DETAILED PROTOCOLS FOR THE SYSTEM TECHNICAL MANAGEMENT RULES

In case of any discrepancy in the wording of the brochure between both languages, Spanish and English, the Spanish version shall prevail

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Detail Protocols for the System Technical Management Rules

RESOLUTION of 13 March 2006, of the Directorate General for Energy Policy and Mines, establishing detail protocols for the System Technical Management Rules

Royal Decree 949/2001 of 3 August, which regulates third party access to gas facilities and establishes an integrated economic system for the natural gas industry, sets out the basic items that should be included in the System Technical Management Rules; Article 13 states that the Technical Manager of the System, in collaboration with the other parties involved, shall draw up a proposal for System Technical Management Rules, which will then be sent to the Ministry of Economy for approval or amendment.

Article 13 of the above Royal Decree also states that the 'Technical Manager of the System will propose detailed protocols relating to the System Technical Management Rules to the Directorate General for Energy Policy and Mines at the Ministry of Economy; these will be subject to approval or amendment by the said Directorate General, upon the issuance of a report by the National Energy Commission.'

Article 1 of Royal Decree 1554/2004 of 25 June, which outlines the basic structural organisation of the Ministry for Industry, Tourism and Trade, amended by Royal Decree 254/2006 of 3 March, assigns the preparation and execution of Government Energy Policy to this department. Meanwhile, Article 4 of Law 50/1997 of 27 November grants the Ministers the exercise of regulatory power over matters relating to their departments.

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In compliance with the above, the Ministry of Industry, Tourism and Trade issued Order ITC/3126/2005 of 5 October, approving the System Technical Management Rules. The first final provision of this order permits the Directorate General for Energy Policy and Mines to adopt the necessary measures for the application and execution thereof, in particular for the approval and amendment of detailed protocols for the System Technical Management Rules and other requirements, rules, documents and operating procedures established for the correct operation of the system.

In line with the above, and with Additional Provision 11.3 of Law 34/1998 of 7 October and Article 13 of Royal Decree 949/2001 of 3 August, this resolution has been subjected to the necessary report by the National Energy Commission.

Based on the foregoing, this General Directorate hereby resolves:

Article One. Approval of the Detail Protocols.

The Detail Protocols referring to the System Technical Management Rules are hereby approved.

Article Two. Scope of application.

The Detail Protocols for the System Technical Management Rules will apply to the Technical Manager of the System, to all those accessing the system, the holders of gas facilities and consumers, and will be enforced at all Spanish Gas System facilities, as established in Article 59 of Law 34/1998 of 7 October, on the Hydrocarbons Sector.

Article Three. Resources.

An appeal against this resolution may be lodged, within one month, with the Honourable Secretary of State for Energy, as per the provisions of Law 4/1999 of 13 January, amendment to Law 30/1992 of 26 November, on the Legal Regime for Public Administration and Common Administrative Procedure, and of Law 6/1997 of 14 April on the Organisation and Operation of the General State Administration.

First Additional Provision. Supply loss.

Within 60 days of the day after the date of publication of this resolution, the Working Group for the Modification of the System Technical Management Rules will set up a working sub-group to study the impacts on the accepted supply loss from the SGERG-88 measurement system included in Protocol 01 ('Measurement'). The conclusions of this study will be taken into account in the annual proposal on supply loss to be drawn up by the Technical Manager of Energy, as per the provisions of Section 2.4.3 'Supply loss and self-consumption' of System Technical Management Rule NGTS-02.

First Transitory Provision. Publication of information about calorific value and correction factors.

Within three months from the day after the publication of this resolution, the Technical Manager of the System will publish on its website intelligible information for end users about the correction factors for pressure and temperature (to standardised relative pressures) applicable to each municipality supplied with natural gas, as well as the daily assigned calorific value.

In the case of municipalities with a natural gas supply from satellite plants or supplied with manufactured gas, this information will be published on the website of the DSO, which will be responsible for keeping the information up-to-date.

Second Transitory Provision. Adaptation of measuring equipment.

The holders of measuring equipment have a period of one month from the date of publication of this resolution to adapt the said equipment to the provisions of Detail Protocol 1.

First Final Provision. Entry into force.

This resolution will enter into force the day after its publication in the "Official State Gazette".

Resolution of 13 March 2006 of the Directorate General for Energy Policy and Mines, establishing detailed protocols for the Technical Management of the Gas System Regulations (published in the Official State Gazette on 4 April).

Validity: 5 April

PD-01

'Gas Measurement, Quality and Odorisation'

Approved by the Resolution of the Directorate General for Energy Policy and Mines of 22 September 2011. Replaces the Protocol approved by the Resolution of 13 March 2006 of the Directorate General for Energy Policy and Mines.

Validity: 30 days after its publication in the Official State Gazette, except for sections 6.4 and 6.5 (relating to metrological control of measuring and analysis facilities and equipment), which will enter into force 6 months after publication, applicable from the time of publication of the legislation ion question, and all sections referring to gas from alternative sources, which will enter into force on the day after publication.

Date of publication in the Official State Gazette: 3 October 2011.

Amended under the Resolution of 29 March 2012 of the Directorate General for Energy Policy and Mines, under which the table in section 4.4.5 was amended. 'Layout diagrams of measuring equipment depending on maximum hourly flow and annual consumption.'

Amended under the Resolution of 21 December 2012 of the Directorate General for Energy Policy and Mines, modifying detailed protocol PD-01 'Gas Measurement, Quality and Odorisation' of the System Technical Management Rules.

Validity: 8 January 2013

Modified by *Resolution of 8 October 2018 of the Directorate General for Energy Policy and Mines, modifying detailed section 5.2 "Gas quality standards" ((B.O.E. 23 October 2018)*

1. Purpose.

The purpose of this detailed protocol is to develop the Technical Management of the Gas System Regulation NGTS-05 'Measurement'. In order to do so, it defined the concepts and procedures relating to gas measurements, quality and odorant addition, manufactured gas, and gases from alternative sources such as biogas, gas obtained from biomass and other types of gas, provided it is technically feasible and safe to inject these gases into the natural gas transmission and distribution network.

2. Glossary.

This detailed protocol uses the definitions given in the Technical Management of the Gas System Regulation NGTS-01 'General Concepts' and, in relation to metrological controls, those listed in Article 2 of Annexes III, IV and VI of Royal Decree 889/2006 of 21 July on governmental metrological controls of measuring equipment.

3. General Conditions.

All obligations and responsibilities relating to the correct operation and metrological control of equipment and facilities for measurement, analysis and odorant addition, as well as those relating to their maintenance, repair and/or replacement where applicable, alongside necessary safety requirements for the equipment and installations in question, are the responsibility of their holders, as per current legislation.

3.1 Right to access measuring equipment and the checking of the same.

At transmission-transmission connection points (including exit connections at LNG regasification plants and underground storage facilities), transmission-distribution and distribution-distribution connection points, and at the point of supply to consumers, the holder of the installation must allow the other party to access the measuring equipment, given prior appointment.

To this effect, the parties involved at connection points are the holders of the interconnected facilities, the Technical Manager of the System (GTS) and the main shipper of the gas in question.

At supply points the parties involved are considered to be the consumer, the DSO/gas transmission company that owns the network to which they are connected and the shipper they send gas to. The Technical Manager of the System is considered one of these parties where, as per the definition included in NGTS-01, it is a consumer whose behaviour can affect the normal operation of the network to which it is connected.

When the holder of the measuring equipment is the party receiving the gas, the party providing the gas will have the right to perform regular checks, such as readings: checks on measuring instruments and the status of sealed elements of these.

In addition to the metrological control obligations that arise from "Ley 3/1985 of 18 March on Metrology, from Royal Decree 889/2006" and its consequent regulations, parties involved on the Gas System (transmission companies, DSO's, shippers and consumers) may request further checks on the measurement systems. These extraordinary checks must have exactly the same scope as the regular checks programmed for the metrological monitoring of the equipment.
The cost of extraordinary checks on measuring equipment will be payable by the requesting party, except where metrological controls confirm that there is a greater deviation than that permitted, in which case this cost will be payable by the holder of the equipment.

3.2 Right of access to data from remote meterings.

The Technical Manager of the System will have constant access to remote meterings at all exit points on the Basic Network. This access will not place any costs on users. The Technical Manager of the System will receive remote meterings from consumers whose behaviour can affect the normal operation of the network to which they are connected on a daily basis, either directly or through the DSO.

At their data management centres, DSO's will also receive measurement readings from the supply points of consumers with remote metering equipment. This data is made available to the parties involved (shippers, gas transmission companies and the GTS) via the Transmission and Distribution Communication System (SCTD), with details by day, by 10:00 the following day.

3.3 Right to install to remote measurement equipment at connection points.

Section modified by Resolution of 21 December 2012, of the Directorate General for Energy Policy and Mines, modifying detailed protocol PD-01 'Gas Measurement, Quality and Odorisation' of the Technical Management of the Gas System Regulations.

Validity: 8 January 2013

At transmission-transmission connection points (including exit connections at LNG regasification plants and underground storage facilities), transmission-distribution and distribution-distribution connection points, and at the point of supply to consumers that could affect network operation, or when it may be necessary for balancing, the holder of the installation must allow the other party to fit remote metering devices to the equipment. The cost of this installation is payable by the party that fits it.

3.4 Regulations and standards applicable to the measurement, quality and addition of odorants to gas.

The GTS will publish and keep up-to-date on its website a list of current regulations and standards (UNE-EN and others) applicable to gas measurement, quality and odorant addition and to gas equipment, allowing users to download any open, free-to-access documents. It will also compile any relevant information contained in this documentation in a way that is clear and comprehensible to the consumer.

Regarding regulations, the list will refer, at least, to:

- Extracts from the regulatory provisions on readings and measurement, as well as the measurement standardisation process.
- The legal Spanish metrological standards and UNE-EN standards applicable to the different equipments: gas meters, converters, chromatographs, etc.
- Current Spanish legislation and UNE-EN standards determining the size of meters for supply points as per Point 4.4.4 of this detailed protocol.
- The UNE or internationally accepted standards that determine the quality characteristics of gas in order to check whether it meets the specifications listed in section 5 of this detailed protocol.
- The UNE or internationally accepted standards that establish the procedures for measurement and calculation applied as per section 6 of this detailed protocol.
- The altitude, in meters, of municipalities used for the calculation of the pressure conversion factor (K_p), and the official statistics organisation that publishes it.

In order to disseminate the above information and make it available to end consumers, both DSO’s and shippers must publish on their websites either a copy of the contents of the GTS website or a link to that website.

3.5 Operation manuals and measurement protocols.

Any operation manuals and/or measurement protocols that the holders of gas system facilities establish with the holders of other nearby facilities or with consumers must be consistent with the contents of this protocol, without prejudice to the parties' ability to make agreements regarding other unregulated topics.

The gas transmission companies will publish on their website the standard operating manuals and measurement protocols used.

4. Measuring equipment and gas analysis.

At transmission-transmission (including exit connections at LNG regasification plants and underground storage facilities), transmission-distribution and distribution-distribution connection points, and at the point of supply to consumers, facilities and measuring equipment must be subject to the metrological control obligations arising from Law 3/1985, Royal Decree 889/2006 and their consequent standards.

In any event, a prior certificate of conformance must be obtained for the installation and the measurement equipment, as per Spanish metrological legislation. Furthermore, the parties involved, in accordance with the definition found in section 3.1, will have the right to documentary evidence showing that the installation and measurement equipment have the necessary certification of conformance, given an appointment with the holder of the same.

4.1 Ownership.

At the transmission-transmission, transmission-distribution and distribution-distribution connection points, and at the point of supply to consumers, the ownership of equipment will be determined by current legislation or, where unavailable, by agreement between the parties.

4.2 Points on the Gas System that must have gas quality analysis equipment.

The measurement equipment for the following connection points must include composition, GCV and density analysers:

1. Connection points with gas pipelines or international gas fields.
2. Connection points with national gas fields.
3. Tanker unloading points at LNG regasification plants.

4. Connection points with LNG regasification plants.
5. LNG truck loading points.
6. Connection points with underground storage facilities.
7. Connection points with production plants for manufactured gas and gas from alternative sources such as biogas, gas obtained from biomass or other types of gas.
8. Points where gas composition may be altered, or particularly representative points whose measurement is necessary for the correct calculation of composition. These points will be referred to as singular gas quality analysis points on the Basic Network.
9. Connection points where consumers may affect normal network operation as per the definition included in NGTS-01.

4.3 Points on the gas system where measurement and analysis equipment should be fitted with remote metering equipment.

The measurement equipment for the following connection points must be fitted with remote digital meters:

1. Connection points with gas pipelines or international gas fields.
2. Connection points with national gas fields.
3. Connection points with LNG regasification plants.
4. Connection points with underground storage facilities.
5. Connection points with production plants for manufactured gas and gas from alternative sources such as biogas, gas obtained from biomass or other types of gas.
6. Connection points where consumers may affect normal network operation as per the definition included in NGTS-01, or any other consumer legally obliged to use remote measurement equipment according to current regulations.

4.4 Characteristics and technical specifications of measurement equipment.

In general, measurement equipment must be subject to the following criteria for action:

- At transmission-transmission (including exit connections at LNG regasification plants and underground storage facilities), transmission-distribution and distribution-distribution connection points, the gas meter must be working above the transition flow (Qt) at that point 80% of the time, and in never under the minimum flow (Qmin).
- In the cases indicated above where the gas meter is found to be working outside the range for which it was intended, the following measures will be adopted, in order of priority:

  1. Adoption of provisional agreements between the network use managers downstream and upstream of the gas meter.

  2. Replacement of the gas meter for one with an adequate range, or in any event, with the lowest range possible without requiring mechanical works.

  3. Modifications to the measurement line where option 2 is not technically possible. In order to do this, the holder of the installation must implement a plan of action that must be approved by the GTS, who will set out the deadlines for presentation and completion of that plan.

  These actions must be taken as soon as possible once the fault has been detected.

4.4.1 LNG truck loading points.

At each LNG truck loading point, the holder of the regasification plant must provide a weighbridge with the following characteristics:

- Range: 60 tonnes.
- Scale: 20 kg.
- Precision: no less than 0.2% of the reading.

The weighbridge and all other equipment used for measuring, such as chromatographs, will be subject to applicable legal metrological control - upon installation, in regular checks and after repair or modification - in order to ensure their precision within the established range.

4.4.2 Entry points on the transmission network and exit points on the basic transmission network.

At the entry points on the transmission networks and exit points on the Basic Network, each line at the measurement installation will consist of the following:

1. A gas meter that has passed the metrological conformity assessment established in the European Union and meets applicable UNE-EN standards, and with an appropriate dynamic for covering the range of flow passing through it. This gas meter must be fitted with a pulse emitter for communication with the flow regulator.

2. A PTZ flow converter that has passed the metrological conformity assessment established in the European Union and meets applicable UNE-EN standards, with associated absolute pressure and temperature transmitters; the set of equipment must be of Class 0.5 as per the relevant UNE standard.

3. An auxiliary measurement line identical to the main line.

4. The measurement installations must be fitted with a remote measurement unit, as per the specifications defined by the gas supply operator, allowing measurement and gas quality data (where available) to be obtained at their remote metering management centres and in accordance with current legislation.

4.4.3 Connection points between distribution networks.

The measuring systems at connection points between DSO’s, regardless of metered pressure, must operate within a range of flows established by the manufacturer, with a double measurement line where winter and summer consumption levels make this advisable.

Where the installation does not have a double meter line, it must be fitted with a bypass to allow replacement of the gas meter. Furthermore, in cases where there is actual or foreseeable reversibility of flow between the two networks, the measurement systems will be capable of taking readings in both directions.

The composition of each of the lines making up the measurement installation will depend on capacity, expressed in nominal hourly capacity, and meter pressure.

In measurement systems with meter pressures above 4 bar, the installations will consist of the same elements as those indicated in section 4.4.2.

In measurement systems with meter pressures of 4 bar or less, installations will consist of:

1. A gas meter that has passed the metrological conformity assessment established in the European Union and meets applicable UNE-EN standards, and with an appropriate dynamic for covering the range of flow passing through it.

2. A PT or PTZ flow converter that has passed the metrological conformity assessment established in the European Union and meets applicable UNE-EN standards. The chosen option will be agreed between the parties, case by case, and will be reflected in a protocol signed by both parties, also establishing their respective rights and obligations.

Measuring systems in operation before this protocol took effect, and the diagrams for which do not meet the provisions of this section, can continue in operation until the end of their useful life, or until they are modified, without prejudice to the foregoing paragraphs.

In the cases described in section 3.2, the measuring systems must be fitted with a remote measurement device to allow access to data from the DSO's remote measurement management centre.

4.4.4 Supply points.

Section modified by "*Resolution of 21 December 2012, of the Directorate General for Energy Policy and Mines, modifying detailed protocol PD-01 'Gas Measurement, Quality and Odorisation of the Technical Management of the Gas System Regulations.*

Validity: 8 January 2013

In the specific case of measurement systems at supply points, the system type in terms of configuration and constituent parts will be determined depending on the maximum hourly flow measured under the benchmark conditions on the gas system (considered as pressure of 1.01325 bar and temperature of 273.15 K) and annual consumption, as indicated in the tables below, and in the measurement system diagrams set out in section 4.4.5.

Table 1: Management systems depending on maximum hourly flow and final consumption for measuring pressures > 0.4 bar

Maximum flow rate [m³/h]	**Annual consumption (GWh)**			
	< 10	≥ 10 and <100	≥ 100 and <150	≥ 150
Q < 150	Fig III with PT converter	–	–	–
150 ≤ Q < 350	Fig III with PT converter	Fig III with PT converter	–	–
350 ≤ Q < 600	Fig III with PT converter	Fig III with PT converter	Fig III with PT converter	Fig III with PT converter
600 ≤ Q < 3500	Fig III with PT converter	Fig III with PT converter	Fig III with PTZ converter	Fig IV with PTZ converter
3500 ≤ Q < 6500	Fig III with PT converter	Fig III with PTZ converter	Fig IV with PTZ converter	Fig IV with PTZ converter
Q ≥ 6500		Fig IV with PTZ converter	Fig IV with PTZ converter	Fig IV with PTZ converter

Table 2: Management systems depending on maximum hourly flow and final consumption for measuring ≤ 0.4 bar

Maximum flow rate [m³/h]	**Annual consumption (GWh)**				
	< 2	**≥ 2 and <5**	**≥ 5 and <10**	**≥ 10 and <100**	**≥ 100**
Q < 150	Fig I	Fig I	Fig I	–	–
150 ≤ Q < 350	Fig I	Fig II	Fig II	Fig III with PT converter	–
350 ≤ Q < 600	Fig I	Fig III with PT converter	Fig III with PT converter	Fig III with PT converter	–
Q ≥ 600		Fig III with PT converter	Fig III with PT converter	Fig III with PT converter	Fig III with PT converter

Note 1: At measurement installations with layouts I and II, correction will take place using the fixed conversion factor resulting from applying the provisions of section 6.2.

Note 2: Installations that should otherwise follow layout I but that, for operational reasons, cannot undergo a change of gas meter during working hours, (from 8:00 to 18:00) should adopt layout II.

Note 3: For the regulation and measurement equipment types A-6, A-10-B and A-10-U listed in UNE 60404-1, the measurement system must comply with the design and operation requirements established in that standard, and the requirements in this section do not apply.

Measurement systems are designed based on the expected maximum hourly flow and its modulation, i.e., it must be ensured that the chosen gas meter covers the range of flows circulating through it at all times, including the minimum hourly flow, as per regulations.

For consumers whose variations in consumption make it impossible to use a measurement system with just one gas meter to cover these variations, gas measurement must be done based on a parallel switch system covering the variations in flow, or different consumption levels should be separated.

In cases where the consumer contracts more supply than before, requiring a change in the existing type of metering, the holder of the installation should set up an adaptation plan, which must be approved previously by the relevant network operator, affording that same right to the pertinent shipper.

In cases where the consumer contracts a lower supply, requiring a change in type of metering, the holder of the installation must set up an adaptation plan, which must be approved previously by the relevant network operator, affording that same right to the commercial operator.

Network operators must inform the consumers connected to their networks who are obliged to have remote measurement equipment installed of their communication protocols so that this information can be received at their remote measurement management centres.

Measuring systems in operation prior to the entry into force of this protocol, and the diagrams for which do not meet the provisions of this section, can continue in operation until the end of their useful life, without prejudice to the foregoing paragraphs.

4.4.5 Layout diagrams for measuring equipment depending on maximum hourly flow and annual consumption.

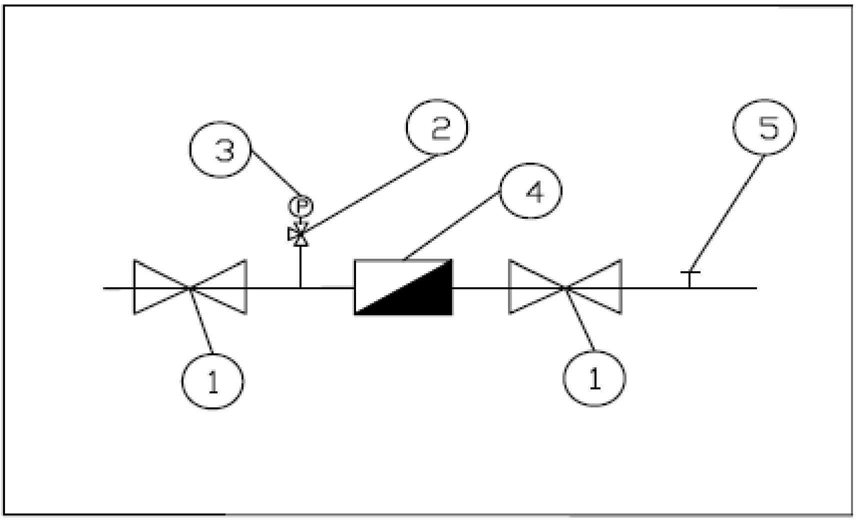
Section modified by *Resolution of 29 March 2012, of the Directorate General for Energy Policy and Mines*, modifying the table in section 4.4.5 'Layout diagrams for measuring equipment depending on maximum hourly flow and annual consumption.'

Validity: 24 April 2012

Section modified by Resolution of 21 December 2012, of the Directorate General for Energy Policy and Mines, modifying detailed protocol PD-01 'Gas Measurement, Quality and Odorisation of the Technical Management of the Gas System Regulations.

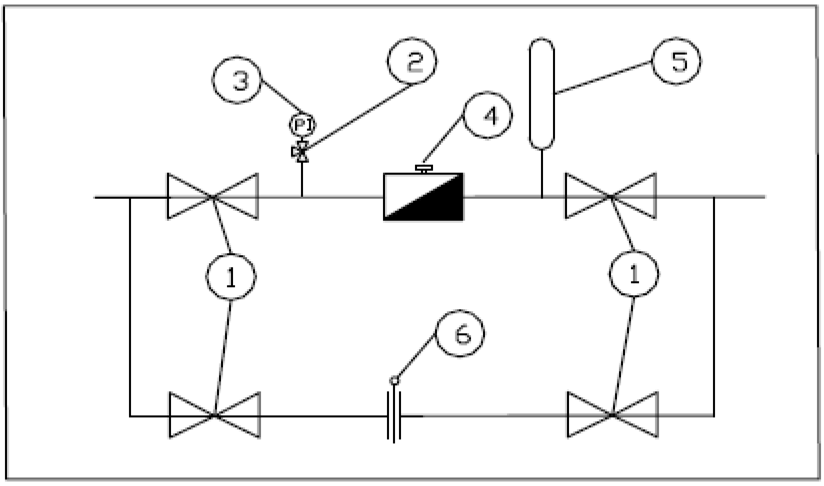
Validity: 8 January 2013

Figure I



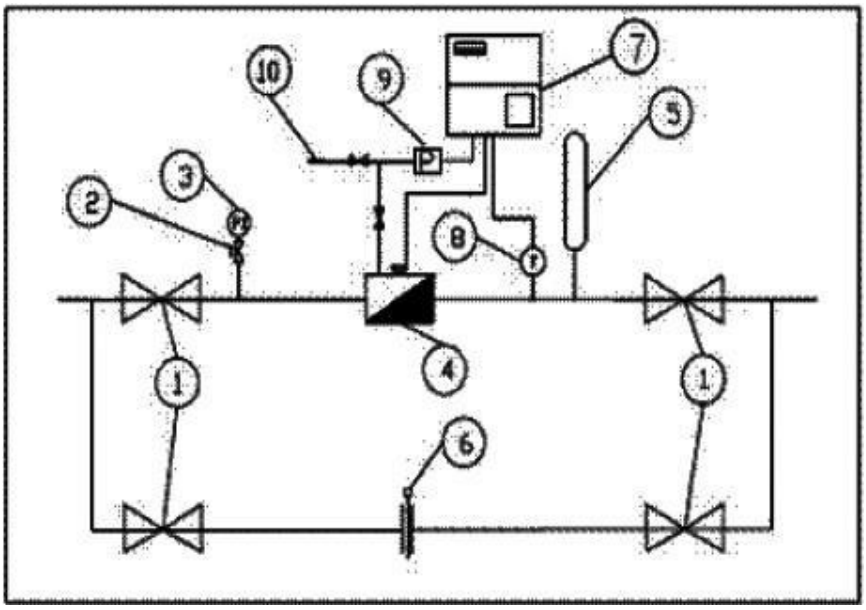
1. Shut-off valve
2. Three-way valve with a ¼" inlet for a standard contrast manometer
3. Appropriate manometer for the working pressure level (*)
4. Gas meter
5. Low pressure calibre inlet (PC<150 mbar)

Figure II



1. Shut-off valve
2. Three-way valve with a ¼" inlet for a standard manometer
3. Appropriate manometer for the working pressure level (*)
4. Gas meter
5. Thermometer
6. Spectacle blinds

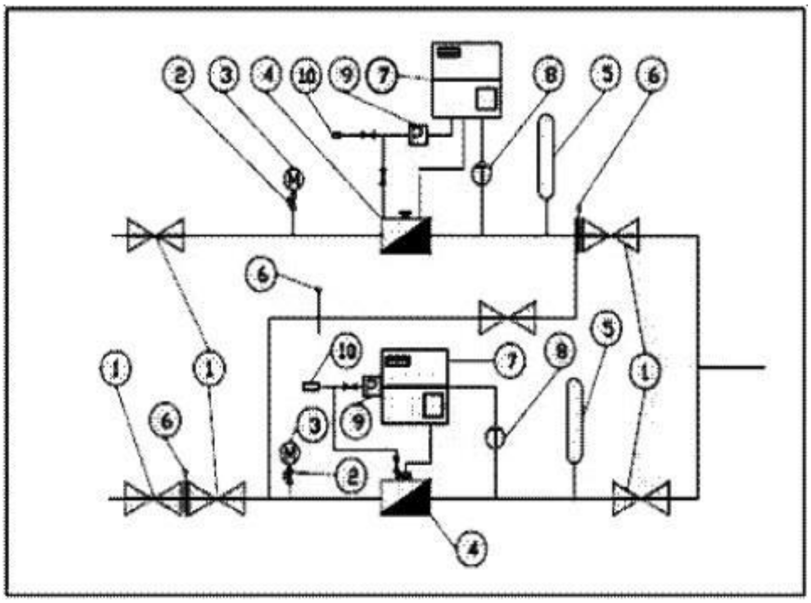
Figure III



1. Shut-off valve
2. Three-way valve with a ¼" inlet for a standard manometer
3. Appropriate manometer for the working pressure level (*)

4. Gas meter
5. Thermometer
6. Spectacle blinds
7. Electronic volume converter
8. Temperature probe
9. Pressure transmitter (can be incorporated in the LCC)
10. ¼" pressure inlet with sealable valves for contrasting

Figure IV



1. Shut-off valve
2. Three-way valve with a ¼" inlet for a standard manometer
3. Appropriate manometer for the working pressure level (*)
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5. Thermometer
6. Spectacle blinds
7. Electronic volume converter
8. Temperature probe
9. Pressure transmitter
10. ¼" pressure inlet with sealable valves for contrasting

(*) Depending on the underlying cause and the working pressure of the gas meter (Pr), the following types of manometers will be used:

Pr <= 0.08 bar	class 1.6 ϕ 80-100 mm sphere, or class 1 ϕ 100 mm sphere
0.08 bar < Pr<= 0.4 bar	class 1 ϕ 100 mm sphere, or class 0.6 ϕ - 150 - 160 mm sphere
Pr > 0.4 bar	class 0.6 ϕ 150 -160 mm sphere.

4.5 Characteristics and technical specifications of measurement equipment.

Quality analysis equipment must have passed a metrological conformity assessment from the relevant European Union authority, they must be digital, take hourly and daily readings, with a minimum storage capacity of 31 days, and must provide, at least, the following information via a continuous analysis of gas flow:

- Molar percentages of each of the following components: Nitrogen, carbon dioxide, methane, ethane, propane, iso-butane, n-butane, n-pentane, iso-pentane, C6+ fraction.
- Inferior calorific value (ICV) and gross calorific value (GCV) in kWh/m3 (under benchmark conditions).
- Relative density (d).
- Wobbe index (W) in kWh/m3 (under benchmark conditions).

These calculations are made as per the relevant UNE standard. The calculation of GCV for volumetric gas is expressed as H_s [t_1,p_1,V(t_2,p_2)] under benchmark conditions [0ºC, V (0 ºC, 1.01325 bar)].

At the international connections via gas pipelines with Europe, for the calculation of the GCV of gas, the provisions of the applicable detailed protocol will be used.

Connection points with production plants for manufactured gas and gas from alternative sources such as biogas, gas obtained from biomass or other types of gas will be fitted with analysis and monitoring equipment that allows continuous checking of the gas entering the system. This equipment must be accepted by the interconnected parties and have obtained the relevant certifications.

The holders of installations fitted with equipment not meeting the above characteristics must draw up a plan to replace or adapt their equipment, which should then be validated by the GTS.

5. Gas quality analysis

5.1 Party responsibility

5.1.1 Points of measurement and regular monitoring of measurement equipment and systems.

The GTS will be responsible for defining the individual measuring points for gas quality analysis on the basic gas network where it is necessary to install an analysis device for the gas quality parameters.

The holder of the installation where a gas quality analysis device is fitted will regularly check the measurement system in order to ensure it is operating correctly, and will send a detailed description of any incidents detected to the GTS as soon as possible, together with the results obtained where corrective measures have been applied.

The GTS will supervise this monitoring and publish an annual report that includes, broken down by holder and facility, a comprehensive summary of any incidents detected over the course of the year, grouping them by uniform types, the details of each incident detected, an assessment of the impact on the measurement, as well as any corrective measures applied, or due to be applied. The holders of the equipment will receive the part of the report referring to them, and a full copy of the report can be requested by the National Energy Commission and the Directorate General for Energy Policy and Mines.

Each and every holder of gas quality control facilities must store the results of all monitoring and analyses performed.

Every six months, the GTS should issue a list of the networks where gas quality must be altered and the new composition to be inserted into the PTZ converters.

5.1.2 Gas quality.

Users of the Gas System who flow gas into the system are responsible for the quality of that gas and for compliance with the specifications given in this detail protocol.

Users injecting manufactured gas or gas from alternative sources, such as biogas, gas obtained from biomass and other types of gas, must provide certification from the relevant authorities to guarantee that the gas provided meets the specifications of section 5.2 for flow into the transmission network.

Furthermore, the introduction of gases produced using microbial digestion must be conditional on an assessment by the user of the potential risk to public health or the integrity of consumption installations or devices posed by micro-organisms and other minority components of these gases.

The holder of the entry point to the Gas System must supervise the quality of the gas introduced into the system in order to report any problems with gas quality to the GTS and all affected parties as soon as possible, with an estimate of the possible duration of any such breach. In any event, the GTS may adopt any measures considered necessary to cancel or minimise the impact that this event may have on the Gas System.

However, when the gas transmission company is warned or can see that the gas received or due to be received at the entry point falls outside the established quality standards, it may:

1. Reject any non-compliant gas, partially or in full.
2. Accept the gas, partially or in full, as an exception in the case of regasification plants, respecting the reliability and safety criteria of the Gas System, i.e. the gas flowed into the transmission and distribution network must meet all quality standards. In this case, the holder of the gas will repay the transmission company for all duly justified costs incurred as a result of accepting natural gas outside these quality specifications.

The holder of the installation with a gas system entry point is not obliged to deliver natural gas to the exit points with precisely the same characteristics as the gas introduced via the entry points, provided that the amount of energy agreed to is delivered.

The gas delivered to the consumer, regardless of source, must not contain dust particles or any other impurities in amounts that could be harmful to consumer health or damage their installations.

5.2 Gas quality standards

Section modified by Resolution of 8 October 2018 of the Directorate General for Energy Policy and Mines, modifying Technical System Management Rules NGTS-06, NGTS-07 and Detailed Protocols PD-01 and PD-02.

All the gas introduced at the point of entry to the Gas System must comply with quality standards in the following table:

Table 3: Quality standards for gas flowed into the Gas System.

Characteristic (*)	Unit	Minimum	Maximum
Wobbe index	kWh/m^3	13.403	16.058
GCV	kWh/m^3	10.26	13.26
Relative density		0.555	0.700
Total S	mg/m^3	–	50
H_2S + COS (as S)	mg/m^3	–	15
RSH (as S)	mg/m^3	–	17
O_2	mol %	–	0.01
CO_2	mol %	–	2.5
H_2O (dew point)	ºC at 70 bar (a)	–	+ 2
HC (dew point)	ºC at 1 -70 bar (a)	–	+ 5
Dust / Particles	–	Technically pure	

(*) Table expressed in the following benchmark conditions: [0ºC, V(0ºC, 1.01325 bar)]

In addition to the above characteristics, gases from alternative sources, such as biogas, gas obtained from biomass or other types of gas produced using microbial digestion, must meet all the quality specifications in the following table:

Table 4: Quality standards for gas from alternative sources introduced into the Gas System.

Characteristic (*)	Unit	Minimum	Maximum
Methane (CH_4)	mol %	95	–
CO	mol %	–	2
H_2	mol %	–	5
Halogen Compounds - Fluoride/Chloride	mg/m^3	–	10/1
Ammonia	mg/m^3	–	3
Mercury	µg/m^3	–	1
Siloxanes	mg/m^3	–	10
Benzine, Toluene, Xylazine (BTX)	mg/m^3	–	500
Microorganisms	–	Technically pure	
Dust/Particles	–	Technically pure	

(*) Table expressed in the following benchmark conditions: [0ºC, V(0ºC, 1.01325 bar)]

Regarding the O_2 content of the injected biogas into the networks, the biogas injection must fulfill with the following:

a) Injection of biogas in transmissionnetworks.

In general terms, the injection of biogas into the transmission network will be accepted with an O_2 content of up to 0.3 mol % provided that the following circumstances are present at the injection point:

1. CO_2 content must at no point exceed 2 mol %.
2. The dew point for water must at no point exceed negative eight degrees centigrade (- 8ºC).

3. The volume of biogas injected into the trunk transmission network must never exceed 5,000 m^3/h (under benchmark conditions) For greater volumes - and in any event for the remaining points of entry to the gas system - the maximum volume of injection for biogas will be determined for each specific case, based on the quality and volume of gas transported through the network in question, by the network holder, and reported to the Directorate General for Energy Policy and Mines, to the GTS and the National Energy Commission.

b) Injection of biogas in distribution networks.

In general terms, the injection of biogas into the distribution networks will be accepted with an O_2 content of up to 1 mol % provided that the following circumstances are present at the injection point:

1. CO_2 content must at no point exceed 2 mol %.
2. The dew point for water must at no point exceed negative eight degrees centigrade (- 8ºC).

When injection into the distribution network takes place without the necessary facilities with which to evacuate the gas to the transmission network, the DSO will notify the user of the maximum flow rate that can be injected. In order to calculate the maximum allowable flow rate, the holder of the distribution network may request information from the Technical Manager of the System or the holders of the connected chain of distribution networks.

The National Markets and Competition Commission will resolve any discrepancies that may arise between parties at the biogas injection points on the distribution network.

Where biogas is injected through a regulation and measurement stations, in order to comply with the previously described requirements in relation to gas quality, the characteristics of the gas will be measured at the exit point of the regulation and measurement stations where the biogas is injected.

5.3 General criteria for the gas composition analysis procedure.

In addition to the requirements established for measurement instruments in the field of metrological control resulting from Law 3/1985 and its associated regulations, the chromatograph will also perform a daily automatic calibration using bottles of span gas made by accredited shippers for natural gas analysis as per ISO Standard 17025.

The chromatograph will be calibrated with span gas of a composition similar to the gas analysed.

Gas quality data necessary for performing the tasks entrusted to the GTS are sent via the Third-party Access Logistics System (SL-ATR).

5.4 Change in gas quality in PTZ converters.

Every six months, the GTS should issue a list of the networks where gas quality must be altered and the new composition to be inserted into the PTZ converters.

This list will include networks where the average GCV for the semester exceeds by ±1% the GCV of the gas flowed into the PTZ correctors of the measurement equipment on a network.

On networks within the variation range of ±1% of GCV, the GTS will analyse the Z variation, making up the average composition of the gas in the previous semester compared to the composition of the gas used at that moment in the PTZ correctors. If a significant difference is observed from the permitted margin of error in the measurement equipment, these networks will also be included on the list issued.

In order to make alterations to the parameters in measuring equipment, current metrological regulations will apply. The parties involved may witness these changes if they wish to do so.

In the case of flow converters connected to the continuous chromatograph, these values are entered as default values, although in case of chromatograph signal failure, the latest validated figure will be used.

6. Gas measurement.

6.1 Measurement procedures at points on the Gas System.

In general, the measurement and calculation procedures will adapt to the provisions of the relevant UNE standard.

6.1.1 Measurement procedure during tanker unloading.

Detail Protocol PD-05 will apply:
'Procedure for the determination of energy unloaded from methane tankers'.

6.1.2 Measurement procedure at the gas transmission network entry and exit points and at transmission-transmission, transmission-distribution and distribution-distribution connection points.

At gas transmission network entry and exit points, connections with LNG regasification plants, international connections, connection points with national gas fields, connection points with underground storage facilities and connection points with production plants for manufactured gas and gas from alternative sources, the holder of the installation will take readings from the equipment.

At points where gas is transferred between two DSO's, meter readings will be taken by the DSO who owns the installation.

In both cases, regardless of the right to witness meter readings given to the other party, should the latter not attend, the party responsible for taking the reading will make it available to the other party within two working days.

Readings will be taken at the end of the monthly reading period, as per a schedule approved by both parties. At delivery points with remote metering, this 'in situ' reading period can be extended, provided both parties come to an agreement.

The relevant operator will draw up a daily gas emissions report and submit it to the upstream DSO or to the gas transmission company, depending on the network to which the installation is connected, so that they DSO or gas transmission company can do their work. This information is provided via SCTD or SL-ATR, depending on the recipient.

6.1.3 Measurement procedure for LNG truck loading.

LNG truck cisterns must comply with current Spanish regulations and legislation for this mode of transport.

For measurement purposes, and before the first load, the holder of the tanker must provide the regasification plant with the following documentation:

- Tank data plate.
- Certificate of capacity issued by an authorised organisation.

The measurement of the LNG loaded into each truck is taken in kWh, based on:

- Net weight (in kg) determined on the weighbridge, by finding the difference between the entry weight and exit weight of the truck.
- LNG quality (GCV expressed in kWh/kg and kWh/m^3 under benchmark conditions) obtained from the continuous chromatograph analysis of representative samples of the LNG loaded onto the trucks.

The amount of LNG loaded onto each truck cistern is calculated based on the above concepts, as will be reflected in the documentation provided.

Furthermore, the holder of the regasification plant will submit a daily report to the GTS, via SL-ATR, on the LNG outflows to each DSO, shipper or consumer flowing gas into the system.

6.1.4 Measurement procedure at supply points.

For consumers with remote metering devices at their installations, the daily consumption data will be transmitted to the network operator through a remote meter using a communication protocol defined by that operator.

Consumers obliged to use remote measurements, but whose remote measurements are not in operation, must provide the consumption readings from the previous day to DSO/transmission company with whom they are connected each day by 06:00.

This is done in the format provided by the DSO/transmission company and will preferably be sent by email.

The network operator will take a monthly reading of data for all consumers with an annual consumption volume above 100,000 kWh, who do not have remote metering installed, or where it is not in operation.

For consumers legally obliged to have remote metering, but who do not have it or where it is not operational, and this is the responsibility of the consumer, the daily consumption allocation will be performed using a procedure established to this end; this procedure must be familiar to the affected consumer and shipper before it can be applied.

The network operator is responsible for transforming this data into energy units and entering it onto SL-ATR so that the relevant Balancing and Distribution can be completed.

For consumers with an annual volume of 100,000 kWh or less, data will be read at the intervals indicated in current legislation. In these cases, the daily consumption allocation will be based on the provisions of the Technical System Management Rule NGTS-06
'Distribution' and NGTS-07 'Balancing'.

In any event, current legislation will apply.

6.2 Conversion of units of volume to units of energy.

Section modified by "Resolution of 15 *February 2019, of the Directorate General for Energy Policy and Mines".*

To convert the unit of measurement of the meters (m^3) to the established unit of energy (kWh), the energy value for natural gas called gross calorific value (GCV) will be used, measured under benchmark conditions for the gas system of 1.01325 bar (1 bar = 10^5 Pa) and 273.15 K. The applicable calculation formula is the following:

$$E[kWh] = V[m^3] * Fc' \left[\frac{kWh}{m^3}\right]$$

Where:

E = energy delivered at the supply point.

V = Volume measured under supply conditions.

Fc' = volume conversion factor.

The conversion factor for the measurement conditions is calculated as:

$$F_c' \left[\frac{kWh}{m^3}\right] = GCV \left[\frac{kWh}{m^3}\right] * F_c$$

Where:

GCV = Gross calorific value of gas at the point of measurement, measured under benchmark conditions (1.01325 bar and 273.15 K).

Fc = Volume conversion factor for converting the measurement conditions into benchmark conditions.

The conversion of the m^3 measured by the meter to m3 under benchmark conditions is done using electronic conversion equipment (converters) that perform this calculation continuously, integrating the pressure, temperature and compressibility signals measured by the relevant transmitters, and using a conversion factor (Fc) obtained using the formula:

$$Fc = \frac{P\ c.supply}{P\ c.benchmark} x \frac{T\ c.benchmark}{T\ c.supply} x \ \frac{Z\ c.benchmark}{Z\ c.supply} = K_p\ x\ K_t\ x\ K_z$$

Where Z is the compressibility factor, defined as the ratio between the true molar volume of a gas and the ideal molar volume of the same gas.

The calculation of the compressibility factor both under benchmark conditions and supply conditions is performed using procedure SGERG-88 included in standard UNE-EN ISO 12213.

Section 4.4 of this protocol establishes the installation requirements for pressure, temperature and compressibility factor converters (PTZ and PT converters) depending on the pressure at which the measurement is taken and the maximum hourly flow.

For consumers supplied a pressure of 0.4 bar or below, the influence of factor Z will be disregarded; in other words, it will be assumed that the value is close to the unit, and consequently the conversion factor by which the volume measured in m3 will be multiplied for expression under benchmark conditions of pressure and temperature will be:

$$Fc = \frac{P\ c.supply}{P\ c.benchmark} x \frac{T\ c.benchmark}{T\ c.supply} = K_p\ x\ K_t$$

K_t = Conversion factor for temperature.

K_p = Conversion factor for pressure.

The conversion factor for temperature is calculated using the following formula:

$$Kt = \frac{273.15}{273.15 + T_{gas}}$$

Where T_{gas} is the temperature 10ºC.

The conversion factor for pressure is calculated using the following formula:

$$K_p = \frac{P_c + P_{atm}}{1{,}01325}$$

Where:

P_c = Relative supply pressure (bar).

P_{atm} = Atmospheric pressure (bar).

The value of atmospheric pressure depends on the altitude (A) of the municipality where the supply point is located and is calculated using the following formula:

$$P_{atm} = 1{,}01325 - k * A = 1{,}01325 - \frac{0{,}1223 * A}{1000}$$

Where A is the altitude of the municipality where the supply point is located, in metres, published by the official statistics authority.

Factor k is calculated, meanwhile, by applying the following formula:

$$k\left[\frac{mbar}{m}\right] = \frac{g\ x\ d}{100} = 0{,}1223$$

Where d is the density of air (ISO 6976) interpolated in T_{gas} (10ºC), and g is the standard acceleration of gravity, with the following values:

d = 1.2471

g = 9.8065 (m/s^2)

In the case of facilities supplying consumers who do not have a pressure corrector in their facilities, but who have a regulator prior to gas measurement, the pressure conversion factor (Kp) will be calculated taking the set pressure of the gas regulator as the supply pressure.

In the case of consumer supply facilities connected to networks with a maximum service pressure of 22 mbar and which do not have a regulator prior to gas measurement, the pressure conversion factor (Kp) will be calculated taking the pressure of 22 mbar as the supply pressure, except in cases where the regulators of the regulating and measuring stations feeding into that network are set to a lower pressure, in which case that pressure shall be taken as reference.

6.3 GCV applicable to consumers connected to transmission networks.

In the case of consumers connected to gas transmission networks, the daily GCV values applied are those which pertain to the closest upstream measurement points.

6.4 GCV applicable to consumers connected to distribution networks.

For supply points not fitted with gross calorific value (GCV) readers, the value assigned to them for invoicing purposes will be the average daily gross calorific value (GCV_{Daily}) for the distribution network where they are located, calculated using the following formula:

$$GCV_{Daily} = \frac{\sum_{i=1}^{m}(V_i * GCV_i)}{\sum_{i=1}^{m} V_i}$$

Where:

i = Connection to the distribution network where the supply point to the gas transmission network is located

m = Number of connections to the distribution network where the supply point to the gas transmission network is located

V_i = Volume of gas transported on day “d” via connection points “i" on the distribution network where the supply point is located

GCV_i = average GCV of the gas measured by the chromatograph associated with connection “i" on the distribution network, located either at the PCTD or the closest upstream.

6.4.1 Consumers without remote metering equipment

In the case of consumers for whom a reading is taken every monthly or more, the average gross calorific value ($GCV_{average}$) used for the calculation of kWh consumed during the period is determined by applying the average of daily values (GCV_{daily}) for the distribution network where the consumer is located, weighted by the daily volume transported through it, for the 30 or 60 days immediately preceding day 'n-2 of the latest reading, depending on whether this is monthly or bi-monthly, and as per the following formula:

Monthly reading:

$$GCV_{Average} = \frac{\sum_{d=n-32}^{n-3}\left(V_d * GCV_{daily,d}\right)}{\sum_{d=n-32}^{n-3} V_d}$$

Bimonthly- reading:

$$GCV_{Average} = \frac{\sum_{d=n-62}^{n-3}\left(V_d * GCV_{daily,d}\right)}{\sum_{d=n-62}^{n-3} V_d}$$

$GCV_{Average}$ = Average gross calorific value applicable to the invoicing period, the reading for which is taken on day «n»

d = Day of invoicing period.

n = Day of latest reading.

V_d = Total volume of gas transported on day "d" via connection points i on the distribution network where the consumer is located, with the transmission network.

$GCV_{Daily,d}$ = Daily GCV of the gas transported to the distribution network where the supply point is located on day "d".

6.4.2 Consumers with remote metering equipment.

In the case of supply points with remote metering, at least the daily gross calorific value (GCV_{Daily}) will be applied, calculated as described, to daily consumption. Hourly data (GCV_{Hourly}) can be used if available.

When hourly GCV data is used, they are assigned as follows:

- If the supply point is located on a distribution network with a single connection point to the transmission network, it will be assigned the hourly GCV determined by the analytical equipment associated with that connection.
- If the supply point is located on a distribution network with several connection points to the transmission network, the hourly GCV used will be the average taken from all hourly GCV data provided by the analytical equipment associated with each different connection, weighted by the hourly volume of gas transported through each one.

6.5 Information to be published on the conversion factor.

The GTS will publish via the SL-ATR a list of municipalities supplied with natural gas (including those supplied by satellite LNG plants), manufactured gas and gas from alternative sources, with the volume conversion factors applicable to consumers without pressure and temperature converters.

This list will include, for each municipality, the applied altitude and the value of the conversion factor (Fc) corresponding to the supply pressure, including at least five standardised relative pressures (20 mbar, 22 mbar, 50 mbar, 55 mbar, 100 mbar y 150 mbar)) at an average supply temperature of 10ºC, which is considered the national weighted average temperature. The DSO will be responsible for informing the GTS of municipalities where gas allocation takes place, together with the identification of the connections of the distribution networks for those municipalities with the transmission network.

Furthermore, the number of connections to the transmission network for each municipal network and the chromatographs associated with each connection will also be identified via the SL-ATR, providing for each one the daily average gross calorific value (GCV) and the daily volume of gas transported through them (V_i), as well as the daily average gross calorific value for the network on which the supply points are located (GCV_{Daily}), calculated as per the provisions of section 6.4.

Every day, the GTS will publish via SL_ATR the average gross calorific value for each distribution network (GCV_{Avg}) for the previous day (day 'n'), calculated as per the provisions of section 6.4.1.

The SL-ATR must keep a record of at least 24 months' information in order to allow the competent bodies to check the calculation of the average GCV used to determine the kWh consumed during the invoicing period.

The above information, clearly comprehensible to the end user, including the conversion factor (Fc) applicable to supply pressures, and each of the five standardised relative pressures (20 mbar, 22 mbar, 50 mbar, 55 mbar, 100 mbar y 150 mbar) for each distribution network, together with the daily gross calorific value (GCV_{Daily}), will be published on the GTS website. This site will also make it possible for consumers with monthly or less frequent readings to obtain the average GCV applicable to their bill by entering the distribution network on which the supply point is located and the date of the latest consumption reading for the bill.

7. Metrological monitoring of measuring installations.

Gas measurement and analysis installations must meet all requirements regulated by applicable Spanish metrological legislation and, in particular, by the provisions of Law 3/1985 of 18 March on Metrology and its consequent regulations.

The meters and converters included in the scope of the Ministerial Order of 26 December 1988 and/or Directive 2004/22/EC of the European Parliament and the Council of 31 March 2004 must have been commissioned as per all applicable regulations.

Since 30 October 2006, the commercialisation and commissioning phase for meters and converters must comply with Annex VI of Royal Decree 889/2006 of 21 July, regulating State metrological control of measuring instruments, and all applicable resulting regulations.

In those areas where there is no regulation, the provisions of this section will apply.

7.1 Party responsibility.

The metrological control of equipment, including metrological checks, will take place as per the provisions regarding the authority, execution and obligations of the different parties. Law 3/1985 and Royal Decree 889/2006 stipulate that all expenses incurred are payable by the holder of the equipment, except in case of signed agreements between the parties, prior to the entry into force of this detailed protocol.

7.2 General requirements

In general, the authoritative framework for the completion of metrological control on measurement systems, the parties involved and their appointment, as well as the requirements to be met, will be those defined under current metrological regulations.

Regular metrological checks must be programmed for the equipment in order to confirm whether these are taking precise readings, or if it is necessary to adjust or repair some of the elements in the system.

Regular metrological checks of meters except ultrasonic ones, should be performed through accredited laboratories as per the criteria of ISO Standard 17025 on gas meter calibration. Where the operating pressure of the gas meter is over 35 bar, metrological checking must be performed through accredited laboratories as per the criteria of ISO Standard 17025 on gas meter calibration, using natural gas as the fluid and at a pressure of 35 bar.

The regular metrological checks on ultrasonic gas meters must take place 'in-situ', applying a particular procedure previously approved by the affected parties and included in the measurement protocol.

The results obtained from these checks, if outside the margin of error accepted under applicable legislation, will give rise to adjustments.

When the operating conditions require a high pressure metrological check (over 35 bar) or the gas meter is being installed for the first time, the error curve produced by testing at different flow rates will be entered into the flow converter, with a view to correcting errors in the meter's habitual operating flows.

The regular metrological checks on flow converters and their associated elements, pressure transmitter and temperature probe, should take place in situ, with the necessary baseline tools.

At the points on the gas system, the shippers affected by the measurements and the operators of the relevant networks will be authorised to require regular metrological checks with the frequency established in applicable regulations, or as set out in this detailed protocol.

As a general rule, network operators will be responsible for ensuring that regular metrological checks are carried out on measurement systems, taking as a starting point the inventory of measuring equipment on the points of the Gas System connected to their network, to guarantee that all devices are checked within the period established under this detailed protocol. Where the holder of a measuring system fails to comply with this obligation, after a maximum of three months after receipt of written notification, the network operator may request that authorised parties be sent to perform the check. All expenses will be payable by the holder.

Similarly, DSO's may check that regular metrological reviews are performed on the measuring systems at the supply points connected to their networks. Where the holder of a measuring system does not meet this obligation within three months of receipt of written notification, the DSO may ask the authorised parties to perform the check. All expenses will be payable by the holder.

As a result of these regular metrological checks, a certificate of verification will be issued for each instrument, reflecting the precision of measurement at each flow interval compared to the acceptable limits defined under current gas legislation, or where this does not exist, the relevant UNE standard. During periods when the said equipment is out of service for checking, the parties involved must previously agree on the consumption to be used for the allocation, assignment or invoicing of the gas supplied or the access services provided.

The provisions for regular metrological checks will also apply for metrological checking after repair or modification.

Repair/adjustment/modification will be performed in case of breakdown or when the result of the regular metrological verification so requires, or as agreed between the relevant parties.

If as the result of a regular metrological check, or in case of breakdown, the gas meter must be repaired, adjusted or modified, the holder of the equipment must fit, as soon as possible or within a maximum of 5 working days, except where duly justified, a replacement gas meter for the time during which the original gas meter is out of service, except where the installation design allows another line of measurement to be used for that period.

For the estimation of daily consumption, in cases where the consumer is the holder of the equipment, and where the repair time exceeds 5 working days, the estimated daily consumption will be calculated as the smallest value between the daily contracted flow and the maximum hourly flow through the meter over a 24-hour period.

For consumers obliged to have remote measurement, if as the result of a regular metrological check, or in case of breakdown, the converter and its associated elements, pressure transmitter and temperature probe must be repaired, adjusted or modified, the holder of the equipment must fit a replacement converter for the time that the original converter is out of service, except where the installation design allows another line of measurement to be used for that period.

7.3 Regular metrological checks on measurement equipment.

The frequencies established in this detailed protocol must be adapted to any prevailing regulations.

7.3.1 Entry points to the gas transmission network.

At the connection points between the gas transmission system and regasification plants, international connections, gas fields, underground storage facilities and production plants for manufactured gas and gas from alternative sources, the regular metrological checks corresponding to conversion factor, pressure and temperature loops and measurement and volume loops (series testing) will be performed monthly.

However, if after performing these monthly operations for a certain period of time, the errors found fall within accepted limits, this frequency can be reduced upon agreement between the affected parties and the GTS, provided that the testing interval does not exceed two months.

7.3.2 Exit points on the transmission network

Regular metrological checks will take place with the frequency indicated in the following table:

Table 5: Regular metrological checks on measurement equipment at exit points on the transmission network

	Periodicity	**Test type**
Conversion factor	6 months [1]	Field
Pressure loop	6 months [1]	Field
Temperature loop	6 months [1]	Field
Measurement and volume (series tests)	6 months [1]	Field
Chromatograph, change in span gas	The change in span gas will be performed before the expiry date of the sample, always under the conditions of use indicated on the certificate.	Field
Metrological checks on meters	6 years [2]	Laboratory

[1] If, after performing these operations at the indicated intervals for a certain period of time, the errors found fall within accepted limits, this frequency can be reduced upon agreement between the involved operators and the Technical Manager of the System, provided that the testing interval does not exceed twelve months.
[2] Provided that the series tests are performed each year and the results fall within the accepted limits.
If the design of the facility does not allow series testing, the gas meter must be laboratory tested every two years.
In all cases, gas meters fitted must have a testing certificate issued within the past two years.

7.3.3 Supply points to final consumers and points of delivery between distribution networks.

Regular metrological checks on measurement equipment will be performed as follows:

Gas meters:

The periodicity of metrological testing on meters is indicated in the following table:

Table 6: Regular metrological checks on meters.

Meter Type:	Annual consumption by line (C) (GWh/year)		
	C ≤ 3 (*)	3 < C ≤ 30	C > 30 (**)
Turbine	4 years	4 years	2 years
Piston	6 years	6 years	N/A
Membrane	15 years	15 years	N/A

(*) For gas meters fitted in homes, this operation can be substituted for continuous sampling statistical techniques.

(**) If the design of the facility allows, annual series testing and metrological gas meter testing every 6 years at most.

Gas meters fitted must have a testing certificate issued within the past two years.

Measurement loops:

The periodicity of metrological testing on measurement loops (pressure transmitters and temperature probes) is indicated in the following table:

Table 7: Regular metrological checks on pressure and temperature measurement loops.

Consumption (C) (GWh/year)	C ≤ 5	5 < C ≤ 100	100 < C ≤ 1,000	C >1,000
Periodicity	4 years	2 years	1 year	6 months

Converters fitted must have a testing certificate issued for at least half of the corresponding verification period.

Chromatographs:

Bottles of span gas will be certified by an accredited laboratory for the analysis of natural gas as per ISO Standard 17025.

The span gas change will be performed before the expiry date of the sample, always under the conditions of use indicated on the certificate.

The chromatograph will be tested at least every 12 months, and whenever there is a change in span gas.

7.4 Extraordinary testing requested by any party.

In addition to the testing obligations arising from Law 3/1985 on Metrology, Royal Decree 889/2006 on State Metrological monitoring of measuring equipment and resulting regulations thereof, for all measurement points on the Gas System, any party affected by the measurement process may request the extraordinary testing of the measurement equipment if there is a justified reason to suspect the incorrect functioning of the measurement equipment in place.

In such cases, the scope of the extraordinary testing will be identical to that of the regular testing set out for metrological control, and these operations on the measurement equipment should be performed by authorised parties as soon as possible, respecting the continuity of supply at all times. The cost of extraordinary checks on measuring equipment will be payable by the requesting party, except where metrological controls confirm that there is a greater deviation than that permitted; in this case, this cost will be payable by the holder of the equipment.

8. Regularisation of readings and measurements

In the case of regular testing, testing after repair or alteration, and/or extraordinary testing upon request, if it is observed that the accepted tolerances for the device in question are exceeded, the supply will be adjusted as described in this section.

If errors are detected outside the admissible tolerances, these will be corrected and the previously established amounts will be regularised based on original readings. The regularisation of quantities will continue for a certain period of time prior to the test date when the error was detected, and will be established based on the following criteria.

The period for correction and complementary re-invoicing where necessary will be calculated as per current legislation.

The GTS will publish on its website the standard procedure for calculating regularisations arising from amounts in excess of the maximum established tolerances.

Once the error has been detected, until the underlying cause is resolved, the limitations of the period time effected will not apply and, consequently, this period will be extended to cover the entire duration, without prejudice to any liability for non-rectification of the error in question. The correction of amount to be applied during the affected period will be that corresponding to the excess over the admissible maximum error.

9. Addition of odorants to natural gas.

Gas must be odorised so that any leak is easily detectable to the normal human nose in a mix with a concentration of one fifth of the lowest limit for inflammability.

9.1 Party responsibility.

The transmission companies for the primary network will deliver odorised natural gas at the entry points to the gas transmission system, at entry points to the distribution network and to consumers directly connected to their networks.

In order to optimise installation costs, in the case of new secondary transmission facilities where the gas is essentially destined for domestic use, the person responsible for odorant addition up to the levels indicated in section 9.3 will be the holder of the secondary transmission-transmission connection point.

DSO’s must ensure that the natural gas they deliver to consumers has the typical odour, adding odorant compounds in the necessary proportions as required, to ensure the presence of gas is detectable.

Odorisation levels, where applicable, in gas pipelines for transmission to third-party nations, will be agreed by the transmission companies involved.

9.2 Odorant requirements.

The odorant used must meet the following conditions:

- Provides a characteristic and persistent odour.

- Provides a specific odour that cannot be confused with other commonly-encountered odours, such as petrol, combustion fuels, cooking fuels, perfumes, etc.
- Easy to handle and add to gas.
- Non-toxic in the concentrations added to gas.
- Not water soluble, but soluble in the gas phase.
- Inert in contact with the different types of materials used in the pipelines and not readily absorbed by the deposits along the network.
- Not readily absorbed into soil.
- Combustible without producing harmful waste products.
- Chemically stable in contact with gas components.

9.3 General criteria for odorant addition.

Section modified by "Resolution of *21 December 2012, of the Directorate General for Energy Policy and Mines, modifying detailed protocol PD-01 'Gas Measurement, Quality and Odorisation' of the Technical Management of the Gas System Regulations.*

Validity: 8 January 2013

The primary natural gas transmission network operators will deliver odorised gas, under the following criteria:

a) 15 mg of THT/m^3 of gas will be added at the entry points to the transmission-distribution network.

b) 7 mg of THT/m^3 of gas will be added at the entry points to the secondary network currently odorised by the primary transmission company.

c) 7 mg of THT/m^3 of gas will be added at the entry points to the distribution network for domestic consumption.

d) For the odorisation of the Barcelona 35 bar ring, 22 mg of THT/m^3 of gas will be added.

In cases b) and c) feeding networks with domestic consumption, it is advisable for the minimum level of odorant to be 18 mg THT/m^3 of gas.

If an odorant other than THT is used, the concentration to be added will be adapted to obtain the equivalent level of detection.

When the gas received already contains an odorant, the substance used must be identified and its compatibility with the new odorant analysed, as a situation may arise where the new additive counteracts the effect of the odorant in the gas received.

The concentrations of odorants to be added are considered to be expressed in the gas system benchmark conditions.

PD-02
'Allocation procedure at transmission-distribution connection points (PCTD) and distribution-distribution connection points (PCDD)'

Approved by Resolution of the Directorate General for Energy Policy and Mines of 04 July 2008. Replaces the Protocol approved by Resolution of 13 March 2006, of the Directorate General for Energy Policy and Mines.

Amended under Resolution of 7 February 2013, by the Directorate General for Energy Policy and Mines, modifying the Technical System Management Rules NGTS-06 'Distribution' and NGTS-07 'Balancing' and Detail Protocol PD-02 'Distribution procedure at transmission-distribution connection points (PCTD)' (Official State Gazette 12/02/2013).

Validity: 1 July 2013

Amended under the Resolution of 30 April 2013 of the Directorate General for Energy Policy and Mines (B.O.E. 16/05/2013).

Validity: 17 May 2013

Amended under the Resolution of 23 December 2015 of the Directorate General for Energy Policy and Mines, approved via Resolution of 13 March 2006 of the Directorate General for Energy Policy and Mines.

Validity: 1 June 2016

Amended under the Resolution of 4 May 2016 of the Directorate General for Energy Policy and Mines (Official State Gazette 10/05/2016)

Validity: 1 June 2016

Amended under the Resolution of 8 October 2018 of the Directorate General for Energy Policy and Mines, (B.O.E. 23 October 2018).

1. Provisional daily allocation

The Provisional Daily Distribution is the allocation of user-owned gas for day d, which takes place on day d+1.

This allocation is calculated using the measurements from transmission and distribution connection points, connection points at the biogas production plants with distribution networks, and from consumption readings.

1.1 Distribution of emissions at connection points for transmission and distribution.

The total amount of gas to be assigned is the emission expressed in kWh at the Transmission-Distribution Connection Points (PCTD) or Distribution-Distribution Connection Points (PCDD), including deliveries made from biogas production plants to distribution networks (PPBD). Where the PCTD/PCDD feeds another DSO's PCDD downstream, the amount for allocation will be that resulting from subtracting the amount measured by the downstream PCDD from the head PCTD/PCDD.

The allocation responsible will assign the measured amount between the users of the facilities. This allocation will be performed with a breakdown by PCTD/PCDD based on daily demand corresponding to each user at the PCTD/PCDD.

The measurement manager will submit the amount for allocation at each PCTD/PCDD on a daily basis using the SL-ATR. This amount will be the figure recorded by the installed measurement equipment as established under detailed protocol PD-01. If this measurement is not available, the amount to be assigned will be obtained as per current measurement procedures between the interconnected operators. This will be made public and accessible to all parties involved.

The DSO will inform the interconnected operators of the PCTD/PCDD where there are no active supply points, in order to coordinate any action resulting from this situation.

Where a PCTD/PCDD does not have active supply points and there are no interconnected networks downstream, the allocation responsible will assign that emission proportionally between all users with provisional daily allocations across the networks of that DSO. This allocation will be proportional to the total allocation for the previous day and will be applied to the supply loss balance.

If the PCTD feeds a DSO's PCDD downstream, and there are no supply points with active consumption upstream fed by the head PCTD/PCDD, the SL-ATR will automatically allocate the net emission proportionally between the all the upstream PCDD users on behalf of the DSO responsible for distributing the PCDD measurement upstream. This allocation will be proportional to the total allocation for those users on the previous day and will be fully applied to the supply loss balance.

Provisionally, until the SL-ATR is adapted to automatically perform the distribution, and in accordance with the previously described methodology, the DSO responsible for allocating the net emission from the upstream PCTD/PCDD will perform this allocation according to the methodology defined for a PCTD/PCDD without active supply points or interconnected networks downstream.

For each PCTD/PCDD, PPBD or PCLD with emission delivery in the provisional daily allocation process, the SL-ATR will make use of a concept called 'maximum foreseeable emission' defined by the transmission company or DSO acting as measurement manager. Those values will initially be calculated in the SL-ATR as the real historical maximum emission from each PCTD/PCDD, PPBD or PCLD, with the measurement manager being responsible for its oversight. Subsequently, the transmission company or DSO may modify them according to the emission forecasts associated with the PCTD/PCDD, PBD or PCLD. A maximum of 1 GWh/day is set as the maximum foreseeable historical emission for a PCTD/PCDD or PCLD.

Where new PCTD/PCDD, PPBD or PCLD come online, the transmission company or DSO acting as measurement manager will be responsible for determining the value of the maximum foreseeable emission and notify the GTS so that it will be implemented in the SL-ATR.

The SL-ATR will perform a daily comparison between the emission delivered by the measurement manager at each PCTD/PCDD and PPBD, and their maximum foreseeable emission. Where the daily emission delivered by the transmission company or DSO for a PCTD/PCDD, PPBD or PCLD exceeds 50% of the value of the maximum foreseeable emission loaded into the SL-ATR, that emission will be estimated on a daily basis by the SL-ATR. Where the connection point is a PCTD or a PCDD, the estimate will be made from the sum of remotely and non-remotely measured allocations and calculated by the DSO (assuming a provisional daily supply loss value of zero) and the emissions from the PCDD connected directly to the network downstream. Where the connection point is a PCLD or PPBD, this estimate will be the actual parameter of the maximum foreseeable emission.

This will be notified via the incident report module to the affected transmission companies, DSO's and shippers so that they may review, modify or reclaim their information within the periods established in the daily allocation process.

With each running of the daily allocation algorithm at a PCTD/PCDD or PCLD, provided that the aggregate of all the allocations per shipper delivered by the allocation responsible does not coincide with the emission in accordance with the provisions of section 1.2, the GTS review algorithm described in section 3 of the Appendix will be activated. This algorithm will allocate to shippers the difference between the net emission to be allocated and the allocations sent by the DSO.

1.2 Consumption allocation

a) Distribution of daily consumption at supply points with remote metering.

For supply points with remote measurement equipment, the reading recorded by the DSO will be used, as per the current measurement procedure between the interconnected parties.

For supply points fitted with remote metering equipment for which remote meterings are not available, an estimate will be made based on the average of the last three recorded readings (real) for equivalent consumption days. Consideration will be given to three types of equivalent days: working days, Saturdays that are not public holidays, and Sundays and public holidays. The calendar of working days and holidays will be those officially published for each Autonomous Community. However, when the user, twelve hours before the end of the gas day, has submitted an update consumption figure to the DSO, this will be used by the DSO instead of an estimated remote metering. This value will not be used as a reference for future estimates.

For new consumers without a consumption history, if remote measurement is not available, the following estimate will be made:

- For consumers on toll 3.4, daily consumption (Cd) will be calculated by dividing the annual contracted flow, expressed in kWh/year (Qa), by 210 days.

$$Cd = Qa/210$$

- For consumers on the remaining tolls for whom daily contracted flow (Qd) information is available, the daily consumption will be taken as the daily contracted flow multiplied by the correction factor for use (fc).

$$Cd = Qd * fc$$

The factor fc is obtained by calculating the consumption ratio over the daily contracted flow for a representative sample of remotely-read consumers; its initial value is 0.75. This figure may be reviewed annually by the Working Group for the Update, Review and Modification of the Technical Gas System

Management Rules; if it is modified, the new value will be published through the SL-ATR at least one month in advance of application.

b) Distribution of daily consumption at supply points without remote metering.

Daily consumption at supply points without remote metering equipment is estimated through itemisation of estimated monthly consumption.

b.1 Calculation of monthly consumption C_m.

The steps below are followed to determine C_m depending on whether or not there are historical values for that supply point:

If there is a monthly consumption figure for the previous year and the same month (C_{m-12}), Cm be the value included on the previous year’s bill with the most days covered in the month under assessment, including a correction coefficient (C_C) over the previous year’s consumption representing the changes or variation in consumption between one year and another, as per the information on changes in conventional demand published by the GTS. This correction coefficient is published via the SL-ATR.

$$C_m = C_{m-12} * C_c$$

Where C_c is the variation in consumption for the previous twelve months available in relation to the same figure for the previous year.

However, in the case of consumers on toll 3.4, a correction coefficient by temperature will apply (Ctemp1) to the previous year's consumption, bearing in mind the variation in consumption due to temperature.

$$C_m = C_{m-12} * C_{temp1}$$

The period Ctemp1 will be calculated for each climate zone as the quotient between the degree days (base 15) for the gas day (n) and the daily average degree days for the same day in the previous year, using real temperatures up to day 'n-1', or if not available, the best possible available forecast, in both cases using the information issued by the State

$$c_{temp1} = \frac{degrees_{gasday\ (n)} + K_{T1}}{\left(\frac{\sum_{i=1}^{N} degreeday\_daily\_equivalentmonths\_previousyear}{N}\right) + k_{T1}}$$

Meteorological Agency.

N is the number of days in the month, with the gas day temperature (n) calculated according to the following expression:

$$degrees_{\text{gas day (n)}} = \begin{cases} 0 & \text{if } T_{min} \geq 15^{o} \\ (15^{o} - T_{min})/4 & \text{if } T_{min} < 15^{o} \leq T_{med} \\ (15^{o} - T_{min})/2 - (T_{max} - 15^{o})/4 & \text{if } T_{med} < 15^{o} \leq T_{max} \\ 15^{o} - T_{med} & \text{if } T_{max} < 15^{o} \end{cases}$$

Where Tmax is the maximum daily temperature, Tmin the minimum daily temperature and Tmed the average daily temperature calculated as (Tmax + Tmin)/2.

The initial coefficient KT1 is 4. This value can be reviewed annually by resolution of the Directorate General for Energy Policy and Mines.

In the case of consumers who have recently joined the gas system, for whom the full series of data is not available from the previous year, the last month available will be used.

In the case of new consumers with no consumption data, the annual contracted flow will be used (Q_a), or the daily contracted flow (Q_d), depending on toll type:

- For consumers on toll 3.4, monthly will be the result of dividing the annual contracted flow, expressed in kWh/year (Qa), by 12 months.

$$Cm = Qa\ /12$$

- For consumers for the remaining tolls, for which there is information on the daily contracted flow (Qd), monthly consumption will be taken as the daily contracted flow multiplied by the correction factor for use (fc) and the number of days in the month (N).

$$Cm = Qd * fc * N$$

Factor fc will be calculated as per section 1.1.

b.2 Daily itemisation of monthly consumption by consumer type.

b.2.1 Consumers in toll group 2.

The daily consumption will be calculated differentiating between working days and non-working days. For the purposes of this protocol, Saturdays, Sundays and holidays are considered non-working days.

- Working day:

  Daily consumption (Cd) is obtained as the product of monthly consumption (Cm) and operation coefficient (Cf) divided by the number of working days in the month (Nwork), as per the expression:

  $$Cd = Cm * Cf / Nwork$$

  Where Cf will have a default value of 0.85, which can be reviewed annually by the Working Group for the Update, Review and Modification of the System Technical Management Rules and Protocols. In case of modification, the new value will be published via the SL-ATR at least one month in advance of application.

- All other days (Saturdays, Sundays and holidays):

  Daily consumption (Cd) is obtained as the product of monthly consumption (Cm) and operation coefficient (1-Cf) divided by the number of non-working days in the month (Nres), as per the expression:

  $$Cd = Cm * (1 - Cf)/ Nres$$

  Where Cf has the same value as for working days.

  The calendar listing working days and holidays will be the one officially published for each Autonomous Community.

b.2.2 Consumers in toll group 3.4.

Daily consumption will be calculated as monthly consumption (Cm) divided by the number of days in the month (N).

$$Cd = Cm/N$$

b.2.3 Consumers in toll groups 3.1, 3.2 and 3.3

The consumption to be assigned daily at a PCTD/PCDD will be calculated as per the formula below:

$$C_d = \sum_j \sum_k Nº Consumers\ es_{jk} * Pu_k * C_{temp2}$$

Where:

- j: Users at the PCTD/PCDD.
- k: Toll group.
- N° Consumor$_{jk}$: Number of consumers supplied by the user j within toll group "k".
- Puk: unit profile in the month corresponding to toll group k in the climate zone of the PCTD/PCDD.
- Ctemp2: correction coefficient for the profile due to temperature.

The CCtemp2 coefficient will be calculated for each climate area as the quotient between the degree days (base 15) for the gas day (n) and the daily average degree days for the same month of the previous year, using real temperature until day 'n—1', or if not available, the best possible available forecast, in both cases using the information issued by the State Meteorological Agency.

$$c_{temp\ 2} = \frac{degrees\ days\_day\_gas(n)}{degreedays\_daypromised\_profile}$$

Temperature in degrees gasday(n) is calculated using the following expression:

$$\text{Degrees gas day (n)} = \begin{cases} 0 & \text{if Tmin=15°} \\ (15º - \text{Tmin})/4 & \text{if Tmin<15°< Tmed} \\ (15º - \text{Tmin})/2 - (\text{Tmax} - 15°)/4 & \text{if Tmed<15° = Tmax} \\ 15º - \text{Tmed} & \text{if Tmax< 15"} \end{cases}$$

Where Tmax is the maximum daily temperature, Tmin the minimum daily temperature and Tmed the average daily temperature calculated as (Tmax + Tmin)/2.

The initial coefficient KT2 shall be equal to 4. This value can be reviewed by resolution of the Directorate General for Energy Policy and Mines.

$$Degreedays\_average\ day\_profile = \frac{\sum_{1}^{K}\left(\left[\frac{\sum_{i=1}^{K} degreedays \quad daily \quad equivalent\ month}{N}\right]\right)}{K}$$

Where N is the number of days in the month and K the number of winters used in the profile calculation.

The climate zone is established based on historical temperature records provided by the State Meteorological Agency. At the outset, 4 climate zones are defined; these are listed in section 1.4, with each province and PCTD/PCDD belonging to a single area. By 1 October each year, the GTS will determine and publish the SL-ATR for the following year, the meteorological stations to be used for the calculation of significant temperatures in each climate zone and correction coefficients for temperature (CCtemp1 and CCtemp2) as well as a list of PCTD/PCDD included in each climate zone. The GTS may request information from transmission companies and DSOs regarding the PCTD/PCDD included in each area.

A unit consumption profile Puk by month, toll group k and climate zone z will be defined using the following formula:

$$P_{uk} = \frac{\sum_{i=1}^{z} F(k,z,month)i}{\sum_{i=1}^{z} NC(k,z,month)i * \sum_{i=1}^{z} Ni}$$

Where:

- F (k,z,month): monthly consumption for toll group k in climatic zone z in the month of the year i.
- NC (k,z,month): Number for consumers for the toll group k in climatic zone “z” in the month of the year i.
- N: number of days of the month of the year i.

The DSOs will calculate the unit consumer profiles as per the above formula using historical data for the previous two years provided by the DSOs operating in each area. For the following year, these profiles will be presented to the Working Group for the Update, Review and Modification of the System Technical Management Rules and Protocols and published by the GTS via SL-ATR by 1 November each year. The National Markets and Competition Commission and the Directorate General for Energy Policy and Mines may request access to the profiles and data used for these calculations for supervision purposes.

The correction coefficients for temperature, unit profiles and climate zone will be common to all DSOs.

1.3 Provisional allocation of daily supply loss balance.

The difference between the PCTD/PCDD emission and the allocated consumption (increased by the corresponding accepted supply loss) plus the delivery of gas to operators connected downstream matches the balance of allocation supply loss, which like the daily allocation,

$$\text{Supply loss Balance} = \text{Emission at Entry Point} - \Sigma\ \text{Consumption TM}_c - \Sigma\ \text{ConsumptionNonTM}_c - \text{Emission Delivered Downstream}.$$

Where:

- Emission at Entry Point: Emission at PCTD/PCDD in kWh.
- Consumption TMc: reading at supply points with remote meterings available for the user c, plus associated supply loss, at the PCTD/PCDD in kWh.
- Consumption NonTMc: Estimated consumption at supply points without remote metering or where remote metering is not available for the user c, plus accepted supply loss, at the PCTD/PCDD in kWh.
- Emission Delivered Downstream: Emission sent to other DSOs at the PCDD in kWh.

The provisional daily supply loss balance, also called 'remaining quantity', can be positive or negative, and is distributed between all the users present on the PCTD/PCDD, in proportion to estimated consumption (including consumers without remote metering). Furthermore, a supply loss balance will be identified for each user for each estimated consumption type (estimated remote metering, Type 1 non-remotely-read with toll 3.4, type 1 non-remotely-read with a toll other than 3.4 and type 2).

Where the percentage of remotely-read consumption for a PCTD/PCDD is 100%, the provisional daily supply loss balance or remaining quantity will be distributed to demand in proportion to the consumption allocated to each user. This percentage can be reviewed annually by the Working Group for the Update, Review and Modification of the System Technical Management Rules and Protocols. In case of modification, the new value will be published via the SL-ATR at least one month in advance of application.

1.4 Calculation of provisional daily allocation.

Each user present at the PCTD/PCDD will be allocated daily consumption, including corresponding supply loss, as the final provisional daily allocation, calculated as indicated in the sections above.

1.5 Submission of provisional daily allocation information

Daily allocation will be submitted by the DSO to the SL-ATR, making it available on the system with the details listed below, by PCTD/PCDD, shipper and direct customer by market and day:

- DSO code: as per SL_ATR code system.
- Shipper code: as per SL_ATR code system.
- Gas date.
- PCTD/PCDD code: as per SL_ATR code system.
- Reviewed: S/N.
- Overall emission to be distributed to PCTD/PCDD.
- Supply loss balance by PCTD/PCDD (total and assigned to corresponding user) and its % of total emission.
- Aggregate value of consumption with available remote meterings (total and assigned to corresponding user).
- Aggregate value of consumption with no available remote meterings, and therefore estimated (total and assigned to corresponding user).
- Aggregate value of estimated Type 1 consumption with no available remote meterings (total and assigned to corresponding user), distinguishing between consumption under toll 3.4 and consumption under a toll other than 3.4.

- Aggregate value of estimated Type 2 consumption with no available remote meterings (total and assigned to corresponding user).
- Aggregate value of accepted supply loss corresponding to the allocated consumption.
- Aggregate value of GTS review (total and assigned to corresponding user).
- Aggregate value of GTS review (total and assigned to corresponding user).
- Aggregate value of provisional daily allocation, including supply loss balance and GTS review (total and assigned to corresponding user).

All additional information necessary to allow users to trace data and calculations relating to provisional daily allocation will be available via the SL-ATR.

The DSO will use the SCTD to make available to each representative an inventory of the Type I points considered for each allocation, as well as the number of Type 2 points by PCTD, toll and climate zone. Specifically, it will make available to users each day:

For Type 1 customers:

- DSO code: as per SL_ATR code system.
- Shipper code: as per SL_ATR code system.
- PCTD code: as per SL_ATR code system.
- Distribution date.
- CUPS.
- Daily consumption in kWh.
- Type of Consumption: Real, Estimated, Shipper Estimate; Non-remotely-read.
- Time and date of publication.

For Type 2 customers:

- DSO code: as per SL_ATR code system.
- Shipper code: as per SL_ATR code system.
- Distribution date.
- PCTD code: as per SL_ATR code system.

- Toll Group: as per SL_ATR code system.
- Number of consumers.
- Daily consumption in kWh.
- Time and date of publication.

This information will be published for all PCTD where the user has supply points of each type. In addition to the data associated with each user, the total number of customers per toll corresponding to each connection point will be provided.

If a user produces a discrepancy from the total allocation for its Type 2 customers, the DSO must submit the information used for the calculation.

1.6 Climate zones.

The provinces are classified into the following four climate zones:

- Climate Zone 1: Average degree days below 1.7.
- Climate Zone 2: Average degree days between 1.7 and 2.4.
- Climate Zone 3: Average degree days between 2.4 and 3.8.
- Climate Zone 4: Average degree days above 3.8.

The assignment of provinces to each area, with their corresponding degree days, will be published via the SL-ATR. These climate zones can be reviewed annually by the Working Group for the Update, Review and Modification of the System Technical Management Rules and Protocols. Updates will be published via the SL-ATR at least one month in advance of application.

Climate zone 1

	Degrees/day
A Coruña.	1,44
Alicante.	1,17
Almería	0,56
Cádiz	0,36
Castellón.	1,18
Córdoba	1,39
Huelva	0,85
Baleares	1,17
Málaga	0,59
Murcia.	1,03
Sevilla	0,82
Valencia	1,64

Cimate zone 2

	Degrees/day
Asturias.	1,82
Badajoz.	1,80
Barcelona	1,84
Bizkaia	2,00
Cáceres	2,20
Cantabria	1,78
Gipuzkoa	2,15
Jaén	2,00
Ourense	2,21
Pontevedra	1,96
Tarragona	2,00

Climate zone 3

	Degrees/day
Albacete	3,30
Ciudad Real	2,75
Cuenca	3,64
Girona	2,50
Granada	2,79
Huesca	3,52
La Rioja	3,14
Lleida	2,95
Lugo	3,60
Madrid	3,18
Navarra	3,52
Toledo	2,67
Zaragoza	2,64

Climate zone 4

	Degrees/day
Araba	4,02
Ávila	4,74
Burgos	5,06
Guadalajara	5,23
León	4,92
Palencia	5,17
Salamanca	4,23
Segovia	4,27
Soria	5,25
Teruel	4,31
Valladolid	4,05
Zamora	4,14

2. Final Provisional Daily Distribution.

The Final Provisional Daily Allocation is the calculation of consumption for day d by user, made in month m+3 (three months after the month corresponding to day d).

This allocation is calculated using the measurements from transmission and distribution connection points and consumption readings.

2.1 Distribution of emissions at connection points for transmission and distribution.

The holder responsible for the unit of measurement will send, by the established deadlines, to the SL-ATR, the monthly amount to be distributed at each PCTD / PCTD with a daily breakdown.

The process is similar to that for the provisional daily allocation.

2.2 Consumption allocation

a) Supply points with remote metering.

In the case of consumers with remote metering, each user will be allocated the daily value indicated in the provisional daily allocation, plus corresponding supply loss, including correction for errors where necessary. the value will coincide with that allocated in the calculation of the provisional daily allocation.

b) Supply points without remote metering.

Those responsible for taking readings for customers will report these readings to the allocation responsibles where applicable and as soon as they are obtained.

At each PCTD/PCDD, for each day n within the meter reading period and for each type of consumption without remote metering, the allocation responsible will proceed as follows:

1. The balance of supply loss for each day will be calculated in the provisional daily allocation, which corresponds to the type of consumption through the application of section 1.3 of this detailed protocol, as the sum of the provisional balances of supply loss assigned to this type of consumption at the PCTD/PCDD.
2. For each type of consumption, the weight of provisional daily

allocation will be obtained for day d, compared to the sum of provisional daily allocation for that customer type, including the allocated supply loss, for the days in the meter reading period:

$$\text{Weight of provisional daily allocation per type of consumption} = \frac{\text{daily allocation for the type of consumption}}{\text{Sum of daily allocations for the type of consumption}}$$

3. To distribute customer consumption readings by day, the weight obtained in point 2 is multiplied by the value of accumulated consumption provided by that reading.

The result of the operation is the consumption value allocated to day d for that customer at the PCTD/PCDD.

To calculate the user consumption allocated at a PCTD/PCDD, the consumption for all that user’s customers are added together.

3. Final Provisional Allocation of supply loss balances.

The difference between the PCTD/PCDD emission and the allocated consumption indicated above (increased by the corresponding accepted supply loss) plus the delivery of gas to operators connected downstream matches the balance of distribution supply loss. In this case, final provisional.

$$\text{Supply loss Balance} = \text{Emission at Entry Point} - \Sigma\ \text{Consumption TMc} - \Sigma\ \text{ConsumptionNonTMc} - \text{Emission Delivered Downstream}$$

Where:

- Emission at Entry Point: Emission at PCTD/PCDD in kWh.
- Consumption TMc: reading at supply points with remote meterings available for the user c, plus accepted supply loss, at the PCTD/PCDD in kWh.
- ConsumptionNonTMc: consumption at supply points without remote metering or where remote metering is unavailable for the user c, plus accepted supply loss, at the PCTD/PCDD in kWh.
- Emission Delivered Downstream: Emission sent on to other DSOs at the

PCDC in kWh.

a. Calculation of final provisional daily allocation.

Each user present at the PCTD/PCDD will be allocated daily consumption, including corresponding supply loss, as the final provisional daily allocation, calculated as indicated in the sections above.

b. Submission of final provisional daily allocation information

By the established deadlines, the DSO will send the final provisional allocation broken down by day for each PCTD/PCTD and shipper to the other interconnected holder and to the Technical Manager of the System. The supply loss balance at each PCTD/PCDD by shipper will also be submitted.

This allocation by shipper will also include the following details by PCTD/PCDD:

- DSO code: as per SL_ATR code system.
- Shipper code: as per SL_ATR code system.
- Gas date.
- PCTD/PCDD code: as per SL_ATR code system.
- Reviewed: S/N.
- Overall emission to be distributed to PCTD/PCDD.
- Aggregate value of remotely-read consumption (total and assigned to corresponding user).
- Aggregate value of non-remotely-read Type 1 consumption with toll group 3.4 (total and assigned to corresponding user).
- Aggregate value of non-remotely-read Type 1 consumption with toll groups other than 3.4 (total and assigned to corresponding user).
- Aggregate value of Type 2 consumption (total and assigned to corresponding user).
- Aggregate value of accepted supply loss corresponding to remotely-read consumption (total and assigned to corresponding user).
- Aggregate value of accepted supply loss corresponding to non-remotely-read allocated Type 1 consumption with toll group 3.4 (total and assigned to corresponding user).
- Aggregate value of accepted supply loss corresponding to non-remotely-read allocated Type 1 consumption with toll group 3.4 (total and assigned

to corresponding user).

- Aggregate value of accepted supply loss corresponding to allocated Type 2 consumption (total and assigned to corresponding user).
- Aggregate value of supply loss balance (total and assigned to corresponding user).
- Aggregate value of final provisional daily allocation, including supply loss balance (total and assigned to corresponding user).

All additional information necessary for data and calculations relating to final provisional daily allocation will be available via the SL-ATR.

DSO's will also make the information used for calculating allocation available to users, specifically:

For Type 1 customers:

- DSO code: as per SL_ATR code system.
- Shipper code: as per SL_ATR code system.
- PCTD code: as per SL_ATR code system
- Distribution month.
- CUPS.
- Daily consumption in kWh.
- Type of Consumption: Real, Estimated, Shipper Estimate; Non-remotely-read.
- Time and date of publication.

For Type 2 customers:

- DSO code: as per SL_ATR code system.
- Shipper code: as per SL_ATR code system.
- PCTD code: as per SL_ATR code system.
- Distribution month.
- Toll Group: as per SL_ATR code system.
- Number of consumers.
- Daily consumption in kWh.
- Time and date of publication.

If a user produces a discrepancy from the total allocation for its Type 2 customers, the DSO must submit the information used for the calculation.

4. Final Definitive Daily Distribution

The Final Provisional Daily Distribution is the calculation of consumption for day d by user, made in month m+15 (fifteen months after the month corresponding to day d).

In month m+15, should there be new information regarding emission or consumption at a PCTD/PCDD that alters the emission or consumption used for the calculation of the final provisional daily allocation, a definitive final daily allocation will be calculated as per the methodology described in section 2 of this Protocol.

All additional information necessary for data and calculations relating to final definitive daily allocation will be available via the SL-ATR with the same details as the final provisional daily allocation.

APPENDIX

Control of provisional daily allocation:

1. Special intervention by the GTS in the provisional daily allocation process at PCTD/PCDD and PCLD in exceptional high-impact situations.

1.1 Definition of special intervention in the process of provisional daily allocation:

'Special intervention in the process of provisional daily allocation' is defined as intervention by GTS in exceptional situations with a high impact on the quality of the provisional daily allocation that may occur during the process. In order to identify these situations, the GTS will apply the controls listed in section 1.2 of this annex on a daily basis.

The declaration of 'special intervention in the process of provisional daily allocation' can also be requested of the GTS by any party in the system taking part in the process (transmission companies, DSO's and shippers). This request must be made in writing and must include at least the following information:

- Requesting party.

- Type of party: Transmission company/DSO/Shipper.
- Gas day.
- Information affected: Emission/Distribution/Both.
- Stage of the process affected: Initial — V1 / Revision — V2.
- Established monitoring or filter not passed by the process and due to which the declaration of 'special intervention in the process of provisional daily allocation' is requested.

Having analysed the impact on users and/or system operation, the GTS may declare 'special intervention in the process of provisional daily allocation'.

1.2 Reasons for special intervention in the process of provisional daily allocation.

1. The provisional daily supply loss balance or remaining quantity to be distributed at each PCTD/PCDD or PCLD exceeds, in absolute value, twice the maximum foreseeable emission defined in section 1.2 of the protocol.
2. The sum of the total emissions to be distributed in the process differs, in absolute value, by more than 100 GWh/day from the total estimate of the GTS depending on operational information.
3. Failures in the allocation processes of the SL-ATR system that prevent information from being made available to shippers regarding the daily allocation within the periods stipulated in point 6.4 of NGTS-06 'Distribution'.
4. Total failure of the systems of a DSO that does not allow any information to become available in the first or second version of the provisional daily allocation in the period stipulated in Point 6.4 of the NGTS-06 'Allocations', where the review of the daily allocation made by the GTS is more than 5% of the absolute value of the overall system emission.
5. When the review of the allocation performed by the GTS represents over 5% of the absolute value of the overall system emission.
6. Failures in the daily allocation process or GTS systems that prevent the information needed by the DSO's for the provisional daily allocation from being made available within the periods stipulated in point 6.4 of the NGTS—06 'Distribution'. This point would apply to GCV files, temperature coefficients, information on daily emission sent via the SL-ATR to DSO's or communications failures with the GTS.

Within the reasons for intervention, daily variations in the provisional daily allocation resulting from the correct application of the formulae established in this detailed protocol will not be considered errors, regardless of size.

1.3 Consequences of special intervention in the process of daily allocation.

1. Chain stoppage on the SL-ATR and the non-publication of provisional daily allocations. Where the problems affect a sole transmission company or DSO, chain stoppage will not prevent the other operators from continuing to submit information by the established deadlines.
2. Communication in case of special intervention in the process of daily allocation:

2.1 Declaration of special intervention in the process of provisional daily allocation:

The declaration of 'special intervention in the process of provisional daily allocation' will be announced, as soon as possible and in writing, to all affected parties. The GTS does this by issuing notification to all parties, transmission companies, DSO's and shippers, indicating the reason for the fault, where identified, and the steps to be taken.

2.2 Monitoring of the special intervention in the process of provisional daily allocation:

As soon as the source of the failure is identified and an estimated period of resolution is available, the GTS will proceed to report on progress to all affected parties. Where the declaration of special intervention in the process of provisional daily allocation is caused by a failure in the systems of transmission companies or DSO's, the latter will be responsible for keeping the GTS informed of all corrective actions taken to return to normal operation and how these are progressing.

2.3 Return to normal operation in the process of provisional daily allocation:

When the situation of the process of provisional daily allocation is considered restored, the affected parties will be informed.

In case of a general failure in the provisional daily allocation process, the GTS will be responsible for notifying all parties, informing them that normal operation has been restored and that the information regarding daily allocation is available to users through the usual channels.

If the failure has been caused by a transmission company or DSO's system, the said transmission company or DSO will be responsible for ensuring their processes are restored. As soon as the transmission companies or DSO's have corrected the failures leading to the special intervention, they will notify the GTS , who will notify all parties, informing them that normal operation has been restored and that the information regarding daily allocation is available to users through the normal channels.

3. Delay in the publication of provisional daily allocation, until the GTS rules that the incident leading to the special intervention has been resolved, effectively reporting on its evolution to all parties.

2. Controls at the source of the provisional daily allocation d+1 at PCTD/PCDD and PCLD

Regardless of the monitoring mechanisms developed by those involved in calculating the provisional daily allocation, it will have, at least, the following common controls:

2.1 Control at emission.

- Responsible party: transmission companies and DSO's.
- Control: check that emission does not exceed the maximum foreseeable emission available on the SL-ATR.
- Action: the party responsible for measurement will review and correct the emission value where necessary, and will notify the parties of the situation. If it is certain that the emission is correct, the maximum foreseeable emission should be updated in the systems and the SL-ATR.

2.2 Control of provisional daily allocation.

- Responsible party: DSO's.
- Control: checking that the real aggregate remote metering for a PCTD does not exceed 1.3 times the emission value.
- Action: the DSO will review the remote metering and, if correct, will file a report on the emission, using the reporting template available via the SL-ATR. If this report requires a modification of emission, it will be corrected for the second submission of daily allocations. If it is found

that the error may lie in one or more real remote meterings, the DSO will follow the procedure for estimation of provisional daily allocation for the remotely-measured customer. This correction will be recorded in the submission of the first version of daily allocations.

2.3 Control of remote meterings.

- Responsible party: DSO's.
- Control: checking that the daily remote reading does not exceed twice the contracted capacity.
- Action: the DSO will review all remote meterings exceeding this figure before the submission of the allocation. If after analysis, it is thought to be incorrect but the correct value is not available, the measurement will be estimated.

3. Calculation and Assignment of GTS review in the process of provisional daily allocation for PCTD/PCDD

For every day and connection point (PCTD/PCDD), the SL-ATR calculates the difference between the real reading of the daily emission sent by the responsible transmission company or DSO and the provisional daily allocation d+1 of the said reading allocated to users. This check is known as the 'GTS Review'. Where the absolute value of this difference at a PCTD/PCDD is greater than an established margin of tolerance (TrevGTS), the SL-ATR will automatically allocate this difference among the users.

Initially, the margin of tolerance T GTSrev is set at 100 kWh/day. This figure may be reviewed annually by the Working Group for the Update, Review and Modification of the System Technical Management Rules and Protocols, and in case of modification the new value will be published via the SL-ATR at least one month in advance of application.

GTS review d, p = Daily emission to be distributed d, p- Daily allocation d, p

Where:

- Daily emission to be distributed d, p: value of the real daily emission reading to be distributed on day d at point 'p'.
- Daily allocation d, p: sum of provisional daily allocation d+1 of demand in allocation allocated to users for day d and point 'p', sent by DSO's and/or processed by the SL-ATR. This amount includes the remotely-read and estimated consumption data, remaining quantity and supply

loss balance.

When the absolute value of the GTS review at a connection point exceeds the tolerance, the SL-ATR will distribute this difference between the users as per the criteria defined in section 3.1.

3.1 Criteria for Assignment of GTS Review when the tolerance is exceeded.

a) A daily emission reading is available for allocation, as well as the amounts for provisional daily allocation d+1 allocated to users (not zero), for the day in the allocation process at the connection point in question.

In this case, the SL-ATR will proceed to assign the GTS review between the users, in the same proportion as the amounts allocated by the allocation initially submitted by the DSO and/or processed by the SL-ATR.

If the daily emission reading to be distributed is zero, the algorithm runs anyway, and negative amounts are allocated to each user.

However, if there is no emission reading for allocation via the SL-ATR, the algorithm will not run.

b) A daily emission reading is available for allocation, but there are no amounts for provisional daily allocation d+1 allocated to users for the day in the allocation process at the connection point in question.

In this case, the SL-ATR will proceed to assign the GTS review to the users who have amounts allocated to them by the allocation process for the day prior to the day in question, in proportion to those amounts. If this information is not available either, the SL-ATR will launch a search for information from the 15 previous days.

If during the search of the 15 previous days, the first day found has an amount of 0 kWh for each of the users located there, the GTS review will be distributed equally between them all.

If the connection point in question has an insufficient allocation record, so that the search algorithm cannot locate a daily allocation with replicable conditions, the GTS review will be distributed between all the users on the System with the daily allocation for the day before the day in question, in the same proportion.

c) A daily emission reading other than zero is available for allocation, but all amounts for provisional daily allocation d+1 allocated to users for the day in the allocation process at the connection point in question are zero.

In this case, the value of the overall GTS review is distributed equally between all the users.

PD-03

'Demand Forecasting'

1. Purpose of Demand Forecasting

Demand forecasting is an estimation of gas consumption on the Gas System for a period of time; annual, monthly, weekly, daily or even hourly. The users use this forecast for programming, for requesting book capacity, and for preparing their nominations. Operators use their own demand forecasts as a tool to complete their operation plan and in general for system management. In order to perform a continuous analysis of system behaviour, the Technical Manager of the System, in coordination with all parties involved, monitors demand across the system as a whole, with the above scopes. Each party in the Gas System is responsible for preparing their own demand forecast.

2. Demand Forecasting Systems

2.1 Prediction for the medium/long-term strategic horizon:

Forecasting tools are used, obtained by extrapolation of short-term models, and bearing in mind, where applicable, the following factors:

- Rate of demographic growth by areas of consumption.
- Price forecasts for gas and other alternative energy sources. Approved infrastructure development.
- Political parameters.
- Macroeconomic parameters.

2.2 Forecasting for short-term operation:

2.2.1 Annual horizon.

Forecasting tools are used, based on generally accepted mathematical models, considering any significant records from previous years and considering the year ahead as climatologically normal. This forecast is itemised monthly and broken down by day. If any deviations are detected from the forecasts made over the course of the year, it will be updated with more recent information.

2.2.2 Monthly, weekly and daily horizon.

Operators must have a forecasting system based on a generally accepted mathematical model, which takes into account the consumption records for recent years, temperature, number of customers and equipment used by them.

The immediate consumption should be determined based on this data and the meteorological forecasts provided by the relevant authorities.

The result obtained is:

- Total base demand.
- Base demand by zone for the different geographical areas.

Where necessary, an automatic process is run every day to update the latest daily and hourly forecast, using mathematical models generally known to be effective.

3. Historical data

Consumers have the right to receive their consumption history from their energy provider.

Consumption records are the real recorded values obtained by daily measuring at supply points on the Gas System. Data from estimates at points where no remote metering is available are also used.

PD-04

'Communication Mechanisms'

Amended under Resolution of 30 April 2013, of the Directorate General for Energy Policy and Mines, modifying Detail Protocol PD-04.
'Communication mechanisms'

Date of publication in the Official State Gazette: 16 May 2013

Valid from: 17 May 2013

1. Purpose

In order to have a flexible, real-time communication tool between the various parties involved in the gas system, thus supporting the management of the entire gas cycle: requests for capacity, contracting, programming and nominations, measurements, allocation, balancing and invoicing, the Technical Manager of the System (GTS) will provide users with access to the SL-ATR (Third-party Access Logistics System) information system.

The GTS shall keep the systems updated and operational, and the system shall be easily accessible, guaranteeing the veracity and up-to-date nature of the information supplied, as well as its security and confidentiality, and with regard to the principles of transparency, objectiveness and non-discrimination.

DSO's will use a computerised system called the Transmission-Distribution Communication System (SCTD) to support the management of their interrelations with shippers and the GTS, observing the principles set out in the System Technical Management Rules and Royal Decree 1434/2002 of 27 December regulating the transmission, distribution, commercialisation, supply and authorisation processes for natural gas facilities.

The SCTD will observe the principles of transparency, objectivity, non-discrimination and confidentiality. It will be accessible to shippers and the GTS based on established procedures and formats that allow information to be processed automatically. The system will support contracting, measurement, and allocation processes, access to records, programming and nominations and will interface with the systems of each DSO, the GTS, and other DSO's and shippers.

All parties involved in the gas system must have the necessary certified technical resources, using the most appropriate technologies at all times for electronic communications and access to previous computerised systems, as well as meeting all other obligations arising from their involvement with the gas system. The affected parties will be notified of any modifications to the information communication systems far enough in advance for them to make the necessary changes to their IT systems.

For access to previous systems it will be necessary to implement user authentication systems.

After consultation with transmission companies and DSO's, the GTS will establish the ideal mechanism for this authentication at all times, reporting it with enough time to allow the affected parties to adapt their systems.

1.1 Specifications

1.1.1 Basic SL-ATR specifications.

The SL-ATR will include, among other things, identification details for:

- Users and user profiles.
- Transmission infrastructure, connection points between transmission networks, and connections between transmission and distribution networks.
- Requests for book capacity and contracting.
- Programming, nominations and renominations.
- Measurements taken at the points on the gas system where measuring devices must be installed.
- Information on gas quality.
- Distribution.
- Balancing by facility/shipper, as per NGTS-07 'Balancing'.
- Imbalances.
- Interfaces with other external systems, such as invoicing.

All infrastructures put into operation by the different transmission companies are modelled in the SL-ATR system.

The SL-ATR also has a powerful and versatile capacity for accessing information for designing and issuing reports, always maintaining an appropriate level of security and confidentiality.

1.1.2 Basic SCTD specifications.

The SCTD will include, among other things, identification details for:

- Users and user profiles.
- Requests for book capacity and contracting.
- Programming and nominations relating to gas consumption, as per the provisions of the System Technical Management Rules.
- Measurements.
- Distribution of gas transmitted through the distribution network, as per the provisions of the System Technical Management Rules.
- Interfaces with external systems (GTS and shippers) and internal DSO systems.

The SCTD will use a standardised system of infrastructure coding, which will match that of the SL-ATR.

1.2 Information exchange

The User:

a) Will use the SL-ATR to manage the following information:

- Requests for contracting from customers connected to transmission networks.
- Book capacity at points of entry to the transmission network, regasification plants and storage facilities.
- Quarterly programming, weekly programming, nominations and renominations for regasification plants and at points of entry to the transmission network, international connections, national gas fields, or underground storage facilities.
- Queries and claims regarding requests for access, contracting, programming, nominations, allocation and balancing.

- Consultation of user contracts for regasification plants and at points of entry to the transmission network, international connections, national gas fields, or underground storage facilities.

b) The SCTD will be used to manage the following information:

- Requests for contracting from customers connected to distribution networks.
- Requests for access to supply point records.
- Programming and nominations relating to gas consumption, as per the provisions of the System Technical Management Rules.
- Consultation of information concerning programming, nominations and contracting requests presented.
- Consultation accessible to customers with

remote metering. The DSO:

a) Will receive all requests, information queries, programming and nomination of shippers and qualified customers via the SCTD, subsequently taking the necessary action.

b) Will send the following information from the SCTD to the AL-ATR:

- Programming and nominations relating to gas consumption, as per the provisions of the System Technical Management Rules.
- Monthly allocation and regularisations by network user, as per the provisions of the System Technical Management Rules.
- Daily allocation by user as per the provisions of the System Technical Management Rules.
- Distribution reviews by network user as per the provisions of the System Technical Management Rules.
- Requests for validation in response to applications for contracting from distribution network users, if so provided for under current legislation.
- Annual consumption and aggregate number of customers per transmission-distribution delivery point.
- Measurements at delivery points between DSO’s.

c) Will receive via the SCTD all request notifications from the SL-ATR and take the appropriate action.

The transmission company:

a) Will receive via the SL-ATR all information sent from the SCTD by DSO's.

b) Will receive via the SL-ATR all requests, capacity reservations, information queries and claims, programming and nomination of users and qualified customers, taking the necessary action.

c) Will send through the SCTD and from the SL-ATR to DSO's:

- Acceptance/Rejection of applications for contracting from distribution network users if so provided for under current legislation.
- Measurement information from DSO delivery points.
- Acceptance/Refusal of programming and nominations, as per the provisions of the System Technical Management Rules.

d) Will send to the SL-ATR:

- Monthly allocation and regularisations of allocation of tankers, trucks and direct lines by user.
- Daily allocation by user of tankers, trucks and direct lines.
- User allocation reviews as per the provisions of the System Technical Management Rules.
- Self-consumption measurements.

e) The GTS will publish via the SL-ATR the daily balance, detailed information on definitive allocation on its networks for consultation by all affected parties and imbalances as per the provisions of the System Technical Management Rules.

The SL-ATR and the SCTD will present information with a level of aggregation for each access profile.

2. Publication of information.

2.1. Purpose

To facilitate and simplify compliance with transparency requirements, this Protocol sets out all obligations relating to the publication of information by parties involved with the gas system, which are currently spread across diverse and varied regulations.

2.2 Applicable legislation

The transparency requirements applicable to the system parties are established in regulations, both national and European, which include a series of requirements related to information declarations.

2.3 Content

All parties to the system must make all information required under current regulations available to the sector (on the SL-ATR and SCTD) and to external parties (by publication on their websites).

The Technical Manager of the System will publish on its website, after approval from the CNE, all information it is required to publish under current regulations, including:

- The content of the information to be published.
- Level of aggregation.
- Figure responsible for publication.
- Frequency (daily, weekly, monthly, etc.).
- The medium (SL-ATR, SCTD, public website).
- The legislation establishing the requirement.

2.4 Mechanism for update

Within ten days of the publication of the regulation requiring the above modifications in the relevant official state gazette, the Technical Manager of the System will submit the proposed update to the CNE for approval. Once approved by the regulatory body, the Technical Manager of the System will complete the update within five days, under the terms established by the regulatory body.

PD- 05
'Procedure for the determination of energy unloaded from methane tankers'

1. General Criteria

Approved by the Resolution of the Directorate General for Energy Policy and Mines of 17 September 2007. Replaces the Protocol approved by Resolution of 13 March 2006, of the Directorate General for Energy Policy and Mines, establishing the detailed protocols for the Technical Management of the Gas System Regulations (BOE 04/04/2006)

Amended under the Resolution of 22 March 2011 of the Directorate General for Energy Policy and Mines, amending Detail Protocol PD-05, adding a new section, 6.6 'Determination of natural gas consumed by the methane tanker in self-consumption'

For the LNG loading and unloading processes, and sufficiently in advance of the first user operation, the user will appoint a representative who will act in accordance with the Contract on behalf of the company. If the loading or unloading operation is shared by a number of users, these will appoint a single representative to act on behalf of them all. The users will notify the regasification plant holders in writing of their representatives and any changes made to them.

The holders of the regasification plant and the tanker will provide these representatives with all necessary information for the control and determination of gas quantities and qualities. This information will be held on file by the holder of the regasification plant and by the user for a minimum of four years.

Annexes 1 and 2 contain documents with standard unloading and loading reports and a list of information to be filed relating to the control and determination of gas quantities and qualities.

The holder of the tanker must provide, maintain and operate the necessary instruments for determining level, pressure and temperature inside the methane tanker LNG tanks.

The holder of the regasification plant must provide, maintain and operate the instruments necessary to determine the quality and composition of the

LNG, sampling systems, and any other instrument necessary for the final determination of the net energy levels loaded or unloaded.

Before any loading or unloading operation, the holder of the tanker must provide the holder of the regasification plant with the correction tables for each tank on board, verified by an independent authority, mutually recognised by the parties, as well as Certificates of Verification for the instruments necessary for determining level, temperature and pressure inside the LNG tanks. These instruments must be sealed by the same authority that issued the calibration certificate to ensure no subsequent tampering has taken place.

The operation takes place and is managed by the relevant holder in the presence of the party representatives. During loading or unloading operations, the parties or their representatives can express disagreement with the operations performed by the holder without this stopping the operation.

Once the operation is complete, the holder of the LNG regasification plant will complete a Loading/Unloading Quantity Report, which will provide the data obtained as well as details of the calculation process used to obtain the said quantities. Before the tanker departs, this report is signed in duplicate by the parties, explicitly indicating their acceptance or concerns about its content. If the user's representative is not present at loading and unloading operations, this must be noted in the report, and the user will be considered to agree with the report.

In case of disagreement with the report, the holder of the regasification plant and the user representative will keep all documentation relating to the operation until the matter is resolved.

In case of development of new procedures, standards, measuring equipment and similar (quality and quantity of gas) providing greater reliability, precision or swiftness and that are economically viable, the holder of the regasification plant and the user agree to study the possibility of using those procedures, standards, etc. or substituting those already in use.

All standards applied in this procedure will correspond to the newest version of the same.

2. Considerations on the position of the methane tanker for commencing loading and unloading operations

After mooring, and prior to starting the loading or unloading operation, the tanker must be positioned with no pitch or roll, taking and recording readings from the inclinometer. The tanker will be fitted with two of these devices; the second one is to be used if the first breaks down.

Readings will likewise be taken from the draft marks, if possible from the jetty and if not, from the remote draft markers from the bridge of the tanker.

If for any reason it is not possible to eliminate tanker pitch and roll when taking measurements, the correction tables for pitch and roll (calibration tables) for the vessel will be applied (where applicable) to the measurements obtained.

In order to determine the energy loaded or unloaded from methane tankers, two readings are taken, before and after the operation, of the basic physical parameters that affect it (fluid level in tanks, fluid temperature, vapour temperature, vapour pressure).

The first reading is taken after the connection of the loading/unloading arms, but before starting to cool them and opening the venting valves.

The second reading is taken 15-30 minutes after completing the operation, with the loading/unloading arms still connected and the venting valves closed, to ensure that the surface of the liquid has stabilised.

3. Determining the level of liquid in tanks

Each LNG tank on board is fitted with two level gauges, based on the two main physical measuring principles. One is primary and the other secondary. The order of preference of use as primary gauge is: microwave, capacitive and float.

If the primary gauge fails, the secondary system is used. If the secondary system is used at the start of the operation, the remaining measurements are taken using that system even if the primary one has been repaired before the operation is complete.

For each type of gauge, the characteristics, tolerances, installation, operation and checks are based on the following standards:

- UNE-ISO 13689 'Refrigerated light hydrocarbon fluids. Liquefied natural gas (LNG). Measurement of liquid levels in tanks containing liquefied gases. Microwave-type level gauge.'
- UNE-ISO 8309 'Refrigerated light hydrocarbon fluids. Measurement of liquid levels in tanks containing liquefied gases. Electrical capacitance gauges'.
- UNE-ISO 10574 'Refrigerated light hydrocarbon fluids. Measurement of liquid levels in tanks containing liquefied gases. Float-type level gauges'.

Both for the initial measurement and the final measurement, at least two readings will be taken for each tank using the level gauges, at intervals of over two minutes, taking as the arithmetical average value of these readings and rounding up to a whole number (in mm).

If necessary, the value obtained for each of the tanks will need the application of pitch/roll corrections. If, in order to obtain readings, a float-type gauge has been used, the necessary corrections must be made for the thermal contraction of the belt or cable holding it due to the difference in temperature between the vapour and the calibration of the level gauge, and for the density of LNG.

At the end of all these corrections, the value will be rounded to a whole number where necessary.

4. Determining the temperature of the liquid and LNG vapour in the tanks

The temperature of the liquid and vapour-phase LNG in each tank on board will be measured immediately after taking a level reading, before the loading or unloading operation and immediately afterwards. Each tank will be fitted with a number of temperature gauges; one will be located at the bottom of the tank and the other at the top to ensure that a reading is taken of the temperature of the liquid and vapour, respectively. The rest of the temperature gauges will be fitted at equidistant intervals up the sides of the tanks.

Their characteristics, installation, operation and checks must meet the requirements established for Class A gauges in UNE-ISO 8310 'Refrigerated light hydrocarbon fluids. Measurement of temperature in tanks containing liquefied gases. Resistance thermometers and thermocouples'.

The temperature of the liquid in each tank is determined as the arithmetic average of the temperatures obtained from the temperature probes immersed in the LNG in that tank. The temperatures and their average value will be rounded up or down to two decimal places.

To determine which probes are immersed in the LNG, bear in mind their relative position in the tank and the height of the liquid inside.

The temperature of the liquid will be determined using the following expression:

$$T_{liquid} = \frac{\sum V_k . T_k}{\sum V_k}$$

Where Vk and Tk are volume (m^3) and temperature (ºC), respectively, of the liquid in each tank.

The result is given to two decimal places.

The temperature of the vapour in each tank is determined as the arithmetic average of the temperatures obtained from the temperature probes not immersed in the LNG in that tank, rounded to two decimal places.

To determine which probes are not immersed in the LNG, bear in mind their relative position in the tank and the height of the liquid inside. If there are any discordant temperatures, such as values that are unreasonable or unusual in relation to the temperature gradient in the tank, the average temperature will be recalculated disregarding the odd figure.

5. Determining pressure

The pressure in the tanks is measured immediately after temperature. The measurements for vapour pressure are taken using the absolute pressure gauges fitted in the part of the tank where the vapour accumulates, as per UNE-ISO 13398 'Refrigerated light hydrocarbon fluids. Liquefied natural gas (LNG). Procedure for custody transfer on board ship'.

This pressure reading is necessary for calculating the energy level of the displaced gas, and is determined as the average pressure in each tank, expressed in millibars and rounded to whole numbers.

If the vessel is not fitted with absolute pressure gauges, it must have atmospheric pressure gauges to measure and record readings simultaneously, for the calculation of absolute pressure.

6. Determining LNG quality

For the determination of LNG quality, the sampling process includes three operations:

- Representative sampling of LNG
- Full vaporisation of the sample
- Conditioning of the gaseous sample prior to transfer to the analyser

Continuous sampling will be performed following standard UNE-ISO 8943 'Refrigerated light hydrocarbon fluids. Sampling. Continuous method'.

The holder of the regasification plant shall keep three samples in bottles, each one in duplicate, taken during the loading or unloading process, when approximately 25%, 50% and 75% of the total amount has been unloaded, and will retain them until the loading/unloading report has been signed with the agreement of both parties. If no agreement is reached regarding the analysis performed, these samples will be kept available for the metrological authority, properly labelled and duly sealed by both parties, until the discrepancy has been resolved.

The taking of liquid samples will take place at the regasification plants, on the unloading line, passing through a continuous vaporiser and analysed with an on-line gas chromatograph. It is also advisable to have a backup vaporiser.

If there are no samples due to a failure in the sampling equipment or it is considered that, due to the operating conditions, the samples are not representative, the LNG quality will be determined by mutual agreement between the parties.

In case of failure of the main and backup chromatograph (where fitted), with the agreement of the user representative, other secondary chromatographs located at the regasification plant can be used, for which manual sampling is performed.

6.1 Determination of the composition of LNG and vapour

The composition of LNG and vapour will be determined using a gas chromatograph approved by a European Union metrological authority.

The chromatograph is calibrated with span gas to ensure that the precision of the equipment matches the approval issued by that authority.

The preparation is performed using a gravimetric method as per ISO 6142 'Gas Analysis – Preparation of calibration gas mixtures – Gravimetric method'.

Before the tanker arrives at the regasification plant, the plant holder, in the presence of the user representative, will check that the chromatograph is working properly. Span gas will be injected to check that the results obtained fall within the permitted tolerances. If the user representative is not present during this check, this will be noted on the report.

The average composition of the gas will be calculated using the analyses performed. To calculate the average composition based on analyses performed, any clearly anomalous readings or ones obtained under unstable operating conditions will be discarded by mutual agreement; in any event, any readings with a methane concentration more than 2% outside the average figure will be discarded. This composition is expressed in
% rounded to three decimal places.

6.2 Determination of sulphur compounds

Sulphur is determined using internationally recognised standards such as:

- UNE-EN 24260 'Petroleum products and hydrocarbons. Determination of sulphur content. Wickbold combustion method. (ISO 4260:1987)'
- ASTM D 4045

6.3 Determination of mercury compounds

This is determined as per UNE-EN ISO 6978 'Natural gas. Determination of mercury', parts 1 and 2.

6.4 Calibration, preparation and checking of chromatographic equipment

The chromatograph is calibrated, before and after each loading or unloading, with a span gas that ensures that the precision of the equipment matches the approval issued by that authority.

The preparation is performed using a gravimetric method as per ISO 6142 'Gas Analysis – Preparation of calibration gas mixtures – Gravimetric method'

Before the tanker arrives at the regasification plant, the plant holder, in the presence of the user representative, will check that the chromatograph is working properly. Span gas will be injected to check that the results obtained fall within the permitted tolerances.

This operation is repeated at the end of the loading/unloading operation. If the user representative is not present during this check, this will be noted on the report.

6.5 LNG sampling

The holder of the regasification plant will keep three samples in bottles (stainless steel cylinders), each one in duplicate, taken during the loading or unloading process, taken when approximately 25%, 50% and 75% of the total amount has been unloaded, and will retain them until the loading/unloading report has been signed with the agreement of all parties.

If no agreement is reached regarding the analysis performed, these samples will be kept available for the metrological authority, properly labelled and duly sealed by both parties, until the discrepancy has been resolved.

6.6 Determination of natural gas consumed by the methane tanker for internal use

Resolution of 22 March 2011 of the Directorate General for Energy Policy and Mines, amending Detail Protocol PD-05, adding a new section, 6.6 'Determination of natural gas consumed by the methane tanker for internal use'

6.6.1 General Criteria.

All methane tankers equipped to use the natural gas they carry as a fuel for the electrical generators, or for any other use or purpose that may be used during loading or unloading operations, must have a measuring system to determine the amount consumed for internal use, consisting of:

a) A massic or volumetric gauge that allows gas consumption under base conditions to be determined.

b) If the gauge is volumetric, a conversion device to transform the volume of natural gas consumed under base conditions to normal conditions, with the characteristics established in Standard EN 12405.

Where applicable, both devices will comply with the following:

a) Model approval issued by a body recognised by the International Legal Metrology Organisation (OIML) for use in fiscal measurement.

b) Valid certificates of verification issued by bodies of recognised prestige and duly sealed by those organisations.

The absence of the above equipment or certificates will be not give rise to a refusal to unload, and the energy consumed for internal use will be determined as per section 6.6.2 depending on the anomaly detected.

The energy consumed as fuel will be calculated:

a) In the case of a massic meter, by multiplying the difference between readings taken at the start and at the end of the operation by the gross calorific value (massic) of the boil-off determined as indicated in section 7.4.

b) In the case of a volumetric meter, by multiplying the difference between readings taken in normal conditions at the start and at the end of the operation by the gross calorific value of the boil-off determined as indicated in section 7.4.

The energy calculated will be added to or subtracted from the total amount loaded or unloaded, as appropriate.

The facility must also be fitted with a valve to ensure the shut-off of gas as a fuel, when desired. This value must be sealable, to ensure that its position has not been modified during the loading/unloading process.

Amendment to section 6.6.2 Measurement in case of anomaly. Resolution of 4 May 2015 of the Directorate General for Energy Policy and Mines amending detailed protocol PD-12 'Applicable procedures for liquefied natural gas trucks destined for satellite plants'.

Validity: 22 May 2015

6.6.2 Measurement in case of anomaly.

If it cannot be ensured that gas is not being used as fuel, either because there is no shut-off valve or because it does not have the seal described above, the determination of energy consumed for internal use will be performed depending on the type of anomaly, which are as follows:

<u>Type 1</u>. The installation does not have any of the approvals, certificates or seals described in section 6.6.1.

The greater of the following two amounts will be taken into account:

If unloading:

a) As determined by the measurement system.

b) 0.10% when the anomaly occurs for the first time at a plant.

0.15% when the anomaly occurs for the second time at a plant.

0.20% when the anomaly occurs for the third or consecutive time at a plant.

If loading:

a) As determined by the measurement system.

b) 0.25% when the anomaly occurs for the first time at a plant.

0.30% when the anomaly occurs for the second time at a plant.

0.35% when the anomaly occurs for the third or consecutive time at a plant.

Type 2. Absence of measurement equipment and other anomalies.

The following are used:

- 0.20% if unloading.
- 0.35% if loading

Before 15 October of each year, the GTS will submit a report to the Directorate General for Energy Policy and Mines and the National Energy Commission containing proposed values for the coefficients mentioned in section 6.6.2 to better adapt to the reality of operations and technological changes. For this reason, transmission companies that own regasification plants will regularly submit loading and unloading data for each plant to the GTS. This report will include a justification of the proposed values, as well as the information used to prepare them.

7. Calculations

7.1 Calculation of the volume of LNG loaded or unloaded

The volume of LNG loaded or unloaded by a tanker is the sum of the LNG loaded/unloaded in each tank on board.

The volume of LNG loaded/unloaded in each tank on board is calculated by using the difference between the initial and final levels of liquid in the tank, obtained as per this protocol and based on the calibration tables for each tank. The volume is expressed in cubic metres, rounded to three decimal places.

7.2 Calculation of the massic Gross calorific value

This is calculated as per standard UNE-EN ISO 6976 '*Natural gas*. *Calculation of calorific values, density, relative density and Wobbe indices from composition*', using the benchmark temperature for combustion fumes established in the System Technical Management Rules.

To obtain a value in kWh/kg, the value in MJ/kg (rounded to three decimal places) is divided by 3.6. The result is also rounded to 3 decimal places.

7.3 Calculating LNG density

LNG density is given in kg/m3, to three decimal places, calculated based on the molecular composition and average temperature of the initial liquid, when unloading, and the final temperature if loading. The calculation method is that described in standard UNE 60555 '*Liquefied natural gas (LNG)*. *Static measurement. Calculation Procedure*'.

7.4 Calculation of returned vapour

Returned vapour is calculated using:

a) If unloading: vapour temperature after the operation, final pressure and vapour composition.

b) If loading: initial vapour temperature, initial pressure and vapour composition.

The volumetric gross calorific value is calculated as per standard UNE-EN ISO 6976 'Natural gas. Calculation of calorific values, density, relative density and Wobbe indices from composition', rounded to three decimal places and at the benchmark temperature for combustion fumes established in the System Technical Management Rules.

The volume of returned vapour, expressed under normal conditions, is considered the ideal behaviour of vapour, and the benchmark conditions established in the GTS Standards will be used, taking the volume of liquid displaced as the gross volume.

Vapour composition is determined preferably using the first of the following methods:

a) Taking of samples from the vapour line, preferably using a continuous method with chromatographic sample analysis.

b) Use of fixed vapour composition to obtain a fixed gross calorific value.

7.5 Calculation of amounts delivered.

The calculation of Energy and Mass delivered is performed based on Standard UNE 60555: '*Liquefied natural gas (LNG). Static measurement. Calculation Procedure*'.

The result is expressed in kWh, with no decimal places. The result of mass measurements is expressed in kg, with no decimal places.

Annex 1

Tanker unloading report

Plant

Start date:

Start time: **Journey Nº:**

End date: **Port of origin:**

End time: **Vessel:**

Unloading port: **Country of origin:**

LNG TEMPERATURES IN TANKS AT START

TANK	1	2	3	4	5	6	7	8	9	10
TEMP.ºC										

LNG TEMPERATURES IN TANKS AT END

TANK	1	2	3	4	5	6	7	8	9	10
TEMP.ºC										

LNG COMPOSITION

N2: ....

C1: ....

C2: ....

C3: ....

IC4: ....

NC4: ....

IC5: ....

NC5: ....

C6+: ....

CO2: ....

____

Temp. Average at Start (ºC)

Temp. Average at End (ºC)

Vol. LNG Start (M3)

Vol. LNG End (M3)

Vol. LNG Unload. (M3)

Signed:

p. 1

Plant

Start Date:
Start time: **Journey Nº:**
End date: **Port of origin:**

End time: **Vessel:**
Unloading port: **Country of origin:**

TEMPERATURES OF BOIL-OFF IN TANKS AT START

TANK	1	2	3	4	5	6	7	8	9	10
TEMP.ºC										

TEMPERATURES OF BOIL-OFF IN TANKS AT END

TANK	1	2	3	4	5	6	7	8	9	10
TEMP.ºC										

BOIL-OFF COMPOSITION

N2: ....
C1: ....
C2: ....
C3: ....
IC4: ....
NC4: ....
IC5: ....
NC5: ....
C6+: ....
CO2: ....

____

Temp. Average at Start (ºC)
Temp. Average at End (ºC)
Vol. LNG Start (M3)
Vol. LNG End (M3)
Vol. LNG Unload. (M3)

Signed:

p. 2

Plant

This certificate indicates the quantity and quality of the liquefied natural gas (LNG) unloaded at the LNG Terminal, by the vessel , on:

Start Date:
Start time: **Journey Nº:**
End date: **Port of origin:**
End time: **Vessel:**
Unloading port: **Country of origin:**

AMOUNT OF LNG UNLOADED:
M3 LNG Vessel at start:................
kg LNG Vessel at start: ....
M3 LNG Vessel at end: ....
kg LNG Vessel at end: ....
M3 LNG Unloaded: ....
kg LNG Unloaded: ....
kWh LNG Totals: ....

AMOUNT OF BOIL-OFF RETURNED:
m^3(*) NG Returned:................
kg NG Returned: ....
kWh NG Totals: ....
m3 LNG equivalent : ....
kg LNG equivalent : ....

VESSEL INTERNAL USE:
Consumption of NG (m^3(n)):...............
kg of NG: ....
kWh Own consumption: ....
m3 LNG equivalent : ....
kg LNG equivalent : ....

ENERGY UNLOADED AT TERMINAL:
m3 LNG equivalent : ....
kg LNG equivalent : ....
kWh unloaded: ....

Signed:

p. 3

Plant

Start Date:
Start time: **Journey Nº:**
End date: **Port of origin:**
End time: **Vessel:**
Unloading port: **Country of origin:**

AVERAGE RESULT OF CHROMATOGRAPHIC ANALYSIS:
MOLAR COMPONENT

N2
C1
C2
C3
IC4
NC4
IC5
NC5
C6+
CO2

% LNG PROPERTIES

MOLECULAR WEIGHT	kg/KMOL
NORMALISED DENSITY	kg/m^3(*)
CALORIFIC VALUE OF GAS	kWh/m^3(*)
DENSITY EXPANSION	m^3(*)/m3L
RATIO	kg/m3L
CALORIF. VALUE LNG/MASS	kWh/kg
CALORIF. VALUE LNG/VOL.	kWh/m3L
WOBBE INDEX	kWh/m^3(*)

(*) See conditions below

Average LNG temperature : ºC
Calorific value (HS): [ºC, MBAR]
Wobbe Index: [ºC, MBAR]

Signed:

p. 4

Plant
Start Date:
Start time: **Journey Nº:**
End date: **Port of origin:**
End time: **Vessel:**
Unloading port: **Country of origin:**

LIQUID COMPOSITION
% COMPONENT

N2
C1
C2
C3
IC4
NC4
IC5
NC5
C6+
CO2

DENSITY CALCULATIONS

LIQUID TEMPERATURE: ºC K1= m^3/kmol
K2= m^3/kmol
DENSITY= kg/m3L

CALORIFIC VALUE
Hm= kWh/kg
Hv= kWh/m3L

AMOUNT DELIVERED

VESSEL ARRIVAL:	M3	TEMP: OF VAPOUR:	°C
VESSEL DEPARTURE:	M3	ABS. PRESSURE. AFTER:	mbar
RECEIVED BY VESSEL:		M3	
CONSUMED BY VESSEL:		M3	

UNLOADED WEIGHT: kg

Signed:

p. 5

Plant

Start Date:
Start time: **Journey Nº:**
End date: **Port of origin:**
End time: **Vessel:**
Unloading port: **Country of origin:**

START OF UNLOADING

Temp. Av. LNG at start (ºC): ....
LNG Density (kg/m3L): ....

LNG QUALITY:

MOLAR COMPOSITION %:
N2: ....
C1: ....
C2: ....
C3: ....
IC4: ....
NC4: ....
IC5: ....
NC5: ....
C6+: ....
CO2: ....

Cal. Value. (kWh/m3L): ....
Molec. weight (kg/kmol): ....
K1: ....
K2: ....
P. of revap. (m3L/m^3(*)): ....
Wobbe I. (kWh/m^3(*)): ....

Signed:

p. 6

Plant

Start Date:
Start time:
End date:
End time:
Unloading port:

Journey Nº:
Port of origin:
Vessel:
Country of origin:

Temp. Av. NG start (ºC): ....
Av. Temp. NG End (ºC): ....
NG Density (kg/m^3(*)): ....

BOIL-OFF QUALITY:

MOLAR COMPOSITION %:
N2: ....
C1: ....
C2: ....
C3: ....
IC4: ....
NC4: ....
IC5: ....
NC5: ....
C6+: ....
CO2: ....

Cal. Value. (kWh/m^3(*)): ....
Molec. weight (kg/kmol): ....
Wobbe I. (kWh/m^3(*)): ....

Signed:

p. 7

SHIPMENT

CERTIFICATE OF QUANTITY

This certificate indicates the amount of unload liquefied natural gas (LNG) that has been received at the Plant, with the following data:

Signed:

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PLANT AT PORT OF

UNLOADING REPORT ( ) PROVISIONAL

( ) PROPOSED

( ) DEFINITIVE

VESSEL:

ORIGIN:

ARRIVAL DATE:

PRODUCT: **LNG**

ATTRIBUTABLE SUPPLY LOSS:

Signed:

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SHIPMENT

CERTIFICATE OF QUANTITY

This certificate indicates the amount of supply loss in liquefied natural gas (LNG) that has been received at the Plant , with the following data

Signed:

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PLANT AT PORT OF

UNLOADING REPORT

( )PROVISIONAL

( ) PROPOSED

( ) DEFINITIVE

VESSEL:

ORIGIN:

ARRIVAL DATE:

PRODUCT: LNG

ATTRIBUTABLE SUPPLY LOSS:

Signed:

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Annex 2

Tanker loading report

Plant

Start Date:
Start time: **Journey Nº:**
End date: **Destination port:**
End time: **Vessel:**
Loading port: **Country of origin:**

LNG TEMPERATURES IN TANKS AT START

TANK	1	2	3	4	5	6	7	8	9	10
TEMP.ºC										

LNG TEMPERATURES IN TANKS AT END

TANK	1	2	3	4	5	6	7	8	9	10
TEMP.ºC										

LNG COMPOSITION

N2: ....
C1: ....
C2: ....
C3: ....
IC4: ....
NC4: ....
IC5: ....
NC5: ....
C6+: ....
CO2: ....

Temp. Average at Start (ºC)
Temp. Average at End (ºC)
Vol. LNG Start (M3)
Vol. LNG End (m3)
Vol. LNG Unload. (m3)

Signed:

p. 1

Plant

Start Date:
Start time: **Journey Nº:**
End date: **Destination port:**
End time: **Vessel:**
Loading port: **Country of origin:**

TEMPERATURES OF BOIL-OFF IN TANKS AT START

TANK	1	2	3	4	5	6	7	8	9	10
TEMP.ºC										

TEMPERATURES OF BOIL-OFF IN TANKS AT END

TANK	1	2	3	4	5	6	7	8	9	10
TEMP.ºC										

BOIL-OFF COMPOSITION

N2: ....
C1: ....
C2: ....
C3: ....
IC4: ....
NC4: ....
IC5: ....
NC5: ....
C6+: ....
CO2: ....

Temp. Av. at start (ºC)
Starting pressure (MBAR)
Temp. Av. At End (ºC)
Ending pressure (MBAR)
Volume returned (m^3)
Volume Returned(m^3(*))
Vessel own consumption (m^3(n))

Signed:

p. 2

Plant
This certificate indicates the quantity and quality of the liquefied natural gas (LNG) loaded at the LNG Terminal, by the vessel , on:

Start Date:
Start time: **Journey Nº:**
Final date: **Destination port:**
End time: **Vessel:**
Loading port: **Country of origin:**

AMOUNT OF LNG LOADED:

m3 LNG Vessel at start:................
kg LNG Vessel at start: ....
M3 LNG Vessel at end: ....
kg LNG Vessel at end: ....
M3 LNG Unloaded: ....
kg LNG Unloaded: ....
kWh LNG Totals: ....

AMOUNT OF BOIL-OFF RETURNED:
m^3(*) NG Returned:................
kg NG Returned: ....
kWh NG Totals: ....
M3 LNG equivalent : ....
kg LNG equivalent : ....

VESSEL INTERNAL USE:
Consumption of NG (m^3(n)):...............
kg of NG: ....
kWh Own consumption: ....
M3 LNG equivalent : ....
kg LNG equivalent : ....

ENERGY LOADED AT TERMINAL:
m3 LNG equivalent : ....
kg LNG equivalent : ....
kWh unloaded: ....

Signed:

p. 3

Plant
Start Date:
Start time: **Journey Nº:**
Final date: **Destination port:**
End time: **Vessel:**
Loading port: **Country of origin:**

AVERAGE RESULT OF CHROMATOGRAPHIC ANALYSIS: %

MOLAR COMPONENT

N2
C1
C2
C3
IC4
NC4
IC5
NC5
C6+
CO2

LNG PROPERTIES

MOLECULAR WEIGHT	kg/KMOL
NORMALISED DENSITY CALORIFIC	kg/m^3(*)
VALUE OF GAS	kWh/m^3(*)
DENSITY EXPANSION	m^3(*)/m3L
RATIO	kg/m3L
CALORIF. VALUE LNG/MASS	kWh/kg
CALORIF. VALUE LNG/VOL.	kWh/m3L
WOBBE INDEX	kWh/m^3(*)

(*) See conditions below

Average LNG temperature : ºC
Calorific value (HS): [ºC, MBAR]
Wobbe Index: [ºC, MBAR]

Signed:

Page
4

Plant

Start Date:
Start time: **Journey Nº:**
End date: **Destination port:**
End time: **Vessel:**
Loading port: **Country of origin:**

LIQUID COMPOSITION

% COMPONENT

N2
C1
C2
C3
IC4
NC4
IC5
NC5
C6+
CO2

DENSITY CALCULATIONS

LIQUID TEMPERATURE: ºC K1 m^3/kmol
K2 m^3/kmol

DENSITY kg/m3L

CALORIFIC VALUE

Hm= kWh/kg
Hv= kWh/m3L

AMOUNT DELIVERED

VESSEL ARRIVAL: M3 TEMP: OF VAPOUR REL.: ºC
VESSEL DEPARTURE: M3 ABS. PRESSURE. AFTER: mbar
RECEIVED BY VESSEL: M3
CONSUMED BY VESSEL: M3

WEIGHT LOADED kg

Signed:

p. 5

Plant

Start Date:
Start time: **Journey Nº:**
End date: **Destination port:**
End time: **Vessel:**
Loading port: **Country of origin:**

START OF LOADING
Av. Temp. LNG at start (ºC): ....
LNG Density (kg/m3L): ....

LNG QUALITY: MOLAR COMPOSITION %: N2: ....
C1: ....
C2: ....
C3: ....
IC4: ....
NC4: ....
IC5: ....
NC5: ....
C6+: ....
CO2: ....

Cal. Value. (kWh/m3L): . ...
Molec. weight (kg/kmol): ....
K1: ....
K2: ....
P. of revap. (m3L/m^3(*)): ....
Wobbe I. (kWh/m^3(*)): ....

Signed:

Page 6

Plant

Start Date:
Start time:
End date:
End time:
Loading port:

Journey Nº:
Destination port:
Vessel:
Country of origin:

Av. Temp. NG start (ºC): ....
Av. Temp. NG End (ºC): ....
NG Density (kg/m^3(*)): ....

BOIL-OFF QUALITY:
MOLAR COMPOSITION %:
N2: ....
C1: ....
C2: ....
C3: ....
IC4: ....
NC4: ....
IC5: ....
NC5: ....
C6+: ....
CO2: ....

Cal. Value. (kWh/m^3(*)): ....
Molec. weight (kg/kmol): ....
Wobbe I. (kWh/m^3(*)): ....

Signed:

p. 7

SHIPMENT

CERTIFICATE OF NET QUANTITY

This certificate indicates the quantity of liquefied natural gas (LNG) loaded at the Plant, with the information listed below:

Signed:

Page 8

PLANT **PORT OF**

WAYBILL ( ) PROVISIONAL

( ) PROPOSED

( ) DEFINITIVE

VESSEL:

ORIGIN:

ARRIVAL DATE:

PRODUCT: **LNG**

ATTRIBUTABLE SUPPLY LOSS:

Signed:

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SHIPMENT

CERTIFICATE OF QUANTITY

This certificate indicates the quantity of supply loss of the liquefied natural gas (LNG) for the indicated load, at the Plant, with the information listed below

Signed:

Page 10

PLANT **PORT OF**

WAYBILL ( ) PROVISIONAL

( ) PROPOSED

( ) DEFINITIVE

VESSEL:

ORIGIN:

DISPATCH DATE:

PRODUCT: **LNG**

ATTRIBUTABLE SUPPLY LOSS:

Signed:

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SHIPMENT

CERTIFICATE OF QUANTITY ON BOARD

This certificate indicates the quantity of liquefied natural gas (LNG) loaded onto the tanker at the Plant, with the information listed below:

VESSEL:

DESTINATION:

LOADING DATE:

PRODUCT:	**LNG**
VOLUME:	m^3
WEIGHT:	kg
kWh:	

Signed:

PD- 06

'Operational regulations for methane tanker unloading activities'

Published in the Resolution of 13 March 2006 of the Directorate General of Energy Policy and Mines and modified by the Resolution of 17 September 2007 of the Directorate General of Energy Policy and Mines (Article Three.- Replaces section 2.1 'Inspection of methane tankers' of Detail Protocol PD-6)

Modification of sections 5 and 6.7 of the Resolution of 4 May 2016 of the Directorate General of Energy Policy and Mines (B.O.E. 10/05/2016)

Validity: 11 May 2016

1. Purpose.

The present document seeks to set out a coordination procedure for the logistical activities permitting the management of LNG unloading.

2. Inspection of methane tankers and compatibility reports.

2.1. Inspection of methane tankers:

The tankers to be used for LNG unloading at regasification facilities must have satisfactorily passed the inspection proceedings ('vetting') required by an internationally reputable company specialising in the assessment of LNG tankers.

The inspections shall be carried out by inspectors with OCIMF (Oil Companies International Marine Forum) accreditation for LNG tankers, following the guidelines and made available through the SIRE (Ship Inspection Report) programme.

The ship inspections will be valid for the following durations: 18 months for vessels less than 5 years old, 12 months for vessels between 5 and 15 years old and 6 months for vessels more than 15 years old.

If a vessel is 15 years old or more, it must have passed a class dry dock inspection in the last 36 months.

Likewise, the holders of regasification plants may ask contractors with vessels that have been in service for 20 years or more to present additional certificates from a classification society about the structural condition of the vessels, such as a Level 1 or 2 CAP (Condition Assessment Programme) or similar accreditation, certifying specific inspections for vessels of this age. Each terminal should publish the details of its requirements. Any modification of requirements should be announced with sufficient advance notice.

If methane tankers are to be unloaded that have not yet passed any internationally recognised inspection procedures, or that have undergone significant modifications since the performance of the said inspection, the shipper, transmission company or qualified consumer contracting the tanker must provide all information requested both by the holder of the unloading facility and the inspection company who will assess the tanker before the unloading process begins.

In any case, the definitive authorisation that will allow a methane tanker that has passed the inspection to moor and unload liquefied natural gas at an LNG reception, storage and regasification plant will be granted by the holder of the said plant. The shipper or qualified consumer must begin the proceedings far enough in advance to complete them as a prior step to the creation of the binding tanker unloading schedule.

2.2 Compatibility reports:

If using methane tankers that have not previously unloaded LNG at the facility in question, in order to be able to analyse the compatibility between the tankers that transport the LNG for the various shippers and the terminal facilities, the said shippers must supply all information about the tankers requested by the facility holder.

This information will be used to assess the compatibility of elements related to the unloading arms, contact points with the seawall, number of mooring points, position of the tanker's manifold and gangplank, among other items. The facility holder promises to issue the said report within 7 working days of the provision of the relevant information by the shipper.

3. Safe mooring and unloading facilities

The holder of the unloading facility must comply with generally accepted standard international regulations in the LNG industry. These include, among others:

- Adequate lighting, within the limits set by the port authorities, that allow jetty access or departure manoeuvres to be performed, in accordance with the specific regulations in force at each Port;
- Unloading arms, pipes and other necessary equipment for the

unloading of LNG;

- Appropriate vapour return equipment to maintain operating pressure in the loading tanks of the methane tanker, always within the operative ranges specified for the tanker;
- Safe access routes for vessel personnel and others boarding the vessel;
- A communications system that complies with applicable regulations and allows uninterrupted communication with the Methane Tanker at all times;
- Systems that facilitate the supply of nitrogen to methane tankers.

4. Authorisations and Port Services

It shall be the responsibility of the Methane Tanker or its designated representative to obtain the corresponding unloading permits from the Port Authority. They are also responsible for contracting mooring services, including (among others): maritime pilots, tugs and moorers.

5. Programming

Vessel unloading will be programmed in accordance with the provisions set out in the System Technical Management Rules, sections 3.6.2.1 and 3.6.2.2, with reference to yearly and monthly programming. Yearly planning shall be informative in nature and monthly planning shall be binding, in accordance with section 3.6.2.2 of the NGTS-02,
'Programming'.

Binding monthly programming shall include, among other information, the programmed date for the unloading, which sets the first day of the period of time allotted for the vessel's arrival. The duration of this period, or unloading window, and the time of day when it begins, depend on the unloading facility. These windows are established as follows:

a) For Barcelona, Cartagena, Bilbao and Sagunto: 36 hours, beginning at 00:00 on the programmed unloading date, for all vessel types.

b) For Huelva and Mugardos: 36 hours, with the window beginning two hours before the first high tide on the programmed unloading date, for all vessel types.

6. LNG logistics activities.

6.1 Vessel nomination:

At least 15 days before unloading, and always before loading, the various shippers and consumers that acquire their own supplies, provided that the criteria set out in section 6.2 are met, will use fax, telex or email to nominate vessels compatible with the Port and the legal and technical requirements of the unloading facilities. These must comply with generally accepted standard international regulations in the Liquefied Natural Gas (hereinafter LNG) industry.

- The said nomination must include, at minimum, the following information:
- Name of vessel.
- ETA, in accordance with the established Programmed Unloading Date.
- Planned quantity to unload, also in accordance with the schedule.
- Gas source.

The facility holder shall respond by accepting or rejecting the nomination within 72 working hours of its reception; any rejection must have corresponding reasoning.

In any case, if the holder does not respond within the allotted period, this will be taken as an implicit acceptance of the nomination.

6.2 Notifications about loading:

Shippers and consumers that acquire their own supplies, or their designated representatives, shall notify the facility holder once the LNG loading is complete about the origin, size and quality of the load through the relevant certificates issued by an independent inspector.

6.3 Estimated Time of Arrival Notifications:

The captain of the methane taker or their designated agent shall inform the plant holder of the estimated Date and Time of the ship's arrival at the entrance buoy, or
'Estimated Time of Arrival' (ETA), taking into account the duration of the voyage in the following cases:

- The first notification must be sent upon departure from the loading port.
- The second notification must be sent no later than seven (7) days before the ETA. If the ETA changes by more than twelve (12) hours, the captain of the methane tanker or their agent must immediately inform the plant holder of the corrected ETA.
- The third notification must be sent no later than seventy-two (72) hours before the ETA. If the ETA changes by more than six (6) hours, the captain of the methane tanker or their agent must immediately

inform the plant holder of the corrected ETA.

- The fourth notification must be sent no later than forty-eight (48) hours before the ETA. If the ETA changes by more than six (6) hours, the captain of the methane tanker or their agent must immediately inform the plant holder of the corrected ETA.
- The fifth notification must be sent no later than twenty-four (24) hours before the ETA. If the ETA changes by more than one (1) hour, the captain of the methane tanker or their agent must immediately inform the plant holder of the corrected ETA.
- The Notice of Readiness (NOR) must be sent by the captain of the methane tanker to the plant holder upon arriving at the entrance buoy or the anchoring area near the unloading port, where the maritime pilot from the unloading port will board the methane tanker. Once the necessary formalities with the relevant authorities have been completed and all preparations have been made to proceed with the mooring and begin unloading, the methane tanker and holder will proceed with all due care to the secure mooring of the tanker at the quay or jetty of the unloading facility.

6.4 Vessel mooring priority.

If a methane tanker arrives within the unloading window, the said tanker will have mooring priority over any others arriving at the same time outside their unloading window, as well as over any that have arrived outside their Programmed Unloading Date and are waiting to moor, except in cases where the other tanker, having arrived in the previous unloading window, is waiting due to bad weather or force majeure.

If the methane tanker does not arrive during its Unloading Window, the facility holder must arrange its mooring for unloading as soon as possible, taking into account the normal regime of the facilities and the unloading schedules of other tankers, using the 'first come first served' principle over other ships that have also arrived outside their respective Unloading Windows. In the interests of guaranteeing supply security, this situation may be modified if the Manager of the System sees fit, modifying the unloading order to address imbalances.

If a methane tanker does not arrive during its unloading window and is transporting gas from a shipper or consumer that acquires its own supplies and is in a state of individual imbalance, this tanker shall have unloading priority over other tankers that have arrived outside their unloading window.

6.5 Mooring operations:

After the NOR has been reported in accordance with the provisions set out in Section 6.3, the captain of the tanker must proceed to the prompt, secure mooring of the Methane Tanker to the jetty, and the facility holder must cooperate to moor the tanker in this manner.

6.6 Unloading operations:

The captain of the methane tanker and the facility holder shall arrange for the unloading to begin as soon as possible after the mooring operations and must cooperate with one another to complete or arrange for the unloading to be completed in a safe, effective and prompt manner.

To unload LNG safely at the rates, pressures and temperatures required by the Methane Tanker and Unloading Facilities, the LNG must be pumped from the Methane Tanker - following the Terminal's instructions - to the receiving facilities in accordance with the agreed laytime, and the facility holder shall return natural gas to the Tanker in the quantities required.

The captain of the Methane Tanker will unmoor safely and promptly once the operation is completed, and the facility holder must cooperate to help the Tanker leave the jetty promptly and safely. If any problem occurs or looks like it may occur, in such a way as to cause a delay to the mooring, unloading or unmooring of the Methane Tanker that could change the programmed times for these operations, the Receiving Facility and Methane Tanker must discuss the problem in good faith and make efforts to minimise or avoid the said delay. At the same time, they must cooperate with one another to take steps to minimise or avoid any similar delays in the future.

6.7 Laytime

6.7.1. Permitted laytime. This is the maximum time allotted to the facility holder to complete the unloading of each shipment without incurring demurrage. This laytime is as follows:

a) Vessels with capacity less than or equal to 200,000 m3 of LNG: Thirty-six (36) consecutive hours, including Saturdays, Sundays, and holidays.

b) Vessels with capacity greater than 200,000 m3 of LNG: Forty-eight (48) consecutive hours, including Saturdays, Sundays, and holidays.

6.7.2. Start of laytime:

6.7.2.1 Cartagena, Barcelona, Bilbao and Sagunto. If the methane tanker arrives at the entrance buoy of the unloading port and sends its

Notice of Readiness (NOR) within its unloading window, the laytime will begin six hours after the NOR is sent, or once the tanker is moored and ready to begin unloading, whichever comes first.

If the methane tanker arrives at the entrance buoy of the unloading port and sends its NOR before the start of its unloading window, the laytime will begin when the first of the following events occurs:

a) The methane tanker is moored and ready to begin unloading.

b) 6:00 on the programmed unloading date.

If the methane tanker arrives at the entrance buoy of the unloading port after its unloading window, or arrives before but does not send its NOR in time, the laytime will begin when the methane tanker is moored and ready to begin unloading.

6.7.2.2 Huelva. If the methane tanker arrives at the entrance buoy of the unloading port and sends its NOR on or before its programmed unloading date, whichever comes first, the laytime will begin when the first of the following events occurs:

a) Four hours after the first high tide within the unloading window that also takes place at least two hours after the NOR is sent, provided this allows the methane tanker to moor safely and unload in accordance with the relevant port regulations.

b) When the methane tanker is moored and ready to begin unloading.

If the methane tanker arrives at the entrance buoy of the unloading port after its unloading window, or arrives before but does not send its NOR in time, the laytime will begin when the tanker is moored and ready to begin unloading.

6.7.2.3 Mugardos. If the methane tanker arrives at the entrance buoy of the unloading port and sends its NOR on or before its programmed unloading date, whichever comes first, the laytime will begin when the first of the following events occurs:

a) Six hours after the first high tide within the unloading window that takes place at least one hour after the NOR is sent, provided this allows the methane tanker to moor safely and unload in accordance with the relevant port regulations.

b) When the methane tanker is moored and ready to begin unloading.

If the methane tanker arrives at the entrance buoy of the unloading port after its unloading window, or arrives before but does not send its NOR in time, the laytime will begin when the tanker is moored and ready to begin unloading.

6.7.3 End of laytime. Laytime will cease to elapse when the unloading arms are detached.

Laytime may be extended for any delays attributable to or period of time required for the following:

a) An action or omission of the methane tanker or its captain;

b) Delays due to special tanker operations such as 'heel out', provisioning, 'bunkering', etc.;

c) Methane tanker compliance with the regulations of the unloading port;

d) Slow unloading due to high LNG temperature;

e) Delays due to adverse weather conditions; and

f) Another other reason of force majeure.

6.7.4. Start of laytime in Bilbao: If the methane tanker arrives at the entrance buoy of the unloading port and sends its NOR within its unloading window, the laytime will begin six hours after the NOR is sent, or once the tanker is moored and ready to begin unloading, whichever comes first.

If the methane tanker arrives at the entrance buoy of the unloading port and sends its NOR before the Programmed Unloading Date, the laytime will begin once the methane tanker is moored and ready to begin unloading; or at 00:00 on the Programmed Unloading Date, whichever comes first.

If the methane tanker arrives at the entrance buoy of the unloading port after its Unloading Window, or arrives before but does not send its NOR in time, the laytime will begin when the methane tanker is moored and ready to begin unloading.

6.7.5. Other Plants: The moment when the laytime begins at other plants that operate the Gas System must be established.

6.7.6. End of Laytime: If the shipment has not been unloaded within the Permitted Laytime, the facility

holder shall allow the methane tanker to continue to occupy the jetty or mooring point until the unloading is complete. The laytime will continue, counting as Demurrage.

Laytime may be extended for any delays attributable to or period of time required for the following:

a) An action or omission of the methane tanker or its captain;

b) Methane tanker compliance with the regulations of the unloading port;

c) Slow unloading due to high LNG temperature;

d) Delays due to adverse weather conditions; and

e) Another other reason of force majeure.

Laytime will cease to elapse when the unloading arms are detached.

6.8 Measuring LNG unloading:

The quantity and quality of LNG unloaded shall be measured by the holder of the unloading facility, using measuring equipment in accordance with the procedures applicable at each moment and the provisions established in the Detail Protocols, complying with the operative regulations on the energy measurement of unloadings.

The group of shippers and consumers that acquire their own supplies, who will eventually share a shipment may designate an Independent Inspector in agreement with their shipper to supervise and verify the measurements, sampling and analysis of the unloaded LNG. The cost of this inspection will be taken on by the companies that share the said shipment.

6.9 Demurrage:

If the unloading of the shipment has not been completed within the Permitted Laytime for reasons not attributable to the methane tanker or its captain, the plant holder must pay demurrage according to the following table of fees per day:

a) For tankers with gross capacity of up to 60,000 m^3: A1 US$/day.

b) For tankers with gross capacity between 60,000 and 110,000 m^3: A2 US$/day.

c) For tankers with gross capacity greater than 110,000 m^3: A3 US$/day.

If, as a result of any delay attributable to an action or omission of the methane tanker or its captain, the unloading of the shipment at the unloading port takes more laytime than the Permitted Laytime, and as a consequence, another tanker cannot access the Facilities upon arriving at the unloading port on its Programmed Unloading Date, the facility holder shall be paid (once the aforementioned situation has been appropriately justified) demurrage according to the following table of fees per day:

a) For tankers with gross capacity of up to 60,000 m^3: A1 US$/day.

b) For tankers with gross capacity between 60,000 and 110,000 m^3: A2 US$/day.

c) For tankers with gross capacity greater than 110,000 m^3: A3 US$/day.

In any of the above cases, quantities will be pro-rated for periods less than one day.

The above prices will be updated in each year of application according to the average annual price increase reported in the OECD 'European Union Consumer Price Index', published by the Organisation for Economic Cooperation and Development in its monthly bulletin.

In both cases, the demurrage shall be paid within twenty (20) days of receiving the invoice; if payment is not made within the allotted time, the debtor party will be obliged to pay the receiving party interest on the demurrage equivalent to 'USD LIBOR' increasing three points in three months, calculated from the day after the end of the allotted payment period.

All claims for demurrage shall be considered null if they are presented with the relevant documentation 90 calendar days or more after the unloading is completed.

Demurrage:

The monetary values referred to as A1, A2 and A3 in section III.6.9 Demurrage, in the Operating Procedure for LNG Unloading Logistics Activities, are given below.

A1) For tankers with gross capacity of up to 60,000 m^3: 26,000 US$/day.

A2) For tankers with gross capacity between 60,000 and 110,000 m^3: 45,000 US$/day.

A3) For tankers with gross capacity greater than 110,000 m^3: 65,000 US$/day.

PD- 07

'Programming, nomination and re-nomination at system transmission infrastructure facilities'

1. Purpose

The present Detail Protocol describes the programming, nomination and re-nomination procedures included in the System Technical Management Rules NGTS-03 and NGTS-04, which the Technical Manager of the System (GTS) and the operators of gas system facilities require for the proper planning and operation of the system.

2. Scope of application

This protocol is applicable at transmission, storage and regasification facilities.

2.1 Regasification plants

The operators of regasification plants and the GTS (Technical Manager of the System) will have access to information about the following subjects:

- Users of the regasification plants,
- DSO's, who shall send the necessary truck loading schedules for consumption on their distribution networks connected to satellite plants

Once this information has been assessed, operators of regasification plants shall provide notification about the viability of the same. The said reports shall be made available to the GTS so that the overall analysis of the system can be performed, and the necessary adjustments made to settle on a definitive confirmed schedule.

This confirmation is not applicable to the regasification process, but is taken into account for the plant's confirmation as a whole, and may affect the confirmation of tanker unloading.

2.2 Underground storage facilities

Information regarding underground storage facilities shall be sent by the users for a single storage facility, independent of the physical installation where the stored gas is located.

In accordance with the above, the GTS will be the figure that coordinates underground storage operators to agree on injection and withdrawal schedules at each facility, with the goal of guaranteeing that all underground storage facilities are used in a way that meets standards of safety and economic efficiency, covering the overall storage needs requested by the users.

The GTS shall send the planned working programme to the operator of the underground storage facility, who will in turn send back any objections to the same. The GTS will then establish the definitive working programme on the basis of the received objections and send it to each of the operators, as well as users' confirmed injection or withdrawal quantities.

2.2 Transmission networks

Transmission network operators and the GTS (Technical Manager of the System) will have access to information about the following subjects:

1. Users, for demand from conventional consumption and electricity generation.

2. Users, in relation to the gas to be transmitted to or from other transmission infrastructure facilities (regasification plants, underground storage facilities, international connections, gas fields and VBP storage, where offered). User information about underground storage facilities and VBP storage (where available) will only be available to the GTS.

3. Other transmission network operators (including adjacent operators of international connections and gas fields). Once the received information has been analysed and processed, the GTS will inform users of the confirmed quantities.

3. Shared parameters

The shared parameters that should be given in every exchange of information about programming, nomination and re-nomination are as follows:

- Date issued.
- Identification of the user that is carrying out the programming, nomination or re-nomination.
- Identification of the operator to whom it is directed.
- Facility and point/service to which it applies.
- Quantity of gas programmed, nominated or re-nominated with the required details.

Programming is to be done in units of energy, using GWh for yearly programming and kWh for monthly programming, weekly programming, nominations and re-nominations.

Besides the information about programming, nominations and re-nominations established in this protocol, the GTS may request the programming, nomination or re-nomination of any other service provided if necessary.

The last quantity sent and recorded in the Third-Party Network Access Logistics System (SL-ATR), regardless of when it was sent, will be taken as monthly programming, weekly programming, nomination or re-nomination so long as it was recorded within the period allotted for its submission.

In the case of programming, when the user has not sent any programming for a given period, the confirmed programming for the longer time horizon will be taken as the programming for the said period. This means that if there is no weekly programming, the confirmed monthly programming will be used, and in its absence, the confirmed yearly programming will be used. Likewise, if there is no monthly programming, the confirmed yearly programming will be used. If no programming has been sent by the user that has been confirmed for the programming period, the programmed quantity allocated to the user will be taken to be zero.

For nominations and re-nominations, the last confirmed nominations or re-nomination will be used. If the user has not sent a confirmed nomination, the last weekly schedule will be taken as a nomination. If the user has not sent confirmed weekly programming, their nominated quantity will be taken as zero. In the case of entries or exits using international connections with Europe, the GTS will apply the default nomination rule agreed upon with the transmission network operator on the other side of the border. The GTS will make this rule available on its website.

4. Yearly programming

4.1 Yearly programming at regasification plants:

4.1.1 Content of programming

Monthly detail for the 12 months of the coming calendar year, addressing the following topics:

1. Tanker unloading

• Monthly quantity (GWh/month).

• Gas source. • Number and size of tankers to be used, in accordance with the classification set out in Detail Protocol PD-13 'Assignment of unloading dates to tankers at regasification plants'.

• Name of the tanker (if known in advance) or type of tanker for each shipment, indicating if the unloading is to be complete or not; if not, the quantity to be unloaded must be noted.

• Requested unloading date for each of the tankers, identifying those that are always dedicated to long-distance traffic from the same starting point.

• Demand sector to which the supply from a given tanker is to be allocated, in accordance with the sector definitions laid out in Detail Protocol PD-13 'Assignment of unloading dates to tankers at regasification plants'. If a vessel is to provide supply to both demand sectors, this will be considered an assignment to the larger sector. Each user may only have one tanker per year that supplies both demand sectors.

• Shared tankers and the user with which it is shared (if not available, indicate what quantity of the shared vessel is allocated to the user).

2. Regasification

• Monthly quantity to be regasified (GWh/month).

• User to whom the regasified quantity is allocated. Whether the user is regasifying the gas for their own use or for another user (if another user is not named, it will be assumed that the regasification is being performed for own use).

3. Truck loading

• Quantity of trucks to be loaded (GWh/month and number of trucks) for the 12 months of the following year, from January through December, listed for each of the satellite plants supplied.

4. Consumption via direct lines connected to the regasification plant, identifying the line for which it is programmed.

5. LNG tank exchanges, indicating the quantity and counterparty (optional).

4.1.2 Calendars (deadlines):

1. Advance programming for year n+1.

  • Submission: until 31 May of year n.

2. Definitive programming for year n+1.

  • Direct market customer and shipper submission (user programming): until 15 September of year n.

  • Other operator submission (truck programming by operators of distribution networks): until 1 October of year n.

  • DSO truck loading appeals period: until 15 October of year n.

  • Notification and viability response about truck programming and assignment of tanker unloading dates from plant operator to users: until 8 October of year n.

  • GTS notice of definitive programming to plant operator and users: until 15 November of year n.

3. Review of the second semester of year n+1.

- Submission: until 1 May of year n+1.
- Viability (plant operator): until 31 May of year n+1.
- GTS viability: until 20 June of year n+1.

4.2 Yearly programming for underground storage facilities

4.2.1 Content of programming: Monthly detail for the 12 months of the coming calendar year, addressing the following topics:

- Injection/withdrawal details:
- Monthly quantity to be injected or extracted (GWh/month).
- Destination of the quantity to be injected or extracted. It shall be noted if the injection or withdrawal is for own use or to be sent to another user.

4.2.2 Calendars (deadlines):

1. Provisional preliminary programming for year n+1.

- Direct market customer and shipper submission to the SL-ATR: until 15 September of year n.

2. Definitive yearly programming for year n+1.

The initial yearly programming shall be provided by 15 November of year n, which is required to establish an initial yearly schedule for the system. However, definitive USF programming may not be available until the firm USF capacities assigned to each user are known. The implications these changes may have for the overall system must be assessed and communicated to the affected operators and users.

3. Review for the second semester of year n+1.

- Submission: until 1 May of year n+1. Once the USF yearly programming has been assessed, the GTS will inform the storage facility operators of the physical injection/withdrawal schedule for each storage facility, broken down by month.

4.3 Yearly programming for transmission networks

4.3.1 Content of programming for year n+1:

1. To be sent directly by users. Monthly detail, in GWh/month, for the 12 months of the coming calendar year, addressing the following topics:

- Demand for electricity generation. Identification of the combined cycle plant or power station for which it is programmed.
- Conventional demand.
- Programmed entries/exits through international connections (CI), regasification plants, underground storage facilities and gas fields, indicating the source/destination users.

4.3.2 Calendars (deadlines)

1. Advance programming for year n+1 (provisional).
   - Submission: until 31 May of year n.
2. Definitive yearly programming for year n+1.
   - User submission: until 15 September of year n.
   - GTS notice of definitive programming to transmission companies: until 15 November of year n.
3. Review of annual programming for the second semester of year n+1.
   - User submission: until 1 May of year n+1.
   - GTS notification of the definitive programming to transmission companies: until 20 June of year n+1.

5. Monthly programming

4.4 Monthly programming at regasification plants

5.1.1 Content of programming: Monthly detail for the following three months. For each of the three months, the following topics will be addressed:

1. Vessels: Binding for the first month and a half and informative for the second month and a half:
   - Date requested for the unloading or loading of each tanker, cooling, LNG transfer and bunkering of each tanker. Users

must respect the dates laid out in their yearly programming with the greatest care. This will provide information about the tanker and date programmed for the performance of the service in each of the programmed months.

• Name of the tanker and quantity to be unloaded (kWh and m3 LNG). See: BOE-A-2016-8928 Verifiable at http://www.boe.es OFFICIAL GAZETTE.

• For shared tankers, the users that share it will be listed, as will the total quantity aboard the tanker. In addition, the best estimation of the origin gas quality will be provided for each of the programmed unloadings.

2. Regasification:

• Daily quantity to be regasified (KWh/day).

• User for whom the regasified quantity is destined. It shall be noted if the regasification is for own use or to be sent to another user.

3. Truck loading

• Daily quantity of trucks to be loaded (kWh/day and number of trucks).

4. Direct line connected to the plant

• Daily details, in kWh/day, identifying the direct line for which it is programmed.

5. LNG tank exchange, indicating date, daily quantity to be exchanged (kWh/day) and counterparty

5.1.2 Calendars (deadlines)

• User submission and consolidation of programming as monthly programming: until the 20th of each month.

• Communication and viability response about trucks and assignment of tanker unloading or loading dates from plant operator to users: until the 25th of each month.

• Communication and confirmation of definitive programming and viability response about trucks and tanker unloading from the GTS to plant operators and users: until the 28th of each month.

5.2 Monthly programming for underground storage facilities:

5.2.1 Content of programming: Monthly detail for the three following months, addressing the following topics: Injection/withdrawal details:

- Daily quantity to be injected or extracted (kWh/day).
- Destination of the quantity to be injected or extracted. It shall be noted if the injection or withdrawal is for own use or to be sent to another user.

5.2.2 Calendars (deadlines):

- User submission and consolidation of programming as monthly programming: until the 20th of each month.
- Communication and confirmation of definitive programming from the GTS to underground storage facility operators and users: until the 28th of each month.

5.3 Monthly programming for transmission networks

5.3.1 Content of programming: Daily details, in kWh/day, for each of the three following months, addressing the following topics: To be sent directly by users

- Conventional consumption. This may be sent broken down by connection point (PCTD, PCLD) or as a daily user aggregate (a single sum per day and user).
- Consumption for electricity generation. Identifying the combined cycle plant or power station for which it is programmed.
- Programmed entries/exits through CI, regasification plants, underground storage facilities and gas fields, indicating the source/destination users.

5.3.2 Calendars (deadlines)

- User submission and consolidation of programming as monthly programming: until the 20th of each month.
- Communication and confirmation of definitive programming from the GTS to transmission operators and users: until the 28th of each month.

6. Weekly programming

6.1 Weekly programming at regasification plants

6.1.1 Content of programming: On a weekly basis, daily details in kWh/day will be sent for the following 7 days of the programmed week in question, from Saturday to Friday, with the same topics and broken down in the same way as the monthly programming. If truck loading is programmed, the provisions of PD-12 'LNG truck cistern logistics' will be applicable.

6.1.2 Calendars (deadlines):

- User submission and consolidation of programming as weekly programming: Thursday before 12:00 AM.
- Communication and response about viability of regasification plant services from plant operator to users: Friday before 10:00 AM.
- Communication and confirmation of definitive programming and viability response about trucks and tanker unloading from the GTS to plant operators and users: Friday before 12:00 AM.

6.2 Weekly programming for basic underground storage facilities:

6.2.1 Content of programming: On a weekly basis, daily details in kWh/day will be sent for the following 7 days of the programmed week in question, from Saturday to Friday, with the same topics and broken down in the same way as the monthly programming.

6.2.2 Calendars (deadlines):

- User submission to connection points between the single underground storage facility with the transmission network and consolidation of programming as weekly programming: Thursday before 12:00 AM.
- Notification and confirmation of definitive programming by the GTS: Friday before 12:00 AM.

6.3 Weekly programming for transmission networks

6.3.1 Content of programming: On a weekly basis, daily details in kWh/day will be sent for the following 7 days of the programmed week in question, from Saturday to Friday, with the same topics and broken down in the same way as the monthly programming. See: BOE-A-2016-8928 Verifiable at http://www.boe.es OFFICIAL GAZETTE

6.3.2 Calendars (deadlines):

- User submission and consolidation of programming as weekly programming: Thursday before 12:00 AM.
- Notification and confirmation of definitive programming from the GTS to transmission companies and users: Friday before 12:00 AM.

7. Nominations and re-nominations

7.1 Content of the nominations and re-nominations:

For all system infrastructure, the content and details required for the nominations/re-nominations is the same as that set out in the weekly programming, except for demand for electricity generation, which will be sent broken down by combined cycle plants and conventional power stations. Re-nominations for the gas day made on the same gas day will be expressed in kWh and indicate the quantity of gas to move for each hour of what remains of the gas day.

If information is not sent about electricity demand on an hourly basis, the nomination or re-nomination will be consolidated as though it were, dividing the daily programming by 24 to transfer it to a per-hour basis

Users shall send the transmission network operator any information they have about relevant stoppages or changes in consumption on direct lines.

The following division criteria will be used to allocate the confirmed nominated or re-nominated quantities for day d by contract:

1. Default:

a. When a single quantity is listed for the sum of all user contracts at the point/service, the confirmed quantity will be divided proportionally among the contracts according to the capacity contracted in each of the contracts, with firm-capacity contracts first.

b. When the user indicates a nomination or re-nomination by contract for day d at the point/service and the confirmed quantity is equal to the sum of the quantities sent by the user, the division indicated by the user in the submission will be kept. If the confirmed quantity is not equal to the sum of the entry quantities, with all specified contracts present and valid for that particular day, infrastructure facility and point/service, the confirmed quantity will be distributed proportionally according to the contract quantities indicated in the submission.

2. Afterwards, the user may use the SL-ATR to distribute, digitally or on paper, the confirmed quantities by contract; they must list these either as a percentage on the contracts, or as the quantity that they wish to allocate to each one if the confirmed quantity and the sum of the quantities assigned to the user by contract do not match, the allocated quantity will prevail by default. This assignment must be made within 4 gas days of the last day of the month.

7.2 Calendars (deadlines):

The nomination and re-nomination periods for transmission network entry infrastructure (plants, underground storage facilities, gas fields and international connections) are as follows:

7.2.1 For all transmission network entry and exit points (except PCTD and PCLD points) from both sides of the point

1. Nominations for day d:

- Reception period for nominations and consolidation of the same: up to 16 hours before the beginning of gas day d.

Processing period: up to 14 hours before the beginning of gas day d. • Deadline for the confirmation of nominations: 14 hours before the beginning of gas day d.

2. Re-nominations for day d:

- Reception period for re-nominations: up to 14 hours before the beginning of gas day d.
- Frequency: cycles of re-nomination at the beginning of each hour from the beginning of the re-nomination period to up to 5 hours before the end of gas day d.
- Cycle length: 2 hours, with the option to re-nominate the first hour and a half of the said cycle. This will be consolidated as re-nomination an hour and a half into the cycle.

- Re-nomination processing: within the first 2 hours of the re-nomination cycle.
- Re-nomination confirmation: carried out by the GTS 2 hours after the beginning of the said re-nomination cycle.
- Start time for effective change: 2 hours after the beginning of the re-nomination cycle, unless change at a later time has previously been requested. The last re-nomination cycle will end 3 hours before the end of the gas day.

7.2.2 For LNG tankers:

1. Nominations for day d:

- Nomination reception period: up to 16 hours before the beginning of gas day d.
- Period for transmission company and GTS viability response (only applicable to tankers): up to 13 hours before the beginning of gas day d. 2. Re-nominations for day d:

a) The day before the gas day:

- Re-nomination reception period: up to 11.5 hours before the beginning of gas day d.
- Period for transmission company and GTS viability response (only applicable to tanker unloadings): up to 11 hours before the beginning of gas day d.

b) On the gas day:

- Re-nomination reception period: up to 3 hours before the end of gas day d.
- Period for transmission company and GTS viability response: up to 1 hour before the end of gas day d.

7.2.3 For Trucks: Nominations and re-nominations shall be made in accordance with the periods established in PD-12 ‘LNG Truck cistern Logistics’.

8. Confirmation criteria for programming/nomination/re-nomination of services at regasification plants

As a general rule, the programming/nomination/re-nomination of a methane tanker or truck loading operation sent by users to a regasification plant will be confirmed if:

- It respects the contracts established for each user.
- It complies at all times with the operational rules for special periods of high demand and minimum stock cover valid at the time when the programming/nomination/re-nomination is sent. See: BOE-A-2016-8928 Verifiable at http://www.boe.es OFFICIAL GAZETTE.
    - The user's individual balance at the plant is within the parameters set out in the System Technical Management Rules.
    - The proposed regasification has been confirmed by the GTS and taken into account by the operator for the overall viability of the infrastructure.
    - The programmed unloadings for each month can be processed without exceeding the maximum physical storage capacity of the plant at any time, in accordance with the provisions laid out in the System Technical Management Rules.
    - The programmed/nominated/re-nominated unloadings comply with the requirements established for the assignment and re-assignment of unloading windows to vessels.

Besides the above criteria, each plant may establish additional criteria based on its technical specifications. If this is the case, the operator of the said plant must have transparent, objective and non-discriminatory procedures that list the specific criteria to be applied at the plant to give viability responses to the proposed schedules. The said procedures shall be published on the websites of the plant operator and GTS.

If any of the above conditions is not met, the programming/nomination/re-nomination will be declared 'unconfirmed', noting the reason for the same, so that the user can modify the proposal.

To resolve cases in which the proposed schedule for a methane tanker is not confirmed because the dates requested by the user cannot be accepted, the regasification plant operator may offer alternative dates.

If no agreement is reached, the affected plant operators and users will send their comments and schedules to the GTS, who will propose a definitive schedule based on the criteria of maximum effectiveness and supply security.

The GTS may resolve possible cases of non-viable user programming by eliminating operations from the schedule or moving programmed operations from one plant to another at which the user has booked capacity.

The regasification associated with the redirected operation may be taken on by the plant that receives it if necessary to prevent affecting the existing viable schedule at the said plant.

To resolve unconfirmed schedules that appear in the yearly programming, the following steps shall be taken:

- Between 1 and 8 November, the plant operators will meet with users to resolve cases of unconfirmed annual programming pertaining to their tanker operations and submitted for the definitive annual programming.
- Between 1 and 15 November, the GTS will hold a meeting of any plant users and operators they deem appropriate to be able to establish a viable annual schedule for the System.

To assess unconfirmed schedules that appear in monthly programming, the user's viable annual programming and variations received in monthly programming must be taken into account as a starting point.

The unloading windows previously assigned in the confirmed yearly programming, especially where they refer to dedicated tankers, will have priority over requests for new unloading dates.

Unconfirmed programming due to changes in tanker operation dates may be resolved by the plant operator through the user's proposal of alternative dates. If no agreement is reached, the plant operator shall request assistance from the GTS, who will propose a definitive schedule before the 28th of each month, taking into account criteria of maximum effectiveness and security of supply and considering the balance condition of each user within the System as a whole.

The GTS must justify its decision using known, objective, transparent and non-discriminatory criteria, which shall appear in its confirmation response; this shall be made available to the parties involved and the National Markets and Competition Commission through the SL-ATR.

Once the monthly programming has been declared confirmed, the GTS must publish the following information through the SL-ATR:

a) Number of vessels (including size) planned at each regasification plant.

b) Quantity of unloading planned, per vessel and plant (GWh/month)

c) Unloading windows available at each plant, listing specific days and maximum allowable sizes. This information will also be made public on the GTS' website.

Unconfirmed programming that may arise in weekly programming, nominations or re-nominations must be resolved before the deadline established in the calendar.

Plant users and operators must do their best to solve any possible non-conformities that may appear at any time, including both those related to the individual balance of each user as well as other situations - such as temporary restrictions, cases of force majeure, etc. - that may arise at the plant.

Plant users and operators shall inform the GTS of any incident that could distort the binding monthly planning as soon as they become aware of it so that the GTS can assess its effect on the System and propose alternatives.

Conformity with the preceding paragraphs is not applicable to regasification, but may be taken into account for the plant's conformity as a whole, and may affect the conformity of vessel operations.

9. Processing of programming, nominations and re-nominations for the transmission network:

The processing of programming, nominations and re-nominations of transmission network entry or exit points (except PCTD and PCLD) from both sides of the point shall take the following variables into account:

- The user's booked capacity and contract type.
- The number of hours in each gas day until the end of the re-nomination cycle.
- The nominal capacity of the facility/point at the moment of processing (hereinafter 'nominal available capacity') and for the remaining hours of the gas day.
- If between hours h and h+1 of gas day d, a user's rights to nomination or re-nomination at a particular point have been suspended through the application of current regulations. In such a case, the quantities on both sides of the point will be processed together, except at international connections, where this will be done in accordance with the current international agreements between the operators.

The following considerations will also be taken into account:

1. The net value of the confirmed programming, nominations or re-nominations of all users at a particular facility/point cannot exceed the nominal available capacity of the facility/point.
2. The gas provisionally moved by a user shall be the sum of the confirmed quantities, pro-rated by the number of hours for which they have been in effect when they impact the entire gas day.
3. If the sum of programming, nominations and re-nominations made by users exceeds the nominal capacity available at the facility/point, the following will be taken into account:
    - In no case may this process reduce user re-nominations to a level below the gas that has already been moved.
    - When access capacity above the nominal available capacity for an international pipeline connection point with Europe has been offered, in accordance with the provisions laid out in National Markets and Competition Commission Circular 1/2013 of 18 December, which establishes the congestion management mechanisms to be applied,

the capacity buy-back mechanisms established in the said Circular will be performed by the GTS together with the connected transmission network operators with the approval of the National Markets and Competition Commission. At all other points, current regulations will be applied.

- As long as there is availability, user nominations cannot be reduced to a level below the sum of the transported gas and their allocated capacity for the rest of the day (firm booked capacity divided by the remaining hours of the day).

In accordance with the above considerations, programming, nominations, and re-nominations shall be reduced in accordance with the following criteria:

1. Those that are above booked capacity will be reduced. They will be reduced proportionally according to the quantity in excess. In the case of a re-nomination, the excess re-nominated capacity will be reduced according to the booked capacity allocated to the user for the remaining hours of the gas day, also accounting for the gas moved by the user up to that point.

2. If the above procedure is insufficient, those re-nominations for interruptible contracts that contribute to resolving the excess programming/nomination/re-nomination will be reduced. For European connections, quantities will be reduced beginning with the newest contracts and ending with the oldest ones. In all other cases, they will be reduced proportionally according to booked capacity.

3. If the above procedures are insufficient, the following process will be performed:

a. The nominal available capacity will be pro-rated among all users with firm booked capacity in proportion with the same. For re-nominations within the gas day, the nominal available capacity will be pro-rated for the rest of the day relative to the capacity contracted for the rest of the day, as follows:

$$Cau = Nominal\ available\ capacity\ x \frac{Booked\ capacity\ per\ user\ bearing\ in\ mid\ the\ moved\ gas\ at\ the\ moment}{Total\ booked\ capacity}$$

b. For each user 'u' that has a programmed, nominated or re-nominated quantity greater than 0, let

Cpu = Programmed, nominated or re-nominated quantity.

c. If Cpu ≤ Cau , the programming, nominations or re-nominations will be accepted.

d. If Cpu > Cau, programming, nomination or re-nomination will be taken to be the maximum value between:

- Moved gas.
- Cau .
- Proportional quantity of the capacity margin from underutilisation by other users (those that meet c). This quota shall be calculated in proportion to the parameter Cau for those users that do not meet section c.

If the connection point is with an underground storage facility (PCAS), user validations in excess of booked capacity established in this section will be performed on the user's injection or withdrawal rights.

If there is notification of unavailability, the validations against the nominal daily and multi-day capacity established in this section will be performed on the facility capacity at that point, taking into account unavailability and the agreements that can be made under current regulations. If additional capacity has been sold at the point using the capacity over-sale mechanism established in current regulations, and there is no notification of unavailability, the validations for the nominal daily and multi-day capacity established in this section will be performed on the nominal capacity raised by the same amount as the additional capacity sold.

10. Appeals procedure at connection points between two different infrastructure facilities.

To avoid any discrepancies in programming, nomination or re-nomination at connection points that connect two separate infrastructure facilities, a procedure must be established that can be followed to resolve any likely discrepancies between the submitted programming, nominations and re-nominations processed by users on both sides of the point. These procedures shall be established in the valid interconnection agreements.

The appeals process may begin once all programming, nominations and re-nominations have been processed, but before they are confirmed. As a general rule, the procedure to appeal the processed user programming is as follows:

- Pairs of programmed, nominated or re-nominated operations that have been processed are appealed when they have to do with the following topics: gas day, connection/facility/service point, flow direction (where applicable), user on one side of the point and user on the other in such a way that, if the amount reported by each is not the same, the smaller quantity of the two will be assigned.

PD- 09

'Calculation of admissible limits for basic control variables within normal system operating values'

Approved by Resolution of the Directorate General of Energy Policy and Mines on 20 April 2007

1. Gas demand classification

1.1 Demand classification by type of consumer

Demand in the gas system, from a consumer point of view, can be classified into:

- Conventional demand Includes industrial and domestic-commercial demand supplied via gas pipelines and truck cisterns. It also includes natural gas demand for co-generation.
- Electricity sector demand Includes demand for supplying conventional power plants (usually fuel-gas) and combined cycle power plants.
- Total National System Demand Includes demand from the conventional and electricity sectors, but does not include the transmission of natural gas being transported to Portugal and France.
- International transit demand Includes transmission from international connections and from LNG plants to international connections.
- Total system demand Includes all National System demand and demand from international transit.
- Transmission branch demand Includes the total demand from all transmission network exits from a branch without multiple network connections
- Secondary transmission network demand Includes total demand from the exits of a secondary transmission network that is fed from the entry points of the basic pipeline network.

- Distribution network demand Includes total system demand from the exits of a distribution network that is fed from the transmission entry points.
- LNG truck demand Includes demand supplied from LNG truck cisterns that load at LNG plants.

There are also other exits from the system, such as the connections with underground storage facilities and gas fields.

1.2 Demand classification by type of market

Demand in the gas system, from a market typology point of view, can be classified into:

- Regulated market
- Liberalised market (ATR)

The regulated market is the sum of all demand from consumers who get their supply under the regulated price scheme.

The ATR (Third Party Access) market is the sum of all demand from consumers who get their supply from the liberalised market.

The interruptible market is the sum of all demand from consumers whose supply may be interrupted under certain conditions.

The system's interruptible market may, in accordance with regulation, be subdivided in the following manner:

- ATR market with A and B interruptible transmission tolls
- ATR market with interruptibility clauses in accordance with RD-1716/2004
- ATR market with interruptibility clauses in accordance with contractual conditions between users and transmission companies.

1.3 Demand behaviour

Demand predictions are made following the Detail Protocol for demand prediction (PD-03).

1.4 Classification of demand during the winter period

During the winter period, the demand classification applicable to working days that allows the identification of the average level of total daily system demand to be identified (conventional + electricity sector) will be used across the various winter periods.

When winter demand is predicted, the various winter levels of daily demand for working days must be identified, as well as the usage factor criterion for combined cycle power plants (CCPP) and the predicted maximum level of for the total daily demand on the conventional market given an extreme cold snap, allowing peak winter demand to be established once electricity sector consumption is added.

2. Identification of control variables related to available capacity in terms of natural gas flowing into the system, including both natural gas and liquefied natural gas

Available capacity for natural gas flowing into the system from LNG plants can be summarised in the following points:

- The units to be used for LNG plant processes are as follows:
  - LNG unloading capacity m^3 LNG/hour
  - Capacity of primary and secondary pumps m^3 LNG/hour
  - Production capacity of flow into transmission network GWh/day
  - Truck cistern capacity Number of trucks and GWh/day
- The unit to be used for transmission processes from regasification plants, international connections, domestic connections and gas fields shall be kWh/day and its multiples MWh/day and GWh/day
- The production capacity of LNG plants corresponds to the Detail Protocol given in the System Technical Management Rules for system capacities and with the Detail Protocols for each regasification plant.
- The entry capacity of the transmission network corresponds to the Detail Protocol given in the System Technical Management Rules for system capacities and with the Detail Protocols for each transmission company and the capacity integration by the Technical Manager of the System.
- For each system input, the basic control variables are as follows:
  - Gas flowing into LNG plants from LNG unloading and the minimum unloading speeds for normal operations

- Minimum flow into the transmission system from the point of view of the upstream facility for its normal operation
- Minimum flow into the transmission system from the point of view of transmission facilities, including gas pipelines, compressor stations and connections.
- System entries with recommendable operating points, taking into account:
  - ✓ LNG plant operating points
  - ✓ Operating points of compressor stations
  - ✓ Entry pressures in the transmission network at its exit points
- Maximum flow into the system possible without creating excessive pressure in the transmission network and creating problems for LNG at plants.

3. Identification of control variables related to the operational ability of gas system LNG reception, storage and regasification plants, compressor stations and flow through gas system hubs

The ability of regasification plants to operate can be subdivided into the following areas:

- LNG reception: Unloading of methane tankers
- LNG storage
- LNG regasification
- LNG truck loading
- Loading of methane tankers

3.1 LNG reception. Unloading of methane tankers

To unload methane tankers, the following variables are used:

- Unloading window: period available for the tanker to enter the plant and begin unloading
- Unloading laytime: time available to complete the LNG unloading after the beginning of the unloading window. Depends on the size of the methane tanker and the plant facilities

- Unloading speed: determines the volume of LNG unloaded (m^3 LNG) per unit time (hour)
- LNG quality: Composition and GCV of the unloaded gas
- LNG quantity: Volume unloaded in m^3 LNG and energy in GWh

In addition, one must account for changes in the unloading date relative to the programmed date found in the monthly programming in accordance with section 3.6.2.2 of the System Technical Management Rules (Monthly programming)

3.2 LNG storage

The following variables are considered for the storage of LNG:

- Minimum storable volume: Heel gas of immobilised LNG in each tank. Units: m^3 LNG and GWh for a given GCV
- Commercial volume included in the regasification toll: Each user has a volume to use as LNG storage as a result of the contracted regasification capacity, complying at all times with section 3.6.3 of the System Technical Management Rules
- Contracted LNG capacity: the storage capacity contracted in tanks at an LNG regasification plant on top of the storage included in the regasification toll, complying at all times with the provisions laid out in section 2.6.3 of the System Technical Management Rules

3.3 LNG regasification

The following variables are taken into account in the regasification of LNG:

- Regasification to pipelines: NG volume (m^3(n)/h).
- It can also be subdivided by seawater vaporisers and submerged combustion vaporisers, taking into account the measurement and odorisation capacity of the transmission network.
- NG/LNG conversion factor: indicates the relationship between 1 m^3 LNG and the equivalent quantity of natural gas in m^3 (n).

3.4 LNG truck loading

The variables considered are as follows:

- Truck loading capacity: indicates the number of trucks that the truck loading bay can load in 1 day
    - nominal capacity
    - demonstrated capacity

- Time on site: Time required for a truck cistern to enter the plant and leave with a load of LNG.
- LNG truck volume: Depends on the size of the trunk reservoir.

3.5 LNG tanker loading

In addition to the unloading window, unloading laytime, LNG quality and quantity described in section a) of the LNG reception section, we also consider the following variables:

- LNG loading speed: Depends on the primary pumps available for the loading operation.
- Cooling down: Use of plant LNG to cool down the methane tanker in order to allow subsequent LNG loading

3.6 The following variables are taken into account in the operation of Compressor Stations:

- Inlet gas pressure
- Output gas pressure
- Combustion chamber temperature
- Temperature of output gas
- Flow of compressed gas
- Compressor speed
- Turbine speed

The said variables may place limits on the gas compression.

3.7 The variables considered in the operation of system hubs are as follows:

- Pressure
- Flow

To deliver gas to the exit points of the quality and quantities specified in the System Technical Management Rules

4. Identification of control variables for excessive pressure or loss of pressure in gas pipelines

It is understood that ‘excessive pressure’ never refers to the operation of gas pipelines at pressures above the acceptable maximum pressures and that ‘loss of pressure’ never refers to pressures below the acceptable minimum pressures.

The supply-demand balance in pipelines may generate two types of situations:

a) More supply than demand:

Cases in which the supply of gas flowing into a pipeline, as a consequence of programming or nomination, falls within the limits of stock management and, later in the gas day, there is a drop in demand that creates excessive pressure in the gas pipeline.

Users can resolve the increase in pressure by reducing the amount of gas flowing into the pipeline, or by reducing the flow of gas elsewhere into the system, or by increasing the offtake of gas to meet other demand, or by increasing injection into underground storage facilities; this is to keep the pressure values within the normal operating range.

When more gas is flowing into a pipeline than flowing out of it, congestion occurs in the pipeline. Congestion can be resolved in different ways given by the congestion solution procedures. Criteria such as ‘First come first served’, 'pro-rata’, ‘auction’, and ‘open season’, among others, have been used by different gas systems

b) More demand than supply

Cases in which the supply of gas being introduced into a pipeline, as a consequence of programming or nomination, falls within the limits of stock management and, later in the gas day, there is a jump in demand or reduction in supply that creates a loss of pressure in the gas pipeline.

The loss of pressure can be resolved by the users by increasing the gas flowing into the pipeline or reducing offtake from the same. Gas flowing into the system from another entry point can also be increased, or pressure can be regulated by increasing withdrawal or reducing injection into underground storage facilities.

The variables to be used by the users in each case are:

- The pipeline input capacity

- The input capacity usage
- The pipeline offtake capacity
- The offtake capacity usage
- Management of pipeline stock
- Management of USF withdrawal/injection
- Management of the pipeline with the gas system
- Regulation of the interruptible market

5. Overall analysis of the basic control variables within the normal system operating ranges

The gas system is understood to be in Normal Operation when the basic variables are within the normal operating ranges of the system.

The system is considered to be in normal operation when it has sufficient operating stock as well as the necessary means of production, transmission and distribution to meet the transmission services and supply needs of the system.

To elaborate on the normal ranges of the basic variables of the gas system, we take the following as reference points for the gas stock:

- Stock in LNG tanks at regasification plants
- Stock in pipelines
- Stock in underground storage facilities
- Stock in distribution networks

To secure sufficient stock in tanks at LNG plants, methane tanker unloadings must be programmed in accordance with the provisions laid out in the System Technical Management Rules regarding yearly and monthly programming, ensuring the viability of the programmed tanker unloadings that will allow the schedules to be followed.

Methane tankers and LNG plants should comply with the information required for the contracting of supply via tankers and the unloading/loading requirements of the methane tankers.

To comply with the programmed unloadings, each methane tanker should begin unloading during the allotted window and complete the unloading during the laytime according to the unloading speed.

Each user can unload a methane tanker if, when unloading begins, the stored stock is equal to or less than the stock specified in the corresponding section in the Technical Management System Standard NGTS-03.

The unloaded LNG stock have a range of admissible stock levels between the minimum (cushion) and maximum volume of each tank. In addition, each user must meet the minimum stock requirements for the current winter action plan.

Supply loss during the processes of tanker loading/unloading, storage and regasification cause reductions in LNG stock.

Exits from regasification plants can be subdivided into the following classes:

- Regasification to the transmission network
- Truck loading
- Loading of methane tankers.

The minimum regasification required to flow gas into the transmission network that allows the regasification plant to remain cold should also be taken into account.

Likewise, in relation to the stock in LNG tanks, a system is understood to be within normal operating values when the stock in each LNG tank are at a level that would allow tankers to unload in accordance with the monthly programming, complying at all times with section 3.6.2.2 of the System Technical Management Rules (Monthly Programming), and provided that the stock in the tanks are predicted to remain above the minimum heel gas level.

To ensure stock in the transmission network, the following must be secured: gas flowing into the system from production at LNG plants, international connections, and connections with gas fields; gas flowing into the system from the withdrawal of underground storage facilities to supply offtake from the transmission network to meet demand; offtake for injection into underground storage facilities and international connections; and the relevant supply loss and self-consumption.

Gas flowing into the system from LNG plants increases stock in the transmission network and reduces stock at the LNG plants.

International connections may increase or reduce stock depending on the way in which they are used: to flow gas into or offtake gas from the system.

Connections with underground storage facilities may increase or decrease stock depending on how they are extracted or injected.

Supply loss in the transmission process leads to a reduction of stock in the transmission network.

Transmission network exits destined to meet demand move within limits determined every year depending on the domestic-commercial market, industrial use, electricity generation and satellite plants fed by truck cisterns.

To move gas from entry points to exit points, transmission capacity and system restrictions must be taken into account.

Likewise, in relation to the stock in the transmission network, the system is understood to be within normal operating values when the stock in the pipelines are between the minimum fill value and the maximum one (which will be determined by the minimum and maximum pressures in the pipelines, taking the loss of load in the same into account) in accordance with the provisions established in the System Technical Management Rules and the agreements between transmission companies and users.

To secure stock levels in underground storage facilities, besides complying with the technical requirements of the facility operators for injection and withdrawal cycles, users may manage their contracted volume taking into account their need for security and modulation stock to meet demand, tailoring the options they offer as much as possible.

Supply loss in the underground storage injection leads to a reduction of stock in the transmission network.

To secure stock levels in distribution networks, the DSO's and supplying transmission companies should analyse the entry points (RMS and MS) needed for each distribution network, taking into account both current and forecast demand.

6. Control variable analysis details

Facility holders must send the Technical Manager of the System the information to be published so that all information from all facility holders can be integrated on the website of the Technical Manager of the System.

The publication of the control variable values must be updated to reflect current data at least once per month.

Updates to the control variables and system analysis should be performed according the periods and scopes outlined in the operational documents prepared by the Technical Manager of the System in accordance with Technical Management System Standard '9.1'.

The permissible ranges should comply with the provisions laid out in the capacity calculation protocol at all times.

In their normal operating ranges, the basic system variables are as follows:

- Unloading window. For each plant, this shall be as specified in Detail Protocol PD-06 (Operational regulations for methane tanker unloading activities)
- Unloading laytime. For each plant, this shall be as specified in Detail Protocol PD-06 (Operational regulations for methane tanker unloading activities)
- Unloading speed. This should be specified for each regasification plant and, within each plant, by LNG tank if necessary
- Regasification plant stock. At each plant, the minimum and maximum volumes for each LNG tank should be listed. The Technical Manager of the System should integrate the information for all the plants, specifying the minimum and maximum volume.
- Regasification plants production. For each plant, the following information should be provided:
  - Minimum production for transmission network
  - Maximum production for transmission network
  - Maximum truck loading
  - Methane tanker loading

  The Technical Manager of the System should integrate the information for all the plants.
- Underground storage facilities. For each underground storage facility, the following information should be provided:
  - Minimum injection into underground storage facility
  - Maximum injection into underground storage facility
  - Minimum withdrawal from underground storage facility
  - Maximum withdrawal from underground storage facility
  - Minimum and maximum storable volume

  The Technical Manager of the System should integrate the information for all underground storage facilities.
- Gas fields. For each gas field, the following information should be provided:
  - Minimum flow into transmission network
  - Maximum flow into transmission network
  - Minimum offtake from transmission network to gas field

- Maximum offtake from transmission network to gas field

  The Technical Manager of the System should integrate the information for all gas fields.

- International Connections. For each international connection, the following information should be provided:
  - Minimum connection inflow.
  - Maximum transmission connection inflow.
  - Minimum connection offtake.
  - Maximum transmission connection offtake.

  The Technical Manager of the System should integrate the information for all connections.

- Transmission Network stock. Each transmission company should publish the minimum and maximum stock for its pipelines. The Technical Manager of the System should integrate the information for all pipelines.
- Pressures. Each transmission company should publish the minimum and maximum pressures for the following connection points:
  - Regasification and transmission plant.
  - Gas field and Transmission
  - Underground Storage Facility and Transmission
  - International connection and Transmission
  - Compressor station inlet side
  - Compressor station discharge side
  - Transmission and Transmission
  - Transmission and Distribution

The agreements signed between operators that modify the delivery pressures specified in the System Technical Management Rules should be listed for the minimum pressures at transmission-transmission and transmission-distribution connections.

The Technical Manager of the System should integrate the information for all connection points.

6.1 System Restrictions

Each transmission company should publish the restrictions that exist for their network as well as a list of saturated branches.

The Technical Manager of the System should integrate the information for all facilities.

All information on system restrictions should take the maintenance plan into account (Technical Management System Standard NGTS-8).

PD-10

'Calculation of facility capacity'

Approved by Resolution of the Directorate General of Energy Policy and Mines on 20 April 2007

Modified by Resolution of the Directorate General of Energy Policy and Mines on 30 April 2012, which published Detail Protocol PD-14
'Criteria for establishing the degree of saturation of regulation and metering stations and metering stations and procedure for carrying out proposed actions' and amended Detail Protocol PD-10 'Calculation of facility capacity' (amendment of section 6.3.4). Published in the BOE on 28 May 2012

1. Purpose

Order ITC/3126/2005 of 5 October, which approved the System Technical Management Rules, in chapter NGTS-02, section 2.8, which discusses the principles used to calculate facility capacity, states that a Detail Protocol shall be used to determine the capacity of the facilities that make up the gas system.

To do so, it states that not only must capacities calculated from the design parameters of the facilities be considered, but also those that must be calculated from certain operating and safety parameters that reduce or limit the design capacity.

The purpose of this Detail Protocol is to outline the main design parameters that have a direct impact on the formulas used to obtain the capacity of gas system facilities, as well as the operating and safety margins that determine the most significant restrictions that reduce the maximum capacity.

This protocol will apply to operators to determine the capacity of each facility and the publication of the same to inform system users.

2. Publication and updating of transmission capacities

The publication of facility capacities is essential to guaranteeing that all users entitled to access gas facilities have the same uniform and sufficient information, allowing for effective decision-making in the exercise of third-party access rights.

Facility holders will publish the maximum, nominal and useful capacity or capacities for each of their facilities, as well as contracting details: capacity contracted for the liberalised market, any capacity booked for the regulated market, capacity contracted for international transfers and capacity available to be contracted.

If useful capacity is reduced by the limitations placed on it by its integration with the system as a whole, the facility holder should indicate the size of this effect and its causes.

To facilitate general access to this information, it must - at the very least - be available for free online.

Facility capacities shall be updated every month. Each update will be published before the fifth working day of the following month.

These capacities shall be published within the time period established by current regulations.

When discussing the capacity of new facilities or expansions of existing facilities pending authorisation or the beginning of operations, the planned nominal capacities with categories A and B in the Planning prepared by the Government or its updated forms shall be provided; if dealing with an expansion, this information shall be presented separately. Contracting details beginning on the planned launch date of the facility shall also be provided if available.

3. Considerations for the calculation of facility capacity

Not only is knowledge of facility capacity within a gas transmission system a basic part of the system’s correct functioning, so too is knowledge of how this capacity is calculated for each system facility using its basic design parameters.

The capacity that a facility can offer users varies within a given range over time, influenced by the technical characteristics of the facility and the fluid mechanics of the gas/liquid (static elements); the way in which it is used by users and operated by transmission companies (dynamic elements); and the limits placed upon it to meet a particular quality of service (operational requirements).

For this reason, when calculating a facility’s capacity, one should consider not only its design parameters, but also any operational parameters that could reduce or limit it, including, for example: service factors, simultaneity, the time of year to which the capacity applies, the guaranteed pressure and the operating margins.

Operating margins are the operational limits needed to guarantee the reliability and operational safety of the equipment and the facility itself. In particular, these include: the tolerances in the calculation models, the storage margins, the minimum operating pressures of the infrastructure, the backup equipment, variable conditions (fluctuations in flow conditions, pressure, etc. over time) and environmental factors.

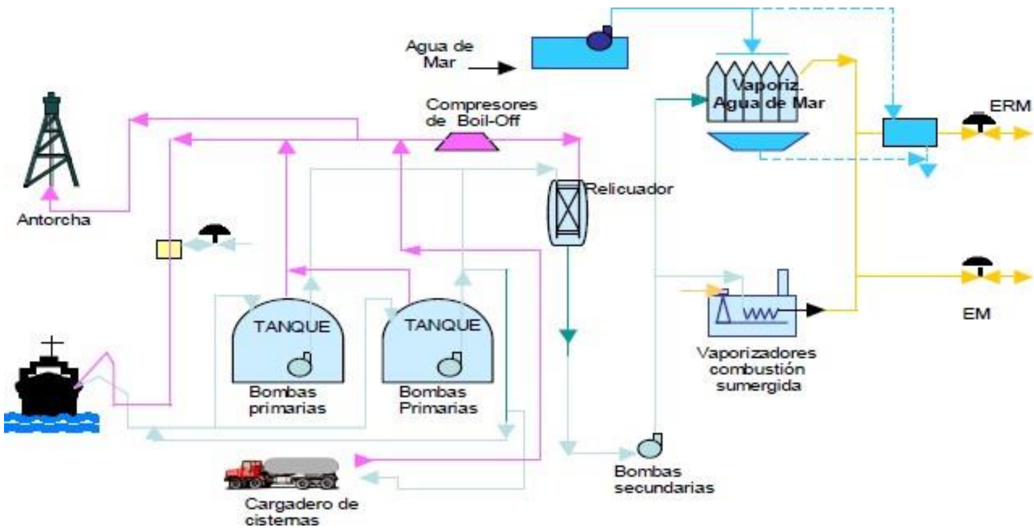
Capacity is specific to each facility and should be calculated by each operator for their infrastructure facility, taking into account the various operating scenarios due to the differences between each operator’s systems and facilities.

For the sole purpose of standardising unit conversions for capacity calculations, we will use a reference PCS of 11.63 kWh/m^3 (n), assume that 1 m^3 of LNG is equivalent to 585 m^3(n) of NG, and use a 24-hour day.

4. Calculation of regasification plant capacity

Capacity is calculated on the basis of the equipment installed at the regasification plant, taking its operational and safety limits into account as well as any limiting effects that pieces of equipment may have on one another.

A general diagram of regasification plant facilities is given below.



In particular, to determine the capacity of the regasification plant, the capacities of its different parts will be considered:

1. Tanker mooring capacity at the plant
2. Tanker unloading capacity.
3. Tank storage capacity.
4. Primary and secondary pumping capacity.
5. Internal liquid connection line capacity.
6. Seawater vaporiser capacity.
7. Submerged combustion vaporiser capacity.
8. Truck loading capacity.
9. Tanker loading and cooling down capacity.

4.1 Tanker mooring capacity

The tanker mooring capacity is determined through the tanker compatibility study described in Detail Protocol PD-06, point 2; at minimum, this study must take the following into account:

- Unloading arms
- Contact points with the seawall
- Number of mooring points
- Manifold position
- Gangplank, etc.

The tanker mooring capacity shall also be calculated taking into account the port's physical and operational conditions, such as:

- Turning and manoeuvrability capacity (if necessary)
- Draft along entire route
- Draft at mooring jetty
- Minimum number of tugs for manoeuvres
- Restrictions due to current, wind and tides, etc.

4.2 Tanker unloading capacity

Unloading capacity shall be calculated taking the following aspects into account:

- Partial or total boil-off recovery
- Plant boil-off production for return to the tanker
- Manifold pressure increase due to tanker or plant restrictions
- Maximum unloading flow rate per arm
- Maximum unloading capacity of the vessel (no. of pumps, etc.).

4.3 Tank storage capacity

Capacity shall be calculated taking the following aspects into account:

- Minimum operating levels of the primary pumps
- Maximum in-tank operating levels

Useful capacity shall be taken to mean the range between the minimum operating levels of the primary pumps and the maximum in-tank operating levels.

The minimum capacity will be determined on the basis of the minimum volume of LNG necessary to start-up the primary pumps.

4.4 Primary and secondary pumping capacity

Primary and secondary pumping capacity shall be calculated based on the flow produced by the pumps.

In addition, when calculating pumping capacity, the following are taken into account:

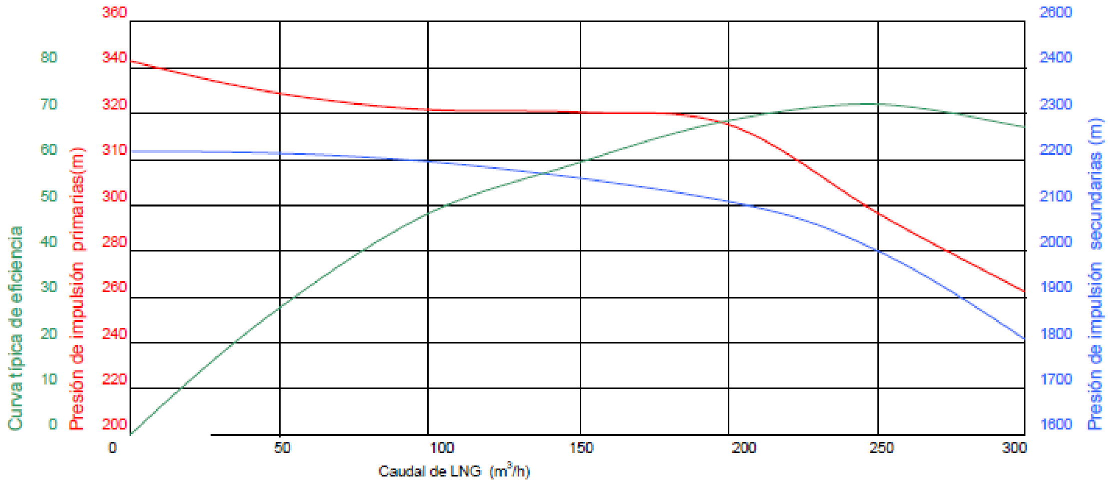
- The arrangement of the pumps.
- The pump curves provided by the manufacturer for each pump, which represent isovelocity and isoefficiency lines by flow, particularly the operating margins that determine the pump curve, maximum speed, minimum speed, maximum flow (‘choking line’) and maximum power curves.
- Cavitation limits
- The discharge pressure must not be above the design pressure of the pipes into which the pump feeds.

For illustrative purposes, typical example curves for primary and secondary pumps are provided below.

Units:

- Primary (mcl)
- Secondary (mcl)
- Flow rate (m^3LNG/h)
- Efficiency (%)

Typical primary and secondary pump curves



4.5 Liquid-gas connection lines capacity

Line capacity - in volume per unit of transmission time - is calculated using the following maximum values along all points of the line:

- Liquid lines: 8 m/s
- Gas lines: 20 m/s

The lines' diameter, length, and friction factor will also be taken into account when calculating these capacities, as will the physicochemical characteristics of the fluids.

4.6 Seawater vaporisers capacity

The vaporisation capacity - in volume of gas regasified per unit time - is calculated taking the following into account:

- Vaporiser design
- Seawater temperature
- Plant pressure
- Environmental conditions.

4.7 Submerged combustion vaporiser capacity

This corresponds to the nominal regasification volume certified by the equipment supplier. The minimum capacity will depend on compliance with environmental regulations.

4.8 Truck loading capacity

Truck loading capacity essentially depends on:

- The capacity of the liquid line from the primary pumps to the loading dock
- The capacity of the return line from the trucks to the plant
- Operating hours of the loading dock

Normally, these capacities are not restrictive and are already adapted to the specific needs of the loading dock when they are designed.

The most relevant aspect that can limit the loading capacity of a truck cistern is its temperature: whether the truck is 'hot' or 'cold'.

4.9 Tanker loading and cooling down capacity

To determine tanker loading capacity, the facilities of both plant and tanker should be considered, as well as if the operation to be performed is loading or cooling.

This capacity will depend on at least the following:

- Number of primary pumps not being used to address regasification needs
- Liquid line capacity
- Unloading capacity (unloading speed) with a liquid line connection arm
- Pressure and temperature shifts in the tanker's tanks
- Total plant boil-off recovery capacity (without flaring)
- If the tanker has a compressor
- Capacity of the plant boil-off return line
- Gas temperature in the tanker's tanks before loading (cold or hot tanker).

If the tanker is 'hot' and is being cooled, the unloading capacity will be reduced, and its loading will require more time.

4.10 Capacities to be published

At regasification plants, the facility holder shall indicate, applying to each of the classification concepts found in section 1.4 of NGTS-01 (on definitions), tank storage capacity (m^3 LNG , GWh , $Mm^3(n)$), capacity to emit to the network (GWh/d), LNG truck loading capacity (Trucks/day), methane tanker unloading capacity (m^3 LNG/h) and methane tanker mooring capacity (m^3 LNG).

5. Calculation of underground storage facility (USF) capacity

Underground storage facilities have two functions: firstly, they are an important tool used to modulate the gas system, providing flexibility with which to address seasonal and daily fluctuations in supply and demand, and secondly, they provide a reserve in case of possible supply shortfall.

Storage capacity, injection capacity and withdrawal capacity are separate concepts.

These capacities are calculated according to geological, geophysical and petrophysical aspects of the geological feature used for underground storage; if applicable, so are the technical specifications of the equipment installed for the operation of the same, taking into account its operating and safety limits, as well as the limiting effects these may have on one another.

5.1 Storage capacity

The capacity of a storage facility is the amount of natural gas it contains at a specific pressure.

This capacity is a function of the geological, geophysical and petrophysical characteristics of the geological feature, which can be modelled mathematically. The greater the available knowledge of the geological feature and its parameters, the more complex the modelling formula will be and the more accurately it will represent reality.

An example formula commonly used to provide an approximate theoretical calculation of the volume of storable gas in situ is:

$$STO = V*\Phi*(1-Swc)/Boi$$

Where:

STO: Volume of gas in situ under standard conditions 25ºC–

1bar Φ: Porosity (0 - 50%)

Swc: Connate water saturation (fraction)

Boi: Volume factor

V: Volume of rock (unit of volume)

5.2 Injection/withdrawal capacity:

Injection is the action of introducing gas into underground storage using the necessary mechanical equipment to overcome the pressure of the storage facility.

Withdrawal, in contrast, is the action of removing gas from an underground storage facility. Normally, this is done using the pressure differential between the stored gas and the surface. If this pressure differential is insufficient, the mechanical tools used for injection may be used in reverse, provided they are capable of this.

This being so, the injection and withdrawal capacities of an underground natural gas storage facility are the flows this facility can produce when these actions take place.

The withdrawal flow rate is a function of how full the storage facility is - and consequently its internal pressure - as well as its specifications.

The withdrawal capacity is a function of the amount of gas in the storage facility at a given time, and will be calculated taking the plant's gas handling equipment, its operating and safety limits, and the gas exit counterpressure in the transmission pipeline to which it is connected.

The maximum withdrawal capacity is given in conditions of maximum storage facility fill and pressure.

The injection capacity is calculated by taking into account the compression equipment installed at the facility, the operation and safety limits, the gas delivery pressure of the transmission pipeline to which it is connected and the existing pressure in the storage facility itself.

In addition, both the injection and withdrawal capacities are influenced by the equipment which allow the surface facilities to be connected to the geological formation of the storage facility. Of the said equipment, the elements with the greatest impact are the entry/exit flow regulation valve ('choke'), the vertical production/injection pipe that connects the storage formation with the surface ('tubing'), and the compressor units installed on the surface for injection.

The different factors that influence the calculation of the withdrawal/injection capacities of an underground storage facility are described briefly below along with their effects on the said facility.

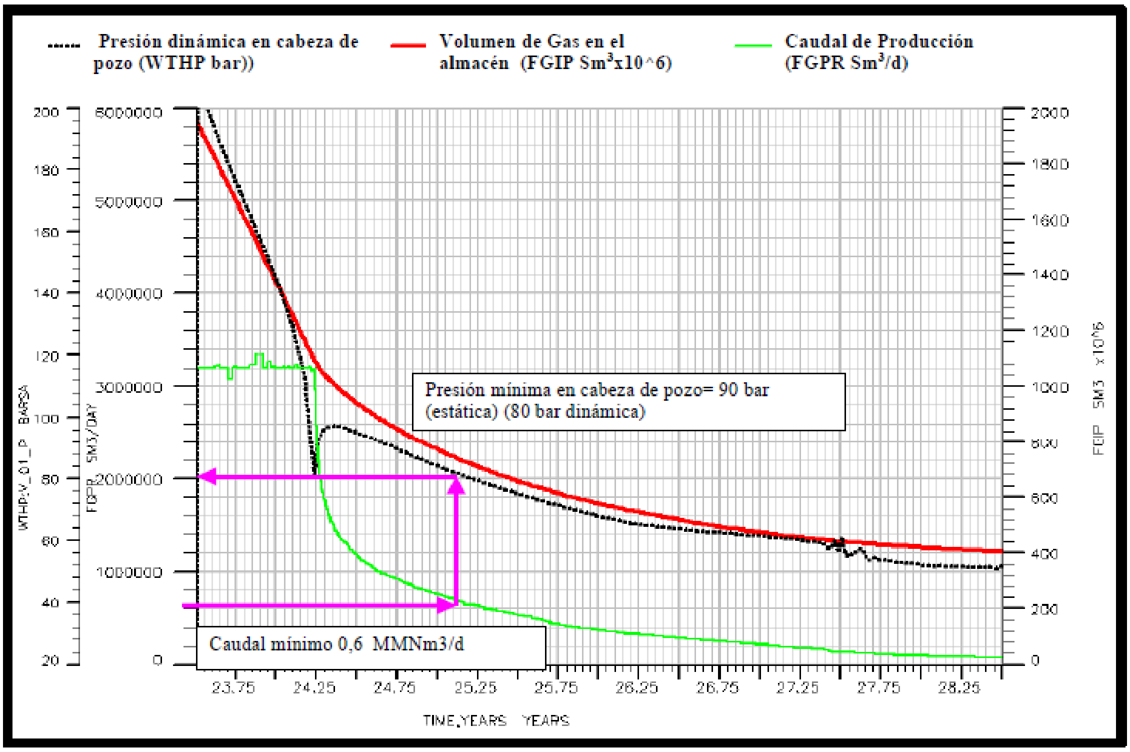
5.2.1 Characteristic curve of a storage formation

The typical curves of a storage formation, which are defined as the relation between the dynamic bottomhole pressure and the injection or withdrawal flow, can be modelled to a greater or lesser degree of precision according to the geological, geophysical and petrophysical characteristics of the geological feature used as underground storage facility.

5.2.2 Decline curve

This is the curve that marks the change in the withdrawal flow rate over time, beginning from a particular ground state (fill level and base pressure), and is a function of the characteristics of the storage formation, tubing, surface pressure and initial withdrawal profile requested. It can pertain to one or several wells, or even to the total withdrawal flow from the storage facility.

An example decline curve is shown below:



5.2.3 Compressor units

Compressor units are the equipment used to overcome the pressure of the storage facility during injection. Injection capacity is therefore mostly a function of the compressor units used for the said purpose.

For this, it is possible to use different types of compression units and arrangements. Centrifugal compressors and reciprocating compressors are among the types of units used; in turn, the arrangement of the units may be parallel, serial or serial/parallel.

To choose the right compressor units and arrange them properly, you must take into account the maximum pressure the storage facility can permit, the flow to be moved and the inlet pressure.

5.2.4 Choke valve

Choke valves are needle valves located in each well line. They can be bi-directional, and they reduce the downstream gas pressure. They serve to regulate and control the flow of natural gas during the withdrawal and/or injection of gas in a well.

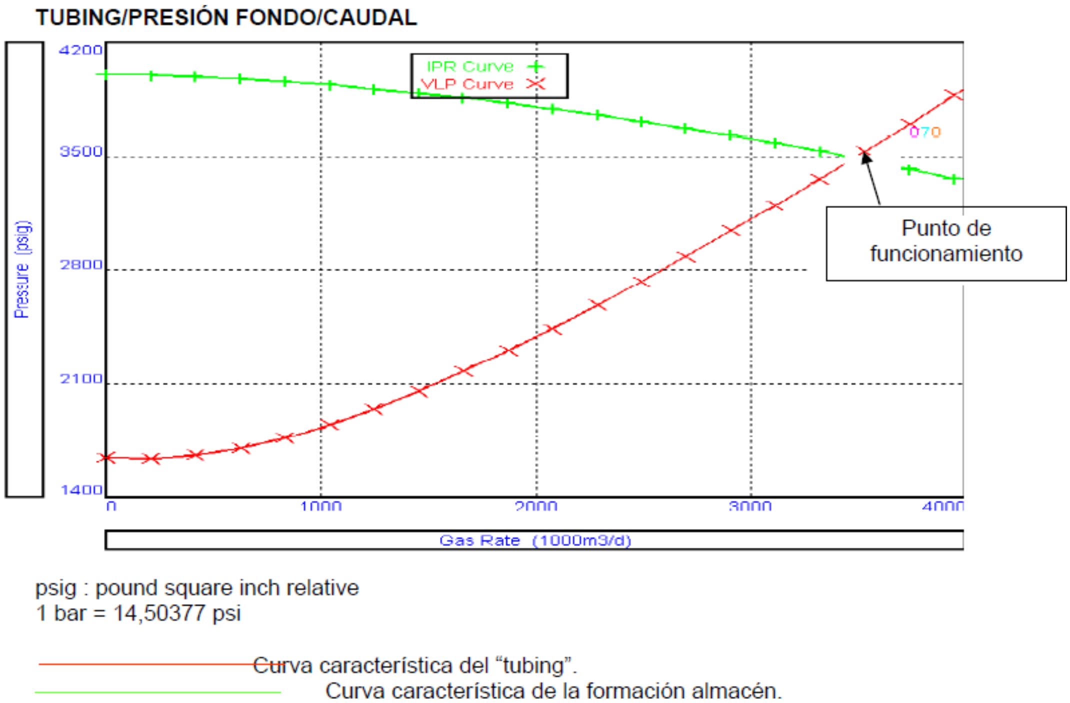
5.2.5 Tubing

This is the vertical production/injection piping that connects the storage formation with the surface (choke valve) and has the proper technical specifications to carry the required flow.

The characteristic curve of the tubing is the relationship between the dynamic bottomhole pressure and its withdrawal or injection flow rate. This depends on the production/injection tubing characteristics for a given dynamic pressure at the well head.

In the following examples, we can see the interaction of the tubing with the underground storage formation withdrawal and injection capacities.

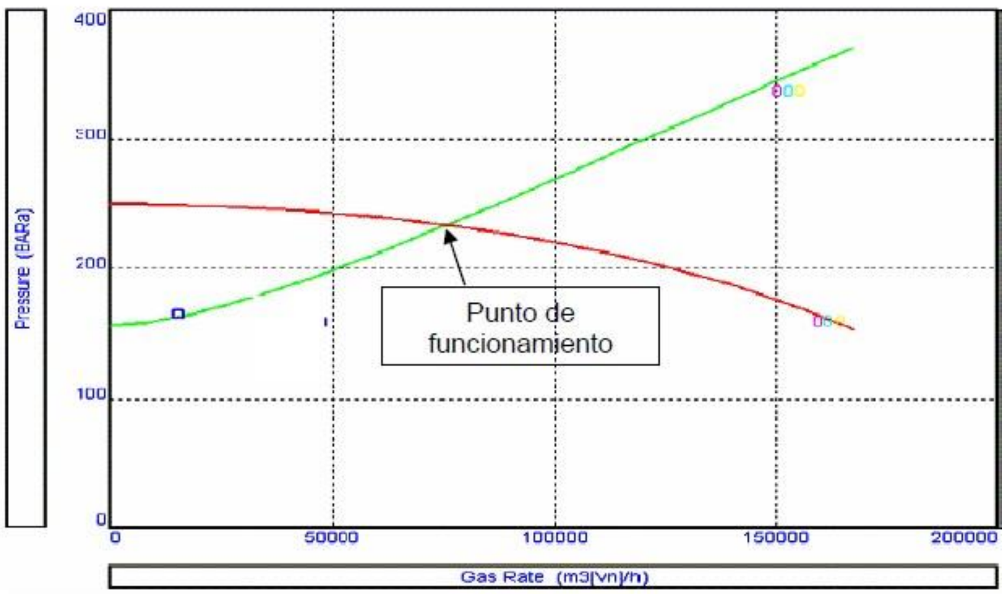
Typical withdrawal curve



At larger diameters, a tubing characteristic curve moves to the right, as larger diameter means a higher production flow at the same bottomhole pressure. The larger the diameter, the less the jump in pressure.

Typical injection curve

TUBING/PRESIÓN FONDO/CAUDAL



psig: Pound square inch relative
1 bar = 14,50377 psi

Curva característica del "tubing".
Curva característica del almacenamiento subterráneo.

At larger diameters, a tubing characteristic curve moves up, as larger diameter means a higher injection flow at the same bottomhole pressure. The larger the diameter, the greater the bottomhole pressure required.

5.2.6 Treatment plant

Once the gas is extracted from the underground storage facility, it must be treated before it can be flowed into the transmission network at the required quality.

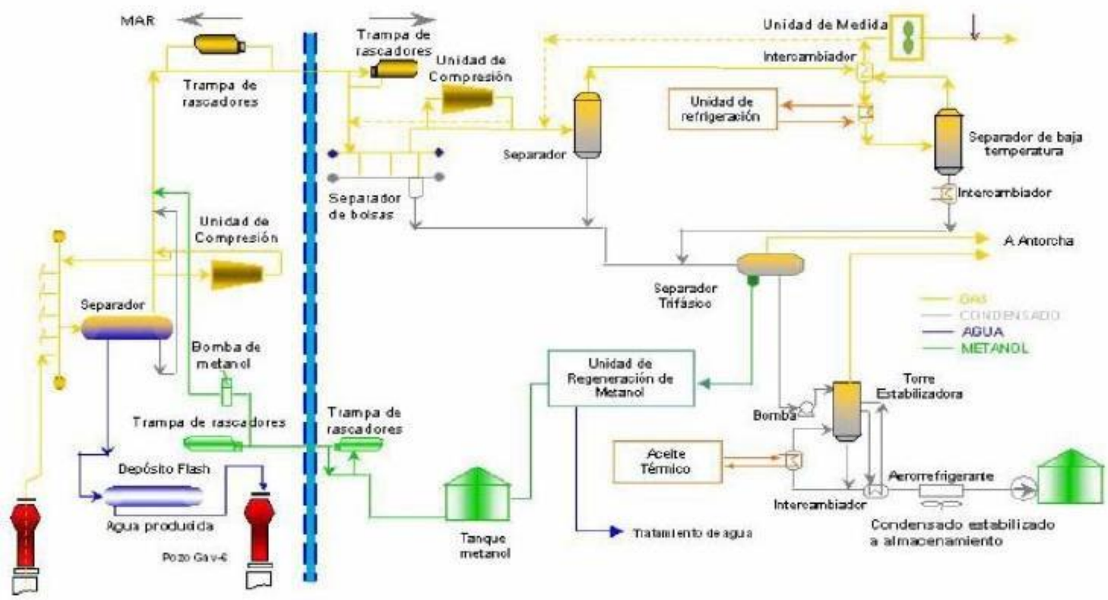
At the treatment plant, the gas is given a first drying by gravity, then dried again in counter-flow dehydrator towers (the dehydrator uses triethylene glycol, hereinafter TEG), so that the gas can then be odorised and measured before being flowed into the transmission network.

Components of the treatment plant:

- Operating point.
- Pig trap.
- Internal pipelines
- Bag separators
- Depressuriser
- Gas stripping towers, including TEG regenerators, injection and transfer pumps, and rich and lean TEG tanks.
- Solid separation filters for the gas
- Process water tank
- Process water injection pumps
- Measurement unit (generally ultrasound)
- Chromatograph
- Odorisation unit
- Combustible gas system
- Compressed gas system
- Water system
- Flare stack with vapour separator
- Electric and diesel transformers

There are critical equipment at the plant designed for the required withdrawal flow rate; if these fail, they limit the gas withdrawal flow. These are the stripper towers and TEG regeneration equipment (TEG is a product used in the counter-flow process in the dehydrator towers).

A general diagram of a treatment plant is shown below:



5.3 Capacities to be published

In underground storage facilities, the facility holder will indicate, applying each of the classifications listed in section 1.4 of NGTS-01 (definitions), the storage, withdrawal and injection capacity of the facility.

Given the influence of fill level at the underground storage facility, the withdrawal values at 75%, 50% and 25% of usable capacity will also be published.

6. Calculation of network capacity

The capacity of a network shall be calculated taking into account:

- Its operating and safety limits
- The limiting effects that pieces of the component equipment may have on one another
- The gas flows supplied at the entry points and the delivery pressure
- The demand met by the network and the minimum guaranteed pressures of its supply
- The gas flows to be provided and the minimum delivery pressure to other transmission companies or DSO’s at the network connection points.

The variables that influence network capacity calculations are described briefly below.

6.1 Calculation of pipeline capacity

Most simply, one can say that the capacity of a pipeline is the amount of gas moved per unit time (flow rate) between the pipeline entry and exit points given certain entry and exit pressures at both.

When gas travels through a pipeline, it loses pressure ('head loss') as it moves through the pipeline due to friction with the walls of the pipe. Pressure is also lost when the gas passes through an accessory, around a curve, into a new section, etc. To overcome this loss of pressure, compressors are installed to compensate for the pressure loss.

To determine the scale of these head losses, formulae or software (simulations) are often used to perform the relevant calculations.

From a technical point of view, the maximum capacity of a pipeline is determined by a set of different design parameters, predominantly diameter, flow and pressure conditions and length, along with other less significant factors discussed below.

The determination of maximum capacity is subject to the relevant physical laws; in this context, and for illustrative purposes, we will here refer to the Darcy formula, although other formulae may also be used for the calculation.

$$p_1^2 - p_2^2 = \frac{16}{\pi^2} \cdot \lambda \cdot \frac{\rho_0 \cdot p_0}{T_0} \cdot \frac{T}{d^5} \cdot l \cdot K \cdot q_0^2 \qquad (1)$$

Where:

p_1 and p_2: Absolute pressure at origin and end of the pipe (bar)

λ : Friction factor

ρ_0: Density of the gas under normal conditions (kg/m^3(n)) p_0:

Pressure at benchmark conditions (1013.25 mbar)

T_0: Temperature at benchmark conditions (273.15 ºK)

T: Gas temperature (ºK)

d: Internal diameter of the pipe (m)

l: Length of the pipe (m)

K: Coefficient of compressibility of the gas relative to normal conditions (Z/Z0)

q_0: Flow referenced to normal conditions (m^3 (n)/h)

This equation does not consider the effects caused by differences in altitude between the origin and endpoint of the pipeline, and the values of its variables refer to IS units.

The friction factor λ is normally found using the Colebrook formula, though other formulae may be used in their valid ranges.

The coefficient of compressibility K is found using the Van der Waals formula, but others are also valid, including Redlich-Kwong, Peng- Robinson, Schmidt-Wenzel, Benedict- Webb-Sterling, AGA8, SGERG88, etc.

This formula is based on operations in a steady state, and capacity will be calculated in these conditions; in other words, when the entry and exit flows are equal.

As a result, pipeline capacity, q0, which will be given in m^3(n)/h, is calculated by solving the above expression (1)

$$q_0 = \frac{\pi}{4} \cdot \sqrt{\frac{(p_1^2 - p_2^2) \, . \, T_0}{p_0 \, . \, \rho_0 \, . \, l. \, K. \, T}} \cdot \sqrt{\frac{d^5}{\lambda}} \quad (2)$$

6.1.1 Influence of internal diameter and friction factor

We can simplify the above formula by assuming that pipeline capacity essentially depends on two parameters, namely the friction factor and the pipe diameter:

$q_0 \sim d^{2.5} \cdot \lambda^{-0.5}$

As friction factor λ is an implicit function of the diameter d, through simplification, we can relate it to capacity using the following expression:

$$q_0 \sim d^{r}$$

Where, for example:

γ = 2.595 for a roughness k of 0.07 mm, a typical value for steel pipes without internal coating.

γ = 2.580 for a roughness k of 0.006 mm, a typical value for steel pipes with internal coating.

The effect of internal diameter on the capacity or flow rate is therefore very pronounced, with an approximate exponent of 2.6.

6.1.2 Influence of pressure

Another important factor that affects the capacity of a pipeline is pressure. By simplifying formula (2), we can obtain the relationship

$$q_0 \sim \sqrt{p_1^{\,2} - p_2^{\,2}}$$

To better see the effect of pressure on capacity, the above quadratic equation can be expressed approximately in linear form:

$$p_1^2 - p_2^2 = (p_1 - p_2) \cdot (p_1 + p_2) = \Delta p \cdot 2 \cdot \overline{p}$$

or:

$$q_0 \sim \sqrt{\Delta p} \cdot \sqrt{\overline{p}}$$

As a result, capacity, or flow, can be said to be proportional to the linear head loss and average pressure. This means that for constantly decreasing pressure, capacity increases by the square root of the average operating pressure.

The maximum pressure loss at which gas is normally moved is between 0.1 and 0.2 bar/km.

6.1.3 Influence of differences in altitude between the origin and endpoint of the pipeline

If there is a significant difference in altitude between the origin and endpoint of the pipe, this is an additional factor that should be taken into consideration, as the head loss increases if the endpoint is at a higher altitude than the origin and decreases if the altitude of the endpoint is lower.

In this case, the Fergusson formula can be used. For horizontal pipes, it is equivalent to equation (1):

$$p_1^2 - e^{\xi} p_2^2 = \frac{16}{\pi^2} \cdot \lambda \cdot \frac{\rho_0 \cdot P_0}{T_0} \cdot \frac{T}{d^5} \cdot K \cdot q_0^2 \cdot l \cdot \frac{e^{\xi} - 1}{\xi}$$

where:

$$\xi = \frac{2 \cdot \rho_0 \cdot g \cdot T_0}{K \cdot T \cdot P_0} \cdot (z_2 - z_1)$$

Where z1 and z2 represent the altitudes at the origin and endpoint of the pipe.

6.1.4 Other factors that influence pipeline capacity

In accordance with the listed formulae, other factors such as gas' physical properties also have an impact (density, coefficient of compressibility, temperature). For example, it is important to take gas temperature into account in order to precisely calculate a pipeline's capacity, above all when calculating the downstream capacity of a compressor station. However, in practice, the average temperature of the fluid over the length of the pipeline is typically used.

Another parameter that limits capacity is the maximum speed to be used for transmission and distribution, as it is necessary that noise and vibrations produced along the pipeline fall within acceptable maximum limits. At an international level, 20 m/s is considered the maximum transmission and distribution speed for a pipeline.

The length of the pipeline also has an impact given that, for example, the aforementioned Darcy formula is based on the functional curve of the loss of pressure that occurs in transport, meaning that the longer the transmission distance, the more pronounced the effect.

Capacity is also affected by environmental conditions in the locations where the gas is transmitted, specifically, the ground temperature and the heat transfer coefficients of the pipe and the ground. These parameters should be considered by each operator using the values for their respective locations.

6.1.5 Parameters and considerations for the calculation of pipeline capacities

In summary, the capacity of a pipeline will be calculated, using generally accepted simulations and programs, taking the following parameters and considerations into account:

- The interior diameter and length of the pipeline
- The friction factor of the pipeline
- Inlet pressure
- The minimum guaranteed pressure at pipeline delivery points
- A maximum speed of 20 m/s, independent of whether the resulting pressures are above the given minimum values
- The difference in altitude between the origin and endpoint of the pipe (if significant)
- Gas temperature
- The coefficient of compressibility of the gas
- Density of the natural gas.

If another parameter not mentioned above is considered in the calculations, the operator must notify system users of this parameter.

6.2 Capacity calculation for a compressor station

Compressor stations are used to make up of the loss of pressure that occurs within networks.

At a compressor station, the following areas can be identified:

a. Capture area.

b. Station bypass.

c. Filters.

d. Compressor units.

e. Anti-pumping system.

f. Cooling unit.

g. Measurement area.

h. Exit area.

The compression process is normally performed with centrifugal compressors, though these can also be reciprocating, using the mechanical energy produced by a gas turbine or reciprocating engine to raise the pressure of gas moved by the compressor.

The performance of the compressor station is determined by:

- The installed power which, if insufficient to compress the gas to the requested requirements, will limit the inlet or discharge pressure of the same
- The performance curves of the compressors
- The parts of the station such as filters, cooling units, etc.

The compression process can be characterised using only a few parameters, including:

- Isentropic or polytropic level
- Polytropic efficiency
- The power absorbed by the compressor.

The polytropic level represents the energy accumulated in the fluid as an increase in thermodynamic energy. The adiabatic pressure may also be calculated (no heat transfer with elements outside the system).

Using the relationship between the pressure and specific volume of a gas in a polytropic transformation of exponent n (PVn constant) between points 1 and 2, the polytropic level is obtained as:

$$H_{pol} = \frac{n}{n-1} Z_1 R T_1 \left[\left(\frac{P_2}{P_1} \right)^{\frac{n-1}{n}} - 1 \right]$$

Where:

Z_1: Coefficient of compressibility of the gas in the inlet or suction area.

P_1 and P_2: Inlet and discharge pressures R:

Characteristic constant of the gas

T_1: Temperature of the gas in the capture or inlet area.

Also taking into account the performance or polytropic efficiency η, the power absorbed by the compressor in kWh will be:

$$P = 735.5 \frac{q_0 \cdot \gamma \cdot H_{pol}}{75 \cdot 3.600\ \eta}$$

Where:

q_0: Flow rate in Nm^3/h

γ : Specific weight of the gas in kg/Nm^3.

This takes the polytropic efficiency η as the factor that determines the performance, realising that the compressor is made of various stages in which the gas loses pressure when it backs up.

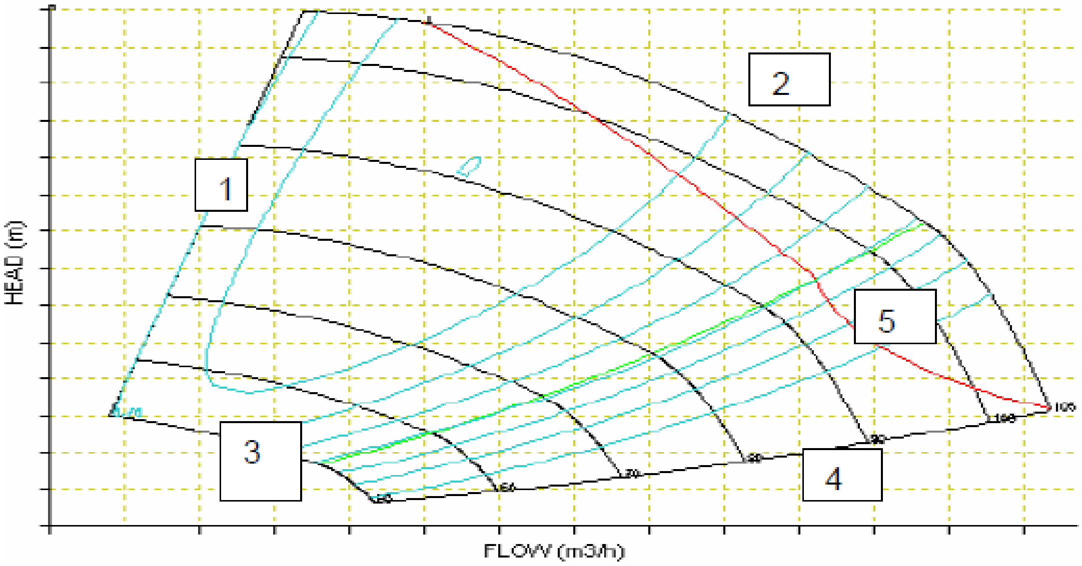
In addition, to calculate power, losses due to mechanical friction should also be taken into account, as should losses created in its interior installation.

Normally, the installed power tends to be slightly higher than that required to cover unexpected situations and have a certain margin in terms of installed capacity.

For each compressor, the manufacturer will provide a performance curve showing the isovelocity and isoefficiency lines, with levels plotted on the y-axis and flow on the x-axis. On this curve chart, we can see the following operating margins that should be respected for the proper operation of the compressor, and therefore for calculating capacity.

- Pumping line (1)
- Maximum speed line (2)
- Minimum speed line (3)
- Maximum flow line (‘chocking line’) (4)
- Maximum power line (in red), above which the turbine cannot power the compressor. (5)

These margins define the operating area for the centrifugal compressor, as visible in the figure.



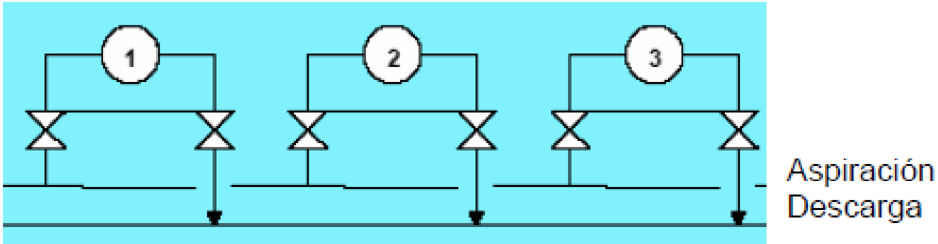
Besides these operating margins, we must take into account the effects of environmental conditions on calculating the maximum available power for the compressor. For example, higher air temperature at the turbine inlet lowers the maximum power line, reducing the range of power available to the compressor.

To calculate the capacity of a compressor station, the inlet pressure should never be below 40 bar, and the discharge pressure should never be above the design pressure of the pipeline into which it feeds; in addition, it should be taken into account that one of the compressor units will not be available, as it is kept as a backup.

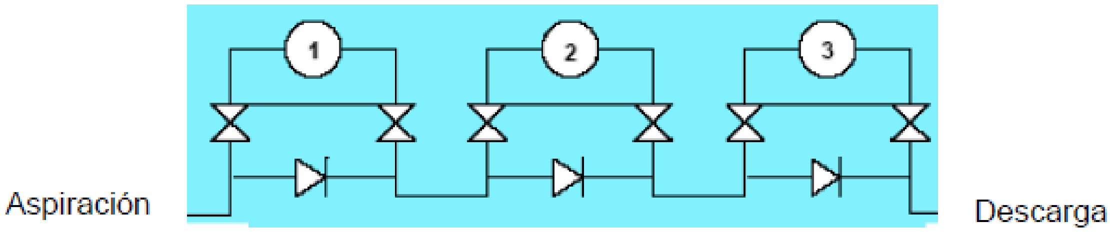
To calculate the capacity of a compressor station, the internal arrangement of its compressors will also be considered, that is, whether they run in series or in parallel. Relative to a normal arrangement, running them in a series increases the pressure differential while maintaining flow, while running them in parallel increases flow while maintaining the pressure differential.

Examples of different possible arrangements:

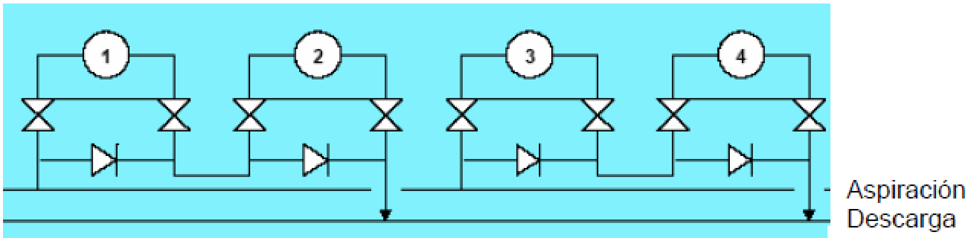
a) Parallel arrangement:



b) Series arrangement:



c) Series/parallel arrangement:



6.2.1 Parameters and considerations for calculating compressor station capacity

In summary, the capacity of a compressor station shall be calculated taking into account:

- The arrangement of the station’s compressors
- The performance curve of each compressor provided by the manufacturer, representing the isovelocity and isoefficiency lines according to flow and, in particular, the operating margins determined by the pumping line, maximum speed line, minimum speed line, maximum flow line ('choking line') and maximum power line
- The inlet pressure must not be below 40 bar
- The discharge pressure must not be higher than the design pressure of the pipeline into which it feeds.

If another parameter not mentioned above is considered in the calculations, the operator must notify system users of this parameter.

6.3 Calculating capacity of a regulation and metering station (RMS) and/or a metering station (MS)

Regulation and metering stations (RMS) or measuring stations (MS) are located at the system points where it is necessary to measure and/or reduce the gas pressure being transmitted to another network or operator. At these facilities, it is therefore necessary to consider how this capacity calculation should be performed and the parameters involved in determining it.

At an RMS, the following areas can be identified for capacity calculations:

a) Capture area.

b) Station bypass.

c) Filters.

d) Gas heating area.

e) Regulation area.

f) Measurement area.

g) Exit area.

A determining factor is the operating inlet pressure; if this is near the minimum inlet pressure, the capacity will decrease.

In addition, assuming that these different areas must be designed to handle the required capacity of the regulating facility, the two key elements for calculating the unit's capacity are as follows:

- Capacity of all the regulator valves
- Capacity of the measurement unit.

In both cases, the following calculations are performed for each regulating line, with the RMS taken as the sum of each line. However, a backup line is taken as a safety operating margin in the hypothetical case that one of the lines in service fails; in such a case, the backup line should begin working immediately.

6.3.1 Regulator valve assembly

The standard regulation capacity is typically calculated for a valve by a reduction in the passage of the fluid, as expressed by:

$$Q = Kv\sqrt{\frac{\Delta p}{\rho}}$$

Which relates head loss (Δp) and gas density (ρ) to obtain the regulating flow, taking into account the coefficient of the valve (Kv) for the reduction in flow that it causes.

The capacity of the regulator will be found depending on the valve coefficient provided by the manufacturer.

6.3.2 Measurement units

In terms of measurement units, at RMS, gas is measured using a turbine, and its capacity is calculated as follows:

Q = 1.6 G Psal

In this formula, we can see how the measurement capacity of a turbine is calculated using G, which is the standard size of the turbine; Psal, which is the absolute measurement pressure; and the coefficient 1.6 (the standard size following that in question).

6.3.3 Ultrasonic meters

If the measurement is made using an ultrasonic meter, its capacity will be as indicated by the manufacturer; the gas velocity, which should not exceed 20 m/sec., will be the limiting factor of this capacity.

6.3.4 Parameters and considerations for calculating regulation and/or metering stations

> *Resolution of 30 April 2012 of the Directorate General of Energy Policy and Mines, which publishes Detail Protocol PD-14 'Criteria for establishing the degree of saturation of regulation and metering stations and metering stations and procedure for carrying out proposed actions', and amends Detail Protocol PD-10 'Calculation of facility capacity'.* Published in the B.O.E. on 28 May 2012
>
> *Validity: 28 May 2012*

The nominal capacity is taken to be the maximum flow that can be moved through the RMS/MS according to its design characteristics, excluding the backup line, using the regulation and metering capacity as parameters.

The regulation capacity of an RMS is calculated as the sum of the regulation capacities of each of the lines, excluding the backup line.

The metering capacity of an RMS/MS is calculated as the sum of the capacities of the measurement equipment installed on its lines, excluding the backup line.

In summary, the capacity of a regulation and/or metering station shall be calculated taking into account:

- Number of lines.
- Regulation capacity of all regulating valves.
- Metering capacity of the turbine, a function of the standard size of the same.
- Pressure and temperature conditions, particularly the operating inlet pressure and absolute discharge pressure.

6.4 Calculation of pipeline fill capacity

The amount of gas that a pipeline can contain is determined on the basis of the product of three variables, in the following way:

$$V = P_m \;.\; V_g \;.\; Z$$

Where:

V: Pipeline capacity in m^3(n)

Pm: Average absolute pressure of the pipeline in bar Vg:

Geometric volume of the pipeline in m^3

Z: Compressibility factor of the gas under normal conditions.

The average pressure (Pm) between the origin and endpoint of the pipeline is calculated using the following expression:

$$P_m = \frac{2}{3}\left((P_1 + P_2) - \left(\frac{P_1 \cdot P_2}{P_1 + P_2}\right)\right)$$

where:

P_1: Pressure at the pipeline origin

P_2: Pressure at the pipeline endpoint

The compressibility factor is the relationship between the molar volume of a real gas and the ideal molar volume of the same gas. It depends on the gas pressure, temperature, and composition and is calculated as described in procedure SGERG-88 of the UNE-EN ISO 12213 standard, as indicated in Detail Protocol PD-
01. As an approximate calculation for pipelines of over 4 bar, the following practical formula may be used:

$$Z = 1 - \frac{P_m}{500}$$

6.5 Calculation of the capacity of an international connection

At an international connection, at least the following should be taken into account in capacity calculations:

- Metering capacity according to the provisions of section 6.3.
- Capacity of the flow regulator valve based on the pressure differential in question.
- Delivery pressure from the connection's upstream operator.

Taking into account that the first two factors should not be limiting when their design is considered compatible with the operational requirements, the most important is the delivery pressure, as it must be greater than the system pressure found downstream of the connection point.

All of this is applicable if, in addition, the connection is considered reversible, and if the flow direction can therefore vary between systems.

7. Calculation of transmission system capacity

The capacity of a transmission system is given, in an initial approximation, by combining the calculated capacities of the elements of which it is made; in other words, the maximum emission of a regasification plant, the maximum flow that can be moved through the transmission pipelines and compressor stations, the maximum emission or injection at underground storage facilities and the maximum flow that can be moved through the regulation and metering stations.

However, the behaviour of these elements when they form part of an integrated transmission system depends on how they interact with one another; in other words, on the arrangement of the network and, to a considerable extent, what the internal flows are within the system, as these can change direction according to the supply-demand situation.

Despite the fact that not all transmission network operators calculate the capacity of their systems in precisely the same way, the concepts applied are the same for all, and all are based on the use of simulations of hydraulic models, generally accepted and recognised within the gas industry, that calculate the distribution of network flows and pressures, taking into account at least the following factors:

- Network arrangement
- Internal models that calculate the explained network elements, taking their physical parameters into account.
- The network in a steady state (gas flowing into the system is equal to gas flowing out of it)
- Different demand scenarios based on normal and seasonal temperatures
- Minimum and maximum pressure values at a technical and commercial level.

In terms of the minimum pressures to be accounted for at exit points, these will be those established in the System Technical Management Rules 40 bar will be taken as the minimum inlet pressure for a compressor station.

7.1 Calculation of operating and available capacity

The steps to be followed to obtain the operating (useful) and available capacity of a transmission system are as follows:

1.- The main points of the system and its flows shall be determined.

The flows to be considered for the system entry and exit points are:

- Flows into and out of the system from/towards an international connection.
- Flows into the system from gas fields
- Flows into the system from regasification plants
- Flows into and out of the system from/to an underground storage facility
- Flows out of the system to consumers for electricity generation
- Flows out of the system to industrial consumers
- Flows out of the system to distribution networks
- Flows into and out of the system from/to connected transmission company networks

2.- There are three base scenarios:

- Peak
- Winter
- Summer.

These scenarios will take into account the typical levels of demand during each period, and when gas is flowed out of the system, this will be associated with the corresponding market segment.

All flows out of the system to consumers or distribution networks will be directed to the three characteristic consumption segments: consumption for electricity generation, industrial consumption and domestic/commercial consumption.

To calculate capacity, the forecast level of demand for to the time period (summer, winter, peak) should be taken into account, as should simultaneity factors and predicted consumption by large clients.

To calculate the network's maximum capacity, operation running at 100% will be used for each operational group of electrical consumers, regardless of whether they are currently in commercial operations or in the testing phase.

In the case of flows out of the system to industrial consumers, available data about their real hourly consumption will be taken into account; in their absence, the average hourly consumption will be determined based on their invoicing and estimated hours of use.

In the case of exit flows to distribution networks, assumed domestic and commercial consumption will depend on:

- Temperatures during the scenario period under consideration: winter, summer, etc.
- Consumption patterns for consumers supplied by the distribution network connected to the exit of the transmission system.

These consumption patterns will be applied, along with the relevant variations according to the temperature of the period in question, on the basis of the demand forecasting applications found in the relevant Detail Protocol (PD-03).

3.- For entry flows, the following will be considered:

- The maximum pressure and flow rate at which each regasification plant can emit
- The maximum delivery pressure and flow rate from the upstream operator at international connections
- The maximum pressure and flow rate at which national gas fields can emit gas
- For secondary transmission pipelines, the maximum delivery pressure and flow rate from the upstream operator at the PCTT

4.- For underground storage facilities:

- For the peak scenario, maximum withdrawal will be considered

- For the winter scenario, withdrawal up to the level established in the current winter regulations will be considered
- For the summer scenario, maximum injection will be considered

5.- The system will be taken to saturation for all scenarios, choosing the most restrictive case for each period. It will be this case that we take as the base peak, winter and summer scenario.

Once all the scenarios have been established in terms of both system entry and exit flows, including underground storage facilities, maximum capacity will be calculated, taking the system to saturation; in other words, the system's internal flows will be maximised until one of the network restrictions is reached. For example, this may be minimum pressure at an entry point, maximum pressure at an entry point or maximum power of a compressor station.

6.- From these base scenarios, capacity will be calculated incrementally based on any new scenarios that may be requested at any time.

To determine the viability of a new connection, we must analyse the network's behaviours at the specific connection point, which is the only way to provide adequate guarantees of the ability to simultaneously supply current clients and new consumption during a scenario of maximum hourly emission.

7.2 Capacities to be published

Each transmission company shall publish, applying to each of the items classified in section 1.4 of NGTS-01 (definitions), the transmission capacity of its entire system, providing details of the capacity of each of its entry points (connections with regasification plants, national gas fields), connections with underground storage facilities, international connections and connections with other transmission companies at each PCTT (in GWh/day, $Mm^3(n)$/day).

They shall also publish the capacities of each compressor station; their relevant system hubs; and of points that are physically congested or that could cause restrictions to the transmission system.

In the case of international connections and PCTT, capacity in both ways shall be published, along with the incremental pressure coefficients per volume unit in bars/$Mm^3(n)$; the latter should be agreed upon by the connection operators.

8. Calculation of capacity of the distribution network and secondary transmission network

The maximum capacity of a distribution network, or of a secondary transmission network with a certain pressure level, is defined as the gas that the said system can move in a scenario of maximum hourly demand ($m^3(n)/h$) while maintaining the most restrictive guaranteed pressure at all points of the system. This capacity depends on the pressure at the network entry point(s), as well as any existing head losses.

8.1 Relevant elements for capacity calculations

The capacity of a distribution network, or secondary transmission network, is given by combining the calculated capacity of the elements of which it is made; in other words, the maximum flow that can be moved through the network and the maximum flow that can be moved through the regulation and/or metering stations.

Despite the fact that not all distribution and secondary transmission network operators calculate the capacity of their systems in an identical way, they do agree on the general concepts to be applied, which are as follows:

a) Have a mathematical model that reproduces the approximate behaviour of the network at times of maximum emission, using a generally accepted network simulator.

b) The calculation of the distribution of flows and pressures in the system is carried out in a steady state; in other words, gas flowing into the system is equal to the gas flowing out of it.

c) The entry and exit flows at times of maximum system emission are taken into account:

- Entry flows: the contributions from regulation and/or metering stations at the head of the system.
- Exit flows: those pertaining to industrial consumers and delivery points to networks and/or domestic and commercial consumers.

For industrial consumers, available data about their real hourly consumption will be taken into account; where this is not available, the average hourly consumption will be determined based on their invoicing and estimated hours of use.

The exit flow values shall be those corresponding to a weather scenario of maximum demand (cold snap), and will include the relevant simultaneity factors.

The said forecasts will be obtained from the demand forecast applications included in the relevant Detail Protocol.

d) The capacity reserve corresponding to organic domestic and commercial growth will be used, as will any planned operational launches for industrial consumers.

e) Maximum calculation pressure at system entry points (PCTT/PCTD):

These shall be those established in the System Technical Management Rules, section 2.4.4., or in mutual agreements between the Shipper and the GTS/transmission company, provided that this does not exceed the maximum authorised operating pressure.

f) Minimum calculation pressures:

Minimum pressures that must be available at the entry to delivery points to guarantee, at minimum, the pressure values set out in section 2.5.2. of the System Technical Management Rules.

g) Maximum gas speed: 20 m/sec, independent of whether the resulting pressures are above the given minimum values.

h) Maximum flow rate that can be provided by the regulation and/or metering stations located at the head of the system, according to the criteria indicated in section 6.3.

8.2 Calculation of operating and available capacity

Once the capacity has been calculated in accordance with the preceding section, the operating (useful) and available capacity of a network will be determined by evaluating the additional flow that can be delivered if the system is taken to saturation, that is, until one of the network limitations is reached, such as the minimum pressure at an exit point, the maximum pressure at an entry point or the maximum emission capacity of a regulation and metering station, maintaining the minimum guaranteed pressures.

The resulting value shall be taken for informational purposes, as the secondary transmission and distribution networks are made up of branches and sub-lines with different diameters, consumption and head loss for each branch or sub-line, resulting in a wide range of available capacity figures according to where the new consumer is located.

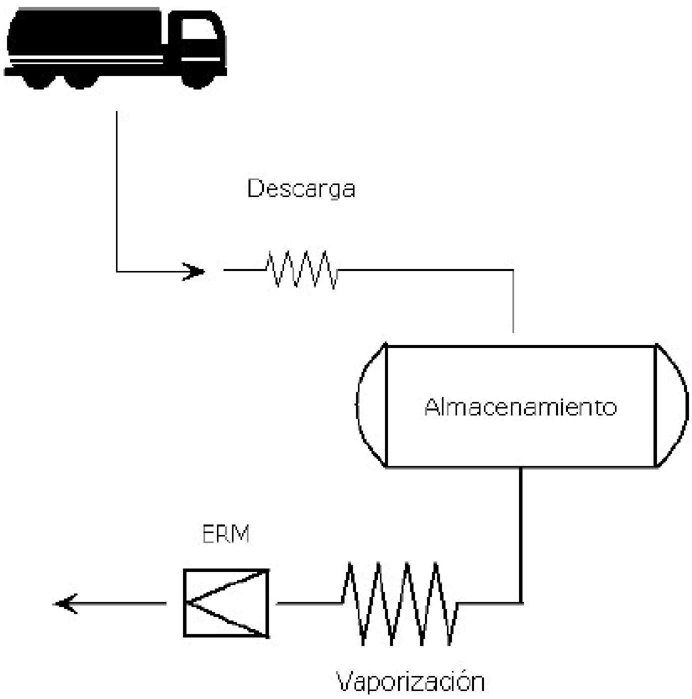
This is why, when determining the real viability of supplying a new consumer, we must analyse the behaviour of the network at the connection point in question. This is the only option that allows us to both adequately guarantee simultaneous supply to clients and the new consumer in a situation of maximum hourly emission.

8.3 Capacities to be published

The information to be published will correspond to the capacities of the secondary transmission pipelines that have similar operating characteristics and exit point density to a primary transmission pipeline, in accordance with the provisions of section 7.2.

9. Calculation of satellite LNG plants capacity

Satellite LNG plants capacity is calculated on the basis of the various equipment that makes up the said plant, taking into account operating, storage and emission capacity and unloading capacity to supply the same, in such a way that the security of supply and proper operation of the facility is guaranteed.



To determine the capacity of a satellite LNG plant, the scaling of its various component parts will be considered:

1. Storage capacity
2. Vaporisation capacity

3. Regulation capacity

4. Unloading capacity

9.1 Storage capacity

The storage capacity will take into account the geometric volume (VG) of the storage tanks, the maximum fill level that will allow them to meet the minimum vaporisation condition and the maximum emptying level under which the cryogenic conditions of the tanks can still be guaranteed. This establishes the real storage capacity (CRA) available in the tanks, reflected by the expression:

$$CRA = 0.85 \cdot VG$$

This should guarantee sufficient stock storage which, as a function of the maximum demand consumption (CMD), allows a margin of autonomous days (DA) in relation to elements affecting supply (transmission, distance to supply plant, unloading frequency, etc.). These stock, or amount of days of autonomy, is reflected by the expression:

$$DA = \frac{CRA}{CMD}$$ where CRA = DA. CMD

As an operating margin, each satellite plant shall have a DA of three days (DA = 3) in normal situations, increasing to 4 days (DA
= 4) in those cases where the DIRECTORATE GENERAL OF ENERGY POLICY AND MINES, MINISTRY OF INDUSTRY, TOURISM AND TRADE, SUB-DIRECTORATE GENERAL OF HYDROCARBONS 03/05/2007 10:55:58 p.
77 satellite plant is located more than 300 km from the supply plant, or the unloading frequency is equal to or greater than 1 truck cistern/day.

9.2 Vaporisation capacity

The vaporisation capacity, expressed in m^3(n)/h, will depend on the following elements:

- Boilers
- Water recirculation pumps
- Associated circuits
- Heat exchangers.

As an operating margin, to prepare for the possibility of a breakdown or required maintenance on the various elements that make up the vaporiser assembly, the vaporisation capacity should guarantee the provision of the forecast supply even when 50% of its elements are out of commission.

9.3 Regulation capacity

The regulation capacity will be calculated as per section 7.3

9.4 Unloading capacity

The unloading capacity should guarantee that the unloading time at the satellite plant remains below 2.5 hours, including connection, unloading and prior and later operations.

As an operating margin, plants with a peak truck unloading frequency of above 2 trucks/day should have at least two independent unloading installations.

9.5 Capacities to be published

Each holder of an LNG satellite plant connected to a public distribution network must publish - for each plant - the municipal terminal where the said plant is located and, applying to each of the classification concepts listed in section 1.4 of NGTS-01 on definitions, the following: storage capacity (m^3 LNG), vaporisation capacity (m^3 (n)/h) and truck cistern unloading capacity (m^3 LNG/h).

PD-11

'Allocation procedure at transmission network entry points'

The Resolution of the Directorate General of Energy Policy and Mines of 4 July 2008, approving Detail Protocol PD-11 'Allocation procedure at transmission network entry points' was published in the BOE of 15 July 2008. The text included the content found in the document
'Protocol PD-11. Allocation procedure at transmission network entry points', dated 4 July 2008 and published on the website of the Ministry of Industry, Tourism and Trade

Section 2.1 'Allocation at international pipeline connection points (PCI)' revised in accordance with the Resolution of 17 September 2012 of the Directorate General of Energy Policy and Mines, which amended System Technical Management Rules NGTS-01 'General concepts' and NGTS-04 'Nominations', and Detail Protocol PD-11 'Allocation procedure at transmission network entry points', and approved Detail Protocol PD-15 'Nominations, metering and allocation at international pipeline connections with Europe'. (B.O.E. 13 October 2012).

Validity: 14 October 2012

1. Purpose

To specify the allocation procedure for entry points to the transmission network, defined in NGTS-06, and to establish the system residual balancing account (hereinafter BRS), which is sub-divided into three levels: BRS-0, BRS-1 and BRS-2.

2. General allocation criteria

The daily quality to be assigned to each user will be equal to their viable nomination/re-nomination after the nomination/re-nomination appeals process. In contrast, the quantities that would have been nominated by the GTS will be assigned to the BRS (BRS-1).

The difference between the total physical quantity delivered at the connection point and the sum of all user nominations will be included in the BRS account not assigned to any party.

The allocation responsible will do so following validation by the other interconnected holder.

2.1 Allocation at international pipeline connection points (PCI)

Section 2.1 'Allocation at international pipeline connection points (PCI)' revised in accordance with the Resolution of 17 September 2012 of the Directorate General of Energy Policy and Mines, which amended the System Technical Management Rule NGTS-01 'General concepts' and NGTS-04 'Nominations', and Detail Protocol PD-11 'Allocation procedure at transmission network entry points', and approved Detail Protocol PD-15 'Nominations, metering and allocation at international pipeline connections with Europe'. (B.O.E. 13 October 2012).

Validity: 14 October 2012

The allocation mechanisms at international connections should comply with current legislation on both sides of the connection point.

At the PCI, the interconnected transmission companies will make the greatest possible effort to establish operating agreements with BRS-type allocation mechanisms that respect the elements set out in the present protocol.

At each PCI, the transmission company that owns the transmission network in Spanish territory, after validation with the other interconnected holder, will inform the GTS of the allocation by the deadlines established in section 6.4.3 of NGTS-06.

The above notwithstanding, at international pipeline connections with Europe, the allocation mechanism established in Detail Protocol PD-15 'Nominations, Metering and Allocation at International Pipeline Connections with Europe'.

3. System Residual Balancing (BRS)

3.1 BRS breakdown

According to the causes of the discrepancies between the quantities assigned to each user, in accordance with the provisions of the previous section and the total physical amount delivered at each connection point, the BRS is broken down into three levels of residual balance: BRS-0, BRS-1 and BRS-2.

3.1.1 BRS-0

This is the sum of the differences between the gas effectively emitted by the transmission companies and the operating instructions of the GTS.

The accumulated BRS-0 must remain within a range of ±A at all times, with A as a function of the nominal capacity of the system entry point:

	Nominal capacity	
	Nominal c. < 750,000 Nm³/h	**Nominal c. < 750,000 Nm³/h**
A	**20 GWh**	**40 GWh**

3.1.2 BRS-1

The sum of the forecast operations programmed by the GTS that belong to one of the following types:

1. Those necessary to respect users' storage rights, in accordance with section 2.4.2 'Storage for commercial operations in the transmission pipeline network' of Technical Management System Standard NGTS-02.

These operations may result in AOC gas (storage for commercial operations in the transmission pipeline network) being temporarily located in LNG storage tanks and underground storage facilities.

The accumulated total sum of these operations will match the excess storage rights of users in relation to the physical capacity of the transmission network at each point in time.

2. Those necessary for transporting facility cushion gas. The accumulated total of these operations will correspond to the transmission needs for cushion gas between the entry points and their final locations. These operations may mean that gas destined to serve cushion gas is temporarily located in AOC, LNG storage tanks and underground storage facilities.

3. Operations programmed by the GTS so that transmission company activities have the smallest possible effect on nominations:

3.1 Insertion of new positions that limit flow or segmentation of the pipeline that results in production different from the schedule. This value will approach 0 for a given period.

3.2 Test of transmission/regasification/underground storage facilities. This will approach 0 for a given period.

3.3 Maintenance of transmission/regasification/underground storage facilities in accordance with Technical Management System Standard NGTS-8. This value will approach 0 for a given period.

4. The operations required to find an appropriate location for transmission supply loss, or excess of the same, at each of the facilities, in accordance with Additional Provision 5 of Order ITC3/863/2007 of 28 December, which established the tolls and fees associated with third-party access to gas system facilities for the year 2008, and which updated particular aspects pertaining to compensation for regulated gas sector activities.

5. Other operations programmed by the GTS in compliance with current regulations.

The accumulated total of these operations will tend to be compensated by opposing totals over a period not exceeding one month. If there is a possible excess or deficit in terms of transmission supply loss, this time period may be greater.

The GTS must carry out programming, nominations and re-nominations in a manner like that of the users, in accordance with the NGTS.

3.1.3 BRS-2

This will be the sum that results from the differences between the operating instructions of the GTS for certain entry points and the quantities assigned to the users and GTS.

These operating instructions will be carried out to guarantee the security of the system in accordance with the criteria included in Detail Protocol PD-09 'Calculation of admissible ranges for basic control variable values within normal system operating ranges' in the following scenarios:

1. If the GTS forecasts consumption different from the nominations submitted by the users, to maintain entry-exit balancing for the network.

2. In the event of Exceptional Operating Situations (SOE).

3. Operations performed to resolve unforeseen congestion.

The accumulated total of these operations will tend to be compensated by opposite sums over time period not exceeding one month.

The GTS will not schedule or nominate these operations, but rather will issue operating instructions different from the nominations.

3.2 Calculating the BRS-0, BRS-1 and BRS-2

The BRS is broken down into the aforementioned three levels in such a way that:

$$BRS = \Sigma\ BRSi \quad i=0,1,2$$

BRS-0 = Emitted gas - GTS operating instructions

BRS-1 = Operations nominated by the GTS

BRS-2 = GTS operating instructions – User nominations – BRS-1

The allocation responsible will calculate the BRS for each day, breaking it down into BRS-0, BRS-1 and BRS-2.

The GTS will carry a daily and accumulated balance of the BRS, broken down into the BRS-0, BRS-1 and BRS-2, for all entry points.

3.3 Communication and publication procedure

transmission companies must publish the Allocation Procedures for international connection points on their websites.

The National Energy Commission will resolve any discrepancies that may arise at connection points with particular allocation conditions different from those described in the present protocol.

As soon as it is known and with detail by day, the GTS will publish the BRS breakdown for each entry point on its website, as well as the justification for the operations included in the BRS-2.

PD-12

'LNG truck cistern logistics'

Approved by the Resolution of 29 March 2012 of the Directorate General of Energy Policy and Mines, which amended the System Technical Management Rule NGTS-02 'Terms and Conditions of use and capacity of gas system facilities', established Detail Protocol PD-12 'Applicable procedures for liquefied natural gas truck cisterns destined for satellite plants' and amended Detail Protocol PD-01 'Gas metering, quality and odorisation'. Published in the B.O.E. on 23 April 2012.

Initially valid from: 23 January 2013 (9 months from its publication in the B.O.E.), amended by the Resolution of 5 December 2012 of the Directorate General of Energy Policy and Mines, which established Detail Protocol PD-16 'Exchange of operating signals between gas system facility holders, and between holders and the Technical Manager of the System', published in
the B.O.E. on 17 December 2012: *"With the exception of the section relating to the amendment of Detail Protocol PD-01, which will apply the day following its publication, this resolution will enter into force on 1 July, 2013.*

Until the said date, the automatic processes of the SL-ATR will consider valid all truck cisterns programmed/nominated using the new system, automatically generating an Order that will include the requested capacity, with the loading of the said trucks limited only by the effective capacity of the Loader'.

Resolution of 4 May 2015 of the Directorate General for Energy Policy and Mines amending Detail Protocol PD-12 'Applicable procedures for liquefied natural gas truck cisterns destined for satellite plants'.

Validity: 22 May 2015

1. Purpose

The present Detail Protocol seeks to establish the coordination method and obligations incumbent on the different subjects who act in the liquefied natural gas (LNG) truck cistern market destined for satellite plants, in order to ensure the necessary continuity, quality and security of supply.

For the purposes of the present protocol, two separate types of plants are identified:

- Single-client satellite plants that feed a single end consumer.
- Distribution satellite plants that feed one or several distribution networks.

2. Scope of application

This protocol applies to all gas system agents and operations described in section 2.6.6 of the Technical Management System Standard NGTS-02 'Terms and Conditions for the use and capacity of gas system facilities'. In particular, the following will be applicable to single-client or distribution satellite plants:

- Single-client satellite plants: For an end customer who acts as a direct market consumer, the dispatcher will be that customer, while if an end customer is supplied by a shipper, the dispatcher will be the shipper, who can delegate the dispatch of the truck cisterns to the end customer by written agreement. The communication of this agreement and its cancellation must be completed before the beginning and end of supply to the regasification plant holder.
- Satellite distribution plants: This category includes satellite plants that are the property of a shipper. In such a case, the shipper will act as the dispatcher.

3. Assignation of satellite plants to regasification plants

For a new satellite distribution plant, the technical manager of the system (GTS), at the instigation of the dispatcher, will designate one of the available system regasification plants as a truck loading plant, which - under normal operating conditions - will be linked to the new satellite plant for LNG deliveries. Generally speaking, this will be the one that is the shortest distance away by road, regardless of whether or not it is being employed by the user to store LNG.

In special cases of intermodal transport, vehicular LNG stations and tax warehouses, the most advisable plant will be assigned. In these cases, more than one regasification plant may be assigned.

In case of a satellite distribution plant in service at the time when the present protocol takes effect, it will be initially assigned to the loading plant it currently uses. The GTS, of its own volition or at the request of other parties involved in the operation of the satellite plant, will study the reassignment of the loading plant and, if necessary, propose it under the same principle applied to the assignment of new satellite plants. This reassignment will be carried out through an agreement with the involved parties. The assignment of satellite distribution plants to truck loading plants will be available on the SL-ATR and will be published on the GTS website.

In the case of single-client satellite plants, the direct market consumer or shipper who supplies them will notify the GTS of the regasification plant where the truck loading will be carried out.

If the loading plant assigned to a satellite plant is out of service due to technical restrictions or inaccessibility, the GTS, after consulting the loaders, will establish an alternative loading plan, independent of the existing contractual conditions, in order to ensure continuity of supply. Generally speaking, the criteria of minimum distance will also be applied, as well as a secondary concern for loading balance. In this case, the satellite plant holder must send the new loader a copy of the documentation listed in section four, provided the loading plant in question does not belong to the same business group as the original loader.

The shipper must have booked capacity at the loading plant assigned to the corresponding satellite plant.

The shippers that load truck cisterns at a regasification terminal must have a contract with the transmission company who owns the said regasification terminal.

If a truck cistern is programmed for a satellite distribution plant and one of the shipper does not have a contract with the loading plant, both the shipper and the transmission company in question will notify the shipper without a contract of this situation as soon as they become aware of it.

The shipper must request and formalise a truck loading contract with the transmission company as soon as they receive this notification. Both the technical manager of the system and the transmission company that owns the regasification terminal will make the necessary arrangements to formalise the said contract before the truck is loaded.

In any event, if the situation has not been resolved before weekly programming, the planned shared truck loading orders for the entire week will be generated automatically. The loading of a truck cistern for a satellite distribution plant cannot be considered non-viable for this reason.

The transmission company that owns the facility will not include any quantity in the truck cistern for a shipper or shippers without contracts, and the quantities withdrawn on behalf of clients they supply will be imputed to the

BRS account managed by the GTS. Once the contractual situation between the transmission company and shipper has been regularised, the transmission company will regularise the quantities initially loaded to the BRS account to the shipper in question, taking as a base the information on the allocation coefficients provided by the DSO.

These regularisations will be carried out within the same calendar month. In any event, the shipper with no contract will be considered to have entered a position of imbalance, and will be subject to the corresponding imbalance penalties.

4. Documentation to be presented before first loading

Before the first delivery of LNG to a new satellite plant, and at least one week before the first loading, the holder of the same should deliver the following documentation to the loader via the shipper/DSO:

1. Plant address.

2. Dispatcher- name, address, contact person, telephone numbers, NIF (tax number).

3. Contact person- name and telephone number.

4. Truck cistern transmission company.

5. Plant ownership with NIF (tax number).

6. Estimated annual consumption.

7. Use of gas for tax purposes, as established in Law 15/2012 of 27 December on tax measures for sustainable energy.

8. For shippers, in compliance with Royal Decree 919/2006, the final certificate for the work and tests performed. Once the arrangements are complete for the holder of the LNG plant regarding the relevant authoritative body of the Autonomous Community, and in compliance with the provisions of PD-12, section 4, the holder, through the company that supplies them, must provide the loader with the Start-up Authorisation.

9. For DSO's, a document accrediting the operational launch of the facility and allocation criteria between the shippers that use the satellite plant.

10. Accreditation that the new addition is a vehicular LNG station, tax warehouse or any other special use directly employing LNG.

11. Accreditation of compliance with the conditions established in Article 5 of Order IET/2446/2013, for contracting capacity for truck loading.

5. Truck cistern transport

5.1 Transport costs at satellite distribution plants.

Before a shipper can access a satellite distribution plant, they must sign a service provision agreement with the distribution company that owns the plant establishing the transmission costs to be assumed by the shipper.

The service agreement model, as well as the costs by satellite plant, will be published on the DSO's website and will be governed by the principles of transparency, objectivity and non-discrimination. The agreement model will be shared across all parts of the country and will include, at the very least, the procedure for dividing the transport costs between each of the shippers.

This model should be prepared by the National Markets and Competition Commission; after submitting this for consultation, it should be presented to the Directorate General of Energy Policy and Mines for its approval or modification within six months of when the present protocol takes effect. Shippers and DSOs will have thirty days, beginning with the approval of the contract, to modify current contracts to the model approved by the Directorate General of Energy Policy and Mines.

5.2 Documentation to perform the loading operation.

Loading companies must require transmission companies to provide the necessary documentation to prove that vehicles, tanks and drivers are in compliance with current regulations on the movement of dangerous goods by road, and keep all permissions and authorisations up to date. This documentation must be up to date before loading is performed.

Likewise, the loader will produce the documentation required by regulation for each load; this will indicate, among other information, the departure time from the loading dock.

The transmission company must have an order to be able to load at regasification plants, as outlined in section 2.6.6 of the System Technical Management Rule NGTS-02.

6. Procedure for the programming, nomination and re-nomination of truck cisterns

Programming, nominations and renominations must comply with the provisions established in the System Technical Management Rules and their Detail Protocols.

Programming must include the following common parameters, to be listed for all exchanges:

- Date issued.
- Identification of the user that is carrying out the programming or nomination.
- Identification of the subject to whom it is directed (loader).
- Identification of the trucking company.
- Programming type.
- Installations at which it applies (satellite plants).
- Amount of gas programmed.
- If the truck cistern is destined for more than one satellite plant, percentage of distribution en route.
- Commercial assignment.

Programming and nominations are produced for entire truck cisterns. For single-client satellite plants, this will be done by shipper or direct market consumer; for distribution satellite plants, this will be done by DSO group, allocating the energy as per System Technical Management Rule NGTS-06 'Allocation' and Detail Protocol PD-02 'Allocation procedure at transmission-distribution connection points (PCTD)'.

The SL-ATR will have a pre-defined commercial allocation for each satellite plant. This will be displayed by default when creating the weekly programming, and may be modified into a new version during the programming process.

All information added for the programming may be viewed in the SL-ATR by the creating party, and with the same breakdown.

6.1 Yearly and monthly programming.

The content and calendar of yearly and monthly programming shall be that established in Detail Protocols PD-07 and PD-08.

6.2 Weekly programming, nomination and renomination.

6.2.1 Information flow for single-client satellite plants.

Once the programming has been agreed upon with the truck cistern transmission companies, the shippers or direct market consumers will enter the said schedule into the SL-ATR within the deadlines established in this protocol. The loader will assess the various schedules and provide notification of viability or non-viability.

On day n-1 or the same gas day, the shippers or direct market consumers will, if necessary, nominate truck cisterns for day n. The loader will assess the various nominations and use the SL-ATR to assign an Order number to each truck cistern/destination it considers viable. If the programming/nomination is not viable in its entirety, the shipper must indicate to which clients it will assign the Order as a proportion of all loads requested.

Once the orders have been received, the SL-ATR will automatically send these via email to a distribution list set by each user at a destination level, including the truck cistern transmission company, in order to be able to carry out the loading.

Each loader and plant at which the load for the destination has been requested will have a load management system that allows the issued order to be validated and accepted, loads to be ordered over the course of the day and the driver's presence to be validated for the party requiring the goods.

The transmission company, to be able to load, must present the documentation listed in section 5.2 of this protocol.

6.2.2 Information flow for satellite distribution plants.

The DSO, once the shipper programming has been assessed, will enter the said schedule into the SL-ATR by the deadlines established in this protocol, and will notify the truck transmission company of the same. The loader will assess the various schedules and provide notification of the viability or non-viability of the schedule.

On day n-1, the DSO's will nominate the truck cisterns for day n before the exit nominations from satellite plants owned by shippers that modify the initial programming or according to their own findings regarding the need to modify the said schedules to maintain continuity of supply.

The loader will assess the various shipper schedules/nominations, and use the SL-ATR to assign an order number to each truck cistern/destination they deem viable.

For weekly programming, the orders for the truck loadings forecast for the entire week will be generated automatically, provided that the programmed truck cisterns are deemed viable.

If an order in the weekly programming must be expanded, the shipper will still prepare the nomination or renomination using an automatically assigned Order Number.

Once the orders have been received, during the nomination/renomination period, the SL-ATR will automatically send these via email to a distribution list set by each user at the satellite plant level.

Each Loader and plant at which the load for the destination has been requested will have a load management system that allows the issued Order to be validated and accepted, loads to be ordered over the course of the day and the driver's presence to be validated for the party requiring the goods.

To be able to load, the truck transmission company must present the documentation listed in section 5.2 of this protocol.

Orders may be viewed for a given amount of time and extracted in Excel format.

6.2.3 Weekly programming.

The content and calendar of weekly programming shall be that established in Detail Protocols PD-07 and PD-08, and will include:

- Number of trucks to be loaded by day and regasification plant.
- The kWh/day-regasification plant.
- The destination that corresponds (satellite plant) to their commercial assignment.
- Priority.
- Commercial assignment for each shipper, for each of the truck cisterns.
- Percentage allocation by satellite plant for multi-destination unloadings.

The transmission company operator deadline for confirming programming is set at 12:00 on Friday, at which time the order codes for the week are generated.

All data entered into the SL-ATR can be consulted in the system with the existing breakdown.

The SL-ATR will have a pre-defined commercial allocation for each satellite plant. This will be displayed by default when creating the weekly programming, and may be modified for a new version during the programming process.

Weekly programming can be consulted by day, period, or weekly programming for the current period, including all loading plants. The said consultation can be extracted in Excel format.

6.2.4 Nomination and re-nomination.

Nominations are made on day n-1.

If no nominations exist, the programmed quantity and destinations confirmed as valid in the weekly programming will be taken as nominations.

The shipper deadline for submitting nominations to the transportation operator is set at 12:00.

The transportation operator deadline for confirming these nominations is set for 14:00, at which time the order codes for day n are generated.

In terms of single-client satellite plants, if a nomination would make a shipper or direct market consumer exceed their total booked capacity, the holder of the relevant plant will still fill it if there is available capacity, according to the order of priorities set out by the shipper or direct market consumer.

All data entered into the SL-ATR can be consulted in the system at the existing level of detail.

Adjustments to nominations for contractual reasons may be entered into the SL-ATR once the re-nomination period for day n-1 opens.

The shipper deadline for submitting re-nominations for day n-1 to the transportation operator is set at 17:00.

The transportation operator deadline for confirming these re-nominations is set for 18:00, at which time the order codes for day n are generated.

If several shippers and/or direct market consumers submit nominations in excess of their contracted amounts at a loading plant and the total number of truck cisterns/day for all the nominations exceeds the plant's loading capacity, the loaders will assign the number of truck cisterns and the allocation of the same in proportion to the capacity contracted by each shipper and/or direct market consumer.

For operational demand reasons, either the shipper, direct market consumer or DSO, depending on if the location in question is a single client or distribution satellite plant, can request - by the established deadline - a re-nomination sent to day n referred to the same day n. Each loader will evaluate the viability of the modifications to the nominated loads requested for day n using the SL-ATR and following an analysis of the said request.

Given the existence of this re-nomination period, even shipper and direct market consumer nominations deemed viable on day n-1 despite exceeding the contracted number of truck cisterns may be later deemed non-viable if, during the re-nomination period, the loading capacity of the plant is exceeded.

The shipper deadline for submitting re-nominations for day n to the transportation operator is set at 10:00.

The transmission operator deadline for confirming these re-nominations is set for 11:00, at which time the order codes for the said day are generated. If the re-nomination involves changing the destinations of viable requests, these are automatically considered viable.

At the moment of the nomination or re-nomination, the SL-ATR will show the commercial assignment entered in the weekly programming or nomination for each satellite plant, which may at that time be changed to another one.

Weekly programming nominations can be consulted by day, period, and/or weekly programming for the current period, including all loading plants. The said consultation can be extracted in Excel format.

6.2.5 Cancelling orders.

For operational or demand reasons, either the loader, direct market consumer or shipper, depending on if the location in question is a single-client or distribution satellite plant, can cancel - by the established deadline - an order related to weekly programming, nomination or re-nomination that has already been sent to the SL-ATR.

The SL-ATR will automatically send an email notification of the order cancellation to a distribution list set by each user at the satellite plant level.

7. Allocation procedure.

The real quantity loaded, both for single-client locations and satellite plants, will be wholly allocated using the allocation criteria established in the order used to perform the loading. This quantity will become part of the commercial balance of each shipper at each plant.

For satellite distribution plants, each shipper will be assigned a provisional allocation indicated by the dispatcher when the load is assigned.

The SL-ATR will facilitate the exchange of a pre-defined commercial assignment, showing by default the one in existence when weekly programming was completed.

To submit adjustments, the DSO's will send the loader the following information:

- Month of adjustment.
- Destination satellite plant.
- Shipper.
- Quantity.

The quantity to be sent must be the definitive allocation for the satellite plant and shipper. The adjustments for each shipper shall be calculated based on these quantities and the provisional allocations made at the time of loading. The said adjustments must meet the following conditions:

- The algebraic sum of the adjustments should be zero.
- No adjustment may lead to a net negative emission from a shipper's truck cisterns.

If this were to occur, the said adjustment would be rejected, and the dispatcher would be notified in order to correct it.

8. Invoicing.

In terms of invoicing for truck loading services, the following sums will be used:

- For single-client destinations, the loaded amount will be divided proportionally among the capacities contracted in all the contracts current on the said day, unless the request indicates a specific contract to which to impute the said truck cistern.
- For satellite distribution plants, the quantity to be distributed will be allocated according to the percentages indicated in the nomination made by the DSO or the default loads at the destinations. These quantities will be assigned to the contract indicated by the shipper, or to the one with the longest term unless otherwise indicated.

9. Communication procedure for maintenance and incidents.

The annual maintenance programme must include the maintenance operations programmed for truck cistern loading docks, meeting all the requirements established in section 8.2 of the Technical Management System Standard NGTS-08 'Maintenance plan'.

If corrective maintenance occurs (situations of force majeure), the loader will immediately provide notification of the incident. The following situations may apply:

1. The corrective maintenance will only affect plant capacity: In these cases, the new loading capacity of the plant will be allocated according to the capacity contracted by each user.

2. The corrective maintenance poses a risk to guaranteed supply: In this case, the supply priorities established in section 10.8.1 of the System Technical Management Rules NGTS-10 'System operation in exceptional situations' will be followed.

If the truck cistern loading dock will be unavailable, reducing the plant’s nominal capacity, viability will be given according to the capacity contracted by shipper, and taking into account the priority ranking of the truck cisterns.

In the case of sudden unavailability outside the viability response periods for day D, the shippers and DSO’s will do their best to supply the truck cisterns for which they are responsible, diverting trucks to other loading plants. Regarding the following days, and if made necessary by unavailability, the GTS will provide the necessary operating instructions to plant holders to temporarily reorganise the loading process, coordinating between available capacities, to ensure supply to protected clients.

In any case, shippers affected by the diversion of truck cisterns will adjust their balancing at the affected loading plants based on the information provided by the agents themselves.

10. Claims management.

Users may present claims against any part of the process, from contracting to the corresponding invoicing and payment.

All pertinent information will be submitted through the SL-ATR so that the presented claims can be adequately monitored.

The claim will be sent to the SL-ATR, and will contain the item that the user wishes to amend and the reason for the request, attaching all relevant information permitting the said request to be assessed and supported.

11. Available information

Truck loading information available via the SL-ATR shall be as follows:

- Date.
- Loading plant.
- Loading time.
- Shipper or direct market consumer/DSO.
- Delivery slip number.
- Truck cistern destination (in cases of multiple unloading destinations, this will include all destinations and their respective percentage allocations).
- LNG trucking company.
- kg Assigned to the load.
- Energy (kWh) assigned to the load.
- Assigned energy (kWh per shipper or direct market consumer).
- PCS (kWh/kg).
- Status: provisional or definitive.

This information shall be in the system during the periods established in the System Technical Management Rules (NGTS) and their Detail Protocols.

At the same time, the SL-ATR will publicise an inventory of satellite distribution plants.

PD-13

'Assignment of unloading dates to tankers at regasification plants'

Amended under Resolution of 29 March 2012 of the Directorate General of Energy Policy and Mines, modifying Detail Protocol PD-13.
'Assignment of unloading dates to tankers at regasification plants', and amending the System Technical Management Rule NGTS-03 'Programming' and Detail Protocol PD-07 'Programming and nominations at transmission infrastructure facilities'. Published in the B.O.E. on 24 April 2012.

Validity: 25 April 2012

1. Purpose

The present Detail Protocol outlines the process of assigning unloading dates to ships programmed by users at System regasification plants.

2. Scope of application

This protocol is applicable to all users that use the methane tanker unloading installations at System regasification plants, to the holders of the said plants and the Technical Manager of the System (GTS).

3. Definitions

3.1 Types of vessels.

For the purposes of this protocol, to assign unloading dates to vessels in yearly programming, they will be classified as follows according to their capacity:

Classification	Volume (m^3 LNG)	Energy to be unloaded by each vessel programmed (GWh)
XXL (extra-large)	V > 216,000	1,660
XL (large)	150,000 < V ≤ 16,000	1,500
L (large)	75,000 < V ≤ 150,000	900
M (medium)	40,000 < V ≤ 75,000	485
S (small)	V ≤ 40,000	220

3.2 Demand segment.

The demand segment refers to the classification of the total demand to be met by users of the regasification plants which are supplied by these installations, to establish the order of priority for the assignment of tanker unloading dates in the yearly programming. The said demand is classified into two groups: Segment 1 and Segment 2.

In any event, the forecast total demand for all users for the programmed year n shall not be greater than a reasonable margin of deviation from the system demand forecast by the GTS for the same year, in accordance with the provisions established in Detail Protocol PD-08 'Programming and Nomination for Consumption in Distribution Networks'. If the forecast user demand is greater than the established limit, it will be adjusted using the procedure set out in the said protocol.

3.2.1 Demand segment 1.

A user's Segment 1 (T1) for the programmed year n is calculated using the following equation:

$T1 = DC + DE + \Delta DC + \Delta DE + I + SGOT + STUR - E + S + A$

Where:

- DC: Real conventional demand from the previous rolling year (defined as the twelve months before the deadline month for submitting yearly programming to plant holders) prepared with monthly balancing data. Closed balancing will be used whenever available; if not available, the best available provisional balancing will be used. Demand met by gas from auctions included in the STUR and SGOT terms will not be included.

- DE: Electrical demand corresponding to combined cycle power plants (CTCC). To calculate this, an average yearly system usage factor will be taken for the system in the programmed year n (FCn), which will be applied to each user according to their load factor in the previous rolling year according to the following formula:

$$FC_i = FCi_{rolling} * \frac{FC_n}{FC_{movil}}$$

Where:

- FCi_n: the load factor of user 'i' forecast for year n.
- $FCi_{rolling}$: load factor for user 'i' in the previous rolling year. To calculate this load factor, any CTCC in the testing phase during the previous rolling year are not considered.
- FC_n: average system load factor forecast for year 'n'.
- $FC_{rolling}$: average system load factor in the previous rolling year.

The GTS will establish and publish on its website the methodology used to calculate FC_n, $FC_{rolling}$ and $FCi_{rolling}$. The GTS will also apply the said methodology to calculate the values for FC_n and $FC_{rolling}$, publishing these on its website.

It will also calculate the FCi_n value in accordance with the published formula and inform each user of the value that pertains to them.

- ΔDC: New conventional demand demonstrated by newly contracted individual clients with annual consumption of over 50 GWh/year for year n. This demand will be discounted if the client was supplied by another shipper in the previous year, as declared by them. Both users will provide appropriate notification to the infrastructure facility holders and the GTS, providing a Client Agreement Letter to the change of shipper. If there is no such document, this consumption will be considered part of Segment 2.

- ΔDE: New electrical demand from combined cycle plants in operation during year n. This demand will be discounted if the plant was supplied by another shipper in the previous year, as declared by the same. Both users will provide appropriate notification to the infrastructure facility holders and the GTS, providing a Client Agreement Letter to the change of shipper, when appropriate. If there is no such document, this consumption will be considered part of Segment 2.

To calculate this new electrical demand, the measures established for the calculation of DE will be used. For those users that did not have consumption corresponding to a combined cycle plant in the previous rolling year, the average system load factor will be used.

For new plants that entered operation in year n, if there is no objective information certified by a third party, the installed power data and programmed start date published by the National Energy Commission in its reports on electricity demand and coverage will be used to calculate the associated demand.

- I: Amount of closed wholesale operations with other System users for year n, defined as sales made by the user for which demand minus purchases are calculated. If a user (Shipper 1) is the one to whom demand is imputed (conventional or electrical) and a different user (Shipper 2) is the one who unloads the LNG at the regasification plant, both will provide appropriate notification to the infrastructure facility holders and the GTS about whether Shipper 1 or 2 should be assigned the unloading date for the demand of Shipper 1, according to the commercial agreement reached between the two.

- SGOT: Gas destined for the operating and minimum fill level of transmission, storage and regasification facilities, to be provided in the programmed year n. This quantity will only be taken into account for those cases where the delivery takes place within the Spanish gas system.

- E: Flows into the system at international connections and underground gas fields assigned to the user in the programmed year n.

- S: Flows out of the system at international connections and regasification plants assigned to the user in the programmed year n.

- STUR: Gas auctioned off for supply at the last-resort rate to be supplied in the programmed year n. This will only be imputed to the successful bidder and will be taken into account only for the period covered by the bid.
- A: Sum total of required maintenance for strategic and operating stock valid for the programmedprogrammed year n (calculated as final stock minus initial stock).

3.2.2 Demand Segment 2.

A user's Demand Segment 2 for the programmed year n will include growth in demand, exports and gas stored in year n, as well as wholesale operations not previously considered when determining Demand Segment 1.

3.2.3 Demand allocation procedure

The Technical Manager of the System will, before 15 September of each year, publish the overall demand profile for the following year, with its minimum, average and maximum scenarios. This will be calculated according to Detail Protocol PD-03 'Demand forecasting', and broken down by clients supplied at pressures below 4 bar and above 4 bar.

Once programming has been received, the process will continue as follows:

1. An admission profile for conventional demand will be established so that:

a. If the yearly aggregate programming profile for all users from year Y+1 (to be programmed) in the conventional market is between the average yearly demand programmed by the GTS +/- 2%, the sent programmings will be taken with no adjustments.

b. If one or more of the months of this aggregated yearly programming is not in line with the average monthly demand published by the GTS (with a margin of +/- 2%), the excess or shortfall of the programming must be distributed between the users for each of the months in question.

2. An admission profile for electricity sector demand will be established so that:

a. If the yearly aggregate programming profile for all users from year Y+1 (to be programmed) in the electricity market is within the range of the average yearly demand programmed by the GTS +/- 7.5%, the sent programmings will be taken with no adjustments.

b. If one of the months of this aggregated yearly programming is not in line with the average monthly demand published by the GTS (with a margin of +/- 7.5%), the excess or shortfall of the programming must be distributed between the users for each of the months in question.

3. To distribute the excess or shortfall, the GTS must assess each user's programming: a. The growth or diminution of each user in the current year will be evaluated. b. A meeting will be held to clarify the programming with the users that fall outside the growth or diminution trends theoretically expected.

4. Excess or shortfall will be distributed for each of the months of the programmed year, respecting the demand programmed by users for industrial clients and adjusting domestic market demand (proportionally to clients supplied at pressures below 4 bar), to make it fit the total demand published by the GTS.

5. Based on the demand assigned to each user, the GTS will establish the annual schedule for each.

4. Assignment of tanker unloading dates in annual regasification plant programming

4.1 Conditioning factors.

Users will create the most uniform possible distribution of unloading programmed for each month.

When assigning unloading dates in the Annual Programming, regasification plant holders and the GTS will take the following conditions into account:

a) The total yearly/monthly quantity to be unloaded at a plant for all users cannot be above the sum of the maximum yearly/monthly emission and truck loading capacities and a reasonable estimate of tanker loading. These capacities will be calculated according to Detail Protocol PD-09 'Calculation of Admissible Ranges for Basic Control Variable Values within Normal System Operating Ranges'.

b) The maximum yearly/monthly amount to be unloaded by a user at a regasification plant cannot be above the yearly/monthly capacity contracted at that plant by the said user, corrected by the wholesale operations conducted at the plant.

c) The total yearly quantity programmed to be unloaded by each user across all System plants must be equal to or less than Segment 1 and Segment 2 of their demand for the programmed year.

d) The maximum monthly quantity to be unloaded by a user (QM) across all regasification plants must fit the following equation:

$QM \leq D_i - E_i + S_i + A_i + I_i + F_i$

Where:

- D_i: Demand of user 'i' for month M of the programmed year, which will include conventional and electrical demand, demand from auctions for supply at the last-resort rate, and the acquisition of working and cushion gas (in cases where the delivery of this gas takes place within the Spanish gas system).
- E_i: Gas flowing into the system assigned to user 'i' from international connections and gas fields during month 'M' of the programmed year.
- S_i: Gas flowing out of the system assigned to user 'i' through international connections and regasification plants during month M of the programmed year.
- A_i: Net underground storage facility gas, defined as injection minus withdrawal, assigned to user 'i' during month M of the programmed year.
- I_i: Sum of all closed wholesale operations with other System users, defined as sales minus purchases, carried out by user 'i' during month M of the programmed year.
- F_i: Logistical flexibility assigned to user 'i' for all system plants. This parameter, which should be nearly 0 for the entire rolling year, is defined for each month as the greater of the two following quantities: 3 days of the daily regasification capacity

contracted across all plants for the month in question, or 450 GWh.

To define A_i, the following conditioning factors are taken into account:

1. If the storage capacity booked by the user for the programmed year n is unknown, the capacity for year n-1 will be used.

2. The final stock calculated at the end of each month will be used as the starting point for the next.

3. For each user, the following limitations on the monthly withdrawal (Lext) and injection (Liny) capacity will be taken into account, using the following formulae:

Lext = CTE x 0.8 x n.º days/month x % Operating volume assigned to user.

Liny = CTI x 0.8 x n.º days/month x % Operating volume assigned to user.

Where:

- CTE: Daily technical withdrawal capacity published by the GTS.
- CTI: Daily technical injection capacity published by the GTS.
- % Operating volume assigned to the user:

$$\frac{(\textit{Total storage capacity} - \textit{Strategic storage capacity})\ \textit{for user}}{(\textit{Total storage capacity} - \textit{Strategic storage capacity})\ \textit{in total}}$$

e) The maximum number of unloading dates admissible at a regasification plant for a particular month will be a function of the capacities of the said plant.

4.2 Process of assigning unloading dates in the Yearly Programming.

The GTS will determine and publish the demand for programmed year n that corresponds to Segment 1 and Segment 2 for the system as a whole. Similarly, it will calculate the demand for programmed year n that corresponds to Segment 1 and Segment 2 for each user, taking into account the information in yearly user demand programming and the provisions of sections 3 and 4.1 of this protocol, and will notify the users and affected plant holders of the same.

With the information provided by the GTS and the user programming, regasification plant holders will proceed to assign tanker unloading dates at their facilities, taking into account the conditioning factors set out in section 4.1, and in accordance with the procedure described below.

Firstly, all users will be assigned unloading dates for tankers associated with Demand Segment 1 for year n. The requested unloading dates may be moved by one day (either forward or backward) in order to reduce clashes between requested dates, provided the affected parties are consulted in advance. Once the process has been finalised, each user will be given the information about their provisional assignment, and the unloading schedule for each plant will be published.

Starting on the day when the schedule is published, the users will have seven calendar days to propose modifications to clashing unloading dates programmed for the assigned tankers through bilateral agreements between users, which they will communicate to the regasification plant holder and the GTS.

Once this period is over, if there are still two or more tankers programmed to unload on the same date or at the same plant and the users have not reached an agreement, (an) unloading date(s) will be booked on the date(s) immediately before or after the date initially requested for the clashing tankers. The tanker(s) that must be given a new date will be placed on the said date(s) until the date when the monthly programming is submitted including the clashing date within month M-3. If at this time, the clash still persists, the procedure outlined in section 7 will take effect.

Once unloading dates have been assigned for all tankers associated with Segment 1 (and taking into account reservations for clashing unloading dates), unloading dates will be assigned for tankers associated with Segment 2. If the unloading date for a Segment 2 tanker clashes with that assigned to a Segment 1 tanker, the date of the Segment 2 tanker will be modified to the closest one possible. If there are two or more Segment 2 tankers with clashing unloading dates, (an) unloading date(s) will be booked on the date(s) immediately before or after the date initially requested for the clashing tankers. The tanker(s) that must be given a new date will be placed on the said date(s) until the date when monthly programming is submitted that includes the clashing date within month M-3. If at this time, the clash still persists, the procedure outlined in section 7 will take effect.

Once the above has been performed, Yearly Programming for vessel unloading will be available with tentative unloading dates. Regasification plant holders will send their viability responses to the users of the plants and the GTS. Once the information has been received from the plant holders, the GTS will assess the programming and its impact on the system as a whole, producing a viability response and publishing the definitive Yearly Programming.

The tentative unloading dates and established chronological order will be used as a reference to assign unloading dates programmed in the Monthly Programming, taking into account that the user must comply with the NGTS, in particular with the LNG plant stock restrictions in force.

4.3 Updating the Yearly Programming.

With 15 January and 15 July as deadlines, the users that unload tankers at system regasification plants can send revisions of the Yearly Schedule that affect the rest of the current year.

Once all user revisions modifying users' yearly programming have been received, the initial Yearly Schedule made by assigning tentative unloading dates will be updated.

If, as a result of this update, clashes arise between unloading dates, priority will be given to those tankers assigned to Segment 1 whose programmed unloading dates have not been modified in the semi-annual revision of the Yearly Schedule. If the clash is the result of the revision of tentative unloading dates by all users, and both tankers are assigned to either Segment 1 or Segment 2 (Segment 1 tankers still have unloading priority over Segment 2 tankers), an information and resolution process for date clashes similar to that used in the preparation of the initial Yearly Schedule will begin.

Separately from the above, users can suggest periodic updates to their Schedule. These will be published as long as they do not cause significant modifications to the overall yearly schedule or have a negative impact on the dates programmed for third parties.

5. Assignment of tanker unloading dates in quarterly programming

Users will send the Monthly Programming corresponding to the three following months with the details indicated in PD-07 'Programming and nominations at transmission infrastructure facilities' by the dates established in the same protocol.

For the viability analysis of the Monthly Schedule, the following reference information will be used:

1. The binding Monthly Schedule carried out in the previous month.

2. The unloading dates established in the Yearly Schedule, for the analysis of the periods where there are not binding unloading dates assigned on the basis of the previous Monthly Schedule.

5.1 First month of the quarter.

The last binding tanker unloading schedule included in the previous Monthly Schedule will be respected, maintaining the assigned unloading dates whenever the expected maximum levels at the plant allow the said unloading to take place. If this is not the case, the first date after the assigned one that is compatible with the physical viability of each plant will be assigned.

Next, for dates that have not yet been assigned in the binding programming of each plant, the unloading dates requested by users for month M-1 in the new Monthly Schedule will be assessed, examining their compliance with the following criteria and in the order in which they are listed, for the prioritisation of unloading:

1. The user should not exceed the average maximum permitted LNG stock across all regasification plants for each period of the year.

2. The user should not exceed 5 days of LNG stock storage in tanks across all regasification plants.

3. The user should not exceed 5 days of LNG stock storage in tanks at each regasification plant.

4. If the above conditions are not met and subsequent unloadings are affected, the programmed unloading date assigned will be the first available date that complies with the limitations on the LNG stock levels at the plant where they are applicable: In cases where dates clash, the unloading priority established in the last available binding programming will be respected.

Next, the viability of transmission will be assessed, in accordance with Detail Protocol PD-09 'Calculation of Admissible Ranges for Basic Control Variable Values within Normal System Operating Ranges', and taking into account the minimum and maximum flows into the system through each connection.

Once any possible need for a diversion has been considered, as per current regulations, the GTS will inform the plant holders about compliance with the unloading prioritisation criteria for each user in order to assign unloading dates for the first month. These will be binding, as per NGTS-03 'Programming' and PD-07 'Programming and nominations at transmission infrastructure facilities', once the GTS has given its viability response.

5.2 Second and third months of the quarter.

Once the unloading schedule for the first month has been established, unloading dates for the second and third months will be assigned, which will be binding, as per NGTS-03 'Programming' and PD-07 'Programming and nominations at transmission infrastructure facilities'

The assignment criteria will be those used in section 5.1.

6. Assignment of tanker unloading dates in intra-month management

To assign tanker unloading dates in response to requests for the modification of binding programming, the same criteria established in section 5.1 will be used, whether they be requests for a change in unloading dates or requests for new unloading dates, following the user’s justification of the need for the said modifications. The requested modifications will be conditional on not affecting third-party unloadings, and should be deemed viable by the regasification plant holder and GTS.

7. Priority rules on unloading requests from tankers with overlapping dates

To assign unloading priority, if there are two or more vessels programmed for the same date at the same plant and the users have not reached an agreement about the modification of the said schedule, the procedure outlined below will be followed.

The GTS will keep an alphabetical list of all users. This list will be re-ordered every year using a draw system that will establish the letter from which the unloading priority order will start, so that the top spots on the list will be occupied by those users whose company name begins with the letter drawn that year, with the rest of the users following in alphabetical order.

If two dates clash, unloading priority will be given to the user that is higher on the list; once assigned, this user will pass to last place. This will be repeated as needed.

PD-14

'Criteria for establishing the degree of saturation of regulation and metering stations and metering stations and procedure for carrying out proposed actions'

Approved by the Resolution of 30 April 2012 of the Directorate General of Energy Policy and Mines, which published Detail Protocol PD-14
'Criteria for establishing the degree of saturation of regulation and metering stations and metering stations and procedure for carrying out proposed actions' and amended Detail Protocol PD-10 'Calculation of facility capacity'. Published in the B.O.E on 28 May 2012.

Validity: 29 May 2012

1. Purpose

This Detail Protocol aims to set the criteria for determining if a transmission system Regulation and Metering Station (RMS) / Metering Station (MS) is saturated in its regulation or metering capacity. It also aims to establish the procedure for suggesting actions for the technical adjustment of the same.

2. RMS/MS Capacity

The capacity should be calculated in accordance with Detail Protocol PD-10 of the System Technical Management Rules (NGTS).

3. Establishment of RMS/MS saturation criteria.

3.1 Evaluation period

As a general rule, the period during which the saturation of RMS/MS should be evaluated is the winter period; as such, it extends from 1 November of the previous year to 31 March of the current year, both inclusive, equivalent to 3,624 sampling hours (3,648 in a leap year).

In cases where peak demand is forecast to occur in a different period of the year, this period will be given special study.

3.2 Types of hourly flow for determining degree of saturation.

Hourly flows are classified as:

- Maximum hourly flow (Q_{max}): maximum value of the average hourly flows observed at the RMS/MS during the evaluation period.
- 80-hour flow ($Q_{80\ hours}$): minimum value of the average hourly flows recorded during the 80 hours of highest consumption during the evaluation period, expressed as a percentage of the maximum capacity. (The
80 hours correspond to the working hours of the working days of a week: 16 working hours/day*5 days/week*1 week = 80 hours).
- 160-hour flow ($Q_{160\ hours}$): minimum value of the average hourly flows recorded during the 160 hours of highest consumption during the evaluation period, expressed as a percentage of the maximum capacity. 160 hours correspond to the working hours of the working days of two weeks: 16 working hours/day*5 days/week*2 weeks = 160 hours).
- Average flow (Q_{av}): average of the average hourly flows observed at the RMS/MS during the evaluation period.

3.3 Determination of the degree of saturation

The following degrees of saturation are used for RMS/MS:

- Grade 3 (G3-Alert).
- Grade 2 (G2-Caution).
- Grade 1 (G1-Monitor).

The said degrees of saturation for RMS/MS are defined on the basis of the hourly flows calculated above, in such a way that an RMS/MS will fall into one of the degree categories (grades) when the conditions established in the following table are met:

Degree of saturation	Conditions		
	Q_{max} > Nominal capacity	$Q_{80\ hours}$ > 90% Nominal capacity	$Q_{160\ hours}$ > 85% Nominal capacity
G3 Alert	√	√	√
	√	√	
G2 Caution	√		√
		√	√
G1 Monitor		√	
			√

4. Establishment of actions to be taken.

4.1 Actions to be taken if an RMS/MS is saturated

The actions to be taken, if possible, are:

- Re-rigging of lines.
- Meter replacement.
- Expansion/replacement of regulators.
- Expansion with an additional line.
- Installation of a new RMS/MS.

When installing a new RMS/MS, some of the following may be taken into consideration:

- Replace the old RMS/MS with a new one in the same location.
- Build a new RMS/MS in a location adjoining the old one.
- Build a new RMS/MS that can serve as an alternative supply point to the connected network.

4.2 Assessment of present RMS/MS saturation status

Each transmission company will prepare, once a year and using the criteria established in this protocol, a study of the current saturation status of their RMS/MS, indicating the degree of saturation.

4.3 Assessment of future RMS/MS saturation status

For all connections with existing networks, the transmission company that owns the facility will ask the interconnected holder (transmission company or shipper) for a growth forecast for the network located downstream of the station for the two following years.

Before 15 June each year, the DSO's and transmission companies will send the demand forecasts for their networks. All holders on the connected chain of facilities will send the information to the holder of the upstream RMS/MS.

These forecasts must include average and peak hourly demand predicted for the following two winter periods, together with their justification, which will distinguish between the demand already contracted for the said periods and the demand expected to be contracted.

Likewise, the shipper may supply any additional information about the networks that they deem appropriate.

The transmission company, with the information received from the other interconnected holder about the maximum and average demand levels, will determine the future forecast degree of saturation for RMS/MS on a yearly basis.

At RMS/MS located at connections between transmission companies, any changes in forecast capacity described in the Mandatory Planning will be taken into consideration.

4.4 RMS/MS adjustment proposal report

Before 30 July of each year, and in line with the previous sections, each transmission company will send an RMS/MS adjustment proposal report to the Technical Manager of the System (GTS). At minimum, this will include:

- Current saturation status of the RMS/MS, including Q_{max}, $Q_{80\ hours}$ and $Q_{160\ hours}$.
- Information about current demand, including average and peak hourly demand during the previous winter period, and the forecast increases for the next two winter periods in the networks connected to the RMS/MS at which the adjustments may be required.

- Predicted saturation status of the RMS/MS for the next two years, including Q_{max}, $Q_{80\ hours}$ and $Q_{160\ hours}$, and distinguishing between contracted demand and that predicted to be contracted.
- Proposed activities to be performed, with an economic assessment (modifications, expansions, new facilities).

The said RMS/MS adjustment proposal report will include completed versions of tables 1.1, 1.2 and 1.3 found in the Appendix. When necessary, the GTS will update the format of the said tables, and will send them to transmission companies and DSO’s sufficiently in advance for them to be properly completed.

As a general rule, proposed actions to be taken at an RMS/MS whose forecast saturation status in one of the two coming years is GRADE 3 will always be included. In addition, proposals for RMS/MS that, for two consecutive years, have been included in the annual report with a forecast saturation status of Grade 2 will also be included. Proposals for RMS/MS that, for three consecutive years, have been included in the annual report with a forecast saturation status of Grade 1 will also be included.

Likewise, as a general principle, of the possible actions to be taken on an existing RMS/MS that is saturated, the most economical option will always be proposed wherever it is technically possible, save where vulnerability issues with the connected distribution network make an alternative supply point advisable.

The actions proposed must be sufficient to meet the forecast increase in demand on the said network for the next five years.

The GTS may request, if it deems necessary, additional information from the transmission company or shipper and, in turn, the transmission company/shipper may provide any additional information they deem appropriate, sending it confidentially and directly to the GTS.

Using all the data received from the transmission companies, the GTS will prepare a final report, which will include both the technical adjustment proposals and their economic estimates as well as an evaluation of their ideal nature. The said report will be sent to the Secretariat of Energy of the Ministry of Industry, Energy and Tourism before 30 September each year.

APPENDIX

Action request for RMS/MSM

Position: XX

Name: XXX

Location: Pipeline XXXX

Table 1.1. Description of the proposed facility/action	Current	Proposed (year n+1)	Proposed (year n+2)	Proposed (year n+3)	Proposed (year n+4)
Installed meter type	√	√	√		
Installed regulator type	√	√	√		
No. of lines (including backup)	√	√	√		
Maximum measurement capacity (Nm³/h)	√	√	√		
Maximum regulating capacity (Nm³/h)	√	√	√		
New RMS by saturation (Yes/ No)		√	√		

▪ optional

Table 1.2. Information Contracted demand from position XX	Current	Year n+1	Year n+2	Year n+3	Year n+4
Q_{max} (Nm^3/h)	√	√	√		
Q_{80h} (Nm^3/h)	√	√	√		
Q_{160h} (Nm^3/h)	√	√	√		
Degree of saturation without expansion	√	√	√		

▪ optional

Table 1.3. Information Forecast demand from position XX (including contracted)	Year n+1	Year n+2
Q_{max} (Nm^3/h)	√	√
Q_{80h} (Nm^3/h)	√	√
Q_{160h} (Nm^3/h)	√	√
Degree of saturation without expansion	√	√

PD-16

'Exchange of operating signals between gas system facility holders, and between holders and the Technical Manager of the System'

Approved by the Resolution of 5 December 2012 of the Directorate General of Energy Policy and Mines, which established Detail Protocol PD-16 'Exchange of operating signals between gas system facility holders, and between holders and the Technical Manager of the System' (B.O.E. 17 December 2012).

Validity: 18 December 2012

1. Purpose

The aim of this protocol is to determine the operating signals that should be exchanged between Gas System facility holders, as well as the signals required by the Technical Manager of the System (GTS) for the supervision and management of the transmission network.

It also establishes the communication protocols both for the sending and reception of the said signals between the facility operator control centres and between these centres and the GTS.

2. Points on the system that should emit basic operating signals (SBO)

To guarantee the continuity of the natural gas supply and proper coordination between the interconnection points described below, those responsible for metering will provide the holder of the gas facility to which the measurement equipment is connected with the basic operating signals (SBO) listed in this protocol.

- Connection points with underground storage facilities (PCA).
- Connection points with national gas fields (PCY).
- Connection points with gas pipelines or international gas fields (PCI).
- Connection points with regasification plants (PCPR).

- Connection points with combined cycle power plants and direct lines (PCLD).
- Connection points between transmission facilities (PCTT).
- Connection points between transmission and distribution facilities (PCTD).
- Connection points between distribution facilities (PCDD).

The party responsible for the measurement, in terms of informing the GTS about the measurement, is the manager of the gas facility.

In addition, so that the GTS can carry out its supervisory and management functions, the holder of gas facilities will make the signals established in this protocol available to the GTS.

2.1 Criteria for determining if a point on the system should provide SBO.

2.1.1 Between the holders of interconnected facilities:

The holders of gas facilities responsible for measurement, or that receive SBO from another agent, should provide the holders of other gas facilities interconnected with their networks with SBO at any of the points listed in the previous section that are applicable.

However, SBO need not be provided at any points of which the following are true:

1. They currently lack remote measurement equipment.
2. They do not have the necessary infrastructure to send information to the control centre of the shipper (electrical connection, mobile phone service, etc.)

2.1.2 Between facility holders and the Technical Manager of the System:

The holders of gas facilities that are responsible for measurement, or that receive SBO from another agent, so long as that agent is not an operator of a gas system facility, should make SBO available to the GTS at all points listed in section 2, with the exception of PCDD.

For pipelines that do not belong to the trunk network of the transmission system and that have signals at the PCTT entry points to the same, the PCTD value furthest from the said entry points will be sufficient.

3. Responsibilities of facility holders

3.1 Regarding the production of SBO in the field:

The figure responsible for the measurement generating the signal will be responsible for delivering the SBO.

3.2 Regarding the transmission of the SBO between control centres: The responsibility for transmitting the information will lie with the control centre that produces the same, except for a line of communication that will be the responsibility of the control centre that contracted it.

4. Communication systems between the control centres of the facility holders, and between these and the technical manager of the system

The communication protocol for the exchange of information between facility holder control centres and between these and the GTS will be the ICCP (IEC-60870-6-503. TASE 2). The blocks to be implemented for this protocol will be 1, 2, 3 and 9.

In accordance with the ICCP protocol mentioned, the exchange of information by the mechanism of exception may be permitted, as established in section 1.4 of the same.

The frequency of information exchange will be, at maximum, the same as the frequency of reception of information from the signals at the producing control centre.

The point-to-point line of communication must be contracted by the control centre that receives the greatest number of signals (in client mode within the protocol).

Those systems of data acquisition in operation prior to the present Detail Protocol taking effect may continue to be used, given that the migration of the currently used communication protocols towards the ICCP is carried out as the operators replace their current data collection systems. Meanwhile, the existing operations will be maintained, as will agreements between interconnected operators.

5. Requirements for facility holder control centres

Facility operator control centres should meet the following requirements:

1. Be connected with one another and with the GTS through dedicated point-to-point lines and/or any other communication technology that guarantees the redundancy of the transmission of the information, such as a VPN (Virtual Private Network), with a bandwidth that guarantees the proper exchange of information (typical minimum value of 256 kbps), when the use of the ICCP protocol is available.

2. They will be supplied with the technical infrastructure and human resources necessary to guarantee 24-hour operation and to have information about the facilities under control, sending this information to interconnected control centres and the GTS. Each centre will be responsible for safety and will have the necessary measures in place to ensure the security, privacy and reliability of communications.

3. They will have a SCADA system in operation 24/7, covering all simple faults in a piece of equipment or function, so that the yearly availability will meet standard levels for this type of critical System.

6. Procedure for interconnection between control centres

The procedure to be followed for connection between control centres is as follows:

1. The receiving control centre (client) will request connection to the sending control centre (server).

2. Both centres will proceed to check compliance with the previously specified technical requirements for the exchange of information with ICCP.

3. An initial protocol will be established for testing the connection in both directions. Any errors detected in the tests must be corrected before they are repeated.

4. Once the proper functioning of the communication system and ICCP protocol has been confirmed, operating tests will be performed.

5. If they operate properly, the receiving control centre (client) will consider the connection activated through written notification sent to the sending control centre (server).

The control centres will make every possible effort to ensure the connections are activated within a month from the connection request date, provided the parties have a SCADA that can handle the ICCP Protocol.

7. Basic operating signals

The basic operating signals to be exchanged between interconnected facility holders, and between these holders and the GTS, are as follows:

1. From measuring equipment installed at interconnection points:
   - Delivery pressure (bar/bara)
   - Flow rate (m3/h in reference conditions) for each flow direction.
   - Daily accumulated volume (m3 in reference conditions) for each flow direction.
   - Flow direction.
2. For gas analysis equipment installed in transmission networks:
   - Gas quality variables (GCV, relative density, H_2 and CO_2).
   - Odorant content (mg/m3 of THT in reference conditions).

   And any others agreed to between the parties

8. Signal unavailability

Those responsible for generating and/or transmitting signals will work together in the interest of maximising signal availability in annual calculations.

These responsible parties must have the necessary human and material resources needed to fix 95% of errors in the remote measurement signals within 72 hours, unless there is a backup line.

If a receiving control centre does experience signal unavailability during an extended period of time, and the sending control centre cannot complete corrective measures, the sending centre will propose the temporary sending of the relevant information by other means.

PD-17

'Provision of information about gas balancing in transmission networks'

Approved by the Resolution of 23 December 2015 of the Directorate General of Energy Policy and Mines, which approved Detail Protocol PD-17 'Provision of information about gas balancing in transmission networks' (B.O.E. 31 December 2015).

Validity: 1 June 2016

1. Purpose

The present detail protocol establishes the information flows between the different subjects of the gas system in the interest of complying with section 16, 'Information to provide to users', of Circular 2/2015 of 22 July, from the National Markets and Competition Commission, which establishes the balancing rules for the gas system transmission network.

2. Body responsible for forecasting

The Technical Manager of the System shall be in charge of providing users with the best available information that exists regarding their balance before the gas day, on the gas day and after the gas day.

All information regarding user balancing will be provided through the Third-party access Logistics System (SL-ATR) of the GTS.

The DSO's and transmission companies will be responsible for creating daily and multi-day forecasting for offtakes from the gas transmission and distribution system, both with and without remote metering, by shipper and connection points.

3. Scope of application

This protocol applies to all subjects involved in the gas system and who are required, according to the aforementioned circular, either to provide information to other parties or receive said information.

For this reason, this protocol is applicable to:

– Users (shippers and direct market consumers).

– DSO’s.

– Transmission companies.

– GTS.

4. Communication flows on day d for gas day d+1

The following communication flows on day d are set for information about gas day d+1:

– Before 10:00, the GTS will use the SL-ATR to make the temperature coefficients of the climate zones corresponding to gas day d+1 available to the sector, according to the calculation algorithm established in Detail Protocol PD-02, with the best temperature forecast sent by the State Meteorological Agency (AEMET).

– Before 10:00, the GTS will make the overall System demand forecast for gas day d+1 available to the sector.

– Before 12:00, the DSO’s will send the following to the SL-ATR: the demand forecast (kWh/day) for gas day d+1, broken down by consumption with and without remote metering, for consumers supplied by their networks, by user and transmission-distribution connection point (PCTD) or distribution-distribution connection point (PCDD). The calculation algorithm for this forecast will be that set out in Detail Protocol PD-02. Likewise, before 12:00, transmission companies will send the SL-ATR the demand forecast for offtakes by direct line connection point (PCLD) for day d+1, by user.

– Before 13:00, the GTS will make an update to the overall system demand forecast for gas day d+1 available to the sector.

– Before 13:00, the GTS will use the SL-ATR to make the demand forecast (in kWh/day) - previously sent to the SL-ATR by DSO’s and transmission companies - available to the sector; this will be for gas day d+1, and be broken down by consumption with and without remote metering, for each user and connection point (PCTD, PCDD and PCLD).

5. Communication flows on day d for gas day d (intra-day)

The following communication flows on day d are set for the same gas day d:

– Before 10:00, the GTS will use the SL-ATR to make the temperature coefficients of the climate zones (defined in PD-02) corresponding to gas day d available to DSO's, according to the calculation algorithm established in the said protocol.

– Before 10:00, the GTS will make the overall System demand forecast for gas day d available to the sector.

– Before 13:30, the DSO's and transmission companies will send the following information to the SL-ATR:

a) An updated estimate of demand without remote measurement for consumers supplied by their networks, in kWh/day, for all of gas day d by user and connection point (PCTD and PCDD). The calculation algorithm for this distribution forecast will be the current one set out in Detail Protocol PD-02.

Information estimating non-remote measuring consumption will be provided with the same level of disaggregation (non-remote measuring Type 1 with toll 3.4, non-remote measuring Type 1 with toll other than toll 3.4 and Type 2) as the provisional daily allocation.

b) Consumption with remote metering by consumers supplied by their networks, in kWh, accumulated between the beginning of gas day d and 11:00 of the same gas day (5-hour total) of those offtakes with remote measurement, broken down by user and connection point (PCTD, PCDD and PCLD). In cases where this information is available with a universal code from the supply point (CUPS), it will be provided with this breakdown to the SL-ATR. If there is no remote metering, the DSO or transmission company will send a substitute value, using the current calculation algorithm as defined in PD-02, indicating that the said value is an estimate. Given that the said PD-02 protocol sets out the method for calculating estimations on a daily basis, the substitute value shall be calculated by pro-rating the accumulated hours in a linear way.

c) The accumulated emission from the beginning of gas day d, in kWh, until 11:00 of the same gas day (5-hour total) at PCTD and PCDD connection points.

– Before 14:00, the GTS will use the SL-ATR to make the following information previously sent to the SL-ATR by DSO's and transmission companies available to users:

a) The updated estimate of demand without remote measurement for consumers supplied, in kWh/day, for all of gas day d by user, broken down by connection point (PCTD and PCDD).

b) Consumption with remote metering by consumers supplied, in kWh, accumulated between the beginning of gas day d and 11:00 of the same gas day (5-hour total) of those offtakes with remote measurement, broken down by user and connection point (PCTD, PCDD and PCLD), distinguishing between real and estimated consumption. If this information is available with CUPS, it will be provided with this breakdown, indicating if the consumption is real or estimated.

c) Consumption with remote measuring, in kWh, accumulated between the beginning of gas day d and 11 a.m. of the same gas day (5 hour total) of those offtakes with remote measurement, broken down by connection point (PCTD, PCDD and PCLD), distinguishing between real and estimated consumption.

d) The accumulated emission from the beginning of gas day d, in kWh, until 11:00 of the same gas day (5-hour total) at PCTD, PCDD and PCBD connection points. This information will also be made available to transmission companies and DSO’s for any connection points that may affect them.

– In addition, before 14:00, the GTS will use the SL-ATR to make available to users the gas flowed into the system as a whole at that point, at each entry point, and the distribution that corresponds to each user, in kWh.

– Before 17:00, the GTS will make the overall updated system demand forecast for gas day d available to the sector.

– Before 17:00, the GTS will use the SL-ATR to make an updated to the temperature coefficients of the climate zones (defined in PD-02) corresponding to gas day d available to the sector, according to the calculation algorithm established in the said protocol.

– Before 20:30, the DSO’s and transmission companies will send the following information to the SL-ATR:

a) An updated estimate of demand without remote measurement for consumers supplied by their networks, in kWh/day, for all of gas day d by user and connection point (PCTD and PCDD). The calculation algorithm for this distribution forecast will be the current one set out in Detail Protocol PD-02.

b) Consumption with remote metering by consumers supplied by their networks, in kWh, accumulated between the beginning of gas day d and 18:00 of the same gas day (12-hour total) of those offtakes with remote measurement, broken down by user and connection point (PCTD, PCDD and PCLD). In cases where this information is available with CUPS, it will be provided with this breakdown to the SL-ATR. If there is no remote metering, the DSO or transmission company will send a substitute value, using the current calculation algorithm as defined in PD-02, indicating that the said value is an estimate. Given that the said PD-02 protocol sets out the method for calculating estimations on a daily basis, the substitute value shall be calculated by pro-rating the accumulated hours in a linear way.

c) The accumulated emission from the beginning of gas day d, in kWh, until 18:00 of the same gas day (12-hour total) at PCTD and PCDD connection points.

– Before 21:00, the GTS will use the SL-ATR to make the following information previously sent to the SL-ATR by DSO's and transmission companies available to users:

a) The updated estimate of demand without remote measurement for consumers supplied, in kWh/day, for all of gas day d by user, broken down by connection point (PCTD and PCDD).

b) Consumption with remote metering by consumers supplied, in kWh, accumulated between the beginning of gas day 'd' and 18:00 of the same gas day (12-hour total) of those offtakes with remote measurement, broken down by user and connection point (PCTD, PCDD and PCLD), distinguishing between real and estimated consumption. If this information is available with CUPS, it will be provided with this breakdown, indicating if the consumption is real or estimated.

c) The accumulated emission from the beginning of gas day d, in kWh, until 18:00 of the same gas day (12-hour total) at PCTD and PCDD connection points. This information will also be made available to transmission companies and DSO's for any connection points that may affect them.

– In addition, before 21:00, the GTS will use the SL-ATR to make available to users the gas flowed into the system as a whole at that point, at each entry point, and the distribution that corresponds to each user, in kWh.

The network model of the PCTD/PCDD and PCLD connection points used for the provision of detailed information in this protocol will be the network model used for the preparation of the provisional daily allocations defined in the PD-02 detail protocol.

6. Indicators

The quality indicators that allow the proper application of the calculation algorithms required by this Protocol to be applied, as well as compliance with the information submission times for DSO's, transmission companies and the GTS, are established in the Annex.

APPENDIX: PD-17

"Provision of information about gas balancing in transmission networks" Indicators of quality and fulfilment of the information communication times"

In the following, the gas day will be referred to as "d", the day before the gas day will be referred to as "d-1" and the day after the gas day will be referred to as "d+1".

1. Indicators relating to compliance with the deadline for the provision of information.

The following indicators are defined regarding compliance with the deadlines for the provision of information, measured as a percentage and calculated as the number of information provisions with respect to the number that each agent must carry out in the calendar year:

• PG: percentage of occasions during the year in which the Technical Manager of the System has not made available to users, through the SL-ATR, the global demand forecast of the system, the publication of information previously sent by carriers, network managers and distributors, together with the information relating to the temperature coefficients of the climatic zones, both on gas day "d-1" and for gas day "d" itself.

• PD: percentage of occasions during the calendar year in which each distributor has not made available to users, through the SL-ATR, the information established in this detailed protocol, both on gas day "d-1" and for gas day "d" itself.

• PT: percentage of occasions during the calendar year in which each carrier or network operator has not made available to users, through the SL-ATR, the information established in this detailed protocol, both on gas day "d-1" and for gas day "d" itself.

For these purposes, failure to provide users with the required information or to make it available without the level of detail required in this detailed protocol will be considered as non-compliance.

2. Indicators relating to the quality of the information sent.

Indicators comparing the daily and intraday information provided to the user with the provisional distribution "d+1" will be calculated on a daily basis.

The indicators comparing the daily and intraday information provided to the user with the provisional final distribution "m+3" will be calculated monthly for each day of month "m".

The following indicators are defined to control the quality of the daily and intraday information provided.

2.1 Emission indicators.

The AHTD1 indicator is defined as the percentage of days in the year in which the emission in each PCTD or PCDD sent to the SL-ATR on gas day "d" by the carrier, network manager or distributor responsible for it is inconsistent, that is:

• The emission reported in the 1:30 p.m. dispatch is higher than the emission reported in the 8:30 p.m dispatch,

• The emission reported in the 8:30 p.m. dispatch is higher than the daily emission reported in the provisional daily delivery process "d+1". Additionally, carriers, network managers and distributors will report through the SL-ATR those cases in which the cumulative emission value for gas day "d" in the 1:30 p.m. or 8:30 p.m. dispatches of any of the PCTDs or PCDDs for which they are responsible for the measurement comes from estimated data, indicating the percentage that these estimated emissions represent with respect to all the emissions for which they are responsible.

2.2 Consumption indicators.

2.2.1 Non-remote measured consumption.

The following indicators will be calculated for each user and each distributor:

• AH0a: daily deviation between the estimate of the user's non-remote measured demand for day "d" reported by the distributor through the SL-ATR on day "d-1" for all its PCTDs and PCDDs, and the user's non-remote measured demand reported by the distributor in the provisional allocation process "d+1" for all its PCTDs and PCDDs.

• AH0b: daily deviation between the estimate of the user's non-remote measured demand for day "d" reported by the distributor through the SL-ATR before 1:30 p.m. on day "d" for all its PCTDs and PCDDs, and the user's non-remote measured demand reported by the distributor in the process of provisional allocations "d+1" for all its PCTDs and PCDDs.

• AH0c: daily deviation between the estimate of the user's non-remote measured demand for day "d" reported by the distributor through the SL-ATR before 8:30 p.m. on day "d" for all of its PCTDs and PCDDs, and the user's non-remote measured demand reported by the distributor in the provisional allocation process "d+1" for all of its PCTDs and PCDDs.

• AH1a: daily deviation between the estimate of the user's non-remote measured demand for day "d" reported by the distributor through the SL-ATR on day "d-1" for all its PCTDs and PCDDs, and the user's non-remote measured demand reported by the distributor in the "m+3" provisional final allocation process for all its PCTDs and PCDDs.

• AH1b: daily deviation between the estimate of the user's non-remote measured demand for day "d" reported by the distributor through the SL-ATR before 1:30 p.m. on day "d" for all its PCTDs and PCDDs, and the user's non-remote measured demand reported by the distributor in the provisional final allocation process "m+3" for all its PCTDs and PCDDs.

• AH1c: daily deviation between the user's estimated non-remote measured demand for day "d" reported by the distributor through the SL-ATR before 8:30 p.m. on day "d" for all of its PCTDs and PCDDs, and the user's non-remote measured demand reported by the distributor in the process of definitive provisional final daily allocations "m+3" for all of its PCTDs and PCDDs.

2.2.2 Remote-measured consumption.

The following indicator will be calculated for each user and each distributor:

• AHD: daily deviation existing between the user's estimated remote-measured consumption demand for day "d" reported by the distributor through the SL-ATR on day "d-1" for all its PCTDs and PCDDs, and the user's remote-measured demand reported by the distributor in the process of provisional allocations "d+1" for all its PCTDs and PCDDs.

The following indicator is calculated for each user and each carrier:

• AHT: daily deviation between the user's estimated remote-measured consumption demand for day "d" reported by the carrier through the SL-ATR on day “d-1” for all its PCLDs and the user’s remote-measured demand reported by the carrier in the process of provisional allocations “d+1” for all its PCLDs.

In addition, carriers and network managers will inform affected users and the GTS of those cases in which the value of the accumulated remote-measured consumption for gas day “d” in the 1:30 p.m. or 8:30 p.m. dispatches of any of their PCLDs comes from estimated data.

2.2.3 Total consumption.

The following indicators will be calculated for each user:

• AT0a: daily deviation between the estimate of the user’s total demand for day “d” reported by distributors and carriers through the SL-ATR on day “d-1” for the set of PCTDs, PCDDs and PCLDs, and the user's total demand reported by distributors and carriers in the provisional allocation process “d+1” for the set of PCTDs, PCDDs and PCLDs.

• AT0b: daily deviation between the estimate of the user’s total demand for day “d” reported by distributors and carriers through the SL-ATR before 1:30 p.m. on day “d” for the set of PCTDs, PCDDs and PCLDs, and the total user demand reported by distributors and carriers in the process of provisional allocations “d+1” in the set of PCTDs, PCDDs and PCLDs.

• AT0c: daily deviation between the estimate of the user's total demand for day “d” reported by distributors and carriers through the SL-ATR before 8:30 p.m. on day “d” for the set of PCTDs and PCDDs, and PCLDs and the user's total demand reported by distributors and carriers in the process of provisional allocations “d+1” in the set of PCTDs, PCDDs and PCLDs.

• AT1a: daily deviation between the estimate of the user’s total demand for day “d” reported by distributors and carriers through the SL-ATR on day “d-1” for the set of PCTDs, PCDDs and PCLDs, and the user's total demand reported by distributors and carriers in the process of provisional final allocations “m+3” in the set of PCTDs, PCDDs and PCLDs.

• AT1b: daily deviation between the estimate of the user’s total demand for day “d” reported by distributors and carriers through the SL-ATR before 1.30 p.m. on day “d” for the set of PCTDs, PCDDs and PCLDs, and the user's total demand reported by distributors and carriers in the process of provisional final allocations “m+3” in the set of PCTDs, PCDDs and PCLDs.

• AT1c: daily deviation between the estimate of the user's total demand for day “d” reported by distributors and carriers through the SL-ATR before 8:30 p.m. on day “d” for the set of PCTDs, PCDDs and PCLDs, and the user's total demand reported by distributors and carriers in the process of provisional final allocations “m+3” in the set of PCTDs, PCDDs and PCLDs.

3. Calculation and publication of indicators and associated reports.

Once the necessary information is available, the Technical Manager of the System will be responsible for calculating and publishing in the SL-ATR (on an annual basis in the case of term indicators and on a daily and monthly basis in the case of quality indicators) the indicators defined in this annex for all carriers, network managers and distributors, and will provide each operator and each user with details of their individualised information.

During May of each year and based on the above information, the Technical Manager of the System will prepare an annual report on the values of the indicators calculated for the previous calendar year. Carriers, network managers and distributors will receive only the section of the report that concerns them, while the entire report will be sent to the Directorate General for Energy Policy and Mines and the National Commission on Markets and Competition. Likewise, the conclusions reached in said report, as well as the data used in the same in an aggregate manner, will be provided to users of the transmission network.

Every year, the Working Group for the Updating, Revision and Modification of the Technical Management of the Gas System Regulations and Protocols may propose modifications in the indicators related to the provision of information.

PD-18

‘Technical parameters that determine the normal operation of the transmission network and the performance of balancing actions at the Virtual Balance Point (PVB) for the Technical Manager of the System'

Approved by the Resolution of 28 September 2016 of the Directorate General of Energy Policy and Mines, which approved Detail Protocol
PD-18 'Technical parameters that determine the normal operation of the transmission network and the performance of balancing actions at the Virtual Balance Point (PVB) for the Technical Manager of the System' (B.O.E. 30 September 2016).

Validity: 1 October 2016

1. Purpose

The aim of this detail protocol is to establish the values and method for calculating the parameters of the transmission network needed to identify its operating status, to manage the network operating balance and for the Technical Manager of the System (GTS) to complete balancing actions at the Virtual Balance Point (PVB).

2. Scope of application.

This protocol applies to the GTS, which will be responsible for calculating the precise values of the technical parameters and variables that determine the normal operation of the transmission network and completing balancing actions at the PVB to keep the network in the normal operating range.

3. Stock level in the transmission network

The indicator that summarises the balance of pressures at points in the transmission network and, therefore, its operating status, will be the level of stock in the network. To balance the level between flows into and out of the transmission network within the minimum guaranteed pressure range established by the System Technical Management Rules at all connection points and the maximum design pressure of the pipelines, the limits on the level of stock in the transmission network within which the network operates under normal conditions will be identified; under these conditions, flows into and out of the system are unaffected, and security of supply is not at risk.

The following limits on stock in the transmission network are as follows:

a) Maximum Permissible Level (LMaxA): If stock exceeds this volume, a pressure surge will occur in a part of the network that could limit or even impede the entry flow of gas to a certain system access point. This limit will be calculated by the GTS through the analysis of hydraulic simulations of low-demand and high-pressure network scenarios. The GTS will provide access to the information and parameters used in the simulations so that the calculations can be replicated by any party that makes such a request.

b) Minimum Permissible Level (LMinA): If stock drops below this volume, the minimum guaranteed pressures established in the System Technical Management Rules may not be met. This limit will be calculated by the GTS through the analysis of hydraulic simulations of high-demand and low-pressure network scenarios. The GTS will provide access to the information and parameters used in the simulations so that the calculations can be replicated by any party that makes such a request.

c) Demand Variability Band (BVD): The accumulated deviation of demand from its average daily value. It is calculated as the maximum accumulated intra-day variation in demand relative to its average hourly value; obtained using statistical techniques, it uses real hourly data from the previous year, and differentiates between conventional demand and that from combined cycle power plants.

d) Maximum Operating Limit (LMaxOp): This is the value obtained by subtracting the Demand Variability Band from the Maximum Permissible Value.

LMaxOp = LMaxA - BVD.

e) Minimum Operating Limit (LMinOp): This is the value obtained by adding the Demand Variability Band to the Minimum Permissible Value.

LMinOp = LMinA + BVD.

The transmission network is considered to be operating under normal conditions when the level of gas stock in the same is between the LMaxOp and LMinOp limits.

4. Stock bands in the transmission network

The following natural gas stock bands are established for the transmission network, which should always remain between the LMaxOp and LMinOp limits.

a) Stock indifference band (BI): When stock falls within this level, the GTS will not take any balancing actions.

b) Stock monitoring band (BV): When stock falls within the BV level, the GTS may take any balancing actions necessary to prevent stock from reaching BA level or to bring stock within BI level. If it does take action, the GTS must consider the following parameters:

- Current stock level.
- Forecast future changes in the stock level.
- Liquidity and prices on the Organised Gas Market.

c) Stock alert band (BA): When stock falls within this level, the GTS is required to take the balancing action necessary to bring the stock level in the transmission network back into the BI or BV range.

5. Benchmark value of stock level in the transmission network

The Benchmark Value for stock in the transmission network (VR) is the stock level value at the midpoint of the BN level, and will be the reference used by the GTS in its continuous management of the operation of the system.

6. Publication of expected aggregate imbalance

The GTS will publish the volume of gas available in the transmission network at the beginning of each gas day, along with the amount it predicts will be available at the end. The volume of gas predicted to be available at the end of the gas day will be updated every hour over the course of the day. In addition, when the GTS needs to make gas purchase-sale offers at the PVB on the organised market, it will inform the sector of this at least an hour in advance by publicising this fact on its website and the website of the organised market.

7. Calculation of parameters.

In accordance with the principles and rules indicated in the present protocol, the GTS - after public consultation - will develop calculation procedures for the parameters set out in the protocol. This procedure will be made public on its website, including a memo justifying the same. In addition, it will send the procedure and justifying memo to the Directorate General of Energy Policy and Mines and the National Markets and Competition Commission, together with the information used to develop the said procedure.

The procedure will be revised every two years, if necessary, modified by the same previous protocol, to provide a more accurate reflection of the storage capacity of the transmission network still permitting normal operation.

The Technical Manager of the System will update the parameter values every time that conditions in the transmission network make changes necessary, and at least in the following cases:

a) Twice per year, once the winter/summer period has elapsed, so that data from historical patterns found in the last corresponding period may be used, as well as forecast demand patterns for the next winter/summer cycle. The new values will take effect on 1 April and 1 October every year.

b) Every time that infrastructure will be connected to the transmission network that will increase the storage capacity of the network by at least 2%.

The new values will be published by the GTS on their website at least one month before taking effect. To ensure that the calculations can be replicated, the GTS will grant access to any non-confidential information used in the calculations to any system user who requests it.

In addition, each time the GTS updates the parameters, it will send a technical report justifying the change to the Directorate General of Energy Policy and Mines and the National Markets and Competition Commission, including all information that supports the update, particularly the data used in the simulations performed, gas flow scenarios and transmission facilities used.