANSI)
- Gas Processors Association (GPA)
- American Gas Association (AGA)
- American Petroleum Institute (API)
- International Standards Organization (ISO)
- German Institute for Standardization (DIN)
- Committee on European Normalization (CEN)

Companies are encouraged to consult experts in the appropriate fields before selecting particular standards to apply.

14.1 American Society of Testing and Materials (ASTM)

www.astm.org

ASTM D240-87 (Reapproved 1991), Standard Test Method for Heat of Combustion of Liquid Hydrocarbon Fuels by Bomb Calorimeter.	Fuel analysis (liquid)
ASTM D287-82 (Reapproved 1987), Standard Test Method for API Gravity of Crude Petroleum and Petroleum Products (Hydrometer Method).	Fuel analysis (liquid)
ASTM D388-92, Standard Classification of Coals by Rank, incorporation by reference for appendix F of this part.	Fuel analysis (solid)
ASTM D941-88, Standard Test Method for Density and Relative Density (Specific Gravity) of Liquids by Lipkin Bicapillary Pycnometer.	Fuel analysis (liquid)
ASTM D1217-91, Standard Test Method for Density and Relative Density (Specific Gravity) of Liquids by Bingham Pycnometer.	Fuel analysis (liquid)
ASTM D1250-80 (Reapproved 1990), Standard Guide for Petroleum Measurement Tables.	Fuel analysis (liquid)
ASTM D1298-85 (Reapproved 1990), Standard Practice for Density, Relative Density	Fuel analysis (liquid)
(Specific Gravity) or API Gravity of Crude Petroleum and Liquid Petroleum Products by Hydrometer Method.	Fuel analysis (liquid)
ASTM D1480-91, Standard Test Method for Density and Relative Density (Specific Gravity) of Viscous Materials by Bingham Pycnometer.	Fuel analysis (liquid)
ASTM D1481-91, Standard Test Method for Density and Relative Density (Specific Gravity) of Viscous Materials by Lipkin Bicapillary Pycnometer.	Fuel analysis (liquid)
ASTM D1826-88, Standard Test Method for Calorific (Heating) Value of Gases in Natural Gas Range by Continuous Recording Calorimeter.	Fuel analysis (gaseous)
ASTM D1945-91, Standard Test Method for Analysis of Natural Gas by Gas Chromatography.	Fuel analysis (gaseous)*
ASTM D1946-90, Standard Practice for Analysis of Reformed Gas by Gas Chromatography.	Fuel analysis (gaseous)*

ASTM D1989-92, Standard Test Method for Gross Calorific Value of Coal and Coke by Microprocessor Controlled Isoperibol Calorimeters.	Fuel analysis (solid)
ASTM D2013-86, Standard Method of Preparing Coal Samples for Analysis.	Fuel analysis (solid)
ASTM D2015-91, Standard Test Method for Gross Calorific Value of Coal and Coke by the Adiabatic Bomb Calorimeter.	Fuel analysis (solid)
ASTM D2234-89, Standard Test Methods for Collection of a Gross Sample of Coal.	Fuel analysis (solid)
ASTM D2382-88, Standard Test Method for Heat of Combustion of Hydrocarbon Fuels by Bomb Calorimeter (High-Precision Method).	Fuel analysis (liquid)
ASTM D2502-87, Standard Test Method for Estimation of Molecular Weight (Relative Molecular Mass) of Petroleum Oils from Viscosity Measurements.	Fuel analysis (liquid)*
ASTM D2503-82 (Reapproved 1987), Standard Test Method for Molecular Weight (Relative Molecular Mass) of Hydrocarbons by Thermoelectric Measurement of Vapor Pressure.	Fuel analysis (liquid)*
ASTM D3154, Standard Test Method for Average Velocity in a Duct (Pitot Tube Method)	Flow rate (gaseous)
ASTM D3174-89, Standard Test Method for Ash in the Analysis Sample of Coal and Coke From Coal.	Ash analysis*
ASTM D3176-89, Standard Practice for Ultimate Analysis of Coal and Coke.	Fuel analysis (solid)
ASTM D3178-89, Standard Test Methods for Carbon and Hydrogen in the Analysis Sample of Coal and Coke.	Fuel analysis (solid)*
ASTM D3238-90, Standard Test Method for Calculation of Carbon Distribution and Structural Group Analysis of Petroleum Oils by the n-d-M Method.	Fuel analysis (liquid)*
ASTM D3286-91a, Standard Test Method for Gross Calorific Value of Coal and Coke by the Isoperibol Bomb Calorimeter.	Fuel analysis (solid)
ASTM D3588-91, Standard Practice for Calculating Heat Value, Compressibility Factor, and Relative Density (Specific Gravity) of Gaseous Fuels.	Fuel analysis (gaseous)
D3796-90(1998), Standard Practice for Calibration of Type S Pitot Tubes	Flow rate (gaseous)
ASTM D4052-91, Standard Test Method for Density and Relative Density of Liquids by Digital Density Meter.	Fuel analysis (liquid)
ASTM D4057-88, Standard Practice for Manual Sampling of Petroleum and Petroleum Products.	Fuel analysis (liquid)
ASTM D4177-82 (Reapproved 1990), Standard Practice for Automatic Sampling of Petroleum and Petroleum Products.	Fuel analysis (liquid)
ASTM D4891-89, Standard Test Method for Heating Value of Gases in Natural Gas Range by Stoichiometric Combustion.	Fuel analysis (gaseous)
ASTM D5291-92, Standard Test Methods for Instrumental Determination of Carbon, Hydrogen, and Nitrogen in Petroleum Products and Lubricants.	Fuel analysis (liquid)*
ASTM D5373-93, "Standard Methods for Instrumental Determination of Carbon, Hydrogen, and Nitrogen in Laboratory Samples of Coal and Coke."	Fuel analysis (solid)*

*Required under U.S. Acid Rain program for carbon content analysis of fuels or ash.

14.2 U.S. Environmental Protection Agency (EPA)

www.epa.gov/airmarkets/monitoring/index.html
http://www.epa.gov/fedrgstr/index.html

EPA Method 1 “Sample and Velocity Traverses for Stationary Sources”	Flow rate (gaseous)
EPA Method 2 “Determination of Stack Gas Velocity and Volumetric Flow Rate (Type S Pitot Tube)” as used by U.S. Acid Rain Program (Part 75).	Flow rate (gaseous)

EPA Method 3 “Gas Analysis for Carbon Dioxide, Oxygen, Excess Air and Dry Molecular Weight”	Concentration measurement
EPA Method 4 “Determination of Moisture Content in stack Gases”	Concentration measurement
EPA Method 5 “Determination Of Particulate Emissions from Stationary sources”	Concentration measurement
EPA Method 10 “Determination of Carbon Monoxide Emissions from Stationary sources”	Emissions method
EPA Method 18 “Measurement of Gaseous Organic Compound Emissions by Gas Chromatography”	Emissions method
EPA Method 21 “Determination of Volatile Organic Compound Leaks”	Emissions method
EPA Method 25 “Measurement of Total Gaseous Non-Methane Emissions as Carbon”	Emissions method
EPA Method 25A “Determination of Total Gaseous Organic Concentrations Using a Flame Ionization Analyzer (FID)”	Concentration measurement
EPA Method 25B “Determination of Total gaseous Organic concentrations Using a Non-Dispersive Infrared Analyzer (NDIR)”	Concentration measurement

14.3 American Society of Mechanical Engineers (ASME)

www.asme.org/catalog/

ASME MFC-3M-1989 with September 1990 Errata, Measurement of Fluid Flow in Pipes Using Orifice, Nozzle, and Venturi	Flow meters (liquid)
ASME MFC-4M-1986 (Reaffirmed 1990), Measurement of Gas Flow by Turbine Meters	Flow meters (gaseous)
ASME-MFC-5M-1985, Measurement of Liquid Flow in Closed Conduits Using Transit-Time Ultrasonic Flowmeters	Flow meters (liquid)
ASME MFC-6M-1987 with June 1987 Errata, Measurement of Fluid Flow in Pipes Using Vortex Flow Meters	Flow meters (liquid)
ASME MFC-7M-1987 (Reaffirmed 1992), Measurement of Gas Flow by Means of Critical Flow Venturi Nozzles	Flow meters (gaseous)
ASME MFC-9M-1988 with December 1989 Errata, Measurement of Liquid Flow in Closed Conduits by Weighing Method	Flow meters (liquid)

14.4 American National Standards Institute (ANSI)

http://webstore.ansi.org/ansidocstore/default.asp

Measurement of Liquid Flow in Closed Conduits-Method by Collection of the Liquid in a Volumetric Tank	Flow rate (liquid)

14.5 Gas Processors Association (GPA)

www.gasprocessors.com/dept.asp?dept_id=2500

GPA Standard 2172-96, Calculation of Gross Heating Value, Relative Density and Compressibility Factor for Natural Gas Mixtures from Compositional Analysis	Fuel analysis (gaseous)
GPA Standard 2261-90, Analysis for Natural Gas and Similar Gaseous Mixtures by Gas Chromatography	Fuel analysis (gaseous)

14.6 American Gas Association (AGA)

www.aga.org/Content/NavigationMenu/Operations_and_Engineering/Codes_and_Standards1/Codes_and_Standards.htm

American Gas Association Report No. 3: Orifice Metering of Natural Gas and Other Related Hydrocarbon Fluids, Part 1: General Equations and Uncertainty Guidelines (October 1990 Edition), Part 2: Specification and Installation Requirements (February 1991 Edition) and Part 3: Natural Gas Applications (August 1992 Edition).	Flow meters (gaseous)
American Gas Association Transmission Measurement Committee Report No. 7: Measurement of Gas by Turbine Meters (Second Revision, April 1996).	Flow meters (gaseous)

14.7 American Petroleum Institute (API)

http://api-ep.api.org/publications/index.cfm?bitmask=002002003000000000

American Petroleum Institute (API) Petroleum Measurement Standards, Chapter 3, Tank Gauging: Section 1A, Standard Practice for the Manual Gauging of Petroleum and Petroleum Products, December 1994; Section 1B, Standard Practice for Level Measurement of Liquid Hydrocarbons in Stationary Tanks by Automatic Tank Gauging, April 1992 (reaffirmed January 1997); Section 2, Standard Practice for Gauging Petroleum and Petroleum Products in Tank Cars, September 1995; Section 3, Standard Practice for Level Measurement of Liquid Hydrocarbons in Stationary Pressurized Storage Tanks by Automatic Tank Gauging, June 1996; Section 4, Standard Practice for Level Measurement of Liquid Hydrocarbons on Marine Vessels by Automatic Tank Gauging, April 1995; and Section 5, Standard Practice for Level Measurement of Light Hydrocarbon Liquids Onboard Marine Vessels by Automatic Tank Gauging, March 1997	Fuel stocks (liquid)
Shop Testing of Automatic Liquid Level Gages, Bulletin 2509 B, December 1961 (Reaffirmed August 1987, October 1992)	Fuel stocks (liquid)
American Petroleum Institute (API) Section 2, "Conventional Pipe Provers," Section 3, "Small Volume Provers," and Section 5, "Master-Meter Provers," from Chapter 4 of the Manual of Petroleum Measurement Standards, October 1988 (Reaffirmed 1993)	Fuel stocks (liquid)

14.8 International Standards Organization (ISO)

www.iso.org

ISO 562:1998 “Hard coal and coke -- Determination of volatile matter”	Fuel analysis (solid)
ISO 579:1999 “Coke -- Determination of total moisture”	Fuel analysis (solid)
ISO 589:2003 “Hard coal -- Determination of total moisture”	Fuel analysis (solid)
ISO 602:1983 “Coal -- Determination of mineral matter”	Fuel analysis (solid)
ISO 609:1996 “Solid mineral fuels -- Determination of carbon and hydrogen -- High temperature combustion method” ISO 609:1996/Cor 1:1996	Fuel analysis (solid)
ISO 625:1996 “Solid mineral fuels -- Determination of carbon and hydrogen -- Liebig method” ISO 625:1996/Cor 1:1996	Fuel analysis (solid)

ISO 687:2004 “Solid mineral fuels -- Coke -- Determination of moisture in the general analysis test sample”	Fuel analysis (solid)
ISO 925:1997 “Solid mineral fuels - Determination of carbonate carbon content - Gravimetric method”	Fuel analysis (solid)
ISO 1013:1995 “Coke -- Determination of bulk density in a large container”	Fuel analysis (solid)
ISO 1014:1985 “Coke -- Determination of true relative density, apparent relative density and porosity” ISO 1014:1985/Cor 1:1994	Fuel analysis (solid)
ISO 1170:1977 “Coal and coke -- Calculation of analyses to different bases”	Fuel analysis (solid)
ISO 1171:1997 “Solid mineral fuels -- Determination of ash” ISO 1171:1997/Cor 1:1998	Fuel analysis (solid)
ISO 1213-1:1993 “Solid mineral fuels -- Vocabulary -- Part 1: Terms relating to coal preparation”	Fuel analysis (solid)
ISO 1213-2:1992 “Solid mineral fuels -- Vocabulary -- Part 2: Terms relating to sampling, testing and analysis”	Fuel analysis (solid)
ISO 1928:1995 “Solid mineral fuels -- Determination of gross calorific value by the bomb calorimetric method, and calculation of net calorific value”	Fuel analysis (solid)
ISO 1988:1975 “Hard coal – Sampling”	Fuel analysis (solid)
ISO 2309:1980 “Coke – Sampling”	Fuel analysis (solid)
ISO 2950:1974 “Brown coals and lignites -- Classification by types on the basis of total moisture content and tar yield”	Fuel analysis (solid)
ISO 3170:2004 “Petroleum liquids -- Manual sampling” ISO 3170:1988/Amd 1:1998	Fuel analysis (liquid)
ISO 3171:1988 “Petroleum liquids -- Automatic pipeline sampling”	Fuel analysis (liquid)
ISO 3648:1994 “Aviation fuels -- Estimation of net specific energy” ISO 3648:1994/Cor 1:1996	Fuel analysis (liquid)
ISO 3675:1998 “Crude petroleum and liquid petroleum products -- Laboratory determination of density -- Hydrometer method”	Fuel analysis (liquid)
ISO 3733:1999 “Petroleum products and bituminous materials -- Determination of water -- Distillation method”	Fuel analysis (liquid)
ISO 3734:1997 “Petroleum products -- Determination of water and sediment in residual fuel oils -- Centrifuge method”	Fuel analysis (liquid)
ISO 3735:1999 “Crude petroleum and fuel oils -- Determination of sediment -- Extraction method”	Fuel analysis (liquid)
ISO 3838:2004 “Crude petroleum and liquid or solid petroleum products -- Determination of density or relative density -- Capillary-stoppered pyknometer and graduated bicapillary pyknometer methods”	Fuel analysis (liquid)
ISO 3993:1984 “Liquefied petroleum gas and light hydrocarbons -- Determination of density or relative density -- Pressure hydrometer method”	Fuel analysis (liquid)
ISO 3966:1977 “Measurement of fluid flow in closed conduits, Part 2 Velocity methods, section 21, Method using Pitot static tubes, Documents the L-Type Pitot tube. (Withdrawn)	Flow rate (gaseous)
ISO 4257:2001 “Liquefied petroleum gases -- Method of sampling”	Fuel analysis (liquid)
ISO 4261:1993 “Petroleum products -- Fuels (class F) -- Specifications of gas turbine fuels for industrial and marine applications”	Fuel analysis (liquid)
ISO 5068:1983 “Brown coals and lignites -- Determination of moisture content -- Indirect gravimetric method”	Fuel analysis (liquid)
ISO 5069-1:1983 “Brown coals and lignites -- Principles of sampling -- Part 1: Sampling for determination of moisture content and for general analysis”	Fuel analysis (solid)
ISO 5069-2:1983 “Brown coals and lignites -- Principles of sampling -- Part 2: Sample	Fuel analysis

preparation for determination of moisture content and for general analysis”	(solid)
ISO 5071-1:1997 “Brown coals and lignites -- Determination of the volatile matter in the analysis sample -- Part 1: Two-furnace method”	Fuel analysis (solid)
ISO 5072:1997 “Brown coals and lignites -- Determination of true relative density and apparent relative density”	Fuel analysis (solid)
ISO 6245:2001 “Petroleum products -- Determination of ash”	Fuel analysis (liquid)
ISO 6570:2001 “Natural gas -- Determination of potential hydrocarbon liquid content -- Gravimetric methods”	Fuel analysis (gaseous)
ISO 6974-1:2000 “Natural gas -- Determination of composition with defined uncertainty by gas chromatography -- Part 1: Guidelines for tailored analysis”	Fuel analysis (gaseous)
ISO 6974-2:2001 “Natural gas -- Determination of composition with defined uncertainty by gas chromatography -- Part 2: Measuring-system characteristics and statistics for processing of data”	Fuel analysis (gaseous)
ISO 6974-3:2000 “Natural gas -- Determination of composition with defined uncertainty by gas chromatography -- Part 3: Determination of hydrogen, helium, oxygen, nitrogen, carbon dioxide and hydrocarbons up to C8 using two packed columns”	Fuel analysis (gaseous)
ISO 6974-4:2000 “Natural gas -- Determination of composition with defined uncertainty by gas chromatography -- Part 4: Determination of nitrogen, carbon dioxide and C1 to C5 and C6+ hydrocarbons for a laboratory and on-line measuring system using two columns”	Fuel analysis (gaseous)
ISO 6974-5:2000 “Natural gas -- Determination of composition with defined uncertainty by gas chromatography -- Part 5: Determination of nitrogen, carbon dioxide and C1 to C5 and C6+ hydrocarbons for a laboratory and on-line process application using three columns”	Fuel analysis (gaseous)
ISO 6974-6:2002 “Natural gas -- Determination of composition with defined uncertainty by gas chromatography -- Part 6: Determination of hydrogen, helium, oxygen, nitrogen, carbon dioxide and C1 to C8 hydrocarbons using three capillary columns” ISO 6974-6:2002/Cor 1:2003	Fuel analysis (gaseous)
ISO 6975:1997 “Natural gas -- Extended analysis -- Gas-chromatographic method”	Fuel analysis (gaseous)
ISO 6976:1995 “Natural gas -- Calculation of calorific values, density, relative density and Wobbe index from composition” ISO 6976:1995/Cor 2:1997 ISO 6976:1995/Cor 3:1999	Fuel analysis (gaseous)
ISO 7941:1988 “Commercial propane and butane -- Analysis by gas chromatography”	Fuel analysis (gaseous)
ISO 8216-1:1996 “Petroleum products -- Fuels (class F) -- Classification -- Part 1: Categories of marine fuels”	Fuel analysis (liquid)
ISO 8216-2:1986 “Petroleum products -- Fuels (class F) -- Classification -- Part 2: Categories of gas turbine fuels for industrial and marine applications”	Fuel analysis (liquid)
ISO 8216-3:1987 “Petroleum products -- Fuels (class F) -- Classification -- Part 3: Family L (Liquefied petroleum gases)”	Fuel analysis (liquid)
ISO 8216-99:2002 “Petroleum products -- Fuels (class F) -- Classification -- Part 99: General”	Fuel analysis (liquid)
ISO 8217:1996 “Petroleum products -- Fuels (class F) -- Specifications of marine fuels”	Fuel analysis (liquid)
ISO 8316: 1987(E) “Measurement of Liquid Flow in Closed Conduits—Method by Collection of the Liquid in a Volumetric Tank”	Flow meter (liquid)
ISO 8681:1986 “Petroleum products and lubricants -- Method of classification -- Definition of classes”	Fuel analysis (liquid)
ISO 8756:1994 “Air quality -- Handling of temperature, pressure and humidity data”	General
ISO 8943:1991 “Refrigerated light hydrocarbon fluids -- Sampling of liquefied natural gas -- Continuous method”	Fuel analysis (liquid)
ISO 8973:1997 “Liquefied petroleum gases -- Calculation method for density and vapour pressure”	Fuel analysis (liquid)
ISO 9096:2003 “Stationary source emissions -- Manual determination of mass concentration of particulate matter”	Concentration measurement

ISO 9162:1989 “Petroleum products -- Fuels (class F) -- Liquefied petroleum gases – Specifications”	Fuel analysis (liquid)
ISO 9169:1994 “Air quality -- Determination of performance characteristics of measurement methods”	General
ISO 9300-1990 “Measurement of gas flow by means of critical flow Venturi nozzles”	Flow rate (gaseous)
ISO/TR 9494:1997 “Petroleum liquids -- Automatic pipeline sampling -- Statistical assessment of performance of automatic samplers determining the water content in hydrocarbon liquids”	Fuel analysis (liquid)
ISO 9931:1991 “Coal -- Sampling of pulverized coal conveyed by gases in direct fired coal systems”	Fuel analysis (solid)
ISO 9951-1993/94 “Measurement of gas flow in closed conduits – Turbine meters”	Flow rate (gaseous)
ISO 10012:2003 “Measurement management systems – Requirements for measurement processes and measuring equipment”	General
ISO 10101-1:1993 “Natural gas -- Determination of water by the Karl Fischer method -- Part 1: Introduction”	Fuel analysis (gaseous)
ISO 10101-2:1993 “Natural gas -- Determination of water by the Karl Fischer method -- Part 2: Titration procedure”	Fuel analysis (gaseous)
ISO 10101-3:1993 “Natural gas -- Determination of water by the Karl Fischer method -- Part 3: Coulometric procedure”	Fuel analysis (gaseous)
ISO 10155:1995 “Stationary source emissions -- Automated monitoring of mass concentrations of particles -- Performance characteristics, test methods and specifications” ISO 10155:1995/Cor 1:2002	Concentration measurement
ISO 10307-1:1993 “Petroleum products -- Total sediment in residual fuel oils -- Part 1: Determination by hot filtration” ISO 10307-1:1993/Cor 1:1997	Fuel analysis (liquid)
ISO 10307-2:1993 “Petroleum products -- Total sediment in residual fuel oils -- Part 2: Determination using standard procedures for ageing”	Fuel analysis (liquid)
ISO 10370:1993 “Petroleum products -- Determination of carbon residue -- Micro method” ISO 10370:1993/Cor 1:1996	Fuel analysis (liquid)
ISO 10396:1993 “Stationary source emissions – Sampling for the automated determination of gas concentrations”	Concentration measurement
ISO 10715:1997 “Natural gas -- Sampling guidelines”	Fuel analysis (gaseous)
ISO 10723:1995 “Natural gas -- Performance evaluation for on-line analytical systems” ISO 10723:1995/Cor 1:1998	Fuel analysis (gaseous)
ISO 10780:1994 “Air Quality – Stationary source emissions – Measurement of velocity and volume flow rate of gas streams in ducts” (S-type Pitot tube)	Flow rate (gaseous)
ISO 11042-1:1996 “Gas turbines -- Exhaust gas emission -- Part 1: Measurement and evaluation”	Emissions method
ISO 11042-2:1996 “Gas turbines -- Exhaust gas emission -- Part 2: Automated emission monitoring”	Emissions method
ISO 11541:1997 “Natural gas -- Determination of water content at high pressure”	Fuel analysis (gaseous)
ISO 11722:1999 “Solid mineral fuels -- Hard coal -- Determination of moisture in the general analysis test sample by drying in nitrogen”	Fuel analysis (solid)
ISO 11726:2004 “Solid mineral fuels -- Guidelines for the validation of alternative methods of analysis”	Fuel analysis (solid)
ISO 12039:2001 “Stationary source emissions -- Determination of carbon monoxide, carbon dioxide and oxygen -- Performance characteristics and calibration of automated measuring systems”	Emissions method
ISO 12141:2002 “Stationary source emissions -- Determination of mass concentration of particulate matter (dust) at low concentrations -- Manual gravimetric method”	Concentration measurement
ISO 12185:1996 “Crude petroleum and petroleum products -- Determination of density -- Oscillating U-tube method”	Fuel analysis (liquid)

ISO 12185:1996/Cor 1:2001	
ISO 12213-1:1997 “Natural gas -- Calculation of compression factor -- Part 1: Introduction and guidelines”	Fuel analysis (gaseous)
ISO 12213-2:1997 “Natural gas -- Calculation of compression factor -- Part 2: Calculation using molar-composition analysis”	Fuel analysis (gaseous)
ISO 12213-3:1997 “Natural gas -- Calculation of compression factor -- Part 3: Calculation using physical properties”	Fuel analysis (gaseous)
ISO/TS 12902:2001 “Solid mineral fuels -- Determination of total carbon, hydrogen and nitrogen -- Instrumental methods”	Fuel analysis (solid)
ISO 12937:2000 “Petroleum products -- Determination of water -- Coulometric Karl Fischer titration method”	Fuel analysis (liquid)
ISO 13443:1996 “Natural gas -- Standard reference conditions” ISO 13443:1996/Cor 1:1997	Fuel analysis (gaseous)
ISO 13686:1998 “Natural gas -- Quality designation”	Fuel analysis (gaseous)
ISO 13758:1996 “Liquefied petroleum gases -- Assessment of the dryness of propane -- Valve freeze method”	Fuel analysis (gaseous)
ISO 13909-1:2001 “Hard coal and coke -- Mechanical sampling -- Part 1: General introduction”	Fuel analysis (solid)
ISO 13909-2:2001 “Hard coal and coke -- Mechanical sampling -- Part 2: Coal -- Sampling from moving streams”	Fuel analysis (solid)
ISO 13909-3:2001 “Hard coal and coke -- Mechanical sampling -- Part 3: Coal -- Sampling from stationary lots”	Fuel analysis (solid)
ISO 13909-4:2001 “Hard coal and coke -- Mechanical sampling -- Part 4: Coal -- Preparation of test samples”	Fuel analysis (solid)
ISO 13909-5:2001 “Hard coal and coke -- Mechanical sampling -- Part 5: Coke -- Sampling from moving streams”	Fuel analysis (solid)
ISO 13909-6:2001 “Hard coal and coke -- Mechanical sampling -- Part 6: Coke -- Preparation of test samples”	Fuel analysis (solid)
ISO 13909-7:2001 “Hard coal and coke -- Mechanical sampling -- Part 7: Methods for determining the precision of sampling, sample preparation and testing”	Fuel analysis (solid)
ISO 13909-8:2001 “Hard coal and coke -- Mechanical sampling -- Part 8: Methods of testing for bias”	Fuel analysis (solid)
ISO 14001:1996 “Environmental management systems – Specification with guidance for use”	General
ISO 14164:1999 “Stationary source emissions – Determination of the volume flow rate of as streams in ducts, Automated method”	Flow rate (gaseous)
ISO 14180:1998 “Solid mineral fuels -- Guidance on the sampling of coal seams”	Fuel analysis (solid)
ISO 14532:2001 “Natural gas – Vocabulary” ISO 14532:2001/Cor 1:2002	Fuel analysis (gaseous)
ISO 15117-1:2004 “Coal flow properties -- Part 1: Bin flow”	Flow rate (solid)
ISO 15167:1999 “Petroleum products -- Determination of particulate content of middle distillate fuels -- Laboratory filtration method”	Fuel analysis (liquid)
ISO 15911:2000 “Petroleum products -- Estimation of net specific energy of aviation turbine fuels using hydrogen content data”	Fuel analysis (liquid)
ISO/TR 18455:1999 “Petroleum products -- Calculation of specific energy of residual fuels from physical and compositional properties -- Basic data”	Fuel analysis (liquid)
ISO 20905:2004 “Coal preparation -- Determination of dust/moisture relationship for coal”	Fuel analysis (solid)

14.9 German Institute for Standardization (DIN)

http://www2.din.de/index.php?lang=en

DIN 51900-1:2000 “Testing of solid and liquid fuels – Determination of gross calorific value by the bomb calorimeter and calculation of net calorific value – Part 1: Principles, apparatus, methods”	Fuel analysis (solid and liquid)
DIN 51857:1997 “Gaseous fuels and other gases - Calculation of calorific value, density, relative density and Wobbe index of pure gases and gas mixtures”	Fuel analysis (gaseous)
DIN 51612:1980 “Testing of liquefied petroleum gases; calculation of net calorific value”	Fuel analysis (liquid)
DIN 51721:2001 “Testing of solid fuels - Determination of carbon and hydrogen content” (also applicable for liquid fuels)	Fuel analysis (solid)

14.10 Committee on European Normalization (CEN)

www.cenorm.be/catweb/cwen.htm

EN 14181 “Stationary source emissions – Quality assurance of automated measuring systems”	QA/QC
EN ISO “14956:2002 “Air quality –Evaluation of the suitability of a measurement procedure by comparison with required uncertainty”	General
EN ISO “17025:2000 “General requirements for the competence and testing of calibration laboratories”	General
EN ISO 4259:1996 “Petroleum products – Determination and application of precision data in relation to methods of test”	Fuel analysis (liquid)

15 Annex E: Unit Conversions

Mass			
1 pound (lb)	453.6 grams (g)	0.4536 kilograms (kg)	0.0004536 metric tons (tonne)
1 kilogram (kg)	2.205 pounds (lb)		
1 short ton (ton)	2'000 pounds (lb)	907.2 kilograms (kg)	
1 metric ton	2'205 pounds (lb)	1'000 kilograms (kg)	1.1023 short tons (tons)
Volume			
1 cubic foot (ft ^{3})	7.4805 gallons (gal)	0.1781 barrel (bbl)	
1 cubic foot (ft ^{3})	28.32 liters (L)	0.02832 cubic meters (m ^{3})	
1 gallon (gal)	0.0238 barrel (bbl)	3.785 liters (L)	0.003785 cubic meters (m ^{3})
1 barrel (bbl)	42 gallons (gal)	158.99 liters (L)	0.1589 cubic meters (m ^{3})
1 litre (L)	0.001 cubic meters (m ^{3})	0.2642 gallons (gal)	
1 cubic meter (m ^{3})	6.2897 barrels (bbl)	264.2 gallons (gal)	1'000 liters (L)
Energy			
1 kilowatt hour (kWh)	3412 Btu (btu)	3'600 kilojoules (KJ)	
1 megajoule (MJ)	0.001 gigajoules (GJ)		
1 gigajoule (GJ)	0.9478 million Btu (million btu)	277.8 kilowatt hours (kWh)	
1 Btu (btu)	1'055 joules (J)		
1 million Btu (million btu)	1.055 gigajoules (GJ)	293 kilowatt hours (kWh)	
1 therm (therm)	100'000 btu	0.1055 gigajoules (GJ)	29.3 kilowatt hours (kWh)
Other			
kilo	1'000		
mega	1'000'000		
giga	1'000'000'000		
tera	1'000'000'000'000		
1 psi	0.06895 bar		
1 kgf / cm ^{3} (tech atm)	0.9807 bar		
1 atmosphere (atm)	1.01325 bar	101.325 kilo pascals	14.696 pounds per square inch (psia)
1 mile (statue)	1.609 kilometers		
1 metric ton CH_4	21 metric tons CO_2 equivalent		
1metric ton N_2O	310 metric tons CO_2 equivalent		
1 metric ton carbon	3.664 metric tons CO_2		

16 Glossary

This glossary of terms is meant to assist the user of this guidance in interpreting information collected and used in the process of developing stationary combustion greenhouse gas emission estimates. Most of the terms presented here are not explicitly used in this guidance document, but may be encountered in the process of its use. The definitions provided below are simply indicative of typical usage, and may not be applicable in a strict (e.g., legal) sense in relation to individual programs or regulations.

Additives/oxygenates. Additives are non-hydrocarbon compounds added to or blended with a product to modify fuel properties (octane, cetane, cold properties, etc.).

- Oxygenates, such as alcohols (methanol, ethanol), ethers such as MTBE (methyl tertiary butyl ether), ETBE (ethyl tertiary butyl ether), TAME (tertiary amyl methyl ether).
- Esters (e.g. rapeseed or dimethylester, etc.).
- Chemical compounds (such as tetramethyl lead, tetraethyl lead and detergents).

Ethanol is not included here, but under Gas/Liquids from Biomass.

Aerosol. Particulate matter, solid or liquid, larger than a molecule but small enough to remain suspended in the atmosphere. Natural sources include salt particles from sea spray and dust and clay particles as a result of weathering of rocks, both of which are carried upward by the wind. Aerosols can also originate as a result of human activities and are often considered pollutants. Aerosols are important in the atmosphere as nuclei for the condensation of water droplets and ice crystals, as participants in various chemical cycles, and as absorbers and scatterers of solar radiation, thereby influencing the radiation budget of the Earth's climate system. See *climate, particulate matter.*

Agglomerating character. Agglomeration describes the caking properties of coal. Agglomerating character is determined by examination and testing of the residue when a small powdered sample is heated to 950°C (1742°F) under specified conditions. If the sample is "agglomerating," the residue will be coherent, show swelling or cell structure, and be capable of supporting a 500-gram (1.102-pound) weight without pulverizing.

Air dried basis. Equivalent to as analyzed basis when the analyses have been performed on an air-dried sample.

Air dried moisture. The moisture in the coal sample after achieving equilibrium with the laboratory atmosphere by exposure to it. Called residual moisture in South African standards. No equivalent term in ASTM, although air dried moisture can refer to a sample dried in an oven with warm air.

Alcohol. A general class of hydrocarbons that contain a hydroxyl group (OH). The term "alcohol" is often used interchangeably with the term "ethanol," even though there are many types of alcohol. (See Butanol, Ethanol, Methanol.)

Alkylation. A refining process for chemically combining isobutane with olefin hydrocarbons (e.g., propylene, butylene) through the control of temperature and pressure in the presence of an acid catalyst, usually sulfuric acid or hydrofluoric acid. The product, alkylate, an isoparaffin, has high octane value and is blended with motor and aviation gasoline to improve the antiknock value of the fuel.

Alternative energy. Energy derived from nontraditional sources (e.g., compressed natural gas, solar, hydroelectric, wind).

Anaerobic decomposition. The breakdown of molecules into simpler molecules or atoms by microorganisms that can survive in the partial or complete absence of oxygen.

Anaerobic digestion. A biochemical process by which organic matter is decomposed by bacteria in the absence of oxygen, producing methane and other byproducts.

Anaerobic. Life or biological processes that occur in the absence of oxygen.

Anthracite. See Hard coal.

Anthracite. The highest rank coal and is characterized by low volatile matter (always less than 10%) and high carbon content. It is a hard, brittle, and black lustrous coal, often referred to as hard coal, containing a high percentage of fixed carbon and a low percentage of volatile matter. The moisture content of fresh-mined anthracite generally is less than 15 percent. The heat content of anthracite ranges from 22 to 28 million Btu per short ton (0.0256 to 0.0326 GJ/kg) on a moist, mineral-matter-free basis. The heat content of anthracite coal consumed in the United States averages 25 million Btu per short ton (0.0291 GJ/kg), on the as-received basis (i.e., containing both inherent moisture and mineral matter). Note. Since the 1980's, anthracite refuse or mine waste has been used for steam electric power generation. This fuel typically has a heat content of 15 million Btu per short ton (0.0174 GJ/kg) or less.

Anthropogenic. Human made. In the context of greenhouse gases, emissions that are produced as the result of human activities.

API gravity. American Petroleum Institute measure of specific gravity of crude oil or condensate in degrees. An arbitrary scale expressing the gravity or density of liquid petroleum products. The measuring scale is calibrated in terms of degrees API; it is calculated as follows.
Degrees API = (141.5 / sp.gr.60 deg.F/60 deg.F) - 131.5

API. The American Petroleum Institute, a trade association.

Aromatic. Applied to a group of hydrocarbons and their derivatives characterized by the presence of the benzene ring.

Ash analysis. Ash is composed of very complex oxides and the ash analysis expresses this composition in terms of its component oxides. Generally the ash consists mostly of silica (SiO_2) and alumina (Al_2O_3). The presence of large amounts of the oxides of iron (Fe_2O_3), calcium (CaO), sodium (Na_2O) and/or potassium (K_20) generally indicates an ash with low ash fusion temperatures. The ash analysis differs from the composition of the minerals in the parent coal (see Ash).

Ash. Impurities consisting of silica, iron, alumina, and other incombustible matter that are contained in coal. Ash increases the weight of coal, adds to the cost of handling, and can affect the burning characteristics. Ash content is measured as a percent by weight of coal on an "as received" or a "dry" (moisture-free) basis.

Asphalt. A dark brown-to-black cement-like material obtained by petroleum processing and containing bitumens as the predominant component; used primarily for road construction. It includes crude asphalt as well as the following finished products. cements, fluxes, the asphalt content of emulsions (exclusive of water), and petroleum distillates blended with asphalt to make cutback asphalts. *Note*. The density conversion factor for asphalt is 5.5 barrels per short ton (0.9639 liters/kg).

As-received condition or as-received basis. Represents an analysis of a sample as received at a facility with combustion units.

Atmospheric lifetime. See *lifetime*.

Average megawatt. (MWa or aMW) One megawatt of capacity produced continuously over a period of one year. 1 aMW = 1 MW x 8760 hours/year = 8,760 MWh = 8,760,000 kWh = 29,890 million btu = 31,536 GJ.

Aviation gasoline. A motor spirit prepared especially for aviation piston engines, with an octane number suited to the engine, a freezing point of -60 degrees C (-76 degrees F), and a distillation range usually within the limits of 30 degrees C (86 degrees F) and 180 degrees C (356 degrees F). In the United States: All special grades of gasoline for use in aviation reciprocating engines, as given in the American Society for Testing and Materials (ASTM) specification D 910. Includes all refinery products within the gasoline range that are to be marketed straight or in blends as aviation gasoline without further processing (any refinery operation except mechanical blending). Also included are finished components in the gasoline range, which will be used for blending or compounding into aviation gasoline.

Backup electricity, backup services. Power or services needed occasionally; for example, when on-site generation equipment fails.

Backup rate. A utility charge for providing occasional electricity service to replace on-site generation.

Baffle chamber. In incinerator design, a chamber designed to settle fly ash and coarse particulate matter by changing the direction and reducing the velocity of the combustion gases.

Baghouse. A chamber containing fabric filter bags that remove particles from furnace stack exhaust gases. Used to eliminate particles greater than 20 microns in diameter.

Barrel (bbl). A liquid-volume measure equal to 42 United States gallons and 158.99 liters at 60 degrees Fahrenheit (15.56 degrees Celsius); used in expressing quantities of petroleum-based products.

Barrel of oil equivalent. A unit of energy equal to the amount of energy contained in a barrel of crude oil. Approximately 5.78 million Btu, 1,700 kWh or 6.10 GJ.

Baseload capacity. The power output that generating equipment can continuously produce.

Baseload demand. The minimum demand experienced by an electric utility, usually 30-40% of the utility's peak demand.

Batch. An amount of fuel or material transferred as one shipment or continuously over a specific period of time.

Benzene. A toxic, six-carbon aromatic component of gasoline. A known carcinogen.

Bias. Systematic error, resulting in measurements that will be consistently low or high relative to a reference value or true value.

Biodegradable. Material that can be broken down into simpler substances (elements and compounds) by bacteria or other decomposers. Paper and most organic wastes such as animal manure are biodegradable. See *nonbiodegradable*.

Biodiesel. A biofuel produced through transesterification, a process in which organically-derived oils are combined with alcohol (ethanol or methanol) in the presence of a catalyst to form ethyl or methyl ester. The biomass-derived ethyl or methyl esters can be blended with conventional diesel fuel or used as a neat fuel (100% biodiesel). Biodiesel can be made from soybean or rapeseed oils, animal fats, waste vegetable oils or microalgae oils.

Bioenergy. Renewable energy produced from organic matter. The conversion of the complex carbohydrates in organic matter to energy. Organic matter may either be used directly as a fuel or processed into liquids or gases.

Biofuel. Gas or liquid fuel made from plant material (biomass). Biofuels cover bioethanol, biodiesel, biomethanol, biodimethylether, biooil. Liquid biofuels are mainly biodiesel and bioethanol/ETBE used as transport fuels. They can be made from new or used vegetable oils and may be blended with or replace petroleum-based fuels. The natural plant feedstock includes soy, sunflower and oil seed rape oils. Under some circumstances, used vegetable oils may also be used as feedstock for the process.

Biogas. A gas composed principally of methane (50-60%) and carbon dioxide produced by anaerobic digestion of biomass, comprising.

- Landfill gas, formed by the digestion of landfilled wastes.
- Sewage sludge gas, produced from the anaerobic fermentation of sewage sludge.
- Other biogas, such as biogas produced from the anaerobic fermentation of animal slurries and of wastes in abattoirs, breweries and other agro-food industries.

Bitumen. Solid, semi-solid or viscous hydrocarbon with a colloidal structure, being brown to black in color, obtained as a residue in the distillation of crude oil, vacuum distillation of oil residues from atmospheric distillation. Bitumen is often referred to as asphalt and is primarily used for surfacing of roads and for roofing material. This category includes fluidized and cut back bitumen. See *tar sand*.

Bituminous coal. A dense coal, usually black, sometimes dark brown, often with well-defined bands of bright and dull material, used primarily as fuel in steam-electric power generation, with substantial quantities also used for heat and power applications in manufacturing and to make coke. Bituminous coal is the most abundant coal in active U.S. mining regions. Its moisture content usually is less than 20 percent. The heat content of bituminous coal ranges from 21 to 30 million Btu per ton (0.0244 to 0.0349 GJ/kg) on a moist, mineral-matter-free basis. The heat content of bituminous coal consumed in the United States averages 24 million Btu per ton (0.0279 GJ/kg), on the as-received basis (i.e., containing both inherent moisture and mineral matter).

BKB (brown coal/peat briquettes). A composition fuels manufactured from brown coal. The lignite/brown coal is crushed, dried and moulded under high pressure into an even-shaped briquette without the addition of binders. These figures include peat briquettes, dried lignite, fines and dust and brown coal breeze. The heading other energy sector includes consumption by briquetting plants.

Black liquor. This is a recycled by-product formed during the pulping of wood in the paper making industry. In this process, lignin in the wood is separated from cellulose, with the latter forming the paper fibres. Black liquor is the combination of the lignin residue with water and the chemicals used for the extraction of the lignin and is burned in a recovery boiler. The boiler produces steam and electricity and recovers the inorganic chemicals for recycling throughout the process.

Blast furnace Gas. Produced during the combustion of coke in blast furnaces in the iron and steel industry. It is recovered and used as a fuel partly within the plant and partly in other steel industry processes or in power stations equipped to burn it. Also included here is oxygen steel furnace gas which is obtained as a by-product of the production of steel in an oxygen furnace and is recovered on leaving the furnace. The gas is also known as converter gas or LD gas. The quantity of fuel should be reported on a gross calorific value.

Boiler horsepower. A measure of the maximum rate of heat energy output of a steam generator. One boiler horsepower equals 33,480 Btu/hr (35.3 MJ/hr)output in steam.

Bottom ash. Noncombustible ash that is left after solid fuel has been burned.

Bottoming cycle. A cogeneration system in which steam is used first for process heat and then for electric power production.

Breeze. The fine screenings from crushed coke. Usually breeze will pass through a 1/2-inch or 3/4-inch screen opening. It is most often used as a fuel source in the process of agglomerating iron ore.

British thermal unit (Btu). The quantity of heat required to raise the temperature of one pound of water one degree of Fahrenheit at or near 39.2 degrees Fahrenheit and one atmosphere pressure (sea level).

Brown coal. See Lignite.

Btu. See British thermal unit

Butane (C_4H_{10}). A normally gaseous straight-chain or branch-chain hydrocarbon extracted from hydrocarbon extracted from natural gas or refinery gas streams. It includes isobutane and normal butane and is designated in ASTM Specification D1835 and Gas Processors Association Specifications for commercial butane.

Butanol or **butyl alcohol.** An alcohol with the chemical formula $CH_3(CH_2)_3OH$. It is formed during anaerobic fermentation using bacteria to convert the sugars to butanol and carbon dioxide.

Calibration error. The difference between the response of a monitoring device to a reference signal (e.g., gas concentration) and the know value of the reference signal.

Calibration gas. A standard reference material as defined by NIST, ISO, or other standards organization.

Calibration. The process of establishing the relationship between the output of a measurement process and the known input.

Capacity factor. The ratio of the electrical energy produced by a generating unit for a given period of time to the electrical energy that could have been produced at continuous full- power operation during the same period.

Capacity. The maximum power that a machine or system can produce or carry safely. The maximum instantaneous output of a resource under specified conditions. The capacity of generating equipment is generally expressed in kilowatts or megawatts. The rated continuous load-carrying ability, expressed in megawatts (MW) or megavolt-amperes (MVA) of generation, transmission, or other electrical equipment.

Carbon black. An amorphous form of carbon, produced commercially by thermal or oxidative decomposition of hydrocarbons and used principally in rubber goods, pigments, and printer's ink.

Carbon cycle. All carbon reservoirs and exchanges of carbon from reservoir to reservoir by various chemical, physical, geological, and biological processes. Usually thought of as a series of the four main reservoirs of carbon interconnected by pathways of exchange. The four reservoirs, regions of the Earth in which carbon behaves in a systematic manner, are the atmosphere, terrestrial biosphere (usually includes freshwater systems), oceans, and sediments (includes fossil fuels). Each of these global reservoirs may be subdivided into smaller pools, ranging in size from individual communities or ecosystems to the total of all living organisms (biota).

Carbon dioxide (CO_2). A colorless, odorless, non-poisonous gas that is a normal part of Earth's atmosphere. Carbon dioxide is a product of fossil-fuel combustion as well as other processes. It is considered a greenhouse gas as it traps heat (infrared energy) radiated by the Earth into the atmosphere and thereby contributes to the potential for global warming. The global warming potential (GWP) of other greenhouse gases is measured in relation to that of carbon dioxide, which by international scientific convention is assigned a value of one (1).

Carbon dioxide equivalent (CO_2 Eq.). A metric measure used to compare the emissions of the different greenhouse gases based upon their global warming potential (GWP). Greenhouse gas emissions in the United States are most commonly expressed as "teragrams of carbon dioxide equivalents" (Tg CO_2 Eq.). Global warming potentials are used to convert greenhouse gases to carbon dioxide equivalents. See *global warming potential*, *greenhouse gas*.

Carbon intensity. The relative amount of carbon emitted per unit of energy or fuels consumed.

Carbon monoxide. (CO) A colorless, odorless gas produced by incomplete combustion. Carbon monoxide is poisonous if inhaled.

Carbon sequestration. The absorption and storage of carbon dioxide from the atmosphere. Naturally-occurring in plants. Trees and plants, for example, absorb carbon dioxide, release the oxygen and store the carbon. Fossil fuels were at one time biomass and continue to store the carbon until burned. See *carbon sinks*.

Carbonisation. The carbonisation of coal is carried out commercially for the production of coke for the iron and steel industry's blast furnaces. The process involves heating coking coal in the absence of air to a temperature of around 1100°C. This is carried out in a coke oven and the coking time is around 14 - 20 hours. The gases and liquids evolved during the process are used on site for their energy content or sold as plant products. In a process very little used today, town gas can also be prepared by carbonisation, with the resulting coke being used as a domestic fuel.

Catalytic converter. A device containing a catalyst for converting automobile exhaust into mostly harmless products.

cfm. Cubic feet per minute.

Charcoal. See Solid biomass.

Chemical reaction. Interaction between chemicals in which there is a change in the chemical composition of the elements or compounds involved.

Coal analysis. Determines the composition and properties of coal so it can be ranked and used most effectively.

- **Proximate analysis** determines, on an as-received basis, the moisture content, volatile matter (gases released when coal is heated), fixed carbon (solid fuel left after the volatile matter is driven off), and ash (impurities consisting of silica, iron, alumina, and other incombustible matter). The moisture content affects the ease with which coal can be handled and burned. The amount of volatile matter and fixed carbon provides guidelines for determining the intensity of the heat produced. Ash increases the weight of coal, adds to the cost of handling, and can cause problems such as clinkering and slagging in boilers and furnaces.
- **Ultimate analysis** determines the amount of carbon, hydrogen, oxygen, nitrogen, and sulfur. Heating value is determined in terms of Btu, both on an as received basis (including moisture) and on a dry basis.
- **Agglomerating** refers to coal that softens when heated and forms a hard gray coke; this coal is called caking coal. Not all caking coals are coking coals. The agglomerating value is used to differentiate between coal ranks and also is a guide to determine how a particular coal reacts in a furnace.
- **Agglutinating** refers to the binding qualities of a coal. The agglutinating value is an indication of how well a coke made from a particular coal will perform in a blast furnace. It is also called a caking index.
- **Other tests** include the determination of the ash softening temperature, the ash fusion temperature (the temperature at which the ash forms clinkers or slag), the free swelling index (a guide to a coal's coking characteristics), the Gray King test (which determines the suitability of coal for making coke), and the Hardgrove grindability index (a measure of the ease with which coal can be pulverized). In a petrographic analysis, thin sections of coal or highly polished blocks of coal are studied with a microscope to determine the physical composition, both for scientific purposes and for estimating the rank and coking potential.

Coal briquets. Anthracite, bituminous, and lignite briquets comprise the secondary solid fuels manufactured from coal by a process in which the coal is partly dried, warmed to expel excess moisture, and then compressed into briquets, usually without the use of a binding substance. In the reduction of briquets to coal equivalent, different conversion factors are applied according to their origin from hard coal, peat, brown coal, or lignite.

Coal carbonized. The amount of coal decomposed into solid coke and gaseous products by heating in a coke oven in a limited air supply or in the absence of air.

Coal chemicals. Coal chemicals are obtained from the gases and vapor recovered from the manufacturing of coke. Generally, crude tar, ammonia, crude light oil, and gas are the basic products recovered. They are refined or processed to yield a variety of chemical materials.

Coal coke. A hard, porous product made from baking bituminous coal in ovens at temperatures as high as 2,000 degrees Fahrenheit. It is used both as a fuel and as a reducing agent in smelting iron ore in a blast furnace.

Coal gasification. Conversion of solid coal to synthetic natural gas (SNG) or a gaseous mixture that can be burned as a fuel.

Coal grade. This classification refers to coal quality and use.

- **Briquettes** are made from compressed coal dust, with or without a binding agent such as asphalt.
- **Cleaned coal or prepared coal** has been processed to reduce the amount of impurities present and improve the burning characteristics.
- **Compliance coal** is a coal, or a blend of coal, that meets sulfur dioxide emission standards for air quality without the need for flue-gas desulfurization.
- **Culm and silt** are waste materials from preparation plants. In the anthracite region, culm consists of coarse rock fragments containing as much as 30 percent small-sized coal. Silt is a mixture of very fine coal particles (approximately 40 percent) and rock dust that has settled out from waste water from the plants. The terms culm and silt are sometimes used interchangeably and are sometimes called refuse. Culm and silt have a heat value ranging from 8 to 17 million Btu per ton (0.0093 GJ/kg to 0.0198 GJ/kg).
- **Low-sulfur coal** generally contains 1 percent or less sulfur by weight. For air quality standards, "low sulfur coal" contains 0.6 pounds or less sulfur per million Btu, which is equivalent to 1.2 pounds of sulfur dioxide per million Btu (approximately 0.516 kg of sulfur dioxide per GJ).
- **Metallurgical coal (or coking coal)** meets the requirements for making coke. It must have a low ash and sulfur content and form a coke that is capable of supporting the charge of iron ore and limestone in a blast furnace. A blend of two or more bituminous coals is usually required to make coke.
- **Pulverized coal** is a coal that has been crushed to a fine dust in a grinding mill. It is blown into the combustion zone of a furnace and burns very rapidly and efficiently.
- **Slack coal** usually refers to bituminous coal one-half inch or smaller in size.
- **Steam coal** refers to coal used in boilers to generate steam to produce electricity or for other purposes.
- **Stoker coal** refers to coal that has been crushed to specific sizes (but not powdered) for burning on a grate in automatic firing equipment.

Coal preparation/washing. The treatment of coal to reject waste. In its broadest sense, preparation is any processing of mined coal to prepare it for market, including crushing and screening or sieving the coal to reach a uniform size, which normally results in removal of some non-coal material. The term coal preparation most commonly refers to processing, including crushing and screening, passing the material through one or more processes to remove impurities, sizing the product, and loading for shipment. Many of the processes separate rock, clay, and other minerals from coal in a liquid medium; hence the term washing is widely used. In some cases coal passes through a drying step before loading.

Coal rank. The classification of coals according to their degree of progressive alteration from lignite to anthracite. In the United States, the standard ranks of coal include lignite, subbituminous coal, bituminous coal, and anthracite and are based on fixed carbon, volatile matter, heating value, and agglomerating (or caking) properties.

Coal sampling. The collection and proper storage and handling of a relatively small quantity of coal for laboratory analysis. Sampling may be done for a wide range of purposes, such as. coal resource exploration and assessment, characterization of the reserves or production of a mine, to characterize the results of coal cleaning processes, to monitor coal shipments or receipts for adherence to coal quality contract specifications, or to subject a coal to specific combustion or reactivity tests related to the customer's intended use.

Coal. A readily combustible black or brownish-black rock whose composition, including inherent moisture, consists of more than 50 percent by weight and more than 70 percent by volume of carbonaceous material. It is formed from plant remains that have been compacted, hardened, chemically altered, and metamorphosed by heat and pressure over geologic time. The rank of coal, which includes anthracite, bituminous coal, subbituminous coal, and lignite, is based on fixed carbon, volatile matter, and heating value. Coal rank indicates the progressive alteration, or coalification, from lignite to anthracite. See *anthracite, bituminous coal, subbituminous coal, lignite.* In the United States: All solid fuels classified as anthracite, bituminous, or lignite by the American Society for Testing and Materials Designation ASTM D388-02 "Standard Classification of Coals by Rank." [other EU or ISO standard?]

Coalbed degasification. This refers to the removal of methane or coal bed gas from a coal mine before or during mining.

Coalbed methane. Methane is generated during coal formation and is contained in the coal microstructure. Typical recovery entails pumping water out of the coal to allow the gas to escape. Methane is the principal component of natural gas. Coal bed methane can be added to natural gas pipelines without any special treatment.

Coalbed. A bed or stratum of coal. Also called a coal seam.

Coal-fired. The combustion of fuel consisting of coal or any coal-derived fuel (except for coal-derived gaseous fuels).

Co-control benefit. It is the additional benefit derived from an environmental policy that is designed to control one type of pollution, while reducing the emissions of other pollutants as well. For example, a policy to reduce carbon dioxide emissions might reduce the combustion of coal, but when coal combustion is reduced, so too are the emissions of particulates and sulfur dioxide.[5] The benefits associated with reductions in emissions of particulates and sulfur dioxide are the co-control benefits of reductions in carbon dioxide.
Cofiring. The process of burning natural gas in conjunction with another fuel to reduce air pollutants.
Cogeneration. The sequential production of electricity and useful thermal energy from a common fuel source. Rejected heat from industrial processes can be used to power an electric generator (*bottoming cycle*). Conversely, surplus heat from an electric generating plant can be used for industrial processes, or space and water heating purposes (*topping cycle*).
Coke (coal). A solid carbonaceous residue derived from low-ash, low-sulfur bituminous coal from which the volatile constituents are driven off by baking in an oven at temperatures as high as 2,000 degrees Fahrenheit (1093 degrees Celsius) so that the fixed carbon and residual ash are fused together. Coke is used as a fuel and as a reducing agent in smelting iron ore in a blast furnace. Coke from coal is grey, hard, and porous and has a heating value of 24.8 million Btu per short ton (0.0288 GJ/kg).
Coke (petroleum). A residue high in carbon content and low in hydrogen that is the final product of thermal decomposition in the condensation process in cracking. This product is reported as marketable coke or catalyst coke. Coke from petroleum has a heating value of 6.024 million Btu per barrel (approximately 0.040 GJ/liter).
Coke oven coke and gas coke. Coke oven coke is the solid product obtained from the carbonisation of coal, principally coking coal, at high temperature. It is low in moisture content and volatile matter. Also included are semi-coke, a solid product obtained from the carbonisation of coal at a low temperature, lignite coke and semi-coke made from lignite. The heading other energy sector represents consumption at the coking plants themselves. Consumption in the iron and steel industry does not include coke converted into blast furnace gas. Gas coke is a by-product of hard coal used for the production of town gas in gas works. Gas coke is used for heating purposes. Coke breeze and foundry coke are also included in this category. Semi-coke, the solid product obtained from carbonisation of coal at low temperature, should be included in this category. Semi-coke is used as a domestic fuel or by the transformation plant itself. This heading also includes coke, coke breeze and semi-coke made from lignite/brown coal.
Coke oven gas. Obtained as a by-product of the manufacture of coke oven coke for the production of iron and steel.
Coke plants. Plants where coal is carbonized in slot or beehive ovens for the manufacture of coke.
Coking coal. Coal, which, because of its characteristics, is suitable for carbonising to produce blast furnace coke. Important properties required technically to produce good coke are good coking and caking properties (such as fluidity, dilation, crucible swelling number etc.) allied with appropriate rank (indicated by reflectance values around 0.9 - 1.5%). Its gross calorific value is greater than 23 865 kJ/kg (5 700 kcal/kg or approximately 20.52 million btu/short ton) on an ash-free but moist basis. See Coke (coal).
Coking coal. See Hard coal.
Combined cycle. Two or more generation processes in series or in parallel, configured to optimize the energy output of the system.
Combined heat and power. (CHP) See cogeneration. The term is more commonly used in Europe and other foreign countries.
Combined-cycle power plant. The combination of a gas turbine and a steam turbine in an electric generation plant. The waste heat from the gas turbine provides the heat energy for the steam turbine.
Combustion air. The air fed to a fire to provide oxygen for combustion of fuel. It may be preheated before injection into a furnace.
Combustion efficiency. The actual heat produced by combustion divided by the total heat potential of the fuel consumed.
Combustion gases. The gases released from a combustion process.
Combustion turbine. See gas turbine.
Combustion unit. A fuel-fired combustion device.
Combustion. Chemical oxidation accompanied by the generation of light and heat. The transformation of biomass fuel into heat, chemicals, and gases through chemical combination of hydrogen and carbon in the fuel with oxygen in the air.
Compressed natural gas (CNG). CNG is natural gas for use in special CNG vehicles, where it is stored in high-pressure fuel cylinders (typically 2000 to 3600 psi). CNG's use stems in part from its clean burning properties, as it produces fewer exhaust and greenhouse gas emissions than motor gasoline or diesel oil. It is used most frequently in

light-duty passenger vehicles and pickup trucks, medium-duty delivery trucks, and in transit and school buses.

Concentration. Amount of a chemical in a particular volume or weight of air, water, soil, or other medium. See *parts per billion, parts per million.*

Condenser. A heat-transfer device that reduces a fluid from a vapor phase to a liquid phase.

Condensing power. Power generated through a final steam turbine stage where the steam is exhausted into a condenser and cooled to a liquid to be recycled back into a boiler.

Condensing turbine. A turbine used for electrical power generation from a minimum amount of steam. To increase plant efficiency, these units can have multiple uncontrolled extraction openings for feed-water heating.

Condensing, controlled extraction turbines. A controlled turbine that bleeds off (condenses) part of the main stream flow at one (single extraction) or two (double extraction) points. Used when process steam is required at pressures below the inlet pressure and above the exhaust pressure.

Continuous Emission Monitoring (CEM) System. The equipment used to sample, analyze, measure, and provide—by means of readings recorded at a high frequency (e.g., every 15 minutes) using a automated data acquisition and handling system—a record of emissions of particular pollutants (e.g., SO_2 or CO_2). This equipment generally includes a stack flow rate monitor to measure gas volumetric flow rate, gas concentration monitor, and a moisture monitoring system.

Conveyor. A mechanical apparatus for carrying bulk material from place to place; for example, an endless moving belt or a chain of receptacles.

Criteria pollutant. In the United States, a pollutant determined to be hazardous to human health and regulated under EPA's National Ambient Air Quality Standards. The 1970 amendments to the Clean Air Act require EPA to describe the health and welfare impacts of a pollutant as the "criteria" for inclusion in the regulatory regime. In this report, emissions of the criteria pollutants CO, NO_x, NMVOCs, and SO_2 are reported because they are thought to be precursors to greenhouse gas formation.

Crude oil. Crude oil is a mineral oil of natural origin comprising a mixture of hydrocarbons and associated impurities, such as sulphur. It exists in the liquid phase under normal surface temperature and pressure and its physical characteristics (density, viscosity, etc.) are highly variable. This category includes field or lease condensate recovered from associated and non-associated gas where it is commingled with the commercial crude oil stream. Depending upon the characteristics of the crude stream, it may also include.

1. Small amounts of hydrocarbons that exist in gaseous phase in natural underground reservoirs but are liquid at atmospheric pressure after being recovered from oil well (casinghead) gas in lease separators and are subsequently commingled with the crude stream without being separately measured. Lease condensate recovered as a liquid from natural gas wells in lease or field separation facilities and later mixed into the crude stream is also included;
2. Small amounts of nonhydrocarbons produced with the oil, such as sulfur and various metals;
3. Drip gases, and liquid hydrocarbons produced from tar sands, gilsonite, and oil shale.

Liquids produced at natural gas processing plants are excluded. Crude oil is refined to produce a wide array of petroleum products, including heating oils; gasoline, diesel and jet fuels; lubricants; asphalt; ethane, propane, and butane; and many other products used for their energy or chemical content. See *petroleum.*

Culm. Waste from Pennsylvania anthracite preparation plants, consisting of coarse rock fragments containing as much as 30 percent small-sized coal; sometimes defined as including very fine coal particles called silt. Its heat value ranges from 8 to 17 million Btu per short ton (0.0093 GJ/kg to 0.0198 GJ/kg).

Cyclone separator. A device used to remove particulate matter suspended in exhaust gases.

Deaeration. Removal of gases from a liquid.

Decomposition. The breakdown of matter by bacteria and fungi. It changes the chemical composition and physical appearance of the materials.

Decoupling. A regulatory design that breaks the link between utility revenues and energy sales to encourage utility investment in conservation.

Denatured. Ethanol that has had a substance added to make it unfit for human consumption.

Desulfurization. The removal of sulfur, as from molten metals, petroleum oil, or flue gases.

Diesel engine. A compression-ignition piston engine in which fuel is ignited by injecting it into air that has been heated (unlike a spark-ignition engine).

Diesel fuel. A low sulfur fuel oil of grades 1-D or 2-D, as defined by the American Society for Testing and Materials standard ASTM D975-91, "Standard Specification for Diesel Fuel Oils," grades 1-GT or 2-GT, as defined by ASTM D2880-90a, "Standard Specification for Gas Turbine Fuel Oils," or grades 1 or 2, as defined by ASTM D396-90a, "Standard Specification for Fuel Oils."

Diesel oil. See Gas/diesel oil.

Digester. An airtight vessel or enclosure in which bacteria decomposes biomass in water to produce biogas.

Diluent gas. A major gaseous constituent in a gaseous pollutant mixture, which in the case of emissions from fossil fuel-fired units are typically carbon dioxide or oxygen.

Direct measurement. A specific quantitative determination of emitted compounds at the source.

Distillate fuel oil. A general classification for one of the petroleum fractions produced in conventional distillation operations. It includes diesel fuels and fuel oils. Products known as No. 1, No. 2, and No. 4 diesel fuel are used in on-highway diesel engines, such as those in trucks and automobiles, as well as off-highway engines, such as those in railroad locomotives and agricultural machinery. Products known as No. 1, No. 2, and No. 4 fuel oils are used primarily for space heating and electric power generation.

No. 1 Distillate. A light petroleum distillate that can be used as either a diesel fuel (see **No. 1 Diesel Fuel**) or a fuel oil. See **No. 1 Fuel Oil**.

- **No. 1 Diesel Fuel.** A light distillate fuel oil that has distillation temperatures of 550 degrees Fahrenheit (288 degrees Celsius) at the 90-percent point and meets the specifications defined in ASTM Specification D 975. It is used in high-speed diesel engines, such as those in city buses and similar vehicles. See **No. 1 Distillate** above.
- **No. 1 Fuel Oil.** A light distillate fuel oil that has distillation temperatures of 400 degrees Fahrenheit (204 degrees Celsius) at the 10-percent recovery point and 550 degrees Fahrenheit (288 degrees Celsius) at the 90-percent point and meets the specifications defined in ASTM Specification D 396. It is used primarily as fuel for portable outdoor stoves and portable outdoor heaters. See **No. 1 Distillate** above.

No. 2 Distillate. A petroleum distillate that can be used as either a diesel fuel (see **No. 2 Diesel Fuel** definition below) or a fuel oil. See **No. 2 Fuel oil** below.

- **No. 2 Diesel Fuel.** A fuel that has distillation temperatures of 500 degrees Fahrenheit (260 degrees Celsius) at the 10-percent recovery point and 640 degrees Fahrenheit (338 degrees Celsius) at the 90-percent recovery point and meets the specifications defined in ASTM Specification D 975. It is used in high-speed diesel engines, such as those in railroad locomotives, trucks, and automobiles. See **No. 2 Distillate** above.
- **Low Sulfur No. 2 Diesel Fuel.** No. 2 diesel fuel that has a sulfur level no higher than 0.05 percent by weight. It is used primarily in motor vehicle diesel engines for on-highway use.
- **High Sulfur No. 2 Diesel Fuel.** No. 2 diesel fuel that has a sulfur level above 0.05 percent by weight.
- **No. 2 Fuel oil (Heating Oil).** A distillate fuel oil that has distillation temperatures of 400 degrees Fahrenheit (204 degrees Celsius) at the 10-percent recovery point and 640 degrees Fahrenheit (338 degrees Celsius) at the 90-percent point and meets the specifications defined in ASTM Specification D 396. It is used in atomizing type burners for domestic heating or for moderate capacity commercial/industrial burner units. See **No. 2 Distillate** above.

No. 4 Fuel. A distillate fuel oil made by blending distillate fuel oil and residual fuel oil stocks. It conforms with ASTM Specification D 396 or Federal Specification VV-F-815C and is used extensively in industrial plants and in commercial burner installations that are not equipped with preheating facilities. It also includes No. 4 diesel fuel used for low- and medium-speed diesel engines and conforms to ASTM Specification D 975.

No. 4 Diesel Fuel and No. 4 Fuel Oil. See No. 4 Fuel above.

District heating or cooling. A system that involves the central production of hot water, steam, or chilled water and the distribution of these transfer media to heat or cool buildings.

Downdraft gasifier. A gasifier in which the product gases pass through a combustion zone at the bottom of the gasifier.

Dry (coal) basis. Coal quality data calculated to a theoretical basis in which no moisture is associated with the sample. This basis is determined by measuring the weight loss of a sample when its inherent moisture is driven off under controlled conditions of low temperature air-drying followed by heating to just above the boiling point of water (104 to 110 degrees centigrade).

Dry ash-free basis. Analytical data calculated to a condition of zero moisture and ash (i.e., a first approximation to "pure coal") to allow comparison of different coals. This is a strictly a hypothetical basis because of the ash only being generated on the incineration of the coal, but is used frequently because of convenience. Dry mineral matter free basis is more precise, but less easy to obtain.

Dry bottom boiler. A boiler from which ash is removed conventionally in solid form. This requires a coal with initial deformation ash fusion temperature of minimum 1200-1250°C.

Dry natural gas. Natural gas which remains after. 1) the liquefiable hydrocarbon portion has been removed from the gas stream (i.e., gas after lease, field, and/or plant separation); and 2) any volumes of nonhydrocarbon gases have been removed where they occur in sufficient quantity to render the gas unmarketable. Note. Dry natural gas is also known as consumer-grade natural gas. The parameters for measurement are cubic feet at 60 degrees Fahrenheit and 14.73 pounds per square inch absolute.

Dual-fired unit. A generating unit that can produce electricity using two or more input fuels. In some of these units, only the primary fuel can be used continuously; the alternate fuel(s) can be used only as a start-up fuel or in emergencies.

Dutch oven furnace. One of the earliest types of furnaces, having a large, rectangular box lined with firebrick (refractory) on the sides and top. Commonly used for burning wood. Heat is stored in the refractory and radiated to a conical fuel pile in the center of the furnace.

E-85. A blend of 15 percent gasoline and 85 percent denatured ethanol by volume.

Effluent. The treated waste water discharged by sewage treatment plants.

Electric power plant. A station containing prime movers, electric generators, and auxiliary equipment for converting mechanical, chemical, and/or fission energy into electric energy.

Electric system losses. Total electric energy losses in the electric system, consisting of transmission, transformation, and distribution losses between supply sources and delivery points. Electric energy is primarily lost due to heating of transmission and distribution elements.

Electrical horsepower. See horsepower.

Electricity generation. The process of producing electric energy or transforming other forms of energy into electric energy. Also the amount of electric energy produced or expressed in watthours (Wh).

Emission inventory. A list of air pollutants emitted into a community's, state's, nation's, or the Earth's atmosphere in amounts per some unit time (e.g. day or year) by type of source. An emission inventory has both political and scientific applications.

Emissions coefficient/factor. A unique value for scaling emissions to activity data in terms of a standard rate of emissions per unit of activity (e.g., grams of carbon dioxide emitted per barrel of fossil fuel consumed).

Emissions. Releases of gases to the atmosphere (e.g., the release of carbon dioxide during fuel combustion). Emissions can be either intended or unintended releases. See *fugitive emissions.*

Energy conservation. Reduction or elimination of unnecessary energy use and waste. See *energy-efficiency*.

Energy intensity. Ratio between the consumption of energy to a given quantity of output; usually refers to the amount of primary or final energy consumed per unit of gross domestic product.

Energy quality. Ability of a form of energy to do useful work. High-temperature heat and the chemical energy in fossil fuels and nuclear fuels are concentrated high quality energy. Low-quality energy such as low-temperature heat is dispersed or diluted and cannot do much useful work.

Energy. The capacity for doing work as measured by the capability of doing work (potential energy) or the conversion of this capability to motion (kinetic energy). Energy has several forms, some of which are easily convertible and can be changed to another form useful for work. Most of the world's convertible energy comes from fossil fuels that are burned to produce heat that is then used as a transfer medium to mechanical or other means in order to accomplish tasks. In the United States, electrical energy is often measured in kilowatt-hours (kWh), while heat energy is often measured in British thermal units (Btu).

Energy-efficiency. The ratio of the useful output of services from an article of industrial equipment to the energy use by such an article; for example, vehicle miles traveled per gallon of fuel (mpg).

Equilibrium moisture. The moisture in the coal after achieving equilibrium with an atmosphere of 96% relative humidity and 30°C. Called equilibrium moisture in ASTM.

Establishment. An economic unit, generally at a single physical location, where a particular type of business is conducted, or services or industrial operations are performed (e.g., generating electricity).

ETBE (ethyl tertiary butyl ether). $(CH_3)_3$COC2H. An oxygenate blend stock formed by the catalytic etherification of isobutylene with ethanol.

Ethane (C_2H_6). A normally gaseous straight-chain hydrocarbon. It is a colorless paraffinic gas that boils at a temperature of -127.48 degrees Fahrenheit (-88.6 degrees Celsius). It is extracted from natural gas and refinery gas streams.

Ethanol (CH_3-CH_2OH). Otherwise known as ethyl alcohol, alcohol, or grain spirit. A clear, colorless, flammable oxygenated hydrocarbon with a boiling point of 78.5 degrees Celsius (173.3 degrees Fahrenheit) in the anhydrous state. Ethanol is typically produced chemically from ethylene, or biologically from fermentation of various sugars from carbohydrates found in agricultural crops and cellulosic residues from crops or wood. In transportation, ethanol is used as a vehicle fuel by itself (E100), blended with gasoline (E85), or as a gasoline octane enhancer and oxygenate (10 percent concentration).

Ether. A generic term applied to a group of organic chemical compounds composed of carbon, hydrogen, and oxygen, characterized by an oxygen atom attached to two carbon atoms (e.g., methyl tertiary butyl ether).

Ethyl tertiary butyl ether. (ETBE) An ether similar to MTBE. ETBE is manufactured by reacting ethanol with isobutylene. ETBE has high octane and low volatility characteristics. Used as an oxygenate.

Ethylene dichloride. A colorless, oily liquid used as a solvent and fumigant for organic synthesis, and for ore flotation.

Ethylene. An olefinic hydrocarbon recovered from refinery processes or petrochemical processes. Ethylene is used as a petrochemical feedstock for numerous chemical applications and the production of consumer goods.

Facility. Includes all buildings, equipment, structures, and other stationary items which are located on a single site or on contiguous or adjacent sites and which are owned or operated by the same person (or by any person which controls, is controlled by, or is under common control, with such person). Also referred to as an “installation.” A facility may contain one or more establishments and any number of combustion units.

Fast pyrolysis. Thermal conversion of biomass by rapid heating to between 450 to 600 degC in the absence of oxygen.

Firm power. (firm energy) Power which is guaranteed by the supplier to be available at all times during a period covered by a commitment. That portion of a customer's energy load for which service is assured by the utility provider.

Fixed carbon. The nonvolatile matter in coal minus the ash. Fixed carbon is the solid residue other than ash obtained by prescribed methods of destructive distillation of a coal. Fixed carbon is the part of the total carbon that remains when coal is heated in a closed vessel until all volatile matter is driven off. A component of the proximate analysis calculated by difference, i.e., 100% less the sum of moisture, ash and volatile matter. Intended to give an indication of char yield. Not to be confused with carbon in the ultimate analysis.

Flaring. The burning of waste gases through a flare stack or other device before releasing them to the air.

Flow monitor. A component of the continuous emission monitoring system that measures the volumetric flow of exhaust gas.

Flow rate. The amount of water that moves through an area (usually pipe) in a given period of time.

Flue gas desulphurization system. A type of add-on emission control used to remove sulphur dioxide from flue gas, commonly referred to as a “scrubber.”

Flue. A conduit of duct through which gases or other matter are exhausted to the atmosphere.

Fluidized bed combustion (FBC). A method of burning particulate fuel, such as coal, in which the amount of air required for combustion far exceeds that found in conventional burners. The fuel particles are continually fed into a bed of mineral ash in the proportions of 1 part fuel to 200 parts ash, while a flow of air passes up through the bed, causing it to act like a turbulent fluid. A stream of hot air is used to suspend a mixture of powdered coal and limestone during combustion. About 90 to 98 percent of the sulfur dioxide produced during combustion is removed by reaction with limestone to produce solid calcium sulfate.

Fluidized-bed boiler. A large, refractory-lined vessel with an air distribution member or plate in the bottom, a hot gas outlet in or near the top, and some provisions for introducing fuel. The fluidized bed is formed by blowing air up through a layer of inert particles (such as sand or limestone) at a rate that causes the particles to go into suspension and continuous motion. The super-hot bed material increased combustion efficiency by its direct contact with the fuel.

Fly ash. Small ash particles carried in suspension in combustion products.

Fossil fuel combustion. Burning of coal, oil (including gasoline), or natural gas. The burning needed to generate energy release carbon dioxide by-products that can include unburned hydrocarbons, methane, and carbon monoxide. Carbon monoxide, methane, and many of the unburned hydrocarbons slowly oxidize into carbon dioxide in the atmosphere. Common sources of fossil fuel combustion include cars and electric utilities.

Fossil fuel. A general term for buried combustible geologic deposits of organic materials, formed from decayed plants and animals that have been converted to crude oil, coal, natural gas, or heavy oils by exposure to heat and pressure in the earth's crust over hundreds of millions of years. Solid, liquid or gaseous fuels formed in the ground after millions of years by chemical and physical changes in plant and animal residues under high temperature and pressure. Oil, natural gas and coal are fossil fuels. See *coal, petroleum, crude oil, natural gas*.

Fossil fuel-fired. The combustion of a fossil fuel or any derivative of a fossil fuel, alone or in combination with any other fuel.

Fouling. A problem in coal combustion in boilers where ash adheres to surfaces inside the boilers’ combustion chambers and flue gas outlets causing efficiency losses and reducing heat transfer. See also Fouling factor.

Foundry coke. This is a special coke that is used in furnaces to produce cast and ductile iron products. It is a source of heat and also helps maintain the required carbon content of the metal product. Foundry coke production requires lower temperatures and longer times than blast furnace coke.

Francis turbine. A water-powered turbine used to transform water falling vertically to mechanical (rotating) energy.

Free moisture. The difference between total moisture and air dried moisture.

Fuel cell. A device capable of generating an electrical current by converting the chemical energy of a fuel (e.g., hydrogen) directly into electrical energy. Fuel cells differ from conventional electrical cells in that the active materials such as fuel and oxygen are not contained within the cell but are supplied from outside. It does not contain an intermediate heat cycle, as do most other electrical generation techniques.

Fuel cycle. The series of steps required to produce electricity. The fuel cycle includes mining or otherwise acquiring the raw fuel source, processing and cleaning the fuel, transport, electricity generation, waste management and plant decommissioning.

Fuel handling system. A system for unloading wood fuel from vans or trucks, transporting the fuel to a storage pile or bin, and conveying the fuel from storage to the boiler or other energy conversion equipment.

Fuel injection. A fuel delivery system whereby gasoline is pumped to one or more fuel injectors under high pressure. The fuel injectors are valves that, at the appropriate times, open to allow fuel to be sprayed or atomized into a throttle bore or into the intake manifold ports. The fuel injectors are usually solenoid operated valves under the control of the vehicle's on-board computer (thus the term "electronic fuel injection"). The fuel efficiency of fuel injection systems is less temperature-dependent than carburetor systems. Diesel engines always use injectors.

Fuel oil. This covers all residual (heavy) fuel oils (including those obtained by blending). Kinematic viscosity is above 10 cSt at 80°C (176 degrees Fahrenheit). The flash point is always above 50°C (122 degrees Fahrenheit) and density is always more than 0.90 kg/l (7.51 lb/gallon).

- Low sulphur content. Heavy fuel oil with sulphur content lower than 1%.
- High sulphur content. Heavy fuel oil with sulphur content of 1% or higher.

Fuel oil includes distillate fuel oil (No. 1, No. 2, and No. 4), and residual fuel oil (No. 5 and No. 6). In the United States: Any petroleum-based fuel (including diesel fuel or petroleum derivatives such as oil tar) as defined by the American Society of Testing and Materials in ASTM D396-90a, “Standard Specification for Fuel Oils” and any recycled or blended petroleum products or petroleum by-products used as a fuel whether in a liquid, solid, or gaseous state. (See Distillate and Residual)

Fuel. Any material substance that can be combusted to supply heat or power. Included are petroleum, coal, and natural gas (the fossil fuels), and other combustable materials, such as biomass, and hydrogen.

Fuel-cell furnace. A variation of the Dutch oven design that usually incorporates a primary and secondary combustion chamber (cell). The primary chamber is a vertical refractory-lined cylinder with a grate at the bottom in which combustion is partially completed. Combustion is completed in the secondary chamber.

Fugitive emissions. Unintended gas leaks from the production processing, transmission, and/or transportation of fossil fuels, CFCs from refrigeration leaks, SF_6 from electrical power distributor, etc.

Furnace. An enclosed chamber or container used to burn biomass in a controlled manner to produce heat for space or process heating. The part of a boiler or warm-air space-heating plant in which combustion takes place.

gal/d. Gallons per day.

Gas coke. A by-product of hard coal used for production of town gas in gas works. Gas coke is used for heating purposes.

Gas Diesel Oil (Distillate Fuel Oil). Obtained from the lowest fraction from atmospheric distillation of crude oil, while heavy gas oils are obtained by vacuum redistillation of the residual from atmospheric distillation. Gas/diesel oil distils between 180 C (356 F) and 380 C (716 F). Several grades are available depending on uses: diesel oil for diesel compression ignition (cars, trucks, marine, etc.), light heating oil for industrial and commercial uses, and other gas oil including heavy gas oils which distil between 380 C (716 F) and 540 C (1004 F) and which are used as petrochemical feedstocks. (Includes heavy gas oils.)

Gas engine. A piston engine that uses gaseous fuel rather than gasoline. Fuel and air are mixed before they enter cylinders; ignition occurs with a spark.

Gas oil. European and Asian designation for No. 2 heating oil and No. 2 diesel fuel.

Gas shift process. A process in which carbon monoxide and hydrogen react in the presence of a catalyst to form methane and water.

Gas turbine. (combustion turbine) A turbine that converts the energy of hot compressed gases (produced by burning fuel in compressed air) into mechanical power. Often fired by natural gas or fuel oil.

Gas works gas. All types of gas produced in public utility or private plants, whose main purpose is the manufacture, transport and distribution of gas. It includes gas produced by carbonisation (including gas produced by coke ovens and transferred to gas works), by total gasification (with or without enrichment with oil products), by cracking of natural gas, and by reforming and simple mixing of gases and/or air. This heading also includes substitute natural gas, which is a high calorific value gas manufactured by chemical conversion of a hydrocarbon fossil fuel.

Gas/diesel oil (distillate fuel oil). Gas/diesel oil is primarily a medium distillate distilling between 180°C (356 degrees F) and 380°C (716 degrees F). Several grades are available depending on uses.

- Transport diesel. on road diesel oil for diesel compression ignition (cars, trucks, etc.), usually of low sulphur content.
- Heating and other gas oil.
  - Light heating oil for industrial and commercial uses.
  - Marine diesel and diesel used in rail traffic.
  - Other gas oil including heavy gas oils which distil between 380°C (716 degrees F) and 540°C (1004 degrees F) and which are used as petrochemical feedstocks.

Gasification. A chemical or heat process to convert a solid fuel to a gaseous form.

Gasifier. A device for converting solid fuel into gaseous fuel. In biomass systems, the process is also referred to as pyrolitic distillation. See pyrolysis.

Gasohol. A blend of finished motor gasoline containing alcohol (generally ethanol but sometimes methanol) at a concentration between 5.7 percent and 10 percent by volume. Also see Oxygenates. Vehicle fuel consisting of a mixture of gasoline and ethyl or methyl alcohol; typically 10 to 23 percent ethanol by volume.

Gasoline type jet fuel (naphtha type jet fuel or JP4). This includes all light hydrocarbon oils for use in aviation turbine power units, distilling between 100°C (212 degrees F) and 250°C (482 degrees F). It is obtained by blending kerosenes and gasoline or naphthas in such a way that the aromatic content does not exceed 25% in volume, and the vapour pressure is between 13.7kPa (1.99 psia) and 20.6kPa (2.99 psia). Additives can be included to improve fuel stability and combustibility.

Gasoline. See Motor gasoline or gasoline type jet fuel.

Gas-works gas. Covers all types of gases including substitute natural gas produced in public utility or private plants, whose main purpose is manufacture, transport and distribution of gas. It includes gas produced by carbonization (including gas produced by coke ovens and transferred to gas-works gas) reported under the “Production” row, by total gasification with or without enrichment with oil products (LPG, residual fuel oil, etc.), by cracking of natural gas, and by reforming and simple mixing of gases and/or air, reported under the “From other sources” row.

Generating unit. Any combination of physically connected generators, reactors, boilers, combustion turbines, and other prime movers operated together to produce electric power. (See Combustion unit)

Generator. A machine used for converting rotating mechanical energy to electrical energy.

Geothermal energy. Energy available as heat emitted from within the earth's crust, usually in the form of hot water or steam. It is exploited at suitable sites.

- For electricity generation using dry steam or high enthalpy brine after flashing.
- Directly as heat for district heating, agriculture, etc.

Global Warming Potential (GWP). The index used to translate the level of emissions of various gases into a common measure in order to compare the relative radiative forcing of different gases without directly calculating the changes in atmospheric concentrations. GWPs are calculated as the ratio of the radiative forcing that would result from the emissions of one kilogram of a greenhouse gas to that from the emission of one kilogram of carbon dioxide over a period of time (usually 100 years). Gases involved in complex atmospheric chemical processes have not been assigned GWPs. See *lifetime*.

gr/SCF. Grains of pollutant per standard cubic foot of gas. A measure of dust particles in a gas stream.

Greenhouse gas (GHG). Any gas that absorbs infrared radiation in the atmosphere. Greenhouse gases include, but are not limited to, water vapor, carbon dioxide (CO_2), methane (CH_4), nitrous oxide (N_2O), hydrochlorofluorocarbons (HCFCs), ozone (O_3), hydrofluorocarbons (HFCs), perfluorocarbons (PFCs), and sulfur hexafluoride (SF_6). See *carbon dioxide, methane, nitrous oxide, hydrochlorofluorocarbon, ozone, hydrofluorocarbon, perfluorocarbon, sulfur hexafluoride.*

Grid connection. Joining a plant that generates electric power to a utility system so that electricity can flow in either direction between the utility system and the plant.

Grid. An electric utility's system for distributing power.

Gross calorific value (GCV). The amount of heat liberated from a unit amount of fuel when it is combusted under standardised conditions in a closed vessel and when the products of combustion have cooled to 25°C. During actual combustion in boilers the gross value is never achieved because some of the products, most importantly water, are lost in the gaseous state with their associated heat of vaporization. Also referred to as Higher Heating Value (HHV). See also Net Calorific Value.

Gross generation. The electrical output at the terminals of the generator.

Gypsum. Calcium sulfate dihydrate (C_aSO_4 $2H_2O$) a sludge constituent from the conventional lime scrubber process, obtained as a byproduct of the dewatering operation and sold for commercial use.

Hard coal. Hard coal refers to coal of gross calorific value greater than 23 865 kJ/kg (5 700 kcal/kg, 20.52 million btu/short ton) on an ash-free but moist basis and with a mean random reflectance of vitrinite of at least 0.6. Hard coal comprises.

(i) Coking coal. Coal with a quality that allows the production of a coke suitable to support a blast furnace charge. The following coal classification codes cover those coals which would fall in this category.

- International classification codes 323, 333, 334, 423, 433, 434, 435, 523, 533 (UN, Geneva, 1956) 534, 535, 623, 633, 634, 635, 723, 733, 823.
- USA classification Class II Group 2 “Medium Volatile Bituminous”.
- British classification Classes 202, 203, 204, 301, 302, 400, 500, 600.
- Polish classification Classes 33, 34, 35.1, 35.2, 36, 37.
- Australian classification Classes 4A, 4B, 5.

(ii) Other bituminous coal and anthracite (steam coal). Steam coal is coal used for steam raising and space heating purposes and includes all anthracite coals and bituminous coals not included under coking coal.

Heat input rate. The product of the calorific value of the fuel and the fuel feed rate into the combustion device and does not include the heat derived from preheated combustion air, recirculated flue gases, or exhaust from other sources.

Heat rate. The amount of fuel energy required by a power plant to produce one kilowatt-hour of electrical output. A measure of generating station thermal efficiency, generally expressed in Btu per net kWh. It is computed by dividing the total Btu content of fuel burned for electric generation by the resulting net kWh generation.

Heavy oil. The fuel oils remaining after the lighter oils have been distilled off during the refining process. Except for start-up and flame stabilization, virtually all petroleum used in steam plants is heavy oil. Includes fuel oil numbers 4, 5, and 6; crude; and topped crude.

HHV. See higher heating value.

Higher heating value. (HHV) See Gross calorific value.

Horsepower. (electrical horsepower; hp) A unit for measuring the rate of mechanical energy output. The term is usually applied to engines or electric motors to describe maximum output. 1 hp = 550 ft.lbs/sec = 745.7 Watts = 0.746 kW = 2,545 Btu/hr.

hp. See horsepower.

Hydrocarbons. Substances containing only hydrogen and carbon. Fossil fuels are made up of hydrocarbons. Some hydrocarbon compounds are major air pollutants.

Hydroelectric power. The generation of electricity using falling or flowing water.

Hydrolysis. A process of breaking chemical bonds of a compound by adding water to the bonds.

Hydropower. See *hydroelectric power*.
Hydropower. Potential and kinetic energy of water converted into electricity in hydroelectric plants. Pumped storage should be included. Detailed plant sizes should be reported net of pumped storage.
Incinerator. Any device used to burn solid or liquid residues or wastes as a method of disposal. In some incinerators, provisions are made for recovering the heat produced.
Inclined grate. A type of furnace in which fuel enters at the top part of a grate in a continuous ribbon, passes over the upper drying section where moisture is removed, and descends into the lower burning section. Ash is removed at the lower part of the grate.
Independent power producer. A power production facility that is not part of a regulated utility.
Induction generator. A variable speed multi-pole electric generator.
Industrial spirit (SBP). Light oils distilling between 30 C (86 F) and 200 C (392 F), with a temperature difference between 5 per cent volume and 90 per cent volume distillation points, including losses, of not more than 60 C (140 F). In other words, Special Boiling Points (SBP) is a light oil of narrower cut than motor spirit. There are 7 or 8 grades of industrial spirit, depending on the position of the cut in the distillation range defined above.
Inherent moisture. Often used to indicate air dried moisture, particularly in Australia. In ASTM, equivalent to bed moisture or equilibrium moisture.
Inorganic compound. Combination of two or more elements, neither of which is carbon. See *organic compound*.
Installation. See Facility.
Intergovernmental Panel on Climate Change (IPCC). The IPCC was established jointly by the United Nations Environment Programme and the World Meteorological Organization in 1988. The purpose of the IPCC is to assess information in the scientific and technical literature related to all significant components of the issue of climate change. The IPCC draws upon hundreds of the world's expert scientists as authors and thousands as expert reviewers. Leading experts on climate change and environmental, social, and economic sciences from some 60 nations have helped the IPCC to prepare periodic assessments of the scientific underpinnings for understanding global climate change and its consequences. With its capacity for reporting on climate change, its consequences, and the viability of adaptation and mitigation measures, the IPCC is also looked to as the official advisory body to the world's governments on the state of the science of the climate change issue. For example, the IPCC organized the development of internationally accepted methods for conducting national greenhouse gas emission inventories.
Investor-owned utility. (IOU) A private power company owned by and responsible to its shareholders and regulated by a public service commission.
Isobutane (C_4H_{10}). A normally gaseous branch-chain hydrocarbon. It is a colorless paraffinic gas that boils at a temperature of 10.9 degrees Fahrenheit (11.72 degrees Celsius). It is extracted from natural gas or refinery gas streams.
Isobutylene (C_4H_8). An olefinic hydrocarbon recovered from refinery processes or petrochemical processes.
Isohexane (C_6H_{14}). A saturated branch-chain hydrocarbon. It is a colorless liquid that boils at a temperature of 156.2 degrees Fahrenheit (67 degrees Celsius).
Isomerization. A refining process that alters the fundamental arrangement of atoms in the molecule without adding or removing anything from the original material. Used to convert normal butane into isobutane (C_4), an alkylation process feedstock, and normal pentane and hexane into isopentane (C_5) and isohexane (C_6), high-octane gasoline components.
Isopentane. A saturated branched-chain hydrocarbon (C_5H_{12}) obtained by fractionation of natural gasoline or isomerization of normal pentane.
Jet fuel. Includes both naphtha-type and kerosene-type fuels meeting standards for use in aircraft turbine engines. Although most jet fuel is used in aircraft, some is used for other purposes such as generating electricity.
Joule. The work done when a force of one Newton moves an object throughone meter in the direction of the force.
Kerogen. Solid, waxy mixture of hydrocarbons found in oil shale, with a fine grained sedimentary rock. When the rock is heated to high temperatures, the kerogen is vaporized. The vapor is condensed and then sent to a refinery to produce gasoline, heating oil, and other products. See *oil shale, shale oil*.
Kerosene type jet fuel. This is a distillate used for aviation turbine power units. It has the same distillation characteristics between 150°C (302 degrees F) and 300°C (572 degrees F) (generally not above 250°C (482 degrees F)) and flash point as kerosene. In addition, it has particular specifications (such as freezing point) which are established by the International Air Transport Association (IATA). This category includes kerosene blending components.

Kerosene. A petroleum distillate that has a maximum distillation temperature of 401 degrees Fahrenheit (205 degrees Celsius) at the 10 percent recovery point, a final boiling point of 572 degrees Fahrenheit (300 degrees Celsius), and a minimum flash point of 100 degrees Fahrenheit. Comprises refined petroleum distillate intermediate in volatility between gasoline and gas/diesel oil. It is a medium oil distilling between 150 C (302 F) and 300 C (572 F). Used in space heaters, cookstoves, and water heaters, and suitable for use as an illuminant when burned in wick lamps.
Ketone-alcohol (cyclohexanol). An oily, colorless, hygroscopic liquid with a camphor-like odor. Used in soapmaking, dry cleaning, plasticizers, insecticides, and germicides.
Kilowatt hour. (kWh) A measure of the quantity of electrical energy delivered or consumed. For example, 1 kWh will light a 100-watt light bulb for 10 hours. 1 kWh = 3,413 Btu.
Kilowatt. (kW) A measure of electrical power equal to 1,000 Watts. 1 kW = 3,413 Btu/hr = 1.341 horsepower.
Landfill gas. Gas that is generated by decomposition of organic material at landfill disposal sites. Landfill gas is approximately 50 percent methane.
Landfill. Land waste disposal site in which waste is generally spread in thin layers, compacted, and covered with a fresh layer of soil each day.
Leaded motor gasoline. See Motor gasoline
LH_2O. The heat (Btu) needed to vaporize and superheat one pound of water.
Light gas oils. Liquid petroleum distillates heavier than naphtha, with an approximate boiling range from 401 degrees Fahrenheit (205 degrees Celsius) to 650 degrees Fahrenheit (343 degrees Celsius).
Light oil. Lighter fuel oils distilled off during the refining process. Virtually all petroleum used in internal combustion and gas-turbine engines is light oil. Includes fuel oil numbers 1 and 2, kerosene, and jet fuel.
Lignite. The lowest rank of coal, often referred to as brown coal, used almost exclusively as fuel for steam-electric power generation. A brownish-black coal of low rank with high inherent moisture and volatile matter content, used almost exclusively for electric power generation. Also referred to as brown coal. A non-agglomerating coal with a gross calorific value of less than 17 435 kJ/kg (4165 kcal/kg, 14.99 million btu/short ton), and greater than 31 per cent volatile matter on a dry mineral matter free basis. It has a high inherent moisture content, sometimes as high as 45 percent. The heat content of lignite ranges from 9 to 17 million Btu per ton (10 466 to 19 770 kJ/kg) on a moist, mineral-matter-free basis. The heat content of lignite consumed in the United States averages 13 million Btu per ton (15 118 kJ/kg, on the as-received basis (i.e., containing both inherent moisture and mineral matter). Oil shale and tar sands produced and combusted directly should be reported in this category. Oil shale and tar sands used as inputs for other transformation processes should also be reported in this category. This includes the portion of the oil shale or tar sands consumed in the transformation process.
Line loss. Electric energy lost in the transmission of electricity through heating effects and insulating losses.
Liquefied natural gas (LNG). Natural gas cooled to approximately –160°C (-256 degrees F) under atmospheric pressure condenses to its liquid form called LNG. LNG is odourless, colourless, non-corrosive and non-toxic.
Liquefied petroleum gases (LPG). LPG are light paraffinic hydrocarbons derived from the refinery processes, crude oil stabilisation and natural gas processing plants. They consist mainly of propane (C3H8) and butane (C4Hl0) or a combination of the two. They could also include propylene, butylene, isobutene and isobutylene. LPG are normally liquefied under pressure for transportation and storage.
Liquefied refinery gases (LRG). Liquefied petroleum gases fractionated from refinery or still gases. Through compression and/or refrigeration, they are retained in the liquid state. The reported categories are ethane/ethylene, propane/propylene, normal butane/butylene, and isobutane/isobutylene.
Load factor. Load factor is the ratio of average demand to maximum demand or to capacity.
Load management. Any method or device that evens out electric power demand by eliminating uses during peak periods or shifting usage from peak time to off-peak time.
Load. (1) The amount of electrical power required at a given point on a system. (2) The average demand on electrical equipment or on an electric system.
Long ton. A unit that equals 20 long hundredweight or 2,240 pounds (approximately 1016 kg). Used mainly in Great Britian.
Lower heating value. (LHV) Quantity of heat liberated by the complete combustion of a unit volume or weight of a fuel assuming that the produced water remains as a vapor and the heat of the vapor is not recovered; also known as net calorific value. See *higher heating value.*
Low-volatile bituminous coal. See Bituminous Coal.
LPG. See Liquefied petroleum gas.
Lubricants. Lubricants are hydrocarbons produced from distillate by-products; they are mainly used to reduce

friction between bearing surfaces. This category includes all finished grades of lubricating oil, from spindle oil to cylinder oil, and those used in greases, including motor oils and all grades of lubricating oil base stocks.

Mass balance. The application of the principle of the conservation of mass.

Mass burn facility. A facility in which the pretreatment of MSW includes only inspection and simple separation to remove oversize, hazardous, or explosive materials. Large mass burn facilities have capacities of 3000 tons of MSW per day or more. Modular plants with capacities as low as 25 tons per day have been built. Mass burn technologies represent over 75% of all the MSW-to-energy facilities constructed in the United States to date. The major components of a mass burn facility include refuse receiving and handling, combustion and steam generation, flue gas cleaning, power generation, condenser cooling water, residue hauling, and storage.

MC. See moisture content.

MCDB. See moisture content, dry basis.

MCWB. See moisture content, wet basis.

Medium-volatile bituminous coal. See Bituminous Coal.

Megawatt. (MW) The electrical unit of power that equals one million Watts (1,000 kW).

Metallurgical coal. Coking coal and pulverized coal consumed in making metallurgical coke and steel.

Metering. The methods of applying devices that measure and register the amount and direction of electrical quantities with respect to time.

Methane (CH_4). A hydrocarbon that is a greenhouse gas with a global warming potential most recently estimated at 21. Methane is produced through anaerobic (without oxygen) decomposition of waste in landfills, animal digestion, decomposition of animal wastes, production and distribution of natural gas and petroleum, coal production, and incomplete fossil fuel combustion. The atmospheric concentration of methane has been shown to be increasing at a rate of about 0.6 percent per year and the concentration of about 1.7 per million by volume (ppmv) is more than twice its pre-industrial value. However, the rate of increase of methane in the atmosphere may be stabilizing.

Methanogen. A methane-producing organism.

Methanol (CH_3OH). A colorless poisonous liquid with essentially no odor and little taste. It is the simplest alcohol with a boiling point of 64.7 degrees Celsius (148.5 degrees Fahrenheit). In transportation, methanol is used as a vehicle fuel by itself (M100), or blended with gasoline (M85).

Methyl tertiary butyl ether. (MTBE) An ether manufactured by reacting methanol and isobutylene. MTBE has high octane and low volatility. Used as a fuel oxygenate.

Metric ton (tonne). Common international measurement for the quantity of greenhouse gas emissions. A metric ton is equal to 1000 kilograms, 2204.6 pounds, or 1.1023 short tons.

mg/l. Milligrams per liter.

mgd. Million gallons per day.

Middle distillates. A general classification of refined petroleum products that includes distillate fuel oil and kerosene.

mill/kWh. A common method of pricing electricity. Tenths of a cent per kilowatt hour.

Mineral matter. Comprises the inorganic components of coal. When coal is burnt the composition of the mineral matter is altered by evolution of the water of hydration of the minerals (this is not determined during the total moisture determination) and other components such as carbon dioxides and sulphur oxides. The end product, the ash, thus has a different composition to the original mineral matter.

Mineral-matter-free basis. Mineral matter in coal is the parent material in coal from which ash is derived, and which comes from minerals present in the original plant materials that formed the coal, or from extraneous sources such as sediments and precipitates from mineralized water. Mineral matter in coal cannot be determined by chemical analysis and is commonly calculated using data on ash and ash-forming constituents. Coal analyses are calculated to the mineral-matter-free basis by adjusting formulas used in calculations in order to deduct the weight of mineral matter from the total coal.

MMbbl/d. One million barrels of oil per day.

MMBtu. One million British thermal units.

MMcf. One million cubic feet.

MMgal/d. One million gallons per day.

MMst. One million short tons.

Moist (coal) basis. "Moist" coal contains its natural inherent or bed moisture, but does not include water adhering to the surface. Coal analyses expressed on a moist basis are performed or adjusted so as to describe the data when the coal contains only that moisture which exists in the bed in its natural state of deposition, and when the coal has not lost any moisture due to drying.

Moisture content, dry basis. Moisture content expressed as a percentage of the weight of an oven-dry fuel.

Moisture content, wet basis. Moisture content expressed as a percentage of the weight of a fuel as-received.

Moisture content. The water content of a substance (a solid fuel) as measured under specified conditions being the "dry basis," which equals the weight of the wet sample minus the weight of a (bone) dry sample divided by the weight of the dry sample times 100 (to get percent); "wet basis," which is equal to the weight of the wet sample minus the weight of the dry sample divided by the weight of the wet sample times 100.

Monitoring. The systematic surveillance of the variation of a certain chemical or physical characteristic of an emission, discharge, consumption, equivalent parameter or technical measure. Based on repeated measurements or observations, at an appropriate frequency in accordance with documented and agreed procedures.

Motor gasoline blending components. Naphthas (e.g., straight-run gasoline, alkylate, reformate, benzene, toluene, xylene) used for blending or compounding into finished motor gasoline. These components include reformulated gasoline blendstock for oxygenate blending (RBOB) but exclude oxygenates (alcohols, ethers), butane, and pentanes plus. *Note.* Oxygenates are reported as individual components and are included in the total for other hydrocarbons, hydrogens, and oxygenates.

Motor gasoline. Motor gasoline consists of a mixture of light hydrocarbons distilling between 35°C (95 degrees F) and 215°C (419 degrees F). It is used as a fuel for land-based spark ignition engines. Motor gasoline may include additives, oxygenates and octane enhancers, including lead compounds such as TEL (Tetraethyl lead) and TML (tetramethyl lead). Motor gasoline can be divided into two groups.

- Unleaded motor gasoline. motor gasoline where lead compounds have not been added to enhance octane rating. It may contain traces of organic lead.
- Leaded motor gasoline. motor gasoline with TEL (tetraethyl lead) and/or TML (tetramethyl lead) added to enhance octane rating. This category includes motor gasoline blending components (excluding additives/oxygenates), e.g. alkylates, isomerate, reformate, cracked gasoline destined for use as finished motor gasoline.

Mscf. One million standard cubic feet.

mscf. One thousand standard cubic feet.

MSW. See municipal solid waste.

MTBE (methyl tertiary butyl ether) (CH$_3$)$_3$COCH$_3$. An ether intended for gasoline blending as described in "Oxygenates."

Municipal solid waste (MSW). Residential solid waste and some non-hazardous commercial, institutional, and industrial wastes. This material is generally sent to municipal landfills for disposal. See *landfill.*

MWa. See average megawatt.

Naphtha. Naphtha is a feedstock destined for either the petrochemical industry (e.g. ethylene manufacture or aromatics production). Naphtha comprises material in the 30°C (86 degrees F) and 2l0°C (410 degrees F) distillation range or part of this range.

Natural gas liquids (NGL). Natural gas liquids are liquid or liquefied hydrocarbons recovered from natural gas in separation facilities or gas processing plants. Natural gas liquids include ethane, propane, butane (normal and iso-), (iso)pentane and pentanes plus (sometimes referred to as natural gasoline or plant condensate). The natural gas may be extracted with crude oil (associated gas) or from a gas field without crude oil. The NGL may be removed from the natural gas stream close to the well-head or transported to a distant gas processing plant. Where gas processing and crude oil production are both occuring, it is common for some of the condensate fraction of the NGL to be injected into the crude oil stream.

Natural gas. Naturally occurring underground deposits of gases consisting of 50 to 90 percent methane (CH_4) and small amounts of heavier gaseous hydrocarbon compounds such as propane (C_3H_4) and butane (C_4H_{10}). Natural gas does not include the following gaseous fuels: landfill gas, digester gas, refinery gas, sour gas, blast furnace gas, coal-derived gas, producer gas, or coke oven gas.

Natural gasoline. A term used in the gas processing industry to refer to a mixture of liquid hydrocarbons (mostly pentanes and heavier hydrocarbons) extracted from natural gas. It includes isopentane.

Neat fuel. Fuel that is free from admixture or dilution with other fuels.

Net capacity. The maximum capacity (or effective rating), modified for ambient limitations, that a generating unit, power plant, or electric system can sustain over a specified period, less the capacity used to supply the demand of station and service or auxiliary needs.

Net generation. Gross generation minus station service or unit service power requirements.

Nitrogen oxides. (NO_x) Regulated air pollutants, primarily NO and NO_2. Nitrogen oxides are precursors to the formation of smog and contribute to the formation of acid rain.

Nitrous oxide (N_2O). A powerful greenhouse gas with a global warming potential most recently evaluated at 310. Major sources of nitrous oxide include soil cultivation practices, especially the use of commercial and organic fertilizers, fossil fuel combustion, nitric acid production, and biomass burning.

No. 1 diesel fuel. A light distillate fuel oil that has distillation temperatures of 550 degrees Fahrenheit (288 degrees Celsius) at the 90-percent point and meets the specifications defined in ASTM Specification D 975. It is used in high-speed diesel engines, such as those in city buses and similar vehicles. See No. 1 distillate below.

No. 1 distillate. A light petroleum distillate that can be used as either a diesel fuel (see No. 1 diesel fuel above) or a fuel oil (see No. 1 fuel oil (below).

No. 1 fuel oil. A light distillate fuel oil that has distillation temperatures of 400 degrees Fahrenheit (204 degrees Celsius) at the 10-percent recovery point and 550 degrees Fahrenheit (288 degrees Celsius) at the 90-percent point and meets the specifications defined in ASTM Specification D 396. It is used primarily as fuel for portable outdoor stoves and portable outdoor heaters.

No. 2 diesel fuel. A fuel that has distillation temperatures of 500 degrees Fahrenheit (260 degrees Celsius) at the 10-percent recovery point and 640 degrees Fahrenheit (338 degrees Celsius) at the 90-percent recovery point and meets the specifications defined in ASTM Specification D 975. It is used in high-speed diesel engines, such as those in railroad locomotives, trucks, and automobiles.

No. 2 distillate. A petroleum distillate that can be used as either a diesel fuel (see No. 2 diesel fuel above) or a fuel oil (see No. 2 fuel oil below).

No. 2 fuel oil (heating oil). A distillate fuel oil that has distillation temperatures of 400 degrees Fahrenheit (204 degrees Celsius) at the 10-percent recovery point and 640 degrees Fahrenheit (338 degrees Celsius) at the 90-percent recovery point and meets the specifications defined in ASTM Specification D 396. It is used in atomizing type burners for domestic heating or for moderate capacity commercial/industrial burner units.

No. 4 fuel oil. A distillate fuel oil made by blending distillate fuel oil and residual fuel oil stocks. It conforms with ASTM Specification D 396 or Federal Specification VV-F-815C and is used extensively in industrial plants and in commercial burner installations that are not equipped with preheating facilities. It also includes No. 4 diesel fuel used for low- and medium-speed diesel engines and conforms to ASTM Specification D 975.

Nonbiodegradable. Substance that cannot be broken down in the environment by natural processes. See *biodegradable*.

Noncondensing, controlled extraction turbine. A turbine that bleeds part of the main steam flow at one (single extraction) or two (double extraction) points.

Nonfirm energy. Energy produced by the hydropower system that is available when water conditions exceed worst historic conditions and after reservoir refill is assured.

Non-methane volatile organic compounds (NMVOCs). Organic compounds, other than methane, that participate in atmospheric photochemical reactions.

Non-point source. Large land area such as crop fields and urban areas that discharge pollutant into surface and underground water over a large area. See *point source*.

Nonutility Power Producer: In the United States, a corporation, person, agency, authority, or other legal entity of instrumentality that owns electric generating capacity and is not an electric utility. Nonutility producers include qualifying cogenerators, qualifying small power producers, and other nonutility generators (including independent power producers) without a designated, franchised, service area that do not file forms listed in the U.S. Code of Federal Regulations, Title 18, Part 141.

Octane enhancer. Any substance that is added to gasoline to increase octane.

OEM. Original equipment manufacturer.

Oil shale. Underground formation of a fine-grained sedimentary rock containing varying amounts of kerogen, a solid, waxy mixture of hydrocarbon compounds. Heating the rock to high temperatures converts the kerogen to a vapor, which can be condensed to form a slow flowing heavy oil called shale oil. See *kerogen, shale oil*.

Oil shale. See lignite/brown coal.

Oil. See crude oil, petroleum.

Oil-fired. The combustion of fuel oil.

Opacity. The degree to which smoke or particles emitted into the air reduce the transmission of light and obscure the view of an object in the background.

Ore. Mineral deposit containing a high enough concentration of at least one metallic element to permit the metal to be extracted and sold at a profit.

Organic compound. Molecule that contains atoms of the element carbon, usually combined with itself and with atoms of one or more other element such as hydrogen, oxygen, nitrogen, sulfur, phosphorus, chlorine, or fluorine. See *inorganic compound*.
Organic content. The share of a substance that is of animal or plant origin.
Organic waste. Waste material of recent animal or plant origin.
Organic. Derived from recently living organisms.
Orimulsion. Emulsified oil made of water and natural bitumen.
Other bituminous coal and anthracite. Steam coal is coal used for steam raising and space heating purposes and includes all anthracite coals and bituminous coals not included under coking coal. Its gross calorific value is greater than 23 865 kJ/kg (5 700 kcal/kg), but usually lower than that of coking coal.
Oxidize. To chemically transform a substance by combining it with oxygen.
Oxygen steel-furnace gas. Obtained as a by-product of the production of steel in an oxygen furnace; it is recovered on leaving the furnace. The gas is also known as converter gas, BOS (basic oxygen steel) or LD gas. The quantity of fuel should be reported on a gross calorific value.
Oxygenate. A gasoline fuel additive containing hydrogen, carbon and oxygen. The oxygen content promotes more complete combustion of gasoline, which reduces tailpipe emissions of carbon monoxide.
Oxygenated gasoline. Gasoline containing an oxygenate.
Oxygenates. Substances which, when added to gasoline, increase the amount of oxygen in that gasoline blend. Ethanol, Methyl Tertiary Butyl Ether (MTBE), Ethyl Tertiary Butyl Ether (ETBE), and methanol are common oxygenates.
Ozone precursors. Chemical compounds, such as carbon monoxide, methane, non-methane hydrocarbons, and nitrogen oxides, which in the presence of solar radiation react with other chemical compounds to form ozone, mainly in the troposphere. See *troposphere*
Ozone. Tropospheric ozone (ground-level ozone), or smog, is formed when volatile organic compounds, oxygen and nitrogen oxides react in the presence of sunlight. Ground-level ozone is a pollutant and a respiratory irritant. Stratospheric ozone occurs in the upper atmosphere and protects the earth from the sun's ultraviolet rays.
Paraffin (oil). A light-colored, wax-free oil obtained by pressing paraffin distillate.
Paraffin (wax). Saturated aliphatic hydrocarbons (with the general formula CnH2n+2). These waxes are residues extracted when dewaxing lubricant oils and they have a crystalline structure with carbon number greater than 12. Their main characteristics are as follows: they are colourless, odourless and translucent, with a melting point above 45 C (113 F). The wax removed from paraffin distillates by chilling and pressing. When separating from solutions, it is a colorless, more or less translucent, crystalline mass, without odor and taste, slightly greasy to touch, and consisting of a mixture of solid hydrocarbons in which the paraffin series predominates.
Paraffinic hydrocarbons. Straight-chain hydrocarbon compounds with the general formula C_nH_{2n+2}.
Particulate emissions. Fine liquid or solid particles discharged with exhaust gases. Usually measured as grains per cubic foot or pounds per million Btu input.
Particulate matter (PM). Solid particles or liquid droplets suspended or carried in the air.
Particulates. See *particulate matter*.
Parts per billion (ppb). Number of parts of a chemical found in one billion parts of a particular gas, liquid, or solid mixture. See *concentration.*
Parts per million (ppm). Number of parts of a chemical found in one million parts of a particular gas, liquid, or solid. See *concentration.*
Patent fuel. A composition fuel manufactured from hard coal fines by shaping with the addition of a binding agent. Note that the amount of patent fuel produced can be slightly higher than the amount of coal consumed in the transformation process because of the addition of a binding agent.
Peak demand. The maximum load during a specified period of time.
Peak load plant. A plant usually housing old, low-efficiency steam units, gas turbines, diesels, or pumped-storage hydroelectric equipment normally used during the peak-load periods.
Peak load. The maximum load during a specified period of time.
Peaking capacity. Capacity of generating equipment normally reserved for operation during the hours of highest daily, weekly, or seasonal loads. Some generating equipment may be operated at certain times as peaking capacity and at other times to serve loads on an around-the-clock basis.
Peat briquettes. See BKB.

Peat. Combustible soft, porous or compressed, fossil sedimentary deposit of plant origin with high water content (up to 90 per cent in the raw state), easily cut, of light to dark brown colour. Peat consists of partially decomposed plant debris. It is considered an early stage in the development of coal. Peat is distinguished from lignite by the presence of free cellulose and a high moisture content (exceeding 70 percent). The heat content of air-dried peat (about 50 percent moisture) is about 9 million Btu per ton (10466 KJ/kg). Most U.S. peat is used as a soil conditioner. The first U.S. electric power plant fueled by peat began operation in Maine in 1990. Only peat used for energy purposes should be reported.

Pentanes plus. A mixture of hydrocarbons, mostly pentanes and heavier, extracted from natural gas. Includes isopentane, natural gasoline, and plant condensate.

Petrochemical feedstock. Oils and gases derived from petroleum, used principally for the manufacture of chemicals, synthetic rubber, and a variety of plastics. The categories reported are naphtha (endpoint less than 401 degrees Fahrenheit (205 degrees Celsius)) and other oils (endpoint equal to or greater than 401 degrees Fahrenheit (205 degrees Celsius)).

Petrochemicals. Chemicals obtained processing petrochemical feedstocks. They may be used directly or as raw materials in the manufacture of most industrial chemicals, fertilizers, pesticides, plastics, synthetic fibers, paints, medicines, and many other products. Organic and inorganic compounds and mixtures that include but are not limited to organic chemicals, cyclic intermediates, plastics and resins, synthetic fibers, elastomers, organic dyes, organic pigments, detergents, surface active agents, carbon black, and ammonia.

Petroleum coke, catalyst. The carbonaceous residue that is deposited on and deactivates the catalyst used in many catalytic operations (e.g., catalytic cracking). Carbon is deposited on the catalyst, thus deactivating the catalyst. The catalyst is reactivated by burning off the carbon, which is used as a fuel in the refining process. That carbon or coke is not recoverable in a concentrated form.

Petroleum coke. A black solid residue, obtained mainly by cracking and carbonising of residue feedstocks, tar and pitches in processes such as delayed coking or fluid coking. It consists mainly of carbon (90 to 95 per cent) and has a low ash content. It is used as a feedstock in coke ovens for the steel industry, for heating purposes, for electrode manufacture and for production of chemicals. The two most important qualities are "green coke" and "calcinated coke". This category also includes "catalyst coke" deposited on the catalyst during refining processes: this coke is not recoverable and is usually burned as refinery fuel.

Petroleum jelly. A semi-solid oily product produced from de-waxing lubricating oil basestocks.

Petroleum refinery. An installation that manufactures finished petroleum products from crude oil, unfinished oils, natural gas liquids, other hydrocarbons, and alcohol.

Petroleum. A broadly defined class of liquid hydrocarbon mixtures. Included are crude oil, lease condensate, unfinished oils, refined products obtained from the processing of crude oil, and natural gas plant liquids. Note. Volumes of finished petroleum products include nonhydrocarbon compounds, such as additives and detergents, after they have been blended into the products.

Photovoltaic and solar thermal energy. Energy radiated by the sun as electromagnetic waves (electromagnetic radiation) that is converted into electricity by means of solar (i.e., photovoltaic) cells or useable heat by concentrating (i.e., focusing) collectors.

Pipeline (natural gas). A continuous pipe conduit, complete with such equipment as valves, compressor stations, communication systems, and meters, for transporting natural and/or supplemental gas from one point to another, usually from a point in or beyond the producing field or processing plant to another pipeline or to points of use.

Pipeline, transmission. A pipeline that conveys gas or oil from a region where it is produced to a region where it is to be distributed.

PM10. Particulate that is less than 10 microns in diameter. These particulates are present in the smoke created by burning wood.

PM2.5. Particulate that is less than 2.5 microns in diameter.

Point of delivery. A point on the electric system where a power supplier or wheeling entity delivers electricity to the receiver of that energy or to a wheeling entity. This point could include an interconnection with another system or a substation where the transmission provider's transmission and distribution systems are connected to another system.

Point of receipt. A point on the electrical system where an entity receives electricity from a power supplier or wheeling entity. This point cold include an interconnection with another system or generator bus bar.

Point source. A single identifiable source that discharges pollutants into the environment. Examples are smokestack, sewer, ditch, or pipe. See *non-point source*.

Pollution. A change in the physical, chemical, or biological characteristics of the air, water, or soil that can affect the health, survival, or activities of humans in an unwanted way. Some expand the term to include harmful effects on all forms of life.

Polyvinyl chloride (PVC). A polymer of vinyl chloride. It is tasteless, odorless and insoluble in most organic solvents. A member of the family vinyl resin, used in soft flexible films for food packaging and in molded rigid products, such as pipes, fibers, upholstery, and bristles.

Pound. Pound mass (sometimes abbreviated lb(m)). A unit of mass equal to 0.454 kilograms.

Power (electrical). An electric measurement unit of power called a voltampere is equal to the product of 1 volt and 1 ampere. This is equivalent to 1 watt for a direct current system, and a unit of apparent power is separated into real and reactive power. Real power is the work-producing part of apparent power that measures the rate of supply of energy and is denoted as kilowatts (kW). Reactive power is the portion of apparent power that does no work and is referred to as kilovars; this type of power must be supplied to most types of magnetic equipment, such as motors, and is supplied by generator or by electrostatic equipment. Voltamperes are usually divided by 1,000 and called kilovoltamperes (kVA). Energy is denoted by the product of real power and the length of time utilized; this product is expressed as kilowathours.

Power. The rate at which energy is transferred. Electrical energy is usually measured in watts. Also used for a measurement of capacity.

Preparation plant. A facility at which coal is crushed, screened, and mechanically cleaned.

Prime mover. The engine, turbine, water wheel, or similar machine that drives an electric generator; or, for reporting purposes, a device that converts energy to electricity directly (e.g., photovoltaic solar and fuel cells).

Process emissions. Greenhouse gas emissions other than “combustion emissions” occurring as a result of intentional and unintentional reactions between substances or their transformation, including the chemical or electrolytic reduction of metal ores, the thermal decomposition of substances, and the formation of substances for use as product or feedstock.

Process fuel. All energy consumed in the acquisition, processing, and transportation of energy. Quantifiable process fuel includes three categories. natural gas lease and plant operations, natural gas pipeline operations, and oil refinery operations.

Process heat. Heat used in an industrial process rather than for space heating or other housekeeping purposes.

Processed gas. Natural gas that has gone through a processing plant.

Producer gas. Fuel gas high in carbon monoxide (CO) and hydrogen (H_2), produced by burning a solid fuel with insufficient air or by passing a mixture of air and steam through a burning bed of solid fuel.

Proof. A measure of ethanol content. 1 percent ethanol content equals 2 proof.

Propane (C_3H_8). A normally gaseous straight-chain hydrocarbon. It is a colorless paraffinic gas that boils at a temperature of -43.67 degrees Fahrenheit (-42.04 degrees Celsius). It is extracted from natural gas or refinery gas streams. It includes all products designated in ASTM Specification D1835 and Gas Processors Association Specifications for commercial propane and HD-5 propane.

Propane air. A mixture of propane and air resulting in a gaseous fuel suitable for pipeline distribution.

Propane, consumer grade. A normally gaseous paraffinic compound (C_3H_8), which includes all products covered by Natural Gas Policy Act Specifications for commercial and HD-5 propane and ASTM Specification D 1835. Excludes. feedstock propanes, which are propanes not classified as consumer grade propanes, including the propane portion of any natural gas liquid mixes, i.e., butane-propane mix.

Propylene (C_3H_6). An olefinic hydrocarbon recovered from refinery processes or petrochemical processes.

Proximate analysis. An analysis which reports volatile matter, fixed carbon, moisture content, and ash present in a fuel as a percentage of dry fuel weight.

psi. Pounds force of pressure per square inch.

psia. Pounds force of pressure per square inch absolute (including atmospheric pressure).

psig. Pounds force of pressure per square inch gauge (excluding atmospheric pressure).

Public utility commissions. State agencies that regulate investor-owned utilities operating in the state.

Public Utility Regulatory Policies Act. (PURPA) A U.S. federal law requiring a utility to buy the power produced by a qualifying facility at a price equal to that which the utility would otherwise pay if it were to build its own power plant or buy power from another source.

Pulp chips. Timber or residues processed into small pieces of wood of more or less uniform dimensions with minimal amounts of bark.

Pulp wood. Roundwood, whole-tree chips, or wood residues.

Pulping liquor (black liquor). The alkaline spent liquor removed from the digesters in the process of chemically pulping wood. After evaporation, the liquor is burned as a fuel in a recovery furnace that permits the recovery of certain basic chemicals.
PURPA. See Public Utility Regulatory Policies Act.
Quad. One quadrillion Btu (10^{15} Btu). An energy equivalent to approximately 172 million barrels of oil.
Quadrillion Btu. 10^{15} Btu.
Qualifying facility. A power production facility that qualifies for special treatment under the U.S. Public Utility Regulatory Policies Act. A qualifying facility must generate its power using cogeneration, biomass, waste, geothermal energy or renewable resources, such as solar and wind. PURPA prohibits utilities from owning majority interest in qualifying facilities.
Quality or grade. An informal classification of coal relating to its suitability for use for a particular purpose. Refers to individual measurements such as heat value, fixed carbon, moisture, ash, sulfur, major, minor, and trace elements, coking properties, petrologic properties, and particular organic constituents. The individual quality elements may be aggregated in various ways to classify coal for such special purposes as metallurgical, gas, petrochemical, and blending usages.
Rate schedule. A price list showing how the electric bill of a particular type of customer will be calculated by an electric utility company.
RDF. See refuse-derived fuel.
Reciprocating engine. And internal combustion engine that generates mechanical, electrical, and/or thermal energy through the operation of pistons rather than heating steam or water.
Recovery boiler. A pulp mill boiler in which lignin and spent cooking liquor (black liquor) is burned to generate steam.
Refinery feedstocks. A refinery feedstock is a processed oil destined for further processing (e.g. straight run fuel oil or vacuum gas oil) excluding blending. With further processing, it will be transformed into one or more components and/or finished products. This definition also covers returns from the petrochemical industry to the refining industry (e.g. pyrolysis gasoline, C4 fractions, gasoil and fuel oil fractions).
Refinery fuel. Oils and gases consumed at the refinery to meet its energy requirements.
Refinery gas (not liquefied). Refinery gas includes a mixture of non-condensable gases mainly consisting of hydrogen, methane, ethane and olefins obtained during distillation of crude oil or treatment of oil products (e.g. cracking) in refineries. This also includes gases which are returned from the petrochemical industry.
Refinery. An installation that manufactures finished petroleum products from crude oil, unfinished oils, natural gas liquids, other hydrocarbons, and oxygenates.
Reformulated gasoline. (RFG) Gasoline that has altered composition or characteristics to reduce emissions of pollutants from vehicles.
Refractory lining. A lining, usually of ceramic, capable of resisting and maintaining high temperatures.
Refuse-derived fuel (RDF). A fuel produced by shredding municipal solid waste (MSW). Noncombustible materials such as glass and metals are generally removed prior to making RDF. The residual material is sold as-is or compressed into pellets, bricks, or logs. RDF processing facilities are typically located near a source of MSW, while the RDF combustion facility can be located elsewhere.
Reid vapor pressure. (RVP) A standard measurement of a liquid's vapor pressure at 100 degrees Fahrenheit (37.8 degrees Celsius). An indication of the propensity of the liquid to evaporate.
Reinjection. The feeding of unburned char and fly ash obtained from mechanical collectors into the furnace for further combustion.
Renewable energy. Fuels and energy obtained from sources that are ultimately replenished from natural solar and gravitational energy flows. Renewable sources of energy include wood, waste, geothermal, wind, photovoltaic, and solar thermal energy. See *hydropower, photovoltaic*.
Repeatability. Repeatability (within laboratory) of an analytical procedure is the maximum acceptable difference between duplicate determinations carried out at different items in the same laboratory on the same analysis sample by the same operator using the same apparatus. This is sometimes called within laboratory tolerance.
Reproducibility. Reproducibility (between laboratories) for an analytical procedure is the maximum acceptable difference between the mean of acceptable replicate determinations carried out in one laboratory, and the mean of acceptable replicate determinations carried out in any other laboratory on representative samples taken from the same bulk sample after the last stage of the reduction process. This is sometimes called between laboratory tolerance.

Reserve margin. The amount by which the utility's total electric power capacity exceeds maximum electric demand.

Residual fuel oil. The heavier oils that remain after the distillate fuel oils and lighter hydrocarbons are distilled away in refinery operations and that conform to ASTM Specifications D396 and D975. Included are No. 5, a residual fuel oil of medium viscosity; Navy Special, for use in steam-powered vessels in government service and in shore power plants; and No. 6, which includes Bunker C fuel oil and is used for commercial and industrial heating, electricity generation, and to power ships. Imports of residual fuel oil include imported crude oil burned as fuel.

Residue gas. Natural gas from which natural gas processing plant liquid products and, in some cases, nonhydrocarbon components have been extracted.

Residuum. Residue from crude oil after distilling off all but the heaviest components, with a boiling range greater than 1,000 degrees Fahrenheit (538 degrees Celsius).

Retrofitting. The application of conservation, efficiency, or renewable energy technologies to existing structures.

Road oil. Any heavy petroleum oil, including residual asphaltic oil used as a dust pallative and surface treatment on roads and highways. It is generally produced in six grades, from 0, the most liquid, to 5, the most viscous.

Sampling. The process by which a portion of a substance, material, or product is removed to form a representative example of the whole, for the purpose of examination of the substance, material, or product under consideration.

Saturated steam. Steam at the temperature that corresponds to its boiling temperature at the same pressure.

SCF. Standard cubic foot.

SCFM. Standard cubic foot per minute.

Scrubber. A device to clean combustible gas or stack gas by the spraying of water.

Semianthracite. See Anthracite.

Shaft horsepower. A measure of the actual mechanical energy per unit time delivered to a turning shaft. 1 shaft horsepower = 1 electric horsepower = 550 ft-lb/second.

Shale oil. Slow-flowing, dark brown, heavy oil obtained when kerogen in oil shale is vaporized at high temperatures and then condensed. Shale oil can be refined to yield gasoline, heating oil, and other petroleum products. See *kerogen, oil shale.*

Short ton. Common measurement for a ton in the United States. A short ton is equal to 2,000 lbs. or 0.907 metric tons.

Silt. Waste from Pennsylvania anthracite preparation plants, consisting of coarse rock fragments containing as much as 30 percent small-sized coal; sometimes defined as including very fine coal particles called silt. Its heat value ranges from 8 to 17 million Btu per short ton (9 303 to 19 770 KJ/kg. Synonymous with culm.

Site energy. The Btu value of energy at the point it enters the home, sometimes referred to as "delivered" energy. The site value of energy is used for all fuels, including electricity.

Size range. Indicates the largest and smallest sizes of particles in a coal sample or stream. The size range of a sample containing sizes from 50 mm down to zero can be written as 50x0 mm, -50+0 mm, 0x50 mm or -50 mm. Some national standards allow for terms such as a nominal upper size (or top size) which is the smallest sieve size such that not more than 5% of the fuel would be oversize, e.g. a coal shipment of nominal size 20 x 40 mm could contain up to 5% of material larger than 40 mm. Imperial units are also used and the ASTM allows use of a numerical numbering system for sieves giving a size range such as 2 in. x No.4.

Slagging. A problem in coal utilization where during combustion the ash melts and forms a slag, making ash removal from the furnace difficult. An initial deformation ash fusion temperature of 1250°C (2282 degrees F) is generally, although not always, considered the minimum acceptable to avoid slagging problems. Slagging boilers are designed such that ash removal is by molten slag from the bottom of the furnace and thus require low ash fusion coals to operate correctly.

Slow pyrolysis. Thermal conversion of biomass to fuel by slow heating to less than 450°C (842 degrees F) in the absence of oxygen.

Smog. A visible haze caused by particulate matter and ground-level ozone.

Solar energy. Solar radiation exploited for hot water production and electricity generation, by.

- Flat plate collectors, mainly of the thermosyphon type, for domestic hot water or for the seasonal heating of swimming pools
- Photovoltaic cells.
- Solar thermal electric plants.

Solid biomass. Covers organic, non-fossil material of biological origin which may be used as fuel for heat production or electricity generation. It comprises.

- Charcoal. Covers the solid residue of the destructive distillation and pyrolysis of wood and other vegetal material.

- Wood, wood wastes, other solid wastes. Covers purpose-grown energy crops (poplar, willow, etc.), a multitude of woody materials generated by an industrial process (wood/paper industry in particular) or provided directly by forestry and agriculture (firewood, wood chips, bark, sawdust, shavings, chips, black liquor, etc.) as well as wastes such as straw, rice husks, nut shells, poultry litter, crushed grape dregs, etc. Combustion is the preferred technology for these solid wastes. The quantity of fuel used should be reported on a net calorific value basis.

Soot. A black substance formed by combustion or separated from fuel during combustion, rising in fine particles, and adhering to the sides of the chimney or pipe conveying the smoke; especially the fine powder consisting chiefly of carbon that colors smoke.

Source. Any process or activity that releases a greenhouse gas, an aerosol, or a precursor of a greenhouse gas into the atmosphere.

Special naphtha. All finished products within the naphtha boiling range that are used as paint thinners, cleaners, or solvents. Those products are refined to a specified flash point.

Spreader stoker furnace. A furnace in which fuel is automatically or mechanically spread. Part of the fuel is burned in suspension. Large pieces fall on a grate.

Stack. A tall, vertical structure containing one or more flues used to discharge products of combustion to the atmosphere.

Steam boiler. A type of furnace in which fuel is burned and the heat is used to produce steam.

Steam coal. All nonmetallurgical coal.

Steam coal. See Hard coal.

Steam turbine. A device that converts high-pressure steam, produced in a boiler, into mechanical energy that can then be used to produce electricity by forcing blades in a cylinder to rotate and turn a generator shaft.

Still gas (refinery gas). Any form or mixture of gases produced in refineries by distillation, cracking, reforming, and other processes. The principal constituents are methane, ethane, ethylene, normal butane, butylene, propane, propylene, etc. Still gas is used as a refinery fuel and a petrochemical feedstock. The conversion factor is 6 million BTU's per fuel oil equivalent barrel.

Stock change. The difference between stocks at the beginning of the reporting period and stocks at the end of the reporting period. Note. A negative number indicates a decrease (i.e., a drawdown) in stocks and a positive number indicates an increase (i.e., a buildup) in stocks during the reporting period.

Stocks. A supply of fuel accumulated for future use, including, but not limited to, coal and fuel oil stocks at a plant site in coal piles, coal cars, tanks, or barges at a plant site or separate storage sites.

Stoichiometric condition. That condition at which the proportion of the air-to-fuel is such that all combustible products will be completely burned with no oxygen remaining in the combustion air.

Subbituminous coal. A coal whose properties range from those of lignite to those of bituminous coal and used primarily as fuel for steam-electric power generation. It may be dull, dark brown to black, soft and crumbly, at the lower end of the range, to bright, jet black, hard, and relatively strong, at the upper end. Subbituminous coal contains 20 to 30 percent inherent moisture by weight. The heat content of subbituminous coal ranges from 17 to 24 million Btu per ton (19770 to 27910 KJ/kg) on a moist, mineral-matter-free basis. The heat content of subbituminous coal consumed in the United States averages 17 to 18 million Btu per ton (19770 to 20 933 KJ/kg), on the as-received basis (i.e., containing both inherent moisture and mineral matter). Non-agglomerating coals with a gross calorific value between 17 435 kJ/kg (4 165 kcal/kg, 14.99 million btu/short ton) and 23 865 kJ/kg (5 700 kcal/kg, 20.52 million btu/short ton) containing more than 31 per cent volatile matter on a dry mineral matter free basis.

Substitute natural gas. This is a high calorific value gas, manufactured by chemical conversion of a hydrocarbon fossil fuel. It is chemically and physically interchangeable with natural gas and is usually distributed through the natural gas grid. The main raw materials for manufacture of substitute natural gas are. coal, oil and oil shales. Substitute natural gas is distinguished from other manufactured gases by its high heat value (above 8 000 kcal/m3 (approximately 1272 kcal/barrel)) and by its high methane content (above 85%). Substitute natural gas produced by synthesis from fuels other than coal-based should also come under From other sources. The quantity of fuel should be reported on a gross calorific value.

Sulfur dioxide (SO_2). A compound composed of one sulfur and two oxygen molecules. Sulfur dioxide emitted into the atmosphere through natural and anthropogenic processes is changed in a complex series of chemical reactions in the atmosphere to sulfate aerosols. These aerosols are believed to result in negative radiative forcing (i.e., tending to cool the Earth's surface) and do result in acid deposition (e.g., acid rain). See *aerosols, radiative forcing, acid deposition, acid rain.*

Sulphur. Can be part of the carbonaceous material in coal or part of the minerals as sulphates or sulphides. Forms sulphur dioxide during coal combustion which is a serious pollutant, most countries having relations regarding emissions to the atmosphere. Undesirable in coking coal because it partly accumulates in the hot metal and requires desulphurisation to remove if above about 0.002%.

Superheated steam. Steam at a given pressure which is above the temperature which corresponds to boiling temperature at that given pressure.

Surface moisture. The difference between total moisture and moisture holding capacity. Called free moisture in ASTM.

Surplus electricity. Electricity produced by cogeneration equipment in excess of the needs of an associated factory or business.

Syngas. A syntheses gas produced through gasification of biomass. Syngas is similar to natural gas and can be cleaned and conditioned to form a feedstock for production of methanol.

Synthetic coal. Coal that has been processed by a coal synfuel plant; and coal-based fuels such as briquettes, pellets, or extrusions, which are formed by binding materials and processes that recycle material.

Synthetic natural gas (SNG). (Also referred to as substitute natural gas) A manufactured product, chemically similar in most respects to natural gas, resulting from the conversion or reforming of petroleum hydrocarbons that may easily be substituted for or interchanged with pipeline-quality natural gas.

System (gas). An interconnected network of pipes, valves, meters, storage facilities, and auxiliary equipment used in the transportation, storage, and/or distribution of natural gas or commingled natural and supplemental gas.

Tailings. Rock and other waste materials removed as impurities when minerals are mined and mineral deposits are processed. These materials are usually dumped on the ground or into ponds.

Tar sand. Swamp-like deposit of a mixture of fine clay, sand, water, and variable amounts of tar-like heavy oil known as bitumen. Bitumen can be extracted from tar sand by heating. It can then be purified and upgraded to synthetic crude oil. See *bitumen*.

Tar sands. see Lignite/brown coal.

Therm. A unit of energy equal to 100,000 British thermal units; used primarily for natural gas.

Thermochemical conversion process. Chemical reactions employing heat to produce fuels.

Tide/wave/ocean energy. Mechanical energy derived from tidal movement or wave motion and exploited for electricity generation.

Tipple. A central facility used in loading coal for transportation by rail or truck.

Topping and back pressure turbines. Turbines which operate at exhaust pressure considerably higher than atmospheric (noncondensing turbines). These turbines are often multistage types with relatively high efficiency.

Topping cycle. A cogeneration system in which electric power is produced first. The reject heat from power production is then used to produce useful process heat.

Total moisture. The moisture in the coal as sampled and removable under standard conditions.

Total suspended particulates. The quantity of solid particles in a gas or exhaust stream. Any finely divided material (solid or liquid) that is airborne with a diameter smaller than a few hundred micrometers.

Toxic substances. A chemical or mixture of chemicals that presents a high risk of injury to human health or to the environment.

Trace metals. Also often called heavy metals. Both terms are not strictly correct but generally refer of those elements in coal which are considered harmful to the environment and are present in very small quantities. Examples are mercury, arsenic, selenium, fluorine, cadmium, etc.

Traveling grate. A type of furnace in which assembled links of grates are joined together in a perpetual belt arrangement. Fuel is fed in at one end and ash is discharged at the other.

Tropospheric ozone precursor. See *ozone precursor.*

TSP. See total suspended particulates.

Turbine. A machine for converting the heat energy in steam or high temperature gas into mechanical energy. In a turbine, a high velocity flow of steam or gas passes through successive rows of radial blades fastened to a central shaft.

Ultimate analysis. The analysis of a coal expressed in terms of carbon, hydrogen, nitrogen, sulphur and oxygen. The analysis refers to the carbonaceous material only and hence is often expressed on a dry ash free basis or dry mineral matter free basis. Oxygen is generally estimated by difference although there are methods for its determination.

Unfinished oils. All oils requiring further processing, except those requiring only mechanical blending. Unfinished oils are produced by partial refining of crude oil and include naphthas and lighter oils, kerosene and light gas oils, heavy gas oils, and residuum.

Unleaded motor gasoline. See Motor gasoline.

VOC. see Volatile organic compounds.

Volatile matter. The loss in mass, less that due to moisture, when coal is heated under standard conditions and out of contact with air. This test is very empirical and results are very sensitive to operating conditions. Results obtained from different standard methods will not necessarily give the same result. The ASTM methods generally gives a higher result than other methods.

Volatile organic compounds (VOCs). Organic compounds that evaporate readily into the atmosphere at normal temperatures. VOCs contribute significantly to photochemical smog production and certain health problems. See *non-methane volatile organic compounds.*

Volatiles. Substances that are readily vaporized.

Volatility. The tendency of a liquid to pass into the vapor state at a given temperature. Vapor pressure.

Waste coal. Usable coal material that is a byproduct of previous processing operations or is recaptured from what would otherwise be refuse. Examples include anthracite culm, bituminous gob, fine coal, lignite waste, coal recovered from a refuse bank or slurry dam, and coal recovered by dredging.

Waste heat boiler. A boiler that receives all or a substantial portion of its energy input from the combustible exhaust gases from a separate fuel-burning process.

Waste materials. Otherwise discarded combustible materials that, when burned, produce energy for such purposes as space heating and electric power generation. The size of the waste may be reduced by shredders, grinders, or hammermills. Noncombustible materials, if any, may be removed. The waste may be dried and then burned, either alone or in combination with fossil fuels.

Waste oils and tar. Petroleum-based materials that are worthless for any purpose other than fuel use.

Waste streams. Unused solid or liquid by- products of a process.

Wastes.

- Industrial wastes. Wastes of industrial non-renewable origin (solids or liquids) combusted directly for the production of electricity and/or heat. The quantity of fuel used should be reported on a net calorific value basis. Renewable industrial waste should be reported in the Solid biomass, Biogas and/or Liquid biofuels categories.
- Municipal solid waste (renewables). Waste produced by households, industry, hospitals and the tertiary sector which contains biodegradable materials that are incinerated at specific installations. The quantity of fuel used should be reported on a net calorific value basis.
- Municipal solid waste (non-renewables). Waste produced by households, industry, hospitals and the tertiary sector that contains non-biodegradable materials that are incinerated at specific installations. The quantity of fuel used should be reported on a net calorific value basis.

Water-cooled vibrating grate. A boiler grate made up of a tuyere grate surface mounted on a grid of water tubes interconnected with the boiler circulation system for positive cooling. The structure is supported by flexing plates allowing the grid and grate to move in a vibrating action. Ashes are automatically discharged.

Watt (W). The common base unit of power in the metric system. One watt equals one joule per second. It is the power developed in a circuit by a current of one ampere flowing through a potential difference of one volt. One Watt = 3.413 Btu/hr or 1/746 horsepower

Watthour (Wh). The electrical energy unit of measure equal to one watt of power supplied to, or taken from, an electric circuit steadily for one hour.

Wax. A solid or semi-solid material derived from petroleum distillates or residues by such treatments as chilling, precipitating with a solvent, or de-oiling. It is a light-colored, more-or-less translucent crystalline mass, slightly greasy to the touch, consisting of a mixture of solid hydrocarbons in which the paraffin series predominates. Includes all marketable wax, whether crude scale or fully refined. The three grades included are microcrystalline, crystalline-fully refined, and crystalline-other. The conversion factor is 280 pounds per 42 U.S. gallons per barrel.

Well. A hole drilled in the earth for the purpose of (1) finding or producing crude oil or natural gas; or (2) producing services related to the production of crude or natural gas.

Wellhead. The point at which the crude (and/or natural gas) exits the ground. Following historical precedent, the volume and price for crude oil production are labeled as "wellhead," even though the cost and volume are now generally measured at the lease boundary. In the context of domestic crude price data, the term "wellhead" is the generic term used to reference the production site or lease property.

Wet bottom boiler. A boiler from which ash removal is by molten slag from the bottom of the combustion chamber. A suitable coal should thus have an ash fusion flow temperature of maximum 1300°C.

Wet bottom boiler. Slag tanks are installed usually at the furnace throat to contain and remove molten ash.

Wet natural gas. A mixture of hydrocarbon compounds and small quantities of various nonhydrocarbons existing in the gaseous phase or in solution with crude oil in porous rock formations at reservoir conditions. The principal hydrocarbons normally contained in the mixture are methane, ethane, propane, butane, and pentane. Typical nonhydrocarbon gases that may be present in reservoir natural gas are water vapor, carbon dioxide, hydrogen sulfide, nitrogen and trace amounts of helium. Under reservoir conditions, natural gas and its associated liquefiable portions occur either in a single gaseous phase in the reservoir or in solution with crude oil and are not distinguishable at the time as separate substances. Note. The Securities and Exchange Commission and the Financial Accounting Standards Board refer to this product as natural gas.

Wheeling. The process of transferring electrical energy between buyer and seller by way of an intermediate utility or utilities.

White spirit and specific boiling point (SBP) spirits. White spirit and SBP are defined as refined distillate intermediates with a distillation in the naphtha/kerosene range. They are subdivided as.

- Industrial Spirit (SBP). Light oils distilling between 30°C (86 degrees F) and 200°C (392 degrees F). There are 7 or 8 grades of industrial spirit, depending on the position of the cut in the distillation range. The grades are defined according to the temperature difference between the 5% volume and 90% volume distillation points (which is not more than 60°C (140 degrees F)).
- White spirit. Industrial spirit with a flash point above 30°C (86 degrees F). The distillation range of white spirit is 135°C (275 degrees F) to 200°C (392 degrees F).

Wind energy. Kinetic energy present in wind motion that can be converted to mechanical energy for driving pumps, mills, and electric power generators.

Wood energy. Wood and wood products used as fuel, including round wood (cord wood), limb wood, wood chips, bark, sawdust, forest residues, charcoal, pulp waste, and spent pulping liquor.

Wood pellets. Sawdust compressed into uniform diameter pellets to be burned in a heating stove.

Wood/wood wastes/other solid wastes. See Solid biomass.