Technical Guide to the STTM

October 2019

Version 4

Business processes required to perform tasks in the STTM

Important notice

PURPOSE

AEMO has prepared this document to provide information about the Short Term Trading Market for natural gas, as at the date of publication.

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VERSION CONTROL

Version	Release date	Changes
#4	01/10/2019	Includes standard market timetable

Executive summary

This document describes the operation of the Short Term Trading Market (STTM) and should be read in conjunction with other relevant AEMO publications.

This document describes the business processes required to perform tasks in the STTM, from the initial registration of trading participants, facilities, and services, through to the trading of gas in the ex ante market and the settlement of amounts owed to or by participants. Processes are described in sufficient detail to permit participants to identify the steps involved in each process and to verify the quantities and amounts produced by the STTM scheduling and settlement processes.

Some processes that are performed by AEMO are also described where they will assist the participant's understanding of how these processes affect the outcomes from the market. Not all AEMO processes, however, are described.

This guide does not describe the rules and procedures under which the STTM operates and assumes that the reader is familiar with the terms and concepts on which the STTM is based.

Examples are introduced progressively through this guide to demonstrate the terms and concepts discussed. The examples do not deal with all possible outcomes, but are provided to assist with the reader's understanding of the core functions of the STTM. The examples are based on a common market scenario, which, when considered in their entirety, describe the overall bid-to-bank process.

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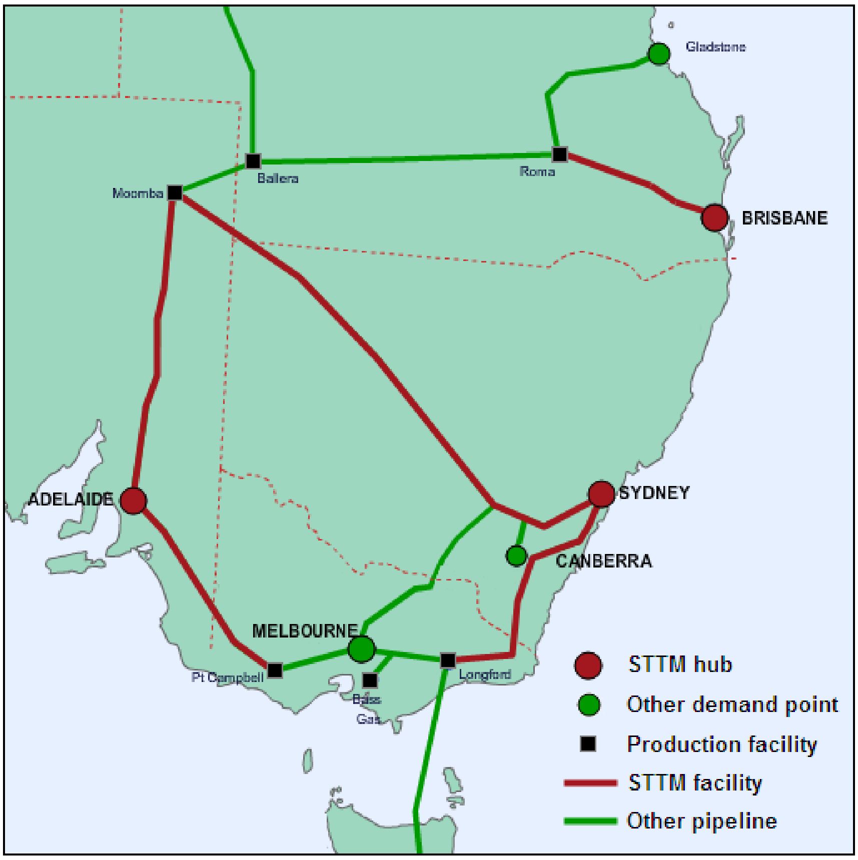
1. Introduction

1.1 The STTM

The Short Term Trading Market (STTM) is a market for the trading of natural gas at the wholesale level at hubs defined by custody transfer points between pipelines and distribution systems. The market is operated by the Australian Energy Market Operator (AEMO). All gas supplied through a hub is transacted daily in the STTM, including gas that is supplied under pre-existing long-term contracts. Gas is traded daily in an ex ante market at each hub. The ex ante market price, which is determined each day at a hub, is applied to all gas that is supplied and withdrawn according to the ex ante market schedules at that hub over the following gas day.

The STTM currently operates three hubs — Sydney, Adelaide, and Brisbane — but has been designed to handle additional hubs in the future. Each hub is scheduled and settled separately, but all hubs operate under the same rules. At any hub, there can be multiple facilities that deliver gas to the hub (such as transmission pipelines, storage facilities, and production facilities) and multiple distribution systems that deliver the gas from the hub to consumers, refer Figure 1.

Figure 1 STTM hubs and facilities



A condition of offering gas to a hub is that the shipper must have the ability to schedule gas under a pipeline haulage contract that allows the delivery of the gas to the hub. Gas deliveries outside of hubs are not required to be part of the STTM, although shippers who hold the necessary haulage contracts can purchase gas at the hub for haulage to points upstream of the hub. Similarly, users wishing to purchase gas at a hub must have the ability to schedule gas to be withdrawn from that hub under a distribution contract or under a contract with a pipeline operator.

Trading participants are paid or receive payment for the gas they supply and withdraw from a hub at the end of each monthly billing period. AEMO monitors the financial exposure that trading participants have to the market and maintains security amounts and trading limits to protect the market.

1.2 About this guide

This document describes the business processes required to perform tasks in the STTM, from the initial registration of trading participants, facilities, and services, through to the trading of gas in the ex ante market and the settlement of amounts owed to or by participants. Processes are described in sufficient detail to permit participants to identify the steps involved in each process and to verify the quantities and amounts produced by the STTM scheduling and settlement processes.

1.3 Market Timelines

The STTM operates on a daily cycle. Many tasks must be completed at specific times, otherwise the data cannot be submitted or is ignored, or default data is substituted. For example, if allocation agents fail to submit allocation data, AEMO will assume the role of allocation agent and perform the allocation using a pre-defined logic. This might distort the initial settlement calculations, and, if not corrected before the end-of-month statements are prepared, can result in a significant under- or over- payment for the trading participants concerned.

The standard market timetable Gas day timelines are defined separately for each hub because they can have different start times. But they all share a common time zone—so activities that are shown to occur at the same time at different hubs will occur concurrently was introduced on 1 October 2019 to harmonise the start time of the gas day used in the Australian short-term trading market hubs and the gas supply hub trading locations with the gas day start time used in the Victorian declared wholesale gas market which is 6.00 am Australian Eastern Standard Time (AEST).

1.3.1 Market timelines by workflow

Process	After	Before
MOS Offers and Stacks		
AEMO Publishes MOS Estimate		40 business days before MOS period. Can be republished up to 20 business days before MOS period.
AEMO seeks offers from shippers		20 business days before MOS period
Shippers submit MOS offers	Any time	1700 hrs 11 gas days before MOS period
AEMO creates MOS stacks	1700 hrs 11 gas days before MOS period	10 gas days before MOS period
AEMO issues MOS stacks	10 gas days before MOS period	10 gas days before MOS period
AEMO issues amended MOS stacks	10 gas days before MOS period	Daily
Trading and Scheduling		
Facility operators submit facility hub capacity data for use in provisional schedules	Anytime	0900 hrs on D-3 and D-2
Facility operator updates facility hub capacity data	0900 hrs on D-3 and D-2	1030 hrs on D-3 and D-2

Process	After	Before
AEMO publishes facility hub capacity data for use in provisional schedules		1030 hrs on D-3 and D-2
Trading participants submit ex ante offers, ex ante bids and price taker bids for use in provisional schedules	Any time	1330 hrs on D-3 and D-2
AEMO runs scheduling and pricing algorithm for provisional schedules	1330 hrs on D-3 and D-2	1430 hrs on D-3 and D-2
AEMO publishes provisional schedules		1430 hrs on D-3 and D-2
Facility operators submit revised facility hub capacity data for use in ex ante market schedule (for gas day D)	0600 hrs on D-1	0900 hrs on D-1
AEMO extends facility hub capacity submission window if no valid data available	0900 hrs on D-1	
If facility hub capacity submission window extended, relevant facility operators confirm previous submission or resubmit	0900 hrs on D-1	1030 hrs on D-1
AEMO publishes facility hub capacity data for gas day D		10 minutes after submission window closes
Trading participants make changes to trading rights for use in ex ante market schedule (for gas day D)	Any time	1130 hrs on D-1
Trading participants submit ex ante offers, ex ante bids and price taker bids for use in ex ante market schedule (for gas day D)	Any time	1130 hrs on D-1
AEMO runs scheduling and pricing algorithm for ex ante market schedule for gas day D	1130 hrs on D-1	1230 hrs on D-1
AEMO performs CPT test	After ex ante market schedule is generated	1230 hrs on D-1
AEMO publishes ex ante market schedules and prices		1230 hrs on D-1
AEMO issues notices of administered market states		1230 hrs on D-1
Trading participants submit contingency gas bids and offers for gas day D	Any time	1800 hrs on D-1
Pipeline Nominations and Schedules		
Shippers nominate quantities to facility operators	Not part of the STTM. Nominations are made according to pipeline operator’s timetable.	
Facility operators issue pipeline schedules	Not part of the STTM. Nominations are made according to pipeline operator’s timetable.	
Facility operators submit CTM data (Brisbane Only)		0930 hrs on D+1
Pipeline operators submit allocation data for transmission connected STTM users		1030 hrs on D+1

Process	After	Before
Pipeline operators submit allocation data for transmission connected STTM users for the billing period		3 business days after end of billing period
Shippers make intraday nominations to facility operators	Not part of the STTM. Nominations are made according to pipeline operator's timetable.	
Allocations		
Shippers submit market schedule variations	1230 hrs on D-1	1700 hrs on D+7
Allocation agents (for facility operators) submit STTM facility allocations (including total MOS and overrun MOS) and MOS step allocations	0600 hrs on D-1	1030 hrs on D+1
AEMO extends facility allocation submission window and delays ex post schedule if no valid data available	1030 hrs on D+1	
AEMO determines STTM distribution system allocations for STTM users		1030 hrs on D+1
If facility allocation submission window extended, relevant allocation agents confirm previous submission or resubmit	1030 hrs on D+1	1430 hrs on D+1
Allocation agents (for shippers) submit registered facility service allocations for STTM shippers	STTM facility allocations published	Before daily settlement calculations and not later than 4 business days after end of gas month
Trading participants confirm MSVs		1700 hrs on D+7
AEMO performs default allocations		Before daily settlement calculations
Ex Post Pricing and Daily Monitoring		
AEMO publishes contingency gas prices		1200 hrs on D+1 (or 1600 hrs if delayed)
AEMO runs ex post schedule for gas day D	1030 hrs on D+1	1130 hrs on D+1 (or 1530 hrs if delayed)
AEMO publishes ex post imbalance price		1130 hrs on D+1
AEMO publishes indicative deviation quantities and charges, plus long and short deviation prices	1138 hrs on D+1	Before daily settlement calculations
AEMO performs prudential monitoring daily	Daily settlement calculations	
AEMO issues prudential notices	Daily settlement calculations	
Settlement		
Allocation agents (for facility operators) submit STTM facility allocations and MOS step allocations for the billing period		3 business days after end of billing period
Allocation agents (for shippers) submit registered facility service allocations for the billing period		4 business days after end of billing period
AEMO determines distribution system allocations for the billing period		4 business days after end of billing period
AEMO generates preliminary settlement statements for the billing period		7 business days after end of billing period

Process	After	Before
Trading participants can query settlement statements		13 business days after end of billing period. Late queries may be deferred to next settlement run.
Allocation agents (for facility operators) resubmit STTM facility allocations and MOS step allocations for the billing period		14 business days after end of billing period
Allocation agents (for shippers) resubmit registered facility service allocations for the billing period		15 business days after end of billing period
AEMO determines latest distribution system allocations for the billing period		15 business days after end of billing period
AEMO issues final statements and invoices		18 business days after end of billing period
Trading participants make payments to AEMO		1200 hrs (noon) 20 business days after end of billing period
AEMO makes payments to trading participants	1200 hrs 20 business days after end of billing period	1400 hrs 20 business days after end of billing period
Allocation agents submit revised allocations	As required	4 business days before revised settlement run
AEMO determines revised distribution system allocations	As required	4 business days before revised settlement run
AEMO runs final settlement revision	As required	9 months after the billing period with provision for further revision up to 18 months

2. Market Information Systems

The STTM is implemented as software and data on computer systems operated by AEMO. The STTM information systems can be accessed by participants through existing links (MarketNet) or through secure channels on the Internet. Public reports will also be available through the AEMO website (www.aemo.com.au).

2.1 Data security and system integrity

All data submitted to AEMO or generated by AEMO is permanently stored in secure databases. AEMO has implemented electronic, physical, and administrative safeguards that provide a high level of data security. These safeguards are designed to prevent unauthorised access to system data and to maintain the confidentiality of all participant information, and include:

- Passwords to authenticate users must be changed regularly.

- The use of secure communication channels when exchanging secure STTM data with authorised data users and providers.
- Authentication before access to STTM processes and data is granted to a person or system.
- Controls to prevent system users with access to STTM system application logic (programs) from unauthorised modification of associated application data.
- An audit system that tracks all changes to system data and records what data was changed, when it changed, and who made the change.

System integrity is assured through the disaster recovery measures employed by the STTM system architecture. These include hardware redundancy, systematic data backup and restoration, and the mirroring and replication of data on geographically separated data storage and processing systems. For information about AEMO's information technology disaster recovery processes.

2.2 Information management

AEMO maintains data and makes data available to participants in accordance with the NGR and STTM Procedures. Access to the STTM systems is available 24 hours a day, 7 days a week, except for notified periods of system maintenance and unplanned outages.

The STTM information systems give participants access to current and historical market data that they are authorised to view. Participants can select from a wide range of standard reports, from which information can be extracted and reformatted.

- Maintaining standing data

AEMO constantly monitors process cycle times of its information systems to ensure that performance standards are met.

- Market Notices and alarms

The STTM information systems monitor market operations for a range of pre-defined market conditions that, if triggered, can result in a market system alarm and the publication of notices to participants. For example, on any day, an alarm is triggered if the ex ante market schedule has not been published by the stipulated deadline. AEMO will act promptly to resolve any market system alarms and will issue market notices to participants if and when required. Market notices are primarily issued by publishing the notices to the AEMO website and the participant's secure folder on the STTM file server, but can also be issued to the participant's registered contact by SMS, e-mail, or fax.

- Accessing the STTM systems

Participants can access the processes and functions of the STTM using an Internet browser over a secure communications channel or by interfacing their business systems to the STTM systems.

When users log in to the STTM, they are presented with an interactive interface to all the data and functions that their participant account is authorised to access. Users can choose to submit data (bids, offers, trading rights data, market schedule variations, and such) by typing the data directly into the interactive forms provided, or by uploading data as text files (with some exclusions) to the STTM file server.

- Publishing market data

There are two types of data published from the STTM: public and private. Public reports are published to the AEMO website and to the participant's public folder on the STTM file server. Private reports that are confidential to the participant are published to the participant's private folder on the STTM file server.

3. Participation in the STTM

Organisations must apply to AEMO to be registered in the STTM for the roles they intend to perform and at what hubs. Participating roles are broadly divided into non-financial roles and trading participants who participate financially in the STTM. Organisations can apply to be registered for multiple roles at the same hub. The details of all organisations participating in the STTM are maintained electronically by AEMO.

In the STTM, the functions and data made available to organisations are restricted by their registered role:

- Non-financial roles
  - STTM facility operator
  - STTM distributor
  - Allocation agent
- Trading participant (financial) roles
  - STTM shipper
  - STTM user

3.1 Registration of organisations

The business interactions required for AEMO to register an organisation that wishes to participate in any role in the STTM are described below. Organisations that intend to operate in multiple roles or on multiple hubs are only required to register once as an organisation with AEMO.

Note. Registered participants of electricity markets are required to register separately for gas markets.

The registration process requires organisations to nominate the roles they intend to perform and on what hubs. This registration process is a prerequisite step for other processes to be performed in the STTM—for example, an allocation agent cannot submit data until it has registered with AEMO.

Note. This information is only provided as a guide. Refer to the AEMO Gas Market Registration and other AEMO publications for more information.

3.1.1 Prerequisites

An organisation intending to participate in the STTM can visit the Short Term Trading Market AEMO website for all guides and registration process steps.

3.2 Registration of Trading Participant

The business interactions required for AEMO to register an organisation as a trading participant at an STTM hub are described below.

3.2.1 Prerequisites

Intending trading participant must be registered as an organisation with AEMO and must have nominated the intention to act as an STTM shipper or an STTM user (or both) and the hub or hubs at which the organisation intends to operate as a trading participant. If the intended role or hub has not been previously indicated on the organisation's registration information, the organisation must update their registration details accordingly.

Only organisations that have one or more registrable capacities, as defined under the NGR, can register as trading participants

3.3 Maintaining information of a participating organisation

On successful completion of the registration of an organisation for participation in the STTM in either a non-financial role or as a trading participant, AEMO will add the organisation's information to the STTM systems and activate the roles for the hub or hubs at which they are eligible and approved. This information can also be updated at the request of an organisation (when their details have changed) or when AEMO changes the status of an organisation's role or roles on one or more hubs.

3.3.1 Prerequisites

STTM information system user must be an authorised AEMO system user.

3.3.2 Process – registering a new organisation

1. If an organisation's participant ID has not been previously issued, AEMO will assign a new ID to the organisation, which applies to all registered roles of the organisation and at all hubs
2. The organisation's registration information is recorded or updated. This includes the organisation's

2.1. Registered trading name

2.2. ABN and CAN

2.3. Contact details (multiple contacts can be created)

2.4. STTM roles (STTM user, STTM shipper, allocation agent, STTM facility operator, and STTM distributor)

2.5. The status of each STTM role is set as either active or suspended or de-activated, with an effective date

2.6. Retail market participant ID (STTM users only).

3. AEMO sets up the organisation's information folders on the STTM file server, populates the information folders with the latest reports, adds the organisation's ID to the required registers, and creates log-in accounts for each system user nominated by the participant
4. AEMO notifies the organisation when the system account is active and the information required to log in to system user accounts

3.3.3 Process – organisation updates their information

1. Participating organisation notifies AEMO that their registered information has changed
2. AEMO updates the information of a registered organisation.

   When registration information is updated, these changes might require further changes to be made in the STTM information systems, such as adding or removing the organisation's ID on certain registers.
3. AEMO notifies the organisation when the changes to the system registers have been completed

3.3.4 Related Information

This section details information about suspending and deregistering participant organisations.

3.4 Suspending a participating organisation

AEMO can suspend participating organisations who fail to meet their prudential obligations within the required timeframe or because of changes in the eligibility of the organisation. Suspension applies to specified roles at specified hubs, and the organisation can continue to participate in the STTM in other roles and hubs that are not affected by the suspension.

The process involves changing the status of the organisation in the various system registers maintained by AEMO. The organisation's information and history are not removed from the STTM system by suspension.

AEMO will only lift the suspension and re-activate the suspended roles in accordance with the NGR when the conditions that led to the suspension have been fully addressed and the requirements for ongoing participation are met by the suspended organisation.

3.5 Deregistering a participant organisation

AEMO can deregister a participating organisation either at the request of the organisation or at the request of the Australian Energy Regulator (AER) or because the organisation has failed to meet the conditions of a suspension notice or because the organisation no longer meets the eligibility requirements for participation in the STTM.

The process involves changing the status of the organisation in the various system registers maintained by AEMO, including the facility services and trading rights that the organisation has registered. Deregistration applies to all registered roles at all hubs. The organisation's information and history are not removed from the STTM system by deregistration.

To re-register, the organisation must complete the registration process required for a new organisation.

4. Facilities

Note. The term "facility" is used generally to refer to both STTM distribution systems and STTM facilities (including transmission pipelines and hub-connected storage and production facilities).

A hub can comprise one or more transmission pipelines, storage facilities, and production facilities that inject gas directly into or withdraw gas directly from an STTM distribution system. All the STTM facilities that make up a hub must be registered in the STTM.

The Brisbane hub also contains deemed STTM distribution systems, which withdraw gas directly from the STTM pipeline. The registration process for a deemed facility differs from other types of facilities and is described separately below.

4.1 Registration of facilities

This workflow describes the business interactions required for AEMO to register a facility for STTM operations.

4.1.1 Prerequisites

Facility is one of:

- An STTM distribution system.
- A deemed STTM distribution system.
- A transmission pipeline or storage or production facility with the capability of directly injecting gas into an STTM distribution system.

4.1.2 Process – STTM facility or STTM distribution system

1. For each hub in the STTM, AEMO requests registration information for the facilities that make up the hub.
2. The facility operators for each facility submit information to AEMO for registration.
3. AEMO accepts the facility information and registers the facilities for each hub.

4.1.3 Process – deemed STTM distribution system (Brisbane Hub only)

1. The contract holder (the STTM user that holds the contract to withdraw gas from the STTM pipeline) submits information to AEMO to register a deemed STTM distribution system.
2. AEMO accepts the facility information and registers the facility at the hub.

4.2 Updating and maintaining facility information

This workflow describes the business interactions required to enable AEMO to capture and maintain information for STTM distribution systems, deemed STTM distribution systems, STTM facilities (STTM pipelines, STTM production facilities, and STTM storage facilities), and their operators.

4.2.1 Prerequisites

- The distribution system operator must be registered as an STTM distributor.
- The facility operator must be registered as an STTM facility operator.
- The deemed operator of a deemed STTM distribution system must be the contract holder and registered as an STTM user.
- The allocation agent nominated by a facility operator must be registered as an allocation agent in the STTM.

4.2.2 Basic Process

1. Facility operator submits facility details to AEMO. In addition to the organisational and contact details required for registration as a facility operator, an STTM facility operator (only) must also provide:
   - Maximum hub capacity. This value is used to validate daily submissions of facility hub capacity data. If above this value, the hub capacity submission is rejected.
   - High and low hub capacity limits. These values are used to validate daily submissions of facility hub capacity data. If outside these limits but within the maximum (see above) and minimum (zero) capacity limits, a warning is issued.
   - Default hub capacity. This value is used when STTM hub capacity data is not submitted or unavailable.
   - Allocation agent. For STTM facilities, this is the party who is responsible for providing all allocation data for all facility services registered in the STTM for that facility.
   - Benchmark information used when assessing contingency gas trigger events.
2. AEMO notifies the nominated allocation agent that they have been nominated by this facility.
3. AEMO notifies the facility operator that the facility is registered.

Facility operators are responsible for ensuring that the facility data provided to the STTM is current and correct.

4.2.3 Related information

For distribution systems, AEMO (in its role as RMO) is the allocation agent. For deemed distribution systems, no allocation agent is appointed—allocations for transmission- connected users are made by the pipeline operator.

5. Contracts, Facility Services, and Distribution Services

The gas supply system operates through facility contracts between pipeline operators and shippers and through distribution contracts between distributors and users. These contracts determine the capacities and types of services (individually referred to as "facility services" and "distribution services") that a shipper or user can provide in the STTM. These facility and distribution services must be registered with AEMO before the shipper or user can use that contract in the STTM. The contract holder (that is, the shipper or user) registers the facility or distribution service with AEMO, and the contract issuer (that is, the facility operator or distributor) confirms the contract details with AEMO.

5.1 Registered services and trading rights

If the contract between the contract issuer and the contract holder contains multiple services; each service on each facility must be registered separately with AEMO. For example, a contract between a facility operator and a shipper might contain services for forward haul with firm capacity and forward haul with as-available capacity. In this case, two facility services would be registered.

The holder of a registered facility service (RFS) or a registered distribution service (RDS) is granted a trading right in the STTM. These trading rights are used in the STTM to validate the offers and bids submitted by shippers and users, and to limit the quantities of gas that each shipper and user are scheduled to supply or withdraw. The contract holder must register this primary trading right before it can be used to place bids or offers in the STTM. In addition primary or sub-allocated trading right must be MOS enabled before it can be used to provide MOS offers.

For facility contracts, multiple trading rights can be associated with one RFS. This occurs when the shipper who holds the contract (contract holder) transfers part or all of its contracted capacity to another shipper (contract participant). The total capacity of all trading rights associated with an RFS equals the registered capacity of that RFS. When a contract participant's trading right is created or modified, the capacity of the new or modified trading right is automatically deducted from the contract holder's trading right.

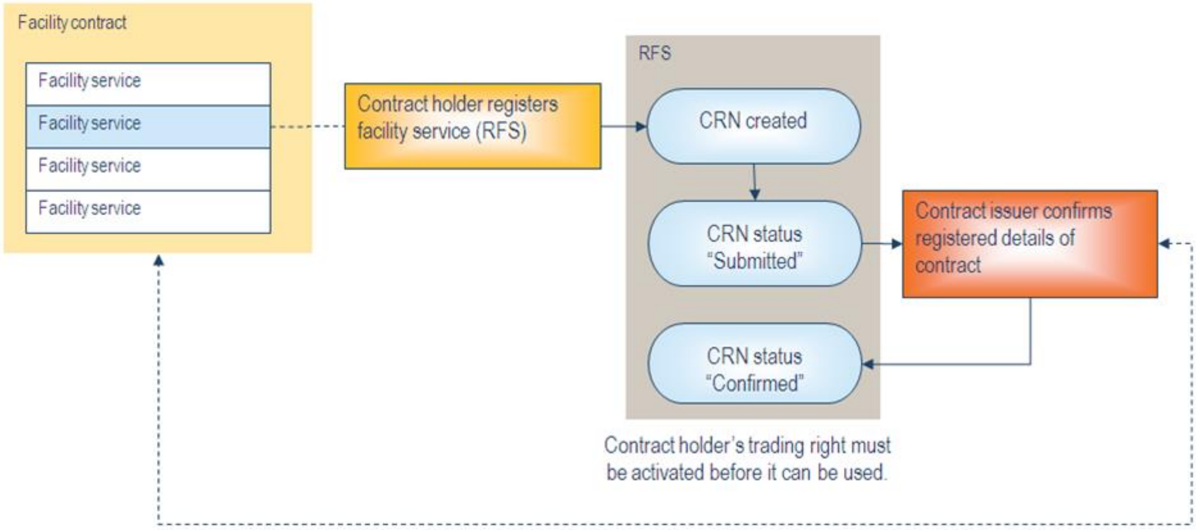
For distribution contracts, the STTM user (contract holder) can only register one distribution service on each distribution system at a hub, and the capacity of the RDS is not transferable. Also, the user's trading right is issued at a hub level—unlike a shipper's trading right, which is specific to a facility at the hub. When a user registers additional services at that hub, the capacity of the new service is added to the user's existing trading right at that hub.

For users on deemed distribution systems (transmission-connected users), the same rules apply as for users on (normal) distribution systems—that is, the user holds a single trading right at the hub. The only difference is that the user on a deemed distribution system holds its distribution contract with a pipeline operator (the contract issuer).

Note. Distribution services (and their trading rights) are always associated with a user at a hub—not the distribution system for which the user holds the service.

5.2 Registering a facility service

Figure 2 Registering facility services



Prerequisites

- The facility to which the contract relates must be registered by AEMO.
- Contract issuer must be the registered operator of the facility.
- Facility contract holder must be registered as a trading participant in the role of STTM shipper.
- Allocation agent must be the registered allocation agent of the facility.

Process

1. Contract holder submits a request to register a facility service. The electronic submission contains the following information:
   - Facility service identifier. The identifier used is at the discretion of the registering party.
   - Facility service description.
   - Facility identifier.
   - Capacity limit.
   - Type of contract (haulage to the hub or haulage from the hub).
   - Scheduling priority, where a value of 1 denotes firm capacity and any other value denotes as-available capacity).
   - Allocation agent. This is the allocation agent appointed by the STTM facility operator responsible for providing all allocation data for this facility at the RFS level.
   - Effective date range.
2. AEMO checks that the roles of the contract issuer, contract holder, and allocation agent are consistent with their registered roles in the STTM. AEMO does not otherwise validate the contract details.
3. AEMO issues a contract registration number (CRN) for each RFS, sends a confirmation to the contract holder, and sets the status of the RFS to "Submitted".
4. AEMO sends notification to the contract issuer requesting that the RFS details are confirmed.
5. Contract issuer confirms RFS information.

6. AEMO changes RFS status to "Confirmed".
7. Contract holder registers a trading right with the full capacity of the RFS as its own trading right.

Timeline

- Registration must be completed at least 10 days before gas is flowed on the RFS.

Related information

- All facility contracts that permit gas to be supplied to or withdrawn from the hub must be registered in the STTM.
- The details of the underlying contract between the contract issuer and the contract holder are not recorded in the STTM. Hence, facility services with the same contractual terms (the same service, haulage direction, and priority), on separate contracts, can be aggregated and registered as a single facility service.
- The contract holder must register a trading right for the full capacity of the RFS before it can be used in the STTM.

5.3 Registering a shipper's trading right

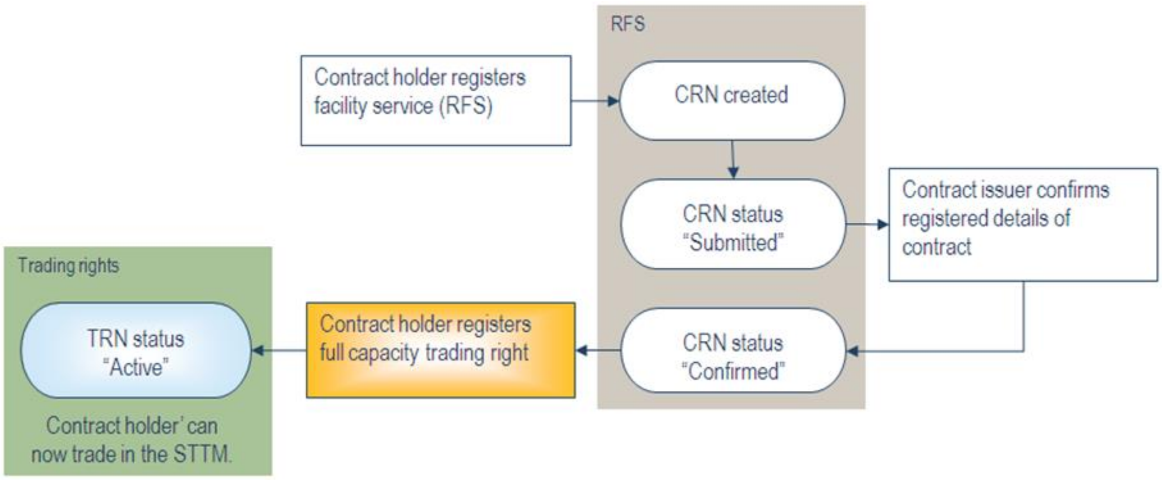
Trading rights can only be registered by the contract holder. The contract holder initially registers its own trading right for the full capacity of the registered facility service. The contract holder can subsequently transfer part or all of its registered capacity to other shippers by registering new, additional trading rights. The contract holder (transferrer) must separately and independently confirm the details of any transferred trading right capacity with the contract participant (transferee) before registering the trading right data with AEMO.

Prerequisites

- STTM information system user must be the registered holder of the registered facility service for which the trading right is created.
- Contract participant must be a trading participant registered in the role of STTM shipper.
- The allocation agent nominated by the contract holder must be registered as an allocation agent in the STTM.
- The contract holder's RFS status is "Confirmed".

Process: registering the contract holder's trading right

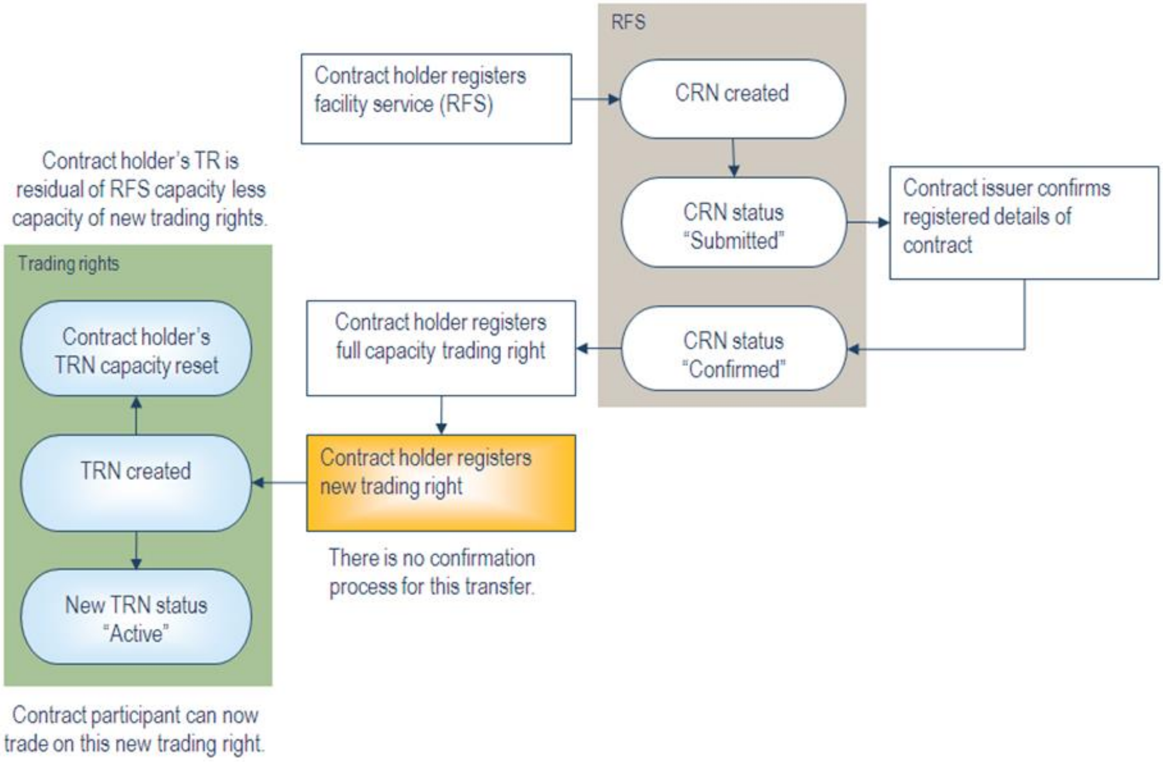
Figure 3 Activating the contract holder's initial trading right



1. Contract holder submits request for registration of trading right. The electronic submission contains the following information:
   - CRN of the registered facility service to which the trading right is associated.
   - The contract holder's STTM participant ID.
   - Trading right capacity in whole units of gigajoules (GJ).
   - Effective date range.
2. AEMO accepts registration request and validates the information.
3. AEMO sends notification to the contract holder confirming receipt.
4. AEMO issues a trading right registration number (TRN) to the contract holder.
5. AEMO sets the status of the contract holder's trading right to "Active".

Process: registering new trading rights (transferring capacity to another party)

Figure 4 Registering new trading rights for an STTM shipper's registered facility service



1. Contract holder submits request for registration of new trading rights. The electronic submission contains the following information:
   - CRN of the registered facility service to which the trading right is associated.
   - For each trading right holder:
     - STTM participant ID.
     - Trading right capacity to be transferred, in whole units of gigajoules (GJ).
     - Effective date range.
   - Allocation agent. This party is responsible for providing all allocation data for this RFS at the trading right level.

2. AEMO accepts registration request and validates the information.
3. AEMO sends notification to the contract holder confirming receipt.
4. AEMO issues a trading right registration number (TRN) for each registered trading right and sends notification to each trading right holder.
5. AEMO sets the status of the new trading rights to "Active".
6. AEMO updates the capacity of the contract holder's trading right.

Related information

- The capacity of the contract holder's trading right is automatically set to the residual of the capacity of the RFS less the transferred capacities.

- Other than capacity, trading rights inherit all other properties of the registered facility service, such as haulage priority and haulage direction.
- A trading right holder can view the details of all trading rights for which it is the holder.
- When a contract participant's trading right expires, the capacity of that trading right is automatically absorbed by the contract holder's trading right.
- When trading rights data is updated, any current bids or offers associated with that trading right might also need to be updated to ensure that the total quantities offered or bid are valid.

5.4 Registering a distribution service

Prerequisites

- The distribution system to which the contract relates must be registered by AEMO.
- Contract issuer must be the registered operator of the facility.
- Contract holder must be registered as a trading participant in the role of STTM user.

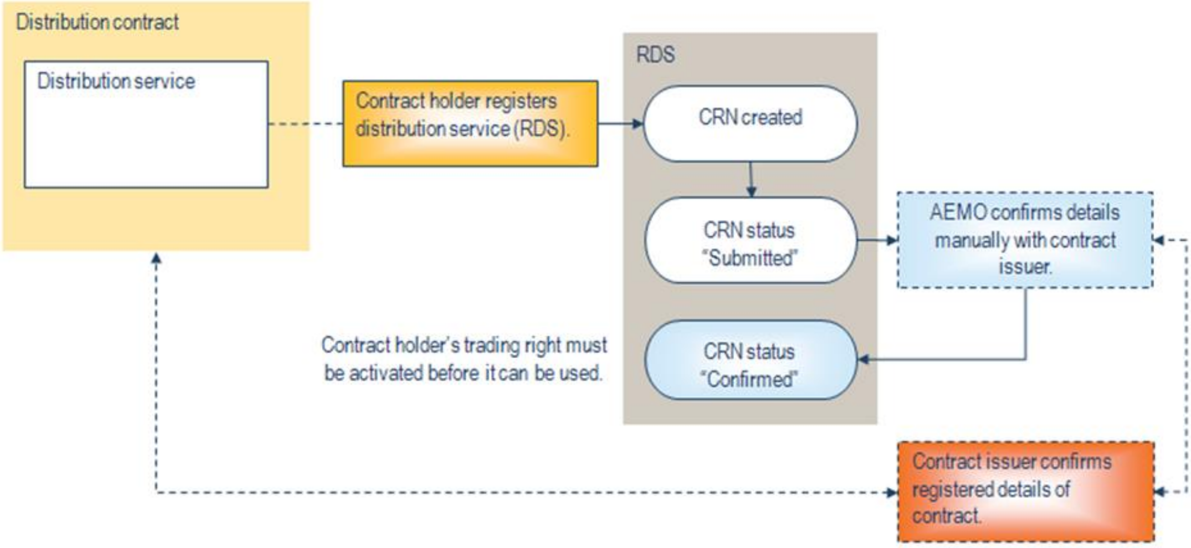
Process: registering an initial distribution service at a hub

1. Contract holder submits a request to register a distribution service. The electronic submission contains the following information:

- Distribution service identifier. The identifier used is at the discretion of the registering party.
- Distribution service description.
- Capacity limit.
- Type of contract (distribution at the hub).
- Effective date range.

2. AEMO checks that the roles of the contract issuer and contract holder are consistent with their registered roles in the STTM. AEMO does not otherwise validate the contract details.
3. AEMO issues a contract registration number (CRN) for the RDS, sends a confirmation to the contract holder, and sets the status of the RDS to "Submitted."
4. At the Sydney and Adelaide hubs, the contract issuer confirms the details electronically (same process as an RFS shown in Figure 6-1). However, at the Brisbane hub, AEMO manually verifies the details of the registered service with the contract issuer (as shown in Figure 5).
5. When confirmed, AEMO changes RDS status to "Confirmed."
6. Contract holder registers a trading right for that hub.

Figure 5 Registering an initial distribution service at the Brisbane hub



Process: registering additional distribution services at a hub

AEMO only issues a single CRN and trading right to each user at a hub. To register an additional distribution service at a hub, the contract holder (user) submits a request to modify the capacity of its existing CRN and trading right at that hub. For more information. Note that, in Brisbane, the confirmation steps are performed manually by AEMO, whereas in Sydney and Adelaide, the changes are confirmed electronically by the contract issuer.

When submitting the changes for an RDS at the Brisbane hub, the details of the new distribution service must be entered in the Comments field. AEMO will use this information to verify the details of the service with the contract issuer.

When confirmed, AEMO adds the additional capacity to the user's trading right at that hub.

Timeline

- Changes to the user's trading right capacity must be activated by AEMO before bids that use the additional capacity can be submitted. It is recommended that submissions are made at least 10 days before the user intends to utilise the additional capacity in its bids.

Related information

- The contract holder can only hold a single service for each distribution system at a hub, the capacities of any additional services are added to the user's single trading right at that hub.
- AEMO issues a single CRN and a single TRN per user per hub. The CRN and TRN represent the combined capacity of all distribution services registered by that user at that hub.
- The capacity of an RDS is not transferable.

5.5 Registering a user's initial trading right at a hub

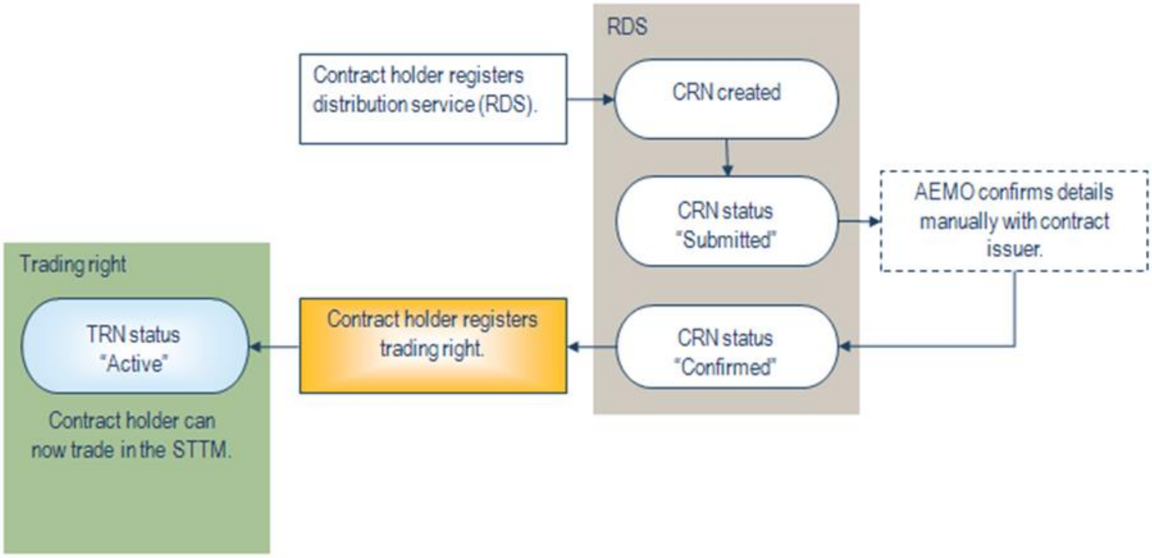
The user's trading right is issued at a hub level—unlike a shipper's trading right, which is specific to a facility at the hub. This initial, single trading right must be activated before the user can trade in the STTM. When a user registers additional services at that hub, the capacity of the new service is added to the user's existing, single trading right at that hub—no additional trading rights are issued.

Prerequisites

- STTM information system user must be the contract holder.
- Contract holder must be a trading participant registered in the role of STTM user.
- The contract holder's RDS status is "Confirmed".

Process

Figure 6 Activating the contract holder's initial trading right (Brisbane)



1. Contract holder submits request for registration of initial trading right at a hub. The electronic submission contains the following information:
   - CRN of the registered distribution service to which the trading right is associated.
   - The contract holder's STTM participant ID.
   - Trading right capacity in whole units of gigajoules (GJ)
   - Effective date range
2. AEMO accepts registration request and validates the information.
3. AEMO sends notification to the contract holder confirming receipt.
4. AEMO issues a trading right registration number (TRN) to the contract holder. This is the STTM user's single trading right for that hub.
5. AEMO sets the status of the STTM user's trading right to "Active."

Related information

- The capacity of any additional distribution services registered by that trading participant is added to the capacity of this initial, single trading right.
- Trading rights for distribution contracts cannot be transferred.
- A trading right holder can view the details of all trading rights for which it is the holder.
- When trading right data is updated, any current bids or offers associated with that trading right might also need to be updated to ensure that the total quantities offered or bid are valid.

5.6 Confirming contract details of registered services

The contract issuer must confirm the details of all newly registered facility services (RFS) and registered distribution services (RDS) or when the details of an RFS or RDS are changed by the contract holder. These details cannot be implemented in the STTM until AEMO has received this confirmation. In the case of a new service, if the contract details have not been confirmed, associated trading rights cannot be registered, and bids and offers cannot be submitted. In the case of an updated service (a change to the capacity, for example), if the new details have not been confirmed, the existing trading rights data is used to validate bids and offers and to run the market.

The details of an RFS are confirmed electronically by the contract holder (at all hubs), At the Sydney and Adelaide hubs, the details of an RDS are also confirmed electronically. However, in Brisbane, the details of an RDS—including when it is first registered, when it is amended, and when an additional distribution service is registered—are confirmed manually by AEMO with the contract issuer. This section only describes the electronic confirmation of an RFS or RDS by the contract issuer.

Prerequisites

- Contract issuer must be registered as an STTM facility operator or STTM distributor and must be the registered operator of the facility.
- Contract holder's RFS or RDS status is "Submitted".

Process: confirming the details of an RFS

1. When a facility service is registered, or the details of an RFS are changed by the contract holder, AEMO notifies the contract issuer requesting that the contract details are confirmed.
2. Contract issuer electronically confirms or rejects the contract details.
   - If rejected, the contract issuer provides AEMO with reasons for rejecting the RFS, and AEMO sets the RFS status to "Rejected."
   - If confirmed, AEMO sets the RFS status to "Confirmed."
3. If rejected, AEMO notifies the contract holder and provides reasons for the rejection.
4. If confirmed, AEMO notifies the contract holder and notifies the allocation agent that they have been appointed to provide allocation data for that RFS.

Related information

- If an error has been made in confirming an RFS, or a contract is terminated or assigned, the contract issuer can instruct AEMO to revoke the RFS and its associated trading rights.

5.7 Maintenance of registered services and trading rights data

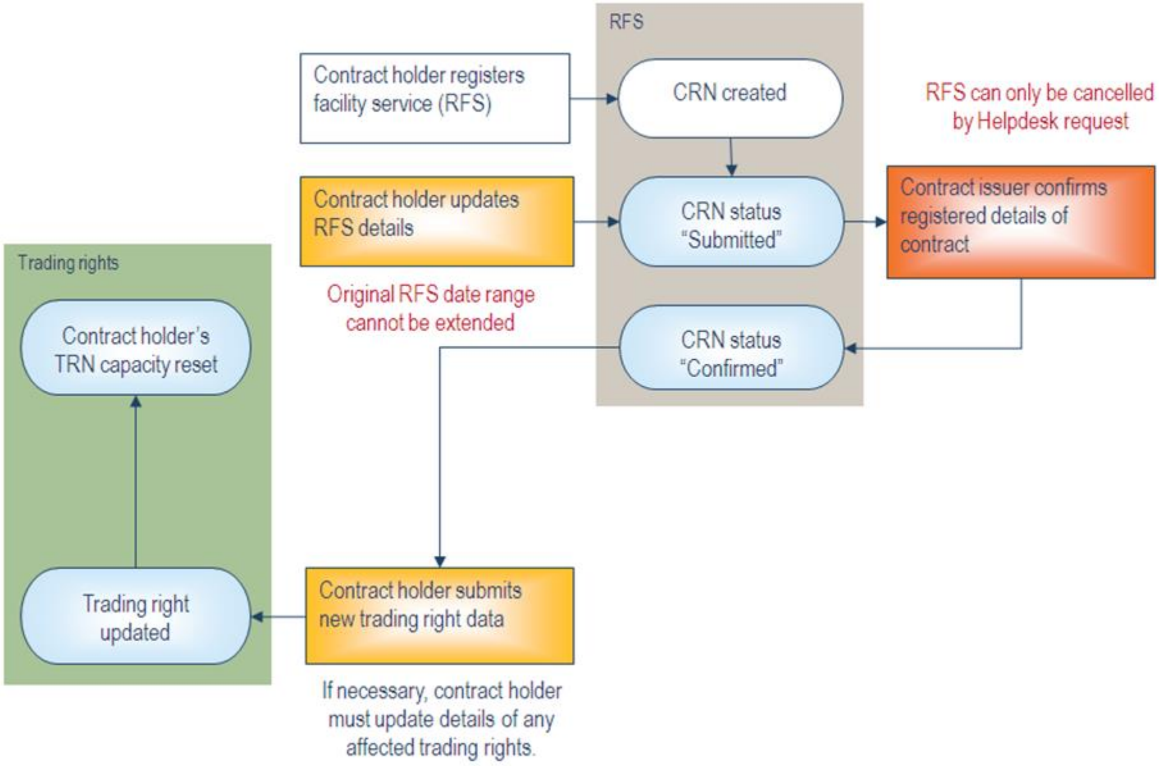
Details of registered facility services, registered distribution services, and trading rights can be updated electronically by the contract holder. All changes to the details of an RFS or RDS must be confirmed by the contract issuer before they can be implemented.

Prerequisites

- For shippers, the RFS or trading right must already be registered.
- For users, the user's initial distribution service and trading right must already be registered for the hub.

Process: updating RFS data

Figure 7 Modifying the details of an existing RFS



1. The contract holder electronically submits changes to registered data.

Note. The original, registered date range of the RFS cannot be extended.

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2. AEMO notifies contract holder confirming receipt.
3. AEMO sets the status of the change request to "Submitted." The current RFS data remains active and is continued to be used in the STTM until the change request has been confirmed.
4. AEMO notifies contract issuer and requests that the changes are confirmed.
5. Contract issuer electronically confirms changes.
6. AEMO changes status to "Confirmed."
7. AEMO updates the trading rights register with the new details of the contract holder's RDS.
8. If required, contract holder submits changes to related trading rights data (see below).

Process: updating RDS data for an existing registered service

1. The contract holder electronically submits changes to registered data.
2. AEMO notifies contract holder confirming receipt.
3. AEMO sets the status of the change request to "Submitted." The current RDS data remains active and is continued to be used in the STTM until the change request has been confirmed.
4. At Sydney and Adelaide hubs, contract issuer electronically confirms changes. At Brisbane hub, AEMO manually verifies the requested changes to the registered service with the contract issuer.

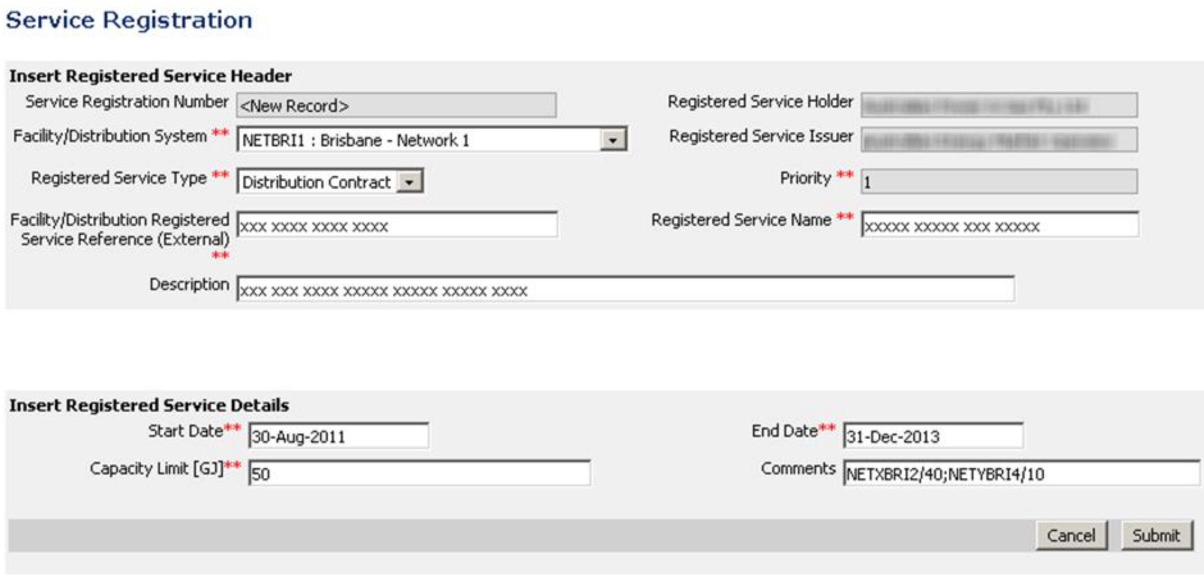
5. AEMO changes status to "Confirmed."
6. AEMO updates the contract holder's trading right.

Process: updating RDS data for a new service at the same hub (Brisbane only)

The contract holder electronically submits changes to the registered capacity on its existing CRN as described in "Process: updating RDS data for an existing registered service" above. The submission must contain the aggregated capacity of all distribution services for the specified date range. The user must provide sufficient details in the Comments field of the submission to permit AEMO to verify the details of any new services with the contract issuer.

For example, Figure 8 shows a modified service registration for the period 30 August 2011 to 31 December 2011 for a total capacity of 50 TJ, comprising 40 TJ on NETXBRI2 (network) and 10 TJ on NETYBRI4 (deemed distribution system).

Figure 8 Using the Comments field to inform AEMO when modifying an existing distribution service



When confirmed, AEMO will update the capacity of the user's CRN and trading right at that hub. No further action is required by the contract holder or contract issuer.

Process: updating trading rights data (RFS only)

1. Registered contract holder electronically submits new trading right data. The electronic submission contains data for only the trading rights that are being updated. The current trading right data remains active and is continued to be used in the STTM until the change has been accepted.
2. AEMO validates the information against the details of the RFS for the specified date range.
3. AEMO updates the trading rights register.
4. AEMO notifies all trading right holders who are affected by the change.
5. AEMO notifies the contract holder that the changes have been implemented.

Related information

- (Shippers only) The capacity of the contract holder's trading right is automatically set to the residual of the capacity of the RFS less the transferred capacities.

- When the capacity of an RFS, RDS, or trading right is changed, bids and offers that have already been submitted and that exceed the updated capacity will be capped at the updated capacity when the market is run. Price taker bids on the same trading right are preferentially scheduled ahead of ex ante bids before being capped.

5.8 Other contracts

Contracts must be registered if the gas supplied under the contract is traded through the STTM.

5.8.1 Upstream demand

Contracts for supply of gas to consumers upstream of the hub need not be registered unless the shipper elects to trade the gas through the STTM. In such cases, the shipper must be registered in the role of STTM shipper and would typically register an RFS to haul the gas (supply) to the hub and another to haul the gas (demand) from the hub.

5.8.2 Matched allocations

Where a matched allocation agreement has been registered with AEMO (as provided in the NGR), the flows to and from the hub associated with this agreement are excluded from the STTM. Matched allocation quantities are excluded from the hub capacity and are not traded in the STTM and so do not require an RFS or trading right.

5.8.3 Transmission-connected users

At the Brisbane hub, the NGR provides for STTM users that are connected to a transmission pipeline—instead of a distribution system. In such cases, the trading participant (a “transmission- connected” STTM user) has the same rights, responsibilities, and abilities as any other STTM user to register their distribution contract as a distribution service and to trade in the STTM. The contract issuer in this case is the pipeline operator with whom the user holds the right to withdraw gas. The processes of registering distribution services and trading rights for transmission-connected users and distribution-connected users are otherwise identical.

6. Trading and Scheduling

Offers to supply gas and bids to withdraw gas from the hub can be submitted any time before the submission window closes at T+5.5 hrs (where T is the hub start time) the day before the gas day. AEMO then runs the Scheduling and Pricing Engine (SPE), which applies the stipulated rules and procedures when scheduling offers and bids submitted by trading participants and calculating market prices.

6.1 Price limits and caps

The price limits that AEMO applies in the operation of the market (see Table 1) are designed to safeguard the trading participants' exposure to inadvertent or unexpected risk. These limits will be reviewed at regular intervals by AEMO in accordance with the NGR, and any recommended changes will be submitted to the Australian Energy Market Commission. The purpose of each limit and the principles by which it is determined are described in the following sections.

Table 1 Settings for price limits

Limit		Setting
Market Price Cap	MPC	Market Price Cap
Minimum Market Price	MMP	Minimum Market Price
Cumulative Price Threshold	CPT	Cumulative Price Threshold
Administered Price Cap	APC	Administered Price Cap
MOS Cost Cap	MCC	MOS Cost Cap
Settlement Surplus Cap	AllCAP	Settlement Surplus Cap

6.1.1 Market Price Cap

Market Price Cap (MPC) is the maximum price allowed in the STTM for all prices set by the STTM, and the submitted price of any type of bid or offer, including contingency gas. It is also applied by the market scheduling and pricing algorithm when there is insufficient available supply to meet forecast withdrawals. In such cases, deviation prices and the cost of trading gas under market schedule variations are capped at MPC.

Principles

- The value of MPC is set with the aim of maximising the opportunity for an efficient market to clear in the short run. This objective implies that longer-term investment costs will be recovered over time, without short-run prices being restricted by long-run average cost.
- The value of MPC is common to all STTM hubs and common across the ex ante market, contingency gas, and the ex post market.

6.1.2 Minimum Market Price

The Minimum Market Price (MMP) is the minimum price allowed in the STTM for all prices set by the STTM, and the submitted price of any type of bid or offer, including contingency gas. The MMP defines the floor for the ex ante market price, the ex post imbalance price, and the high and low contingency gas prices. Any deviation price calculated with a value less than MMP will be reset to MMP.

6.1.3 Cumulative Price Threshold

The Cumulative Price Threshold (CPT) is the value against which a cumulative total of specified maximum prices (the cumulative price) is compared with over a 7-day period, and, if exceeded, will result in an Administered Price Cap State. This protects participants from uncontrollable risks due to high prices being sustained for an extended period of time.

Under the NGR, the CPT is set at 110% of the MPC.

For more information on cumulative price and administered market states.

6.1.4 Administered Price Cap

The Administered Price Cap (APC) is the maximum market price that can be applied under the following conditions:

- Ex ante market price is capped at APC in an Administered Price Cap State or market administered scheduling state.
- Ex post imbalance price, and high and low contingency gas prices are capped at APC in an administered ex post pricing state, Administered Price Cap State, market administered scheduling state, and market administered settlement state.

- Pipeline flow direction constraint price is not capped by APC, although it can be defined to be zero in some circumstances in administered scheduling state or administered settlement state.

Although the APC is primarily a risk management device, its value is set such that the long-run costs of infrastructure serving the market can be recovered.

6.1.5 MOS Cost Cap

The MOS cost cap (MCC) is the maximum price that AEMO can pay for MOS service. MOS price offers are capped at MCC. The MOS cost cap is set as low as is necessary for MOS to be made available to AEMO, while still being greater than the cost of securing additional pipeline capacity.

6.2 Provisional schedules

The SPE is run daily using the current bids and offers available for the two days following the next gas day. These two-day- and three-day-ahead forecasts are published by AEMO daily at T+8.5 hrs. In addition to assisting participants with their own forecasting tasks, the provisional schedules also provide advance warning of potential contingency gas events.

6.3 STTM facility hub capacity data

The operators of STTM facilities provide AEMO with daily estimates of the capacity that their STTM facility has available to deliver gas to the hub on the following three gas days. These capacities exclude any upstream take-off and registered matched allocation agreements that are not traded in the STTM. The hub capacity of an STTM facility limits the quantity of gas that the STTM will schedule for delivery to the hub from that facility on a gas day.

Because the facility hub capacity can have a significant effect on the resulting ex ante schedule, AEMO validates the data submitted daily by the facility operators. If AEMO is unable to obtain valid data by the required cut-off time of 900 hrs on D-1, AEMO will extend the submission window for a maximum of one-and-a-half hours to allow facility operators time to either confirm that their submitted data is valid or submit new data.

If the facility operator fails to submit hub capacity data by the required time (which, in the case of the ex ante schedule, can be extended), the provisional hub capacity information submitted on previous days for the relevant gas day will be used. If no data is available, then the registered default capacity of the STTM facility is used to generate the market schedules and provisional schedules.

Prerequisites

- STTM information system user must be registered as an STTM facility operator

and must be the registered operator of the STTM facility.

Process: submitting hub capacity data

1. Facility operator determines the expected STTM facility hub capacity for the next three days.
2. Facility operator electronically submits STTM facility hub capacity data for each of the facilities that it operates. The data provided includes:
   - Hub identifier
   - STTM facility identifier
   - Gas days to which the estimate relates
   - Estimated hub capacity in whole gigajoules (GJ)

   If hub capacity data exists for a gas day covered by the submission, the old data is replaced by the new data.

3. AEMO validates the submitted data (see following process). Any validation error will result in the rejection of the entire submission.
4. AEMO notifies the facility operator indicating whether the submission was accepted or rejected.

Process: validating hub capacity data

On submission, facility hub capacities are validated for format, integrity, and range. If the submission fails any of these tests, the entire submission is rejected. For the purpose of applying the default capacity, a rejected submission is equivalent to "no submission".

If the allocation passes the above tests, a further validation test is performed to check that it is within a normal range. These warning limits are set by the pipeline operator.

If the hub capacity is within the rejection limits but outside the warning limits, AEMO will notify the facility operator's registered contact by SMS or e-mail. The facility operator can then either confirm (see following process) that the data is correct or can submit new data. But the data is not rejected. If the facility operator does not confirm or does not submit new data by the required time, the latest (not rejected) data is used, but AEMO will flag the value as "unconfirmed".

Process: confirming a submission

1. If the hub capacity is within the rejection limits but outside the warning limits, AEMO will notify the facility operator's registered contact by SMS or e-mail.
2. Facility operator can electronically confirms submission or submits new hub capacity data.

Process: facility operator fails to submit data

1. After the cut-off time for submission of facility hub capacities (or extended cut-off time, see below), AEMO identifies facilities for which a hub capacity has not been received for the next gas day—that is, since gas day start time on D-1.
2. For each facility without a hub capacity, AEMO uses the D-2 hub capacity. If not available, AEMO uses the D-3 hub capacity. Otherwise AEMO uses the default hub capacity.

Timeline

- Estimates for gas day D must be submitted by T+3 hrs on day D-3 and can be amended at any time up to T+3 hrs on day D-1. Amended hub capacities submitted after the cut-off time will not be used when the schedules are generated on that day.
- Before T+3 hrs, the facility operator can resubmit at any time. If a submission is made that is within the warning limits or a submission is confirmed before T+3 hrs, the submission window is not extended. The last valid submission is used when the submission window closes.
- If a submission has not been received by T+3 hrs or a submission has not been confirmed by this time (see validation process above), then the submission window is extended for a maximum of one-and-a-half hours (T+4.5 hrs) or until a valid submission is received or a submission is confirmed,
- After T+3 hrs, once a valid submission has been made or a submission has been confirmed, the submission window is closed and no further submissions can be made.
- If a submission has not been received by T+4.5 hrs (or remains rejected), AEMO performs a default process (see "Process: facility operator fails to submit data" above).
- If a submission has not been confirmed by T+4.5 hrs, AEMO will accept the submission but flags it as unconfirmed.
- Hub capacity data is published not later than 10 minutes after the submission window closes.

6.4 Validating hub capacity data

Because of the importance of hub capacity data to the proper operation of the market, a range validation is performed (in addition to the usual validations for format and data integrity). The process for validating ex ante (D-1) and provisional (D-2, D-3) hub capacities is outlined in Figure 9.

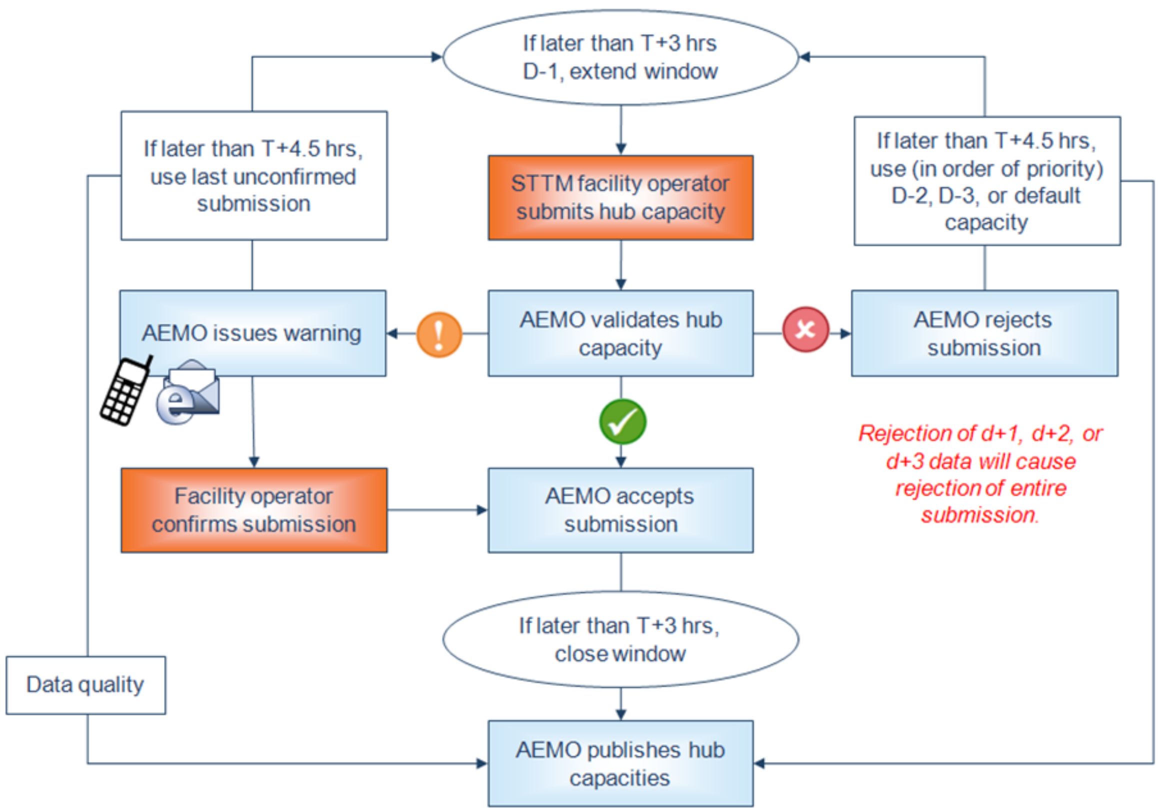
Normally, the pipeline operator submits valid ex ante (for next day) capacity data by the required cut- off time, which is duly accepted. The pipeline operator can resubmit amended data any time up to cut-off time of 900 hrs. Shortly after the submission window closes, AEMO then publishes the hub capacity.

If, however, the data fails the validation test due to a format problem or the value is outside the maximum and minimum hub capacities (see Figure 10), a rejection notice is issued, and the pipeline operator must resubmit. If the pipeline operator fails to submit valid hub capacity data by the normal cut-off time, the submission window is extended by up to one-and-a-half hours to allow the pipeline operator additional time. If a valid submission is made (within the warning limits) after the normal cut- off time, the submission window closes immediately.

If AEMO does not receive a valid submission within one-and-a-half hours of the normal closing time, it applies (in order of priority, if available) the D–2 (submitted the day before), D–3 (submitted two days before), or the default hub capacity (stored in the STTM database and maintained by the pipeline operator).

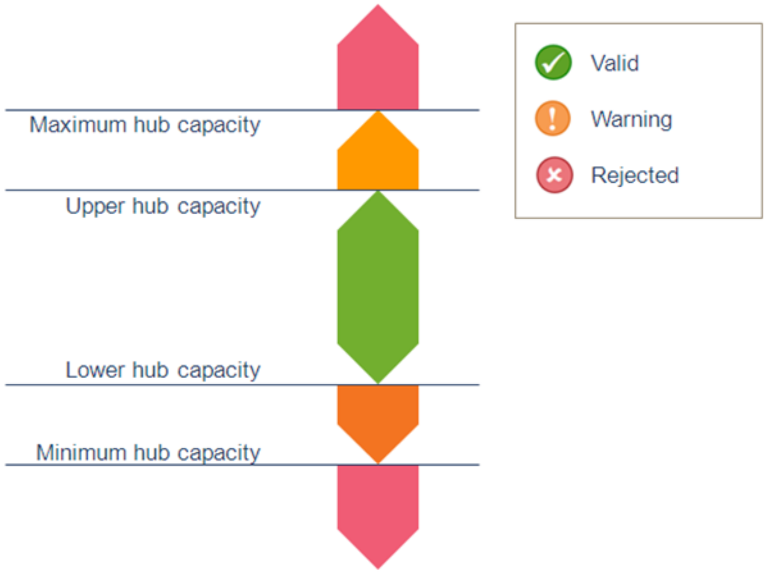
The validation limits provided by the pipeline operator have two levels: the rejection limits (described above) and warning limits (see Figure 10). If the submitted hub capacity is between the warning limits, AEMO issues a warning (by SMS and e-mail) to the pipeline operator, alerting them to a possible problem with the data. But the data is not rejected. This time, the pipeline operator can simply confirm that the data is valid or, if there is a problem, they can resubmit. Again, additional time is provided for this to happen. And should the pipeline operator fail to confirm that the data is valid or fails to submit new data, then AEMO will accept the last submission but will set a data quality flag to show that the data was unconfirmed.

Figure 9 Ex ante hub capacity validation process



The validation process for provisional data is similar to the ex ante data, but no warnings are issued. Because the ex ante data (for the next day) and provisional data (for the following two days) are submitted together, if either fail the validation test, then the entire submission will be rejected.

Figure 10 Hub capacity validation limits



6.5 Ex ante offers

A trading participant must submit ex ante offers to supply gas to the hub, including gas transported over or parked in pipelines, or gas injected directly from production facilities and storage facilities.

Prerequisites

- STTM information system user must be a registered trading participant.
- Trading participant must be an STTM shipper with trading rights that allow delivery of gas to the hub from an STTM pipeline, STTM storage facility, or STTM production facility.

Process: submitting new ex ante offers interactively

1. Trading participant can choose to view their current and historical trading rights data.
2. Trading participant can choose to view their current and historical bids and offers for a date range.
3. Trading participant selects to submit a new ex ante offer.
4. Trading participant enters the details of an ex ante offer by:

   Selecting a trading right and applicable capacity from available trading rights held by the trading participant (see Figure 11).

   Entering a date range.

   Entering up to 10 price-quantity steps for the specified date range for the selected trading right (see Figure 12).

   Offers are made for each entire gas day in the specified date range, including the starting and ending dates. Price steps are entered in increasing order of price with cumulative quantities of gas. Quantities are in whole gigajoules (GJ) and prices are in $/GJ to four decimal places. The total quantity offered cannot exceed the capacity of the trading right.
5. Trading participant submits the offer.

6. AEMO validates the offer. The trading participant is notified if the offer is rejected. Any error will result in the entire offer being rejected.
7. AEMO sends details of each successful offer to the trading participant's MIS report folder.
8. Trading participant submits additional offers for other date ranges and trading rights.

Figure 11 Selecting an ex ante offer in the STTM

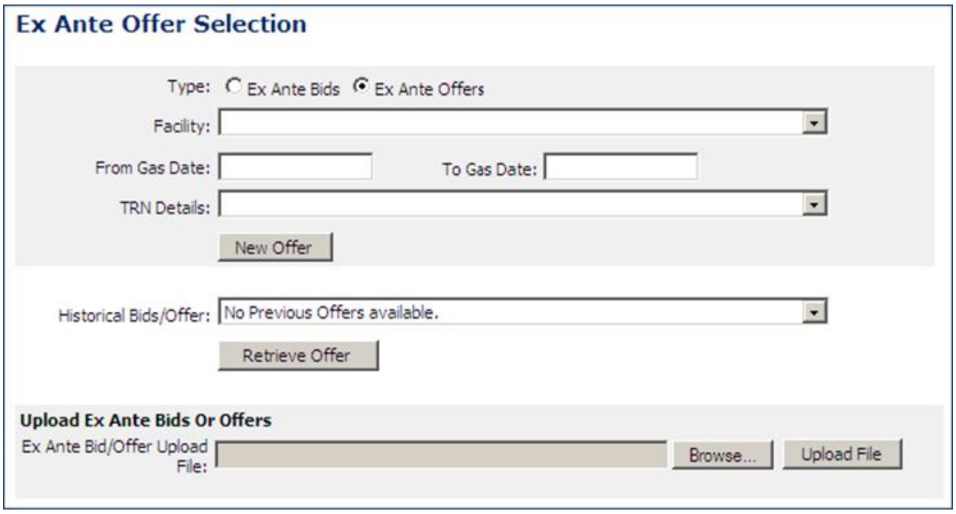
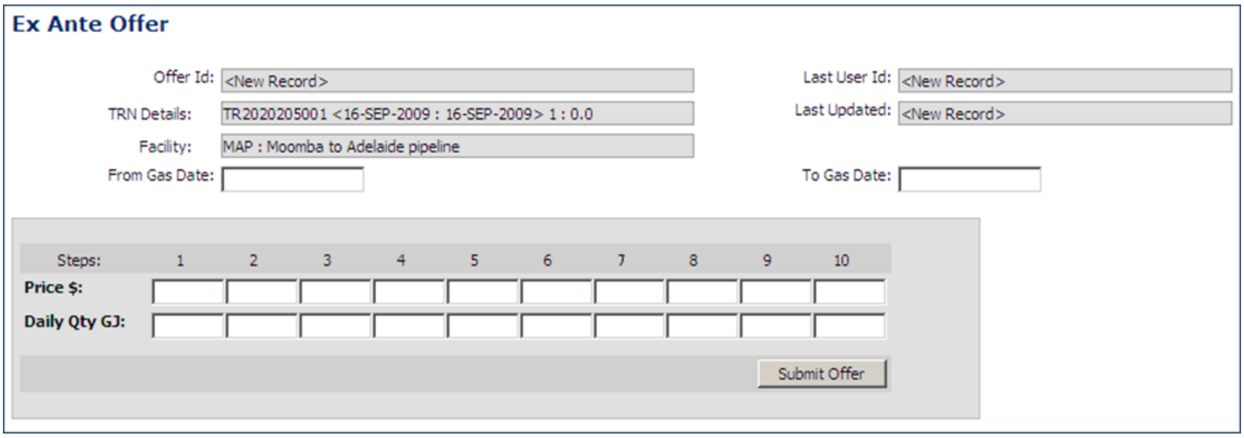


Figure 12 Submitting an ex ante offer in the STTM



Process: uploading new ex ante offers

1. Trading participant selects to upload an ex ante offer (see Figure 11).
2. Trading participant selects the CSV file.
3. Trading participant uploads and submits the CSV file.
4. AEMO validates the offer. The trading participant is notified if the offer is rejected. Any error will result in the entire offer being rejected.
5. AEMO sends details of each successful offer to the trading participant's system folder.

Process: replacing existing offers

- Once submitted, an offer cannot be cancelled or modified. But it can be replaced. All offers have explicit date ranges. If there is an existing offer for the same trading right on each or any date in the date range of the new offer, the existing offer is entirely replaced (all price steps) for that date by the new offer. Only offers on the same trading right are replaced. Only offers on the overlapping dates are replaced.

Timeline

- STTM offers used in provisional schedules should be submitted any time before T+7.5 hrs on day D-2 and D-3. Trading participants are encouraged to place offers at the earliest possible date so that the provisional schedules prepared on day D-2 and D-3 give a meaningful forecast for gas day D.
- Final STTM offers can be submitted for gas day D at any time before T+5.5 hrs on gas day D-1.

Related information

- A single-step zero-gigajoule offer can be submitted. This will effectively cancel any existing offers for that trading right over that date range.
- When trading rights data is updated, any current offers associated with that trading right might also need to be replaced to ensure that the total quantities offered are valid. Otherwise, the quantity scheduled may be limited to the quantity offered at the original capacity.

6.6 Ex ante bids

A trading participant must submit ex ante bids to withdraw gas from the hub. Price taker bids (for withdrawals by STTM users only), which can be submitted on the same trading right.

Prerequisites

- STTM information system user must be a registered trading participant.
- Trading participant must be either an STTM shipper with trading rights that allow the transport of gas away from the hub, or an STTM user with a trading right that allows withdrawal of gas at the hub.

Process: submitting new ex ante bids interactively

1. Trading participant can choose to view their current and historical trading rights data.
2. Trading participant can choose to view their current and historical bids and offers for a date range.
3. Trading participant selects to submit a new ex ante bid.
4. Trading participant enters the details of a bid by:

   Selecting a trading right and applicable capacity from available trading rights held by the trading participant (see Figure 13).

   Entering a date range.

   Entering up to 10 price-quantity steps for the specified date range for the selected trading right (see Figure 14).

   Bids are made for each entire gas day in the specified date range, including the starting and ending dates. Price steps are entered in decreasing order of price with cumulative quantities of gas. Quantities are in whole gigajoules (GJ) and prices are in $/GJ to four decimal places. The total quantity bid cannot exceed the capacity of the trading right.
5. Trading participant submits the bid.
6. AEMO validates the bid. The trading participant is notified if the bid is rejected. Any error will result in the entire bid being rejected.
7. AEMO sends details of each successful bid to the trading participant's MIS reports folder.
8. Trading participant submits additional bids for other date ranges and trading rights.

Figure 13 Selecting an ex ante bid in the STTM

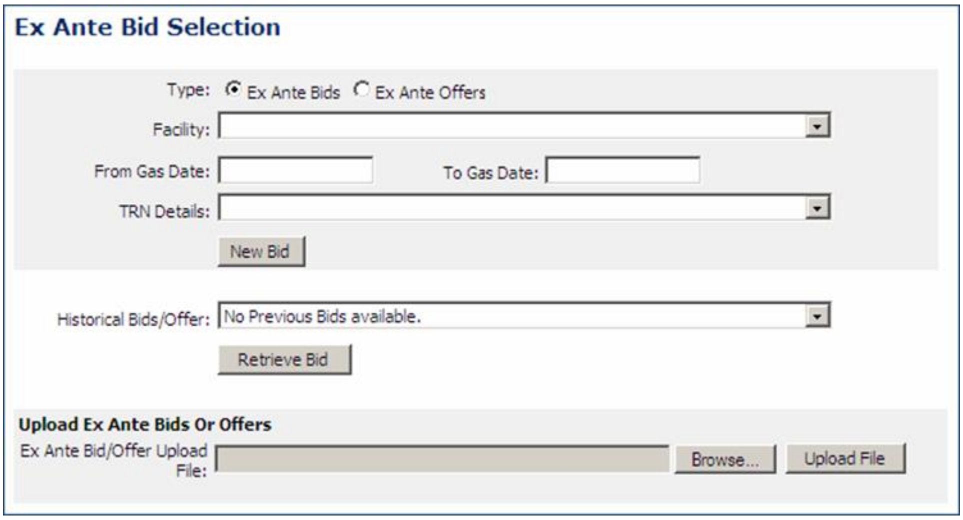
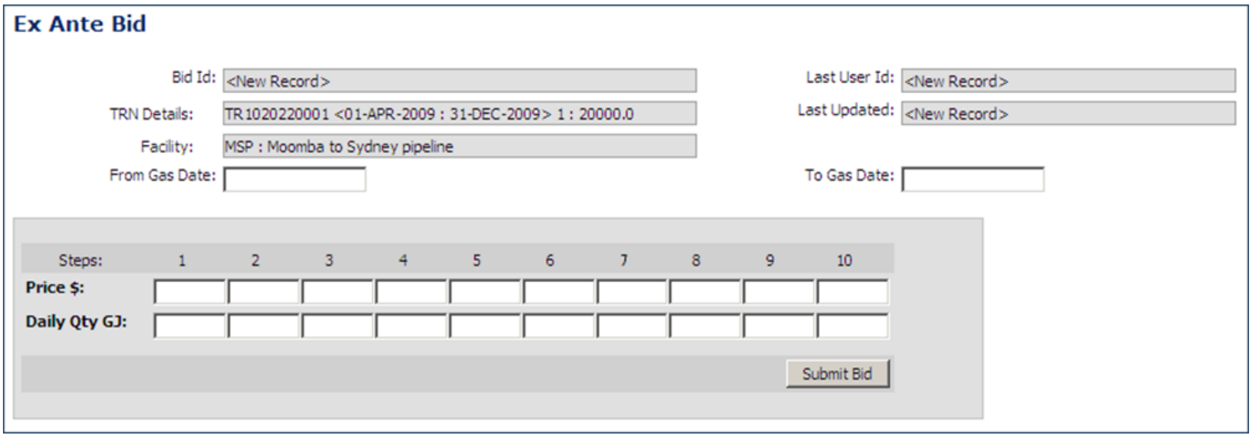


Figure 14 Submitting an ex ante bid in the STTM



Process: uploading new ex ante bids

1. Trading participant selects to upload an ex ante bid (see Figure 13).
2. Trading participant selects the CSV file.
3. Trading participant uploads and submits the CSV file.
4. AEMO validates the bid. The trading participant is notified if the bid is rejected. Any error will result in the entire bid being rejected.
5. AEMO sends details of each successful bid to the trading participant's system folder.

Process: replacing existing bids

- Once submitted, a bid cannot be cancelled or modified. But it can be replaced. All bids have explicit date ranges. If there is an existing bid for the same trading right on each or any date in the date range of the new bid, the existing bid is entirely replaced (all price steps) for that date by the new bid. Only bids on the same trading right are replaced. Only bids on the overlapping dates are replaced.

Timeline

- STTM bids used in provisional schedules should be submitted any time before T+7.5 hrs on day D-2 and D-3. Trading participants are encouraged to place bids at the earliest possible date so that the provisional schedules prepared on day D-2 and D-3 give a meaningful forecast for gas day D.
- Final STTM bids can be submitted for gas day D at any time before T+5.5 hrs on gas day D-1.

Related information

- A single-step zero-gigajoule bid can be submitted. This will effectively cancel any existing bids for that trading right over that date range.
- When trading rights data is updated, any current bids associated with that trading right may also need to be replaced to ensure that the total quantities bid are valid. Otherwise, the quantity scheduled may be limited to the quantity bid at the original capacity.

6.7 Price taker bids

An STTM user can place a price taker bid, which specifies the quantity of gas it will accept at any price.

Prerequisites

- STTM information system user must be a registered trading participant.
- Trading participant must be an STTM user with a trading right that allows withdrawal of gas at the hub.

Process: submitting new price taker bids interactively

1. Trading participant can choose to view their current and historical trading rights data.
2. Trading participant can choose to view their current and historical bids for a date range.
3. Trading participant selects to submit a new price taker bid.
4. Trading participant enters the details of a price taker bid by:

   Selecting a trading right and applicable capacity from available trading rights held by the trading participant.

   Entering the date of the gas day.

   Entering a quantity for the specified date for the selected trading right.

   Price taker bids are made for an entire gas day. Quantities are in whole gigajoules (GJ). The quantity of the price taker bid plus the total quantity of any ex ante bid made on the same trading right for the same day cannot exceed the capacity of the trading right.
5. Trading participant submits the price taker bid.
6. AEMO validates the bid. The trading participant is notified if the bid is rejected.
7. AEMO sends details of each successful price taker bid to the trading participant's system folder.
8. Trading participant submits additional price taker bids for other dates and trading rights.

Process: uploading new price taker bids

1. Trading participant selects to upload a price taker bid.
2. Trading participant selects the CSV file.
3. Trading participant uploads and submits the CSV file.
4. AEMO validates the bid. The trading participant is notified if the bid is rejected.
5. AEMO sends details of each successful price taker bid to the trading participant's system folder.

Process: replacing existing price taker bids

- Once submitted, a price taker bid cannot be cancelled or modified. But it can be replaced. All price taker bids have an explicit date. If there is an existing price taker bid for the same trading right and on the same date as the new price taker bid, the existing price taker bid is replaced. Only the price taker bid on the same trading right and the same date is replaced.

Timeline

- Price taker bids used in provisional schedules should be submitted any time before T+7.5 hrs on day D-2 and D-3. Trading participants are encouraged to place bids at the earliest possible date so that the provisional schedules prepared on day D-2 and D-3 give a meaningful forecast for gas day D.
- Final price taker bids can be submitted for gas day D at any time before T+5, 5 hrs on gas day D-1.

Related information

- A zero-gigajoule price taker bid can be submitted. This will effectively cancel any existing price taker bid for that trading right on that date.

6.8 Validating bids and offers

On submission, ex ante offers, ex ante bids, and price taker bids are validated for:

Data integrity

- Date format is valid.
- Dates are not earlier than the next gas day.
- Quantities are integers, are non-negative (≥0), and increase with each step.
- Offer prices are expressed up to four decimal places, are greater than or equal to MMP and less than or equal to MPC, and increase with each step.
- Bid prices are expressed up to four decimal places, are greater than or equal to MMP and less than or equal to MPC, and decrease with each step.

Trading rights

- Trading right is held by the trading participant.
- Trading right is valid for the entire date range of the bid or offer.
- Total quantity of all ex ante bid price steps plus any price taker bid associated with the same trading right does not exceed the trading right capacity on each gas day in the date range.
- Total quantity of all ex ante offer price steps does not exceed the selected trading right capacity on each gas day in the date range.

6.9 Scheduling and prices

Each day, AEMO produces market schedules for the following three gas days. The D-2 (two-day ahead) and D-3 (three-day ahead) provisional schedules provide forecasts for gas day D. The D-1 (one-day ahead) schedule is the ex ante market schedule for gas day D. The ex ante market schedules are generated daily as soon as practicable after the submission window for bids and offers closes at T+5.5 hrs, and are published not later than T+6.5 hrs the same day. The provisional schedules are generated daily as soon as practicable after T+7.5 hrs, and are published not later than T+8.5 hrs the same day. For more information about publishing timelines.

6.9.1 Scheduling data

All valid data submitted by the required cut-off times is used to generate the schedules:

Cut-off times for ex ante market schedules

- STTM facility hub capacities as at T+4.5 hrs on D-1
- STTM offers, bids and price taker bids as at T+5.5 hrs on D-1

Cut-off times for provisional schedules

- STTM facility hub capacities as at T+6.5 hrs on D-2 and D-3
- STTM offers, bids and price taker bids as at T+7.5 hrs on D-2 and D-3

The data is used by the Scheduling and Pricing Engine (SPE) to create the market schedule for a gas day includes:

- All current ex ante offers that are valid for that gas day.
- All current ex ante bids (see Section 7.6) and price taker bids that are valid for that gas day.
- The current STTM facility hub capacities for each STTM facility that serves the hub.
- The capacities and haulage priorities of registered facility services.
- The capacities of registered trading rights.
- Price limits
- Scheduling parameters provided by AEMO, which are used to resolve solution ambiguities and infeasibilities.
- For ex post schedules, the market long offer and market short bid.

6.9.2 Scheduling constraints

The SPE applies the following constraints when the scheduling data is analysed:

Hub energy balance constraint

The total quantity of ex ante offers scheduled across all STTM facilities serving each hub must equal the total quantity of ex ante bids and price taker bids scheduled to withdraw gas at the hub plus the total quantity of ex ante bids scheduled to haul gas away from the hub. In other words, an energy balance is achieved by the solution, such that

$$\sum Qw + \sum Qb = \sum Qo \qquad \text{........................} \quad (1)$$

Where

Qw are price taker withdrawal quantities

Qb are ex ante bid quantity steps

Qo are ex ante offer quantity steps

Trading right capacity constraint

- The total quantity of gas scheduled from ex ante offers associated with the same trading right cannot exceed the capacity of that trading right.
- The total quantity of gas scheduled from ex ante bids and price taker bids associated with the same trading right cannot exceed the capacity of that trading right.

Note. If the capacity of a trading right is changed between when the offer or bid was validated (on submission) and when the schedule is run, then the offer or bid may be capped when it is considered for scheduling.

Pipeline hub capacity constraint

- The total quantity of ex ante offers scheduled on the same STTM facility cannot exceed the STTM facility hub capacity for that facility.

Pipeline flow-direction constraint

- The total quantity of gas scheduled to be hauled away from the hub on an STTM facility cannot exceed the total quantity of gas scheduled to be hauled to the hub on the same STTM facility.

Bid and offer step quantity constraint

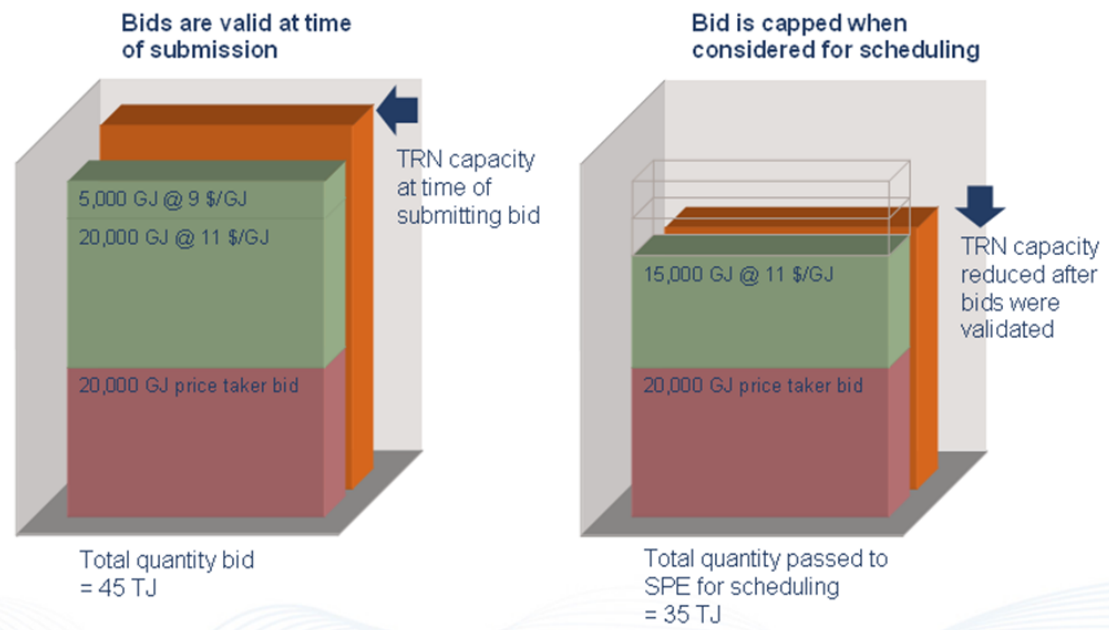
- The quantity scheduled from a price taker bid, an offer step, or a bid step, must be between zero and the incremental quantity available from that step.

6.9.3 Capping bids and offers

If the cumulative quantity of steps in an offer or bid exceeds the trading right capacity (at the time of running the schedule), it is capped at the trading right capacity. When an offer or bid is capped, the quantity of the step at which the capacity is exceeded is adjusted downwards, and the quantities of subsequent steps are set to zero.

On an STTM user's trading right, price taker bids are considered first, and then bid steps are considered in decreasing price order until the trading right capacity is reached. Offer steps are considered in increasing price order until the trading right capacity is reached.

Figure 15 Example of how a price taker bid and ex ante bid steps on the same TRN are capped



6.9.4 Scheduling parameters

Small increments or adders are used in the SPE to resolve ambiguities and infeasibilities that can arise when solving the scheduling problem. AEMO sets and revises these parameters to achieve the required behaviour of the SPE without distorting market prices. These values are very small and are not reflected in the resulting schedule quantities (1 GJ precision) or prices (0.0001 $/GJ precision).

6.9.5 Scheduling process

After the data submission windows have closed, the process of scheduling the market is performed by AEMO. The basic steps involved are:

1. AEMO generates reports, as required, for:
   - Ex ante offers, ex ante bids, and price taker bids available at the cut-off time.
   - STTM facility hub capacities missing at the cut-off time.
   - Trading rights utilisation at the cut-off time.
2. AEMO runs the schedule for each hub; once to generate the ex ante market schedule for the following gas day, and twice to generate provisional schedules for the two- and three-day ahead forecasts.

Note. The SPE is also used to generate the ex post schedule

Each time, the SPE is run using the available scheduling data within the scheduling constraints. The scheduling process produces the following outputs:

- The quantity in GJ to be delivered to or withdrawn from the hub by each shipper, reported by trading right.
- The quantity in GJ to be withdrawn at the hub by each user, reported by trading right.
- Ex ante market price in units of $/GJ.
- Capacity price for each pipeline in units of $/GJ.
- Pipeline flow direction constraint price for each pipeline in units of $/GJ.

All prices are reported to a resolution of $0.0001, and all quantities are reported to a resolution of 1 GJ.

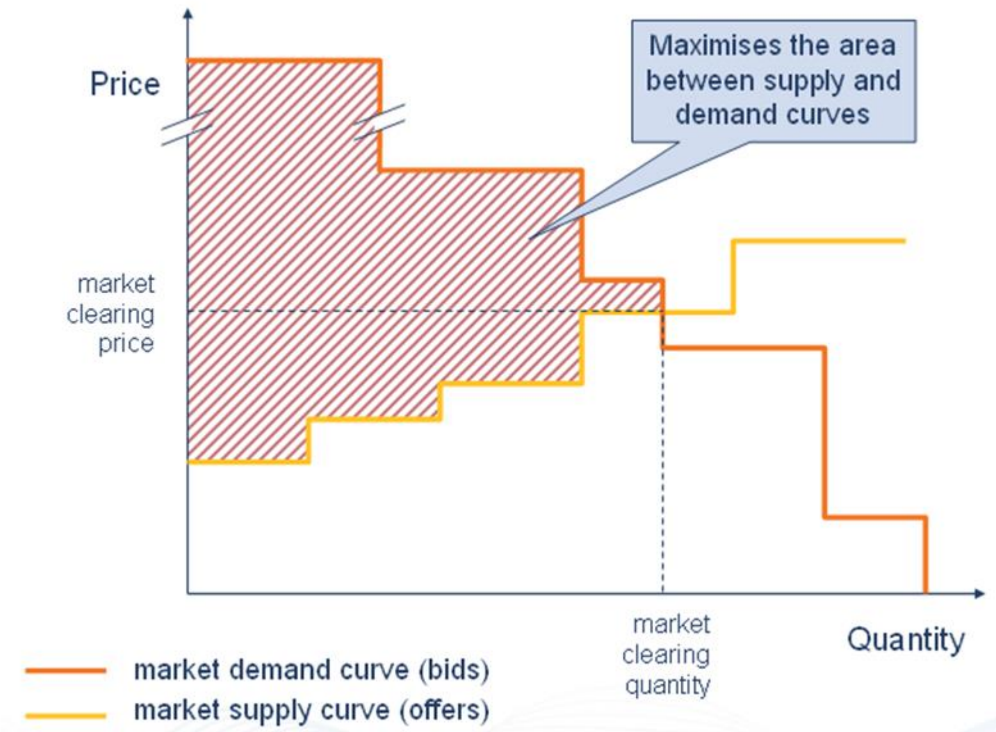
3. AEMO reviews the schedules and prices to identify if schedules and prices need to be administered, and to identify if contingency gas measures are indicated. AEMO has the option to run multiple schedules, which might occur to resolve IT issues, or (for reasons unrelated to the current schedule) if an administered state is triggered prior to the cut-off time for publishing a schedule.
4. AEMO issues the schedules and prices.

6.9.6 Scheduling and pricing algorithm

Central to the STTM is the scheduling and pricing algorithm (SPA) which applies the rules (stipulated by the NGR) when scheduling offers and bids submitted by trading participants and calculating market prices. The SPE is the software implementation of the SPA.

AEMO applies the SPA to determine the two-day- and three-day-ahead provisional schedules and prices, the ex ante market schedule and market prices, and the ex post imbalance price. The SPA solves a linear programming (LP) problem that seeks to maximise the amount by which the value of bids and price taker withdrawals scheduled (based on bid prices) exceeds the cost of offers (based on offer prices) while satisfying the constraints.

Figure 16 SPA maximises the benefit to the market



6.9.7 Scheduling offers and bids

The SPA must schedule the offers and bids in price order. There are, however, situations where a unique solution cannot be found, and so the SPA employs a tie-breaking logic, which ensures that any ambiguities are removed. This is achieved by adding or subtracting small values from the supply or demand curve. The logic employed does not change prices or the overall demand at the hub.

Note. Tie-breaking can only be achieved to the extent allowed by constraints on the problem. For example, if tie-breaking logic requires that an offer is scheduled at a quantity that would exceed the facility hub capacity, then a lesser quantity will be scheduled than the tie-breaking rules allow.

Special scheduling cases addressed by the SPA tie-breaking logic include:

Price taker withdrawals have priority

Price taker withdrawals are scheduled ahead of all other bids by setting their price fractionally greater than the highest price allowed by the market.

Price taker bids cannot be fully scheduled

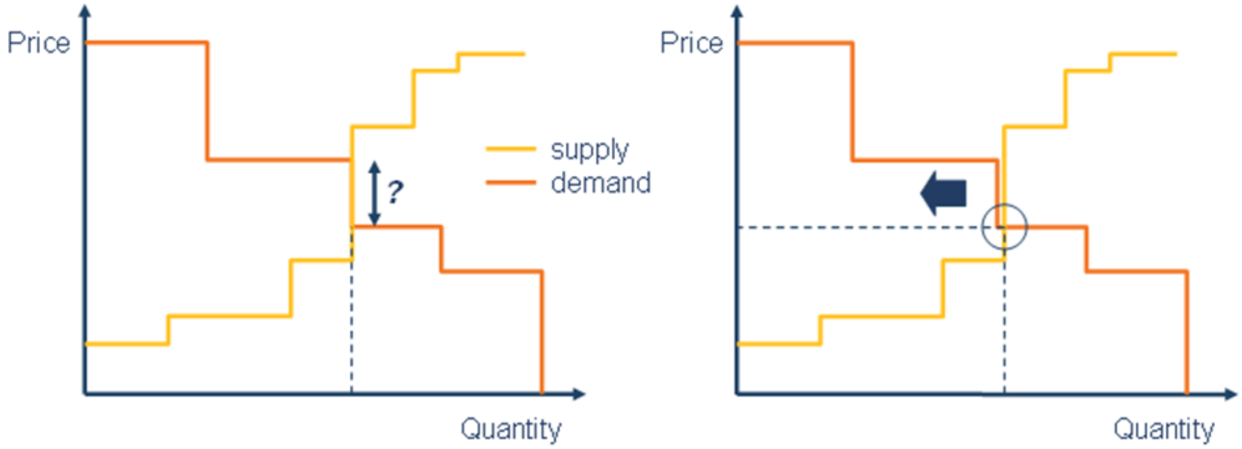
If all price taker bids cannot be fully scheduled, they are scheduled in proportion to the quantity bid, allowing for trading right capacities.

The market clears between offer and bid steps

When the market clears between bid and offer steps, this can result in a market-clearing price ambiguity, a pipeline capacity price ambiguity, or a market-clearing quantity ambiguity. These three cases are illustrated and described below.

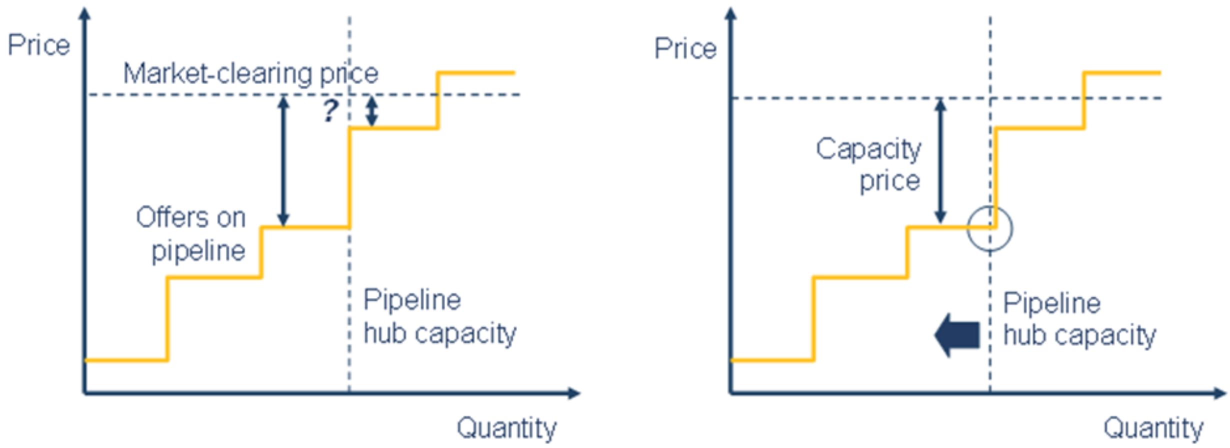
Referring to Figure 17, there is a range of prices at which the market can clear at the hub. It is resolved by reducing total demand at the hub by a small quantity. This approach minimises the hub price.

Figure 17 Market-clearing price ambiguity is resolved by subtracting a small value from the total demand



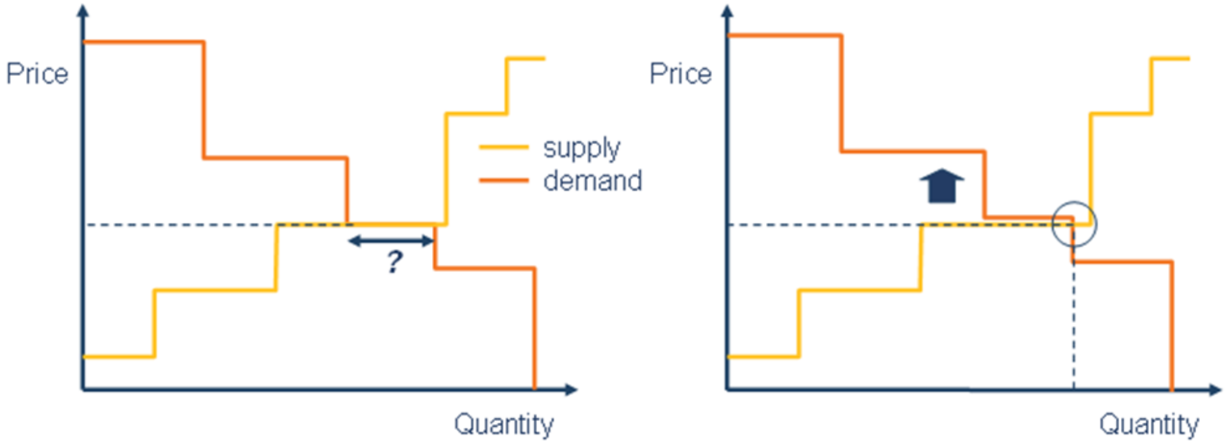
Referring to Figure 18, clearing the market between two offers steps can also produce a range of capacity prices on a pipeline. This is resolved by reducing the pipeline hub capacity by a small quantity, which has the effect of maximising capacity prices.

Figure 18 Pipeline capacity price ambiguity is resolved by subtracting a small value from the pipeline hub capacity



Referring to Figure 19, there is a range of quantities at which the market can clear. This is resolved by adding a small value to each bid step, which has the effect of maximising the supply to the hub.

Figure 19 Market-clearing quantity ambiguity is resolved by adding a small value to each bid step



Bid steps are tied and cannot be fully scheduled

The SPA employs the following logic when bids by users and shippers are tied at the same price:

1. Tie-break between facilities:
   – The total quantity of tied bids is scheduled between facilities (STTM facilities and STTM distribution systems) in proportion to the total tied quantity bid on each facility.
2. Tie-break between bids on each facility:
   – For bids by users, schedule in proportion to the quantity of each bid step.
   – For bids by shippers, on each pipeline, schedule the quantity available on that facility to tied bids by their haulage priority. For example, priority 2 bids are fully scheduled before priority 3 bids. For bids with equal priority on the same pipeline, schedule in proportion to the quantity of each bid step.

Offer steps are tied and cannot be fully scheduled

The SPA employs the following logic when offers are tied at the same price:

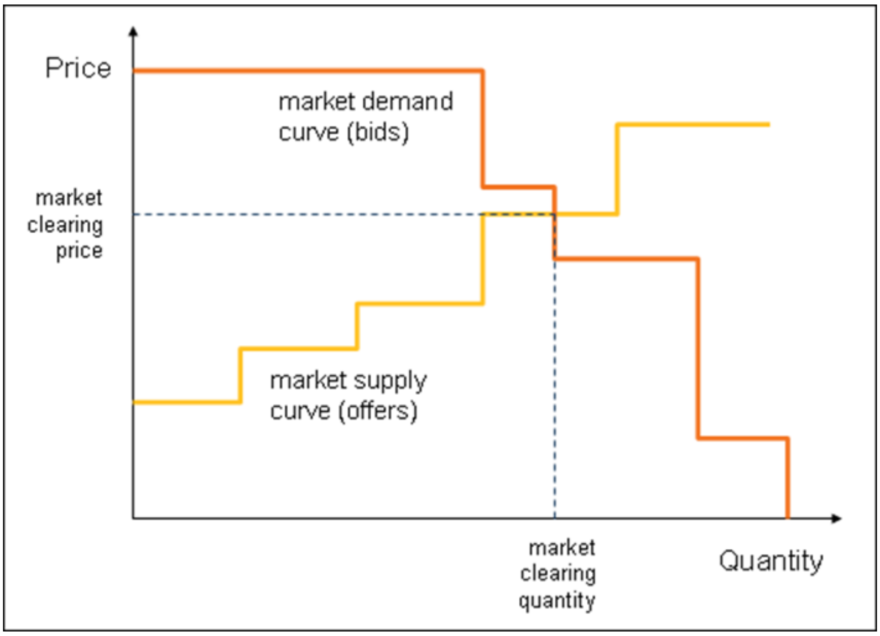
1. The optimisation is first solved without imposing tie-breaking between offers on different STTM facilities, which allows tied bids to be correctly determined.
2. Offers are then grouped by price and priority and then scheduled from these groups to meet bids on the same pipeline. The lowest cost and highest priority gas is used first.
3. Offers not scheduled in step 2 are then considered in inter-facility tie-breaking. Where ties exist, gas is portioned between the pipelines based on the remaining quantities in each group of offers.
4. The quantity scheduled on each pipeline is the sum of the quantities scheduled in steps 2 and 3. These total quantities are assigned to individual offers with the lowest cost and highest priority gas is used first.

6.9.8 Determining the ex ante market price

The SPA determines the ex ante market price, or market clearing price, which is the marginal cost at which a small increase or decrease in demand at the hub is satisfied. Conceptually, the market supply curve is formed by stacking all offers to supply gas to the hub in increasing order of price up to the capacity of each pipeline. The market demand curve is formed by stacking all bids to withdraw gas from the hub or withdraw gas at the hub in decreasing order of price. The point at which the curves intersect is the market clearing point and defines the market clearing price (ex ante market price) and the optimal demand at the hub. Constraints are applied to ensure that the quantities of gas scheduled do not exceed a facility's hub capacity.

This is represented graphically in Figure 20 (this is a simplification).

Figure 20 Market supply and demand curves



For example, if the highest priced offer scheduled on pipeline 1 is 6.0 $/GJ and further demand is met on pipeline 2 with a highest priced scheduled offer of 7.0 $/GJ, then the ex ante market price is set by pipeline 2 at 7.0 $/GJ. Examples of how the market clearing point is set under other market conditions are shown in Figure 21.

Figure 21 Market clearing point examples

6.9.9 Determining capacity prices

On an unconstrained pipeline, the notional price of gas on the pipeline (or the pipeline price) equals the ex ante market price. On a constrained pipeline, the pipeline price is set at the price of the highest priced offer scheduled on that pipeline. The capacity price (CP) of pipeline k on day d is the difference between the ex ante market price (HP) and the pipeline price (PP):

```
CP(d,k) = HP(d) – PP(d,k)                    ........................ (2)
```

Hence, on an unconstrained pipeline, the capacity price is always zero, and on a constrained pipeline, the capacity price can be greater than zero. For example, if the highest priced offer scheduled on pipeline 1 is 6.0

$/GJ, and further demand is met on pipeline 2, and the ex ante market price is 7.0 $/GJ, then the capacity price on pipeline 1 is 1.0 $/GJ, and the capacity price on pipeline 2 is zero.

The maximum capacity price possible on an STTM facility is the difference between MPC and MMP.

6.9.10 Determining pipeline flow direction constraint prices

A pipeline flow direction constraint (PFDC) restricts the total quantity of gas scheduled to be flowed away from the hub on an STTM facility such that it cannot exceed the total quantity of gas scheduled to be hauled to the hub on the same STTM facility.

Where a pipeline is flow-direction constrained, situations can arise where bids to haul gas away from the hub that are higher than the market clearing price can be economically supplied by offers on the same pipeline that would not otherwise be scheduled, all without affecting the net supply at the hub. In such cases, a non-zero pipeline flow direction constraint price is applied to scheduled offers and bids on that pipeline. The pipeline flow direction constraint price is otherwise (and usually) zero. The net flow on the pipeline remains zero, but more gas is flowed in each direction.

The SPA determines all prices (including the ex ante, ex post, capacity, and PFDC prices) such that they reflect the marginal cost of supplying gas. The marginal cost is the incremental change in the cost of matching supply with demand caused by an incremental change in demand. The price set will depend on the many factors considered by the SPA when it solves the optimisation problem. Among other factors, the SPA ensures that the following constraints are satisfied:

The total supply to the hub must equal the total demand.

The total flow to the hub on an STTM facility must not exceed the STTM facility hub capacity.

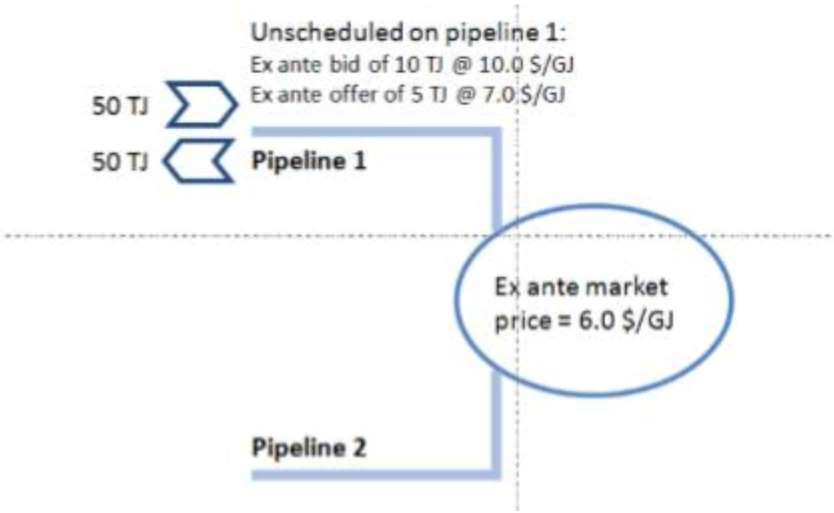
The total flow from the hub on an STTM facility must not exceed the total flow to the hub on that facility.

The first two constraints are most directly related to how the SPA determines the ex ante market price and pipeline constraint prices, respectively. That is, the cost of an incremental change in demand at the hub (constraint a) is reflected in the ex ante market price, while the cost of an incremental change in the capacity of a pipeline (constraint b) is reflected in the capacity price for that pipeline.

Similarly, the cost of an incremental change in constraining flow away from the hub on a pipeline (constraint c) is reflected in the PFDC price. If incrementally more gas is permitted to flow away from the hub than is flowed to the hub on a pipeline, then the solution might change on the margin in a number of different ways. The most efficient outcome—the one that maximises the difference between the changed value of withdrawals and the changed cost of supply—will set the PFDC price.

For example, if flow to the hub and flow from the hub on pipeline 1 is 50 TJ, and the ex ante market is cleared at a price of 6.00 $/GJ by an offer on pipeline 2, but there is a bid of 10 TJ at 10.00 $/GJ to take gas away from the hub on a pipeline 1, and, on the same pipeline, there is an offer to supply 5 TJ at 7.00 $/GJ. In this situation, it makes sense to schedule the 5 TJ of the 7.00 $/GJ offer to satisfy the demand at 10.00 $/GJ, even though the offer price is above the market clearing price.

Figure 22 Example: non-zero PFDC price

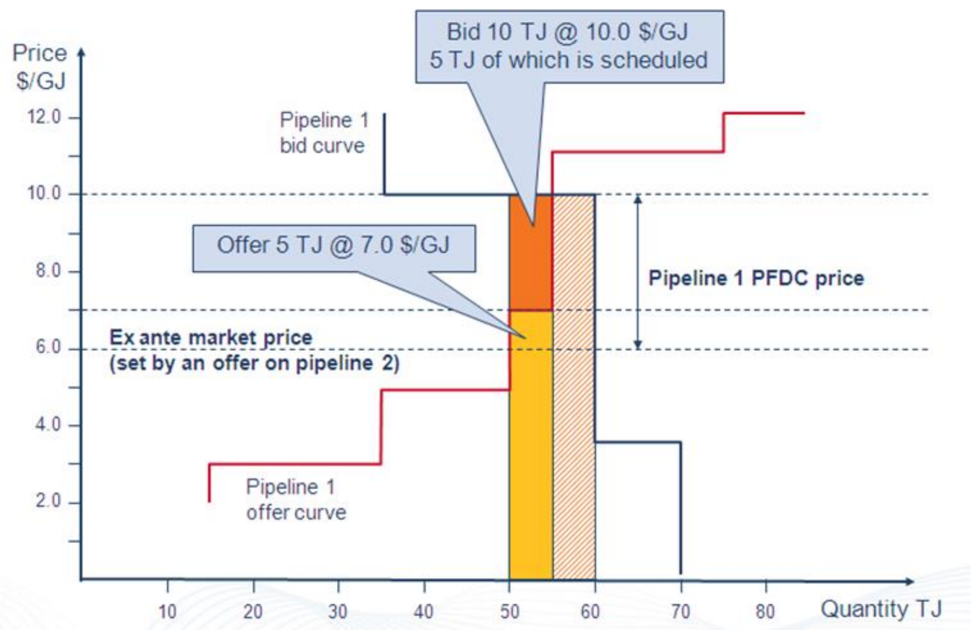


So the options are:

- Do nothing at a net market benefit of zero.
- Flow an extra 1 GJ to the hub on the pipeline at the ex ante market price of 6 $/GJ to allow 1 GJ extra to flow from the hub, which creates a benefit of $10. The net market benefit is thus $4.

The second option maximises the benefit to the market, with a net market benefit of $4 for a 1 GJ change in directional flow constraint. Hence the ability to flow 1 GJ more gas away from the hub than is flowed to the hub has a value of 4 $/GJ, which is the PFDC price.

Figure 23 Example: bid-offer stack on pipeline with non-zero PFDC price



The PFDC price is paid by all shippers withdrawing gas from the hub on that pipeline. To compensate the supplying shippers (who would otherwise only receive the ex ante market price), the PFDC price is paid to all shippers supplying the hub on that pipeline.

6.10 Issuing market prices and schedules

AEMO issues the market prices and ex ante market schedules for each trading participant by T+6.5 hrs the day before the gas day. Failure to publish prices or schedules by this time (in the absence of a provisional schedule) can trigger a market administered scheduling state .

Note. Once the ex ante market price and other market prices have been published, they are never amended, even consequent to disputes and data revisions.

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7. Producer and Pipeline Nominations and Schedules (non-STTM)

After the ex ante market schedules are published, shippers make nominations to producers and pipeline operators in accordance with their relevant contracts. The process by which trading participants communicate their nominations to their producer or pipeline operators is not part of the STTM. Similarly, the STTM has no involvement in any distribution processes for managing the scheduling of withdrawals from a hub. Shippers will nominate to pipeline operators and users will nominate to distributors in accordance with the contracts they hold with those operators.

A shipper is required to submit offers for scheduling by AEMO in good faith under the NGR. A pipeline operator might, for operational reasons, be unable to schedule the pipeline in accordance with nominations received from shippers, even if shippers nominate in accordance with their market schedules.

During the gas day, as consumption requirements at the hub become clearer, and depending on the terms of their haulage contracts, shippers may be able to renominate quantities to adjust their positions. To the extent that these renominations can be accommodated within the available capacity, the pipeline operator will usually schedule the adjusted quantities for transportation.

At the end of the gas day, the facility operators determine the net quantities that flowed to the hub over the gas day. The difference between the final pipeline schedule (including intraday nominations) and the net quantities that actually flowed to the hub is called a “pipeline deviation”. Pipeline deviations are handled in the STTM by a market operator. These deviations can lead to additional charges or reduced payments to the shippers involved in the deviation. Shippers can avoid the charges and payments arising from deviations by submitting market schedule variations to AEMO.

8. Market Operator Service

The market operator service (MOS) is a daily mechanism for allocating balancing gas provided by pipelines to maintain pressures at receipt points. This balancing gas is the difference between what was scheduled by a pipeline operator and the actual quantities of gas flowed on a pipeline on the gas day. MOS is managed by AEMO through arrangements established with MOS providers (STTM shippers) and is implemented through a daily process under which pipeline operators provide pipeline allocation data to AEMO.

When the net flow on a STTM pipeline deviates from the final pipeline schedule, then MOS is deemed to have provided the gas. The pipeline operator allocates MOS in accordance with the relevant MOS stack issued by AEMO for each pipeline. If the MOS stack is exhausted, any residual pipeline deviation is allocated as overrun MOS.

The MOS provider's modified market schedule is adjusted to account for MOS and overrun MOS allocations and so do not attract deviation charges and payments.

8.1 Procuring MOS

Every three months, AEMO estimates the MOS requirements for the next MOS period (the MOS estimate). Each month AEMO seeks MOS offers from trading participants who want to provide MOS gas. Only STTM shippers holding MOS enabled trading rights can offer MOS. MOS providers can submit MOS offers for future MOS periods before 1700 hrs 11 gas days before the start of the next MOS period.

MOS providers can submit a MOS increase offer to increase flow to the hub consisting of up to ten price-quantity steps (MOS increase steps). Similarly, an offer to decrease flow to the hub (MOS decrease offer) can contain up to ten MOS decrease steps. A MOS provider can place a maximum of one MOS increase offer and one MOS decrease offer on an STTM facility. Each offer step specifies a price and quantity and must be associated with one or more MOS enabled trading rights held by the MOS provider. Price steps are capped at the MOS cost cap.

The MOS provider is only paid if and when MOS gas is supplied. The MOS provider is paid for providing the MOS service (the costs associated with storing and transporting gas) at the offered MOS increase or decrease step price, and receives separate payment (or is charged) for the commodity cost of MOS gas. For more information.

8.2 Issuing MOS stacks

AEMO will accept all valid MOS offers, irrespective of the MOS estimate, and uses these to prepare a MOS increase stack and a MOS decrease stack for each STTM facility at a hub on which MOS is provided. MOS Stacks are ordered such that the cost of supplying MOS gas is minimised. Each step on each stack defines a MOS provider, the maximum quantity that can be allocated to that step, the step price and the MOS enabled TRN providing the MOS. AEMO then publishes the MOS stacks and provides them to each pipeline operator.

8.3 Allocating MOS

The total quantities of MOS and overrun MOS are allocated in the facility operator's STTM facility allocations. In addition to these total allocations, the individual MOS increase and MOS decrease steps allocated by the pipeline operator are submitted separately as MOS step allocations.

Note. Shippers and pipeline operators decide, independently of the STTM, which registered facility services will be used when MOS and overrun MOS are allocated.

8.3.1 MOS step allocations

For a gas day, pipeline operators use the MOS stacks to allocate pipeline deviations to MOS steps. Increased flows to the hub are allocated to the next available (lowest cost) step on the MOS increase stack, and decreased flows are allocated to the next available step on the MOS decrease stack. These allocations are submitted to AEMO the day following the gas day. The MOS provider's ex ante market schedule is adjusted to account for MOS step allocations and so do not attract deviation charges and payments.

Prerequisites

- STTM information system user must be the registered allocation agent for that STTM facility.
- Process

1. Allocation agent electronically submits the MOS increase steps and MOS decrease step allocated by an STTM facility operator. The data provided includes, for each step:
   - Gas day
   - Trading participant identifier (MOS provider)
   - MOS stack identifier
   - MOS step identifier
   - Quantity in whole gigajoules allocated to that step.
2. AEMO validates the data and notifies the allocation agent of any validation errors. The data is validated by checking that the quantity allocated to each step does not exceed the MOS step quantity specified in the MOS offer. If any error is detected, then the entire submission is rejected.
3. AEMO confirms receipt of data.

Process: allocating steps when allocation agent fails to submit data

1. After the cut-off time for submission of MOS step allocations (see below) and before the time data is required for determining the ex post market or settlement and prudential monitoring, AEMO identifies facilities that
2. For each facility without a MOS step allocation, AEMO sets the MOS and overrun MOS quantities to zero.

Timeline

- MOS step allocations must be submitted daily, not later than T+4.5 hrs, for all MOS gas flows on the previous gas day. This can be extended if the facility allocation submission window is extended

Allocation rules

- Allocations are performed according to rules agreed between pipeline operators and shippers and are outside the control of AEMO. However, these rules need to be applied in a manner that is consistent with the NGR. Specifically, allocations beyond the pipeline operator's final pipeline schedule, after accounting for intraday renominations, should, wherever possible, be allocated to MOS providers. Hence, if all shippers match their pipeline schedules, then any pipeline deviation will be represented by MOS allocations.

Related information

- A separate process is used to submit overrun MOS.
- MOS can only be provided by the holder of a MOS enabled TRN.
- Each step on each stack defines a MOS provider, the maximum quantity that can be allocated to that step, the step price and the MOS enabled TRN providing the MOS. MOS providers can have up to 10 MOS steps with each step using the same or different MOS enabled TRNs.
- The sign of the MOS quantity in the facility allocation is checked for consistency with the RFS flow direction and MOS stack used

8.3.2 Allocating overrun MOS

If all price steps available on the MOS stack have been allocated by the STTM pipeline operator (the total pipeline deviation exceeds the capacity of the MOS stack), then the remaining quantity is allocated by the facility operator using normal allocation rules for that facility. These quantities are submitted to AEMO as overrun MOS in the operator's STTM facility allocation data.

8.4 Payment for MOS gas

MOS

MOS allocated from MOS stacks is paid in two components: the MOS service payment and the MOS commodity payment or charge. The MOS service payment is paid to the MOS provider on a pay-as- bid basis according to the MOS price steps allocated on the gas day. The MOS commodity cost is paid to or charged to the MOS provider for the total MOS gas allocation on the gas day at the ex ante market price two days after the gas day. MOS providers can factor into the MOS step price a component to allow for the loss of opportunity during this period. The MOS provider can then choose to submit bids or offers in the gas day d+2 ex ante market for the gas it needs to replace or run down its MOS gas allocation. The MOS provider, however, is not required to actually trade its gas in the d+2 ex ante market, but it bears all associated risks if it does not.

Overrun MOS

Overrun MOS is paid for in a similar way to MOS gas with a service payment for providing the MOS service and a commodity payment or charge at the d+2 ex ante market price. However, the service payment is determined by AEMO in each flow direction for each facility on which overrun MOS is provided according to the following rules:

- If the total quantity allocated from a MOS stack is less than or equal to the MOS estimate for that direction of MOS usage (that is, not enough MOS was offered), then overrun MOS will be settled at the quantity-weighted average per GJ cost, capped at MCC, of the MOS steps provided from that MOS stack for that gas day in that direction of MOS usage.
- If the total quantity allocated to from a MOS stack is greater than to the MOS estimate for that direction of MOS usage (that is, more MOS was required than expected), then overrun MOS will be settled at the price for the highest price MOS step allocated from that MOS stack on that day in that direction of MOS usage.

These rules ensure that trading participants are not penalised if the market under- or over-estimates MOS requirements, while preserving the incentives for providing MOS via MOS stacks.

9. Contingency Gas

Contingency gas is a limited mechanism for balancing supply and withdrawals at a hub or meeting an operational requirement at a hub when normal mechanisms are unable (or not expected to be able) to do this within or over a gas day. Contingency gas provides pipeline operators and distributors with a means of avoiding, or at least minimising, the need to involuntarily curtail shippers supplying the hub or users withdrawing at the hub. However, its availability or use does not imply any limit on the rights of these operators to implement involuntary curtailment.

Note. Contingency gas cannot be used to address events on pipelines that do not impact a hub.

9.1 Contingency gas procedures

Trading participants are able to view the aggregate supply and withdrawal outlook at a hub up to three days ahead of the gas day, and price information for the gas day is available when the market schedule has been produced the day before. This information assists trading participants to forecast their gas requirements and provide the market with advanced warning of potential contingency gas trigger events.

The trigger events for contingency gas are:

- Pressure conditions are forecast to be under or over acceptable operating levels at a hub or a custody transfer point. Note that intraday pressure issues can arise even when supply and withdrawal is balanced over the day.
- An STTM facility is forecast to be unable to meet the normal seasonal levels of daily delivery capacity to the hub.
- An event, upstream of an STTM distribution system, could reasonably be expected to adversely affect the supply of natural gas to that STTM distribution system.
- Price taker bids in an ex ante market schedule or an outlook schedule issued by AEMO are not fully scheduled due to inadequate supply of natural gas to that hub on that gas day.

A trigger event does not mean that contingency gas will be called. Rather, it triggers an assessment process which may or may not lead to contingency gas being called. If required, AEMO will call on the contingency gas bids or contingency gas offers submitted the day before the gas day, until the requirement is met or until the available contingency gas is exhausted.

Contingency gas is expected to be called in situations where there is a gas shortfall at a hub, following one of the triggers outlined above. In this case, trading participants who have submitted contingency gas offers will be scheduled; these are offers to either increase supply of gas to the hub or to voluntarily curtail withdrawals from the hub. However, the design also allows for situations when there is expected to be a surplus of gas at the hub, although this is expected to occur less frequently. In this case, trading participants who have submitted contingency gas bids will be scheduled; these are bids to either decrease supply of gas to the hub or to increase withdrawals from the hub.

Contingency gas will typically be called ahead of the gas day, which allows distributors time to plan curtailment measures if there is inadequate response. There may be occasions where contingency gas is called intraday. The same process is followed, however, due to time constraints, the response capability may be much reduced.

Process

1. Trading participants electronically submit contingency gas offers and/or bids for each gas day. Only trading participants who have completed this step can provide confirmation at step 7.

2. STTM facility operators, STTM distributors, STTM shippers, or STTM users must notify AEMO as soon as they become aware of a contingency gas trigger event.
3. AEMO issues a notice to STTM participants describing the nature of the trigger event, who called it and when.
4. AEMO convenes a contingency gas assessment conference with the relevant STTM facility operators, STTM distributor and any other party which AEMO believes could assist in resolving the issue. At this conference:
   – Information about the trigger event is exchanged, and an assessment is made of the operational requirements for the STTM distribution network and STTM facilities for the affected gas days.
   – An assessment is made as to whether contingency gas is required; if so, what quantity of contingency gas is required, the location and timing for delivery of that contingency gas.
5. AEMO convenes a wider industry conference with participants at the affected hub to discuss the outcome of the contingency gas assessment conference. Trading participants may discuss whether an industry response to the trigger event without scheduling contingency gas is possible. However, if at the assessment conference, AEMO considers that contingency gas is urgently required, it may not have time to convene the industry conference before the time which contingency gas needs to be called. In this case, AEMO may skip the industry conference and go straight to step 6.
6. Following the conferences, AEMO determines whether contingency gas is required or not, based on the information provided to it. This will include the quantity, location and timing for when contingency gas will be required.
7. AEMO carries out a confirmation process with trading participants who submitted contingency gas offers or bids by 18:00 hrs on gas day D-1 to electronically confirm the quantity of contingency gas they expect to be able to provide within the required time. Note that participants must have a bid or offer already in place to provide a confirmation on the day an event occurs.
   – The available quantity confirmed may be more or less than the quantity in the contingency gas offer or bid. The available quantity can be changed, but the offer or bid price steps cannot be changed. If the available quantity is reduced, price steps in order of highest to lowest will be marked as unavailable, or the last price step will be extended if the available quantity is increased.
   – A trading participant may confirm availability of contingency gas for individual price steps provided it has registered facilities related to those price steps with AEMO.
   – As part of the confirmation, an STTM user will also provide the location of any customer facilities that would be used to make contingency gas available.
8. Subject to the information determined in step 7, AEMO then proceeds to schedule contingency gas. To rectify a supply shortfall, AEMO calls contingency gas offers in order of increasing price. To rectify a supply surplus, AEMO calls contingency gas bids in order of decreasing price. Quantities called will not exceed the quantities confirmed in step 7. All contingency gas offers or bids called are recorded by AEMO for settlement purposes.
9. AEMO continues to monitor the situation and liaise with participants until the situation is rectified. This response does not preclude the need for involuntary curtailment. AEMO may also request participants to reduce their response; however, this will be voluntary because responses may already be committed. If a provider is able to reduce its response, and agrees to do so, then AEMO will reduce the quantity of contingency gas called for settlement purposes.

Related information

- Throughout any contingency gas event, AEMO will communicate frequently and transparently with all participants.

- Once called, it is the responsibility of the participants scheduled to provide contingency gas to make the necessary arrangements with their facility operators, distributors, or consumers. For example, a shipper would make an intraday nomination to increase flows to the hub, or a user would instruct its interruptible consumers to curtail their consumption.
- Trading participants should not submit market schedule variations with respect to contingency gas. AEMO will account for contingency gas allocations in settlement without further interaction with participants.

9.2 Registration of facilities for confirming individual price steps

If trading participants wish to confirm individual price steps when confirming contingency gas availability, they must register the facility to which those price steps relate. 'Facility' includes upstream production facilities, storage facilities, and customer sites (including plant within such sites). This allows confirmation of volumes of specific price steps of a contingency gas bid or offer instead of only the maximum volume of a contingency gas bid or offer.

The ability to confirm individual price steps allows load aggregators or users with multiple load curtailment sites to price contingency gas more efficiently in the market since each site can have its curtailment load priced individually, confirmed and scheduled accordingly. The same applies to the supply side since it would allow shippers to confirm supply from individual gas fields.

Confirmation of volumes of individual price steps can be partially confirmed or skipped in their entirety. The price of a step cannot be changed during the confirmation process.

A trading participant may register a facility for the purpose of confirming individual contingency gas price steps by submitting a completed application form, available on AEMO website (www.aemo.com.au).

9.3 Contingency gas offers and bids

Contingency gas offers can be submitted by STTM shippers who can increase the supply of gas to the hub or by STTM shippers and STTM users who can reduce withdrawals from the hub. Contingency gas bids can be submitted by STTM shippers who can reduce supply to the hub or by STTM shippers and STTM users who can increase withdrawals from the hub. The same trading participant can submit both offers and bids for contingency gas at the same hub.

Note. Unlike ex ante market offers and bids, which are associated with a trading right, contingency gas offers and bids are associated with the facility or distribution system on which the trading participant increases or decreases supply to the hub.

Prerequisites

- STTM information system user must be a registered trading participant.

Process: submitting new contingency gas offers and bids

1. Trading participant can select to view its existing contingency gas offers and bids for a gas day.
2. Trading participant selects to submit a new contingency gas offer or contingency gas bid.
3. Trading participant enters the details of a contingency gas offer or bid by specifying:

   Facility identifier.

   Date range.

Flow direction (to the hub, from the hub, or at the hub).

Up to 10 price steps for the specified date range for the selected trading right. Offer price steps are entered in increasing order of price with cumulative quantities of gas, and bid prices in decreasing order of price.

Contingency gas offers and bids are made for each entire gas day in the specified date range, including the starting and ending dates. Quantities are in whole gigajoules (GJ) and prices are in $/GJ to four decimal places.

4. Trading participant submits the contingency gas offer or bid.
5. AEMO validates the offer or bid. Each submission is validated for:

- Date format is valid.
- From and to dates are not earlier than the next gas day.
- Quantities are integers, are non-negative (≥0), and increase with each step.
- Offer prices are expressed up to four decimal places, are greater than or equal to MMP and less than or equal to MPC, and increase with each step.
- Bid prices are expressed up to four decimal places, are greater than or equal to MMP and less than or equal to MPC, and decrease with each step.

The trading participant is notified if the submission is rejected. Any error will result in the entire offer or bid being rejected.

6. AEMO sends details of each successful contingency gas offer and bid to the trading participant's system folder.
7. Trading participant submits additional contingency gas offers and bids for other date ranges.

Process: replacing existing contingency gas offers and bids

- Once submitted, a contingency gas offer or a bid cannot be cancelled or modified. But it can be replaced. All offers and bids have explicit date ranges. If there is an existing offer or bid for the same date in the date range, the existing offer or bid is entirely replaced (all price steps) for that date by the new offer or bid.

Timeline

- Final contingency gas offers and bids can be submitted for gas day D at any time before 1800 hrs (all hubs) on gas day D-1.

Related information

- A single-step zero-gigajoule offer or bid can be submitted. This will effectively cancel any existing offers or bids over that date range.
- Contingency gas offers and bids are not associated with an RFS or a trading right, but they are associated with an STTM facility and flow direction.
- On a multi–distribution system hub, contingency gas offers and bids by users are associated with a distribution system (whereas ex ante bids are associated with a trading right at a hub).

9.4 Scheduling contingency gas

The NGR requires that trading participants deliver the contingency gas that they are scheduled to provide, and to notify AEMO if, for any reason, they do not expect to be able to provide the gas. After AEMO schedules contingency gas from a trading participant, the trading participant must make the arrangements necessary with its facility operator, distributor, or customers, as required. For example, an STTM shipper will typically provide its facility operator with an intraday nomination for the quantity called.

When contingency gas is called, a contingency gas provider has an opportunity to confirm how much gas they can provide at that time. After the event, the contingency gas provider needs to demonstrate that it has delivered the contingency gas scheduled by the time and at the location required. Consequently, the participant will be exposed to ad hoc charges where the evidence shows that it has not delivered contingency gas according to the contingency gas requirements.

Note. Because AEMO calls contingency gas, AEMO records that the shipper's expected gas flows will be updated by the quantity of contingency gas called, which removes the need for the market schedule variation.

9.5 Contingency gas prices

The prices paid or charged for contingency gas are determined the day after the gas day on which it is called. The high contingency gas price is the most expensive price step called to increase net supply to the hub. All contingency gas offers scheduled will be paid at the high contingency gas price. The low contingency gas price is the least expensive price step called to decrease net supply to the hub. All contingency gas bids scheduled will be paid at the low contingency gas price. If no contingency gas is called on a gas day, then there is no contingency gas price set (it is not zero).

Contingency gas prices are used in settlement of the market, can be used in pricing deviations, and also contribute to the cumulative price threshold calculations used to trigger an Administered Price Cap State.

9.6 Evidence of delivery of Contingency Gas

In the event that contingency gas is scheduled, all relevant Trading Participants must provide reasonable evidence that they have delivered their respective contingency gas volumes in accordance with the requirements of the event (by time and location as specified in AEMO's determination published on AEMO's website). Evidence must be provided to AEMO no later than 40 business days after the end of the relevant gas day.

AEMO will then assess the evidence provided and determine actual contingency gas volumes delivered for the purposes of the contingency gas resettlements process.

Trading Participants may apply to AEMO for pre-approval of a methodology to be used as evidence for the quantity of contingency gas provided on any gas day using a specific facility under given supply, demand or production conditions for a future contingency gas event.

10. Allocations

The day after the gas day, allocation agents appointed by STTM facility operators submit allocation data to AEMO. AEMO records this data without adjustment as the actual quantities of gas flowed to and from the hub by STTM shippers.

In Brisbane, the STTM pipeline operator also submits CTM data, which AEMO uses to determine aggregate withdrawals by STTM users. Allocation data for gas withdrawn from the hub by STTM users is submitted to AEMO through separate retail market systems, and AEMO, as the retail market operator, submits this data to the STTM. Where there are deemed distribution systems at the hub, pipeline operators submit allocations for transmission-connected STTM users.

Note. There are differences between the allocation processes in Brisbane and the other hubs, which arise because there are multiple distribution systems at the Brisbane hub.

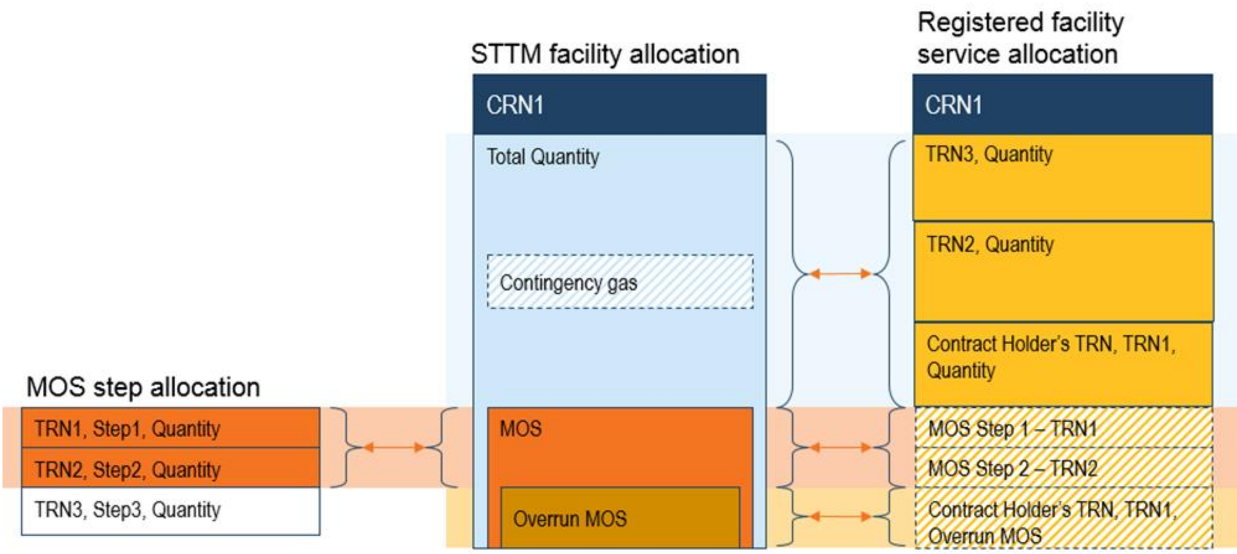
The amounts paid and received by trading participants in settlement of the market depend on, amongst other things, the quantities they have been allocated, the quantities of confirmed market schedule variations, the quantities by which they have deviated from their modified market schedules, the market prices calculated by the SPA the day before the gas day, and the ex post imbalance price, which is calculated the day after the gas day.

10.1 Overview of allocation processes

10.1.1 Allocations for shippers

Determining the quantities used in settlement of the market is a multi-step process, which commences with STTM facility allocations at the RFS level for STTM shippers. STTM facility allocations include total MOS and overrun MOS quantities; however, a separate process is used to submit the quantities allocated to individual MOS steps. Allocation agents for registered facility services then submit registered facility service allocations to shipper's trading rights. The relationships between these different types of allocations are summarised in Figure 24.

Figure 24 STTM shipper allocations



10.1.2 Allocations for users

With the exception of users on deemed distribution systems, allocations to STTM users are determined by AEMO in its role as retail market operator. These allocations are aligned with the flows measured by pipeline operators such that the net flow at the hub on any day is zero. These allocations are further revised after settlement as the quality of meter data improves or to correct for metering errors.

Because there are multiple and deemed distribution systems at the Brisbane hub, the pipeline operator in Brisbane is required to make additional submissions so that AEMO is able to determine the aggregated flows for each system and to determine the allocations to transmission-connected users. In Sydney and Adelaide, however, the aggregated flows are obtained from the STTM facility allocations and there are no transmission-connected users. There are also differences in reporting allocations to users. These differences are summarised in Figure 25 and Figure 26.

10.1.3 Allocations for transmission-connected users

In Brisbane, the pipeline operator submits allocations to transmission-connected users on deemed STTM distribution systems (called "deemed STTM distribution system allocations") (see Figure 26).

10.1.4 CTM data

In Brisbane, facility operators submit CTM data to the STTM (see Figure 26) so that AEMO can determine the aggregated flows on each distribution system. In Sydney and Adelaide, the aggregated flows are obtained from the STTM facility allocations (see Figure 25).

Figure 25 Distribution system allocation process at the Adelaide and Sydney hubs

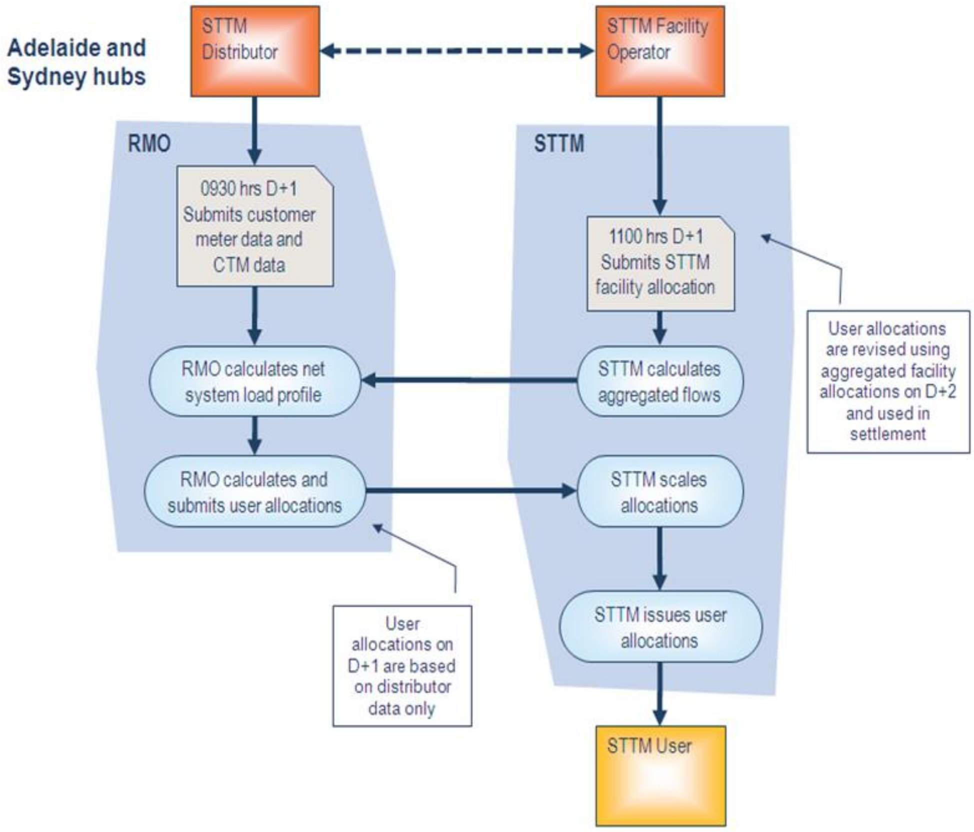
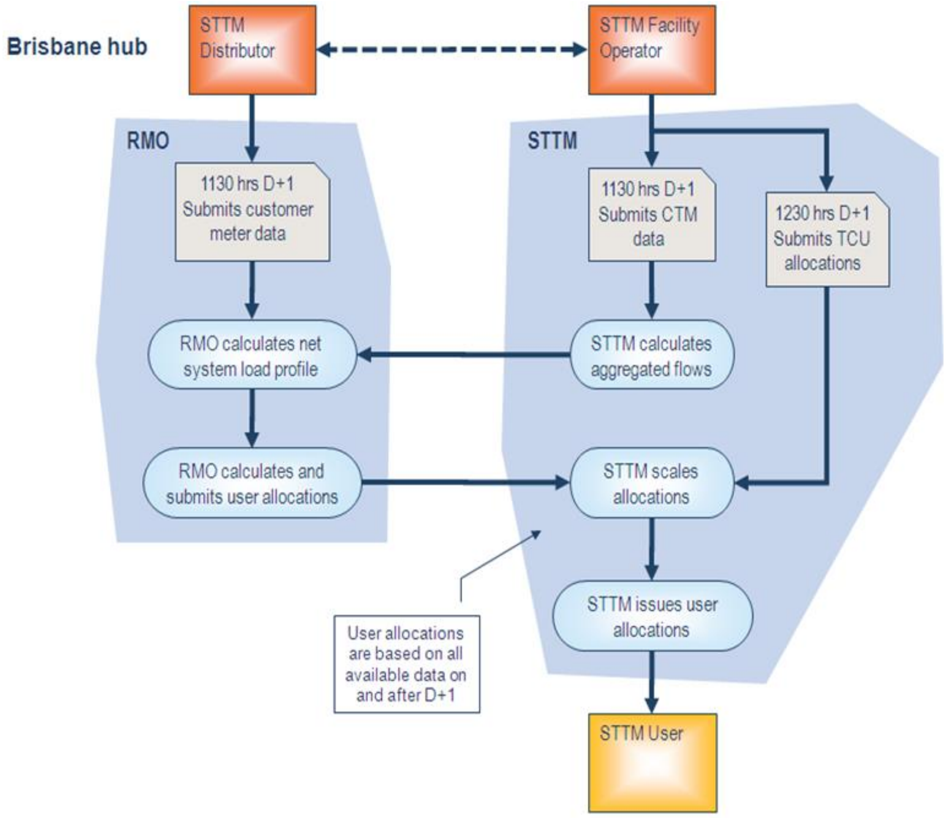


Figure 26 Distribution system allocation process at the Brisbane hub



10.2 STTM facility allocations

STTM facility allocations allocate flows on the gas day to the registered facility services on that facility. These allocations are submitted by the allocation agents appointed by the operators of each STTM facility. In the absence of this data, AEMO will act as allocation agent and make allocations according to default allocation rules.

Allocations are subsequently and separately sub-allocated at the trading right level. Although STTM facility allocations are inclusive of allocations for MOS gas and overrun MOS gas, the MOS step allocations must be submitted separately. For information about submitting MOS step allocations.

Prerequisites

- STTM information system user must be the registered allocation agent for that STTM facility.

Process: submitting STTM facility allocations

1. Allocation agent electronically submits allocation data for all gas flows to and from a hub. The data provided includes, for each RFS to which flows are allocated:
   - CRN of the RFS
   - Gas day date
   - Facility identifier
   - Trading participant (STTM shipper) identifier
   - Total quantity inclusive of MOS and overrun MOS allocations
   - Total MOS allocation inclusive of overrun MOS

- Overrun MOS gas allocation

2. AEMO validates the allocation data and notifies the operator or allocation agent of any validation errors. If any format error is detected or the total allocation is outside the rejection limits for the facility (see Section 11.3), then the entire submission (for all CRNs) is rejected. If the total allocation is within the rejection limits but outside the warning limits, AEMO will ask the facility operator to confirm the submission or submit a new allocation file.
3. Allocation agents can resubmit allocations at any time before the cut-off time. If AEMO has not received a valid submission by this time, the submission window is extended for a maximum of four hours or until a confirmation or a valid submission is received. For more information about the extended timeline, see "Timeline" below.

Process: validating facility allocation data

On submission, facility allocations are validated for format, integrity, and range. If the submission fails any of these tests, the entire submission is rejected. For the purpose of applying the default allocation, a rejected submission is equivalent to "no submission".

If the allocation passes the above tests, a further validation test is performed to check that it is consistent with historical data. These warning limits are determined daily based on allocations for the previous 30 days.

If the allocation is within the rejection limits but outside the warning limits, AEMO will notify the facility operator's registered contact by SMS or e-mail. The facility operator can then either confirm (see following process) that the data is correct or can submit new data. But the data is not rejected. If the facility operator does not confirm or does not submit new data by the required time, the latest (not rejected) data is used, but AEMO will flag the value as "unconfirmed".

Process: confirming a submission

1. If the allocation file is within the rejection limits but outside the warning limits (see Section 11.3), AEMO will notify the facility operator's registered contact by SMS or e-mail.
2. Facility operator electronically confirms submission or submits a new allocation file.

Process: allocating flows when allocation agent fails to submit data

1. After the cut-off time for submission of STTM facility allocations (or extended cut-off time, see below) and before the time data is required for settlement or prudential monitoring, AEMO identifies RFSs that do not have allocated quantities.
2. For each RFS without an allocation, AEMO allocates the ex ante market schedule quantity.

Timeline

- STTM facility allocations must be submitted daily for gas flows on the previous gas day no later than T+4.5 hrs.
- Before T+4.5 hrs, the allocation agent can resubmit allocations at any time. The last valid submission is used.
- If a submission has not been received by T+4.5 hrs or a submission has not been confirmed by this time, then the submission window is extended for a maximum of four hours (T+8.5 hrs) or until a valid submission (within the warning limits) is received or a submission is confirmed,
- After T+4.5 hrs, once a valid submission has been made or confirmed, that submission will be used for the purposes of determining the ex post imbalance price.
- f a submission has not been received by T+8.5 hrs (or is rejected), AEMO performs a default allocation (see "Process: allocating flows when allocation agent fails to submit data" above).

- If a submission has not been confirmed by T+8.5 hrs, AEMO will accept the submission but flag it as unconfirmed.

Related information

- All quantities are in whole gigajoules (GJ).
- A separate process is used to submit MOS step allocations. If these do not match the total MOS allocated on a facility, the MOS step allocations are rejected. If a valid submission is not available by the required time (see above), all MOS quantities in the facility allocations are zeroed.
- When the facility allocation submission window is extended, the MOS step allocation can also be resubmitted.
- When the facility allocation submission window is extended, the ex post schedule is delayed and will be issued by T+9.5 hrs.
- Failure to allocate MOS gas according to the MOS stacks because of contractual reasons is considered a breach of the MOS provider's obligations.
- Gas supplied under contingency gas measures must be included in the total quantity of an STTM facility allocation.

10.3 Validating STTM facility allocations

On submission, facility allocations are validated for.

- Data integrity and format.
- The MOS step allocation for that facility is available, and the total quantity of MOS gas in the facility allocation equals the total quantity of MOS steps allocated on that facility.
- The sign of the MOS and MOS overrun quantities are the same.
- The sign of the MOS quantity is consistent with the MOS stack used:
- MOS increase on RFS to hub: positive MOS quantity
- MOS increase on RFS from hub: positive MOS quantity
- MOS decrease on RFS from hub: negative MOS quantity
- MOS decrease on RFS to hub: negative MOS quantity
- The total quantity of the allocation on that facility is between the maximum and minimum rejection limits (see Figure 27). The maximum rejection limit is set at the maximum hub capacity limit, which is supplied by the facility operator and stored in the STTM database. The minimum rejection limit is zero. If outside these limits, the submission is rejected.

If the submission fails any of the above tests, the entire submission is rejected. For the purpose of applying default allocations, a rejected submission is equivalent to "no submission".

If the pipeline operator fails to submit valid data by the normal cut-off time, the submission window is extended by up to four hours to allow the pipeline operator additional time. If a valid submission is made after the normal cut-off time, the submission window closes immediately.

If the allocation passes the above tests, a further validation test is performed:

- The total delivered quantity of the allocation on that facility is between the upper and lower warning limits (see Figure 27). The total delivered allocation quantity is the total allocation quantity for all RFS to the hub plus MOS allocations on RFS from the hub (decrease MOS on an RFS from the hub would be subtracted). These limits are calculated daily for each facility based on the allocations received over the previous 30 days.

If the submitted hub capacity is between the warning limits, AEMO issues a warning (by SMS and e- mail) to the pipeline operator, alerting them to a possible problem with the data. But the data is not rejected. The pipeline operator can then either confirm that the data is valid or, if there is a problem, they can resubmit. Again, additional time is provided for this to happen. And should the pipeline operator fail to confirm that the data is valid or fails to submit new data, then AEMO will accept the last submission but will set a data quality flag to show that the data was unconfirmed.

If AEMO does not receive a valid submission by the normal cut-off time, it then performs a default allocation for all shippers on that pipeline.

The validation and confirmation process is outlined in Figure 28.

Figure 27 Facility allocation validation limits

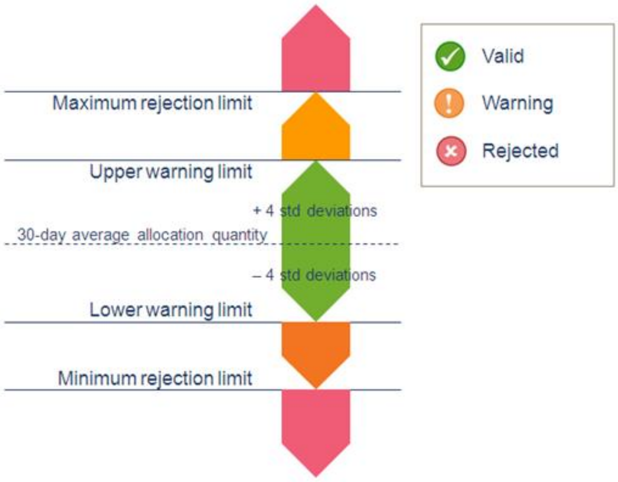
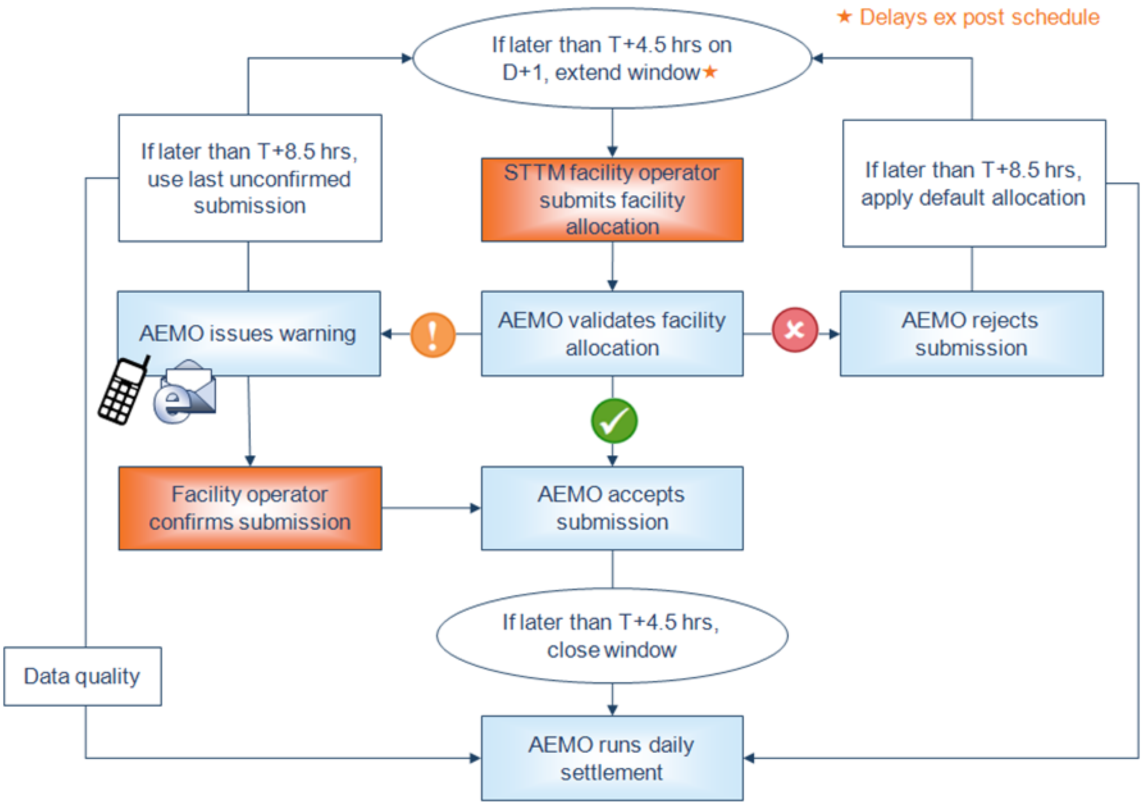


Figure 28 Facility allocation validation process



10.4 Registered facility service allocations

Allocation agents appointed by the contract holder provide allocation data for each RFS at a trading right level, which provides AEMO with the detail necessary to allocate flows by trading right to individual shippers. It is the allocations at trading right level that are used in settlement. In the absence of this data, AEMO will act as allocation agent and apportion the quantities allocated to an RFS to its associated trading rights using standard default allocation rules.

Prerequisites

- STTM information system user must be the registered allocation agent for the RFS.
- STTM facility allocation data has been submitted to or determined by AEMO.
- STTM facility contract data and trading right data has been published by AEMO.

Process: submitting a registered facility service allocation

1. AEMO publishes STTM facility allocation data.
2. Allocation agent electronically submits allocation data for a registered facility service for which they are the appointed allocation agent. The data submitted includes:
   - Gas day date
   - Facility identifier
   - For each trading right:
   - TRN (including the contract holder's TRN)
   - Allocation quantity in whole gigajoules.

   All MOS allocations must be included in the quantity allocated to the contract holder's TRN. AEMO will subsequently deduct the MOS allocation submitted in the STTM facility allocation for that RFS from the trading participant MOS enabled trading right allocation.

Important. The total of all trading right allocation quantities for this RFS must equal the total quantity submitted in the corresponding STTM facility allocation.

3. AEMO validates the data.
4. AEMO confirms receipt to the allocation agent.

Process: allocating flows when no allocation agent is nominated

1. AEMO identifies all RFSs that do not have allocation agents.
2. For each trading right associated with the RFS, except the contract holder's TRN, AEMO allocates the ex ante market schedule quantity.
3. The residual quantity, positive or negative (that is, the difference between the STTM facility allocation for that RFS excluding MOS and the total quantity allocated to trading rights), is allocated to the contract holder's TRN.

Process: allocating flows when allocation agent fails to submit data

1. Before the time data is required for settlement or prudential monitoring, AEMO identifies TRNs that do not have allocated quantities or have been rejected.
2. For each TRN, except the contract holder's TRN, AEMO allocates the ex ante market schedule quantity.

3. The residual quantity, positive or negative (that is, the difference between the STTM facility allocation for that RFS excluding MOS and the total quantity allocated to TRNs), is allocated to the contract holder's TRN.

Timeline

- All available, valid data will be used in that day's settlement calculations.
- Allocations can be submitted any time after the STTM facility allocation for that RFS has been submitted and must be submitted not later than 3 days before the end-of-month settlement run.

Related information

- If an allocation agent has not been appointed, or the allocation data is not submitted by the required time, then AEMO will perform the role of allocation agent without notice.
- Each MOS stack step relates to one MOS enabled TRN for a RFS for that facility, and so is allocated to that MOS enabled TRN by the Allocation Agent for the RFS.

10.5 Deemed STTM distribution system allocations (Brisbane only)

Withdrawals by transmission-connected STTM users are submitted by the STTM facility operator (pipeline operator).

Prerequisites

STTM information system user must be registered as an STTM facility operator and must be the registered operator of the STTM facility.

Process: submitting deemed STTM facility allocations

1. Facility operator electronically submits allocation data for all withdrawals on deemed STTM distribution systems on that facility. The data provided includes, for each STTM user to which flows are allocated:
   - Gas day date
   - Facility identifier (of the deemed STTM distribution system)
   - Trading participant (STTM user) identifier
   - Total quantity in gigajoules
2. AEMO validates the allocation data and notifies the operator of any validation errors. If any error is detected, then the entire submission (for all users) is rejected.

Process: allocating flows when facility operator fails to submit data

1. After the cut-off time for submission of deemed STTM distribution allocations (see below) and before the time data is required for settlement or prudential monitoring, AEMO identifies trading rights of STTM users that do not have allocated quantities.
2. For each user (including those with valid allocations), AEMO allocates the ex ante market schedule quantity.

Note. This is an "all-or-none" process: if any user allocations are missing, including those submitted by the RMO, then all users at the hub are assigned their ex ante market schedule quantities.

Timeline

- Deemed STTM distribution system allocations must be submitted daily for gas flows on the previous gas day not later than T+4.5 hrs.

Related information

- All quantities are in whole gigajoules (GJ).

10.6 CTM data submissions (Brisbane only)

Custody transfer meter (CTM) readings are submitted daily by the STTM facility operator (pipeline operator) for all meters (MIRNs) that define the STTM distribution systems in the STTM Brisbane hub.

Prerequisites

- STTM information system user must be registered as an STTM facility operator and must be the registered operator of the STTM facility.

Process: submitting CTM data

1. Facility operator electronically submits data for all custody transfer meters on that facility that are defined as active for the hub. The data provided includes, for each meter:
   - Meter installation registration number (MIRN)
   - Gas day date
   - Total quantity in gigajoules
   - Quality identifier

2. AEMO validates the data and notifies the operator of any validation errors. If any error is detected, then the entire submission (for all meters) is rejected.
3. AEMO compares the aggregated CTM data against the aggregated STTM facility allocations (net to and from hub) and aggregated deemed STTM distribution system allocations. If the difference is greater than the allowable tolerance in gigajoules, AEMO notifies the facility operator and requests the operator to resubmit all allocation data (CTM data, deemed STTM distribution system allocations, and STTM facility allocations).

Process: allocating flows when facility operator fails to submit data

1. After the cut-off time for CTM data submissions (see below) and before the time data is required for settlement or prudential monitoring, AEMO identifies if CTM data is missing.
2. If data is not available for any gas day in the settlement period, AEMO, in its function as retail market operator, uses meter data provided by distributors. If that data is also not available, AEMO estimates the meter reading from historical data.

Timeline

- CTM data must be submitted daily for gas flows on the previous gas day not later than T+3.5 hrs.

Related information

- All quantities are in whole gigajoules (GJ).
- CTM data is submitted to the STTM at the Brisbane hub only. A different process in the retail market is used at the Sydney and Adelaide hubs.

- Each submission must contain data for all active MIRNs that define the distribution systems at the Brisbane hub for each gas day that the submission covers. Any omission or an unknown MIRN will cause the entire submission to be rejected.

10.7 STTM distribution system allocations

Withdrawals by STTM users are submitted to and processed by AEMO in its function as retail market operator. The resultant STTM distribution system allocations are applied in the STTM.

Prerequisites

- STTM information systems user is an authorised AEMO user.
- Distribution data has been submitted by pipeline operators and distributors to the retail market operator (AEMO). If AEMO has not received distribution system data, it will perform a default allocation.

Process

1. AEMO electronically submits STTM distribution allocation data. The data submitted includes:
   - Gas day date
   - Hub identifier
   - RMO participant identifier (STTM user)
   - Allocated quantity in whole gigajoules.
2. AEMO validates the data. This includes matching the participant's RMO ID with the participant's STTM ID and registered distribution service (RDS).
3. AEMO scales the quantities such that the total STTM distribution system allocations at a hub equal the net total of STTM facility allocations at that hub (that is, the net flow to the hub) on that day. At the 9-month revised settlement, scaling would only be required if a matching could not be achieved within a reasonable period of time.

Note. In Brisbane, if allocations to any STTM users on deemed STTM distribution systems are not available (for any reason), then AEMO will perform a default allocation, whereby all users at the hub are assigned their ex ante market schedule quantities, which are then scaled to balance supply to the hub.

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4. AEMO publishes the allocations to STTM distributors and STTM users.

Timeline

- AEMO determines allocation data by T+4.5 hrs on day D+1 for gas day D.

Related information

- On any given gas day, an STTM user must only have one registered distribution service for each distribution system at which they are registered.
- The registered capacity of an STTM user at a hub is the sum of the registered capacities of its distribution services at that hub.

11. Market Schedule Variations

Market schedule variations are used by shippers and users to inform AEMO that their ex ante market schedules need to be adjusted.

Note. The adjusted ex ante market schedule is called the modified market schedule. Apart from market schedule variations, the modified market schedule also accounts for MOS and overrun MOS allocations, and contingency gas quantities called by AEMO.

There are two ways in which market schedule variations can be used:

- When a shipper makes an intraday nomination to a pipeline operator, the shipper can submit a market schedule variation to inform AEMO of the change and so avoid the deviation charges or payments that would otherwise arise.
- A shipper or user can submit a market schedule variation without a corresponding intraday nomination to transfer a deviation to another shipper or user.

There are two parties to every market schedule variation: the shipper or user who submits the market schedule variation and the confirming shipper or user who accepts it. Market schedule variations must be accepted by the confirming party before AEMO will apply the variation to each party's schedules.

Note. AEMO provides a service to assist market participants with identifying counterparties to MSVs. The service provides market participants who subscribe to the service with information about deviations by other subscribing participants. Deviations are listed for each subscribing market participant, which are ranked by their daily deviation quantity at each facility.

Prerequisites

- STTM information system user submitting a market schedule variation must be a trading participant with the registered role of STTM shipper or STTM User.
- STTM information system user confirming market schedule variations must be a trading participant.

Conditions

Note. When submitting an MSV, the submitting shipper or user always enters a positive quantity and specifies whether the MSV increases or decreases the submitting party's modified market schedule for the specified flow direction and facility. This results in either a positive or negative flow relative to that flow direction. The term "the flow is positive" refers to the resulting flow, not the sign of the quantity entered in the MSV, which must always be positive.

- Each MSV must have a net zero effect on flows at the hub
- For shipper-to-user market schedule variations, where the submitting shipper is hauling from the hub, then
  - The flow is positive for an increased flow away from the hub by the shipper and corresponding decreased consumption at the hub by the user (or negative for an opposite flow).
  - The quantity is added to the submitting shipper's modified market schedule.
  - The quantity is subtracted from the confirming user's modified market schedule.
- For shipper-to-user market schedule variations, where the submitting shipper is hauling to the hub, then
  - The flow is positive for an increased flow to the hub by the shipper and corresponding increased consumption at the hub by the user (or negative for an opposite flow).
  - The quantity is added to the submitting shipper's modified market schedule.
  - The quantity is added to the confirming user's modified market schedule.
- For shipper-to-shipper market schedule variations, where the submitting shipper is hauling to the hub and the confirming shipper is also hauling to the hub, then
  - Both shippers must be on the same pipeline.
  - The flow must be positive, indicating an increased flow to the hub (the shipper with an increased flow to the hub must be the submitting party).
  - The quantity is added to the submitting shipper's modified market schedule.
  - The quantity is subtracted from the confirming shipper's modified market schedule.
- For shipper-to-shipper market schedule variations, where the submitting shipper is hauling to the hub and the confirming shipper is hauling away from the hub, then
  - Shippers can be on different pipelines.
  - The flow is positive for an increased flow to the hub by the submitting shipper if hauling to the hub and negative if hauling away from the hub.
  - The quantity is added to the submitting shipper's modified market schedule.
  - The quantity is added to the confirming shipper's modified market schedule.
- For shipper-to-shipper market schedule variations, where the submitting shipper is hauling away from the hub and the confirming shipper is also hauling away from the hub, then
  - Both shippers must be on the same pipeline.
  - The flow must be positive, indicating an increased flow away from the hub (the shipper with an increased flow away from the hub must be the submitting shipper).
  - The quantity is added to the submitting shipper's modified market schedule.
  - The quantity is subtracted from the confirming shipper's modified market schedule.
- For user–to-user market schedule variations, where the both users are hauling away from the hub, then
  - Both users must be at the same hub.
  - The flow must be positive, indicating an increased flow away from the hub (the user with an increase flow away from the hub must be the submitting user).
  - The quantity is added to the submitting user's modified market schedule.
  - The quantity is subtracted from the confirming user's modified market schedule.

Process: submitting a market schedule variation

1. An STTM shipper or user electronically submits a market schedule variation. The information contained in the submission includes:

- Gas day date
- Participant identifier of submitting party (shipper)
- Facility identifier of submitting party
- Role of submitting party (shipper supplying to hub or shipper withdrawing from hub).
- Participant identifier of confirming party (shipper or user)
- Facility identifier of confirming party (only required if confirming party is a shipper on a different facility)
- Role of confirming party (shipper supplying to hub, shipper withdrawing from hub, or user)
- Quantity is a positive number in gigajoules specified to one decimal place
- Indicate whether the variation quantity is added to or subtracted from the submitting party's modified market schedule (for the specified flow direction and facility)

2. AEMO validates the submitted data.
3. AEMO publishes the market schedule variation to both the submitting and the confirming shipper.
4. Confirming party confirms market schedule variations (see below).
5. AEMO uses the confirmed market schedule variations in settlement and prudential calculations.

Process: confirming market schedule variations

1. The confirming party verifies the information and, if in agreement, electronically submits confirmation.
2. AEMO flags that the market schedule variation is confirmed.

Timeline

- Market schedules variation for gas day D can be submitted any time between T+6. 5 hrs on day D-1 (when the ex ante market schedules are issued) and 1700 hrs on day D+7 (on the seventh day following the gas day).
- Market schedules variations must be confirmed by 1700 hrs on day D+7.

Related information

- AEMO will only use confirmed market schedule variations when performing settlement calculations.
- AEMO does not receive intraday pipeline nominations and does not validate MSVs other than as described above.
- Where the MSV spans two pipelines (a shipper on one pipeline increases flow and a shipper on another pipeline decreases flow, for example), if the intraday nomination by one of the shippers is rejected, the change in flow for the other shipper will be seen as a deviation in the STTM.
- For each confirmed shipper-to-user MSV, only the user pays a variation charge.
- For each confirmed shipper-to-shipper MSV, only shippers hauling away from the hub pay a variation charge.

12. Deviations

A deviation is the difference between the total quantity of gas that a trading participant was scheduled to deliver to or withdraw from a hub according to its modified market schedule and the total quantity of gas that was allocated to the trading participant on that gas day. For the purpose of calculating deviations, the quantities that a shipper hauls to and hauls away from the hub on each facility are treated as separate deviations (so that they cannot balance out), and if the shipper also participates as a user, its deviation quantity as a user is also treated separately.

The trading participant is required to pay deviation charges for any reduction in net supply and receive deviation payments for any increase in net supply.

12.1 Determining the ex post imbalance price

The ex post imbalance price is calculated the day after the gas day (D+1) to determine a price that reflects the impact that deviations on the gas day would have had on the ex ante market price if they had been included in the original (ex ante market) schedule.

If the market is long (more gas was scheduled than was needed), a low-priced market long offer is added, and if the market is short a high-priced market short bid is added. The same scheduling data and constraints used to generate the ex ante market schedule are otherwise applied in generating the ex post schedule. The ex post schedule is discarded, but the ex post imbalance price is recorded. Once the ex post imbalance price is published, it is never amended.

To determine the market long offer and market short bid:

Where

X= the total quantity delivered to the hub (which equals the total allocations to the hub, including MOS, less the total MOS allocations from the hub)

Y= the total quantity of gas scheduled to be flowed to the hub according to the ex ante market schedule

Then

If the difference (X-Y) is negative (more gas was scheduled than was allocated), then the market is long, and the difference is the market long offer quantity. The market long offer price is set slightly below MMP.

If the difference (X-Y) is positive (more gas was allocated than was scheduled), then the market is short, and the difference is the market short bid quantity. The market short bid price is set slightly above MPC.

If the market is long:

- The market long offer shifts the supply curve to the right by the quantity by which the market is long. The market clearing price is the ex post imbalance price. When long, the ex post imbalance price will be less than or equal to the ex ante market price.

If the market is short:

- The market short bid shifts the demand curve to the right by the quantity by which the market is short. The market clearing price is the ex post imbalance price. When short, the ex post imbalance price will be greater than or equal to the ex ante market price.

Conditions

- When the market is long, the total quantity of scheduled STTM offers plus the market long offer quantity must equal the total quantity of scheduled price taker bids plus the total quantity of scheduled STTM bids.
- When the market is short, the total quantity of scheduled STTM offers must equal the total quantity of scheduled price taker bids plus the total quantity of scheduled STTM bids plus the market short bid quantity.
- The market long offer quantity equals the quantity by which the market is long.

- The market short bid quantity equals the quantity by which the market is short.

12.2 Modified market schedules

The quantities in a trading participant's ex ante market schedule are adjusted for settlement purposes to account for:

- Confirmed market schedule variations
- MOS and overrun MOS allocations submitted in STTM facility allocations
- Contingency gas quantities called by AEMO

12.3 Deviation estimates

Estimates of deviation quantities are issued to trading participants during the afternoon of D+1 after the ex post imbalance price has been published. This involves performing a settlement run with the available allocation data. This provides trading participants with a provisional guide to their deviations on the previous day, but is subject to change consequent to the acceptance of market schedule variations and revised allocation data.

A1. Settlement

The net settlement amount for each trading participant over the billing period is calculated from the sum of:

- Ex ante market charges and payments
- Pipeline flow direction constraint charges and payments
- Capacity charges and payments
- Variation charges
- MOS gas charges and payments
- Contingency gas charges and payments
- Deviation charges and payments
- Participant fees
- Settlement surplus or shortfall
- Other charges and payments

A1.1 Settlement process

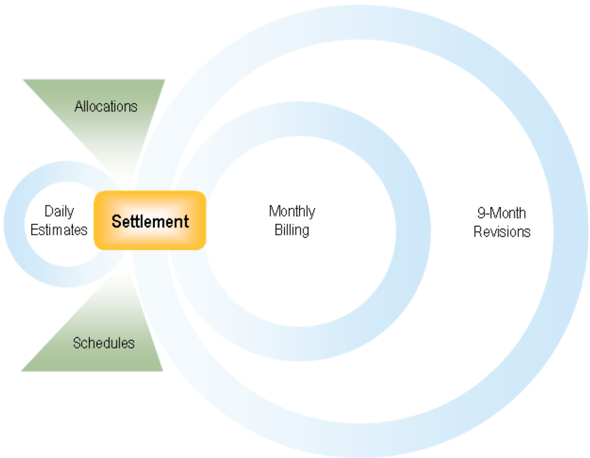
The overall settlement process involves collecting data used in settlement, calculation of settlement amounts, prudential monitoring, and issuing statements. Settlements are run over three cycles:

- Daily settlement runs to provide provisional deviations and prudential monitoring.
- Monthly settlement runs for billing purposes.

- Nine months after settlement for revisions. Settlement calculations are performed to a resolution of one gas day.

Note. Provision is also made for revisions up to 18 months after settlement if errors materially change the settlement amounts.

Figure 29 Settlement cycles in the STTM



A1.1.1 Daily settlement estimates

Settlement runs are performed daily (during the afternoon of the following day) for prudential monitoring purposes and to provide information to trading participants, such as indicative levels of deviations.

Process

1. AEMO maintains settlement standing data.
2. Allocation agents submit allocation data for STTM shippers.
3. Pipeline operators submit allocation data for transmission-connected STTM users.
4. Pipeline operators or distributors submit CTM data.
5. AEMO determines network allocation data for STTM users.
6. If required, AEMO performs default allocations.
7. AEMO obtains settlement data.
8. AEMO calculates modified market schedules and deviation quantities.
9. AEMO calculates settlement amounts.
10. AEMO performs prudential monitoring.
11. AEMO issues prudential notices.
12. AEMO issues deviation estimates.

A1.1.2 Monthly billing and settlement

A complete set of allocation data for the entire billing period is submitted at the end of each gas month for settlement. AEMO then provides trading participants with a preliminary settlement statement for the billing period. This preliminary settlement statement is provided for information purposes only, and allows trading participants to query values before the statement is finalised.

Before AEMO produces a final settlement statement, the allocation data for the entire billing period, which may contain revised or improved data, is re-submitted. Trading participants must settle in accordance with the final settlement amount and timetable.

Process

1. Allocation agents and pipeline operators submit allocation data at the end of the billing period.
2. AEMO obtains settlement data.
3. AEMO recalculates modified market schedules and deviation quantities.
4. AEMO calculates settlement amounts for billing period.
5. AEMO issues preliminary settlement statements.
6. AEMO publishes supporting settlement data.
7. AEMO issues final statements.
8. Trading participants pay or receive settlement amounts.

A1.1.3 Settlement revisions

A revised settlement is performed nine months after the end of each billing period to account for any revisions to data made after the initial settlement. Allocation agents must submit a complete set of allocation data for the billing period. Further revisions may occur up to 18 months after the end of the billing period if errors cause material changes in settlement amounts.

A1.2 Settlement data

AEMO obtains the following data for each hub, which is used in settlement calculations:

Scheduling data

- Ex ante market schedule quantities for each trading participant.
- Ex ante market price.
- Capacity price for each STTM facility.
- Pipeline flow direction price for each STTM facility.
- Contingency gas schedules.
- High contingency gas price.
- Low contingency gas price.
- Ex post imbalance price.
- Administered state indicators.
- Ex ante offers made on firm capacity trading rights.

Standing data

- Market limits (APC, MMP, MPC, and such)
- Variation charge tables

Allocation data

- STTM facility allocations

- MOS step allocations
- Registered facility service allocations
- STTM distribution system allocations
- Deemed STTM distribution system allocations (Brisbane)

Financial data

- Credit limits and current credit levels for each trading participant
- Contract and participant data
- Details of registered facility services and trading rights for each trading participant
- Registered details and status of trading participants

The data used by AEMO to calculate settlement statements is made available to trading participants for a limited time, after which it will be archived and only available at the request of the trading participant.

A1.3 Settlement equations

The mathematical operators used in the equations that follow are described in Table 2. The variables are, in general, defined as they appear, but a complete list of settlement variables can also be found in Appendix A.

Important. The formulas used in this section are from the STTM Procedures. Use the STTM Procedures formulas if any discrepancy in these formulas is found.

Note. Quantities for STTM users are aggregated at the hub level. References to facility $k \in SN$ should be interpreted as the sum of all distribution facilities at the hub.

Table 2 Mathematical operators used in settlement equations

Operator	Term	Definition
ABS(x)	Absolute	The absolute value of x.
MAX(x, y,...)	Maximum	The maximum of the values x, y,...
MIN(x. y,...)	Minimum	The minimum of the values x, y,...
$\Sigma_x y(x)$	Sum for all values of x	The sum of all values y for all values of x.
$\Sigma_{x \in S}\ y(x)$	sum for values of x that are elements of set S	The sum of values y for which x is an element of set S.
$X \in S$	Element of	X is an element of set S.

A1.3.1 Net settlement amount

The net participant settlement amount (NPSA) for trading participant p for the billing period is:

$$NPSA(p) = (SSC(p) - SSP(p))$$
$$+ \Sigma_d((MktC(p,d) - MktP(p,d))$$

$$+ \ (\mathrm{PFDCC}(p,d) - \mathrm{PFDCP}(p,d))$$
$$+ \ \mathrm{VarC}(p,d)$$
$$+ \ (\mathrm{CGC}(p,d) - \mathrm{CGP}(p,d))$$
$$+ \ (\mathrm{MosC}(p,d) - \mathrm{MosP}(p,d))$$
$$+ \ (\mathrm{DevC}(p,d) - \mathrm{DevP}(p,d))$$
$$+ \ (\mathrm{SCC}(p,d) - \mathrm{SCP}(p,d))$$
$$+ \ \mathrm{MPC}(p,d)$$
$$+ \ (\mathrm{AHC}(p,d) - \mathrm{AHP}(p,d)))$$

(3)

Where

$\mathrm{SSC}(p)$ and $\mathrm{SSP}(p)$ are settlement surplus/shortfall charges and payments.

$\mathrm{MktC}(p,d)$ and $\mathrm{MktP}(p,d)$ are ex ante market charges and payments.

$\mathrm{PFDCC}(p,d)$ and $\mathrm{PFDCP}(p,d)$ are pipeline flow direction constraint charges and payments.

$\mathrm{VarC}(p,d)$ are variation charges.

$\mathrm{CGC}(p,d)$ and $\mathrm{CGP}(p,d)$ are contingency gas charges and payments.

$\mathrm{MosC}(p,d)$ and $\mathrm{MosP}(p,d)$ are MOS gas charges and payments.

$\mathrm{DevC}(p,d)$ and $\mathrm{DevP}(p,d)$ are deviation charges and payments.

$\mathrm{SCC}(p,d)$ and $\mathrm{SCP}(p,d)$ are capacity charges and payments.

$\mathrm{MPC}(p,d)$ are market participation charges.

$\mathrm{AHC}(p,d)$ and $\mathrm{AHP}(p,d)$ are ad hoc charges and payments.

A1.3.2 Ex ante market charges and payments

The ex ante market charge or payment to a trading participant is calculated by the ex ante market price multiplied by the net quantity scheduled from that trading participant as either a user or a shipper. If the net quantity is positive, then the trading participant is paid by the market. If the net quantity is negative, then the trading participant is a net buyer and must pay money to the market.

Equations

The market payment for trading participant p in the ex ante gas market for gas day d is:

$$\mathrm{MktP}(p,d) = \mathrm{HP}(d) \times \Sigma_{k \in SP} \Sigma_{ct(k)} \mathrm{MQ}^{S}(p,d,ct(k)) \ \ldots\ldots\ldots\ldots\ldots\ldots \quad (4)$$

Where

$\mathrm{HP}(d)$ is the ex ante market price on gas day d (obtained from scheduling data).

$\mathrm{MQ}^{S}(p,d,c(k))$ is the ex ante market schedule quantity for participant p supplying gas as a shipper on gas day d on trading right $c(k)$ for facility k (obtained from scheduling data).

The market charge for trading participant p in the ex ante gas market for gas day d is:

$$\mathrm{MktC}(p,d) = \mathrm{HP}(d) \times (\Sigma_{k \in SP} \Sigma_{cf(k)} \mathrm{MQ}^{S}(p,d,cf(k))$$
$$+ \Sigma_{k \in SN} \Sigma cf(k) \ \mathrm{MQ}^{U}(p,d,cf(k))) \ \ldots\ldots\ldots\ldots \quad (5)$$

Where

$\mathrm{HP}(d)$ is the ex ante market price on gas day d (obtained from scheduling data).

$\mathrm{MQ}^{S}(p,d,c(k))$ is the ex ante market schedule quantity for participant p withdrawing gas as a shipper on gas day d on trading right $c(k)$ for facility k (obtained from scheduling data).

$MQ^{U}(p,d,c(k))$ is the ex ante market schedule quantity for participant p withdrawing gas as a user on gas day d on trading right c(k) for facility k (obtained from scheduling data).

Important. Quantities for STTM users are aggregated at the hub level. References to facility $k \in SN$ should be interpreted as the sum of all distribution facilities at the hub.

A1.3.3 Pipeline flow direction constraint charges and payments

If the pipeline flow direction price on an STTM facility is non-zero, then an additional payment is made to a shipper on that STTM facility equal to the pipeline flow direction price for that STTM facility multiplied by the net supply scheduled from that shipper on that STTM facility. Shippers with a negative net flow pay money to the market, and shippers with a positive net flow receive money from the market.

Equations

The pipeline flow direction constraint payment to trading participant p for the ex ante market supply of gas to the hub for gas day d is:

$$PFDCP(p,d) = (\Sigma_{k \in SP}(FDCP(d,k) \times \Sigma_{cf(k)} MQS(p,d,ct(k))) \quad \ldots\ldots\ldots\ldots\ldots \quad (6)$$

The pipeline flow direction constraint charge to trading participant p for the ex ante market withdrawal of gas from the hub for gas day d is:

$$PFDCC(p,d) = \Sigma_{k \in SP}(FDCP(d,k) \times \Sigma_{cf(k)} MQS(p,d,cf(k))) \quad \ldots\ldots\ldots\ldots\ldots \quad (7)$$

Where

FDCP(d,k) is the pipeline flow direction price for pipeline k on gas day d (obtained from scheduling data).

MQS(p,d,c(k)) is the ex ante market schedule quantity for participant p supplying gas as a shipper on gas day d on trading right c(k) for facility k (obtained from scheduling data).

A1.3.4 Capacity charges and payments

Capacity charges and payments can only occur on constrained pipelines. On a constrained pipeline, shippers using as-available haulage make a capacity payment based on the gas that they actually flow on the gas day. On the same constrained pipeline, shippers using firm haulage, receive capacity payments based on the amount of gas that was offered into the ex ante market but which did not actually flow.

The total capacity revenue on an STTM facility is calculated by the capacity price multiplied by the lesser of the quantity of as-available gas scheduled and the quantity of firm gas offered but not scheduled, net of MOS allocations. Shippers who used as-available haulage are charged a rate equal to the total revenue divided by the total quantity of as-available haulage used. Shippers with firm haulage who do not flow gas are paid a rate equal to the total revenue divided by the total quantity of firm haul offered but not used.

For example, if the capacity price is 2.00 $/GJ on an STTM facility and 10 TJ of as-available haulage is used on that pipeline and 12 TJ of firm gas does not flow, then the total revenue recovered is 2.00 $/GJ × 10,000 GJ = $20,000. As-available shippers each pay ($20,000/10,000 GJ =) 2.00 $/GJ, and firm shippers are paid ($20,000/12,000 GJ =) 1.67 $/GJ. If, instead, 10 TJ of as-available gas had flowed and 8 TJ of firm gas had not flowed, then the total revenue recovered is 2.00 $/GJ × 8,000 GJ = $16,000. As-available shippers each pay ($16,000/10,000 GJ =) 1.60 $/GJ, and firm shippers are paid ($16,000/8,000 GJ =) 2.00 $/GJ.

Conditions

- Capacity charges and payments are only applied on constrained pipelines, that is, if the entire capacity of the pipeline (as advised by the facility operator, see Section 7.3) has been scheduled.

Equations

The capacity charge for trading participant p on gas day d for its gas flows on as-available trading rights is:

$$SCC(p,d) = \Sigma_{k\in SP}(ECCA(d,k) \times \Sigma_{cf(k)\in AH}\ EAQ^{S}(p,d,ct(k))) \ldots\ldots\ldots\ldots\ldots \quad (8)$$

The capacity payment for trading participant p on gas day d for firm trading rights offered but not utilised are:

$$SCP(p,d) = \Sigma_{k\in SP}(ECPF(d,k) \times \Sigma_{cf(k)\in FH}\ MAX(0,\ (FGO(p,d,ct(k)) - EAQ^{S}(p,d,ct(k))))) \quad (9)$$

Where

ECCA(d,k) is the effective capacity charge rate for as-available trading rights on gas day d and facility k.

$EAQ^{S}(p,d,ct(k))$ is the effective allocated quantity for trading participant p and gas day d for trading right c(k) which allows the supply of gas to the hub on facility k.

ECPF(d,k) is the effective capacity payment rate for firm trading rights on gas day d and facility k.

FGO(p,d,ct(k)) is the deemed firm gas offered to be supplied to the hub by trading participant p for gas day d on trading right c(k) on facility k.

Effective quantities used in capacity calculations

Capacity charges to shippers are based on the quantity of gas with as available trading rights (excluding MOS allocations and overrun MOS allocations). An as available trading right is a trading right with a haulage priority greater than 1. MOS allocations and overrun MOS allocations are removed because they are an allocation of actual pipeline flows and cannot cause a firm shipper to fail to access its pipeline capacity.

Capacity payments to shippers are based on the quantity of gas with firm trading rights not used – being the difference between the gas offered and the gas actually flowed (excluding MOS allocations and overrun MOS allocations)—on firm trading rights. A firm trading right is a trading right with a haulage priority equal to 1.

In situations where gas is being flowed away from a hub on facility k, no capacity charges or payments are incurred. Similarly, there are no payments or charges for a facility if the capacity price on the facility is zero.

The effective allocated quantity of gas supplied to the hub (based on pipeline allocations) by trading participant p on gas day d on trading right ct(k) for which trading participant p is the contract holder on facility $k\in SP$ is:

$$EAQ^{S}(p,d,ct(k)) = MAX(0,\ AQ^{S}(p,d,ct(k)) - MAQ^{S}(p,d,ct(k)) - OMAQ^{S}(p,d,ct(k))) \ldots\ldots \quad (10)$$

Where

$AQ^{S}(p,d,ct(k))$ is the quantity of gas allocated to flow to the hub by trading participant p on gas day d on trading right c(k) on facility k (obtained from allocation data).

$MAQ^{S}(p,d,ct(k))$ is the MOS quantity allocated to flow to the hub on trading right c(k) on facility k on gas day d by trading participant p (obtained from allocation data).

$OMAQ^{S}(p,d,ct(k))$ is the overrun MOS quantity allocated to flow by trading participant p to the hub on trading right c(k) on facility k on gas day d (obtained from allocation data).

This effective allocated quantity is the supply to the hub net of MOS allocated to that trading right on gas day d. No limit is imposed that forces this effective allocated quantity to be within the capacity of the trading right. This ensures that the trading participant pays for the full flow allocated to that trading right, even if that flow is infeasible according to the data held by AEMO.

The deemed gas offered on firm haulage capacity to be supplied to the hub by trading participant p for gas day d on firm trading right ct(k) on facility k∈SP is:

$$FGO(p,d,ct(k)) = MIN(CAP(p,d,ct(k)),\ OQF^{S}(p,d,ct(k))) \quad \ldots\ldots\ldots\ldots \quad (11)$$

Where

CAP(p,d,ct(k)) is the capacity to flow gas to the hub on trading right c(k) (obtained from trading rights data).

OQF^{S}(p,d,ct(k)) is the quantity of gas offered by trading participant p on trading right c(k) with firm haulage to flow to the hub on facility k (obtained from scheduling data)

The quantity is capped at the trading right capacity because, where a trading right capacity is updated after an offer has been submitted, it is possible for the trading right capacity to be less than the gas offered. A trading participant will only be scheduled up to the trading right limit.

The total effective quantity of gas flowed via as available trading rights to the hub for gas day d on facility k∈SP is:

$$TAFGQ(d,k) = \Sigma_{p}\ \Sigma_{ct(k)\in FH}\ EAQ^{S}(p,d,ct(k)) \quad \ldots\ldots\ldots\ldots\ldots\ldots \quad (12)$$

The total quantity of gas offered on firm trading rights to the hub but not flowed (based on the effective allocated quantity of gas flowed) for gas day d on facility k∈SP is:

$$TFGNQ(d,k) = \Sigma_{p}\ \Sigma_{ct(k)\in FH}\ MAX(0,\ FGO(p,d,ct(k)) - EAQ^{S}(p,d,ct(k)))\ . \quad (13)$$

The capacity quantity traded for gas day d on facility k∈SP is:

$$CQT(d,k) = MIN(TAFGQ(d,k),\ TFGNQ(d,k)) \quad \ldots\ldots\ldots\ldots\ldots\ldots \quad (14)$$

Capacity charges and payments

The effective capacity charge rate for as available trading rights on gas day d and facility k∈SP is:

If $TAFGQ(d,k) = 0$

$$ECCA(d,k) = 0 \quad \ldots\ldots\ldots\ldots\ldots\ldots \quad (15)$$

Else

$$ECCA(d,k) = CP(d,k)) \times CQT(d,k) / TAFGQ(d,k) \quad \ldots\ldots\ldots\ldots\ldots \quad (16)$$

Where

CP(d,k) is the capacity price for facility k on day d (obtained from scheduling data)

CQT(d,k) is the capacity quantity for facility k on day d (obtained from scheduling data)

TAFGQ(d,k) is the total effective quantity of gas flowed via as available trading rights to the hub for gas day d on facility k.

The effective capacity payment rate for firm trading rights on gas day d and facility k∈SP is:

If $TFGNQ(d,k) = 0$

$$ECPF(d,k) = 0 \quad \ldots\ldots\ldots\ldots\ldots\ldots \quad (17)$$

Else

$$ECPF(d,k) = CP(d,k)) \times CQT(d,k) / TFGNQ(d,k) \quad \ldots\ldots\ldots\ldots\ldots \quad (18)$$

Where

CP(d,k) is the capacity price for facility k on day d (obtained from scheduling data)

`CQT(d,k)` is the capacity quantity traded for facility `k` on day `d` (obtained from scheduling data)

`TFGNQ(d,k)` is total quantity of gas offered on firm trading rights to the hub but not flowed for facility `k` on day `d`.

Because the capacity quantity traded cannot exceed the values of `TAFGQ(d,k)` or `TFGNQ(d,k)`, these equations ensure that neither the capacity charge rate nor the capacity payment rate can exceed the value of the capacity price. If the quantity of as available trading right gas flowed exactly equals the firm trading right capacity offered but not utilised, then each of the capacity charge rate and capacity payment rate will equal the capacity price.

A1.3.5 Variation charges

Variation charges are applied to users and shippers based on the absolute percentage of their cumulative market schedule variation compared with their ex ante market schedule.

For example, if the ex ante market schedule is 10 TJ and the cumulative market schedule variation is –2 TJ, then a 20% percentage variation has occurred. The percentage variation is also 20% for a +2 TJ variation.

The variation charge is calculated by two methods on a graduated pricing scale. One method uses the absolute percentage variation and the other the absolute quantity (GJ). The charges are obtained from standing data tables (see Section 3.3). The variation charges for each band are summed for each method, and the total that is most advantageous to the trading participant is applied. The average variation price is capped at the difference between the MPC (or APC, if applicable) and the ex ante market price.

Conditions

Variation charges apply to market schedule variations for which the trading participant is the confirming party and is either:

- An STTM shipper withdrawing gas from the hub.

- An STTM user withdrawing gas from the hub and the market schedule variation results in a change to the total gas flow to the hub.

Equations

Each trading participant p has a single variation quantity `VQ(p,d)` for a gas day:

`VQ(p,d) = ABS(Σk Σh CSC(p,d,k,fd))` .... (19)

Where

`CSC(p,d,k,fd))` is the quantity of market schedule variations for trading participant `p` on gas day `d` for facility `k` for flows in direction `h` which is subject to variation charges.

If the trading participant is both an STTM user and an STTM shipper hauling from the hub, then `VQ(p,d)` reflects the net change in their withdrawals from the hub that are subject to variation changes. This does not include MSVs that do not incur a charge.

The variation charge `VarC(p,d)` for trading participant `p` for market schedule variations for gas day `d` is:

`VarC(p,d) = MIN(PVarC(p,d), GVarC(p,d))` .... (20)

Where

`PVarC(p,d)` is the variation charge calculated by the percentage method.

GVarC(p,d) is the variation charge calculated by the quantity method.

Pre-processing market schedule variations

Confirmed MSVs are pre-processed to determine the accumulated quantities of chargeable and non-chargeable MSVs.

Equations

The quantity of a confirmed MSV (obtained from settlement data) is

MSV(d,(op,ok,ofd),(rp,rk,rfd)) .... (21)

Where

d is the gas day

p is the originating participant identifier

ok is the originating facility identifier

ofd is the originating flow direction

rp is the receiving participant identifier

rk is the receiving facility identifier

rfd is the receiving flow direction

The total variation quantity of chargeable variations for participant p on day d is CSC, and the total variation quantity of non-chargeable variations for participant p on day d is FSC.

Initially, all values are set to zero:

CSC = 0

FSC = 0

And then, for each value of i, d, k, h, the submitted quantities (MSV) are accumulated according to:

If ok∈SP and ofd="to" and rk∈SP and rfd="to" and MSV>0 then

FSC(op,d,ok,ofd) = FSC(op,d,ok,ofd) + MSV(d,(op,ok,ofd),(rp,rk,rfd))

FSC(rp,d,rk,rfd) = FSC(rp,d,rk,rfd) − MSV(d,(op,ok,ofd),(rp,rk,rfd)) .(22)

If ok∈SP and ofd="to" and rk∈SP or SN and rfd="from" then

FSC(op,d,ok,ofd) = FSC(op,d,ok,ofd) + MSV(d,(op,ok,ofd),(rp,rk,rfd))

CSC(rp,d,rk,rfd) = CSC(rp,d,rk,rfd) + MSV(d,(op,ok,ofd),(rp,rk,rfd)) .(23)

If ok∈SP and ofd="from" and rk∈SP and rfd="from" and MSV>0 then

FSC(op,d,ok,ofd) = FSC(op,d,ok,ofd) + MSV(d,(op,ok,ofd),(rp,rk,rfd))

FSC(rp,d,rk,rfd) = FSC(rp,d,rk,rfd) − MSV(d,(op,ok,ofd),(rp,rk,rfd)) .(24)

If ok∈SP and ofd="from" and rk∈SN and rfd="from" then

FSC(op,d,ok,ofd) = FSC(op,d,ok,ofd) + MSV(d,(op,ok,ofd),(rp,rk,rfd))

FSC(rp,d,rk,rfd) = FSC(rp,d,rk,rfd) − MSV(d,(op,ok,ofd),(rp,rk,rfd)) .(25)

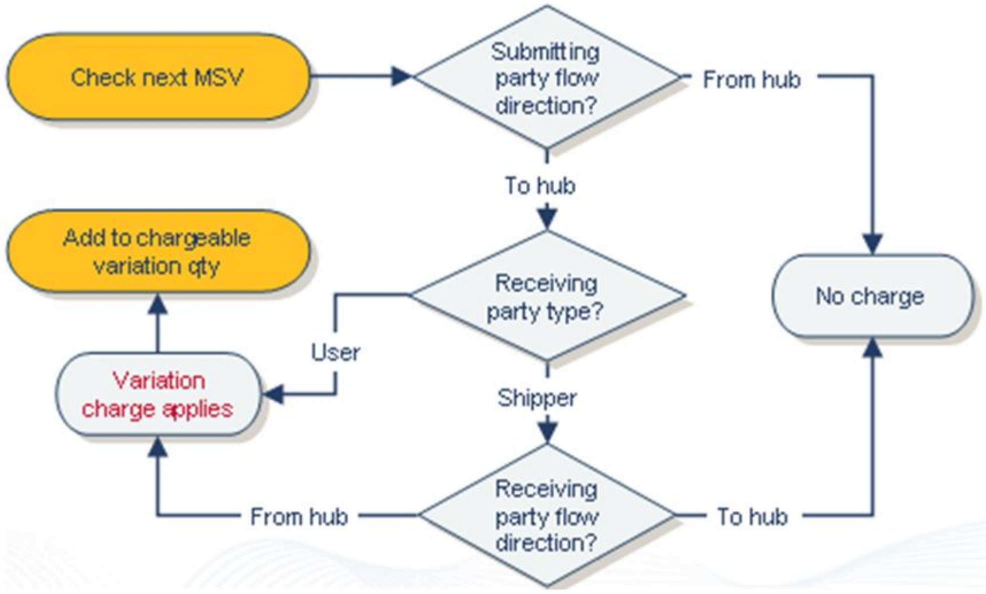
If ok∈SN and ofd="from" and rk∈SN and rfd="from" then

FSC(op,d,ok,ofd) = FSC(op,d,ok,ofd) + MSV(d,(op,ok,ofd),(rp,rk,rfd))

FSC(rp,d,rk,rfd) = FSC(rp,d,rk,rfd) − MSV(d,(op,ok,ofd),(rp,rk,rfd)) .(26)

The logic applied to determining if an MSV is chargeable is summarised in Figure 30. The final accumulated FSC and CSC quantities are used in the settlement calculations.

Figure 30 Determining if an MSV is chargeable



Percentage method

The total variation quantity for a participant `VQ(p,d)` is distributed into steps, where the size of each step is a percentage of the participant's ex ante market schedule as a user and as a shipper hauling from hub. The upper limit of each percentage step is defined by `PVarR(f)` for `f=1,2,3,...` and the variation step quantity `PVarU` of trading participant `p` is:

For `f=1`

$$\mathrm{PVarU}(p,d,f) = \mathrm{MIN}(\mathrm{VQ}(p,d),\ (\mathrm{PVarR}(f) \times \Sigma k\ (\Sigma_{cf(k)}\ \mathrm{MQ}^{U}(p,d,cf(k)) + \Sigma_{cf(k)}\ \mathrm{MQ}^{S}(p,d,cf(k))))) \quad \ldots\ldots\ldots\ldots\ldots\ldots \quad (27)$$

For `1<f<Maxf`

$$\mathrm{PVarU}(p,d,f) = \mathrm{MIN}(\mathrm{VQ}(p,d),\ (\mathrm{PVarR}(f) \times k\ (\Sigma_{cf(k)}\ \mathrm{MQ}^{U}(p,d,cf(k)) + \Sigma_{cf(k)}\ \mathrm{MQ}^{S}(p,d,cf(k))))) - \Sigma_{f'<f}\ \mathrm{PVarU}(p,d,f') \quad \ldots\ldots\ldots\ldots\ldots\ldots \quad (28)$$

For `f=Maxf`

$$\mathrm{PVarU}(p,d,f) = \mathrm{VQ}(p,d) - \Sigma_{f'<f}\ \mathrm{PVarU}(p,d,f') \quad \ldots\ldots\ldots\ldots\ldots\ldots \quad (29)$$

Where

$\mathrm{MQ}^{U}(p,d,cf(k))$ is the ex ante market schedule quantity for gas withdrawn from the hub by trading participant p as a user on trading right `c(k)` (obtained from scheduling data).

$\mathrm{MQ}^{S}(p,d,cf(k)$ is the ex ante market schedule quantity for gas withdrawn from the hub by trading participant p as a shipper on trading right `c(k)` (obtained from scheduling data).

The last step `(f=Maxf)` is used where there is no ex ante market schedule for withdrawal from the hub for the trading participant, and the entire variation quantity is allocated to the final step.

For example, if the participant's ex ante market schedule quantity is 100 GJ, and the steps are defined as PVarR(1)=3%, PVarR(2)=10%, and PVarR(3)=80%; and the participant's variation quantity is –50 GJ, then the market schedule variation quantity is distributed into three steps of 3 GJ, 7 GJ, and 40 GJ. which are calculated by VQ(p,d) = ABS(–50) = 50, PVarU(p,d,1) = MIN(50, 0.03×100) = 3, PVarU(p,d,2) = MIN(50, 0.1×100) – 3 = 7, and PVarU(p,d,3) = MIN(50, .8 ×100) – 3 – 7 = 40.

A variation penalty rate PVarF(f), which is expressed as a fraction of the market price, is associated with each step f, from which the variation charge PVarC is then calculated:

If VQ(p,d) = 0

PVarC(p,d) = 0 .... (30)

Else

PVarC(p,d) = VQ(p,d) × MIN(MAXP(d) – HP(d), ABS(HP(d)) × (Σ_f (PVarU(p,d,f) × PVarF(f))) / VQ(p,d)) ... (31)

Where

MAXP(d) is the maximum price to be applied in the settlement of gas day d. This is normally MPC, or APC during administered pricing periods (obtained from standing data).

HP(d) is the ex ante market price for gas day d (obtained from scheduling data).

This caps the average variation charge at the maximum market price less the ex ante market price. This ensures that a trading participant who traded its MSV quantity at the ex ante market price will never have a variation charge that would bring its total $/GJ payment for that gas above the applicable maximum price (MAXP) in the market.

Quantity method

The total variation quantity for a participant VQ(p,d) is distributed into steps, where the size of each step is an absolute quantity in GJ. The upper limit of each quantity step is defined by GVarR(f) for f=1,2,3,... and the variation step quantity GVarU of trading participant p is:

For f=1

GVarU(p,d,f) = MIN(VQ(p,d), GVarR(f)) .... (32)

For 1<f<Maxf

GVarU(p,d,f) = MIN(VQ(p,d), GVarR(f)) – $\Sigma_{f'<f}$ GVarU(p,d,f') ...... (33)

For f=Maxf

GVarU(p,d,f) = VQ(p,d) – $\Sigma_{f'<f}$ GVarU(p,d,f') .... (34)

The last step (f=Maxf) contains any remaining variation quantity.

For example, if the participant's ex ante market schedule quantity is 100 GJ, and the steps are defined as GVarR(1)=10 GJ, GVarR(2)=60 GJ, and GVarR(3)=80 GJ; and the participant's variation quantity is –50 GJ, then the market schedule variation is distributed into three steps of 10, 40, and 0. which are calculated by VQ(p,d) = ABS(–50) = 50, GVarU(p,d,1) = MIN(50, 10) = 10, GVarU(p,d,2) = MIN(50, 60) – 10 = 40, and GVarU(p,d,3) = MIN(50, .80) – 10 – 40= 0.

A variation penalty rate GVarF(f), which is expressed as a fraction of the market price, is associated with each step f, from which the variation charge GVarC is then calculated:

If $VQ(p,d) = 0$

$$GVarC(p,d) = 0 \quad \ldots\ldots\ldots\ldots\ldots\ldots\ldots (35)$$

Else

$$GVarC(p,d) = VQ(p,d) \times MIN(MAXP(d) - HP(d), ABS(HP(d)) \times (\Sigma_f(GVarU(p,d,f) \times GVarF(f)))/VQ(p,d)) \quad .. (36)$$

Where

$MAXP(d)$ is the maximum price to be applied in the settlement of gas day d. This is normally MPC, or APC during administered pricing periods (obtained from standing data).

$HP(d)$ is the ex ante market price for gas day d (obtained from scheduling data).

This caps the average variation charge at the maximum market price less the ex ante market price. This ensures that a trading participant who traded its MSV quantity at the ex ante market price will never have a variation charge that would bring its total $/GJ payment for that gas above the applicable maximum price (MAXP) in the market.

A1.3.6 MOS gas charges and payments

When a pipeline operator makes a MOS allocation for a MOS provider, AEMO pays the MOS provider for increased flows or decreased flows in accordance with the relevant MOS offer step. In addition to the MOS service payment, the MOS provider is paid for MOS allocations which increase net flow to the hub and are charged for MOS allocations which decrease the net flow from the hub on gas day d at the gas day d+2 ex ante market price.

Process

1. Facility operators submit STTM facility allocations to AEMO daily for the previous gas day. Facility allocations include the total quantities of MOS gas and overrun MOS gas, allocated by CRN.
2. Facility operators submit MOS step allocations to AEMO daily for the previous gas day.
3. AEMO calculates the quantity of MOS gas allocated to each MOS provider on each day of the billing period.
4. AEMO calculates the quantity of overrun MOS gas allocated to each STTM shipper on each day of the billing period.
5. AEMO pays or charges the MOS provider for MOS gas supplied on gas day d at the ex ante market price on day d+2. Where MOS gas increased supply to the hub, the provider is paid; where the MOS gas decreased supply at the hub, the provider is charged.
6. AEMO pays or charges STTM shippers allocated overrun MOS.
7. AEMO calculates MOS service payments from the MOS offers, which pays the provider for providing the MOS service.

Equations

The payments and charges are based on the sum of the payments required for the MOS service and the amounts for cashing out MOS gas.

The MOS payment to trading participant p as a MOS provider for gas day d is:

$$MosP(p,d) = MCP(p,d) + MOP(p,d) + MCCP(p,d) + MCOP(p,d) \quad \ldots\ldots\ldots (37)$$

Where

$MCP(p,d)$ is the payment to trading participant p for MOS service for gas day d

$MOP(p,d)$ is the payment to trading participant p for overrun MOS service for gas day d

$MCCP(p,d)$ is the commodity payment for trading participant p for MOS on day d for gas day d-2

$MCOP(p,d)$ is the commodity payment for trading participant p for overrun MOS on day d for gas day $d-2$

The MOS charge on trading participant p as a MOS provider for gas day d is:

$$MosC(p,d) = MCCC(p,d) + MCOC(p,d) \quad \ldots\ldots\ldots\ldots\ldots\ldots\ldots \quad (38)$$

Where

$MCCC(p,d)$ is the commodity charge for trading participant p for MOS on day d for gas day $d-2$

$MCOC(p,d)$ is the commodity charge for trading participant p for overrun MOS on day d for gas day $d-2$

Overrun MOS pricing

The rules for pricing overrun MOS are designed to maintain incentives for offering MOS under normal forecast conditions while ensuring that overrun MOS providers are not disadvantaged when MOS usage exceeds the forecast:

- If no MOS was allocated to MOS steps then the overrun MOS price is zero. This ensures that providers of overrun MOS are no better off than MOS providers.
- If the MOS allocated to MOS steps did not exceed the maximum expected MOS increase (MOSRI) or MOS decrease (MOSRD) for that facility, then the overrun MOS price equals the volume-weighted average cost of MOS increase or MOS decrease allocated on that facility and gas day. This provides an incentive to offer MOS when expected MOS usage occurs.
- If the MOS allocated to MOS steps exceeds the maximum expected MOS increase (MOSRI) or MOS decrease (MOSRD) for that facility, then the overrun price equals the maximum MOS increase or MOS decrease step cost incurred by the market for a MOS provider on that facility. This ensures that overrun MOS providers are paid no worse than MOS providers when unexpected MOS usage occurs.

Equations

The total MOS increased gas flows to the hub allocated under MOS stacks on facility $k \in SP$ is:

$$TCMIQ(d,k) = \Sigma_i\ \Sigma_{m(k)}\ \Sigma_j\ MOSAIS(p,d,m(k),j) \quad \ldots\ldots\ldots\ldots\ldots\ldots \quad (39)$$

Where

$MOSAI^S(p,d,m(k),j)$ is the quantity of MOS increase allocated to step j for trading participant p on gas day d on MOS offer m on facility k (obtained from allocation data).

$ORPI(d,k)$ is the overrun price of MOS for increased gas flows to the hub for facility $k \in SP$ on gas day d and is calculated by:

If $TCMIQ(d,k) = 0$

$$ORPI(d,k) = 0 \quad \ldots\ldots\ldots\ldots\ldots\ldots \quad (40)$$

If $TCMIQ(d,k) > 0$ and $TCMIQ(d,k) \leq MOSRI(k)$ then

$$ORPI(d,k) = (\Sigma_p\ \Sigma_{m(k)}\ \Sigma_j\ MOSIC^S(p,d,m(k),j) \times MOSAI^S(p,d,m(k),j))\ /\ TCMIQ(d,k) \quad \ldots\ldots\ldots \quad (41)$$

If $TCMIQ(d,k) > 0$ and $TCMIQ(d,k) > MOSRI(k)$ then for all steps j for all MOS offers $m(k)$ for all participants i for which $MOSAI^S(p,d,m(k),j) > 0$ on gas day d

$$ORPI(d,k) = MAX(MOSIC^S(p,d,m(k),j),\ldots). \quad \ldots\ldots\ldots\ldots\ldots\ldots\ldots \quad (42)$$

Where

$\texttt{MOSRI(k)}$ is the forecast maximum MOS increase on facility $\texttt{k}$ for gas day $\texttt{d}$ (obtained from MOS offer data).

$\texttt{MOSAI}^S\texttt{(p,d,m(k),j)}$ is the quantity of MOS increase allocated to step $\texttt{j}$ for trading participant $\texttt{p}$ on gas day $\texttt{d}$ on MOS offer $\texttt{m}$ on facility $\texttt{k}$ (obtained from allocation data).

$\texttt{MOSIC}^S\texttt{(p,d,m(k),j)}$ is the MOS step cost for increased gas flow from step $\texttt{j}$ for trading participant $\texttt{p}$ as a shipper on gas day $\texttt{d}$ on MOS offer $\texttt{m}$ on facility $\texttt{k}$ (obtained from MOS offer data).

The total MOS decreased gas flows to the hub allocated under MOS stacks on facility $\texttt{k} \in \texttt{SP}$ is:

$$\texttt{TCMDQ(d,k)} = \Sigma_i \Sigma_{m(k)} \Sigma_j \texttt{MOSAD}^S\texttt{(p,d,m(k),j)} \quad \ldots\ldots\ldots\ldots\ldots\ldots \quad (43)$$

Where

$\texttt{MOSAD}^S\texttt{(p,d,m(k),j)}$ is the quantity of MOS decrease allocated to step $\texttt{j}$ for trading participant $\texttt{p}$ on gas day $\texttt{d}$ on MOS offer $\texttt{m}$ on facility $\texttt{k}$ (obtained from allocation data).

$\texttt{ORPD(d,k)}$ is the overrun price of MOS for decreased gas flows to the hub for facility $\texttt{k} \in \texttt{SP}$ on gas day d and is calculated by:

If $\texttt{TCMDQ(d,k)} = 0$

$$\texttt{ORPD(d,k)} = 0 \quad \ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots \quad (44)$$

If $\texttt{TCMDQ(d,k)} > 0$ and $\texttt{TCMDQ(d,k)} \leq \texttt{MOSRD(k)}$ then

$$\texttt{ORPD(d,k)} = (\Sigma_i \Sigma_{m(k)} \Sigma_j \texttt{MOSDC}^S\texttt{(p,d,m(k),j)}$$

$$\times \texttt{MOSAD}^S\texttt{(p,d,m(k),j))} / \texttt{TCMDQ(d,k)} \quad \ldots\ldots\ldots\ldots \quad (45)$$

If $\texttt{TCMDQ(d,k)} > 0$ and $\texttt{TCMDQ(d,k)} > \texttt{MOSRD(k)}$ then for all steps $\texttt{j}$ for all MOS offers $\texttt{m(k)}$ for all participants $\texttt{i}$ for which $\texttt{MOSADS(p,d,m(k),j)} > 0$ on gas day $\texttt{d}$

$$\texttt{ORPD(d,k)} = \texttt{MAX(MOSDC}^S\texttt{(p,d,m(k),j),...)} \quad \ldots\ldots\ldots\ldots\ldots\ldots\ldots \quad (46)$$

Where

$\texttt{MOSRD(k)}$ is the forecast maximum MOS decrease on facility $\texttt{k}$ for gas day $\texttt{d}$ (obtained from MOS offer data).

$\texttt{MOSAD}^S\texttt{(p,d,m(k),j)}$ is the quantity of MOS decrease allocated to step $\texttt{j}$ for trading participant $\texttt{p}$ on gas day $\texttt{d}$ on MOS offer $\texttt{m}$ on facility $\texttt{k}$ (obtained from allocation data).

$\texttt{MOSDC}^S\texttt{(p,d,m(k),j)}$ is the MOS step cost for decreased gas flow from step $\texttt{j}$ for trading participant $\texttt{p}$ as a shipper on gas day $\texttt{d}$ on MOS offer $\texttt{m}$ on facility $\texttt{k}$ (obtained from MOS offer data).

MOS service payments

The MOS service payment increases and decreases based on the quantities allocated to those MOS offers.

MOS overrun service payments for increases and decreases under trading rights are based on the MOS overrun allocations to registered facility services, which are associated by AEMO in settlement with the trading right of the contract holder for that registered facility service. The overrun price for increases is applied to quantities that increase net flow to the hub, and the overrun prices for decreases is applied to quantities that decrease net flow to the hub.

Equations

The payment to trading participant $\texttt{p}$ for MOS service for gas day $\texttt{d}$ is:

$$\texttt{MCP(p,d)} = \Sigma_{k \in SP} \Sigma_{m(k)} \texttt{MOSFP(p,d,m(k))}$$

$$+ (\Sigma_{k \in SP} \Sigma_{m(k)} \Sigma_j \texttt{MOSIC}^S\texttt{(p,d,m(k),j)} \times \texttt{MOSAI}^S\texttt{(p,d,m(k),j))}$$

$$+ \ (\Sigma_{k\in SP}\ \Sigma_{m(k)}\ \Sigma_{j}\ MOSDC^{S}(p,d,m(k),j)\ \times\ MOSAD^{S}(p,d,m(k),j)) \quad (47)$$

Where

$MOSIC^{S}(p,d,m(k),j)$ is the MOS step cost for increased gas flow from step j for trading participant p as a shipper on gas day d on MOS offer $m(k)$ on facility k (obtained from MOS offer data).

$MOSAI^{S}(p,d,m(k),j)$ is the quantity of MOS decrease allocated to step j for trading participant p on gas day d on MOS offer $m(k)$ on facility k (obtained from allocation data).

$MOSDC^{S}(p,d,m(k),j)$ is the MOS step cost for decreased gas flow from step j for trading participant p as a shipper on gas day d on MOS offer $m(k)$ on facility k (obtained from MOS offer data).

$MOSAD^{S}(p,d,m(k),j)$ is the quantity of MOS decrease allocated to step j for trading participant p on gas day d on MOS offer m on facility k (obtained from allocation data).

The payment to trading participant p for overrun MOS service for gas day d is:

$$\begin{aligned} MOP(p,d) \ = \ & (\Sigma_{k\in SP}\ ORPI(d,k)\ \times\ MAX(0,\ \Sigma_{t(k)}(OMAQ^{S}(p,d,ct(k)) \\ & + OMAQ^{S}(p,d,cf(k)))) \ + \ (\Sigma_{k\in SP}\ ORPD(d,k) \\ & \times\ -1\ \times\ MIN(0,\ \Sigma_{t(k)}(OMAQ^{S}(p,d,ct(k)) \\ & + OMAQ^{S}(p,d,cf(k)))) \qquad \ldots\ldots\ldots\ldots\ldots\ldots\ldots \ (48) \end{aligned}$$

Where

$ORPI(d,k)$ is the overrun MOS increase price for facility k on gas day d

$ORPD(d,k)$ is the overrun MOS decrease price for facility k on gas day d

$OMAQ^{S}(p,d,cf(k))$ is the overrun MOS quantity allocated to flow by trading participant p from the hub on trading right $c(k)$ on facility on gas day d (obtained from allocation data).

$OMAQ^{S}(p,d,ct(k))$ The overrun MOS quantity allocated to flow by trading participant p to the hub on trading right $c(k)$ on facility on gas day d (obtained from allocation data).

MOS commodity charges and payments

The commodity cost of MOS gas and overrun MOS gas for day $d-2$ is cashed out on day d. A payment is made if the change in net gas allocated to flow to the hub is positive. A charge is made if the change in net gas allocated to flow to the hub is negative.

Equations

The MOS cash-out payment for trading participant p as a MOS provider at the gas day d price for MOS gas provided on gas day $d-2$ is:

$$\begin{aligned} MCCP(p,d) \ = \ & HP(d)\ \times\ \Sigma_{k\in SP}\ (\Sigma_{cf(k)}\ MAX(0,\ MAQ^{S}(p,d-2,cf(k))) \\ & + \Sigma_{cf(k)}\ MAX(0,\ MAQ^{S}(p,d-2,ct(k)))) \ \ldots\ldots \ (49) \end{aligned}$$

The MOS cash-out charge for trading participant p as a MOS provider at the gas day d price for MOS gas provided on gas day $d-2$ is:

$$\begin{aligned} MCCC(p,d) \ = \ & HP(d)\ \times\ \Sigma_{k\in SP}\ (\Sigma_{cf(k)}\ MAX(0,\ -1\ \times\ MAQ^{S}(p,d-2,cf(k))) \\ & + \Sigma_{cf(k)}\ MAX(0,\ -1\ \times\ MAQ^{S}(p,d-2,ct(k)))) \quad (50) \end{aligned}$$

The MOS cash-out payment for trading participant p as an overrun MOS provider at the gas day d price for MOS gas provided on gas day $d-2$ is:

$$MCOP(p,d) \ = \ HP(d)\ \times\ \Sigma_{k\in SP}\ (\Sigma_{cf(k)}\ MAX(0,\ OMAQ^{S}(p,d-2,cf(k)))$$

$$+ \Sigma_{cf(k)} \text{ MAX}(0, \text{ OMAQ}^{S}(p,d-2,ct(k)))) \text{ .... } (51)$$

The MOS cash-out charge for trading participant p as an overrun MOS provider at the gas day d price for MOS gas provided on gas day d−2 is:

$$\text{MCOC}(p,d) = \text{HP}(d) \times \Sigma_{k\in SP} (\Sigma tF(k) \text{ MAX}(0, -1 \times \text{OMAQ}^{S}(p,d-2,cf(k)))$$

$$+ \Sigma_{cf(k)} \text{ MAX}(0, -1 \times \text{OMAQ}^{S}(p,d-2,ct(k)))) \quad (52)$$

Where

HP(d) is the ex ante market price for day d (obtained from scheduling data).

$MAQ^{S}(p,d,cf(k))$ is the MOS quantity allocated to flow by trading participant p from the hub on trading right c(k) on facility on gas day d (obtained from allocation data).

$MAQ^{S}(p,d,ct(k))$ is the MOS quantity allocated to flow by trading participant p to the hub on trading right c(k) on facility on gas day d (obtained from allocation data).

$OMAQ^{S}(p,d,cf(k))$ is the overrun MOS quantity allocated to flow by trading participant p from the hub on trading right c(k) on facility on gas day d (obtained from allocation data).

$OMAQ^{S}(p,d,ct(k))$ The overrun MOS quantity allocated to flow by trading participant p to the hub on trading right c(k) on facility on gas day d (obtained from allocation data).

A1.3.7 Contingency gas charges and payments

Participants called to provide contingency gas will be settled at the relevant contingency gas price. If a hub has a shortfall of supply, so that contingency gas offers are scheduled, then the high contingency gas price CGPH(d) applies. If a hub has a surplus of supply, so that contingency gas bids are scheduled, then the low contingency gas price CGPL(d) applies and those who decrease the quantity of gas shipped to that hub or who raise the quantity withdrawn at that hub are charged this price.

Equations

The contingency gas payment to trading participant p for gas day d when contingency gas is called to increase net supply to the hub is:

$$\text{CGP}(p,d) = \text{CGPH}(d) \times (\Sigma_{k\in SP} \text{ MAX}(0, \text{ CQS}(p,d,k,fd=\text{"to"}))$$

$$+ (\Sigma_{k\in SN} \text{ MAX}(0, -1 \times \text{CQU}(p,d,k,fd=\text{"from"}))$$

$$+ \Sigma_{k\in SP} \text{ MAX}(0, -1 \times \text{CQS}(p,d,k,fd=\text{"from"}))) \text{ .... } (53)$$

The contingency gas charge to trading participant p for gas day d when contingency gas is called to decrease net supply to the hub is:

$$\text{CGC}(p,d) = \text{CGPL}(d) \times (\Sigma_{k\in SP} \text{ MAX}(0, -1 \times \text{CQ}^{S}(p,d,k,fd=\text{"to"}))$$

$$+ \Sigma_{k\in SN} \text{ MAX}(0, \text{ CQ}^{U} (p,d,k,fd=\text{"from"}))$$

$$+ \Sigma_{k\in SP} \text{ MAX}(0, \text{ CQ}^{S}(p,d,k,fd=\text{"from"}))) \text{ .... } (54)$$

Where

CGPH(d) is the high contingency gas price on day d (obtained from scheduling data)

CGPL(d) is the low contingency gas price on day d (obtained from scheduling data)

$CQ^{S}(p,d,k,fd))$ is the change to be applied to the market schedule quantity due to contingency gas scheduled by AEMO to be supplied to the hub (h = "to") or withdrawn from the hub (h= "from") by trading participant p as a shipper on gas day d on facility k.

$CQ^{U}(p,d,k,fd))$ is the change to be applied to the market schedule quantity due to contingency gas scheduled by AEMO to be withdrawn from the hub (h = "from") by trading participant p as a user on gas day d on facility k.

Ad Hoc Charges for Contingency Gas Resettlement

Ad hoc charges for Contingency Gas Resettlement will apply where the evidence shows that a Trading Participant has not delivered contingency gas according to the contingency gas requirement.

When contingency gas is called to increase supply to the hub, the amount payable by the Trading Participant is an ad hoc charge calculated by determining the undelivered contingency gas quantity and charging for this quantity at the difference between the high contingency price and the deviation price for a long deviation quantity.

When contingency gas is called to decrease supply to the hub, the amount payable by the Trading Participant is an ad hoc charge calculated by determining the undelivered contingency gas quantity and paying for this quantity at the difference between the low contingency gas price and the deviation price for a short deviation quantity.

Equations

The ad hoc charge for Trading Participant p in relation to a scheduled quantity of contingency gas to increase supply to the hub on gas day d is:

$$AHC\ (p,d) = MAX\ (0,\ (CGPH(d) - PDevPT(p,d,k)) \times \{ \Sigma_{k\in SP}\ [MAX(0,\ (MAX(0,\ CQ^{S}(p,d,k,\ fd=\text{“to”})) - MAX(0,\ -1 \times DQT(p,d,k)) - MAX(0,CQP^{S}\ (p,d,k\ fd=\text{“to”}))))] + \Sigma_{k\in SP}\ [MAX(0,(MAX(0,\ -1 \times CQ^{S}(p,d,k,fd=\text{“from”})) - MAX(0,\ -1 \times DQF(p,d,k)) - MAX(0,\ -1 \times CQP^{S}\ (p,d,k,fd=\text{“from”}))))] + \Sigma_{k\in SN}\ [MAX(0,\ (MAX(0,\ -1 \times CQ^{U}(p,d,k,fd=\text{“from”})) - MAX(0,\ -1 \times DQF(p,d,k)) - MAX(0,\ -1 \times CQP^{U}\ (p,d,k,fd=\text{“from”}))))]\}) \quad \ldots\ldots\ldots (55)$$

The ad hoc charge for Trading Participant p in relation to a scheduled quantity of contingency gas to decrease supply to the hub on gas day d is:

$$AHC\ (p,d) = MAX\ (0,\ (PDevNT(p,d,k) - CGPL(d)) \times \{ \Sigma_{k\in SP}\ [MAX(0,\ (MAX(0,\ -1 \times CQ^{S}(p,d,k,\ fd=\text{“to”})) - MAX(0,\ DQT(p,d,k)) - MAX(0,\ -1 \times CQPS\ (p,d,k\ fd=\text{“to”}))))] + \Sigma_{k\in SP}\ [MAX(0,\ (MAX(0,\ CQ^{S}(p,d,k,\ fd=\text{“from”})) - MAX(0,\ DQF(p,d,k)) - MAX(0,\ CQP^{S}\ (p,d,k\ fd=\text{“from”}))))] + \Sigma_{k\in SN}\ [MAX(0,\ (MAX(0,\ CQ^{U}(p,d,k,\ fd=\text{“from”})) - MAX(0,\ DQF(p,d,k)) - MAX(0,\ CQP^{U}\ (p,d,k\ fd=\text{“from”}))))]\}) \quad \ldots\ldots\ldots\ldots\ldots (56)$$

Where

$CGPH(d)$ is the high contingency gas price on day d (obtained from scheduling data)

$CGPL(d)$ the low contingency gas price on day d (obtained from scheduling data)

$CQ^{S}(p,d,k,fd))$ is the change to be applied to the market schedule quantity due to contingency gas scheduled by AEMO to be supplied to the hub (h = “to”) or withdrawn from the hub (h= “from”) by trading participant p as a shipper on gas day d on facility k.

$CQ^{U}(p,d,k,fd))$ is the change to be applied to the market schedule quantity due to contingency gas scheduled by AEMO to be withdrawn from the hub (h = “from”) by trading participant p as a user on gas day d on facility k.

$CQP^{S}(p,d,k,fd)$ is the quantity of contingency gas AEMO has determined to have been delivered under Rule 449(3) for Trading Participant p (as an STTM Shipper) on gas day d on market facility $k\in SP$ (an STTM Facility) and in flow direction fd.

$\text{CQP}^{U}(p,d,k,fd)$ is the quantity of contingency gas AEMO has determined to have been delivered under Rule 449(3) for Trading Participant p (as an STTM User) on gas day d on market facility $k \in SN$ and in flow direction fd (fd = "from" only).

$\text{DQF}(p,d,k)$ is the total GJ deviation of Trading Participant p supplying gas to the hub on market facility k on gas day d.

$\text{DQT}(p,d,k)$ is the total GJ deviation of Trading Participant p withdrawing gas from the hub on market facility k on gas day d.

$\text{PDevNT}(p,d,k)$ is the deviation price of a negative deviation for Trading Participant p on gas day d for supply to the hub on market facility k.

$\text{PDevPT}(p,d,k)$ is the deviation price of a positive deviation for Trading Participant p on gas day d for supply to the hub on market facility k.

Ad Hoc Payments for Contingency Gas Resettlement

Funds received by AEMO through the Ad Hoc Charges for Contingency Gas Resettlement will be distributed by way of Ad Hoc Payments to other Trading Participants who are impacted as a result of the undelivered contingency gas.

Any residual funds will be distributed through the Market Surplus and Shortfall mechanism.

Equations

The ad hoc payment for Trading Participant p on gas day d depends on the Trading Participant's deviation quantity (whether short or long) and the nature of the relevant contingency gas requirement (whether for increased or decreased supply to the hub) and is determined as follows:

1. Calculate the Trading Participant's short deviation quantity for the relevant hub and gas day:

$$\begin{aligned}\text{SDQ}(p,d) = &\textstyle\sum_{k\in SP} [\text{MAX}(0, -1 \times \text{DQT}(p,d,k))] \\ &+ \textstyle\sum_{k\in SP} [\text{MAX}(0, -1 \times \text{DQF}(p,d,k))] \\ &+ \textstyle\sum_{k\in SN} [\text{MAX}(0, -1 \times \text{DQF}(p,d,k))] \quad \ldots\ldots\ldots\ldots\ldots\ldots\ldots (57)\end{aligned}$$

2. Calculate the Trading Participant's long deviation quantity for the relevant hub and gas day:

$$\begin{aligned}\text{LDQ}(p,d) = &\textstyle\sum_{k\in SP} [\text{MAX}(0, \text{DQT}(p,d,k))] \\ &+ \textstyle\sum_{k\in SP} [\text{MAX}(0, \text{DQF}(p,d,k))] \\ &+ \textstyle\sum_{k\in SN} [\text{MAX}(0, \text{DQF}(p,d,k))] \quad \ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots (58)\end{aligned}$$

3. Trading Participant's ad hoc payment where contingency gas was required to increase supply to the hub:

$$\begin{aligned}\text{AHP}(p,d) = &\\ &\text{MAX}\ [0, \\ &\text{MIN}\ (\text{PDevNT}(p,d,k) - \text{RDevN}(d), \textstyle\sum_p \text{AHC}(p,d) / \textstyle\sum_p \text{SDQ}(p,d)) \\ &\text{x}\ \text{SDQ}(p,d)] \quad \ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots (59)\end{aligned}$$

4. Trading Participant's ad hoc payment where contingency gas was required to decrease supply to the hub:

$$\begin{aligned}\text{AHP}(p,d) = &\\ &\text{MAX}\ [0, \\ &\text{MIN}(\ \text{RDevP}(d) - \text{PDevPT}(p,d,k), \textstyle\sum_p \text{AHC}(p,d) / \textstyle\sum_p \text{LDQ}(p,d)) \\ &\text{x}\ \text{LDQ}(p,d)] \quad \ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots (60)\end{aligned}$$

Where

$\text{AHC}(p,d)$ is the ad hoc charge for trading participant p for gas day d.

$\text{AHP}(p,d)$ is the ad hoc payment for trading participant p for gas day d.

DQF(p,d,k) is the total GJ deviation of Trading Participant p supplying gas to the hub on market facility k on gas day d.

DQT(p,d,k) is the total GJ deviation of Trading Participant p withdrawing gas from the hub on market facility k on gas day d.

SDQ(p,d) is the short deviation quantity for Trading Participant p at a hub on gas day d.

LDQ(p,d) is the long deviation quantity for Trading Participant p at a hub on gas day d.

PDevNT(p,d,k) is the deviation price of a negative deviation for Trading Participant p on gas day d for supply to the hub on market facility k.

PDevPT(p,d,k) is the deviation price of a positive deviation for Trading Participant p on gas day d for supply to the hub on market facility k.

RDevN(d) is a revised deviation price for a short deviation quantity at a hub on gas day d. It is determined by adjusting the high contingency gas price and recalculating the deviation price applicable to a short deviation quantity on the gas day. If a Trading Participant does not deliver contingency gas as scheduled, this may result in a requirement to schedule additional contingency gas. The adjusted high contingency gas price excludes any additional contingency gas that was scheduled to replace the contingency gas that was not delivered.

RDevP(d) is a revised deviation price for a long deviation quantity at a hub on gas day d. It is determined by adjusting the low contingency gas price and recalculating the deviation price applicable to a long deviation quantity on the gas day. If a Trading Participant does not deliver contingency gas as scheduled, this may result in a requirement to schedule additional contingency gas. The adjusted low contingency gas price excludes any additional contingency gas that was scheduled to replace the contingency gas that was not delivered.

A1.3.8 Modified market schedules

The modified market schedules for trading participants for gas day d must take account of market schedules for gas day d, MOS allocations and overrun MOS allocations by pipeline operators for gas day d, contingency gas scheduled to be delivered on gas day d, and the net impact of market schedule variations.

Each trading participant has a modified market schedule quantity in its role as an STTM user reflecting its withdrawals from the hub, and two different modified market schedule quantities for each pipeline in its role as an STTM shipper, with one quantity relating to flows to the hub and the other relating to withdrawals from the hub.

Equations

The modified market schedule quantities for trading participant p on gas day in its role as an STTM shipper on facility $k \in SP$ with flow direction h is:

If h = "from":

$$MMSQ^{S}(p,d,k,fd) = \Sigma_{cf(k)}\ (MQ^{S}(p,d,cf(k)) - MAQ^{S}(p,d,cf(k)) - OMAQ^{S}(p,d,cf(k))) + CQ^{S}(p,d,k,fd) + FSC(p,d,k,fd) + CSC(p,d,k,fd) \quad \ldots\ldots\ldots\ldots\ (61)$$

If h = "to":

$$MMSQ^{S}(p,d,k,fd) = \Sigma_{ct(k)}\ (MQ^{S}(p,d,ct(k)) + MAQ^{S}(p,d,ct(k)) + OMAQ^{S}(p,d,ct(k))) + CQ^{S}(p,d,k,fd) + FSC(p,d,k,fd) + CSC(p,d,k,fd) \quad \ldots\ldots\ldots\ldots\ (62)$$

Note. Because positive MOS flow for a shipper flowing from the hub implies reduced flow from the hub, then a positive MOS flow must decrease the modified market schedule for that shipper.

The modified market schedule quantities for trading participant p on gas day in its role as an STTM user on facility $k \in SN$ with flow direction h is:

If h = "from":

$$MMSQ^{U}(p,d,k,fd) = \Sigma_{cf(k)} (MQ^{U}(p,d,cf(k))) + CQ^{U}(p,d,k,fd) + FSC(p,d,k,fd) + CSC(p,d,k,fd) \quad \ldots\ldots\ldots\ldots\ (63)$$

If h = "to" there cannot be a modified market schedule quantity as STTM users can only withdraw from the hub so:

$$MMSQ^{U}(p,d,k,fd) = 0 \quad \ldots\ldots\ldots\ldots\ldots\ldots\ldots\ (64)$$

Where

$MQS(p,d,ct(k))$ is the ex ante market schedule quantity for gas supplied to the hub by trading participant p as a shipper on gas day d on trading right $c(k)$ for facility k (obtained from scheduling data).

$MQU(p,d,cf(k))$ is the ex ante market schedule quantity for gas supplied to the hub by trading participant p as a user on gas day d on trading right $c(k)$ for facility k (obtained from scheduling data).

$MAQS(p,d,ct(k))$ is the MOS quantity allocated to flow to the hub on trading right $c(k)$ on facility k on gas day d by trading participant i.

$OMAQS(p,d,ct(k))$ is the overrun MOS quantity allocated to flow to the hub on trading right $c(k)$ on facility k on gas day d by trading participant i.

$CQS(p,d,k,fd)$ is the change to be applied to the market schedule quantity due to contingency gas scheduled by AEMO to be supplied to the hub (h = "to") or withdrawn from the hub (h= "from") by trading participant p as a shipper on gas day d on facility k.

$CQU(p,d,k,fd)$ is the change to be applied to the market schedule quantity due to contingency gas scheduled by AEMO to be withdrawn from the hub (h= "from") by trading participant p as a user on gas day d on facility k.

$FSC(p,d,k,fd)$ is the change, due to market schedule variations, to be applied to the market schedule quantity for trading participant p on gas day d for facility k for flows in direction h, where the change is not subject to variation charges.

$CSC(p,d,k,fd)$ is the change, due to market schedule variations, to be applied to the market schedule quantity for trading participant p on gas day d for facility k for flows in direction h, where the change is subject to variation charges.

The value of $MMSQ^{S}(p,d,k,fd)$ and $MMSQ^{U}(p,d,k,fd)$ can be positive or negative.

Important. Quantities for STTM users are aggregated at the hub level. References to facility $k \in SN$ should be interpreted as the sum of all distribution facilities at the hub.

A1.3.9 Deviation quantities

Deviation quantities reflect the difference between the modified market schedule quantities and the relevant pipeline allocations or network allocations.

A long deviation is when a shipper supplying a hub, a shipper withdrawing from a hub, or a user at a hub has deviated in a manner that increases net supply to the hub.

A short deviation is when a shipper supplying to a hub, a shipper withdrawing from a hub, or a user at a hub has deviated in a manner that decreases net supply to the hub

Equations

The total deviation quantity for trading participant p for its withdrawals from the hub as a network user on facility $k \in SN$ on gas day d is:

$$DQF(p,d,k) = MMSQ^{U}(p,d,k,fd=\text{"from"}) - \Sigma_{cf(k)}\ AQ^{U}(p,d,cf(k)) \quad \ldots\ldots \quad (65)$$

The total deviation quantity for trading participant p for its withdrawals from the hub as a shipper on facility $k \in SP$ on gas day d is:

$$DQF(p,d,k) = MMSQ^{S}(p,d,k,fd=\text{"from"}) - \Sigma_{cf(k)}\ AQ^{S}(p,d,cf(k)) \quad \ldots\ldots \quad (66)$$

The total deviation quantity for trading participant p for its supply to the hub as a shipper on facility $k \in SP$ on gas day d is:

$$DQT(p,d,k) = \Sigma_{ct(k)}\ AQ^{S}(p,d,ct(k)) - MMSQ^{S}(p,d,k,fd=\text{"to"}) \quad \ldots\ldots. \quad (67)$$

The total deviation quantity for trading participant p for its supply to the hub as a network user on facility $k \in SN$ on gas day d is by definition:

$$DQT(p,d,k) = 0 \quad \ldots\ldots\ldots\ldots\ldots\ldots\ldots \quad (68)$$

Where

$MMSQ^{U}(p,d,k,fd)$ is the modified market schedule quantity for trading participant p acting as a user on facility k for flow in direction h on gas day d.

$MMSQ^{S}(p,d,k,fd)$ is the modified market schedule quantity for trading participant p acting as a shipper on facility k for flow in direction h on gas day d.

$AQ^{U}(p,d,cf(k))$ is the allocated quantity for gas withdrawn from the hub by trading participant p on gas day d on trading right c(k) on facility k (obtained from allocation data).

$AQ^{S}(p,d,cf(k))$ is the allocated quantity for gas supplied to the hub by trading participant p on gas day d on trading right c(k) on facility k (obtained from allocation data).

The values of DQF(p,d,k) and DQT(p,d,k) can be positive or negative.

Important. Quantities for STTM users are aggregated at the hub level. References to facility $k \in SN$ should be interpreted as the sum of all distribution facilities at the hub.

A1.3.10 Average MOS cost

A MOS increase cost or a MOS decrease cost is calculated for each hub and gas day.

The MOS increase cost is only calculated if the net MOS gas requirement at the hub is positive (increase MOS). The MOS increase cost is the sum of MOS and overrun MOS payments for gas day d, and MOS cash-out payments from gas day d+2 (for MOS provided on gas day d) for all increase MOS allocated on gas day d at the hub, divided by the quantity of all increase MOS allocated on gas day d at the hub.

The MOS decrease cost is only calculated if the net MOS gas requirement at the hub is negative (decrease MOS). The MOS decrease cost is the sum of MOS and overrun MOS payments for gas day d and MOS cash-out charges from gas day d+2 (for MOS provided on gas day d) for all decrease MOS allocated on gas day d at the hub, divided by the quantity of all decrease MOS allocated on gas day d at the hub. The MOS decrease cost may be a positive or negative value.

The daily MOS price (average MOS cost) is based upon allocation data for a gas day provided by 11.00 am (or 12.30 pm) the next day (as is used for the ex post imbalance price calculations), and the ex ante price for the gas day + 2. If the ex post imbalance price is delayed, the calculation of the MOS price will also be delayed to account for changes to allocation data. However, the average MOS cost is not amended if there is a change to facility allocations for a gas day after d+1.

The equations for the determination of the average MOS cost are set out in the STTM Procedures. For the purpose of this guide, the equations have been disaggregated into their three core components:

1. Calculate MOS settlement amounts for the hub and gas day,
2. Calculate the total quantity of MOS allocated for the hub and gas day, and
3. Calculate the average MOS price for the hub and gas day.

Equations

1. Calculate MOS settlement amounts

The increase MOS amounts for gas day d is:

$$\Sigma_p\ \Sigma_{k\in SP}\ \Sigma_{m(k)}\ \Sigma_j\ (\ \mathrm{MOSIC^S}(p,d,m(k),j)\ \times\ \mathrm{MOSAI^S}(p,d,m(k),j)\ )$$
$$+\ \Sigma_p\ \Sigma_{k\in SP}\ (\ \mathrm{ORPI}(d,k)\ \times\ \Sigma_{c(k)}\{\ \mathrm{MAX}(\ 0,\ \mathrm{OMAQ^S}(p,d,ct(k))\ )$$
$$+\ \mathrm{MAX}(\ 0,\ \mathrm{OMAQ^S}(p,d,cf(k))\ )\ \}\ )\ +\ \Sigma_p\ \mathrm{MCCP}(p,d+2)$$
$$+\ \Sigma_p\ \mathrm{MCOP}(p,d+2)\ \ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ (69)$$

The decrease MOS amounts for gas day d is:

$$\Sigma_p\ \Sigma_{k\in SP}\ \Sigma_{m(k)}\ \Sigma_j\ (\ \mathrm{MOSDC^S}(p,d,m(k),j)\ \times\ \mathrm{MOSADS}(p,d,m(k),j)\ )$$
$$+\ \Sigma_p\ \Sigma_{k\in SP}\ (\ \mathrm{ORPD}(d,k)$$
$$\times\ (-1\ \times\ \Sigma_{c(k)}\{\ \mathrm{MIN}(0,\ \mathrm{OMAQ^S}(p,d,ct(k))\ )$$
$$+\ \mathrm{MIN}(\ 0,\ \mathrm{OMAQ^S}(p,d,cf(k))\ )\ )\ \}\ -\ \Sigma_p\ \mathrm{MCCC}(p,d+2)$$
$$-\ \Sigma_p\ \mathrm{MCOC}(p,d+2)\ \ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ (70)$$

Where

$\mathrm{MOSIC^S}(p,d,m(k),j)$ is the MOS step cost for increased gas flow from step j for trading participant p as a shipper on gas day d on MOS offer m(k) on facility k∈SP.

$\mathrm{MOSDC^S}(p,d,m(k),j)$ is the MOS step cost for decreased gas flow from step j for trading participant p as a shipper on gas day d on MOS offer m(k) on facility k∈SP.

$\mathrm{MOSAI^S}(p,d,m(k),j)$ is the quantity of MOS for increase allocated to step j for trading participant p as a shipper on gas day d on MOS offer m on facility k. This is a positive value.

$\mathrm{MOSAD^S}(p,d,m(k),j)$ is the quantity of MOS for decrease allocated to step j for trading participant p as a shipper on gas day d on MOS offer m on facility k. This is a positive value.

ORPI(d,k) is the overrun MOS increase price for facility k on gas day d.

ORPD(d,k) is the overrun MOS decrease price for facility k on gas day d.

$\mathrm{OMAQ^S}(p,d,ct(k))$ is the overrun MOS quantity allocated to flow by trading participant p to the hub on trading right ct(k) on facility k∈SP on gas day d. This value may be positive or negative.

$\mathrm{OMAQ^S}(p,d,cf(k))\ )$ is the overrun MOS quantity allocated to flow by trading participant p from the hub on trading right cf(k) on facility k∈SP on gas day d. This value may be positive or negative.

$MCCP(p,d+2)$ is the MOS cash-out payment from gas day $d+2$ (for MOS provided on gas day d) to trading participant p for the restoration of MOS gas under a MOS offer. This amount is positive.

$MCCC(p,d+2)$ is the MOS cash-out charge from gas day $d+2$ (for MOS provided on gas day d) to trading participant p for the restoration of MOS gas under a MOS offer. This amount is negative.

$MCOP(p,d+2)$ is the MOS cash-out payment from gas day $d+2$ (for MOS provided on gas day d) to trading participant p for the restoration of MOS gas as overrun MOS. This amount is positive.

$MCOC(p,d+2)$ is the MOS cash-out charge from gas day $d+2$ (for MOS provided on gas day d) to trading participant p for the restoration of MOS gas as overrun MOS. This amount is negative.

2. Calculate MOS quantity

   a. The increase MOS quantity for gas day d is:

$$\Sigma_p \ \Sigma_{k\in SP} \ \Sigma_{c(k)} \ \{ \ MAX(\ 0,\ MAQ^S(p,d,ct(k))\ ) \\ +\ MAX(\ 0,\ MAQS(p,d,cf(k))\ ) \\ +\ MAX(\ 0,\ OMAQS(p,d,ct(k))\ ) \\ +\ MAX(\ 0,\ OMAQS(p,d,cf(k))\ )\ \} \quad (71)$$

   b. The decrease MOS quantity for gas day d is:

$$\Sigma p \ \Sigma_{k\in SP} \ \Sigma c(k) \{ \ MIN(\ 0, MAQS(p,d,ct(k))\ ) \\ +\ MIN(\ 0,\ MAQS(p,d,cf(k))\ )\ ) \\ +\ MIN(\ 0,\ OMAQS(p,d,ct(k))\ ) \\ +\ MIN(\ 0,\ OMAQS(p,d,cf(k))\ )\ \} \quad (72)$$

Where

$OMAQ^S(p,d,ct(k))$ is the overrun MOS quantity allocated to flow by trading participant p to the hub on trading right $ct(k)$ on facility $k\in SP$ on gas day d. This value may be positive or negative.

$OMAQ^S(p,d,cf(k))\ ))$ is the overrun MOS quantity allocated to flow by trading participant p from the hub on trading right $cf(k)$ on facility $k\in SP$ on gas day d. This value may be positive or negative.

$MAQ^S(p,d,ct(k))$ is the MOS quantity allocated to flow to the hub on trading right $ct(k)$ on facility $k\in SP$ on gas day d by trading participant p. This value may be positive or negative.

$MAQ^S(p,d,cf(k))$ is the MOS quantity allocated to flow from the hub on trading right $cf(k)$ on facility $k\in SP$ on gas day d by trading participant p. This value may be positive or negative.

3. The MOS price (increase/decrease) for gas day d is:

   If the net MOS gas requirement at the hub is positive:

   MOS increase cost = Increase MOS amounts / Increase MOS quantity

   If the net MOS gas requirement at the hub is negative:

   MOS decrease cost = Decrease MOS amounts / Decrease MOS quantity

A1.3.11 Deviation prices

A short (negative) deviation price and a long (positive) deviation price are calculated for each hub and gas day. The deviation prices are fixed once the ex post imbalance price is set. AEMO publishes the deviation price via a Market Information System (MIS) report on a daily basis.

The scheduling of contingency gas is considered in the deviation settlement price so that trading participants who act to minimise their exposure to the contingency gas price are not penalised:

- If increase contingency gas is scheduled on a gas day at a hub (generating a High Contingency Gas Price (CGPH(d)), the MOS decrease cost will be disregarded for that hub.
- If decrease contingency gas is scheduled on a gas day at a hub (generating a Low Contingency Gas Price (CGPL(d)), the MOS increase cost will be disregarded for that hub.

The short deviation price is limited by the maximum deviation price, i.e. the market price cap (MPC) plus the MOS cost cap (MCAP). The long deviation price is limited by the minimum deviation price, i.e. the minimum market price (MMP) minus MCAP. When the market is in either the administered price cap state, administered ex post pricing state, market administered scheduling state or market administered settlement state, minimum deviation price will be the MMP and the maximum deviation price will be the administered price cap (APC).

Note. Long deviation price could have a negative value. This could occur when the MOS service payments exceed the MOS cash-out charges or the MOS cash-out charges are very low. This would result in a deviation payment with a negative value (i.e. a payment to AEMO).

Equations

For Trading Participant p with a long deviation quantity for withdrawals from the hub (i.e. lower withdrawal than expected) on market facility `k` on gas day `d`, the deviation price is:

If `DPFlag(d) = 0`

If `CGPH(d) ≥ 0`

```
PDevPF(p,d,k) = MAX( MINP(d), MIN( MAXP(d), HP(d), IHP(d),
                                   CGPL(d) ) ) ............. (73)
```

Else

```
PDevPF(p,d,k) = MAX( MINP(d), MIN( MAXP(d), HP(d), IHP(d),
                                   CGPL(d),MOSXD(d) ) ) .... (74)
```

If DPFlag(d) = 1

```
PDevPF(p,d,k) = HP(d) ................................... (75)
```

For Trading Participant `p` with a short deviation quantity for withdrawals from the hub (i.e. higher withdrawal than expected) on market facility `k` on gas day `d`, the deviation price is:

If `DPFlag(d) = 0`

If `CGPL(d) ≥ 0`

```
PDevNF(p,d,k) = MIN( MAXP(d), MAX( MINP(d), HP(d), IHP(d),
                                   CGPH(d) ) ) ............. (76)
```

Else

```
PDevNF(p,d,k) = MIN( MAXP(d), MAX( MINP(d), HP(d), IHP(d),
                                   CGPH(d), MOSXI(d) ) ) ... (77)
```

If `DPFlag(d) = 1`

```
PDevNF(p,d,k)= MAXP(d) .................................. (78)
```

For Trading Participant `p` with a long deviation quantity for gas supplied to the hub (i.e. higher supply than expected) on market facility `k` on gas day `d`, the deviation price is:

If `DPFlag(d) = 0`

If CGPH(d) ≥ 0

```
PDevPT(p,d,k) = MAX( MINP(d), MIN( MAXP(d), HP(d), IHP(d),
                                CGPL(d) ) ) ............. (79)
```

Else

```
PDevPT(p,d,k)= MAX( MINP(d), MIN( MAXP(d), HP(d), IHP(d),
                                CGPL(d), MOSXD(d) ) ) ... (80)
```

If DPFlag(d) = 1

```
PDevPT(p,d,k)= HP(d) .................................... (81)
```

For Trading Participant p with a short deviation quantity for gas supplied to the hub (i.e. lower supply than expected) on market facility k on gas day d, the deviation price is:

If DPFlag(d) = 0

If CGPL(d) ≥ 0

```
PDevNT(p,d,k) = MIN( MAXP(d), MAX( MINP(d), HP(d), IHP(d),
                                CGPH(d) ) ) ............. (82)
```

Else

```
PDevNT(p,d,k)= MIN( MAXP(d) , MAX(MINP(d), HP(d), IHP(d),
                                CGPH(d), MOSXI(d) ) ) ... (83)
```

If DPFlag(d) = 1

```
PDevNT(p,d,k)= MAXP(d) .................................. (84)
```

Where

DPFlag(d) is an operator set variable with a value of 0 or 1. It is set in response to the Administered Deviation Pricing State.

CGPH(d) is the high contingency gas price for gas day d.

CGPL(d) is the low contingency gas price for gas day d.

MAXP(d) is the maximum deviation price to be applied in the settlement of gas day d for a hub.

MINP(d) is the minimum deviation price to be applied in the settlement of gas day d for a hub.

HP(d) is the ex ante market price at the hub for gas day d.

IHP(d) is the ex post imbalance price at the hub for gas day d.

MOSXI(d) is the MOS increase cost for a hub for gas day d.

MOSXD(d) is the MOS decrease cost for a hub for gas day d.

A1.3.12 Deviation charges and payments

Deviation payments and charges are applied separately to shippers who have deviations of flows to a hub, and deviations of flows from a hub, and to deviations by users. Deviations are not cumulative, and so a long deviation on one pipeline cannot offset a short deviation on another. In each case, the deviation quantity equals the difference between the pipeline allocation or distribution system allocation and the modified market schedule. The modified market schedule equals the total quantity of the ex ante market schedule for a shipper supplying gas to a hub or withdrawing gas from a hub, or a user withdrawing gas from a hub, inclusive of market schedule variations, pipeline MOS allocations, and contingency gas called.

The trading participant pays the market for short deviations. The deviation charge is calculated by multiplying the short deviation quantity by the short deviation price. The deviation charge amount is positive.

The trading participant receives payments for long deviations. The deviation payment is calculated by multiplying the long deviation quantity by the long deviation price. The deviation payment amount may be positive or negative.

Deviation payments and charges are dependent on pipeline allocation and distribution system allocation data. Hence, deviation charges and payments can change if allocation data is revised.

Equations

The deviation payment for Trading Participant p for a long deviation quantity in withdrawals from the hub (i.e. lower withdrawal than expected) on market facility k on gas day d is:

```
DevPFA(p,d,k) = MAX( 0 , DQF(p,d,k) ) × PDevPF(p,d,k) ......... (85)
```

The deviation charge for Trading Participant p for a short deviation quantity in withdrawals from the hub (i.e. higher withdrawal than expected) on market facility k on gas day d is:

```
DevNFA(p,d,k) = MAX( 0, -1 × DQF(p,d,k) ) × PDevNF(p,d,k) ..... (86)
```

The deviation payment for Trading Participant p for a long deviation quantity in gas supplied to the hub (i.e. higher supply than expected) on gas day d is:

```
DevPTA(p,d,k) = MAX( 0 , DQT(p,d,k) ) × PDevPT(p,d,k) ......... (87)
```

The deviation charge for Trading Participant p for a short deviation quantity in gas supplied to the hub (i.e. lower supply than expected) on gas day d is:

```
DevNTA(p,d,k) = MAX( 0 , -1 × DQT(p,d,k) )× PDevNT(p,d,k) ..... (88)
```

The total deviation payment to Trading Participant p for the hub for gas day d is:

$$DevP(p,d) = \Sigma_k \{ DevPFA(p,d,k) + DevPTA(p,d,k) \} .... (89)$$

The total deviation charge to Trading Participant p for the hub for gas day d is:

$$DevC(p,d) = \Sigma_k \{ DevNFA(p,d,k) + DevNTA(p,d,k) \} .... (90)$$

A1.3.13 Market fees

AEMO charges trading participants a market participation fee `MPC(p,d)`, which covers the costs of operating the market. At the time of publication, market fee rates had yet to be determined.

A1.3.14 Market surplus and shortfall

The daily settlement payments to trading participants do not usually match the daily settlement charges paid by trading participants. This is caused by the pricing of deviations, market schedule variations, MOS, capacity payments, and contingency gas. Contingency gas prices are a primary driver for deviation charges and payments, but in the event that contingency gas is over-called, the cost is recouped through the market surplus and shortfall. In the rare event that contingency gas is called to increase flow on one facility and simultaneously decrease flow on another, a significant shortfall can arise in the market.

Over a billing period, AEMO accumulates the daily settlement surpluses and shortfalls at a hub and distributes the net settlement balance (NSB) over the billing period to trading participants based on a formula that accounts for the participant's total allocation quantities and total, absolute deviation quantities over that billing period. The NSB does not include market fees.

The settlement surplus is capped at a percentage of the average $/GJ amount (AllCAP) that a participant pays for deviations relative to the ex ante market price. This cap is designed to stop participants with very large deviation quantities and large deviation charges, which will increase the surplus, from recouping those charges as settlement shortfalls and surpluses.

The total variation charge over the billing period, plus any residual surplus caused by the settlement surplus cap, is allocated to all trading participants in proportion to their total withdrawals from the hub.

The settlement data used to calculate the settlement surplus or shortfall includes:

- Settlement surplus cap in $/GJ (obtained from settlement standing data)
- Daily total positive deviation quantity as a shipper to the hub
- Daily total negative deviation quantity as a shipper to the hub
- Daily total positive deviation quantity as a shipper from the hub
- Daily total negative deviation quantity as a shipper from the hub
- Daily total positive deviation quantity as a user
- Daily total negative deviation quantity as a user
- Total allocation over the billing period as a shipper from the hub
- Total allocation over the billing period as a user
- Net market balance for the billing period
- Administered days within the billing period

The net income for a hub is determined for all the days in the billing period or, for prudential purposes, the billing period to date, and then distributed accordingly.

When there is a settlement shortfall for the hub for the billing period, the shortfall amount plus any variation charges are divided amongst the participants based on their share of the withdrawals in the month.

When there is a settlement surplus for the hub for the billing period, the total surplus dollars in the month is divided by the total quantity of gigajoules. This gives a deviation price per gigajoule.

If this amount is less than or equal to the surplus cap (currently $0.14), then the funds are distributed to each participant based on their share of the total deviations. If the amount is greater than the cap then each participant who deviated during the month receives a payment of $0.14 per GJ of deviation. This amount is called `DVA(p)`.

The remaining monies plus any variation charges are then divided amongst the participants based on their share of the withdrawals in the month.

Note. Market fees are retained by AEMO and are not distributed in market surplus and shortfall.

Equations

Net market balance (NMB)

The gross market income for the hub for the billing period, excluding fees and variation charges, before settlement surplus and shortfall allocation, is:

$$GMI = \Sigma_d \Sigma_p \ (MktC(p,d) + PFDCC(p,d) + CGC(p,d) + MosC(p,d) + DevC(p,d) + SCC(p,d) + AHC(p,d)) \ \ldots\ldots\ldots \ (91)$$

The gross market outgoing of the market for the billing period, excluding fees and variation charges, before settlement surplus and shortfall allocation, is:

$$GMO = \Sigma_d \Sigma_p \ (MktP(p,d) + PFDCP(p,d) + CGP(p,d) + MosP(p,d) + DevP(p,d) + SCP(p,d) + AHP(p,d)) \ \ldots\ldots\ldots \ (92)$$

The settlement surplus/shortfall for a billing period (excluding variation charges) is:

$$NMB = GMI - GMO \qquad \ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots \ (93)$$

If $NMB > 0$ then the market is in surplus (ignoring variation charges), and

if $NMB < 0$ then the market is in shortfall (ignoring variation charges).

Billing period deviation quantities

The billing period deviation quantity for trading participant p for the billing period is:

$$\begin{aligned} \mathrm{DQB(p)} = \Sigma d \{ & \Sigma_{k\in SN} [\mathrm{MAX}(0,\mathrm{DQF(p,d,k)}) \\ & \times \mathrm{LI(d,k)} - \mathrm{MIN}(0,\mathrm{DQF(p,d,k)}) \times \mathrm{LD(d,k)}] \\ & + \Sigma_{k\in SP} [\mathrm{MAX}(0,\mathrm{DQF(p,d,k)}) \\ & \times \mathrm{LI(d,k)} - \mathrm{MIN}(0,\mathrm{DQF(p,d,k)}) \\ & \times \mathrm{LD(d,k)} + \mathrm{MAX}(0,\mathrm{DQT(p,d,k)}) \\ & \times \mathrm{LI(d,k)} - \mathrm{MIN}(0,\mathrm{DQT(p,d,k)}) \\ & \times \mathrm{LD(d,k)}] \} \quad \ldots\ldots\ldots\ldots\ldots\ldots\ldots (94) \end{aligned}$$

DQB(p) is the sum of absolute values of all eligible deviations for the billing period for the trading participant p. LI(d,k) can have a value of either 0 or 1 to exclude or include a deviation that increases net supply at the hub in the allocation of settlement surpluses and shortfalls over the billing period. Similarly, LD(d,k) controls deviations that decrease net supply at the hub.

DPFlag(d) is an operator-set variable with a value of 0 or 1. It is set when an Administered Price Cap State results from a material involuntary curtailment.

If DPFlag(d) = 0

LI(d,k) = 1 and LD(d,k) = 1 for all k∈SP and all k∈SN

if DPFlag(d) = 1 and NMB ≥ 0

LI(d,k) = 1 and LD(d,k) = 1 for all k∈SP

if DPFlag(d) = 1 and NMB <0

LI(d,k) = 0 and LD(d,k) = 1 for all k∈SP

if DPFlag(d) = 1 and NMB ≥ 0

LI(d,k) = 1 and LD(d,k) = 1 for all k∈SN

if DPFlag(d) = 1 and NMB < 0

LI(d,k) = 0 and LD(d,k) = 1 for all k∈SN

The conditions with LI(d,k)= 0 are the only conditions that materially protect trading participants. On days where DPFlag(d)= 1 then, if the market is in shortfall over the billing period, those users or shippers who deviated so as to increase net supply to the hub (because a user was involuntarily curtailed) on that gas day are exempted from funding that shortfall.

Surplus and shortfall allocation based on billing period deviations

The shortfall or surplus allocation based on deviations for trading participant p for the hub for the billing period is:

If $\Sigma_{p'}$ DQB(p') = 0

DVA(p) = 0

Otherwise

$$\mathrm{DVA(p)} = \mathrm{MAX}(0, \mathrm{MIN}(\mathrm{AllCAP} \times \mathrm{DQB(p)} , \mathrm{NMB} \times \{\mathrm{DQB(p)} / \Sigma_{p'} \mathrm{DQB(p')} \})) \quad \ldots\ldots\ldots\ldots\ldots\ldots\ldots (95)$$

Where p' is another index for the set of trading participants. The NMB is allocated in proportion to deviations over the billing period, capped at an amount equivalent to AllCAP, the $/GJ cap on positive valued allocations. This prevents trading participants who deviated from recouping deviation charges as a settlement shortfall/surplus.

Residual surplus and shortfall allocation based on withdrawals

The shortfall/surplus allocation to trading participant p based on withdrawals for the hub for the billing period is:

$$\text{If } \Sigma_{p'} \Sigma_{d\in BP}\{ \Sigma_{k\in SN} \Sigma_{cf(k)} AQ^U(p',d,cf(k)) + \Sigma_{k\in SP} \Sigma_{cf(k)} AQ^S(p',d,cf(k)) \} = 0$$

$$WDA(p) = 0$$

Otherwise

$$\begin{aligned} WDA(p) = (NMB - \Sigma_{p'} DVA(p') \\ + \Sigma_d \Sigma_{p'} VarC(p',d)) \times (\Sigma_d (\Sigma_{k\in SN} \Sigma_{cf(k)} AQ^U(p,d,cf(k)) \\ + \Sigma_{k\in SP} \Sigma_{cf(k)} AQ^S(p,d,cf(k))) / \Sigma_{p'} \Sigma_d (\Sigma_{k\in SN} \Sigma_{cf(k)} AQ^U(p',d,cf(k)) \\ + \Sigma_{k\in SP} \Sigma_{cf(k)} AQ^S(p',d,cf(k)))) \quad \ldots\ldots\ldots\ldots\ldots\ldots\ldots \quad (96) \end{aligned}$$

This allocates the residual settlement shortfall or surplus plus the market income from variation charges back to trading participants in proportion to their share of total net withdrawals from the hub over the billing period.

Net surplus and shortfall payments and charges

The settlement shortfall payment to trading participant p for the billing period is:

$$SSP(p) = MAX(0, DVA(p)) + MAX(0, WDA(p)) \qquad (55)$$

The settlement shortfall charge to trading participant p for the billing periods is:

$$SSC(p) = MAX(0, -1 \times DVA(p)) + MAX(0, -1 \times WDA(p)) \quad \ldots\ldots\ldots\ldots \quad (97)$$

Where

DVA(p) is the shortfall/surplus allocation based on deviations for trading participant p for the billing period

WDA(p) is the shortfall/surplus allocation based on withdrawals for trading participant p for the billing period

A1.3.15 Other charges and payments

AEMO may determine other amounts that the trading participant is required to pay to the market or be paid by the market. This settlement process is not part of the normal settlement process and can only be performed by AEMO personnel with the necessary authorisation.

Ad hoc payments

From time to time AEMO may need to make ad hoc payments AHP(p,d) or apply additional charges AHC(p,d) to trading participants to address disputes, and such. These are applied as manual line items in settlement.

When Contingency Gas Resettlement occurs, the charges and payments will be entered as ad hoc charges AHC(p,d) and ad hoc payments AHP(p,d).

Participant compensation fund

The settlement systems include provision for the payment of compensation to participants and the collection of monies required to fund that compensation.

Settlement quantities

The modified market schedules (after accounting for MSVs, MOS and contingency gas) and the resulting deviation quantities for each shipper and user are shown in Table 3.

Referring to Table 3, note that P's modified market schedule for flow to the hub on pipeline 1 includes 3,000 GJ of MOS, which was included in the STTM facility allocation to RFS A1-2. Hence, the modified market schedule and allocation quantities match up, resulting in no deviation. Similarly, Q's confirmed MSV for 5,000 GJ ensures that it also has no deviation. On pipeline 2, however, the 5,000 GJ that Q bumped from R, results in deviations for both shippers (to the hub, on pipeline 2).

Table 3 Flows to the hub

Shipper	TRN	Ex Ante Market Schedule	Total for Facility	MOS*	OR MOS	MSV	CG	Modified Market Schedule	Allocation	Deviation
P	A1-1-1	45,000	45,000	N/A	0	0	0	48,000	48,000	0
P	A1-2-1	0		3,000						
P	A1-3-1	0		N/A						
Q	B1-1-1	5,000	5,000	N/A	0	5,000	0	10,000	10,000	0
Q	B1-2-1	0		0						
Q	B1-3-1	0		N/A						
R	C1-1-1	35,000				0	0	35,000	35,000	0
TOTAL	P/L 1	85,000				5000	0	93,000	93,000	0
P	A2-1-1	40,000				0	0	40,000	40,000	0
Q	B2-1-1	30,000	30,000	N/A	0	0	0	30,000	35,000	5,000
Q	C2-1-2	0		N/A						
R	C2-1-1	10,000	30,000	N/A	0	0	0	30,000	25,000	-5,000
R	C2-2-1	20,000		N/A						
TOTAL	P/L 2	100,000				0	0	100,000	100,000	0

Note: * If a TRN is MOS enabled then a value is allocated. MOS disabled TRNs are listed as 'N/A'

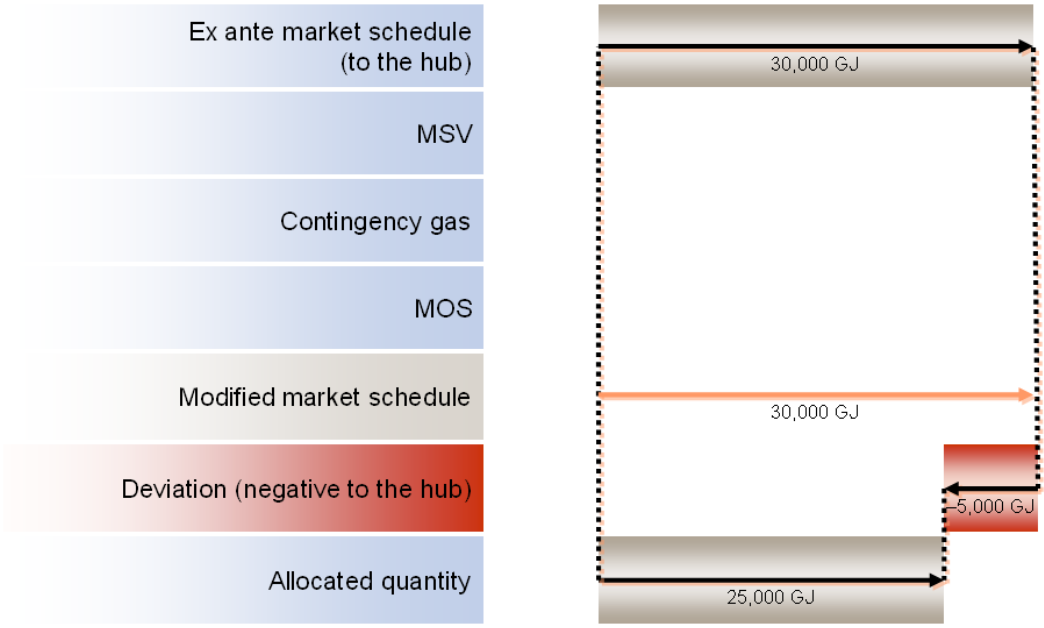
Note. For the purpose of calculating deviation quantities, quantities are summed by participant role, facility, and flow direction.

For example, the deviation by shipper R delivering to the hub on pipeline 2 is illustrated in Figure 31. Note that for shippers supplying to the hub, the sign of the deviation quantity is determined by:

Deviation Qty = Allocated Qty – MMS Qty

So in this case, the deviation is negative, which decreases net supply to the hub.

Figure 31 Negative deviation by shipper R delivering to the hub on pipeline 2



Referring to Table 4, P's modified market schedule for flow from the hub on pipeline 2 matches its allocation, and so has no deviation.

Table 4 Flows away from the hub

Shipper	TRN	Ex Ante Market Schedule	Total for Facility	MOS*	OR MOS	MSV	CG	Modified Market Schedule	Allocation	Deviation
P	D1-1-1	0	0	0	0	0	0	0	0	0
P	D1-2-1	0		N/A						
Q	E1-1-1	0		0	0	0	0	0	0	0
Q	E1-2-1	0		N/A						
P	F2-1-1	15,000	15,000	N/A	0	0	0	15,000	15,000	0
TOTAL		15,000		0	0	0	0	15,000	15,000	

Note: * If a TRN is MOS enabled then a value is allocated. MOS disabled TRNs are listed as 'N/A'

Referring to Table 5, Q's modified market schedule as a user includes the MSV submitted in its role as shipper. Each user ends up with a deviation, which, when summed, equal the deviation in net flow to the hub on pipelines 1 and 2.

Table 5 Withdrawals at the hub

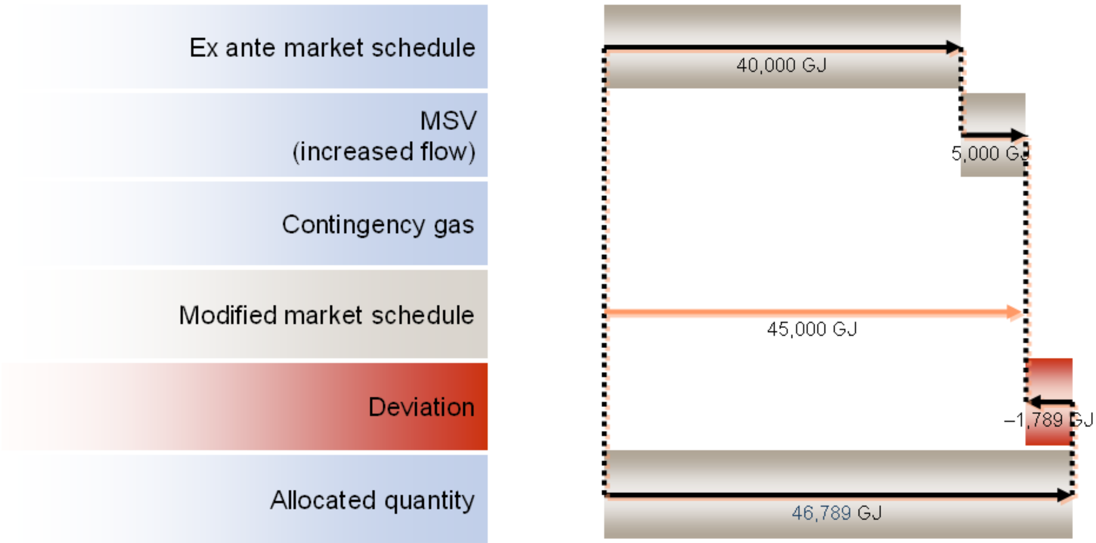
User	TRN	Ex Ante Market Schedule	MSV	CG	Modified Market Schedule	Allocation	Deviation
P	HA-1-1	80,000	0	0	80,000	79,337	663
Q	HB-1-1	40,000	5,000	0	45,000	46,789	–1,789
R	HC-1-1	50,000	0	0	50,000	51,874	–1,874
TOTAL		170,000	0	0	178,000	178,000	3,000

Each user ends up with a deviation. For example, the deviation by user Q withdrawing at the hub is illustrated in Figure 32. Note that for shippers and users withdrawing from the hub, the sign of the deviation quantity is determined by:

Deviation Qty = MMS Qty – Allocated Qty

This is the inverse of shippers supplying to the hub (see above). So in this case, the deviation is negative, which decreases net supply to the hub.

Figure 32 Negative deviation by user Q withdrawing at the hub



Settlement calculations

In the calculations that follow, only the non-zero components are detailed, and conditions that do not influence the calculation (the effect of contingency gas prices on deviation charges, for example) are not always discussed.

Ex ante market settlement

Referring to the ex ante modified market schedules in the tables above, trading participant P supplies 85,000 GJ to the hub as a shipper (40,000 GJ + 45,000 GJ), withdraws 15,000 GJ from the hub as a shipper, and withdraws 80,000 GJ as a user. These quantities are all settled at the ex ante market price of 7.00 $/GJ, which results in a net charge to trading participant of $70,000. Similarly, as shown in Table 6, trading participant Q is charged $30,000, and trading participant R receives $105,000.

Table 6 Settlement of the ex ante market

Trading Participant	Supplied GJ	Withdrawn GJ	Price $/GJ	Payment $	Charge $	Net $
P	85,000	95,000	7.00	595,000	665,000	70,000
Q	35,000	40,000	7.00	245,000	280,000	35,000
R	65,000	50,000	7.00	455,000	350,000	–105,000
TOTAL	185,000	185,000		1,295,000	1,295,000	0

Pipeline directional flow constraint charges and payments

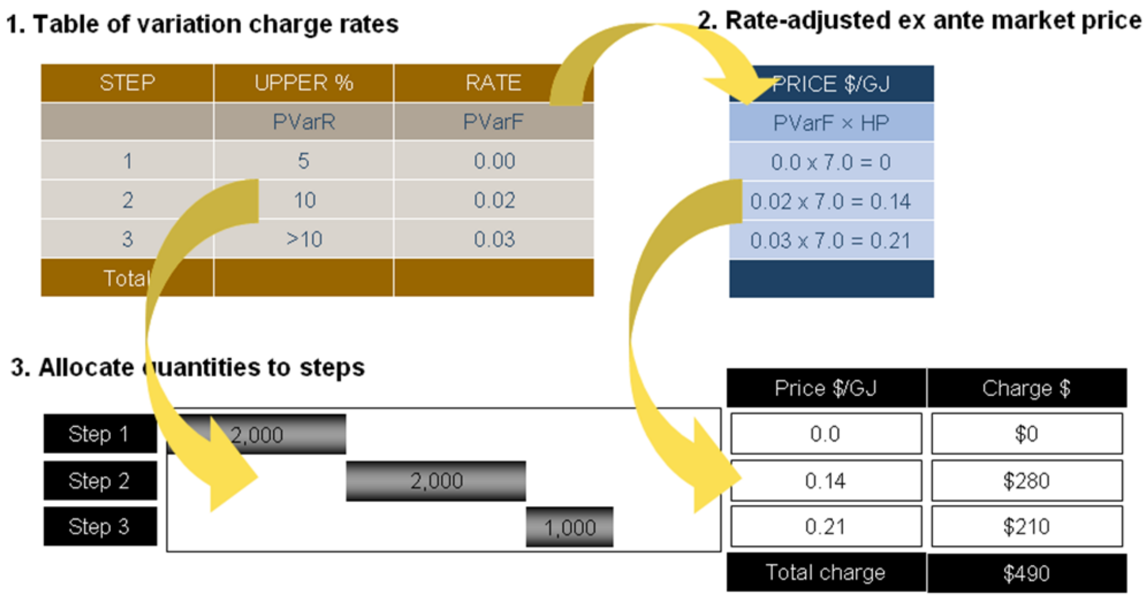
No pipeline directional flow constraint charges or payments are made in this example.

Variations

Participant Q, as the STTM user receiving the MSV, pays for its variation. No variation charge applies to the originating shipper (also Q). The variation quantity (VQ) is ABS(5,000) = 5,000 GJ. The variation charge is calculated by two methods (see Figure 33 and Figure 34 for details).

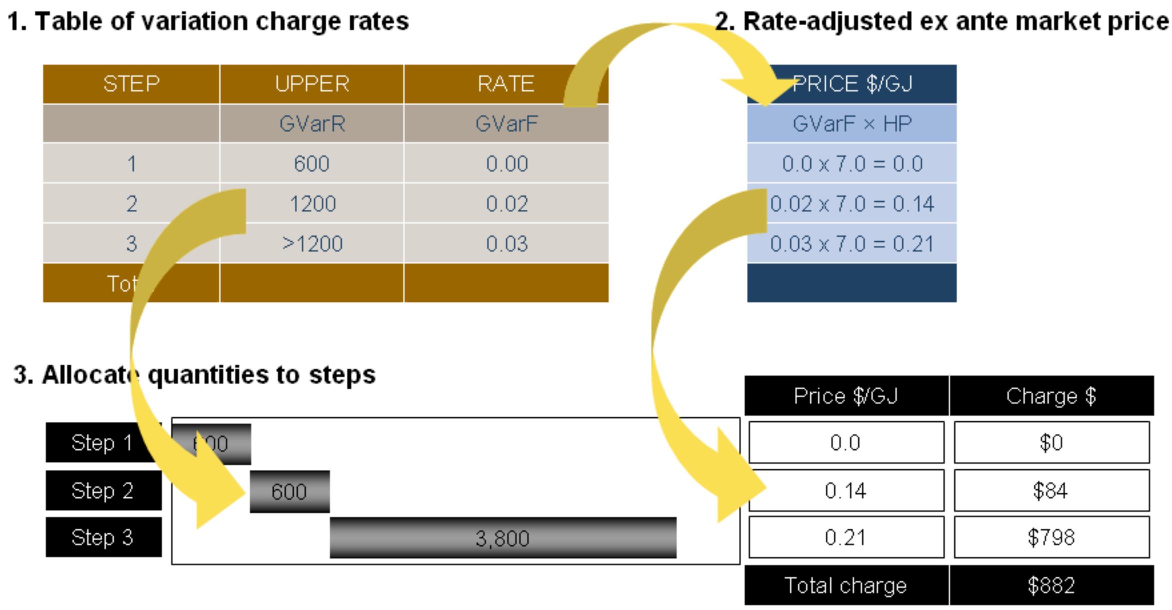
Referring to Figure 33, using the percentage method, the charge rate is applied to the ex ante market price (7.00 $/GJ) to determine the rate-adjusted ex ante market price. In this case, the rate- adjusted ex ante market price is applied. The step price is then applied to the corresponding step quantity. The quantity in each step is set as a percentage of the ex ante market scheduled withdrawal of user Q, which is 40,000 GJ (see Table 5). So 5,000 GJ represents 12.5% of the total withdrawal. The 5,000 GJ is divided into 3 steps of 5% + 5% + residual, or 2,000 + 2,000 + 1,000 GJ. The resulting variation charge calculated by the percentage method is $490.

Figure 33 Calculating variation step prices, quantities, and charges by the percentage method



Referring to Figure 34, using the quantity method, the same charge rates apply, but the quantity in each step is determined by GJ steps of 600 + 600 + residual. Hence, the 5,000 GJ is divided into 3 steps of 600 + 600 + 3,800 GJ. The resulting variation charge calculated by the quantity method is $882.

Figure 34 Calculating variation step prices, quantities, and charges by the quantity method



The lesser charge is applied, which, in this example, is a charge of $490, calculated by the percentage method.

MOS payment

Shipper P has provided 3,000 GJ of MOS increase on pipeline 1 at a MOS increase step price of 2.00 $/GJ via MOS enabled TRN A1-2-1 (see Table 4). So shipper P receives a service payment of $6,000. Let's say that the ex ante market price two days later is 6.00 $/GJ. So shipper P also receives a commodity payment of $18,000. There is no overrun MOS. Note that the timing of the commodity payment depends on which billing period d+2 gas day falls, even though the MOS gas might have been provided in the previous billing period.

Capacity charges and payments

The capacity price on pipeline 2 is 1.00 $/GJ. Referring to Table 6, shipper R was scheduled in the ex ante market to supply 20,000 GJ on pipeline 2 using as-available trading right C2-2-1. Shipper Q offered 20,000 GJ into the market on firm trading right C2-1-2 (offer step #7), which was not scheduled due to price. Shipper Q subsequently nominated 5,000 GJ and was scheduled 5000 GJ by the pipeline. Because the pipeline was constrained, this resulted in only 15,000 GJ of shipper R's nomination of 20,000 GJ being scheduled. Hence the quantity of firm capacity gas that did not flow on pipeline 2 was 15,000 GJ. So, in this case, all the conditions necessary for capacity charges and payments were satisfied:

- The pipeline was constrained
- Firm capacity offered into the market was not flowed
- As-available gas was flowed

Consequently, shipper R pays a capacity charge of $15,000. This is distributed amongst the firm shippers who did not flow, which, in this case, means that shipper Q receives a capacity payment of $15,000.

Average MOS cost

Either a MOS increase cost (Table 7) or a MOS decrease cost is calculated for each hub and on each gas day. The net MOS quantity of the hub is 3,000 GJ (MOS increase quantity) which is provided by Shipper P and no overrun MOS on the day. Shipper P receives a service payment of $6,000 and a commodity payment of $18,000.

The MOS increase cost for the hub on the day is:

Table 7 MOS increase cost

Increase MOS amounts	Increase MOS quantity	MOS increase cost
$6,000 + $18,000 = $24,000	3,000 GJ	$24,000 / 3,000 GJ = $8.00

MOS decrease cost is not determined because the MOS increase quantity is greater than the MOS decrease quantity.

Deviation prices

Deviation prices, long deviation price and short deviation price, are calculated for each hub and gas day.

In this example, no administered market states are invoked and no contingency gas prices are set.

Referring to Table 8, the short (negative) deviation price is 8.00 $/GJ which is the maximum of the ex ante market price, the ex post imbalance price and the MOS increase cost.

Referring to Table 8, the long/positive deviation price is 7.00 $/GJ which is the minimum of the ex ante market price and the ex post imbalance price.

Table 8 Deviation prices

Ex ante market price	Ex post imbalance price	MOS increase cost	MOS decrease cost	High contingency gas price	Low contingency gas price	Max deviation price (MPC+MCAP)	Min deviation price (MMP-MCAP)
7.00 $/GJ	8.00 $/GJ	$8.00 $/GJ				$450 $/GJ	-$50 $/GJ

Deviation charges and payments

Deviation charges and payments are calculated separately for each trading participant role, on each facility, for positive and negative deviations, and in each direction. All trading right quantities for the same participant, on the same facility, in the same direction are summed, and MSV and CG quantities are applied to these totals.

Deviation payments and charges for trading participant Q are detailed in the following tables. Participant Q has a positive deviation of 5,000 GJ as a shipper supplying to the hub (see Table A19) on pipeline 2 and a negative deviation of –1,789 GJ as a user (see Table 9).

Deviation charges and payments are calculated by multiplying deviation quantity by deviation price.

Positive deviation as a shipper supplying to the hub

Deviation payment for shipper Q is $35,000 (= 5,000 GJ x 7.00 $/GJ).

Negative deviation as a user

Deviation charge for shipper Q is $14,312 (= -1,789 GJ x -1 x 8.00 $/GJ).

Table 9 Deviation quantities, charges, and payments

Participant	Facility	Flow Drn	Modified Market Schedule GJ	Allocated Quantity GJ	Deviation GJ	Deviation Charge $	Deviation Payment $
P	Distribution	From	80,000	79,337	663	0	4,641
P	Pipeline 1	From	0	0	0	0	0
P	Pipeline 1	To	48,000	48,000	0	0	0
P	Pipeline 2	From	0	0	0	0	0
P	Pipeline 2	To	40,000	40,000	0	0	0
Total P						**0**	**4,641**
Q	Distribution	From	45,000	46,789	–1,789	14,312	0
Q	Pipeline 1	From	0	0	0	0	0
Q	Pipeline 1	To	10,000	10,000	0	0	0
Q	Pipeline 2	From	0	0	0	0	0
Q	Pipeline 2	To	30,000	35,000	5,000	0	35,000
Total Q						**14,312**	**35,000**
R	Distribution	From	50,000	51,874	–1,874	14,992	0
R	Pipeline 1	From	0	0	0	0	0
R	Pipeline 1	To	35,000	35,000	0	0	0
R	Pipeline 2	From	0	0	0	0	0
R	Pipeline 2	To	30,000	25,000	–5,000	40,000	0
Total R						**54,992**	**0**
Total						**69,304**	**39,641**

Total net cost of deviations is a surplus of $29,663 (= $69,304 – $ 39,641).

Surplus and shortfall

Table 10 Charges and payments allocated to the surplus and shortfall

Component	Cost $
Variation charges (surplus)	490
Subtotal	490
Net deviation cost (surplus)	29,663
MOS service cost (shortfall)	-6,000
MOS commodity cost (shortfall)	-18,000
Subtotal	5,663
Total	**6,153**

The total of deviation charges, deviations payments, MOS service charges, and MOS commodity costs comes to $5,663. The settlement surplus is allocated to participants based on their absolute total of deviations. This is capped by the settlement surplus cap, which is set at 0.14 $/GJ (cap is only applied to surplus). The total deviation quantity is 14,326 GJ, hence the maximum surplus that can be distributed by deviations is (14,326 GJ x 0.14 $/GJ) $2,005.64.

Table 11 Distribution of surplus by deviations

Participant	Deviations GJ		Distributed by deviations $	Rate
P	663	4.6%	92	0.14
Q	6,789	47.4%	951	0.14
R	6,874	48.0%	963	0.14
Total	**14,326**	**100.0%**	**2,006**	

The residual $3,657 and added to the total variations charges, which gives the amount to be distributed by withdrawals of $4,147.36.

Table 12 Distribution of residual surplus and variation charges by withdrawals

Participant	Withdrawals GJ		Distributed by withdrawal $
P	94,337	48.9%	2,028
Q	46,789	24.2%	1,003
R	51,874	26.9%	1,116
Total	**193,000**	**100.0%**	**4,147**

Table 13 Settlement surplus payments

Participant	Distributed by deviations	Distributed by withdrawals	Surplus playment
P	92	2,028	2,120
Q	951	1,003	1,954
R	963	1,116	2,079
Total	**2,006**	**4,147**	**6,153**

Net settlement

The net of all charges and payments for each participant excluding market fees is shown in Table 14. Note that the net of all payments and charges for the entire market (excluding market fees) is zero. A negative amount indicates it is paid to the participant.

Table 14 Net settlement

Settlement component		P	Q	R	Net total
Ex ante market	MktC – MktP	70,000	35,000	-105,000	0
Pipeline flow direction	PFDCC – PFDCP	0	0	0	0
Variations	VarC	0	490	0	490
MOS	MosC – MosP	-24,000	0	0	-24,000
Capacity	SCC – SCP	0	-15,000	15,000	0
Deviations	DevC – DevP	-4,641	-20,688	54.992	29,663
Contingency gas	CGC – CGP	0	0	0	0
Surplus	SSC – SSP	-2,120	-1,954	-2,073	-6.153
Other	AHC – AHP	0	0	0	0
Net	NPSA	39,239	-2,152	-37,081	

A1.4 Settlement Equation Variables

Variable	Definition
`AH`	The set of trading rights for as available haulage that allows supply to the hub.
`AHC(p,d)`	Ad hoc charge for trading participant `p` for gas day `d`.
`AHP(p,d)`	Ad hoc payments to trading participant `p` for gas day `d`.
`AllCAP`	The settlement surplus cap, which is a $/GJ parameter used in settlement to cap the maximum payment to trading participants stemming from settlement surpluses.
`AQS(p,d,c(k))`	The allocated quantity for gas supplied to the hub by trading participant `p` on gas day `d` on trading right `c(k)` on facility `k∈SP`. This includes any MOS allocated to the trading right.

Variable	Definition
AQU(p,d,c(k))	The allocated quantity for gas withdrawn from the hub by trading participant p on gas day d on trading right c(k) on facility k∈SN.
c, c(k)	Denotes a trading right on facility k. A trading right c(k) can be for supply to the hub (represented by cf(k)) or for withdrawal from the hub (represented by cf(k)).
CAP(p,d,c(k)	The capacity of trading right c(k) on facility k registered to trading participant p for gas day d.
cf(k)	Denotes a trading right that allows gas to be withdrawn from the hub on facility k (which can be a pipeline or a network). See also c(k).
CGC(p,d)	Contingency gas charge to trading participant p for gas day d.
CGP(p,d)	Contingency gas payment to trading participant p for gas day d.
CGPH(d)	The high contingency gas price for gas day d.
CGPL(d)	The low contingency gas price for gas day d.
CP(d,k))	Capacity price for facility k · SP on gas day d determined in the ex ante market. This term is greater than or equal to zero.
CQP^S(p,d,k,fd)	The quantity of contingency gas AEMO has determined to have been delivered under Rule 449(3) for Trading Participant p (as an STTM Shipper) on gas day d on market facility k∈SP (an STTM facility) in flow direction fd. This term may be positive or negative, where a positive value for supply to the hub increases net supply to the hub, while a positive value for withdrawal from the hub decreases net supply to the hub.
CQP^u(p,d,k,fd)	The quantity of contingency gas AEMO has determined to have been delivered under Rule 449(3) for Trading Participant p (as an STTM User) on gas day d on market facility k∈SN and in flow direction fd (fd = "from" only). This term may be positive or negative, where a positive value for withdrawal from the hub decreases net supply to the hub.
CQS(p,d,k,fd)	The change to be applied to the market schedule quantity due to contingency gas scheduled by AEMO to be supplied to the hub (fd = "to") or withdrawn from the hub (fd = "from") by trading participant p as a shipper on gas day d on facility k∈SP. This term can be positive or negative, where a positive value for supplies increases net supply to the hub, and a positive value for withdrawals decreases net supply to the hub.
CQT(d,k)	The capacity quantity traded on facility k∈SP for gas day d.
CQU(p,d,k,fd)	The change to be applied to the market schedule quantity due to contingency gas scheduled by AEMO to be withdrawn from the hub (fd = "from") by trading participant p as a network user on gas day d on facility k∈SN. This term can be positive or negative, where a positive value for withdrawals decreases net supply to the hub.
CSC(p,d,k,fd)	The change, due to market schedule variations, to be applied to the market schedule quantity for trading participant p on gas day d for facility k for flows in direction fd, where the change is subject to variation charges.
ct(k)	Denotes a trading right that allows gas to be supplied to the hub on facility k (which must be a pipeline). See c(k).
d	Gas day.
DevC(p,d)	The net deviation charge for trading participant p for gas day d.
DevP(p,d)	The net deviation payment to trading participant p for gas day d.
DPFlag(d)	The DPFlag(d) is an operator set variable with a value of 0 or 1. It is set in response to the Administered Deviation Pricing State. If it is 0, then settlement calculations are unaffected. If it is 1, then

Variable	Definition
	all positive deviations are settled at the ex ante market price, while all negative deviations are settled at the maximum price applicable to gas day d.
DQB(p)	The billing period deviation quantity for trading participant p.
DQF(p,d,k)	Total GJ deviation of trading participant p (as a shipper or network user) withdrawing gas from the hub on facility k on gas day d. If it is positive, the trading participant is long; if it is negative, the trading participant is short.
DQT(p,d,k)	Total GJ deviation of trading participant p (which must be a shipper) supplying gas to the hub on facility k on gas day d. If it is positive, the trading participant is long; if it is negative, the trading participant is short.
DVA(p)	The settlement shortfall/surplus allocation for a billing period to trading participant p.
EAQS(p,d,ct(k))	The effective allocated quantity for trading participant p and gas day d for trading right ct(k) which allows the supply of gas to the hub on facility k∈SP. This is the total pipeline allocation on that trading right corrected to remove the allocation of MOS gas to that trading right.
ECCA(d,k)	The effective capacity charge rate for as available trading rights on gas day d and facility k∈SP.
ECPF(d,k)	The effective capacity payment rate for firm trading rights on gas day d and facility k∈SP.
f	The steps of the variance charge penalty table. A finite number of steps are defined where each step must have a PVarR(f) value and a PVarF(f) value (for a percentage method) or a GVarR(f) value and a GVarF(f) value (for quantity method). The term f' indicates a step other than f.
fd	The flow direction of a trading right which can be "to" or "from" the hub. For shipper supplying the hub on an STTM facility (k∈SP) fd = "to". For a shipper withdrawing gas from the hub on an STTM facility (k∈SP) fd = "from". For a network user withdrawing gas from the hub on an STTM distribution network (k∈SN) fd = "from".
FDCP(d,k)	The pipeline flow direction constraint price, which reflects the price on gas day d of the constraint limiting the withdrawal from the hub on facility k to not exceed the supply to the hub on facility k. This price is positive in value if the constraint restricts flow and is zero otherwise.
FGO(p,d,ct(k))	The deemed firm gas offered to be supplied to the hub by trading participant p for gas day d on firm trading right ct(k) on facility k∈SP.
FH	The set of trading rights for firm haulage that allows supply to the hub.
FSC(p,d,k,fd)	The change, due to market schedule variations, to be applied to the market schedule quantity for trading participant p on gas day d for facility k for flows in direction fd, where the change is not subject to variation charges.
GMI	Gross market income (amount collected by AEMO) for a billing period (excluding income from variation charges).
GMO	Gross market outgoings (amount paid by AEMO) for a billing period.
GVarC(p,d)	The GJ based variation charge for trading participant p for gas day d. This term is greater than or equal to zero.
GVarF(f)	Defines the penalty factor for each step of the quantity variance charge penalty table.
GVarR(f)	Defines the boundaries to each step of the quantity variance charge penalty table.
GVarU(p,d,f)	The variance quantity of step f for trading participant p usage GJ variances on gas day d. This term is greater than or equal to zero.
HP(d)	The ex ante market price at the hub for gas day d.

Variable	Definition
IHP(d)	The ex post imbalance price at the hub for gas day d.
j	MOS offer step. This term indicates which step of a MOS offer is being referred to. Note that there are two sets of steps for each MOS offer, one for increased gas flows and one for decreased gas flows.
k	Denotes a facility that can be an STTM facility (k∈SP) or the set STTM distribution networks (k∈SN).
LD(d,k)	Describes whether or not a daily deviation which decreases net supply (viz. supply less consumption) at the hub is to be included in the allocation of settlement surpluses and shortfalls for gas day d during the billing period. The daily deviation is included if LD(d,k) = 1, but not if LD(d,k) = 0.
LDQ(p,d)	The long deviation quantity for Trading Participant p at a hub on gas day d.
LI(d,k)	Describes whether or not a daily deviation which increases net supply (viz. supply less consumption) at the hub is to be included in the allocation of settlement surpluses and shortfalls for gas day d during the billing period. The daily deviation is included if LI(d,k) = 1, but not if LI(d,k) = 0.
m	Denotes a MOS offer.
MAQ^{S}(p,d,cf(k))	The MOS quantity allocated to flow from the hub on trading right cf(k) on facility k∈SP on gas day d by trading participant p. This value may be positive or negative. A positive value indicates increased net flow to the hub implying a decreased flow from the hub on a trading right. MOS can only be allocated to MOS enabled trading rights in the MOS stack.
MAQ^{S}(p,d,ct(k))	The MOS quantity allocated to flow to the hub on trading right ct(k) on facility k∈SP on gas day d by trading participant p. This value may be positive or negative. A positive value indicates increased net flow to the hub implying an increased flow to the hub on a trading right. MOS can only be allocated to MOS enabled trading rights in the MOS stack.
Maxf	The last step (f) of the variance charge penalty table with the greatest value of PVarF(f) (for the percentage method) or GVarF(f) (for the quantity method).
MAXP(d)	The maximum deviation price to be applied in the settlement of gas day d for a hub. This will normally be MPC plus the MOS cost cap (MCAP) but will be the administered price cap when either an administered price cap state, administered ex post pricing state, market administered scheduling state or market administered settlement state applies to gas day d.
MCAP	The MOS cost cap.
MCCP(p,d)	The MOS cash-out payment for gas day d to trading participant p for the restoration of MOS gas under a MOS offer. This amount is positive.
MCCP(p,d+2)	The MOS cash-out payment from gas day d+2 (for MOS provided on gas day d) to trading participant p for the restoration of MOS gas under a MOS offer. This amount is positive.
MCOP(p,d)	The MOS cash-out payment on gas day d to trading participant p for the restoration of MOS gas as overrun MOS. This amount is positive.
MCOP(p,d+2)	The MOS cash-out payment from gas day d+2 (for MOS provided on gas day d) to trading participant p for the restoration of MOS gas as overrun MOS. This amount is positive.
MCCC(p,d)	The MOS cash-out charge for gas day d to trading participant p for the restoration of MOS gas under a MOS offer. This amount is negative.
MCCC(p,d+2)	The MOS cash-out charge from gas day d+2 (for MOS provided on gas day d) to trading participant p for the restoration of MOS gas under a MOS offer. This amount is negative.
MCOC(p,d)	The MOS cash-out charge on gas day d to trading participant p for the restoration of MOS gas as overrun MOS. This amount is negative.

Variable	Definition
MCOC(p,d+2)	The MOS cash-out charge from gas day d+2 (for MOS provided on gas day d) to trading participant p for the restoration of MOS gas as overrun MOS. This amount is negative.
MCP(p,d)	The payment to trading participant p for MOS service provided under a MOS offer for gas day d.
MINP(d)	The minimum deviation price to be applied in the settlement of gas day d for a hub. This will be MMP less the MCAP for that gas day.
MktC(p,d)	The ex ante market charge for trading participant p for gas day d.
MktP(p,d)	The ex ante market payment for trading participant p for gas day d.
MMSQS(p,d,k,fd)	The modified market schedule quantity for trading participant p acting as shipper on facility k for flow in direction fd on gas day d.
MMSQU(p,d,k,fd)	The modified market schedule quantity for trading participant p acting as network user on facility k for flow in direction fd on gas day d.
MOP(p,d)	The payment to trading participant p for MOS service provided as overrun MOS for gas day d.
MOSADS(p,d,m(k),j)	The quantity of MOS decrease allocated to step j for trading participant p as a shipper on gas day d on MOS offer m on facility k. This is a positive value.
MOSAIS(p,d,m(k),j)	The quantity of MOS for increase allocated to step j for trading participant p as a shipper on gas day d on MOS offer m on facility k. This is a positive value.
MosC(p,d)	The MOS charge to trading participant p as MOS provider for gas day d.
MOSDCS(p,d,m(k),j)	The MOS step cost for decreased gas flow from step j for trading participant p as a shipper on gas day d on MOS offer m(k) on facility k∈SP.
MOSFP(p,d,m(k))	A fixed payment for gas day d to trading participant p for providing MOS gas from MOS offer m(k) on facility k∈SP. This feature will not be used at market commencement with all fixed payments being equal to zero.
MOSICS(p,d,m(k),j)	The MOS step cost for increased gas flow from step j for trading participant p as a shipper on gas day d on MOS offer m(k) on facility k∈SP.
MosP(p,d)	The MOS payment to trading participant p as a MOS provider for gas day d.
MOSRD(d,k)	The estimated maximum MOS decrease (in GJ) on facility k for gas day d. This is a positive value and will be zero for facilities which do not provide MOS (e.g. STTM distribution networks and hub supplier pipelines). This value should not change during the 3 month period to which a MOS tender relates but may change between those periods.
MOSRI(k,d)	The estimated maximum MOS increase (in GJ) on facility k for gas day d. This is a positive value and will be zero for facilities which do not provide MOS (e.g. STTM distribution networks and hub supplier pipelines). This value should not change during the 3 month period to which a MOS tender relates but may change between those periods.
MOSXD(d)	The MOS decrease cost for a hub for gas day d. This term is null (i.e. has no impact on settlement) unless the net total of MOS gas allocated on all facilities supplying the hub on gas day d is decrease MOS. This is a price in $/GJ and may be a positive or negative value.
MOSXI(d)	The MOS increase cost for a hub for gas day d. This term is null (i.e. has no impact on settlement) unless the net total of MOS gas allocated on all facilities supplying the hub on gas day d is increase MOS. This is a price in $/GJ and is a positive value.
MPC(p,d)	Market participation charge, or fee, for trading participant p for gas day d.

Variable	Definition
MQS(p,d,cf(k))	The ex ante market schedule quantity for gas withdrawn from the hub by trading participant p as a shipper on gas day d on trading right cf(k) for facility k∈SP.
MQS(p,d,ct(k))	The ex ante market schedule quantity for gas supplied to the hub by trading participant p as a shipper on gas day d on trading right ct(k) for facility k∈SP.
MQU(p,d,cf(k))	The ex ante market schedule quantity for gas withdrawn from the hub by trading participant p as a network user on gas day d on trading right cf(k) for facility k∈SN.
MSV[d,(sp,sk,sfd),(cp,ck,cfd)]	The market schedule variation quantity associated with a market schedule variation for gas day d, submitted by trading participant p=sp and pertaining to the schedules of trading participant p=sp on facility k=sk for flows in direction fd=sfd, with this quantity offset against the schedule of trading participant p=cp on facility k=ck for flows in direction fd=cfd.
NMB	The settlement surplus/shortfall for a billing period (excluding variation charges). If this is positively valued then a market surplus is allocated based on billing period deviation quantities. If this is negative, then a market shortfall is allocated based on billing period deviation quantities.
NPSA(p)	The net participant settlement amount for trading participant p for a billing period.
OMAQS(p,d,cf(k))	The overrun MOS quantity allocated to flow by trading participant p from the hub on trading right cf(k) on facility k∈SP on gas day d. This value may be positive or negative. A positive value indicates increased net flow to the hub implying a decreased flow from the hub on a trading right. Pipeline operators will allocate this quantity to a registered facility service. The only party that can be allocated MOS on that RFS is the contract holder so AEMO will associate this quantity with the contract holder's trading right on that registered facility service for the purpose of settlement.
OMAQS(p,d,ct(k))	The overrun MOS quantity allocated to flow by trading participant p to the hub on trading right ct(k) on facility k∈SP on gas day d. This value may be positive or negative. A positive value indicates increased net flow to the hub implying an increased flow to the hub on a trading right. Pipeline operators will allocate this quantity to a registered facility service. The only party that can be allocated MOS on that RFS is the contract holder so AEMO will associate this quantity with the contract holder's trading right on that registered facility service for the purpose of settlement.
OQFS(p,d,c(k))	The quantity of gas offered by trading participant p on trading rights c(k) with firm haulage on facility k, registered to trading participant p, to be shipped to the hub on gas day d.
ORPD(d,k)	The overrun MOS decrease price for facility k on gas day d.
ORPI(d,k)	The overrun MOS increase price for facility k on gas day d.
p	Denotes a trading participant. The term p' indicates another trading participant, and can be interpreted identically to p except that trading participant p is not necessarily trading participant p'.
PFDCC(p,d)	The pipeline flow direction constraint charge to trading participant p for the withdrawal of gas from the hub on gas day d.
PFDCP(p,d)	The pipeline flow direction constraint payment to trading participant p for the supply of gas to the hub on gas day d.
PDevNF(p,d,k,g)	The deviation price of a negative deviation for Trading Participant p on gas day d for withdrawals from the hub on market facility k.
PDevNT(p,d,k,g)	The deviation price of a negative deviation for Trading Participant p on gas day d for supply to the hub on market facility k.
PDevPF(p,d,k,g)	The deviation price of a positive deviation for Trading Participant p on gas day d for withdrawals from the hub on market facility k.
PDevPT(p,d,k,g)	The deviation price of a positive deviation for Trading Participant p on gas day d for supply to the hub on market facility k.

Variable	Definition
PVarF(f)	Defines the penalty factor for each step of the percentage variance charge penalty table.
PVarR(f)	Defines the boundaries to each step of the percentage variance charge penalty table.
PVarU(p,d,f)	The variance volume of step f for trading participant p usage percentage variances on gas day d. This term is greater than or equal to zero.
RDevN(d)	A revised deviation price for a short deviation quantity at a hub on gas day d. This value is determined in STTM Procedures clause 10.6B and applied only for the purposes of contingency gas resettlement.
RDevP(d)	A revised deviation price for long deviation quantity at a hub on gas day d. This value is determined in STTM Procedures clause 10.6B and applied only for the purposes of contingency gas resettlement.
S (superscript)	Indicates a shipper specific term.
SCC(p,d)	Capacity charge for trading participant p as a shipper for gas day d.
SCP(p,d)	Capacity payment for trading participant p as a shipper for gas day d.
SDQ(p,d)	The short deviation quantity for Trading Participant p at a hub on gas day d.
SN	The set of STTM distribution networks. Note that where multiple networks exist at a hub, these will be translated into a single network for the purpose of settlement calculations.
SP	The set of STTM facilities.
SSC(p)	Settlement surplus/shortfall charge to trading participant p for a billing period.
SSP(p)	Settlement surplus/shortfall payment to trading participant p for a billing period.
TAFGQ(d,k)	Total quantity of gas as allocated to 'as available' trading rights on gas day d on facility k.
TCMDQ(d,k)	The total quantity of MOS decrease to which gas is allocated on facility k and gas day d.
TCMIQ(d,k)	The total quantity of MOS increase to which gas is allocated on facility k and gas day d.
TFGNQ(d,k)	Total quantity of gas offered to be supplied to the hub under 'firm' trading rights but not allocated for gas day d on facility k.
U (superscript)	Indicates a network user specific term.
VarC(p,d)	Variation charge for trading participant p for gas day d. This term is greater than or equal to zero.
VQ(p,d)	Total GJ variation of trading participant p on gas day d. This term is greater than or equal to zero.
WDA(p)	The shortfall/surplus allocation for a billing period to trading participant p as a result of its allocated withdrawals from the hub over the billing period (whether as a shipper or as a network user). This allocation includes the allocation of variation charges generated over the month and settlement surplus not allocated to DVA(p) as a result of the AllCAP limit (i.e. settlement surplus cap).

A2. Prudential monitoring

As part of the registration process for a trading participant (see Section 4.2), trading participants are required to lodge credit support, such as a bank guarantee. AEMO will set a minimum exposure for the trading participant that is sufficient to cover participant fees. Before the trading participant can be registered by AEMO in the STTM, at least this minimum amount of credit support will need to be lodged. The participant can choose how much additional credit support it wishes to provide. AEMO sets a trading limit for each trading participant, which is a percentage of the security amount. If this limit is exceeded, AEMO issues a margin call, which requires the trading participant to promptly provide additional credit support or a pre-payment. In addition to the trading participant's trading limit, AEMO also sets a warning limit, at which a warning notice is issued. AEMO monitors the trading position of every trading participant daily and takes the required action if these limits are exceeded.

Prudential monitoring is based on the net financial exposure of the trading participant across all its registered roles and across all hubs. The prudential monitoring process is performed after the settlement calculation has been performed each day for the previous gas day.

If a trading participant fails to act on a margin call within the required time, AEMO will issue a suspension notice, which may be restricted to specified roles at specified hubs. If a suspended

trading participant fails to act on the suspension notice within the required time, the trading participant may be subject to the relevant retailer of last resort processes and will then be deregistered from the STTM.

A2.1 Credit support and trading limit

A full collateralisation approach is used in the STTM, which requires all credit to be secured by a suitable guarantee, letter of credit, or cash deposit. This ensures that a trading participant is able to meet its current and potential liability at any time, protecting the other participants from payment defaults.

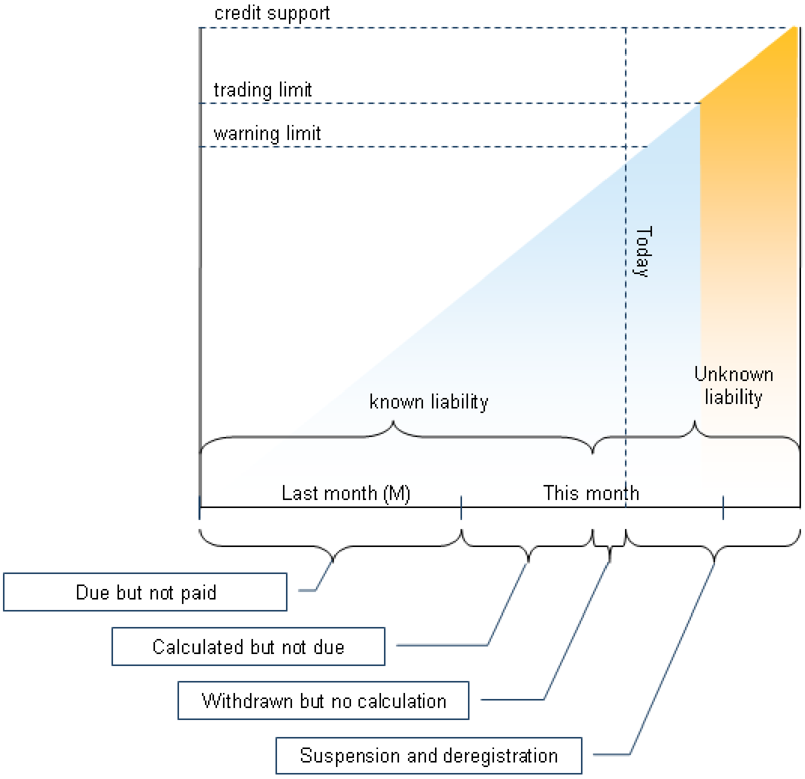
Credit support is designed to cover a trading participant's known liability and its unknown potential liability. A trading participant's known liability comprises:

- Settlement amounts due but not yet paid.
- Settlement amounts calculated after the gas day but not yet due. And the unknown potential liability includes:
- Amounts related to allocated gas flows for which there is not yet a settlement calculation.
- Amounts that could be incurred prior to deregistration of a participant.
- Revised settlement amounts from previous billing cycles.

If a trading participant defaults on settlement day for the charges relating to the last billing period, it is likely that they will already have incurred substantial liability in the current billing period. Once the default occurs, the steps that follow will take time to complete, during which the trading participant (or its customers) could withdraw further gas, adding to the total potential liability.

Based on the credit support provided, AEMO will establish a trading limit for each trading participant. The trading limit is generally equal to 85% of the credit support provided. Figure 35 shows the various components of the liability and how they relate to the credit support and trading limit amounts. Note that the diagram is simplified and does not include provision for revised settlement amounts.

Figure 35 The components of credit support



For prudential purposes, a single business trading as an STTM shipper and an STTM user can net off trading amounts, including amounts in each STTM hub. The prudential arrangements also take into account market schedule variations.

A2.2 Notifications

AEMO will issue a warning notice if a trading participant exceeds its warning limit, which is typically equal to 80% of the trading limit. Further warning notices are issued for each day that its warning limit is exceeded.

When the trading limit is breached, AEMO will issue a margin call and the trading participant must respond on the same business day or the next business day, depending on when the margin call was issued. To respond to the margin call, the trading participant can either pay an amount against the next settlement statement that reduces the trading participant's exposure below the trading limit, or it can lodge additional credit support that raises the trading participant's trading limit above its current estimated credit exposure.

A2.3 Suspension and deregistration

If the trading participant fails to respond to a margin call, AEMO must suspend the participant. If a suspended trading participant fails to rectify the problem within the required time, the trading participant may be subject to the relevant retailer of last resort processes and then be deregistered from the STTM.

For the period that the trading participant's estimated credit exposure exceeds its margin call limit, AEMO can charge the trading participant a daily margin call fee.

A3. Administered market states

The market conditions that trigger administered market states and the actions taken by AEMO during periods of market administration are strictly governed by the STTM Procedures in accordance with the relevant National Gas Rules (NGR) and National Gas Law (NGL). AEMO notifies the market (see Section 3.5) when any administered market state is triggered.

Important. This guide only contains an overview of administered market states and their triggers. The reader must refer to the relevant sections of the NGR and STTM Procedures for a complete description of these states.

Market states are specific to a hub; multiple market states can exist at the same hub; one state can trigger another; and some states can preclude other states.

A3.1 Administered Price Cap State

Triggers

Events that can cause an Administered Price Cap State include any of the following:

- AEMO fails to publish the ex ante schedule by the required time on day D-1 and, instead, uses a provisional schedule.
- High prices are sustained over a 7-day period and trigger CPT.
- A retailer ceases to operate and the retailer of last resort (ROLR) is invoked. This trigger is used where the proportion of the market impacted is small (a minor ROLR event).
- Technical or operational problems in a pipeline or STTM distribution system have materially affected the ability of trading participants to supply or withdraw gas at a hub or for end-use customers to be supplied gas from the STTM distribution system.

Administered state

During an Administered Price Cap State, the normal scheduling and settlement processes apply, but ex ante market prices, ex post imbalance prices and contingency gas prices are capped at the APC. Capacity prices may be modified to account for the impact of the APC. MOS and directional flow constraint prices are not impacted.

When an Administered Price Cap State is invoked prior to (and up to) the publication of the ex ante schedule:

- Ex ante market price is capped at APC.
- Ex post imbalance price is capped at APC.
- Capacity price equals the capped ex ante market price less the minimum of APC and the difference between the uncapped ex ante market price and the uncapped capacity price.
- High and low contingency gas prices are capped at APC.
- Pipeline flow direction price is not capped.

- Deviation prices are capped at APC.
- Variation prices are capped at APC less the capped ex ante market price.

If the state is invoked after the ex ante market price has been published then the outcomes are the same except that the ex ante market price and capacity prices are not capped.

A3.1.1 Trigger for CPT

AEMO calculates the cumulative price each day after the ex ante market price has been finalised for the following day. If an ex ante market price is not determined (in an administered ex ante market schedule state, for example), then the cumulative price is not calculated,

An administered pricing period commences the next gas day when

$$CP(d) > CPT$$

And continues until the gas day following the gas day on which the cumulative price is less than the CPT.

Where

CPT is the cumulative price threshold

$CP(d)$ is the cumulative price on day d

The cumulative price is calculated by:

$$CP(d) = CP(d-1) + A(d) - A(d-7)$$

Where

$A(d)$ is the contribution added to the cumulative price on day d

And is calculated by:

$$A(d) = Cx(d) + Cy(d) + Cz(d)\ Cx(d) = \max(0, HP(d))$$

$$Cy(d) = \max(0, (HCGP1(d) - Cx(d-1)))$$

If a major ROLR event has been declared

$$Cz(d) = \max(0, \max(IHP(d), HCGP2(d), MPC(d-1)) - Cy(d-1) - Cx(d-2))$$

Otherwise

$$Cz(d) = \max(0, \max(IHP(d), HCGP2(d)) - Cy(d-1) - Cx(d-2)$$

Where

$HP(d)$ is the ex ante market price calculated on gas day d (for $d+1$).

$HCGP1(d)$ is the highest contingency gas price scheduled as at 12 noon on gas day d, or, if no contingency gas is used on day d, then $HCGP1(d) = 0$.

$HCGP2(d)$ is the final high contingency gas price determined on gas day d (for $d-1$), or, if no contingency gas is used on day d, then $HCGP2(d) = 0$.

$IHP(d)$ is the ex post imbalance price for gas day d (calculated on $d+1$)

$MPC(d)$ is the market price cap on gas day d

In an administered market state, there are specific exceptions to how capped prices are used in determining the value of $A(d)$. For more information, refer to the NGR.

The state applies for entire gas days.

A3.2 Administered Ex Post Pricing State

Trigger

- AEMO fails to publish the ex post imbalance price by the required time.

Administered state

When triggered at a hub,

- The ex post imbalance price is set at the ex ante market price, which may be capped at APC.

A3.3 Market Administered Scheduling State

Triggers

- Ex ante schedule for gas day D has not been published by the required time on day D-1, and, no provisional schedules were published on days D-2 or D-3.
- Intervention by a government body directing the operation of gas suppliers and retailers.
- A retailer ceases to operate and the retailer of last resort (ROLR) is invoked. This trigger is used where the proportion of the market impacted is large (major ROLR event).

Administered state

When triggered at a hub,

- The ex ante market schedule is not published. AEMO instructs participants to follow the last published schedule and to use their own judgement.
- Ex ante market price is set at the 30-day rolling average ex ante market price, where the prices used to calculate the rolling average are capped at APC.
- Capacity price is zero.
- Pipeline flow direction constraint price is zero.
- Contingency gas prices (high and low) are set at the calculated ex ante market price.
- AEMO will back-calculate an ex ante market schedule from allocations and other settlement data such that no participant will be exposed to deviation payments and charges.

A3.4 Market Administered Settlement State

This state can only be applied after the ex ante market schedule has been published. When ex ante market schedules are determined normally, there is no capping of ex ante market prices or capacity prices (unless caused by other states).

Triggers

- Intervention by a government body directing the operation of gas suppliers and retailers.
- A retailer ceases to operate and the retailer of last resort (ROLR) is invoked. This trigger is used where the proportion of the market impacted is large (major ROLR event).

Administered state

When triggered at a hub,

- Ex ante market price is capped at APC.

- Capacity price is zero.
- Pipeline flow direction price is zero.
- Contingency gas price (high or low) is set at the calculated ex ante market price.
- AEMO will back-calculate an ex ante market schedule from allocations and other settlement data such that no participant will be exposed to deviation payments and charges.

A4. Compensation

The general dispute resolution and compensation framework is described in the National Gas Law and the National Gas Rules. Trading participants make contributions to a compensation fund to cover compensation claims (see Section 14.3.15). Compensation is, in general, restricted to situations where a trading participant incurs cost in the market that is not funded by prices in the market. This can occur when AEMO makes a scheduling error. Additional costs incurred by trading participants during administered market states are funded through the settlement process—not by the compensation fund. For more information, refer to the relevant sections of the NGR.

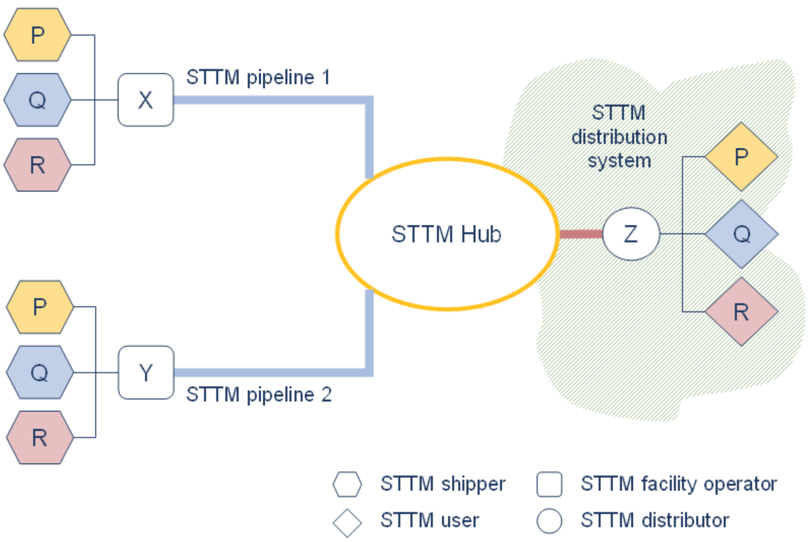
A5. Worked example

This is a “sunny day” scenario, which provides a worked example of a specific set of offers and bids at a hypothetical hub. No contingency gas is called and no administered market states are invoked, nor are the consequences of such exceptions to the normal operation of the market considered or explained in the scheduling, pricing and settlement calculations.

A5.1 STTM facilities and trading participants

In this example, there are two STTM pipelines, labelled 1 and 2, and one STTM distribution system. The default hub capacity of each pipeline is 100,000 gigajoules per day (GJ/d).

Figure 36 Trading participants and facilities



Organisations P, Q, and R have been registered by AEMO as trading participants. Each organisation participates in this hub in the roles of both STTM user and STTM shipper.

A5.2 Contracts, facility services, and trading rights

The facility contracts and their associated registered facility services and trading rights are summarised in Table A1 and Table A2. The distribution contracts and their associated registered distribution services and trading rights are summarised in Figure A-2. These trading rights data are used to validate and schedule bids and offers.

Pipeline 1

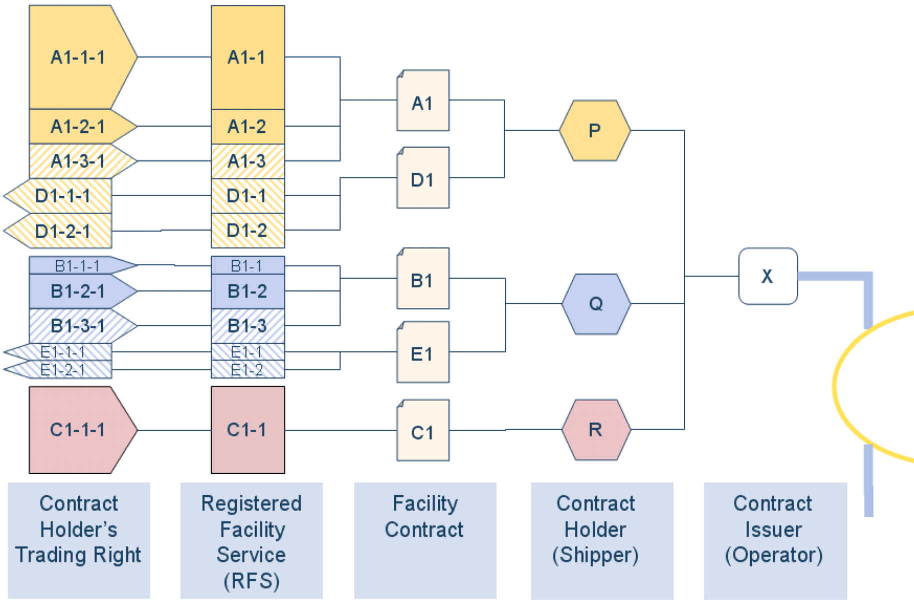
Referring to Table 15, the operator of pipeline 1 has issued three facility contracts A1, B1, and C1 for delivery to the hub, which are registered in the STTM as seven separate facility services. There are also two contracts D1 and E1 for flows away from the hub, which are registered as four facility services.

Table 15 Registered facility services and trading rights on pipeline 1

Contract holder	Facility contract	RFS (CRN)	Haulage direction	RFS capacity GJ/d	Haulage priority	Trading right holder	Trading right (TRN)	Trading right capacity GJ/d
P	A1	A1-1	To	45,000	1	P	A1-1-1	45,000
P	A1	A1-2	To	10,000	1	P	A1-2-1	10,000
P	A1	A1-3	To	10,000	2	P	A1-3-1	10,000
P	D1	D1-1	From	10,000	3	P	D1-1-1	10,000
P	D1	D1-2	From	10,000	3	P	D1-2-1	10,000
Q	B1	B1-1	To	5,000	1	Q	B1-1-1	5,000
Q	B1	B1-2	To	10,000	1	Q	B1-2-1	10,000
Q	B1	B1-3	To	10,000	2	Q	B1-3-1	10,000
Q	E1	E1-1	From	5,000	3	Q	E1-1-1	5,000
Q	E1	E1-2	From	5,000	3	Q	E1-2-1	5,000
R	C1	C1-1	To	35,000	1	R	C1-1-1	35,000

With all facility contracts, the full trading right has been retained by the contract holder. So for each trading right (referring to Figure 37), the capacity (height), direction (right=to, left=from) and haulage priority (solid=firm, hatch=as available) is the same as its RFS. A number of TRNs are MOS enabled and can provide MOS.

Figure 37 Registered facility services and trading rights on pipeline 1



For example, contract A1 has firm capacities under different contractual terms, which are registered separately to shipper P as registered facility service A1-1 (to the hub, firm capacity of 45,000 GJ/d) and A1-2 (to the hub, firm capacity of 10,000 GJ/d, reserved for MOS). Contract A1 also contains an as-available capacity of 10,000 GJ/d, which is registered to shipper P as facility service A1-3. Similarly, contract D1 has two registered components D1-1 (from the hub, as-available capacity of 10,000 GJ/d) and D1-2 (from the hub, as-available capacity of 10,000 GJ/d), both of which are registered to shipper P.

Note that in the "haulage priority" column of Table 15, a value of 1 means "firm" and any other value (2, 3, 4, etc.) means "as available." The increasing value of the as-available capacities reflects the decreasing priority applied when the pipeline operator schedules flows on its pipeline.

Note that although the registered hub capacity of pipeline 1 is 100,000 GJ, the firm capacity of all trading rights registered for pipeline 1 in the STTM totals 105,000 GJ. AEMO plays no role in the contracting process and relies on the information provided by the contract holder. And so, if a pipeline operator chooses to over-sell its firm capacity, then this is a commercial decision taken solely by the operator.

Pipeline 2

Similarly, on pipeline 2, there are three facility contracts A2, B2, and C2 for delivery to the hub, which are registered as four facility services, and one facility contract F2 for withdrawals from the hub with a single registered facility service.

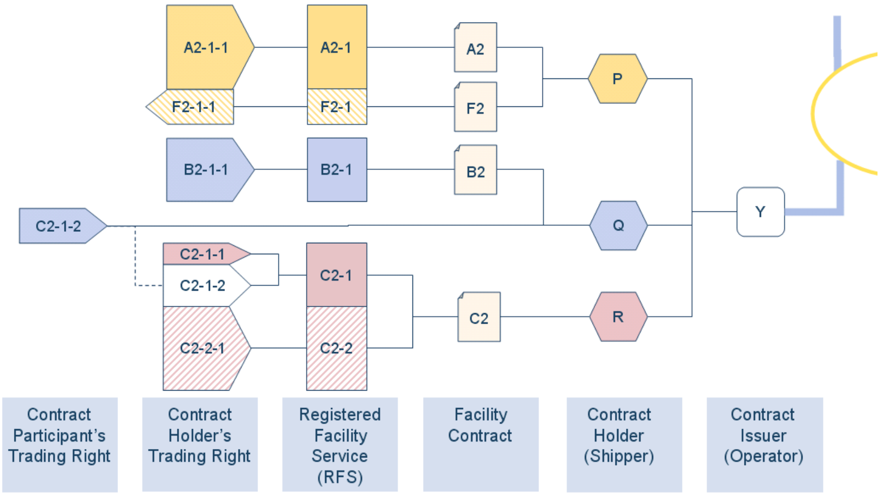
Table 16 Registered facility services and trading rights on pipeline 2

Contract holder	Facility contract	RFS (CRN)	Haulage direction	RFS capacity GJ/d	Haulage priority	Trading right holder	Trading right (TRN)	Trading right capacity GJ/d
P	A2	A2-1	To	40,000	1	P	A2-1-1	40,000
P	F2	F2-1	From	15,000	3	P	F2-1-1	15,000
Q	B2	B2-1	To	30,000	1	Q	B2-1-1	30,000
R	C2	C2-1	To	30,000	1	R	C2-1-1	10,000
R	C2	C2-1	To	30,000	1	Q	C2-1-2	20,000
R	C2	C2-2	To	40,000	2	R	C2-2-1	40,000

For simplicity, in this example, MOS is only provided on pipeline 1.

With all facility contracts except C2-1, the full trading right has been retained by the contract holder. On facility contract C2-1, the contract holder (shipper R) has retained a capacity of 10,000 GJ/d on trading right C2-1-1 and has transferred 20,000 GJ/d of capacity to shipper Q on trading right C2-1-2. The haulage priority is the same on all trading rights associated with the same RFS; that is, the transferred trading right C2-1-2 and the contract holder's trading right C2-1-1 both have firm capacity.

Figure 38 Registered facility services and trading rights on pipeline 2



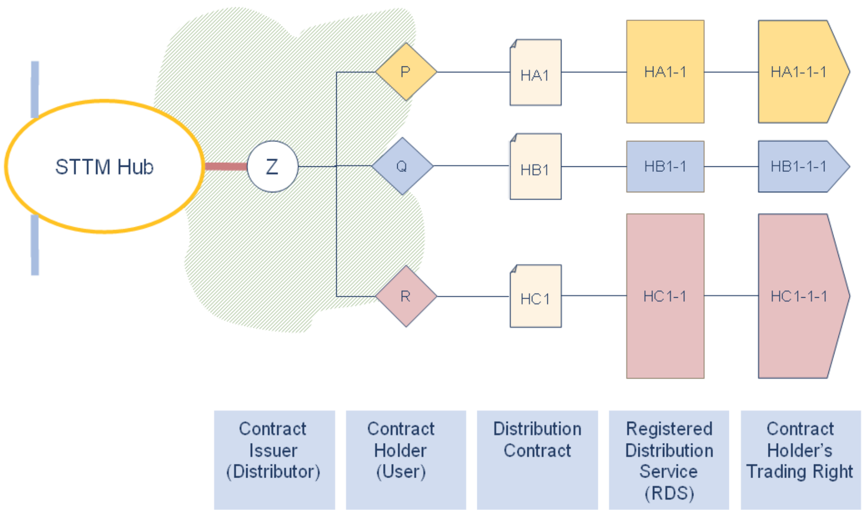
The distribution system

Referring to Table 17, the distributor has issued three distribution contracts (HA1, HB1, and HC1) to STTM users P, Q, and R, which are registered as distribution services HA1-1, HB1-1, and HC1-1, with trading rights HA1-1, HB1-1, and HC1-1, respectively. The capacity of an STTM user's trading right cannot be transferred. And, unlike shippers, a user's CRN does not have a priority.

Table 17 Distribution contracts and trading rights

Distribution contract (CRN)	Contract holder	Contract capacity GJ	Registered distribution service	Trading right holder	Trading right (TRN)	Trading right capacity GJ
HA1	P	80,000	HA1-1	P	HA1-1-1	80,000
HB1	Q	40,000	HB1-1	Q	HB1-1-1	40,000
HC1	R	105,000	HC1-1	R	HC1-1-1	105,000

Figure 39 Registered distribution services and trading rights



A5.3 Bids and offers

Offers by shippers to deliver to the hub

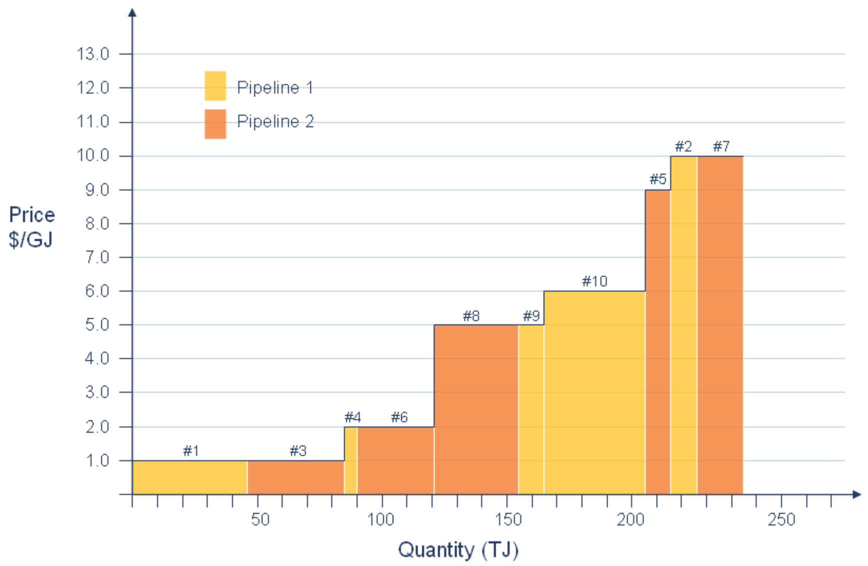
In the example shown in Table 18, only one offer step is submitted on each trading right, although ten are possible. Each price step specifies the maximum quantity offered on its trading right. The "#" column is provided only to assist with identifying each offer step through the scheduling process and has no meaning otherwise in the STTM. The table shows both cumulative and incremental quantities in each step, which, in this example, are equal because there is only one step in each offer. However, only the cumulative quantities are submitted to the STTM. Offers are submitted with a date range, but, in this example, we are only concerned with one gas day.

Table 18 STTM offers to deliver gas to the hub

Shipper	#	Haulage priority	Pipeline	Trading right	Trading right capacity GJ	Cumulative quantity GJ	Incremental quantity GJ	Price $/GJ
P	1	1	1	A1-1-1	45,000	45,000	45,000	1.0000
P	2	2	1	A1-3-1	10,000	10,000	10,000	10.0000
P	3	1	2	A2-1-1	40,000	40,000	40,000	1.0000
Q	4	1	1	B1-1-1	5,000	5,000	5,000	2.0000

Shipper	#	Haulage priority	Pipeline	Trading right	Trading right capacity GJ	Cumulative quantity GJ	Incremental quantity GJ	Price $/GJ
Q	5	2	1	B1-3-1	10,000	10,000	10,000	9.0000
Q	6	1	2	B2-1-1	30,000	30,000	30,000	2.0000
Q	7	1	2	C2-1-2	20,000	20,000	20,000	10.0000
R	8	1	1	C1-1-1	35,000	35,000	35,000	5.0000
R	9	1	2	C2-1-1	10,000	10,000	10,000	5.0000
R	10	2	2	C2-2-1	40,000	40,000	40,000	6.0000

Figure 40 Ex ante offers



Price taker bids

Price taker bids submitted by STTM users to withdraw gas at the hub are shown in Table 19. Price taker bids are submitted as a single quantity, one gas day at a time. The "#" column is provided only to assist with identifying each bid step through the scheduling process and has no meaning otherwise in the STTM.

Table 19 Price taker bids to withdraw gas at the hub

User	#	Trading right	Trading right capacity GJ	Quantity GJ	Price $/GJ
P	20	HA1-1	80,000	60,000	Price taker
Q	221	HB1-1	40,000	30,000	Price taker
R	322	HC1-1	105,000	40,000	Price taker

Bids by users to withdraw at the hub

Bids placed by users to withdraw gas at the hub are shown in Table 19. These bids are submitted separately from price taker bids. However, the cumulative total of all bids associated with the same trading right must not exceed the trading right capacity. For example, the cumulative quantity of price taker bid #20 (60,000 GJ) and ex ante bids #15 (15,000 GJ) and #16 (5,000 GJ), which are all associated with trading right HA-1, is 80,000 GJ, which equals the capacity of trading right HA1-1 (see Table 17).

Table 20 shows the cumulative and incremental quantities for each sequence of price steps. For example, bid steps #18 and #19 are placed on the same trading right, and the incremental quantity of bid step #18 is 5,000 GJ @ 8.0000 $/GJ, and the incremental quantity of bid step #19 is 60,000 GJ @ 7.0000 $/GJ. Bids are submitted with a date range, but, in this example, we are only concerned with one gas day.

Table 20 Ex ante bids to withdraw gas at the hub

User	#	Trading right	Trading right capacity GJ	Cumulative quantity GJ	Incremental quantity GJ	Price $/GJ
P	15	HA1-1-1	80,000	15,000	15,000	11.0000
P	16	HA1-1-1	80,000	20,000	5,000	10.0000
Q	17	HB1-1-1	40,000	10,000	10,000	9.0000
R	18	HB1-1-1	105,000	5,000	5,000	8.0000
R	19	HC1-1-1	105,000	65,000	60,000	7.0000

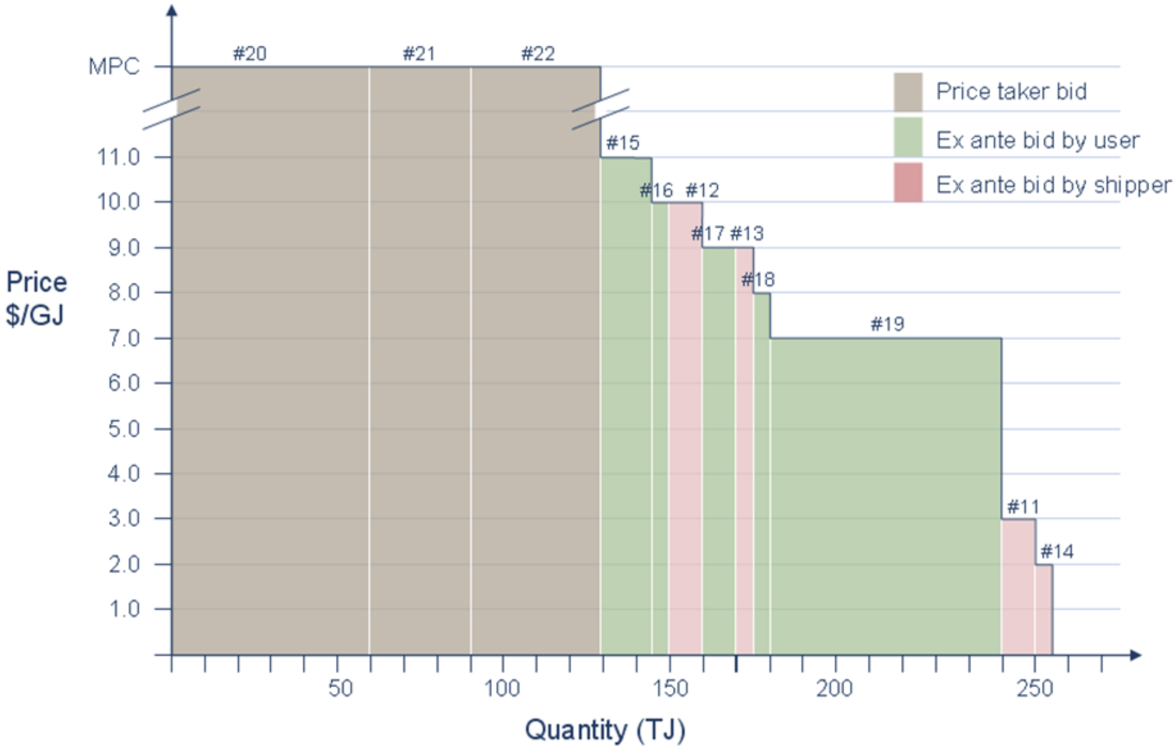
Bids by shippers to withdraw from the hub

Ex ante bids submitted by shippers to take gas away from the hub are shown in Table 21. For example, bid steps #12 and #13 are placed on the same trading right, and the incremental quantity of bid step #12 is 10,000 GJ @ 10.0000 $/GJ, and the incremental quantity of bid step #13 is 5,000 GJ @ 9.0000 $/GJ. Bids are submitted with a date range, but, in this example, we are only concerned with one gas day.

Table 21 Ex ante bids to withdraw gas from the hub

Shipper	#	Haulage priority	Pipeline	Trading right	Trading right capacity GJ	Cumulative quantity GJ	Incremental quantity GJ	Price $/GJ
P	11	3	1	D1-2-1	10,000	10,000	10,000	3.0000
P	12	3	2	F2-1-1	15,000	10,000	10,000	10.0000
P	13	3	2	F2-1-1	15,000	15,000	5,000	9.0000
Q	14	3	1	E1-2-1	5,000	5,000	5,000	2.0000

Figure 41 Price taker bids and ex ante bids



A5.4 Ex ante market schedule

Scheduling offers and bids

The pipeline operators have submitted STTM facility hub capacities of 100,000 GJ for each of the two pipelines. The results of running the scheduling and pricing algorithm (SPA) using these hub capacities and the offers and bids listed in the above tables are shown in Table 20, Table 21, and Figure 41. The solution schedules 85,000 GJ of supply on pipeline 1 and 100,000 GJ of supply on pipeline 2 to satisfy 185,000 GJ of demand, of which 170,000 GJ is withdrawn at the hub by users, and the remaining 15,000 GJ is hauled away from the hub by shipper P on pipeline 2.

In Table 22, offers are ordered by increasing price. The "Scheduled" column shows the quantity of each offer step that has been scheduled. Note that offer #10 is only partially scheduled to bring the quantity scheduled on pipeline 2 up to its full capacity. The cumulative total quantity of gas scheduled on each pipeline by each shipper is shown in columns "On PL 1" and "On PL 2". Note that pipeline 2 is fully scheduled (it is “constrained”) to its capacity of 100,000 GJ, but only 85,000 GJ is needed on pipeline 1 to meet the demand at the hub. At the market clearing point, there is 15,000 GJ of capacity remaining on pipeline 1.

Table 22 Registered facility services and trading rights on pipeline 1

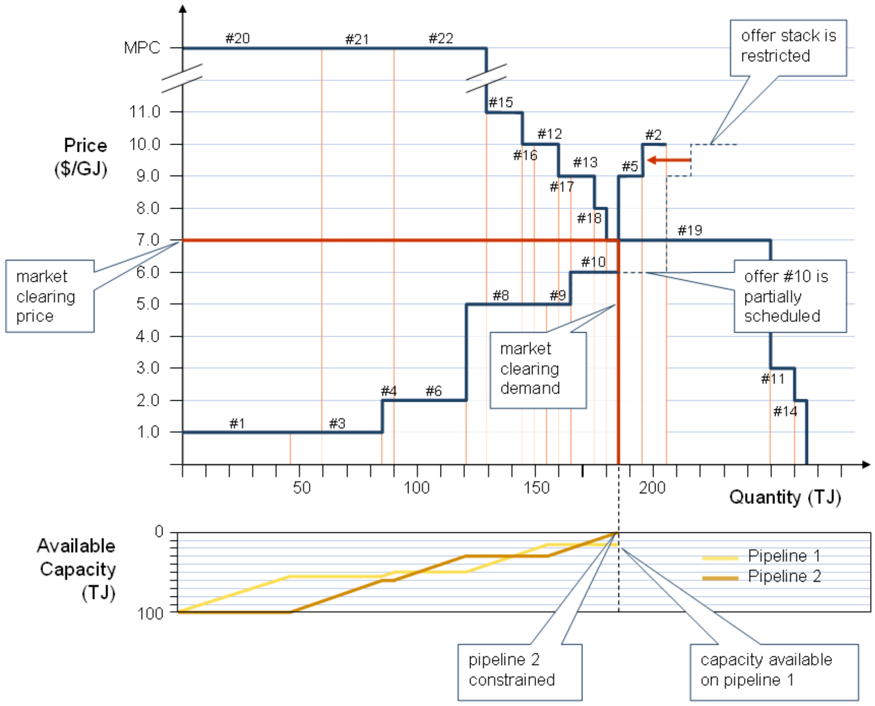
Shipper	#	PL	TRN	Step quantity GJ	Step price $/GJ	Haulage priority	Scheduled GJ	On PL 1	On PL 2
P	1	1	A1-1-1	45,000	1.0000	1	45,000	45,000	
P	3	2	A2-1-1	40,000	1.0000	1	40,000		40,000
Q	4	1	B1-1-1	5,000	2.0000	1	5,000	50,000	
Q	6	2	B2-1-1	30,000	2.0000	1	30,000		70,000
R	8	1	C1-1-1	35,000	5.0000	1	35,000	85,000	
R	9	2	C2-1-1	10,000	5.0000	1	10,000		80,000
R	10	2	C2-2-1	40,000	6.0000	2	20,000		100,000
Q	5	1	B1-3-1	10,000	9.0000	2	0		
P	2	1	A1-3-1	10,000	10.0000	2	0		
Q	7	2	C2-1-2	20,000	10.0000	1	0		
Total							**185,000**	**85,000**	**100,000**

Table 23 Scheduled bids

User Shipper	#	Direction	Step quantity GJ	Step price $/GJ	Scheduled GJ	Total
P	20	Withdrawal	60,000	Price taker	60,000	60,000
Q	21	Withdrawal	30,000	Price taker	30,000	90,000
R	22	Withdrawal	40,000	Price taker	40,000	130,000
P	15	Withdrawal	15,000	11.0000	15,000	145,000
P	16	Withdrawal	5,000	10.0000	5,000	150,000
P	12	Away on P/L 2	10,000	10.0000	10,000	160,000
Q	17	Withdrawal	10,000	9.0000	10,000	170,000
P	13	Away on P/L 2	5,000	9.0000	5,000	175,000
R	18	Withdrawal	5,000	8.0000	5,000	180,000
R	19	Withdrawal	60,000	7.0000	5,000	185,000
A	11	Away on P/L 1	10,000	3.0000	0	
B	14	Away on P/L 1	5,000	2.0000	0	

In Table 23, bids are ordered by decreasing price. The SPA sets the value of price taker bids (#20, #21, and #22) slightly above MPC so they are scheduled first (see Figure 42). The "Scheduled" column shows the quantity of each bid step that has been scheduled. Note that bid #19 is only partially scheduled (60,000 GJ bid, 5,000 GJ scheduled). Of the total 185,000 GJ demand, 15,000 GJ is withdrawn from the hub by shipper P (bids #12 and #13) on pipeline 2 and 170,000 GJ is injected into the distribution system.

Figure 42 Market clearing point



A5.5 Ex ante market prices

Ex ante market price

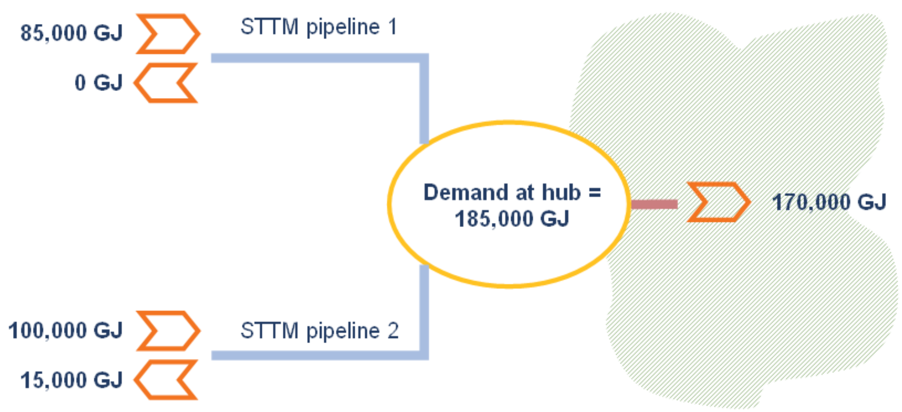
The market supply-demand curve shown in Figure 42 illustrates how the SPA determines the market clearing price (ex ante market price) of 7.00 $/GJ at the market clearing quantity (hub demand) of 185,000 GJ. The ex ante market price is set by the lowest priced scheduled bid, that is, bid step #19 at 7.00 $/GJ.

Note that the SPA adds small increments of price and quantity to the input data to ensure that a unique solution is always found and the correct priority is applied when multiple solutions are possible. These increments are not shown in the tables of this example—they are so small that they are not detectable at the accuracies of quantity (1 GJ) and price (0.0001 $/GJ) used in the reports.

Pipeline flow direction constraint prices

The total flow to the hub on pipeline 1 is 85,000 GJ and on pipeline 2 is 100,000 GJ. The total flow from the hub on pipeline 1 is 0 GJ the total flow from the hub on pipeline 2 is 15,000 GJ. Hence flow from the hub on each pipeline is not limited by flow to the hub on each pipeline so the pipeline flow direction price on both pipelines is zero.

Figure 43 Scheduled flows



Capacity prices

Pipeline 1 is unconstrained, hence the capacity price on pipeline 1 is zero. The capacity price on pipeline 2 is 1.00 $/GJ, which is the difference between the ex ante market price (7.00 $/GJ) and the highest priced offer flowed on that pipeline (#10 at 6.00 $/GJ).

A5.6 Pipeline schedules

After AEMO issues the ex ante market schedules, shippers nominate the quantities they wish to flow over the following gas day. The pipeline operators then issue their pipeline schedules. The pipeline schedule quantities and ex ante market schedule quantities for each CRN are shown in Table 24, Table 25, Table 26, and Table 27. The ex ante market schedule quantities are not part of the pipeline schedules, but are shown here for ease of comparison.

Pipeline 1

On pipeline 1, the pipeline schedule for supply to the hub matches the ex ante market schedule (see Table 24). There is no flow away from the hub scheduled on pipeline 1 (see Table 25).

Table 24 Pipeline 1 schedule for supply to the hub

Shipper	Pipeline	CRN	Priority	Capacity	Pipeline schedule GJ	Ex ante market schedule GJ
P	1	A1-1	1	45,000	45,000	45,000
P	1	A1-3	2	10,000	0	0
Q	1	B1-1	1	5,000	5,000	5,000
Q	1	B1-3	2	10,000	0	0
R	1	C1-1	1	35,000	35,000	35,000
Total					85,000	85,000

Table 25 Pipeline 1 schedule for withdrawals from the hub

Shipper	Pipeline	CRN	Priority	Capacity	Pipeline schedule GJ	Ex ante market schedule GJ
P	1	D1-2	3	10,000	0	0
Q	1	E1-2	3	5,000	0	0
Total					0	0

Pipeline 2

Referring to Table 26, on pipeline 2, the quantities scheduled on RFS A2-1 and B2-1 match the ex ante market schedule. Shipper R is the contract holder of RFS C2-1 and was scheduled 10,000 GJ in the ex ante market on its trading right C2-1-1. This quantity has also been scheduled by the pipeline operator. Shipper Q has asked shipper R to nominate 5,000 GJ on C2-1 (firm). Shipper R has also nominated 20,000 GJ on C2-2 (as available). Because C2-1 has priority over C2-2, and, because there is no capacity available to fully schedule both nominations, the pipeline operator has accepted the nomination by shipper Q and scheduled 15,000 GJ for shipper R. In doing so, shipper Q has bumped 5,000 GJ from shipper R's ex ante market schedule, which will have consequences in settlement.

Table 26 Pipeline 2 schedule for supply to the hub

Shipper	Pipeline	CRN	Priority	Capacity	Pipeline schedule GJ	Ex ante market schedule GJ
P	2	A2-1	1	40,000	40,000	40,000
Q	2	B2-1	1	30,000	30,000	30,000
R	2	C2-1	1	30,000	15,000	10,000
R	2	C2-2	2	40,000	15,000	20,000
Total					100,000	100,000

Referring to Table 27, the pipeline schedules for flows away from the hub on pipeline 2 match the ex ante market schedules.

Table 27 Pipeline 2 schedule for withdrawals from the hub

Shipper	Pipeline	CRN	Priority	Capacity	Pipeline schedule GJ	Ex ante market schedule GJ
P	2	F2-1	3	15,000	15,000	15,000
Total					15,000	15,000

A5.7 On the day

Intraday nominations

During the gas day, user Q requires an additional 5,000 GJ to meet an increased forecast demand at the hub. Pipeline 2 is constrained, and so additional demand must be supplied on pipeline 1. Shipper Q (the same entity as user Q) has 10,000 GJ of spare capacity on RFS B1-3 on pipeline 1, and so shipper Q makes an intraday nomination to the operator of pipeline 1 to flow an additional 5,000 GJ on B1-3.

Table 28 Final pipeline schedules

Shipper	Pipeline	CRN	Priority	Capacity	Pipeline schedule GJ
P	1	A1-1	1	45,000	45,000
P	1	A1-3	2	10,000	0
Q	1	B1-1	1	5,000	5,000
Q	1	B1-3	2	10,000	5,000
R	1	C1-1	1	35,000	35,000
Total to hub on pipeline 1					90,000
P	2	A2-1	1	40,000	40,000
Q	2	B2-1	1	30,000	30,000
R	2	C2-1	1	30,000	15,000
R	2	C2-2	2	40,000	15,000
Total to hub on pipeline 2					100,000
P	2	F2-1	3	15,000	15,000
Total away from hub on pipeline 2					15,000

Pipeline deviations

At the end of the gas day, the pipeline operators record the CTP meter readings. Despite the intraday nomination by shipper Q, the net quantity delivered on pipeline 1 was determined at 93,000 GJ, which is 8,000 GJ greater than the original pipeline schedule, and 3,000 GJ greater than the final pipeline schedule. Hence 3,000 GJ of MOS gas was flowed on pipeline 1.

The net quantity delivered on pipeline 2 was determined at 100,000 GJ, which matches the final pipeline schedule.

Contingency gas prices

Because no contingency gas was called on the day, no contingency gas prices are set (they are not zero). There is an important distinction between not setting a contingency gas price and a zero price because, although not included in this example, this affects the cumulative price calculation used to test for an Administered Price Cap State.

A5.8 Allocations

MOS step allocations

In this simplified example, MOS is only provided on pipeline 1; however, shippers on pipeline 2 would normally also offer MOS. The MOS increase estimate on pipeline 1 for the current MOS period is 12,000 GJ and the MOS decrease estimate is 8,000 GJ. The MOS stacks issued by AEMO at the start of the MOS period are shown in Table A15, which provide a total of 10,000 GJ of MOS increase and 10,000 GJ of MOS decrease.

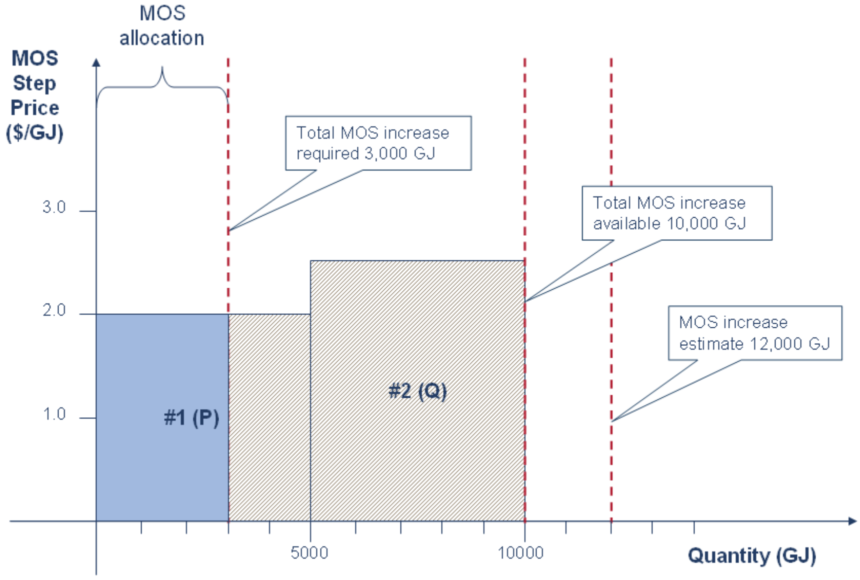
The CRN information shown in this table is not part of the stack issued by AEMO but reflects the agreement between the shippers and the pipeline operator on how MOS will be allocated. As each MOS Step is associated with one MOS enabled TRN, AEMO uses the MOS Allocation to allocate MOS from the CRN level to the TRN level.

Table 29 MOS increase and decrease stacks

Stack	MOS Step #	Pipeline	MOS Provider	Step Price $/GJ	Step Quantity GJ	CRN (direction)		Trading Right (TRN)
Increase	1	1	P	2.00	5,000	A1-2	TO hub	A1-2-1
Increase	2	1	P	2.25	3,000	D1-1	FROM hub	D1-1-1
Increase	3	1	Q	2.50	5,000	B1-2	TO hub	B1-2-1
Increase	4	1	Q	3.00	3,000	E1-1	FROM hub	E1-1-1
Decrease	1	1	P	0.50	5,000	A1-2	TO hub	A1-2-1
Decrease	2	1	P	2.25	3,000	D1-1	FROM hub	D1-1-1
Decrease	3	1	Q	2.00	5,000	B1-2	TO hub	B1-2-1
Decrease	4	1	Q	3.00	3,000	E1-1	FROM hub	E1-1-1

There was 3,000 GJ of unscheduled flow to the hub on pipeline 1, and so the operator of pipeline 1 allocates an increased flow to MOS increase step #1 as an increase on shipper P's MOS enabled TRN A1-2-1. In this example, the total MOS increase allocation is less than the total available on the MOS increase stack, and so overrun MOS is not required.

Figure 44 MOS step allocations on pipeline 1



STTM facility allocations

The allocations submitted by allocation agents for pipeline operators for the total 193,000 GJ supplied to the hub and the 15,000 GJ withdrawn from the hub are shown in Table 30 and Table 31. The allocations include

3,000 GJ of MOS. Shipper Q has an intraday nomination of 5,000 GJ on CRN B1-3. No overrun MOS was needed to be allocated on the day.

Table 30 STTM facility allocations to hub

Shipper	Pipeline	CRN	Final Pipeline Schedule	Total Allocation	Total MOS	Overrun MOS
P	1	A1-1	45,000	45,000	0	0
P	1	A1-2	0	3,000	3,000	0
P	1	A1-3	0	0	0	0
Q	1	B1-1	5,000	5,000	0	0
Q	1	B1-2	0	0	0	0
Q	1	B1-3	5,000	5,000	0	0
R	1	C1-1	35,000	35,000	0	0
Total	1		90,000	93,000	3,000	0
P	2	A2-1	40,000	40,000	0	0
Q	2	B2-1	30,000	30,000	0	0
R	2	C2-1	15,000	15,000	0	0
R	2	C2-2	15,000	15,000	0	0
Total	2		100,000	100,000	0	0

Table 31 STTM facility allocations away from hub

Shipper	Pipeline	CRN	Final Pipeline Schedule	Total Allocation	Total MOS	Overrun MOS
P	1	D1-1	0	0	0	0
P	1	D1-2	0	0	0	0
Q	1	E1-1	0	0	0	0
Q	1	E1-2	0	0	0	0
Total	1		0	0	0	0
P	2	F2-1	15,000	15,000	0	0
Total	2		15,000	15,000	0	0

Registered facility service allocations

Except for C2-1, in this example, shippers' registered facility services have a single trading right (the contract holder's trading right). Hence, allocations at the trading right level match the STTM facility allocations listed in the previous tables. Note that the quantity allocated to the RFS C2-1 in Table 30 is 15,000 GJ, which includes the quantities allocated to both trading rights C2-1-1 and C2-1-2. The registered facility service allocation splits this into 10,000 GJ to the shipper R's contract holder's trading right C2-1-1 and 5,000 GJ to shipper Q's trading right C2-1-2, which it acquired from shipper R.

STTM distribution system allocations

AEMO allocates the data received from distributors to STTM users according to the current profiles, and then scales the allocations such that the total withdrawals match the net flow to the hub of 178,000 GJ (193,000 – 15,000 GJ). The allocations determined by AEMO as RMO are shown in Table 32.

Table 32 STTM distribution system allocations

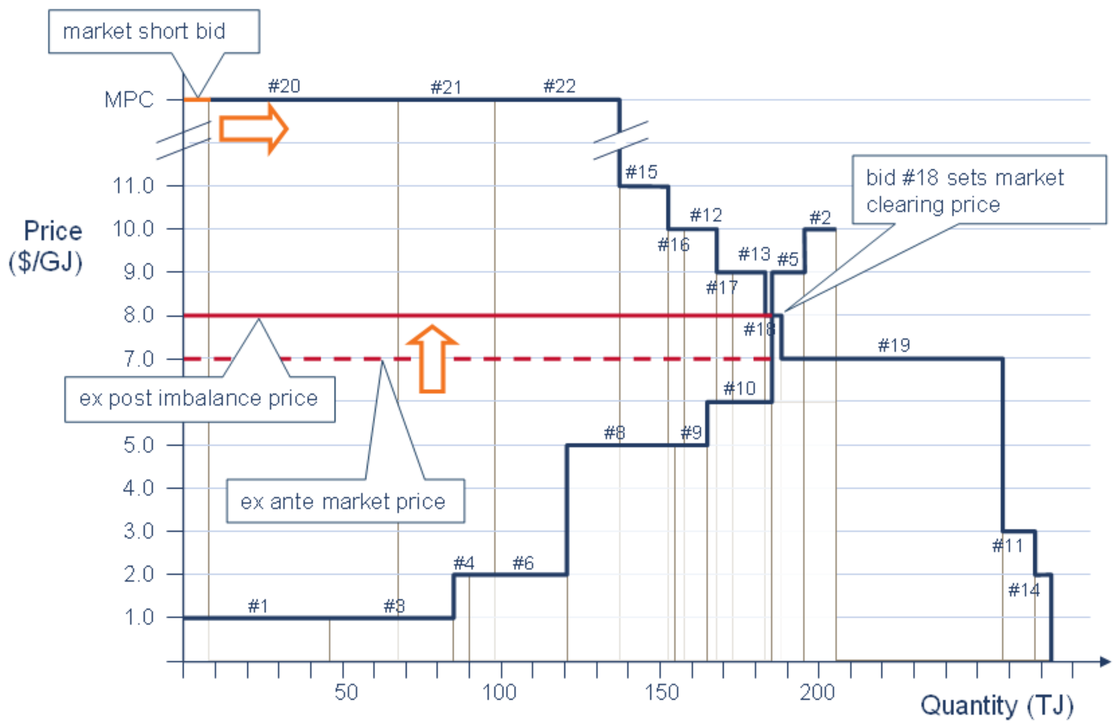
User	CRN	Ex Ante Market Schedule	Allocated
A	HA-1	80,000	79,337
B	HB-1	40,000	46,789
C	HC-1	50,000	51,874
Total		170,000	178,000

A5.9 Ex post imbalance price

Determining the ex post imbalance price

When the total scheduled flows to the hub of 185,000 GJ is subtracted from the total allocated flows to the hub of 193,000 GJ, the difference is 8,000 GJ. The difference is positive, hence the market is short (more gas was allocated than was scheduled), and the market short bid is 8,000 GJ. The result of running the schedule ex post is shown in Figure 45. The demand curve has moved 8,000 GJ to the right, which gives an ex post imbalance price of 8.00 $/GJ at 193,000 GJ set by bid #18.

Figure 45 Ex post imbalance price



A5.10 Market schedule variations

Shipper Q submits an MSV to AEMO for 5,000 GJ and nominates user Q as the receiver. User Q confirms the MSV and AEMO will, when it calculates settlement quantities, apply the variation quantities to the modified market schedules.

A5.11 Settlement quantities

The modified market schedules (after accounting for MSVs, MOS and contingency gas) and the resulting deviation quantities for each shipper and user are shown in Table 33, Table 34, and Table 35.

Referring to Table 33, note that P's modified market schedule for flow to the hub on pipeline 1 includes 3,000 GJ of MOS, which was included in the STTM facility allocation to RFS A1-2. Hence, the modified market schedule and allocation quantities match up, resulting in no deviation. Similarly, Q's confirmed MSV for 5,000 GJ ensures that it also has no deviation. On pipeline 2, however, the 5,000 GJ that Q bumped from R, results in deviations for both shippers (to the hub, on pipeline 2).

Table 33 Flows to the hub

Shipper	TRN	Ex ante market schedule	Total for Facility	MOS*	OR MOS	MSV	CG	Modified market schedule	Allocation	Deviation
P	A1-1-1	45,000	45,000	N/A	0	0	0	48,000	48,000	0
P	A1-2-1	0		3,000						
P	A1-3-1	0		N/A						
Q	B1-1-1	5,000	5,000	N/A	0	5,000	0	10,000	10,000	0
Q	B1-2-1	0		0						
Q	B1-3-1	0		N/A						
R	C1-1-1	35,000	35,000	0	0	0	0	35,000	35,000	0
Total	P/L 1	85,000	85,000	3,000		5,000	0	93,000	93,000	0
P	A2-1-1	40,000	40,000	0	0	0	0	40,000	40,000	0
Q	B2-1-1	30,000	30,000	N/A	0	0	0	30,000	35,000	5,000
Q	C2-1-2	0		N/A						
R	C2-1-1	10,000	30,000	N/A	0	0	0	30,000	25,000	-5,000
R	C2-2-1	20,000		N/A						
Total	P/L 2	100,000	100,000	0	0	0	0	100,000	100,000	0

Note: * If a TRN is MOS enabled then a value is allocated. MOS disabled TRNs are listed as 'N/A'.

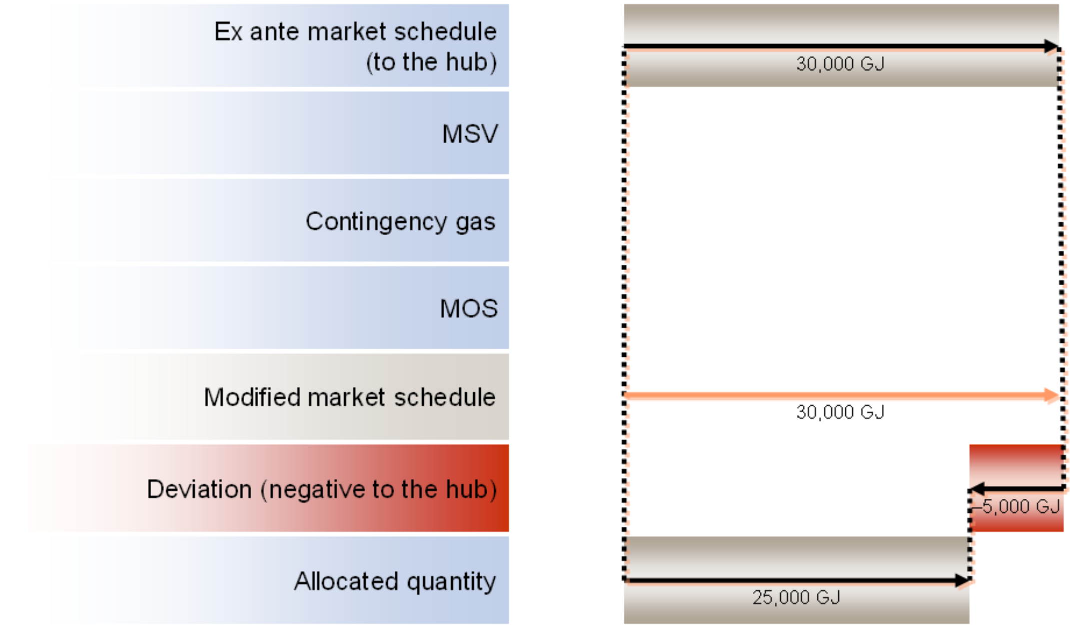
Note. For the purpose of calculating deviation quantities, quantities are summed by participant role, facility, and flow direction.

For example, the deviation by shipper R delivering to the hub on pipeline 2 is illustrated in Figure 46. Note that for shippers supplying to the hub, the sign of the deviation quantity is determined by:

Deviation Qty = Allocated Qty – MMS Qty

So in this case, the deviation is negative, which decreases net supply to the hub.

Figure 46 Negative deviation by shipper R delivering to the hub on pipeline 2



Referring to Table 34, P's modified market schedule for flow from the hub on pipeline 2 matches its allocation, and so has no deviation.

Table 34 Flows away from the hub

Shipper	TRN	Ex ante market schedule	Total for Facility	MOS*	OR MOS	MSV	CG	Modified market schedule	Allocation	Deviation
P	D1-1-1	0	0	0	0	0	0	0	0	0
P	D1-2-1	0		N/A						
Q	E1-1-1	0	0	0	0	0	0	0	0	0
Q	E1-2-1	0		N/A						
P	F2-1-1	15,000	15,000	N/A	0	0	0	15,000	15,000	0
Total		15,000		0	0	0	0	15,000	15,000	

Note: * If a TRN is MOS enabled then a value is allocated. MOS disabled TRNs are listed as 'N/A'.

Referring to Table 35, Q's modified market schedule as a user includes the MSV submitted in its role as shipper. Each user ends up with a deviation, which, when summed, equal the deviation in net flow to the hub on pipelines 1 and 2.

Table 35 Withdrawals at the hub

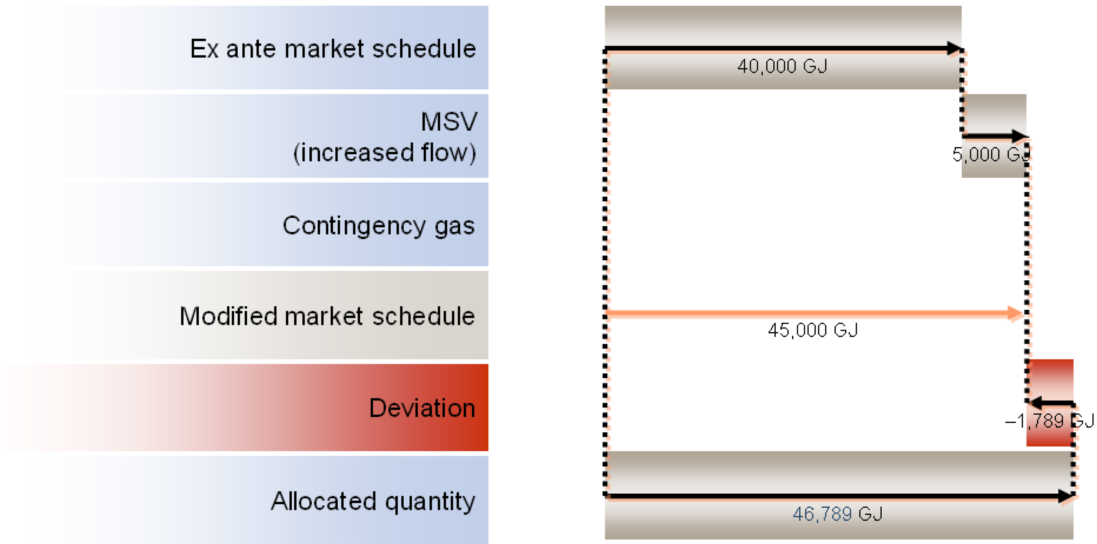
Shipper	TRN	Ex ante market schedule	MSV	CG	Modified market schedule	Allocation	Deviation
P	HA1-1-1	80,000	0	0	80,000	79,337	663
Q	HB1-1-1	40,000	5,000	0	45,000	46,789	-1,789
R	HC1-1-1	50,000	0	0	50,000	51,874	-1,874
Total		170,000	0	0	178,000	178,000	3,000

Each user ends up with a deviation. For example, the deviation by user Q withdrawing at the hub is illustrated in Figure 47. Note that for shippers and users withdrawing from the hub, the sign of the deviation quantity is determined by:

Deviation Qty = MMS Qty – Allocated Qty

This is the inverse of shippers supplying to the hub (see above). So in this case, the deviation is negative, which decreases net supply to the hub.

Figure 47 Negative deviation by user Q withdrawing at the hub



A5.12 Settlement calculations

In the calculations that follow, only the non-zero components are detailed, and conditions that do not influence the calculation (the effect of contingency gas prices on deviation charges, for example) are not always discussed.

Ex ante market settlement

Referring to the ex ante modified market schedules in the tables above, trading participant P supplies 85,000 GJ to the hub as a shipper (40,000 GJ + 45,000 GJ), withdraws 15,000 GJ from the hub as a shipper, and withdraws 80,000 GJ as a user. These quantities are all settled at the ex ante market price of 7.00 $/GJ, which results in a net charge to trading participant of $70,000. Similarly, as shown in Table 36, trading participant Q is charged $35,000, and trading participant R receives $105,000.

Table 36 Settlement of the ex ante market

Trading Participant	Supplied GJ	Withdrawn GJ	Price $/GJ	Payment $	Charge $	Net $
P	85,000	95,000	7.00	595,000	665,000	70,000
Q	35,000	40,000	7.00	245,000	280,000	35,000
R	65,000	50,000	7.00	455,000	350,000	-105,000
Total	185,000	185,000		1,295,000	1,295,000	0

Pipeline directional flow constraint charges and payments

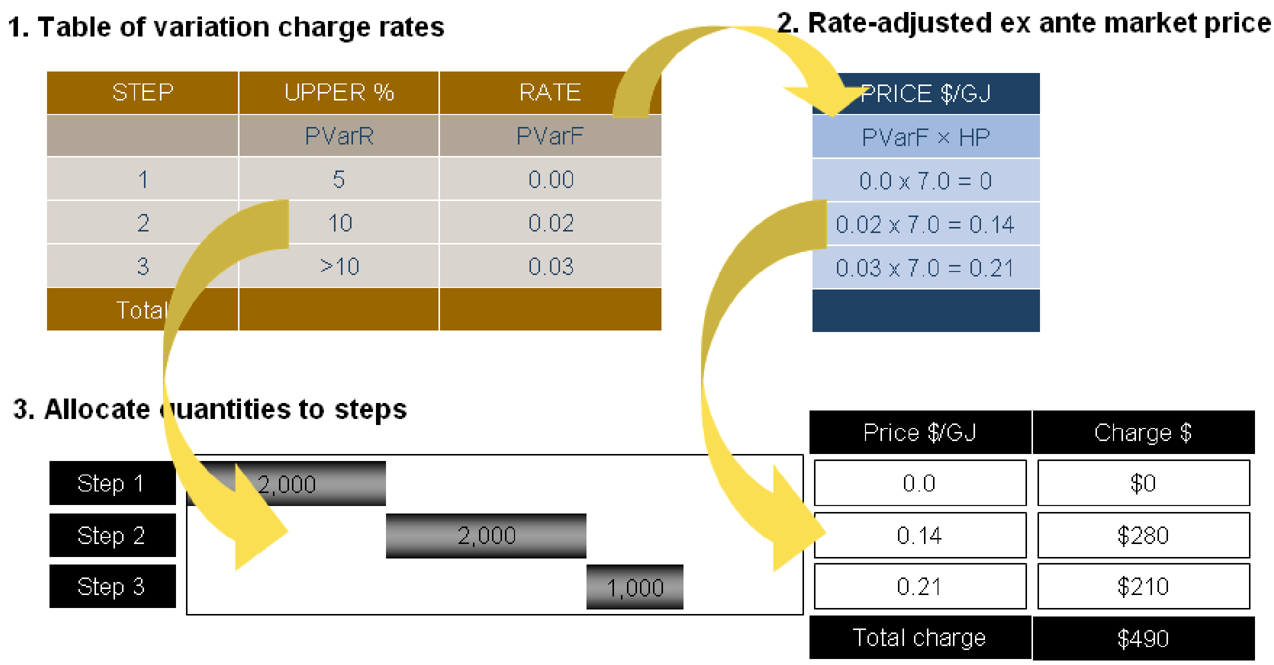
No pipeline directional flow constraint charges or payments are made in this example.

Variations

Participant Q, as the STTM user receiving the MSV, pays for its variation. No variation charge applies to the originating shipper (also Q). The variation quantity (VQ) is ABS(5,000) = 5,000 GJ. The variation charge is calculated by two methods (see Figure 48 and Figure 49 for details).

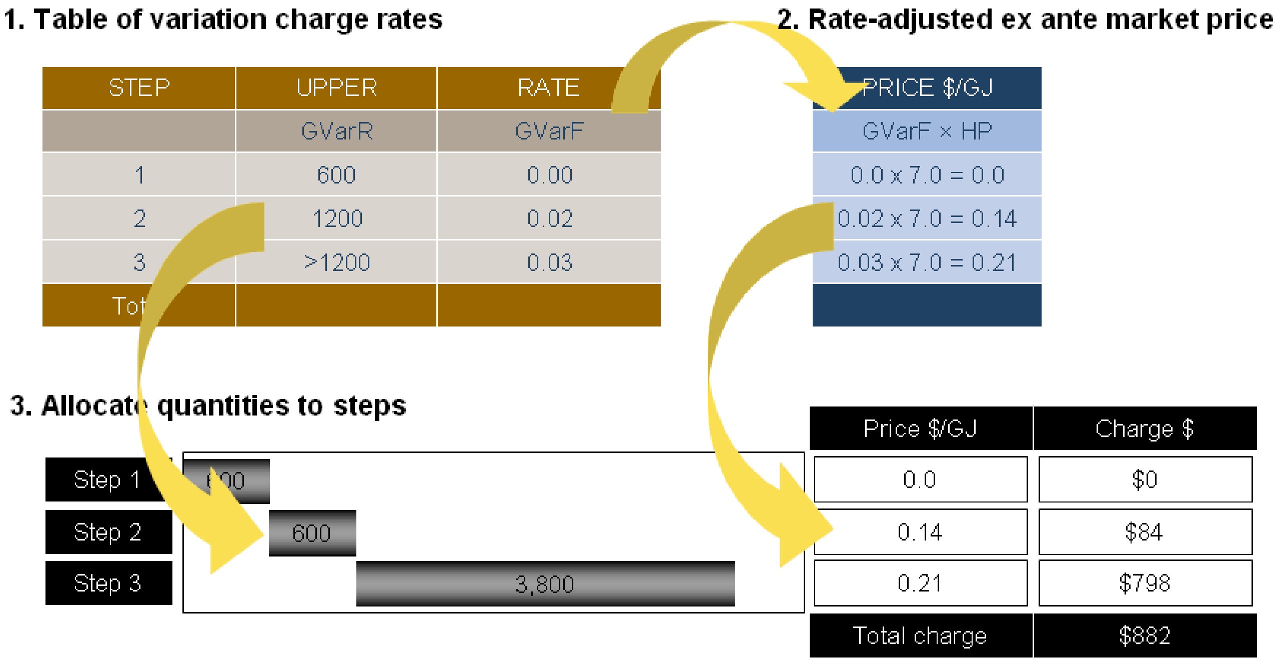
Referring to Figure 48, using the percentage method, the charge rate is applied to the ex ante market price (7.00 $/GJ) to determine the rate-adjusted ex ante market price. In this case, the rate-adjusted ex ante market price is applied. The step price is then applied to the corresponding step quantity. The quantity in each step is set as a percentage of the ex ante market scheduled withdrawal of user Q, which is 40,000 GJ (see Table 35). So 5,000 GJ represents 12.5% of the total withdrawal. The 5,000 GJ is divided into 3 steps of 5% + 5% + residual, or 2,000 + 2,000 + 1,000 GJ. The resulting variation charge calculated by the percentage method is $490.

Figure 48 Calculating variation step prices, quantities, and charges by the percentage method



Referring to Figure 49, using the quantity method, the same charge rates apply, but the quantity in each step is determined by GJ steps of 600 + 600 + residual. Hence, the 5,000 GJ is divided into 3 steps of 600 + 600 + 3,800 GJ. The resulting variation charge calculated by the quantity method is $882.

Figure 49 Calculating variation step prices, quantities, and charges by the quantity method



The lesser charge is applied, which, in this example, is a charge of $490, calculated by the percentage method.

MOS payment

Shipper P has provided 3,000 GJ of MOS increase on pipeline 1 at a MOS increase step price of 2.00 $/GJ via MOS enabled TRN A1-2-1 (see Table 29). So shipper P receives a service payment of $6,000. Let's say that the ex ante market price two days later is 6.00 $/GJ. So shipper P also receives a commodity payment of $18,000. There is no overrun MOS. Note that the timing of the commodity payment depends on which billing period d+2 gas day falls, even though the MOS gas might have been provided in the previous billing period.

Capacity charges and payments

The capacity price on pipeline 2 is 1.00 $/GJ. Referring to Table A8, shipper R was scheduled in the ex ante market to supply 20,000 GJ on pipeline 2 using as-available trading right C2-2-1. Shipper Q offered 20,000 GJ into the market on firm trading right C2-1-2 (offer step #7), which was not scheduled due to price. Shipper Q subsequently nominated 5,000 GJ and was scheduled 5000 GJ by the pipeline. Because the pipeline was constrained, this resulted in only 15,000 GJ of shipper R's nomination of 20,000 GJ being scheduled. Hence the quantity of firm capacity gas that did not flow on pipeline 2 was 15,000 GJ. So, in this case, all the conditions necessary for capacity charges and payments were satisfied:

- The pipeline was constrained.
- Firm capacity offered into the market was not flowed.
- As-available gas was flowed.

Consequently, shipper R pays a capacity charge of $15,000. This is distributed amongst the firm shippers who did not flow, which, in this case, means that shipper Q receives a capacity payment of $15,000.

Average MOS cost

Either a MOS increase cost or a MOS decrease cost is calculated for each hub and on each gas day. The net MOS quantity of the hub is 3,000 GJ (MOS increase quantity) which is provided by Shipper P and no overrun MOS on the day (see Table 33 and Table 34). Shipper P receives a service payment of $6,000 and a commodity payment of $18,000.

The MOS increase cost for the hub on the day is:

Table 37 MOS increase cost

Increase MOS amounts	Increase MOS quantity	MOS increase cost
$6,000 + $18,000 = $24,000	3,000 GJ	$24,000 / 3,000GJ = $8.00

MOS decrease cost is not determined because the MOS increase quantity is greater than the MOS decrease quantity.

Deviation prices

Deviation prices, long deviation price and short deviation price, are calculated for each hub and gas day.

In this example, no administered market states are invoked and no contingency gas prices are set.

Referring to Table 38, the short (negative) deviation price is 8.00 $/GJ which is the maximum of the ex ante market price, the ex post imbalance price and the MOS increase cost.

Referring to Table 38, the long/positive deviation price is 7.00 $/GJ which is the minimum of the ex ante market price and the ex post imbalance price.

Table 38 Deviation prices

Ex ante market price	Ex post Imbalance price	MOS increase cost	MOS decrease cost	High contingency gas price	Low contingency gas price	Max deviation price (MPC+ MCAP)	Min deviation price (MMP- MCAP)
7.00 $/GJ	8.00 $/GJ	8.00 $/GJ				450.00 $/GJ	-50.00 $/GJ

Deviation charges and payments

Deviation charges and payments are calculated separately for each trading participant role, on each facility, for positive and negative deviations, and in each direction. All trading right quantities for the same participant, on the same facility, in the same direction are summed, and MSV and CG quantities are applied to these totals.

Deviation payments and charges for trading participant Q are detailed in the following tables. Participant Q has a positive deviation of 5,000 GJ as a shipper supplying to the hub (see Table 39) on pipeline 2 and a negative deviation of –1,789 GJ as a user (see Table 39).

Deviation charges and payments are calculated by multiplying deviation quantity by deviation price.

Positive deviation as a shipper supplying to the hub

Deviation payment for shipper Q is $35,000 (= 5,000 GJ x 7.00 $/GJ).

Negative deviation as a user

Deviation charge for shipper Q is $14,312 (= -1,789 GJ x -1 x 8.00 $/GJ).

Table 39 Deviation quantities, charges, and payments

Participant	Facility	Flow Drn	Modified market schedule GJ	Allocated quantity GJ	Deviation GJ	Deviation charge $	Deviation payment $
P	Distribution	From	80,000	79,337	663	0	4,641
P	Pipeline 1	From	0	0	0	0	0
P	Pipeline 1	To	48,000	48,000	0	0	0
P	Pipeline 2	From	0	0	0	0	0
P	Pipeline 2	To	40,000	40,000	0	0	0
Total P						0	4,641
Q	Distribution	From	45,000	46,789	-1,789	14,312	0
Q	Pipeline 1	From	0	0	0	0	0
Q	Pipeline 1	To	10,000	10,000	0	0	0
Q	Pipeline 2	From	0	0	0	0	0
Q	Pipeline 2	To	30,000	35,000	5,000	0	35,0000
Total Q						14,312	35,0000
R	Distribution	From	50,000	51,874	-1,874	14,992	0
R	Pipeline 1	From	0	0	0	0	0
R	Pipeline 1	To	35,000	35,000	0	0	0
R	Pipeline 2	From	0	0	0	0	0
R	Pipeline 2	To	30,000	25,000	-5,000	40,0000	0
Total R						54,992	0
Total						69,304	39.641

Total net cost of deviations is a surplus of $29,663 (= $69,304 – $ 39,641).

Surplus and shortfall

Table 40 Charges and payments allocated to the surplus and shortfall

Component	Cost $
Variation charges (surplus)	490
Subtotal	490
Net deviation cost (surplus)	29,663
MOS service cost (shortfall)	-6,000
MOS commodity cost (shortfall)	-18,000
Subtotal	5,663
Total	6,153

The total of deviation charges, deviations payments, MOS service charges, and MOS commodity costs comes to $5,663. The settlement surplus is allocated to participants based on their absolute total of deviations. This is capped by the settlement surplus cap, which is set at 0.14 $/GJ (cap is only applied to surplus). The total deviation quantity is 14,326 GJ, hence the maximum surplus that can be distributed by deviations is (14,326 GJ x 0.14 $/GJ) $2,005.64.

Table 41 Distribution of surplus by deviations

Participant	Deviations GJ		Distributed by deviations $	Rate $/GJ
P	663	4.6%	92	0.14
Q	6,789	47.4%	951	0.14
R	6,874	48.0%	963	0.14
Total	14,326	100.0%	2,006	

The residual $3,657 and added to the total variations charges, which gives the amount to be distributed by withdrawals of $4,147.36.

Table 42 Distribution of residual surplus and variation charges by withdrawals

Participant	Withdrawals GJ		Distributed by withdrawals $
P	94,337	48.9%	2,028
Q	46,789	24.2%	1,003
R	51,874	26.9%	1,116
Total	193,000	100.0%	4,147

Table 43 Settlement surplus payments

Participant	Distributed by deviations $	Distributed by withdrawals $	Surplus payment
P	92	2,028	2,120
Q	951	1,003	1,954
R	963	1,116	2,079
Total	2,006	4,147	6,153

Net settlement

The net of all charges and payments for each participant excluding market fees is shown in Table 44. Note that the net of all payments and charges for the entire market (excluding market fees) is zero. A negative amount indicates it is paid to the participant.

Table 44 Net settlement

Settlement component		P	Q	R	Net total
Ex ante market	MktC – MktP	70,000	35,000	-105,000	0
Pipeline flow direction	PFDCC – PFDCP	0	0	0	0
Variations	VarC	0	490	0	490
MOS	MosC – MosP	-24,000	0	0	-24,000
Capacity	SCC – SCP	0	-15,000	15,000	0
Deviations	DevC – DevP	-4,641	-20,688	54,992	29,663
Contingency gas	CGC – CGP	0	0	0	0
Surplus	SSC – SSP	-2,120	-1,954	-2,073	-6,153
0	AHC – AHP	0	0	0	0
Net	NPSA	39,239	-2,152	-37,081	0