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Carbon dioxide capture —

Part 1: Performance evaluation methods for post-combustion CO_2 capture integrated with a power plant

Captage du dioxyde de carbone —

Partie 1: Méthodes d'évaluation des performances pour le captage du CO_2 post-combustion intégré à une centrale thermique

Reference number
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Foreword

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This document was prepared by Technical Committee ISO/TC 265, *Carbon dioxide capture, transportation and geological storage*.

A list of all the parts in the ISO 27919 series can be found on the ISO website.

Any feedback or questions on this document should be directed to the user's national standards body. A complete listing of these bodies can be found at www.iso.org/members.html.

Introduction

It is very important to reduce atmospheric carbon dioxide (CO_2) emissions in order to meet climate change mitigation targets. Inclusion of carbon dioxide capture and storage (CCS) among the variety of available emission reduction approaches enhances the probability of meeting these targets at the lowest cost to the global economy. CCS captures CO_2 from industrial and energy-related sources and stores it underground in geological formations. It can capture emissions from carbonaceous fuel-based combustion processes, including power generation, and is the only technology capable of dealing directly with emissions from several industrial sectors, such as cement manufacture and fertilizer production.

This document is the first in a series of standards for CO_2 capture. It is limited to evaluation of key performance indicators (KPIs) for post-combustion CO_2 capture (PCC) from a power plant using a liquid-based chemical absorption process. New or revised standards focused on other capture technologies and approaches will be developed at a later date.

PCC is applicable to all combustion-based thermal power plants. A simplified block diagram illustrating the PCC is shown in Figure 1.

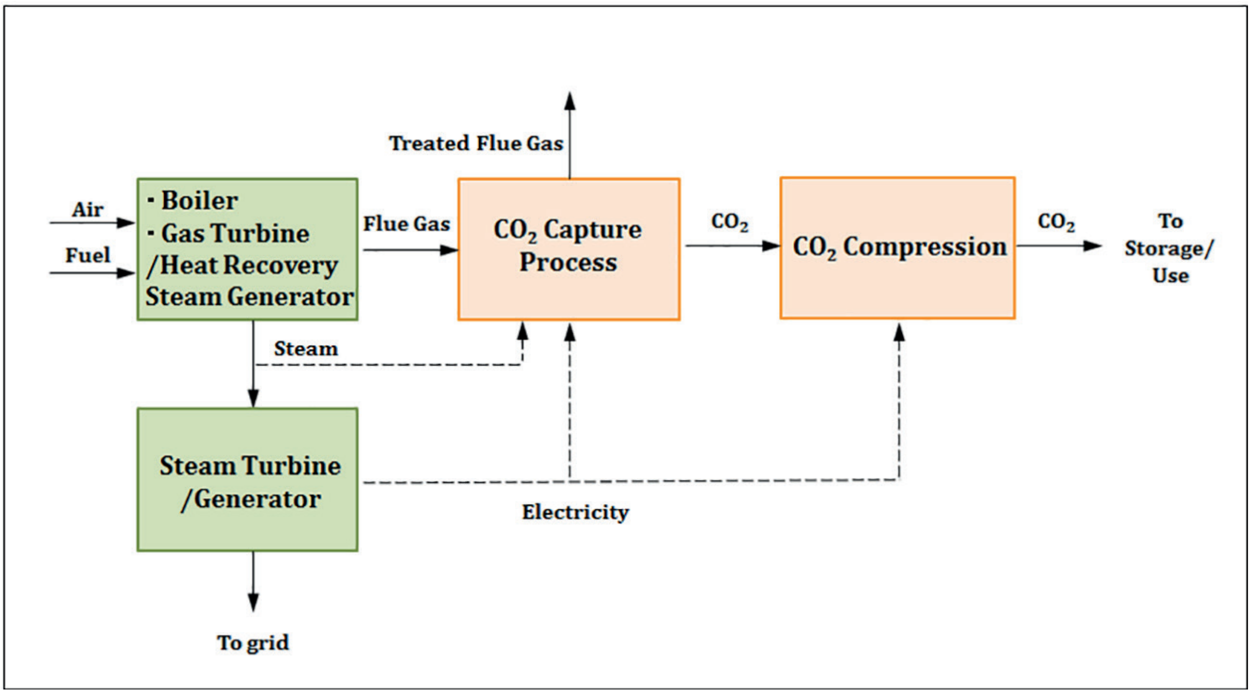


Figure 1 — Simplified block diagram for PCC

In a typical power generation facility, carbonaceous fuel (e.g. coal, oil, gas, biomass) is combusted with air in a boiler to raise steam that drives a turbine/generator to produce power. In a gas turbine combined cycle system, the combustion occurs in the gas turbine to drive power generation, and steam generated through a heat recovery steam generator (HRSG) contributes to additional power generation. Flue gas from the boiler or gas turbine consists mostly of N_2, CO_2, H_2O and O_2 with smaller amounts of other compounds depending on the fuel used. The CO_2 capture process is located downstream of conventional pollutant controls. Chemical absorption-based PCC usually requires the extraction of steam from the power plant's steam cycle or, depending on the absorption liquid/process employed, the use of lower grade heat sources for absorption liquid regeneration.

The intended readership for this document includes power plant owners and operators, project developers, technology developers and vendors, regulators, and other stakeholders. The document will provide several benefits, as outlined in the clauses below. In brief, it provides a common basis to estimate, measure, evaluate and report on the performance of a PCC plant integrated with a power plant. It can help various stakeholders to identify potential efficiency improvements among different plant components. It can help to guide the selection of measurement methodologies, and serve as a resource in development of regulations. Finally, it provides the basis for future standards development.

Carbon dioxide capture —

Part 1: Performance evaluation methods for post-combustion CO_2 capture integrated with a power plant

1 Scope

This document specifies methods for measuring, evaluating and reporting the performance of post-combustion CO_2 capture (PCC) integrated with a power plant, and which separates CO_2 from the power plant flue gas in preparation for subsequent transportation and geological storage. In particular, it provides a common methodology to calculate specific key performance indicators for the PCC plant, requiring the definition of the boundaries of a typical system and the measurements needed to determine the KPIs.

This document covers thermal power plants burning carbonaceous fuels, such as coal, oil, natural gas and biomass-derived fuels, which are producing CO_2 from boilers or gas turbines, and are integrated with CO_2 capture.

The PCC technologies covered by this document are those based on chemical absorption using reactive liquids, such as aqueous amine solutions, potassium carbonate solutions, and aqueous ammonia. Other PCC concepts based on different principles (e.g. adsorption, membranes, cryogenic) are not covered. The PCC plant can be installed for treatment of the full volume of flue gas from the power plant or a fraction of the total (i.e. a slip stream). Captured CO_2 is processed in a compression or liquefaction step as determined by the conditions for transportation and storage.

The KPIs considered in this document are the following:

a) Specific thermal energy consumption (STEC);

b) Specific electrical energy consumption (SEC);

c) Specific equivalent electrical energy consumption (SEEC);

d) Specific reduction in CO_2 emissions (SRCE);

e) Specific absorbent consumption (SAC) and specific chemical consumption (SCC).

The calculations are based on measurements at the boundaries of the considered system, particularly of energy and utilities consumption. The integrated system includes the definition of interfaces between the PCC plant and the power plant.

This document includes the following items:

— The system boundary which defines the boundaries of the PCC plant and identifies which streams of energy and mass are crossing these boundaries to help power plant operators identify the key streams that are applicable for their particular case.

— Basic PCC plant performance which defines the parameters that describe the basic performance of the PCC plant.

— Definition of utilities and consumption calculation which lists the utility measurements required and provides guidance on how to convert utility measurements into the values required for the KPIs.

— Guiding principles - Basis for PCC plant performance assessment which describes all guidelines to prepare, set-up and conduct the tests.

— Instruments and measurement methods which lists the standards available for the relevant measurements and considerations to take into account when applying measurement methods to PCC plants.

— Evaluation of key performance indicators which specifies the set of KPIs to be determined and their calculation methods to provide a common way of reporting them.

This document does not provide guidelines for benchmarking, comparing or assessing KPIs of different technologies or different PCC projects.

NOTE For the purposes of this document, thermal energy and electric energy are expressed by the unit of "J" (Joule) and "Wh" (Watt hour) respectively unless otherwise noted, with a prefix of International System of Units (SI) if necessary. (1 J = 1 W·s, 1 Wh = 1 W·h = 3 600 J).

2 Normative references

There are no normative references in this document.

3 Terms, definitions and symbols

For the purposes of this document, the following terms and definitions apply.

ISO and IEC maintain terminological databases for use in standardization at the following addresses:

— ISO Online browsing platform: available at https://www.iso.org/obp

— IEC Electropedia: available at http://www.electropedia.org/

3.1 Terms and definitions

3.1.1
absorbent
substance able to absorb liquid or gas

[SOURCE: ISO/TR 27912:2016, definition 3.1]

3.1.2
measurement accuracy
accuracy of measurement
accuracy
closeness of agreement between a measured quantity value and a true quantity value of a measurand

[SOURCE: ISO/IEC Guide 99:2007, definition 2.13]

3.1.3
auxiliary unit
unit providing heat, power and/or other utilities for the PCC plant

3.1.4
boiler feed water
water consisting of the condensate and the make-up water that is sent to the boiler

3.1.5
carbon dioxide capture and storage
CCS
process consisting of the separation of CO_2 from industrial and energy-related sources, transportation and injection into a geological formation, resulting in long term isolation from the atmosphere

Note 1 to entry: CCS is often referred to as Carbon Capture and Storage. This terminology is not encouraged because it is inaccurate: the objective is the capture of carbon dioxide and not the capture of carbon. Tree plantation is another form of carbon capture that does not describe precisely the physical process of removing CO_2 from industrial emission sources.

Note 2 to entry: The term "sequestration" is also used alternatively to "storage". The term "storage" is preferred since “sequestration” is more generic and can also refer to biological processes (absorption of carbon by living organisms).

Note 3 to entry: Long term means the minimum period necessary for CO_2 geological storage to be considered an effective and environmentally safe climate-change-mitigation-option.

Note 4 to entry: The term carbon dioxide capture, utilization (or use) and storage (CCUS) includes the concept that isolation from the atmosphere could be associated with a beneficial outcome. CCUS is embodied within the definition of CCS to the extent that long term isolation of the CO_2 occurs through storage within geological formations. CCU is Carbon Capture and utilization (or use) without storage within geological formations.

Note 5 to entry: CCS should also ensure long term isolation of CO_2 from oceans, lakes, potable water supplies and other natural resources.

[SOURCE: ISO 27917:2017, definition 3.1.1]

3.1.6
carbonaceous fuels
any solid, liquid or gaseous fuels containing carbon atoms

3.1.7
capture plant
process and associated equipment that produces a CO_2 stream

3.1.8
chemical absorption
process in which CO_2 is absorbed by chemical reaction

3.1.9
CO_2 capture efficiency
capture efficiency
CO_2 removal efficiency of the capture plant calculated as the amount of CO_2 captured divided by the total amount of CO_2 contained in the flue gas at the inlet of the capture plant

Note 1 to entry: The CO_2 capture efficiency is expressed as a percentage.

3.1.10
CO_2 captured
absolute amount of pure CO_2 captured by the capture plant

3.1.11
CO_2 stream
stream consisting overwhelmingly of carbon dioxide

[SOURCE: ISO 27917:2017, definition 3.1.1, modified — The Note was deleted.]

3.1.12
condensate
water produced by condensation of steam, e.g. a boiler of PCC return to the steam cycle and/or auxiliary boiler

3.1.13
deep flue gas desulfurization
deep FGD
SO_2 removal unit placed downstream of the main flue gas desulfurization process intended to lower the SO_2 content to the level required by the CO_2 capture plant

Note 1 to entry: Also called a "polishing" FGD.

Note 2 to entry: In the case where no FGD is required by local regulations, and FGD is installed for the purposes of CCS, the new unit will be considered as deep FGD.

3.1.14
dehydrator
moisture removal system and/or equipment

3.1.15
demineralized water
water from which the mineral matter or salts have been removed

[SOURCE: ISO/TR 27912:2016, definition 3.24, modified — The second term "demin water" was removed and in the definition the word "of" was replaced by "from".]

3.1.16
DeNO*x*
process or equipment used to remove NO*x* from the flue gas

3.1.17
effluent
liquid discharged to the environment

3.1.18
fuel specific emission
amount of component generated from complete combustion per unit of heat energy released

3.1.19
host power plant
power plant from which flue gas is sent to the PCC plant

3.1.20
impurities
non-CO_2 substances that are part of the CO_2 stream that may be derived from the source materials or the capture process, or added as a result of commingling for transportation, or released or formed as a result of sub-surface storage and/or leakage of CO_2

[SOURCE: ISO 27917:2017, definition 3.2.12, modified — Notes 1 and 2 were deleted.]

3.1.21
interface
mechanical, thermal, electrical, or operational common boundary between two elements of a system

[SOURCE: ISO 10795:2011, definition 1.120, modified — The abbreviation "I/F" was deleted.]

3.1.22
key performance indicator
measure of performance relevant to the PCC plant integrated with a power plant

3.1.23
measurement uncertainty
uncertainty of measurement
uncertainty
non-negative parameter characterizing the dispersion of the quantity values being attributed to a measurand, based on the information used

Note 1 to entry: Measurement uncertainty includes components arising from systematic effects, such as components associated with corrections and the assigned quantity values of physical properties, as well as the definitional uncertainty. Sometimes estimated systematic effects are not corrected for; associated measurement uncertainty components are incorporated instead.

Note 2 to entry: The parameter may be, for example, a standard deviation called standard measurement uncertainty (or a specified multiple of it), or the half-width of an interval, having a stated coverage probability.

Note 3 to entry: Measurement uncertainty comprises, in general, many components. Some of these may be evaluated by Type A evaluation of measurement uncertainty from the statistical distribution of the quantity values from a series of measurements and can be characterized by standard deviations. The other components, which may be evaluated by Type B evaluation of measurement uncertainty, can also be characterized by standard deviations, evaluated from probability density functions based on experience or other information.

Note 4 to entry: In general, for a given set of information, it is understood that the measurement uncertainty is associated with a stated quantity value attributed to the measurand. A modification of this value results in a modification of the associated uncertainty.

Note 5 to entry: "Type A evaluation of measurement uncertainty" is defined as an evaluation of a component of measurement uncertainty by a statistical analysis of measured quantity values obtained under defined measurement conditions. "Type B evaluation of measurement uncertainty" is defined as an evaluation of a component of measurement uncertainty determined by means other than a Type A evaluation of measurement uncertainty".

[SOURCE: ISO/IEC Guide 99:2007, definition 2.26, modified — "measurement standards" in Note 1 was changed to "physical properties" and a Note 5 was added.]

3.1.24
PM
particulate matter including $PM_{2,5}$, PM_{10}, and/or total suspended particulate matter

[SOURCE: ISO 25597:2013, definition 3.21]

3.1.25
particulate removal
action to remove particulate matter from the flue gas stream

3.1.26
PCC plant
process and associated equipment that produces a CO_2 stream from combustion gases

3.1.27
permanent plant instrument
instrument installed in the power plant and capture plant for control and monitoring

3.1.28
post-combustion CO_2 capture
capture of carbon dioxide from flue gas stream produced by carbonaceous fuel combustion

[SOURCE: ISO/TR 27912:2016, definition 3.51, modified — In the term, "CO_2" was added and "fuel air combustion" was modified to "carbonaceous fuel combustion" in the definition.]

3.1.29
product CO_2 stream
stream produced by a CO_2 capture and compression/liquefaction process

3.1.30
reclaiming system
system used to recover CO_2 absorbents for use in the PCC plant to remove the heat stable salts produced by the reaction of organic and inorganic acids with the amine(s) in the absorbents

3.1.31
redundant instrument
duplicate instrument necessary to plant functioning in case of failure of similar instruments for measurement of the same parameters

3.1.32
reference power plant
power plant that is considered to be representative of power generation without CO_2 capture

Note 1 to entry: The power plant is either real or hypothetical.

3.1.33
regeneration
process to regenerate an activity of absorbent after use to its operationally effective state

3.1.34
rejected heat
heat dissipated to the environment by cooling equipment

3.1.35
specific absorbent consumption
amount of CO_2 absorbent consumed to capture and compress/liquefy a tonne of CO_2

3.1.36
specific reduction in CO_2 emissions
calculated net decrease of the CO_2 emissions per unit output of a reference power plant by implementing the PCC process to the host power plant

Note 1 to entry: This measure of emission reduction is normalised with respect to the output of the power plant.

[SOURCE: ISO 27917:2017, definition 3.2.8, modified — "baseline scenario and the CCS project output" has been replaced by "per unit output of a reference power plant by implementing the PCC process to the host power plant".]

3.1.37
specific chemical consumption
amount of chemical consumed to capture and compress/liquefy a tonne of CO_2

3.1.38
specific equivalent electrical energy consumption
overall electrical energy consumption attributed to capture and compression/liquefaction of a tonne of CO_2

3.1.39
specific electrical energy consumption
electrical energy consumed to capture and compress/liquefy a tonne of CO_2

3.1.40
specific thermal energy consumption
thermal energy consumed to capture and compress/liquefy a tonne of CO_2

3.1.41
reference conditions
conditions for a reference point where results of performance evaluation could be adjusted for the purpose of comparability in the reporting of the results and benchmarking

Note 1 to entry: See Annex E which presents standard reference conditions used as a reference point to adjust the results of performance evaluation.

3.1.42
thermal power plant
power plant that converts heat e.g. released by the combustion of carbonaceous fuels into electricity

3.1.43
tie-in point
point of connection between the utility supply and the PCC plant

Note 1 to entry: This point sits at the PCC plant boundary.

3.1.44
treated flue gas
flue gas of which the CO_2 concentration has been reduced after passing through a PCC plant

3.1.45
utilities
ancillary services needed in the operation of a process, such as steam, electricity, cooling water (CW), demineralised water, compressed air, refrigeration and effluent disposal

3.1.46
vent gases
gases other than flue gases or treated flue gases that are intentionally emitted to the atmosphere

3.1.47
waste heat
heat generated by a process that would normally be dissipated to the environment if special measures for its utilization were not implemented

3.1.48
waste water
excess water allowed to run to waste from the water circuit

[SOURCE: ISO 1213-1:1993, definition 5.1.18]

3.1.49
wet-basis
condition in which a solid, such as a fuel or a gas, such as flue gas, contains moisture

3.2 Abbreviations

CCS	carbon dioxide capture and storage
CW	cooling water
DP	differential pressure
FGD	flue gas desulfurization
FSE	fuel specific emission
GTCC	gas turbine combined cycle
HP	high pressure
HRSG	heat recovery steam generator
IP	intermediate pressure

KPI	key performance indicator
LHV	lower heating value
LP	low pressure
MP	medium pressure
NO*x*	nitrogen oxides
PCC[a]	post-combustion CO_2 capture
PM	particulate matter
SAC	specific absorbent consumption
SCC	specific chemical consumption
SCWD	specific cooling water duty
SEC	specific electrical energy consumption
SEEC	specific equivalent electrical energy consumption
SO*x*	sulphur oxides, sulfur oxides
SRCE	specific reduction in CO_2 emissions
STEC	specific thermal energy consumption
[a] PCC is often used for pulverized coal combustion. In this document, it refers to post-combustion CO_2 capture.	

3.3 Symbols

The following mathematical symbols are preparatory for revising variables and formulae in Clause 5, Clause 6 and Clause 9 based on the ISO directives and relevant standards.

$c_{\text{p CW}}$	Specific heat of CW	[kJ/(kg K)]
ΔE	Fractional increase in plant energy input per unit of product	[-]
FSE	Fuel specific emission	[kg/kJ]
h_{steam}	Specific enthalpy of steam	[kJ/kg]
$h_{\text{condensate}}$	Specific enthalpy of condensate	[kJ/kg]
LHV_{fuel}	LHV of a fuel	[kJ/kg]
P_{CW}	Electrical power requirement of CW pump	[MW]
P_{LGP}	Change in gross power output due to the steam extraction from the host power plant steam cycle and/or auxiliary unit	[MW]
P_{PCC}	Electrical power requirement of the PCC plant	[MW]
$P_{\text{NET,ref}}$	Net power output of a reference power plant	[MW]
$P_{\text{NET,cap}}$	Net power output of a power plant with a PCC plant	[MW]
p_e	Absolute pressure of a gas stream	[kPa]
p_{CWin}	Pressure of CW at the supply side	[kPa]
p_{CWout}	Pressure of CW at the return side	[kPa]
$q_{m\text{CO}_2\text{\_comp\_a}}$	Mass flow rate of a product CO_2 stream after compression	[t/h]
$q_{m\text{CO}_2\text{\_comp\_b}}$	Mass flow rate of a product CO_2 stream before compression	[t/h]
$q_{m\text{CO}_2}$	Mass flow rate of a product CO_2 stream	[t/h]

$q_{m\mathrm{CO_2},\mathrm{ref}}$	Mass flow rate of CO_2 emission from a reference power plant	[t/h]
$q_{m\mathrm{CO_2}\mathrm{e,cap}}$	Mass flow rate of CO_2 emission from a power plant with a PCC plant	[t/h]
$q_{m\ \mathrm{stream}}$	Mass flow rate of steam to a PCC plant	[kg/h]
$q_{m\ \mathrm{condensate}}$	Mass flow rate of condensate from a PCC plant	[kg/h]
$q_{m\ \mathrm{absorbent}}$	Consumption rate of absorbent at a PCC plant	[kg/h]
$q_{m\ \mathrm{chemical}}$	Consumption rate of a chemical compound at a PCC plant	[kg/h]
q_V	Volume flow rate at a measurement or specific condition	[m^3/h]
q_{Vr}	Volume flow rate at the standard temperature (273,15 K) and pressure (100 kPa) conditions	[m^3/h]
$q_{Vr\mathrm{CO_2}\mathrm{in}}$	Volume flow rates of CO_2 at a PCC plant inlet on a dry basis at the standard temperature (273,15 K) and pressure (100 kPa) conditions	[m^3/h]
$q_{Vr\mathrm{CO_2}\mathrm{out}}$	Volume flow rates of CO_2 at a PCC plant outlet (treated flue gas emission side) on a dry basis at the standard temperature (273,15 K) and pressure (100 kPa) conditions	[m^3/h]
$q_{Vr\mathrm{flue\ gas\ in}}$	Volume flow rate of a flue gas to a PCC plant on a dry basis at the standard temperature (273,15 K) and pressure (100 kPa) conditions	[m^3/h]
$q_{Vr\mathrm{flue\ gas\ out}}$	Volume flow rate of a flue gas at a PCC plant outlet on a dry basis at the standard temperature (273,15 K) and pressure (100 kPa) conditions	[m^3/h]
$q_{Vr\mathrm{CO_2}\ \mathrm{comp\_a}}$	Volume flow rate of a product CO_2 stream after compression on a dry basis at the standard temperature (273,15 K) and pressure (100 kPa) conditions	[m^3/h]
$q_{Vr\mathrm{CO_2}\ \mathrm{comp\_b}}$	Volume flow rate of a product CO_2 stream before compression on a dry basis at the standard temperature (273,15 K) and pressure (100 kPa) conditions	[m^3/h]
SAC	Specific absorbent consumption	[kg/t]
SCC	Specific chemical consumption	[kg/t]
$SCWD$	Specific cooling water duty	[m^3/t]
SEC	Specific electrical energy consumption	[kWh/t]
$SEEC$	Specific equivalent electrical energy consumption	[kWh/t]
$SRCE$	Specific reduction in CO_2 emissions	[t/MWh]
$STEC$	Specific thermal energy consumption	[GJ/t]
T_{CWin}	Temperature of CW at the supply side	[K]
T_{CWout}	Temperature of CW at the return side	[K]
T_S	Average temperature of a gas stream	[K]
w_c	Percentage of carbon by mass in fuel on an as-fired basis	[%]
$\eta_{\mathrm{CO_2}}$	CO_2 capture efficiency	[%]
η_M	Efficiency of motor	[%]
η_P	Efficiency of CW pump	[%]

$\eta_{\text{gas to PCC}}$	Proportion of total flue gas flow to a PCC plant	[%]
η_{ref}	Net power output efficiency of a reference power plant	[%]
η_{PCC}	Net power output efficiency of a power plant with PCC	[%]
ρ_{CW}	Density of CW	[kg/m^3]
Φ_{CW}	Total cooling heat duty at a PCC plant	[kJ/h]
$\varphi_{\text{CO}_2\text{in\_cap}}$	Volume concentration of CO_2 in the flue gas to a PCC plant on a dry basis	[%]
$\varphi_{\text{CO}_2\text{out\_cap}}$	Volume concentration of CO_2 in the flue gas at a PCC plant outlet (treated flue gas emission side) on a dry basis	[%]
$\varphi_{\text{CO}_2\text{out\_comp\_a}}$	Volume concentration of CO_2 in the product CO_2 stream after compression on a dry basis	[%]
$\varphi_{\text{CO}_2\text{out\_comp\_b}}$	Volume concentration of CO_2 in the product CO_2 stream before compression on a dry basis	[%]
(Chemical symbols)		
CO_2	Gaseous product by reaction of oxygen in air (combustion) with carbon atom in fuel	

4 Defining the system boundary

4.1 PCC plant integrated with a host power plant

This document is designed to assess the performance of a PCC plant integrated with a carbonaceous fuel-fired thermal power plant, including combined heat and power generation. This document covers the use of all carbonaceous fuel.

A PCC plant integrated with a thermal power plant (also called a host power plant) is characterized as follows:

a) Receives flue gas from one or more host power plants. Flue gas may be pre-conditioned within the host power plant(s), within the PCC plant, or a combination of both;

b) Typically receives utilities and energy from the host power plant or any other auxiliary units, or delivers energy to the host power plant;

c) PCC plant load control is integrated with the host power plant as required by both sides.

Hereafter these applications are called “PCC plant integrated with a host power plant”.

4.2 Boundary of the PCC plant, host power plant and utilities

Figure 2 presents a typical boundary of a PCC plant integrated with a host power plant. Minor variations may result from the specific configuration of a host power plant or a PCC plant. Figure 2 represents a comprehensive configuration that includes a carbonaceous fuel-fired boiler or a natural gas combined cycle, which are prevailing types in this field, and includes multiple items that may not be applicable to all cases. The boundary of any PCC plant may include the following interfaces:

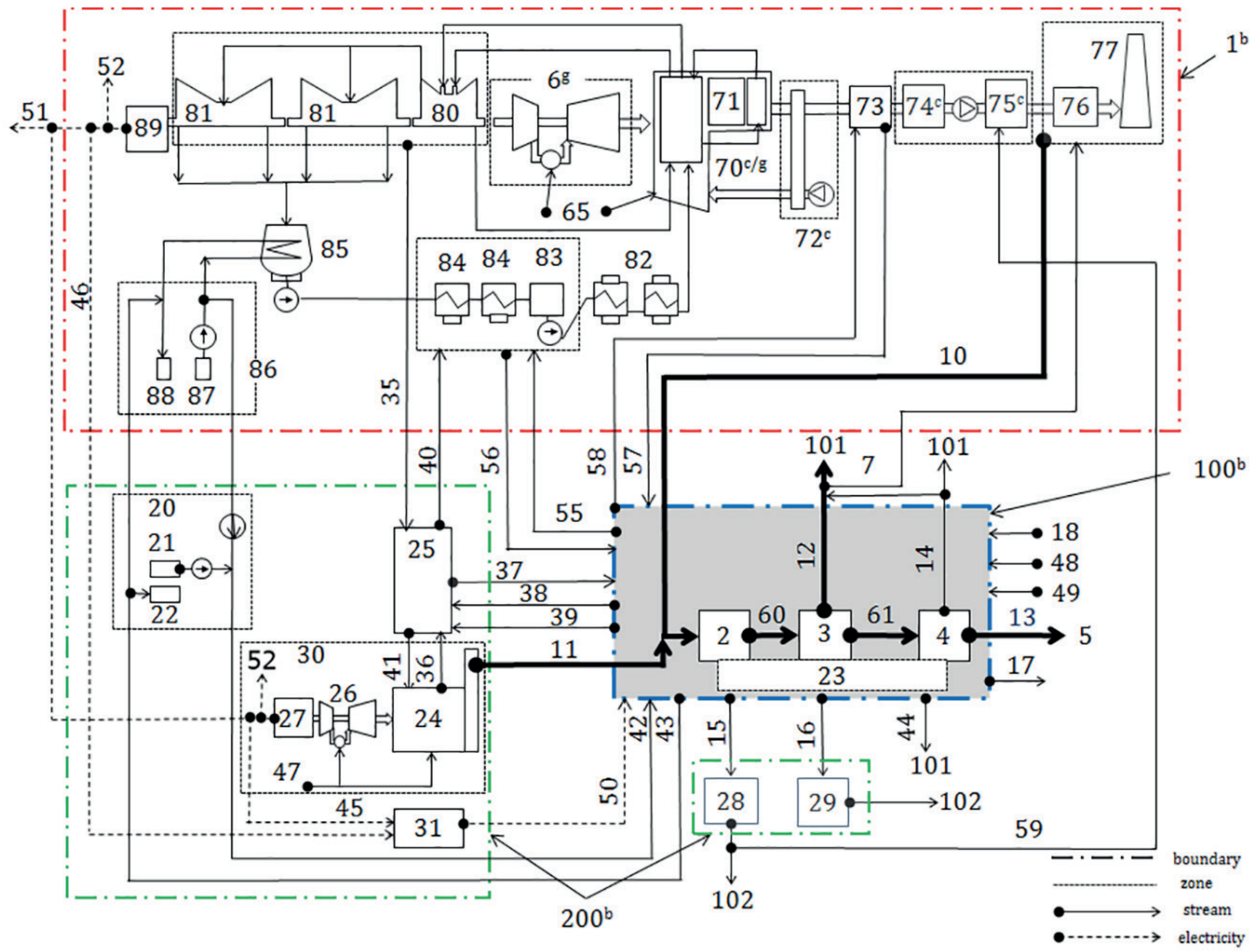
a) Interface with the host power plant: Important elements at this interface include flue gas (downstream of any existing environmental control systems), electricity and heat transfer media, if these are supplied by a host power plant.

b) Interface with auxiliary units: It includes the auxiliary boiler or auxiliary gas turbine with HRSG that supplies heat transfer media and electrical power to the PCC plant, instead of, or in combination with, a host power plant in case the modification of, or any operational impact on, a host power plant is quite restricted. Only the utility consumption affecting the performance evaluation of the PCC plant should be included in the consumption calculations (see Clause 6).

c) Interface with the environment: The outlet of the PCC plant discharges directly to the atmosphere and waste streams such as waste water, solid waste, and consumables (e.g., filters) should also be included in calculating consumption and utility requirements if present (see Clause 6).

d) Interface with CO_2 transportation infrastructure: It is the first flange at the outlet piping from the CO_2 stream compressor or CO_2 stream pump, if applied.

The performance evaluation boundary of a PCC plant integrated with a host power plant is depicted as a thick dashed line – labelled 100 – in Figure 2. Given the complexity of the system, explanations of the various streams and equipment are provided in Table 1 to Table 5.



Key

1 host power plant boundary – this block flow configuration is typical for a coal fired boiler and a GTCC plant

2 pre-treatment (quencher, deep-FGD, flue gas fan) – conditioning of the flue gas in preparation for separation of CO_2. This can include removal of contaminants that could damage the absorbent, temperature control to optimize absorber efficiency, etc.

3 CO_2 capture section

4 CO_2 compression/liquefaction section (including CO_2 purification)

5 CO_2 transportation system

6 gas turbine in a GTCC - the item designated as a boiler (70) would be a HRSG and the air preheater and forced draft fan (72), particulate removal system (74), and FGD (75) would be removed

7 ducting to a stack if required (this stream, if it exists, might contain residual CO_2)

10 flue gas from host power plant

11 flue gas from auxiliary unit (auxiliary steam and power generation system, #30)

45 electricity from an auxiliary power generation system

46 electricity from the host power plant to the PCC plant

47 fuel to the auxiliary steam and power generation system

48 chemicals

49 demineralized water, industrial water

50 electricity diverted to power equipment and systems associated with the PCC plant, including fans, pumps, and the compression system

51 net power export

52 electricity diverted from the host power plant or the auxiliary power generation system to power other equipment within the same plant or system

55 medium transferring waste heat from the PCC plant to the host power plant – (e.g. boiler feed water for pre-heating)

12 treated flue gas (mostly nitrogen, but might contain residual CO_2) to be vented or sent to a stack

13 product CO_2 stream, sent for transport

14 CO_2 vent stream to the atmosphere required for start-up, shut-down, emergency and during significant operational disturbances

15 waste water sent for treatment

16 waste sent to a waste handling system

17 by-product

18 fresh absorbent

20 CW generation system – the cooling system can include cooling towers, a once-through CW system, or air fin coolers

21 CW intake - A CW intake can be common to the host power plant or the PCC plant

22 CW outfall - A CW outfall can be common to the host power plant or the PCC plant

23 air fin cooler integrated into PCC plant

24 auxiliary steam generation system - e.g. HRSG on auxiliary gas turbine or auxiliary boiler

25 steam distribution system

26 auxiliary gas turbine

27 auxiliary generator

28 waste water treatment system

29 waste handling system

30 auxiliary steam and power generation system

31 power distribution system – controls the amount of power diverted to the PCC plant to operate fans, pumps, blowers, and the compression system

35 steam from a host power plant – although labelled as steam here, this can also be a different thermal energy transfer medium (e.g. hot oil)

36 steam from an auxiliary steam generation system – although labelled as steam here, this can also be a different thermal energy transfer medium (e.g. hot oil)

56 host power plant waste heat used in the PCC plant or return of PCC plant waste heat used in the host power plant – this stream can represent host power plant waste heat that is used in the absorbent regeneration process in the PCC plant or the return of waste heat that was generated in the PCC plant and used in the host power plant (e.g. boiler feed water preheating)

57 medium transferring waste heat from the host power plant to the PCC plant. A common source of waste heat in a host power plant is the heat contained in the flue gas. This stream integrates the heat supplied to the PCC plant by stream 37

58 power plant waste heat return from PCC plant – this stream represents the return of waste heat from stream 57 to the host power plant

59 use of PCC plant effluent in FGD – waste water from the PCC plant can potentially be used as make-up water in the FGD system

60 flue gas after pre-treatment – this stream is the flue gas stream after contaminants have been removed and temperature adjustments have been made in preparation for entering the absorber (from item 2 to 3)

61 product CO_2 stream leaving the CO_2-capture section prior to entry into the compression system (from item 3 to 4)

65 fuel to host power plant

70 boiler – or HRSG in GTCC case

71 NO_x removal system

72 air preheater and forced draft fan (not applicable in GTCC case)

73 flue gas heat recovery system

74 particulate removal system (not applicable in GTCC case)

75 FGD (not applicable in GTCC case)

76 flue gas heater, if necessary

77 stack and treated flue gas duct

80 high pressure (HP) – intermediate pressure (IP) turbine

81 low pressure (LP) turbine

82 HP heaters

83 deaerators

84 LP heaters

85 steam condenser

37	steam supplied from the host power plant to PCC plant to drive absorbent regeneration and other processes -– although labelled as steam here, this can also be a different thermal energy transfer medium (e.g. hot oil)	86	power plant CW supply system
38	exhaust steam from the PCC to the host power plant – if steam is the heat transfer medium used in the PCC, any exhaust steam can be returned to the host power plant	87	power plant CW intake
39	steam condensate from the PCC to the host power plant – if steam is used and condensed in the PCC, this stream returns the condensate to the host power plant	88	power plant CW outfall
40	steam condensate return to the host power plant	89	power plant generator
41	steam condensate return to the auxiliary steam generation system	100	Line representing the PCC plant boundary
42	CW feed – if the CW system for the host power plant and/or auxiliary unit is used to supply CW to the PCC plant, it is accounted for in this stream	101	atmosphere
43	CW return – CW returned from the PCC to the host power plant and/or to the auxiliary unit	102	landfill and/or hydrosphere
44	rejected heat from the process cooler integrated into the PCC plant (# 23)	200	auxiliary unit boundary

NOTE All different streams and equipment for this figure are summarized in ascending order in Annex A. Only three superscripts are used. These superscripts indicate either different options related to the type of power system (c for coal, g for a gas) or to demark a system boundary.

[b] Boundary.

[c] Only in the case of coal fired boiler.

[g] Only in the case of GTCC.

Figure 2 — PCC plant boundary

Several of the items numbered in Figure 2 have a direct bearing on the KPIs defined in Clause 1. Items related to specific reduction in CO_2 emissions are included in Table 1. These include flue gas streams entering the PCC plant from the host power plant and any auxiliary units as well as streams leaving the PCC plant following CO_2 separation. Note the flue gas streams entering the PCC plant do not necessarily represent all of the CO_2-containing flue gas generated by the host power plant or auxiliary units. The PCC plant may be designed for partial capture, with a certain percentage of the flue gas routed to the PCC plant for treatment while the remaining flue gas and its associated CO_2 simply vented to the atmosphere. This possibility is discussed further in Clause 5.

It should also be noted that the KPIs related to the equivalent electrical energy consumption, i.e. SEEC and SRCE, can be applied to a case with an auxiliary unit defined in 4.2 b). The auxiliary unit can be included with a host power plant when calculating the KPI as explained in 9.4 and 9.5, if the electricity generated in the auxiliary unit is used to power equipment in the PCC plant and their application is agreed among the related parties due to its specification depending on each project. In this case the interpretation of the above KPI is influenced by both the fuel specific emissions [kg/kJ] explained in D.2 and the heat rate of the auxiliary unit. If these are different from a host power plant, then the main parameters used for each calculation should be listed with the KPI for mutual understanding among the related parties.

Table 1 — Description of streams and equipment shown in Figure 2 related to the SRCE

Stream/ Equipment Number	Description
7	Ducting to a stack if required (this stream, if it exists might contain residual CO_2)
10	Flue gas from host power plant
11	Flue gas from auxiliary unit (auxiliary steam and power generation system, #30)
12	Treated flue gas (mostly nitrogen, but might contain residual CO_2) to be vented or sent to a stack
13	Product CO_2 stream, sent for transport

Items related to the KPI for STEC are noted in Table 2. Steam and/or waste heat can be transferred from the host power plant or auxiliary unit to help drive processes in the PCC plant. In addition, waste heat generated in the PCC plant can sometimes be used in the host power plant or the auxiliary unit, as noted in Table 2.

Table 2 — Description of streams and equipment shown in Figure 2 related to the STEC

Stream/ Equipment Number	Description
35	Steam from a host power plant – although labelled as steam here, this can also be a different thermal energy transfer medium (e.g. hot oil)
36	Steam from an auxiliary steam generation system – although labelled as steam here, this can also be a different thermal energy transfer medium (e.g. hot oil)
37	Steam supplied from the host power plant to PCC plant to drive absorbent regeneration and other processes – although labelled as steam here, this can also be a different thermal energy transfer medium (e.g. hot oil)
38	Exhaust steam from the PCC plant to the host power plant – if steam is the heat transfer medium used in the PCC plant, any exhaust steam can be returned to the host power plant
39	Steam condensate from the PCC plant to the host power plant – if steam is used and condensed in the PCC plant, this stream returns the condensate to the host power plant
40	Steam condensate return to the host power plant
41	Steam condensate return to the auxiliary steam generation system
42	CW feed – if the CW system for the host power plant and/or auxiliary unit is used to supply CW to the PCC plant, it is accounted for in this stream
43	CW return – CW returned from the PCC plant to the host power plant and/or to the auxiliary unit
44	Rejected heat from the process cooler integrated into the PCC plant (# 23)
55	Medium transferring waste heat from the PCC plant to the host power plant – (e.g. boiler feed water for pre-heating)
56	Host power plant waste heat used in the PCC plant or return of PCC plant waste heat used in the host power plant – this stream can represent host power plant waste heat that is used in the absorbent regeneration process in the PCC plant or the return of waste heat that was generated in the PCC plant and used in the host power plant (e.g. boiler feed water preheating)
57	Medium transferring waste heat from the host power plant to the PCC plant. A common source of waste heat in a host power plant is the heat contained in the flue gas. This stream integrates the heat supplied to the PCC plant by stream 37
58	Power plant waste heat return from PCC plant– this stream represents the return of waste heat from stream 57 to the host power plant

Items related to the KPIs for SEC and SEEC are noted in Table 3. Electricity generated in the host power plant or auxiliary unit can be used to power equipment (including compression) in the PCC plant.

Electrical energy used for these purposes contributes to the SEEC. In addition, steam used by the PCC plant to drive CO_2 separation processes (noted in Table 2) that could have been used to generate electricity in the absence of CO_2 capture also contributes to the SEC and the SEEC.

Table 3 — Description of streams and equipment shown in Figure 2 related to the SEC and the SEEC

Stream/ Equipment Number	Description
31	Power distribution system – controls the amount of power diverted to the PCC plant to operate fans, pumps, blowers, and the compression system
45	Electricity from an auxiliary power generation system
46	Electricity from the host power plant to the PCC plant
50	Electricity diverted to power equipment and systems associated with the PCC plant, including fans, pumps, and the compression system
51	Net power export
52	Electricity diverted from the host power plant or the auxiliary power generation system to power other equipment within the same plant or system

Items related to the KPI for specific absorbent and chemical or auxiliary materials consumption or decrease in functional activity are noted in Table 4.

Table 4 — Description of streams and equipment shown in Figure 2 related to the SAC and the SCC

Stream/ Equipment Number	Description
15	Waste water sent for treatment
16	Waste sent to a waste handling system
17	By-product
18	Fresh absorbent
48	Chemicals or auxiliary materials
49	Demineralized water, industrial water

Finally, items that are included in Figure 2 but do not have direct impacts on calculation of KPIs are listed in Table 5. The inclusion of these items in Figure 2 provides framing for a better understanding of processes and equipment that do impact KPIs.

Table 5 — Description of streams and equipment shown in Figure 2

Stream/ Equipment Number	Description
PCC plant	
2	Pre-treatment (quencher, deep-FGD, flue gas fan) – conditioning of the flue gas in preparation for separation of CO_2. This can include removal of contaminants that could damage the absorbent or temperature control to optimize absorber efficiency, etc.
3	CO_2 capture section
4	CO_2 stream compression/liquefaction section (including CO_2 stream purification)

[b] Boundary.

[c] Only in the case of coal fired boiler.

[g] Only in the case of GTCC.

Table 5 *(continued)*

Stream/ Equipment Number	Description
14	CO_2 vent stream to the atmosphere required for start-up, shut-down, emergency and during significant operational disturbances
23	Air fin cooler integrated into PCC plant
60	Flue gas after pre-treatment – this stream is the flue gas stream after contaminants have been removed and temperature adjustments have been made in preparation for entering the absorber (from item 2 to 3)
61	The product CO_2 stream leaving the CO_2-capture section prior to entry into the compression system (from item 3 to 4)
100[b]	PCC plant boundary
Host power plant	
1[b]	Host power plant boundary – this block flow configuration is typical for a coal fired boiler and a GTCC plant
6[g]	Gas turbine in a GTCC - the item designated as a boiler (70) would be a HRSG and the air preheater and forced draft fan (72), particulate removal system (74), and FGD (75) would be removed
65	Fuel to host power plant
70[c/g]	Boiler – or HRSG in GTCC case
71	NOx removal system
72[c]	Air preheater and forced draft fan (not applicable in GTCC case)
73	Flue gas heat recovery system
74[c]	Particulate removal system (not applicable in GTCC case)
75[c]	FGD (not applicable in GTCC case)
76	Flue gas heater, if necessary
77	Stack and treated flue gas duct
80	High pressure (HP) – intermediate pressure (IP) turbine
81	Low pressure (LP) turbine
82	HP heaters
83	Deaerators
84	LP heaters
85	Steam condenser
86	Power plant CW supply system
87	Power plant CW intake
88	Power plant CW outfall
89	Power plant generator
Auxiliary unit (where installed)	
20	CW generation system – the cooling system can include cooling towers, a once-through CW system, or air fin coolers
21	CW intake - A CW intake can be common to the host power plant or the PCC plant
22	CW outfall - A CW outfall can be common to the host power plant or the PCC plant
24	Auxiliary steam generation system – e.g. HRSG on auxiliary gas turbine or auxiliary boiler
25	Steam distribution system
26	Auxiliary gas turbine

[b] Boundary.

[c] Only in the case of coal fired boiler.

[g] Only in the case of GTCC.

Table 5 *(continued)*

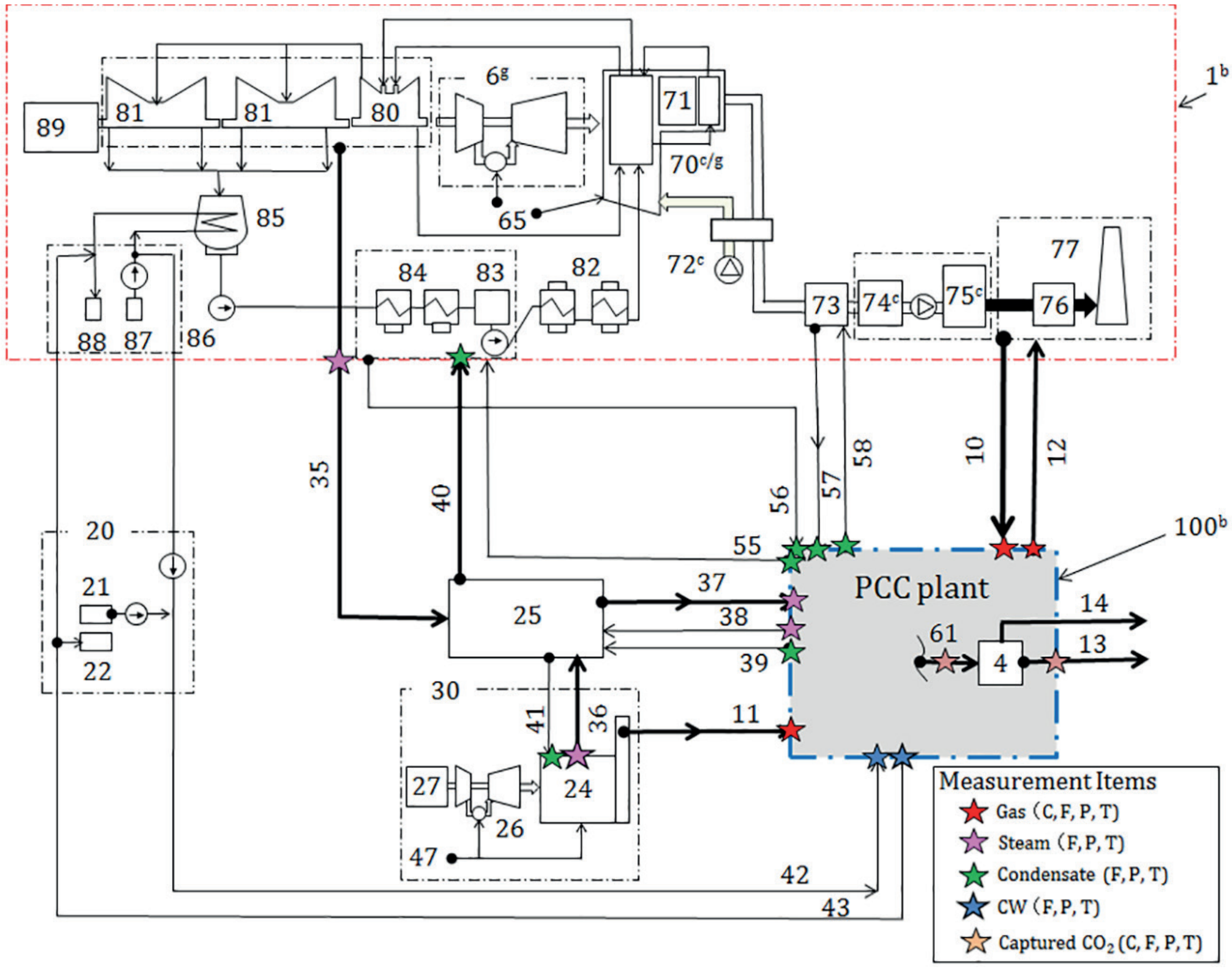
Stream/ Equipment Number	Description
27	Auxiliary generator
28	Waste water treatment system
29	Waste handling system
30	Auxiliary steam and power generation system
47	Fuel to the auxiliary steam and power generation system
59	Use of PCC plant effluent in FGD – waste water from the PCC plant can potentially be used as make-up water in the FGD system
200[b]	Auxiliary unit boundary
Out of boundary	
5	CO_2 transportation
101	Atmosphere
102	Landfill and/or hydrosphere

[b] Boundary.

[c] Only in the case of coal fired boiler.

[g] Only in the case of GTCC.

Evaluation of the KPIs related to energy use and CO_2 emissions is dependent on measurements at several points within the system. These points and their associated streams are illustrated in Figure 3. The stream/equipment numbers used are the same as those used in Figure 2. As indicated, these measurements include concentrations, flow rates, pressures and temperatures for flue gases entering and leaving the PCC and for the product CO_2 stream (#13) sent for transport. In addition, flow, pressure and temperature measurements for steam, condensate, and CW streams entering and leaving the PCC are used in evaluation of the KPIs.



Key

1 host power plant boundary – this block flow configuration is typical for a coal fired boiler and a GTCC plant

4 CO_2 stream compression/liquefaction section (including CO_2 stream purification)

6 gas turbine in a GTCC - the item designated as a boiler (70) would be a HRSG and the air preheater and forced draft fan (72), particulate removal system (74), and FGD (75) would be removed

10 flue gas from host power plant

11 flue gas from auxiliary unit (auxiliary steam and power generation system, #30)

12 treated flue gas (mostly nitrogen, but might contain residual CO_2) to be vented or sent to a stack

13 product CO_2 stream, sent for transport

55 medium transferring waste heat from the PCC plant to the host power plant – (e.g. boiler feed water for pre-heating)

56 host power plant waste heat used in the PCC plant or return of PCC plant waste heat used in the host power plant – this stream can represent host power plant waste heat that is used in the absorbent regeneration process in the PCC plant or the return of waste heat that was generated in the PCC plant and used in the host power plant (e.g. boiler feed water preheating)

57 medium transferring waste heat from the host power plant to the PCC plant. A common source of waste heat in a host power plant is the heat contained in the flue gas. This stream integrates the heat supplied to the PCC plant by stream 37

58 power plant waste heat return from PCC plant – this stream represents the return of waste heat from stream 57 to the host power plant

61 product CO_2 stream leaving the CO_2-capture section prior to entry into the compression system (from item 3 to 4)

65 fuel to host power plant

70 boiler – or HRSG in GTCC case

20 CW generation system – the cooling system can include cooling towers, a once-through CW system, or air fin coolers

21 CW intake - A CW intake can be common to the host power plant or the PCC plant

22 CW outfall - A CW outfall can be common to the host power plant or the PCC plant

23 air fin cooler integrated into PCC plant

24 auxiliary steam generation system - e.g. HRSG on auxiliary gas turbine or auxiliary boiler

25 steam distribution system

26 auxiliary gas turbine

27 auxiliary generator

30 auxiliary steam and power generation system

35 steam from a host power plant – although labelled as steam here, this can also be a different thermal energy transfer medium (e.g. hot oil)

36 steam from an auxiliary steam generation system – although labelled as steam here, this can also be a different thermal energy transfer medium (e.g. hot oil)

37 steam supplied from the host power plant to PCC plant to drive absorbent regeneration and other processes -– although labelled as steam here, this can also be a different thermal energy transfer medium (e.g. hot oil)

38 exhaust steam from the PCC to the host power plant – if steam is the heat transfer medium used in the PCC, any exhaust steam can be returned to the host power plant

39 steam condensate from the PCC to the host power plant – if steam is used and condensed in the PCC, this stream returns the condensate to the host power plant

40 steam condensate return to the host power plant

41 steam condensate return to the auxiliary steam generation system

42 CW feed – if the CW system for the host power plant and/or auxiliary unit is used to supply CW to the PCC plant, it is accounted for in this stream

43 CW return – CW returned from the PCC to the host power plant and/or to the auxiliary unit

47 fuel to the auxiliary steam and power generation system

71 NO_x removal system

72 air preheater and forced draft fan (not applicable in GTCC case)

73 flue gas heat recovery system

74 particulate removal system (not applicable in GTCC case)

75 FGD (not applicable in GTCC case)

76 flue gas heater, if necessary

77 stack and treated flue gas duct

80 high pressure (HP) – intermediate pressure (IP) turbine

81 low pressure (LP) turbine

82 HP heaters

83 deaerators

84 LP heaters

85 steam condenser

86 power plant CW supply system

87 power plant CW intake

88 power plant CW outfall

89 power plant generator

100 Line representing the PCC plant boundary

NOTE All different streams and equipment for this figure are summarized in ascending order in Annex A.

b Boundary.

c Only in the case of coal fired boiler.

g Only in the case of GTCC.

Measurement items:

C concentration

F flow

P pressure

T temperature

Figure 3 — Measurement streams/locations used to evaluate KPIs

The utility consumption evaluation boundaries within the PCC plant boundary for the thermal energy, CW and the electrical consumption are indicated in Figure 4 to Figure 6 respectively, consistent with Figure 2. All flows included in the definitions in Clause 5 cross the PCC plant boundary (line 100 in Table 5). Clause 6 includes some flows that do not cross the PCC plant boundary. Some of these flows are important when evaluating performance of the host power plant and the PCC plant.

5 Definition of basic PCC plant performance

5.1 General

This clause defines the parameters that describe the basic performance of the PCC plant and integrated system.

5.2 Input and output streams

To calculate the CO_2 capture efficiency, the flow rate, temperature, pressure and composition of the following input streams shall be accounted for:

a) flue gas from host power plant [stream #10];

b) flue gas from auxiliary steam and power generation system [stream #11].

Similarly, the following output streams shall be accounted for:

a) treated gas from PCC plant [stream #12];

b) untreated exit gas from power plant, auxiliary boiler and/or auxiliary gas turbine not routed through the PCC;

c) product CO_2 [stream #13];

d) vent gases and other losses [stream #14].

5.3 Capture efficiency of the absorber

The calculation method described in this clause is only valid for flows across the boundary of a PCC plant as described in Figure 2. CO_2 capture efficiency (η_{CO_2}) is defined as follows:

$$\eta_{CO_2} = \frac{q_{Vr\mathrm{CO_2in}} - q_{Vr\mathrm{CO_2out}}}{q_{Vr\mathrm{CO_2in}}} \times 100 \tag{1}$$

where

$q_{Vr\mathrm{CO_2in}}$ is the volume flow rates of CO_2 at the PCC plant inlet on a dry basis at the standard temperature (273,15 K) and pressure (100 kPa) conditions [m^3/h];

$q_{Vr\mathrm{CO_2out}}$ is the volume flow rates of CO_2 at the PCC plant outlet (treated flue gas emission side) on a dry basis at the standard temperature (273,15 K) and pressure (100 kPa) conditions [m^3/h].

$$q_{Vr\mathrm{CO_2in}} = q_{Vr\text{flue gas in}} \times \frac{\varphi_{\mathrm{CO_2in\_cap}}}{100} \tag{2}$$

The outlet flow rates may vary due to both capture of CO_2 and due to changes in the inlet flow rate. If the inlet rate is not measured at the same time, that variation might not be apparent. To avoid errors that might arise from using two different, independent measurements of the inlet flow rate and of the outlet flow rate, this procedure uses inlet flow values, and inlet and outlet CO_2 volumetric concentrations to make the actual calculation as given in Formula (3).

$$q_{Vr\mathrm{CO_2out}} = q_{Vr\text{flue gas in}} \times \frac{1-\dfrac{\varphi_{\mathrm{CO_2in\_cap}}}{100}}{1-\dfrac{\varphi_{\mathrm{CO_2out\_cap}}}{100}} - q_{Vr\text{flue gas in}} \times \left(1-\frac{\varphi_{\mathrm{CO_2in\_cap}}}{100}\right) \tag{3}$$

where

$q_{Vr\text{flue gas in}}$	is the volume flow rate of a flue gas to the PCC plant on a dry basis at the standard temperature (273,15 K) and pressure (100 kPa) conditions [m^3/h];
$\varphi_{\mathrm{CO_2in\_cap}}$	is the volume concentration of CO_2 in the flue gas to the PCC plant on a dry basis [%];
$\varphi_{\mathrm{CO_2out\_cap}}$	is the volume concentration of CO_2 in the flue gas at the PCC plant outlet (treated flue gas emission side) on a dry basis [%] It is assumed that there is no ingress of air;

The CO_2 concentration is normally measured as a volumetric concentration on the dry basis.

5.4 Flow rate of the product CO_2 stream from a PCC plant

The flow rate of the product CO_2 stream from a PCC plant [t/h] is measured by the flow meter installed in the product CO_2 stream line (either before or after CO_2 stream compression), corrected by the operating condition.

$$q_{m\mathrm{CO_2\_comp\_b}} = q_{Vr\mathrm{CO_2comp\_b}} \times \frac{\varphi_{\mathrm{CO_2out\_comp\_b}}}{100} \times \frac{44{,}0}{22{,}7\times 1\,000} \tag{4}$$

where

$q_{Vr\mathrm{CO_2\ comp\_b}}$	is the volume flow rate of a product CO_2 stream before compression on a dry basis at the standard temperature (273,15 K) and pressure (100 kPa) conditions [m^3/h];
$q_{m\mathrm{CO_2\_comp\_b}}$	is the mass flow rate of a product CO_2 stream before compression [t/h];
$\varphi_{\mathrm{CO_2out\_comp\_b}}$	is the volume concentration of CO_2 in the product CO_2 stream before compression on a dry basis [%].

$$q_{m\mathrm{CO_2\_comp\_a}} = q_{Vr\mathrm{CO_2comp\_a}} \times \frac{\varphi_{\mathrm{CO_2out\_comp\_a}}}{100} \times \frac{44{,}0}{22{,}7\times 1\,000} \tag{5}$$

where

$q_{Vr\mathrm{CO_2comp\_a}}$ is the volume flow rate of a product CO_2 stream after compression on a dry basis at the standard temperature (273,15 K) and pressure (100 kPa) conditions [m^3/h];

$q_{m\mathrm{CO_2\_comp\_a}}$ is the mass flow rate of a product CO_2 stream after compression [t/h];

$\varphi_{\mathrm{CO_2out\_comp\_a}}$ is the volume concentration of CO_2 in the product CO_2 stream after compression on a dry basis [%].

5.5 Properties of product CO_2 stream at CO_2 compression system outlet

5.5.1 General

The point at the inlet valve of the pipeline defines the system boundary between capture and transportation. The composition, temperature, and pressure of the CO_2 stream at this point shall be within a range that meets the requirements for transportation. Further details are provided in ISO 27913.

5.5.2 Compositions of product CO_2 stream

5.5.2.1 Measurement of product CO_2 stream

Product CO_2 stream is defined as the captured and compressed/liquefied CO_2 stream at the interface with the CO_2 transportation. CO_2 purity is defined as the CO_2 concentration of the product CO_2 indicated on a wet basis and should be measured by the recommended measurement methods(s) specified in Clause 8.

5.5.2.2 Impurities in product CO_2 stream

Impurities in the product CO_2 stream (in particular, H_2O and O_2) should be defined with regards to transport and storage/usage requirements. Further information on the specification of the product CO_2 stream can be found in ISO 27913:2016, Annex A. In addition, CO_2 emissions from these units need to be accounted for when determining the overall CO_2 balance of the PCC plant with inclusion of minor inlet flows, if any. If the required limits on moisture (H_2O) and oxygen (O_2) concentrations are too stringent to be met by the PCC plant as depicted in Figure 2, it may be necessary to install a dehydrator (moisture removal system) and/or an oxygen removal system. These additional units may require additional utilities. The energy consumed by these units should be included in calculations for the energy consumption attributable to CO_2 capture and compression.

5.5.2.3 Measurement of impurities

Concentrations of impurities should be made using methods or instruments as suggested in Clause 8 or by a documented equivalent means. Should a dehydrator or oxygen removal unit be installed in the product CO_2 stream line, concentration of impurities in product CO_2 stream should be measured after these units.

5.5.2.4 Determination of composition of the product CO_2 stream

The concentration of CO_2 stream in the product CO_2 stream can be calculated as the difference between the measured concentrations of all impurities and 100 % if it is difficult to measure a CO_2 concentration very close to 100 % (e.g., greater than 99 %).

5.5.3 CO_2 stream compressor system outlet pressure

The outlet pressure of the CO_2 stream compressor should be confirmed before being used in evaluation of the electrical energy consumption of the CO_2 stream compressor. The measuring point should be as close as possible to the interface point of the transportation so that the pressure loss to the battery limit should be negligible.

5.5.4 Others

It is important to have quality control measures in place that apply to all property values that are measured for use in calculations in this clause. CO_2 stream metering may be required as a means of demonstrating compliance with third party requirements applicable to both transportation and sequestration.

6 Definition of utilities and consumption calculation

6.1 General

This clause specifies how to evaluate the utility consumption of a PCC plant. The characteristics of the utility system are defined, including heat transfer media; various sources of process water; chemicals, including absorbent; and electrical energy. The concentration of specified impurities in the flue gas differs in each project, which can affect the utilities consumption.

In case an additional CO_2 emitting source is required to provide additional heat or electrical energy, such as auxiliary boiler and/or auxiliary gas turbine, the required energy and utilities for these facilities shall not be included. However, they shall be reported so that they can be evaluated as a whole in Clause 9.

Pieces of equipment with intermittent or batch operation, such as the reclaimer, are evaluated on the average value during an appropriate length of time that takes the average quantity of CO_2 removed during the same period.

The incremental utility consumption related to flue gas pre-treatment for PCC plant should be included in the estimation of overall energy consumption. This includes additional DeNO*x*, FGD and PM-abatement as required in the PCC plant.

6.2 Low-pressure – medium-pressure steam

6.2.1 Definition of utility

The definition of utilities includes the following:

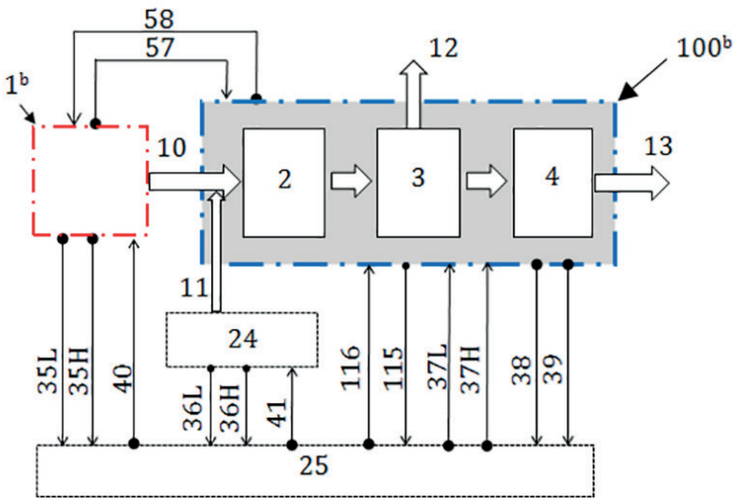
a) The required steam or thermal energy for the PCC plant is extracted from the steam cycle of the host power plant or from a separate utility plant such as the auxiliary boiler or the HRSG on the auxiliary gas turbine.

b) The thermal energy in the condensate from the PCC plant, which returns in the condensate system of the host power plant or the separate utility plant is accounted for.

c) For rotating machinery, such as pumps, blowers, compressors, or steam turbines, MP or HP steam can be used instead of the electrical motors as the driver. Their utility consumption is accounted for. When the steam turbine driver is selected, the outlet steam can be used again for PCC plant and this case is included for evaluation.

d) For the CO_2 desorption process, it is possible to use other thermal heat sources such as hot water or hot oil, and this is accounted for.

The steam consumption calculation boundary is the crossing points of feed and return lines of the thermal energy including the steam and its condensate with the PCC plant boundary within which the thermal energy is consumed and indicated in Figure 4 with the outside support system to supply and receive and with the reference of each key listed in the table below.



Key

- 1 host power plant boundary – this block flow configuration is typical for a coal fired boiler and a GTCC plant
- 2 pretreatment (quencher, deep-FGD, flue gas fan) – conditioning of the flue gas in preparation for separation of CO_2. This can include removal of contaminants that could damage the absorbent or temperature control to optimize absorber efficiency, etc.
- 3 CO_2 capture section
- 4 CO_2 stream compression/liquefaction section (including CO_2 stream purification)
- 10 flue gas from host power plant
- 11 flue gas from auxiliary unit (auxiliary steam and power generation system, #30)
- 12 treated flue gas (mostly nitrogen, but might contain residual CO_2) to be vented or sent to a stack
- 13 product CO_2 stream, sent for transport
- 24 auxiliary steam generation system - e.g. HRSG on auxiliary gas turbine or auxiliary boiler
- 25 steam distribution system
- 35L LP steam from a host power plant – although labelled as steam here, this can also be a different thermal energy transfer medium (e.g. hot oil)
- 36H MP or HP steam from an auxiliary steam generation system – although labelled as steam here, this can also be a different thermal energy transfer medium (e.g. hot oil)
- 37L LP steam supplied from the host power plant to PCC to drive absorbent regeneration and other processes - although labelled as steam here, this can also be a different thermal energy transfer medium (e.g. hot oil)
- 37H MP or HP steam supplied from the host power plant to PCC to drive absorbent regeneration and other processes - although labelled as steam here, this can also be a different thermal energy transfer medium (e.g. hot oil)
- 38 exhaust steam from the PCC to the host power plant – if steam is the heat transfer medium used in the PCC, any exhaust steam can be returned to the host power plant
- 39 steam condensate from the PCC to the host power plant – if steam is used and condensed in the PCC, this stream returns the condensate to the host power plant
- 40 steam condensate return to the host power plant
- 41 steam condensate return the auxiliary steam generation system
- 57 medium transferring waste heat from the host power plant to the PCC plant. A common source of waste heat in a host power plant is the heat contained in the flue gas. This stream integrates the heat supplied to the PCC plant by stream 37
- 58 power plant waste heat return from PCC plant – this stream represents the return of waste heat from stream 57 to the host power plant
- 100 PCC plant boundary
- 115 utilization of waste heat of steam distribution system by PCC (Return)

35H MP or HP steam from a host power plant – although labelled as steam here, this can also be a different thermal energy transfer medium (e.g. hot oil)

36L LP steam from an auxiliary steam generation system – although labelled as steam here, this can also be a different thermal energy transfer medium (e.g. hot oil)

116 utilization of waste heat of steam distribution system by PCC (Feed)

b Boundary.

Figure 4 — PCC plant LP (-MP) Steam consumption calculation boundary

6.2.2 Consumption calculation

The consumption calculation of utilities requires the following:

a) For each tie-in point, flow rate, pressure and temperature should be measured and reported and the enthalpy of each flow should be calculated.

b) The tie-in points should be close to the PCC plant so that the pressure loss and the heat loss during the transportation from its source, which may cause decrease of heat transfer due to the temperature drop caused or increase of the thermal energy consumption respectively, be considered negligible.

c) In case of intermittent use, the average flow rate during an appropriate length of time should be applied, unless there are technical reasons for using instantaneous values.

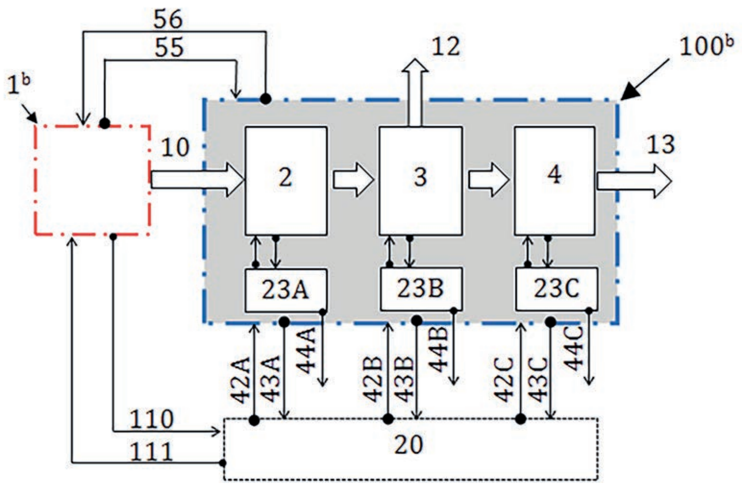
d) If other heating media, such as hot water and hot oil, are utilized in combination or alternately, the same items of these utilities shown in the above should be measured and reported.

6.3 Cooling water

6.3.1 Definition of CW

CW is used at several points. The volume and temperature of CW can be affected by the design parameters and the PCC performance.

When once-through seawater or fresh water for cooling is insufficient, a natural or mechanical draft cooling tower can be used. If it is difficult to secure CW, then air-cooling is an alternative. In case chilled water is needed to supplement CW to achieve the desired absorption temperatures, it is included inside the PCC plant consumption evaluation boundary. A rejected heat duty can be converted to an electrical energy consumption equivalent of a one pass water cooling system as evaluated in 6.4.1. The CW consumption calculation boundary is the crossing points of the CW feed and return lines including the rejected heat dissipated to the atmosphere, if any, with the PCC plant boundary within which the rejected heat is generated and indicated in Figure 5 with its feed source and return sink and with the reference of each key listed in the table below.



Key

1 host power plant boundary – this block flow configuration is typical for a coal fired boiler and a GTCC plant

2 pretreatment (quencher, deep-FGD, flue gas fan) – conditioning of the flue gas in preparation for separation of CO_2. This can include removal of contaminants that could damage the absorbent, temperature control to optimize absorber efficiency, etc.

3 CO_2 capture section

4 CO_2 stream compression/liquefaction section (including CO_2 stream purification)

10 flue gas from host power plant

12 treated flue gas (mostly nitrogen, but might contain residual CO_2) to be vented or sent to a stack

13 product CO_2 stream, sent for transport

20 CW generation system – the cooling system can include cooling towers, a once-through CW system, or air fin coolers

23A air fin cooler integrated into pre-treatment

23B air fin cooler integrated into CO_2 capture

23C air fin cooler integrated into CO_2 stream compression

42A CW feed to pre-treatment

42B CW feed to CO_2 capture

42C CW feed to CO_2 stream compression

43A CW return from pre-treatment to the CW generation system

43B CW return from CO_2 capture to the CW generation system

43C CW return from CO_2 stream compression to the CW generation system

44A rejected heat from the process cooler integrated into pre-treatment

44B rejected heat from the process cooler integrated into CO_2 capture

44C rejected heat from the process cooler integrated with CO_2 stream compression

55 medium transferring waste heat from the PCC plant to the host power plant – (e.g. boiler feed water for pre-heating)

56 host power plant waste heat used in the PCC plant or return of PCC plant waste heat used in the host power plant – this stream can represent host power plant waste heat that is used in the absorbent regeneration process in the PCC or the return of waste heat that was generated in the PCC and used in the host power plant (e.g. boiler feed water preheating)

100 PCC plant boundary

110 CW feed from a host power plant CW system

111 CW return to a host power plant CW system

b Boundary.

Figure 5 — CW consumption calculation boundary

6.3.2 Consumption calculation

The heat rejected to CW is calculated separately for the three unit blocks shown in Figure 5 to account for the deviation from design performance and design conditions.

If a chiller is used, it shall be included in the CW consumption calculation. If other cooling media, such as boiler feed water or condensate, are used, then heat rejection into these media should not be accounted for. Based on the rejected heat duty the equivalent electrical energy consumption for CW is calculated for the evaluation specified in Clause 9.

6.4 Electrical energy

6.4.1 Definition of electrical energy consumption evaluation

The electrical energy consumption should be separately measured and reported and consist of the following contributions:

a) Quencher or flue gas pre-treatment;

b) CO_2 capture;

c) CO_2 stream compression;

d) Utility facilities.

Electrical energy consumption should be evaluated on the same boundary and operating conditions as the overall material and energy balances are calculated.

The determination of the electrical energy consumption for generation of CW is outside the evaluation boundary. The electrical energy consumption for CW pumps can be determined by the calculation of the electrical power required for CW:

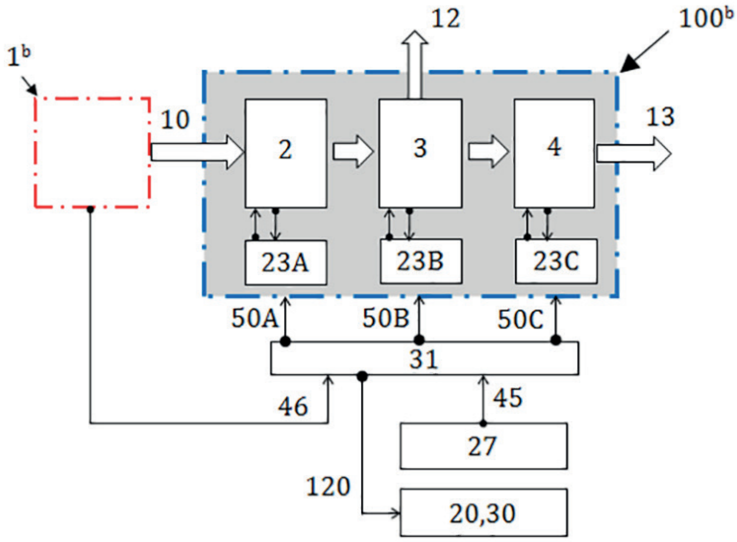
$$P_{\mathrm{CW}} = \frac{\dfrac{\Phi_{\mathrm{CW}}}{3\,600 \times 1\,000}}{c_{\mathrm{pCW}} \times \rho_{\mathrm{CW}} \times \left(T_{\mathrm{CWout}} - T_{\mathrm{CWin}}\right)} \times \left(p_{\mathrm{CWin}} - p_{\mathrm{CWout}}\right) \times \frac{100}{\eta_P} \times \frac{100}{\eta_M} \quad (6)$$

where

P_{CW}	is the electrical power requirement of the CW pump [MW];
Φ_{CW}	is the total cooling heat duty at the PCC plant [kJ/h];
T_{CWin}	is the temperature of CW at the supply side [K];
T_{CWout}	is the temperature of CW at the return side [K];
p_{CWin}	is the pressure of CW at the supply side [kPa];
p_{CWout}	is the pressure of CW at the return side [kPa];
$c_{\mathrm{p\,CW}}$	is the specific heat of CW [kJ/(kg K)];
ρ_{CW}	is the density of CW [kg/m^3];
η_{M}	is the efficiency of motor [%] (default value 95 %);
η_{P}	is the efficiency of CW pump [%] (default value 80 %).

If steam is extracted from the host power plant, the CW requirement of the base power plant can be significantly reduced to enable available CW to be used by the PCC plant. The available CW duty is deducted from Φ_{CW} in Formula (6). In case an additional CW pump is needed for the supply of CW from the power plant to the PCC plant, its electrical energy consumption should be included in the overall calculation.

The electrical energy consumption of the steam supply system is outside of the evaluation boundary. The electrical energy consumption calculation boundary is the crossing points of feed lines with the PCC plant boundary within which the electrical energy is consumed and indicated in Figure 6 with its feed source and with the reference of each key listed in the table below.



Key

1 host power plant boundary – this block flow configuration is typical for a coal fired boiler and a GTCC plant

2 pretreatment (quencher, deep-FGD, flue gas fan) – conditioning of the flue gas in preparation for separation of CO_2. This can include removal of contaminants that could damage the absorbent or temperature control to optimize absorber efficiency, etc.

3 CO_2 capture section

4 CO_2 stream compression/liquefaction section (including CO_2 stream purification)

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13 product CO_2 stream, sent for transport

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23A air fin cooler integrated into pre-treatment

23B air fin cooler integrated into CO_2 capture

23C air fin cooler integrated into CO_2 stream compression

27 auxiliary generator

30 auxiliary steam and power generation system

31 power distribution system – controls the amount of power diverted to the PCC plant to operate fans, pumps, blowers, and the compression system

45 electricity from an auxiliary power generation system

46 electricity from the host power plant

50A electricity diverted to power equipment and systems associated with the pre-treatment, including fans, pumps, and the compression system

50B electricity diverted to power equipment and systems associated with the CO_2 capture, including fans, pumps, and the compression system

50C electricity diverted to power equipment and systems associated with the CO_2 stream compression, including fans, pumps, and the compression system

100 PCC plant boundary

120 power supply to the utility facilities

Figure 6 — Electrical energy consumption evaluation boundary

6.5 Demineralized water and industrial water

In the PCC plant demineralized water is required for liquid absorbent make up. Industrial water is used in the quencher and CW system. These are not used for the performance evaluation in Clause 8, however the use of demineralized or industrial water should be reported to define the evaluation basis, since it can affect the CW consumption or performance.

6.6 Absorbent and chemical

The use of absorbents and chemicals is important for operation of the power plant and also for environmental impact assessments. Absorbent and chemical consumptions should be summarized in the form presented in Table 6. CW temperature can influence the consumption of absorbents. Absorbents for gas components and chemicals required for operation within the PCC boundary depending on the applied technology, such as additives, defoamer and anti-corrosion agent, filters, and demineralized water should be added to the table. This list is not exhaustive.

Table 6 — Absorbent and chemical consumption summary

	Absorbent and chemicals		
	Absorbent	**Chemical name 1**	**Chemical name 2**
Unit	kg/h as 100 % purity	kg/h as 100 % purity	kg/h as 100 % purity
Quencher (Pre-scrubber)			
Additional pretreatment			
CO_2 recovery			
CO_2 compression			
Utility system	Not included	Not included	Not included
Consumption figures should be reported on an appropriate time-averaged basis.			
NOTE Additional pretreatment requirements should be filled out with basic data such as FGD capacity, flue gas conditions to FGD including SOx, oxygen and moisture entering PCC.			

7 Guiding principles — Basis for PCC plant performance assessment

7.1 General

This clause provides guidance on the conduct of the PCC plant testing, and outlines the steps required to plan and conduct a test of the PCC plant performance. Adherence to this document is recommended to ensure the likelihood of high quality results.

Different relationships exist with the host power plant in respect to the thermal energy supply and related efficiencies. The impact of steam extraction on power plant efficiency can be determined using standards such as those in the IEC 60953 series. This document deals with items specific to integration of PCC plant using the IEC 60953 series to determine the impact on the host power plant.

The performance test should be carried out with the representative configuration of normal operation. Throughout any performance test, emissions other than CO_2 and any discharges to the environment, shall as a minimum, meet requirements of the permitting authorities. Determinations of emissions other than CO_2 are outside of the scope of this document, and as such, no emission limitations or required measurements are specified.

The test plan should specify any other than CO_2 emission levels that affect the result of the assessment.

7.2 Guiding principle of the performance test

7.2.1 General

The test(s) should be run at a specified CO_2 recovery capacity load that is near the plant condition of interest. Regardless of any test goal, the results of a test should be corrected to the plant reference conditions. If test conditions differ from the plant reference conditions, correction curves should be applied in the evaluations. The test(s) should be designed with the appropriate goal in mind to ensure proper procedures achieve the required operating mode during the test.

The following are actions that should be considered and/or conducted:

a) Agreement among the relevant parties on scope, measurement accuracy, timing and typical items relating to the performance test should be achieved in advance. This should include the specific objectives, the test programmes and the measuring methods including calibration and the method of plant operation.

b) A test procedure should be prepared and agreed upon by the relevant parties before beginning the test campaign to allow sufficient time for the test to be set up. The correction methods or curves to the plant reference condition should be previously agreed to in the test procedure.

c) The schedule of test activity and the detail of test procedure should be further agreed upon by the relevant parties as early as practically possible.

d) Any deviation from the test procedure and guidelines given in this document should be identified and recorded and the involved parties should agree on a resolution for each recorded deviation to avoid aborting the test run.

e) The responsibilities of test personnel and the organization conducting the performance test should be agreed upon by the relevant parties, and representatives of all the parties involved in the test should be present to verify that tests are conducted according to the test procedure and the guidelines given in this document. A leader should be designated and made responsible for the conduct of the test.

f) Pre-test uncertainty analysis should be confirmed. This includes calculating and integrating all deviations of the parameters derived from measured values in accordance with JCGM 100. Target uncertainty agreement can be ensured by selecting the instruments with the appropriate accuracy grade and confirming the accuracy grade of each instrument system.

g) Measurement locations, which should be prepared at the design stage, should be selected to provide the lowest level of measurement uncertainty. The preferred location is at the test boundary, but it is possible to move the location if it is the best place for determining the required parameters.

7.2.2 Power plant and capture unit conditions

Prior to commencement of the tests, the power plant and PCC plant equipment including the auxiliary units should be in good working order. Each should be free of leakage, failures and any other malfunctions that could influence the performance of the PCC plant. Equipment that is not operating properly should be identified and the possible influence of any such malfunctions should be evaluated.

The cleanliness, condition, and age of the equipment should be determined. Cleaning should be completed prior to the test and equipment cleanliness agreed upon.

Any condition that can influence the test results should be kept steady before the test begins, and shall be so maintained throughout the test within the limit of permissible variations to ensure that the facilities can be considered to be in steady state operation.

All chemicals related to PCC plant operation should be analysed to determine and confirm the concentration requirement as per design values. If any concentration is out of the allowable range, the relevant chemical should be replaced or adjusted by a new and clean chemical additive and/or chemicals.

All effort should be made to conduct the test as close as possible to the plant reference conditions. The plant reference condition is defined by the plant operator as a stable operating condition of the power plant with the rated load operation or the ordinary load operation. Operating parameters should be within the ranges given in the Table B.2, within the 'Allowable maximum deviation from plant reference conditions' column.

The test should be conducted under such conditions that all required measurements referred to in Clause 5 are fulfilled.

The results of the test run can be used to determine the KPIs defined in Clause 9 and the check list of the performance evaluation is explained as a sample procedure to obtain some of the KPIs in Annex F.

Further information is given in Annex B and in the IEC 60953 series.

8 Instruments and measurement methods

8.1 General requirement

8.1.1 Introduction

This clause presents the requirements for the instrumentation to be installed or used and the recommended measurement methods.

The instrumentation recommended might become more rigorous and accurate as technology advances. Under the mutual agreement of all parties involved in the tests, more advanced instruments may supersede the recommended instruments recommended, providing that the application of such instruments has demonstrated accuracy and reliability.

Instrument and measurement methods should be followed according to the standards or methods recognized internationally, which are recommended in Annex C, so that these results can be traced. Since these standards are for the different power plant performance tests, they can also be applied for PCC plant integrated with a power plant.

The measurement point list and location are summarized in Figure 3 in Clause 4.

The following clauses indicate the general requirements for the instrumentation and measurement methods for a PCC plant performance test. Detailed description and further information is presented in Annex C.

8.1.2 Instrument classification

Instruments are classified in accordance with both the use of the measured variables and depending on how the measured variables affect the final result.

a) Primary variables: variables that are used in calculations of test results

   They are further classified into:

   1) Class 1 primary variables: those which have a relative sensitivity coefficient of 0,2 (%/%) or greater, which require higher-accuracy instruments with more redundancy than Class 2.

      NOTE The relative sensitivity coefficient is defined as a relative change in the result divided by the relative change in a parameter (or variable) evaluated near a desired testing point and expressed as a percentage.

2) Class 2 primary variables: those which have a relative sensitivity coefficient of less than 0,2 (%/%).

b) Secondary variables: Variables that are measured but do not enter into the calculation of the test results. These variables are measured throughout a test period to ensure that the required test condition was not violated.

8.1.3 Measurement uncertainty

The measurement of each quantity used for the calculation of the test result is liable to some degree of error and the test result is subject to a degree of uncertainty depending on the combined effect of measurement uncertainties as indicated by the formula defined in ISO/IEC Guide 98-3:2008, 5.1.3.

The measuring uncertainty and calculation procedure of the overall test result uncertainty should be clearly reported, including all inputs and assumptions, formulation and calculation procedure. The measuring uncertainty, as well as the overall test results uncertainties, can be calculated from the uncertainties of the individual measurement as per ISO/IEC Guide 98-3 and the referred standards for instrumentation and measurements of this document.

For pre-test uncertainty analysis, the level of uncertainty for each individual measurement shall be chosen in reasonable relationship with the influence of the reading based on the overall uncertainty requirement and instrument classification. Typical accuracy level is given in Table C.1 for systematic uncertainty that should be expected for individual measured variables.

8.1.4 Calibration of instrument

Primary instrumentation calibration shall be done before the test and it should not be done more than one year before the test. Calibration guidelines are contained in Annex C. Any calibration after the test shall be decided under mutual agreement between parties involved during the test. Degree of calibration shall be chosen in reasonable relationship with the influence of the reading based on the instrument classification, as explained in Annex C.

8.1.5 Permanent plant instrument

It is only acceptable to use permanent plant instrumentation for primary variables if they can be demonstrated to meet the overall uncertainty requirements. In the case of flow measurement, all instrument measurements (process pressure, temperature, differential pressure, or pulses from metering device) should be made available because plant flows are often not rigorous enough for the required accuracy.

This document recommends the use of permanent plant instrumentation for tank level variations or any type of cross-check against temporary instrumentation. In case permanent plant instrumentation is used for primary variable measurements, the equipment should be verified before starting the test.

Verification of the permanent plant instrumentation involves a set of checks that establish the evidence (by calibration or inspection) that specified requirements have been met. It provides a means for drift check between values indicated by a measuring instrument and corresponding known values that are consistently smaller than tolerance or allowable limits defined in a standard, test procedure or specification.

8.1.6 Redundant instrument

Redundant instruments are two or more devices measuring the same parameter at the same location. Redundant instruments should be used to measure all primary (Class 1 or Class 2) variables.

Other independent instruments in separate locations can also monitor instrument integrity. An example would be a constant enthalpy process in which pressure and temperature in a steam line at one point can be used to verify the pressure and temperature of another location in the line by comparing enthalpies. Flow measurement in the condensate phase obtains a higher accuracy in general than in steam.

8.2 Measurement method

8.2.1 Flue gas

CO_2 capture efficiency defined in Formula (1) of 5.3 is verified in relation to the flue gas conditions in, or close to, the reference conditions.

a) Flue gas flow rate

ISO 10780, which requires a multipoint traverse of the stack or duct during sampling to account for components or items distributed along the diameter side, may be used to determine the flue gas flow rate. This can be done at the PCC flue gas inlet sampling locations, using specified measuring methods detailed on referred ISO 10780.

b) Moisture measurement

The recognized methods applicable to determine the moisture content of flue gas at the PCC flue gas inlet and emission side outlet are:

— absorption weighing method, which passes the sample gas through an absorption tube and measures its mass increase;

— chilled mirror technology, which uses a mirror that is chilled to dew point for moisture to start condensing on it (ISO 6327);

— capacitive or dielectric instruments methods, which have a material that changes its dielectric properties and increases its capacitance by absorption of moisture.

There are many technologies for moisture measurement purposes that can be applicable, provided that such applications have a demonstrated accuracy equivalent to those required in this document. The application is the same for the moisture content of product CO_2 stream.

c) Oxygen and carbon monoxide measurements

Measurement methods based on online analysis by non-dispersive infrared sensors or equivalent, or those based on sampling and manual analysis (titration), such as an Orsat analyser, can be used. Note that NH_3 may be present, and its interference should be checked through evaluation of uncertainties level depending on the PCC process. Applicable recognized equivalent standards are given in C.8.2, and may be used to determine oxygen and CO_2 levels at the PCC flue gas inlet and emission side outlet

8.2.2 Product CO_2 stream at the CO_2 compressor outlet

a) Purity of product CO_2 stream

CO_2 purity is measured based on the guideline set by the ISO 6974 series, using gas chromatography optimized for high-purity CO_2 converted from natural gas application, employing the general rule for gas chromatography according to the recognized standard.

If the impurity compositions are known, O_2, moisture and N_2 levels can be measured and their sum deducted from 100 %, also using ISO 6974 optimized for this purpose. The leakage of air, which is the cause of increased uncertainties, should be completely avoided in this sampling.

It is also possible to measure the CO_2 with titration analyser (equivalent to an Orsat analyser); but, this method may require a high level of skill of test personnel.

b) Flow rate of the product CO_2 stream

Generally various types of flow metering technologies have been used to meter CO_2 streams across various applications, including CCS systems. Consideration should be given to the pressure drop incurred by installing flow meters in the pipeline to check if this could inadvertently change the phase and fluid properties of the CO_2 stream (especially if flow conditions lie close to the CO_2 phase boundaries). This will necessitate an accurate understanding of the flow conditions at the given meter locations. Clear knowledge of the fluids density and viscosity is also required.

DP type meters provide the most common flow-measurement device, in particular in CO_2 enhanced oil recovery applications. Its use should be based on a series of ISO 5167, on the condition that the CO_2 stream shall be almost pure and stay as a single, stable phase to maintain measurement accuracy. In this case, special care is necessary when routing the lead pipe connecting to the tap of the DP type meter, as specified in the ISO 5167 series. One of the main drawbacks of orifice plates is their low turndown ratio, which means they have a limited flow rate range over which they can accurately operate.

Turbine meters have been used for decades within industry as a method for measuring both liquid and supercritical CO_2 flow in pipelines. These meters will work in single phase gas, liquid or supercritical fluid, if of the correct design. In the gas phase, ISO 10780 may be used. Applicable standards are recommended in C.8.

Pipelines should be of considerable diameter to economically transport large volumes of CO_2. This can affect the choice of flow meter, because some types of flow meter can only operate over limited pipeline diameters.

CO_2 gas may give significant problems in flow measurement at supercritical condition due to the difficulty of density determination. There are a number of options, such as electronic devices, ultrasonic flow meters and mass flow techniques (Coriolis type) that may be utilized, if application of such instrument has demonstrated accuracy equivalent to that required by this document. To ensure the accuracy of flow measurements, flowmeters should have required amount of straight pipeline length upstream and downstream of the meter, depending on the type of flow device.

The location before CO_2 compression contains the volume percentage of water with ppm (v) levels of O_2, N_2, and NH_3, if any in some cases. Flow measurement devices such as vortex type are applicable. However, in this case, loss of CO_2 during the compression including the dehydration (1 % to 2 % level generally, depending the process) can be expected and shall be deducted to obtain the interface CO_2 stream flow rate, if these losses can be clarified. If a DP type meter is applied to a low pressure CO_2 line, it can increase the electrical energy consumption, depending on the applied DP type meter.

8.2.3 Steam and steam condensate

General flow measurement is based on ISO 5167 and ASME PTC 19.5. Measurement of the steam and the steam condensate is based on IEC 60953-1. The temperature and pressure measurement is integrated in the above measurement and IEC 60953-1 can also be applied.

Other applicable standards are recommended in Annex C.

8.2.4 Cooling water

Possible measurement options are shown in IEC 60953-1:1990, 4.3.9, other applicable standard are recommended in Annex C.

IEC 60953-1 can be applied to temperature and pressure measurement.

8.2.5 Electric power measurement

Electrical power measurement should be based on IEC 60044 series, IEC 61869 series or ANSI/IEEE 120.

Additional information on watt-meters, which is one option for measurement, is given in Annex C.

8.2.6 Measurement of pressure and temperature

The measurement of pressure and temperature is based on IEC 60953-1. Applicable recognized equivalent standards are recommended in Annex C.

8.2.7 Data collection and handling

A data acquisition system is used to collect the test data to the extent possible. Other parameters will be recorded manually, such as equipment settings, and significant observation during the test. The observations shall include the date and the time of day, ambient conditions (temperature, pressure and relative humidity). The position of each measurement shall be clearly marked on the flow sheet. They shall be the actual readings without the application of any instrument corrections.

The automatic data collecting equipment shall be calibrated to secure the required accuracy. If the calibration is impractical, each piece of equipment in the measurement loop should be calibrated individually considering the entire measurement loop.

Signal inputs from the instruments should be stored to permit post test data correction for application of new calibration corrections.

The simultaneous reading of certain test points under the same conditions from the multiple instrument inputs should be considered to attain the required accuracy.

9 Evaluation of key performance indicators

9.1 Introduction

This clause defines the indicators for process performance evaluation of a PCC plant integrated with a power plant. Utility consumption (steam and electrical energy consumption) has a major impact on the process performance of a PCC plant and shall be evaluated using the indicators described in this clause. The process performance should be evaluated under the design condition and the reference conditions specified in Annex E. The symbols used in this clause are defined in Clause 3.

In the calculation of the indicators, the amount of energy (thermal and electrical) is important but the source of the energy is not essential even though any associated CO_2 emissions are. Therefore, utility generated by renewable energy such as sun, wind, water, biomass and geothermal energy can be treated in the same manner as fossil source. However, it is acceptable to offset the energy requirement of the PCC plant through the utilization of waste energy. For example, one can use the recovery of thermal energy from the power plant flue gases to partially meet the heat requirement of the PCC plant.

In addition to the KPIs in this clause, there are other informative performance indicators introduced in annex D in order to evaluate process performance of post-combustion CO_2 capture integrated with a power plant.

9.2 Specific thermal energy consumption (STEC)

STEC is the thermal energy consumed to capture and compress/liquefy a tonne of CO_2. STEC shall be calculated by:

$$STEC = \frac{q_{m\,\text{steam}} \times h_{\text{steam}} - q_{m\,\text{condensate}} \times h_{\text{condensate}}}{q_{m\text{CO}_2}} \times \frac{1}{10^6} \quad (7)$$

where

$STEC$	is the specific thermal energy consumption [GJ/t];
$q_{m\text{CO}_2}$	is the mass flow rate of a product CO_2 stream [t/h].
	$q_{m\text{CO}_2} = q_{m\text{CO}_2\text{\_comp\_b}}$ or $q_{m\text{CO}_2} = q_{m\text{CO}_2\text{\_comp\_a}}$
$q_{m\,\text{stream}}$	is the mass flow rate of steam to a PCC plant [kg/h];

$q_{m\ \mathrm{condensate}}$ is the mass flow rate of condensate from a PCC plant [kg/h];

h_{steam} is the specific enthalpy of steam [kJ/kg];

$h_{\mathrm{condensate}}$ is the specific enthalpy of condensate [kJ/kg].

Thermal energy can also be provided by another heat transfer media other than a single steam source with returning it as condensate in which case Formula (7) needs to be modified.

The flow rate of the captured CO_2 stream ($q_{m\mathrm{CO_2}}$) shall be measured by the flow meters installed in the product CO_2 stream line before or after CO_2 stream compression/liquefaction ($q_{m\mathrm{CO_2\_comp\_a}}$ and $q_{m\mathrm{CO_2\_comp\_b}}$) as described in 5.4.

If a steam turbine driver is applied for compressors or pumps instead of an electric motor, its steam consumption shall be considered to calculate STEC.

9.3 Specific electrical energy consumption (SEC)

SEC is the electrical energy consumed to capture and compress/liquefy a tonne of CO_2. The electrical energy consumption consists of all consumptions at facilities such as flue gas pre-treatment (including quencher), CO_2 capture, CO_2 stream compression and utility system (e.g. CW supply system). They are described in 6.4 and informative procedures for obtaining P_{PCC} are introduced in Table F.3 of Annex F. Based on the summation of all sources of electrical energy consumption, SEC shall be calculated by:

$$SEC = \frac{P_{\mathrm{PCC}}}{q_{m\mathrm{CO_2}}} \times 1\,000 \tag{8}$$

where

SEC is the specific electrical energy consumption [kWh/t];

$q_{m\mathrm{CO_2}}$ is the mass flow rate of a product CO_2 stream [t/h];

P_{PCC} is the electrical power requirement of the PCC plant [MW]

NOTE The electrical energy consumption in the PCC plant is defined by the boundary in Figure 2 and the required electrical energy consumption for CW supply to PCC plant is considered in Formula (6). This calculation needs to take into account any reductions in CW supply to the host power plant and auxiliary unit as described in 6.4.1.

The flow rate of the captured CO_2 stream ($q_{m\mathrm{CO_2}}$) should be measured by the flow meters installed in the product CO_2 line before or after CO_2 stream compression/liquefaction ($q_{m\mathrm{CO_2\_comp\_a}}$ and $q_{m\mathrm{CO_2\_comp\_b}}$) as described in 5.4.

9.4 Specific equivalent electrical energy consumption (SEEC)

SEEC is the overall electrical energy consumption attributed to capture and compression/liquefaction of a tonne of CO_2. SEEC is calculated as the total change in gross power output due to PCC plant divided by the amount of CO_2 captured:

$$SEEC = \frac{P_{\mathrm{LGP}} + P_{\mathrm{PCC}}}{q_{m\mathrm{CO_2}}} \times 1\,000 \tag{9}$$

where

$SEEC$	is the specific equivalent electrical energy consumption [kWh/t];
q_{mCO_2}	is the mass flow rate of a product CO_2 stream [t/h];
P_{LGP}	is the change in gross power output due to the steam extraction from the host power plant steam cycle and/or auxiliary unit [MW];
P_{PCC}	is the electrical power requirement of the PCC plant [MW].

NOTE For a new power plant, a reference plant can be developed that uses same generation technology but without installation of CO_2 capture.

9.5 Specific reduction in CO_2 emissions (SRCE)

SRCE is the calculated net decrease of the CO_2 emissions per unit output of a reference power plant by implementing the PCC process to the host power plant.

SRCE can be calculated by:

$$SRCE = \frac{q_{mCO_2,\mathrm{ref}}}{P_{\mathrm{NET,ref}}} - \frac{q_{mCO_2\mathrm{e,cap}}}{P_{\mathrm{NET,cap}}} \tag{10}$$

where

$SRCE$	is the specific reduction in CO_2 emissions [t/MWh];
$q_{mCO_2,\mathrm{ref}}$	is the mass flow rate of CO_2 emission from a reference power plant [t/h];
$q_{mCO_2\mathrm{e,cap}}$	is the mass flow rate of CO_2 emission from a power plant with a PCC plant [t/h];
$P_{\mathrm{NET,ref}}$	is the net power output of a reference power plant [MW];
$P_{\mathrm{NET,cap}}$	is the net power output of a power plant with a PCC plant [MW].

When the steam and/or electric energy is supplied from an auxiliary unit, the terms in Formula (10) include the total emission and output power of the host power plant and the auxiliary unit.

9.6 Specific absorbent consumption and specific chemical consumption (SAC and SCC)

SAC and SCC are the amount of absorbent and chemicals, respectively, which are consumed to capture and compress/liquefy a tonne of CO_2. SAC and SCC shall be calculated by:

$$SAC = \frac{q_{m\,\mathrm{absorbent}}}{q_{mCO_2}} \tag{11}$$

$$SCC = \frac{q_{m\,\mathrm{chemical}}}{q_{mCO_2}} \tag{12}$$

where

SAC is the specific absorbent consumption [kg/t];

SCC is the specific chemical consumption [kg/t];

$q_{m\mathrm{CO_2}}$ is the mass flow rate of a product CO_2 stream [t/h];

$q_{m\ \mathrm{absorbent}}$ is the consumption rate of absorbent at a PCC plant [kg/h];

$q_{m\ \mathrm{chemical}}$ is the consumption rate of a chemical compound at a PCC plant [kg/h].

The absorbent that is regenerated by the reclaiming system shall not be included as absorbent consumption, but the absorbent that is discharged from the PCC plant as waste shall be included. Other chemicals used in PCC plant that cannot be regenerated shall be included as chemical consumption.

Annex A
(informative)

Summary of streams and equipment nomenclature

A.1 General

The purpose of this annex is to summarize the different streams and equipment that could be encountered when using this document.

A.2 Summary of streams and equipment nomenclature used in this document.

This annex refers to Figure 2 and Figure 3 of Clause 4. Table A.1 summarizes the different streams and equipment number (in ascending order) as listed in Table 1 to Table 5 of Clause 4.

Table A.1 — Description of streams and equipment shown in Figure 2 and Figure 3 of Clause 4

Stream/ Equipment number	Description	Stream origin/ Equipment location	Relevant to which KPI evaluation
1[b]	Host power plant boundary – this block flow configuration is typical for a coal fired boiler and a GTCC plant	Host power plant	—
2	Pre-treatment section (quencher, deep-FGD, flue gas fan) – conditioning of the flue gas in preparation for separation of CO_2. This can include removal of contaminants that could damage the absorbent or temperature control to optimize absorber efficiency, etc.	PCC plant	—
3	CO_2 capture section	PCC plant	—
4	CO_2 stream compression/liquefaction section (including CO_2 stream purification)	PCC plant	—
5	CO_2 transportation system	(Out of boundary)	—
6[g]	Gas turbine in a GTCC - the item designated as a boiler (70) would be a HRSG and the air preheater and forced draft fan (72), particulate removal system (74), and FGD (75) would be removed	Host power plant	—
7	Ducting to a stack if required (this stream, if it exists, might contain residual CO_2)	PCC plant	SRCE
10	Flue gas from host power plant	Host power plant	SRCE
11	Flue gas from auxiliary unit (auxiliary steam and power generation system, #30)	Auxiliary unit	SRCE
12	Treated flue gas (mostly nitrogen, but might contain residual CO_2) to be vented or sent to a stack	PCC plant	SRCE
13	Product CO_2 stream, sent for transport	PCC plant	SRCE
14	CO_2 vent stream to the atmosphere required for start-up, shut-down, emergency and during significant operational disturbances	PCC plant	–

[b] Boundary.

[c] Only in the case of coal fired boiler.

[g] Only in the case of GTCC.

Table A.1 *(continued)*

Stream/ Equipment number	Description	Stream origin/ Equipment location	Relevant to which KPI evaluation
15	Waste water sent for treatment	PCC plant	SCC
16	Waste sent to a waste handling system	PCC plant	SAC and SCC
17	By-product	PCC plant	SAC and SCC
18	Fresh absorbent	PCC plant	SAC and SCC
20	CW generation system – the cooling system can include cooling towers, a once-through CW system, or air fin coolers	Auxiliary unit	—
21	CW intake - A CW intake can be common to the host power plant or the PCC plant	Auxiliary unit	—
22	CW outfall - A CW outfall can be common to the host power plant or the PCC plant	Auxiliary unit	—
23	Air fin cooler integrated into PCC plant	PCC plant	—
24	Auxiliary steam generation system - e.g. HRSG on auxiliary gas turbine or auxiliary boiler	Auxiliary unit	—
25	Steam distribution system	Auxiliary unit	—
26	Auxiliary gas turbine	Auxiliary unit	—
27	Auxiliary generator	Auxiliary unit	—
28	Waste water treatment system	Auxiliary unit	—
29	Waste handling system	Auxiliary unit	—
30	Auxiliary steam and power generation system	Auxiliary unit	—
31	Power distribution system – controls the amount of power diverted to the PCC plant to operate fans, pumps, blowers, and the compression system	Auxiliary unit	SEC and SEEC
35	Steam from a host power plant – although labelled as steam here, this can also be a different thermal energy transfer medium (e.g. hot oil)	Host power plant	STEC
36	Steam from an auxiliary steam generation system – although labelled as steam here, this can also be a different thermal energy transfer medium (e.g. hot oil)	Auxiliary unit	STEC
37	Steam supplied from the host power plant to PCC plant to drive absorbent regeneration and other processes – although labelled as steam here, this can also be a different thermal energy transfer medium (e.g. hot oil)	Auxiliary unit	STEC
38	Exhaust steam from the PCC to the host power plant – if steam is the heat transfer medium used in the PCC, any exhaust steam can be returned to the host power plant	PCC plant	STEC
39	Steam condensate from the PCC to the host power plant – if steam is used and condensed in the PCC, this stream returns the condensate to the host power plant	PCC plant	STEC
40	Steam condensate return to the host power plant	Auxiliary unit	STEC
41	Steam condensate return to the auxiliary steam generation system	Auxiliary unit	STEC
42	CW feed – if the CW system for the host power plant and/or auxiliary unit is used to supply CW to the PCC plant, it is accounted for in this stream	Host power plant Auxiliary unit	STEC

[b] Boundary.

[c] Only in the case of coal fired boiler.

[g] Only in the case of GTCC.

Table A.1 *(continued)*

Stream/ Equipment number	Description	Stream origin/ Equipment location	Relevant to which KPI evaluation
43	CW return – CW returned from the PCC to the host power plant and/or to the auxiliary unit	PCC plant	STEC
44	Rejected heat from the process cooler integrated into the PCC plant (23)	PCC plant	STEC
45	Electricity from an auxiliary power generation system	Auxiliary unit	SEC and SEEC
46	Electricity from the host power plant to the PCC plant	Host power plant	SEC and SEEC
47	Fuel to the auxiliary steam and power generation system	Auxiliary unit	—
48	Chemicals	PCC plant	SAC and SCC
49	Demineralized water, industrial water	PCC plant	SAC and SCC
50	Electricity diverted to power equipment and systems associated with the PCC plant, including fans, pumps, and the compression system	Auxiliary unit	SEC and SEEC
51	Net power export	Host power plant Auxiliary unit	SEC and SEEC
52	Electricity diverted from the host power plant or the auxiliary power generation system to power other equipment within the same plant or system	Host power plant Auxiliary unit	SEC and SEEC
55	Medium transferring waste heat from the PCC plant to the host power plant – (e.g. boiler feed water for preheating)	PCC plant	STEC
56	Host power plant waste heat used in the PCC plant or return of PCC plant waste heat used in the host power plant – this stream can represent host power plant waste heat that is used in the absorbent regeneration process in the PCC plant or the return of waste heat that was generated in the PCC plant and used in the host power plant (e.g. boiler feed water preheating)	Host power plant	STEC
57	Medium transferring waste heat from the host power plant to the PCC plant. A common source of waste heat in a host power plant is the heat contained in the flue gas. This stream integrates the heat supplied to the PCC plant by stream 37	Host power plant	STEC
58	Power plant waste heat return from PCC plant – this stream represents the return of waste heat from stream 57 to the host power plant	PCC plant	STEC
59	Use of PCC plant effluent in FGD – waste water from the PCC plant can potentially be used as make-up water in the FGD system	Auxiliary unit	—
60	Flue gas after pre-treatment – this stream is the flue gas stream after contaminants have been removed and temperature adjustments have been made in preparation for entering the absorber (from item 2 to 3)	PCC plant	—
61	The product CO_2 stream leaving the CO_2-capture section prior to entry into the compression system (from item 3 to 4)	PCC plant	—
65	Fuel to host power plant	Host power plant	—

[b] Boundary.

[c] Only in the case of coal fired boiler.

[g] Only in the case of GTCC.

Table A.1 *(continued)*

Stream/ Equipment number	Description	Stream origin/ Equipment location	Relevant to which KPI evaluation
70[c/g]	Boiler – or HRSG in GTCC case	Host power plant	—
71	NOx removal system	Host power plant	—
72[c]	Air preheater and forced draft fan (not applicable in GTCC case)	Host Power Plant	—
73	Flue gas heat recovery system	Host power plant	—
74[c]	Particulate removal system (not applicable in GTCC case)	Host power plant	—
75[c]	FGD (not applicable in GTCC case)	Host power plant	—
76	Flue gas heater, if necessary	Host power plant	—
77	Stack and treated flue gas duct	Host power plant	—
80	High pressure (HP) – intermediate pressure (IP) turbine	Host power plant	—
81	Low pressure (LP) turbine	Host power plant	—
82	HP heaters	Host power plant	—
83	Deaerators	Host power plant	—
84	LP heaters	Host power plant	—
85	Steam condenser	Host power plant	—
86	Power plant CW supply system	Host power plant	—
87	Power plant CW intake	Host power plant	—
88	Power plant CW outfall	Host power plant	—
89	Power plant generator	Host power plant	—
100[b]	This line represents the PCC plant boundary	PCC plant	—
101	Atmosphere	(Out of boundary)	—
102	Landfill and/or hydrosphere	(Out of boundary)	—
200[b]	Auxiliary unit boundary	Auxiliary unit	—

b Boundary.

c Only in the case of coal fired boiler.

g Only in the case of GTCC.

Annex B
(informative)

Test principles and guidelines

B.1 Emissions and any discharges during the test

a) Atmospheric emission

— As CO_2 is captured in a PCC plant, the concentration of flue gas impurities (SO_x, NO_x, PM, HCl, HF, N_2O, Hg and NH_3) will increase at the outlet of the PCC plant. For the existing local environmental regulations, it may be an issue, since the flue gas impurities would be over the limits.

— The temperature at which the treated flue gas is discharged may also be an issue. Depending on the technology, a temperature decrease of the treated flue gas may occur. The lack of buoyancy could result in poor dispersion of its components.

— Finally, the level of emissions of absorbent and absorbent degradation products might impact the assessment of the key performance indicators.

b) Effluent

Effluent amount, pH, composition, suspended solids concentration, biological oxygen demand, and chemical oxygen demand, and inclusion of regulated substances should be made clear.

c) Waste

The amount of waste generated and its general characteristics regarding handling (water content, viscosity), treatment method (Ca, N, Na or S content, heating value) and category (whether or not it is a hazardous substance, based on local regulations) should be reported.

B.2 Additional testing

The owner(s) of the power plant and the PCC plant may wish to perform additional testing to determine plant performance and/or gather data during other conditions, such as load following or plant trips. The terms of the testing and performance criteria should be determined in advance and included in an approved document. This annex may be used as a template for such testing.

B.3 Duration and number of test runs

A test run is a complete set of readings with the power plant and PCC plant running at stable operating conditions. A test may be composed of a single test run or a series of test runs. To ensure repeatability of the results, this document recommends that each test be composed of at least two or more test runs. A test composed of different test runs can provide a means to validate and/or reject outlying measurements. The final results used to calculate the KPIs should be the average of different accepted test run results.

The duration of each test run should be determined by operating considerations and the requirements of the involved parties. This document recommends the minimum duration of each test run according to the typology of combustion system used in the power plant as indicated in Table B.1:

Table B.1 — Minimum duration of each test run

Fuel type	Test run duration h
Solid fuel boiler (e.g. coal, lignite)	2
Fluidized bed/stocker and cyclone (e.g. petcoke, biomass)	4
Gas turbine/combined cycle (including supplementary firing)	1
Oil/gas fired boiler	2

B.4 Pre-tests

Before starting the test campaign, several pre-tests may be carried out to tune or set up the control settings to reach test condition requirements. They also help to identify any type of anomaly or equipment malfunction. To allow for any corrective action, this document recommends carrying out pre-tests before the test campaign begins.

B.5 Start and stop of the test

Once the test conditions are established and the stability criteria reached, the test leader should decide to start the test by recording and communicating the time and date to all involved parties. The test will run for the duration that was mutually agreed upon. During this time, the plant should be operated under automatic, stable conditions. Control settings should not be modified during this period. At the end of each test run, the time should be recorded and the test leader should declare the end of the test to all the parties.

If the stability or test conditions are not compliant with the given requirements during the test run, the test leader may decide to stop and abort the test. The data taken during the part of the test run which is compliant with the requirements can be considered acceptable for the evaluation of the performance; the test run can be retained as valid with the exception of where it deviates during the test.

B.6 Electrical and thermal consumption line up

Prior to beginning the tests, all the electrical consumers should be aligned according to the plant design configuration. Each electrical consumer should be identified and fed by the power plant source referenced in the test plan. Any redundant consumers should be switched off. In case a redundant consumer cannot be switched off, mutual agreement should be reached between the parties involved during the test to measure and deduct any additional consumption during the performance evaluations.

All thermal consumption or steam extraction flows from the power plant should be aligned before starting the test. The steam extractions and PCC plant equipment fed by the power plant should be aligned according to the plant design configuration. Any thermal source coming from other plant or steam generator outside the boundary should be isolated; if this is not possible, it should be measured and deducted during the performance evaluations.

The electrical and thermal consumption line up should be done prior to start the test campaign.

B.7 Test conduct and evaluation principle

Sufficient readings for each measured parameter should be taken during the test duration to reduce measurement uncertainty as much as possible. When a data acquisition system is used, a minimum of 30 sets of readings for each primary parameter should be recorded for each test run.

The arithmetic average of each reading should be calculated and the stability criteria should be verified. Data acquired during each test run should be reviewed and rejected in part or in whole if they are not compliant with the requirements within the stability criteria.

B.8 Stability criteria for power plant and PCC plant

The PCC plant should be operated under stable conditions to ensure good quality measurements and performance results. To do this, the power plant should meet stability criteria and requirements given in the applicable international standards (e.g. the IEC 60953 series and ASME PTC 6 and ASME PTC 4). This will ensure that all the interfaces between power plant and PCC plant is stable (e.g. flue gas flow, steam extractions and power supply).

PCC plant parameters that do not interface with the power plant and ambient conditions should also meet the stability criteria outlined in Table B.2 before and during the performance test:

Table B.2 — Stability criteria for power plant and PCC plant

Parameter	Allowable standard deviation	Allowable maximum deviation from plant reference conditions
Generator power output	±0,25 %	Note 1
Generator power factor	±1,0 %	Note 3
Generator frequency	±0,25 %	±2,0 %
Generator voltage	—	±5,0 %
Solid fuel characteristics (heating value and constituents)	—	Note 2
Natural gas fuel heating value	—	Note 2
Oxygen leaving boiler/economizer (oil/gas units)	0,2 %-Vol	—
Oxygen leaving boiler/economizer (coal units)	1,0 %-Vol	—
CO_2 stream purity	±0,5 %-Vol	±1,0 %-Vol
CO_2 flow	±1,0 %	±5,0 %
Condensate flow from PCC plant	±1,0 %	±5,0 %
Refrigerant and cooling water temperature	±1,0 K	±5,0 K
Refrigerant and cooling water flow	±1,5 %	±15,0 %
Fuel flow (gas and oil)	±1,3 %	Note 3
Fuel gas pressure	±0,65 %	Note 2
Fuel gas temperature	±3,0 K	Note 2
Exhaust flue gas temperature	±2,0 K	Note 3
Steam pressures (note 4)	±0,5 %	±3,0 %
Steam temperatures (note 4)	±2,0 K	±8,0 K
Ambient temperature (dry bulb)	±2,0 K	Note 3
Ambient temperature (wet bulb)	±2,0 K	Note 3
Ambient pressure	±0,5 %	Note 3

NOTE 1 Refers to applicable steam-turbine or power plant standard.

NOTE 2 Values taken from fuel specification limits. If the fuel characteristics are not within these limits, the involved parties should agree which correction is to be applied or postpone the tests.

NOTE 3 This value depends on the maximum or minimum specified value in the plant reference conditions. Beyond this value mutual agreement should be reached for the correction.

NOTE 4 Parameters are inside of the test boundaries. They are monitored to ensure the entire stability of the power plant operation. The values could be changed, depending on applicable standards of the steam turbine performance test.

Stability is calculated by the standard deviation of the measurements along each test run. To calculate KPIs, a period of stabilization is required before each test run to ensure it is representative of stable operations.

Annex C
(informative)

Instruments and measurement methods

C.1 General

The following results are to be determined as part of the performance test standard:

a) Capture efficiency (see 5.3);

b) Captured CO_2 flow rate of a PCC plant (see 5.4);

c) Properties of CO_2 stream at CO_2 compression system output (see 5.5);

d) Specific thermal energy consumption (see 9.2);

e) Specific electrical energy consumption (see 9.3);

f) Specific equivalent electrical energy consumption (see 9.4);

g) Specific reduction in CO_2 emissions (see 9.5);

h) Specific absorbent consumption and specific chemical consumption (see 9.6).

Items a) to e) are obtained directly from the measurement results. For the item f) to g), LGP: loss of gross power output by the steam extraction from the steam turbine should be measured according to IEC 60953-1 or IEC 60953-2 depending on the type of a host power plant after the operation is established based on the thermal energy requirement/consumption detail obtained by this document. Item h) is calculated by the specific absorbent consumption and the specific chemical consumption forwarded by the technology suppliers.

C.2 Measurement points diagram

Suitable measurement equipment should be installed at different points of the PCC plant when evaluating the performance of the PCC plant integrated with a power plant. Before starting the test campaign, the number and the position of all instruments to be installed and used during the tests should be confirmed. For this purpose, this document recommends preparing a measurement points diagram and including it in the test procedure.

The PCC plant and all its interfaces should be represented in this diagram, including the lines or streams that link the equipment to both power plant and PCC plant. The type of sensor (e.g. pressure, temperature, flow meter) that will be used for the performance verification test should also be represented on the relevant line and equipment. Figure 3 shows a typical example of a measurement points diagram.

C.3 Instrument classification

Any deviation, if the whole or part of the instrumentation does not fit with the recommendation given here below, should be confirmed.

In the following clauses, accuracy recommendation is given for primary and secondary instrumentation, according to the type of measured physical parameter.

This type of instrumentation is installed temporarily before starting the test campaign and each instrument should be calibrated in a certified laboratory according to the recommendations given in the ISO 17025 and as per C.4.

If there is a high probability of a certain temperature, pressure or velocity profile at a specific measurement point, this document recommends including sufficient measurements to take all possible profiles into account. Averages may be calculated as a weighted average of surface or velocity, depending on the physical parameter, according to the relevant international standards.

Table C.1 shows the typical accuracy and allowable systematic uncertainties for primary instrumentation.

Table C.1 — Typical accuracy level for the instrumentation

Measured parameter	Recommended devices	Range	Maximum allowable systematic uncertainty (accuracy)
Pressure	Absolute, gauge and differential	All	±0,3 %
Temperature	RTD[a] for temperatures	<150 °C	±0,3 °C
	Thermocouples for temperatures	>150 °C	±0,6 °C
Flow (water and steam)	Venturi	—	Calibrated: ±0,5 % steam, ±0,4 % water uncalibrated ±1,2 % steam, ±1,1 % water
	Orifice	—	Calibrated: ±0,5 % steam, ±0,4 % water uncalibrated ±0,75 % steam, ±0,70 % water
Flow (Flue gas and CO_2 stream)	Multipoint pitot tube	—	Calibrated: ±5,0 % uncalibrated ±8,0 %
	Coriolis	—	See C8.2
	Ultrasonic	—	See C8.2
	Venturi	—	±1,5 %
Flue gas analysis	Oxygen portable analyser	—	±5,0 % of reading ±2,0 % of span
	Carbon monoxide (Orsat analyser)	—	±0,2 points
	Oxides of nitrogen	—	±10 ppm(v)
	Ammonia	—	To be specified
Electrical power	Wattmeter	—	±0,5 %
	Clamp-on	—	±2,0 %
	Watt-hour counter	—	±0,03 %
Current	Ammeter	—	±0,3 %
Voltage	Voltmeter	—	±0,3 %
Frequency	Electronic revolution meter	—	±0,1 %

[a] RTD: resistance temperature detector.

Table C.1 *(continued)*

Measured parameter	Recommended devices	Range	Maximum allowable systematic uncertainty (accuracy)
Ambient pressure	Absolute pressure transmitter	—	±0,075 %
Moisture	Hygrometer	—	±2,0 % RH
	Psychrometer	—	±0,5 %
Data acquisition	Digital data logger	—	±0,1 %
[a] RTD: resistance temperature detector.			

This document recommends using permanent plant instrumentation in this category.

C.4 Calibration requirements

Table C.1 shows the typical accuracy level for the instrumentation to be used to test the performance of a PCC plant. The calibration procedure and the acceptance criteria should meet ASME PTC 19.5, ANSI/IEEE 120, ASTM E2744-16, BS 1041, and ISO/IEC 17025. Any other recognized international standard should be agreed and accepted by the parties involved during the test.

C.5 Manual measurement by international standard

The parameters required for the basic PCC plant performance explained in Clause 5 will be measured according to the measurement method explained in 8.2. This should be in accordance with the requirements for temporary instruments either manually operated or a combination of online instruments of primary instrumentation grade.

C.6 Online measurement by temporary or permanent plant instrumentation

If the instrumentation or measurement methods to be used are not addressed in this document then they should be subject to agreement between the relevant parties to determine the level of accuracy to be applied to each respective instrument or measurement method.

C.7 Flow measurements

All the streams crossing the boundary line of the PCC plant and used for the performance evaluation of the PCC plant should be measured or determined via indirect methods (e.g. heat and mass balance) in cases where a flow device cannot be installed.

The recommended flow devices to be used for flow measurements are given in BS 7405 and accord with the guidelines in ISO/TR 9464. All measurements and evaluations using pressure-drop flow devices should comply with ISO 5167.

This document recommends referring to ISO/TR 15377 if the measured steam flow is beyond that given in ISO 5167.

The main applications for PCC plant performance test flow measurements are given below.

C.8 Flue gas and CO_2 stream measurements

C.8.1 Flue gas flow rate

To determine volume flow rate, velocity traverse measurements are needed at numerous locations in a plane perpendicular to the flow for large pipe diameters, or in closed conduits where pressure, velocity and temperature profile can be present.

Sampling should take place in a length of straight duct with constant shape and cross-sectional area, as far as possible downstream from any obstruction that may cause a disturbance and produce a change in the direction of flow. ISO 10780 requires that the straight duct that includes the sampling plane should have at least seven hydraulic diameters long straight section and the sampling plane should be located at a distance of five hydraulic diameters from the straight duct inlet to ensure the uncertainty is 3 %. Other conditions specified include the Reynolds member should be higher than 1 200, which corresponds to a flue gas flow rate of (5 to 50) m/s.

The measurements should be according to ISO 3966 and ISO 14164. These measurements should include at least velocity pressure, static pressure, and temperatures at several locations corresponding to the centres of equal areas with a probe inserted into the duct.

Practically, large conduits may be not able to fulfil these duct requirements as per ISO 3966 and ISO 14164. If so, the number of the measurement points should be increased (up to 30) according to the recommendation of ASME PTC 19.5, depending on the actual straight length of the same shape. The details including Pitot type and the number of the sampling points are also referred to in ISO 3966 and ASME PTC 19.5.

The flow may be calculated from velocity, the duct cross-sectional area and the gas density calculated from the flue gas main components analysis. The duct cross-sectional area might be difficult to determine accurately because of obstructions within the duct, or inaccurate dimensions. The plugging of probes by the mist or droplet should be considered, depending on the flue gas quality.

An alternative method or for cross check purposes, the flue gas flow rate could be determined by combustion calculations. However, if all of the flue gas is extracted for treatment, then some slip to or inclusion of the air needs to be considered.

C.8.2 Flue gas composition

This document recommends that the relevant flue gas components (CO_2, SO_x, NO_x, or O_2) should be monitored continuously throughout the test, to ensure that the condition of the flue gas is maintained within the acceptable variation range. The distribution of the component concentrations is regarded as uniform, unless removing or mixing of the component occurs near the inlet of the PCC plant.

The impurity components (SO_2, SO_3, NO_2, HCl, HF, NH_3, CO) and PM analysis can impact on design, performance and uncertainty of the measurement of the PCC plant. The methods of measurement of flue gas impurities are not specified in this document and they should be cross-checked and clarified by the provision of information from the flue gas source side.

ISO 10396 describes the method, and provides the guidelines to determine impurities (i.e. O_2, CO, NOx and NH_3) that will be found in the product CO_2 stream.

The following standards are also recommended:

— ISO 12039, ISO 17179, ISO 10849, EN 1911, ISO 7935, and ISO 15713

By measuring or determining the quantity of impurities, the CO_2 concentration can also be determined by difference. All impurities (i.e. O_2, CO, NO_x and NH_3 in volumetric concentration) can be measured by the said standards. CO_2 concentration can then be determined by subtracting the percentages of each impurity from 100 %.

C.8.3 Treated flue gas composition from PCC plant

Applied standards are shown in Table C.2. If a regulated component is present in the flue gas its measurement is not in the scope of this document, but they should be clarified in the performance test procedure.

Table C.2 — List of standards

Interface withPCC Plant	Parameters	Details of parameters	Applicable standard/(methods)		
			ISO/IEC	ANSI/ASME/EPA	Remarks for application
Inlet flue gas	Flue gas flow rate	(kNm^3/h)	ISO 10780	EPA Method 1 (Sample and Velocity Traverses for StationarySources) EPA Method 2 (Determination of Stack Gas Velocity andVolumetric Flow Rate) (Type S Pitot Tube)	—
	Flue gas composition	H_2O (vol %)	—	EPA method 4 (Determination of Moisture Content in StackGases) (Reference method is applied)	—
		CO_2 (vol %-dry)	—	EPA method 3A (Instrumental) (DETERMINATION OF CARBON DIOXIDE ANDOXYGEN FROM STATIONARY SOURCES) (Continuous measurement)	NDIR(Nondispersive infrared sensor) or Orsat analyzer(USEPA Method 3B)are normally applied-JIS B 7986 Continuous analyzer for Carbon dioxide in the flue gas
	Temperature	°C	—	ASME PTC19.3 (Temperature measurement)	—
	Pressure	kPaG		ASME PTC19.2 (Pressure Measurement)	—
Outlet flue gas	Fuel gas composition	H_2O (vol %)	—	EPA method 4 (Moisture content)	—
		CO_2 (vol %-dry)	—	EPA method 3A (Instrumental)	NDIR(Nondispersive infrared sensor) or Orzat analyzer(USEPA Method 3B) are normally applied
	Temperature	°C	—	ASME PTC19.3	—
	Pressure	kPaG	—	ASME PTC19.2	—
Product CO_2 (Before CO_2 compression)	Flow rate	kNm^3/h	ISO 10780 ISO 5167 ISO 9951	SME PTC 19.5 (Flow Measurement) ASME MFC-6-2013	ISO 5167 Venturi Pipe could be recommended.
	CO_2 purity	vol%	ISO 6974	EPA method 3A	Conbination with JIS K 0114 General rule for gas chromatograph
	Temperature	°C	—	ASME PTC19.3	—
	Pressure	MPaG	—		—

Table C.2 *(continued)*

Interface withPCC Plant	Parameters	Details of parameters	Applicable standard/(methods)		
			ISO/IEC	ANSI/ASME/EPA	Remarks for application
Product CO_2 (After CO_2 compression)	Flow rate	kNm^3/h	ISO 10780 ISO 5167 ISO 9951	ASME PTC 19.5 (Flow Measurement) ASME MFC-6-2013	ISO 5167 Venturi Pipe could be recommended.
	CO_2 purity	vol%	ISO 6974	EPA method 3A	Conbination with JIS K 0114 General rule for gas chromatograph
	Temperature	°C	—	ASME PTC 19.3	—
	Pressure	MPaG	—	ASME PTC 19.2	—
Utilities	LP/MP SteamCondensate/Liquid	Flow rate(t/h)	ISO 17089	ASME PTC 19.5	—
		Pressure (MPaG)	IEC 60953-1	ASME PTC 19.2	—
		Temperature (°C)	IEC 60953-1	ASME PTC 19.3	—
	CW	Flow rate (m^3/h)	ISO 5167 IEC 60953-1 ISO 17089	ASME PTC 19.5	—
		Temperature (°C)	IEC 60953-1	ASME PTC 19.3	—
Electricity	—	MWh/h	IEC 60044 IEC 61869	ANSI/IEEE 120	The accuracy of the Current Transformer, Voltage Transformer and the Power Meters should be studied indetail. A sensitivity analysis would be required
Performance Test/ Uncertainty	—	—	IEC 60953-1 ISO 5168 ISO/IEC Guide 98-3(JCGM 100) ISO/IEC Guide 98	ASME PTC 46 (Performance test code on Overall PlantPerformance) ASME PTC 19.1 (Test Uncertainty)	—

C.9 Product CO_2 stream before compression

Product CO_2 stream purity can be determined by analysing moisture, oxygen, nitrogen and CO_2 concentration using ISO 6974 according to a standard that explains the characteristics of the gas chromatography, such as JIS K 0114 or an equivalent standard. The general rules for gas chromatography should be followed. Oxygen measurement should be carried out online to avoid inclusion of air, which results in large uncertainties. Environmental Protection Agency (EPA) method 3A is equivalent to the above technology. The product CO_2 stream may also include CO, NO_x and NH_3, which can be measured using gas chromatography. Moisture content can be analysed by EPA method 4, or calculated by temperature and the pressure measurements, since the product CO_2 stream is saturated with water (depending on the process).

C.10 Steam flow measurement

Pressure drop devices are recommended for this type of application. Precaution measures should be taken to avoid a high pressure drop in the pipes which could influence or directly impact the PCC process.

If steam-turbine steam extraction cannot be measured because a measurement device is either unavailable or impossible to install, heat and mass balance should be carried out for the steam-turbine cycle to determine the required steam flow. In this case, all the instrumentation installed around the steam-turbine cycle (power plant side) should meet the requirements and recommendations in IEC 60953-2.

C.11 Condensate, CW and refrigerant flow measurement

All the measurements and evaluations should be conducted according to ISO 5167 for condensate flow measurements.

Both condensate, CW and refrigerant flow measurements could be measured by an ultrasonic flow meter device, following the recommendations given in ISO 12242. If the main CW or refrigerant flow rate cannot be measured, the heat and mass balance method around the entire cycle or heat exchanger is recommended, and should be written in the test procedure under mutual acceptance and agreement among the involved parties.

In case flow meter calibration is required, the calibration should be conducted as per ASME PTC 19.5 and the installation should be according to C.7.

C.12 Electrical power measurement

Temporary single-phase or poly-phase precision watt-meters or watt-hour-meters should be used and connected to appropriate voltage and current transformers for electrical energy consumption measurements of PCC plant. The three watt-meter method is recommended to measure three phase electrical energy consumption according to ANSI/IEEE 120.

The temporary watt-meters and/or watt-hour-meters should measure the current, voltage, power factor, frequency and active power. The error of each watt-meter or watt-hour-meter should not exceed 0,2 % of the readings. The recording of the watt-hour-meters should be in a manner that any inaccuracy will not exceed 0,03 %. Watt-hour-meter readings should be recorded during the test at regular intervals (at least every 5 min).

Depending on the type of performance verification, the instrument transformer precision may differ. If the entire PCC plant electrical energy consumption is to be verified, Class 0.2 current and voltage transformers are required. If the performance of the entire power plant including PCC plant is to be verified, Class 0.2 or higher is acceptable, unless an agreement between the parties requires a specific precision class.

C.13 Pressure measurement

Pressure measurements should be performed according to IEC 60953-1 and ASME PTC 19.2. Accuracy and range values are specified in Table C1. Pressure transmitter installation and manifolds should be according to the guidelines given in ISO 2186.

The flue gas flowing through a duct may have non-uniform velocity, temperature and composition, especially near a flow disturbance, such as a bend or transition. Generally, temperature uncertainty can be reduced either by sampling more points or by using more sophisticated calculation methods. If a pressure or velocity (dynamic pressure) profile is present inside of the conduits, it is recommended to follow the guidelines given in ISO 3966 and ISO 10780 for the case of flue gas flow measurements.

C.14 Temperature measurement

The selection of temperature sensors and the number and distribution of the measurement points should be according to BS 1041 including all the parts.

If a temperature profile is present in the conduits or on the surfaces, this document recommends following the guidelines given in ISO 3966 and ISO 10780.

The typical accuracy level should be according to Table C1 and the calibration should be according to the requirements specified in C.4.

C.15 Chemical additives and non-fuel sources

Chemical additives and non-fuel sources should be measured using the PCC technology supplier best practices to ensure the best level of precision and accuracy of the measurements. This measurement includes flow and chemical composition.

The ISO 5167 series may be used as reference standards for chemical additives and non-fuel sources flow measurements.

The determination of chemical composition (and purity) may use standard methods and procedures and may be done by a recognized and/or certified laboratory.

Annex D
(informative)

Additional approaches of performance evaluation for a PCC plant integrated with a power plant

D.1 Incremental fuel use and equivalent electrical energy consumption for PCC

The energy requirement for a PCC plant integrated with a power plant will lead to a change in the net plant efficiency compared with the reference power plant. This results in a fractional increase fuel use (or energy input) per unit power output, defined by Formula (D.1):

$$\Delta E = \frac{\eta_{\text{ref}}}{\eta_{\text{PCC}}} - 1 \qquad \text{(D.1)}$$

Where ΔE is the incremental fuel use per unit of power output and η_{PCC} and η_{ref} are the net power output efficiencies of the power plant with PCC and the reference power plant, respectively.

The incremental fuel use can be interpreted as a measure of the impacts on resource utilization for power generation.

The PCC energy requirement also results in an equivalent electrical energy consumption which is defined as the fractional decrease in power plant output for fixed fuel use (or energy input), ΔE^* as given in Formula (D.2):

$$\Delta E* = \frac{\eta_{\text{PCC}}}{\eta_{\text{ref}}} \qquad \text{(D.2)}$$

The equivalent electrical energy consumption can be interpreted as a measure of the impacts on the power plant output levels.

D.2 Approximate calculation of specific equivalent electrical energy consumption

When the performance evaluation focuses solely on a PCC plant, a simple way to design models for both a power plant with PCC and a reference power plant is most practical.

The specific equivalent electrical energy consumption (SEEC), defined in 9.4, is the overall electrical energy consumption attributed to capture and compression/liquefaction of a tonne of CO_2. The determination of the SEEC should be based on practical measurement or mathematical simulation. An approximate value can be provided by key parameters and Formula (D.3).

$$SEEC = \frac{100}{\eta_{CO_2}} \times \frac{100}{\eta_{\text{gas to PCC}}} \times \frac{\eta_{\text{ref}} - \eta_{\text{PCC}}}{100 \times FSE \times 3{,}6} \qquad \text{(D.3)}$$

where η_{ref} is the net generation efficiency of the reference power plant, *FSE* is the fuel specific emission, $\eta_{\text{gas to PCC}}$ is a proportion of total flue gas flow to PCC plant, and η_{CO_2} is the CO_2 capture efficiency of a PCC plant.

The FSE is defined as in the following Formula (D.4):

$$FSE = \frac{44}{12} \cdot \frac{w_C}{100} \cdot \frac{1}{LHV_{\text{fuel}}} \tag{D.4}$$

where

w_C	is the mass fraction of carbon in fuel on the as-fired basis;
LHV_{fuel}	is lower heating value.

D.3 Specific primary energy consumption for CO_2 avoided (SPECCA)

The specific primary energy consumption for the avoidance of CO_2 emissions as a result of integrating PCC with a power plant can be expressed by the SPECCA. It expresses the amount of energy resource used per unit of CO_2 emission avoided. SPECCA (in kJ/kg) is defined as given in Formula (D.5):

$$SPECCA = \frac{HR_{\text{PCC}} - HR_{\text{ref}}}{E_{\text{ref}} - E_{\text{PCC}}} = 3\,600 \cdot \frac{{100}/{\eta_{\text{PCC}}} - {100}/{\eta_{\text{ref}}}}{E_{\text{ref}} - E_{\text{PCC}}} \tag{D.5}$$

where

HR_{PCC}	is the heat rate of a power plant with PCC [kJ/kWh];
HR_{ref}	is the heat rate of a reference power plant [kJ/kWh];
E_{PCC}	is the specific CO_2 emission from a power plant with PCC [kg/kWh];
E_{ref}	is the specific CO_2 emission from a reference power plant [kg/kWh];
η_{PCC}	is the net power output efficiency of a power plant with PCC [%];
η_{ref}	is the net power output efficiency of a reference power plant [%].

SPECCA can be referred to "IEAGHG, CO_2 Capture at Gas Fired Power Plants".

D.4 Specific cooling water duty (SCWD)

SCWD is the cooling water that is required to capture and compress/liquefy a tonne of CO_2. The SCWD is calculated by:

$$SCWD = \frac{\Phi_{\text{CW}}}{c_{\text{pCW}} \times \rho_{\text{CW}} \times \left(T_{\text{CWout}} - T_{\text{CWin}}\right)} \times \frac{1}{q_{m\text{CO}_2}} \tag{D.6}$$

where

$SCWD$	is the specific cooling duty [m^3/t];
Φ_{CW}	is the total cooling duty at the PCC plant [kJ/h];
T_{CWin}	is the temperature of CW at the supply side [K];
T_{CWout}	is the temperature of CW at the return side [K];

c_{pCW} is the specific heat of CW [kJ/(kg K)];

ρ_{CW} is the density of CW [kg/m^3];

q_{mCO_2} is the mass flow rate of a product CO_2 stream [t/h].

The total cooling duty incorporates any reduction in cooling water duty for the host power plant and any auxiliary units as a result of the installation of the PCC plant.

NOTE The cooling system is dependent on each PCC project. It can include cooling towers, a once-through CW system, or air fin coolers.

Annex E
(informative)

Reference conditions

E.1 General

It is desirable to conduct the performance evaluation under the design conditions and the reference conditions. Reference conditions are generally used as a reference point to adjust the results of the performance evaluation as needed for the purpose of comparability in reporting and benchmarking.

This annex presents the suggested conditions for evaluating the performance of the PCC plant.

To determine the optimal conditions for standardizing performance evaluations of PCC plant, this document highly recommends that this annex be reviewed regularly once more PCC plants are in operation.

E.2 Ambient conditions

This clause specifies the ambient conditions for pressure, temperature and humidity.

— Ambient pressure: 101,325 kPa

— Ambient temperature: 15 °C (288,15 K)

— Relative humidity: 60 %

E.3 CO_2 concentration in the flue gas

The CO_2 concentration in the flue gas could depend on factors such as fuel composition or excess air. It should be noted that the energy performance of the PCC plant can be greatly influenced by the concentration of CO_2 in the flue gas.

The following CO_2 volume concentration can serve as comparison basis for evaluation under reference conditions:

— Coal fired power plant firing bituminous coal: 14 % vol. (dry basis)

— Natural Gas Combined Cycle (NGCC) power plant[1]: 4 % vol. (dry basis)

E.4 Product CO_2 conditions

— CO_2 concentration: Overwhelmingly CO_2

— Outlet pressure (Ex-compressor): 14 MPa (gauge pressure)

— Outlet temperature (Ex-compressor): 40 °C (313,15 K)

1) This should be reviewed based on the standard reference conditions recommended under ISO 13443.

E.5 Utilities

— Cooling water temperature: 15 °C (288,15 K)

— Cooling water temperature difference: 10 K

— Electricity and steam conditions as required by the PCC plant are supplied by the host power plant or an auxiliary unit.

E.6 CO_2 capture efficiency

The CO_2 capture efficiency is defined as the percentage of the amount of captured CO_2 relative to the total amount of CO_2 present in the flue gas being processed.

The total amount of flue gas processed could be the full volume of flue gas from the power plant or a fraction of the total (i.e. a slip stream).

For the reference conditions, the following CO_2 capture efficiencies (η_{CO2}) are commonly recommended.

— Coal-fired power plant: 90 %

— NGCC power plant: 85 %

Annex F
(informative)

Check list for performance evaluation

The procedure in this checklist for the performance evaluation is explained below, and refers to Table F.1 to Table F.7 given the URN link below.

a) It is first necessary to clarify the outline of the project; the information of the host power plant, which has many interfaces with a PCC plant; and the PCC plant design requirement.

b) To evaluate the specific equivalent electrical energy consumption of the PCC plant, the important directly related parameters and the ancillary parameters to be checked are listed together in Table F.7. These parameters are identified by the colour of the cells according to the 'colour code' rule shown below.

c) Based on Table F.4 and Table F.5, the parameters relating to the thermal energy and the CW consumption should be checked in detail.

d) The summary is listed in Table F.3, which is input into Clause 9.

e) Effluent and emission are parameters in PCC plant design to be considered together with Table F.6 results and should be reported in Table F.2.

An electronic version of the tables presented in this annex is available at:

standards.iso.org/iso/27919/-1/ed-1/en

The user is permitted to use the tables in their original format without any modifications for the purposes specified in the document.

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