Independent Market Operator

Wholesale Electricity Market Design Summary

September 2006

This document provides only a summary of the content of the Wholesale Electricity Market Rules.

No person or organisation should act on the basis of any matter contained in this report without considering the Wholesale Electricity Market Rules. For the Market Rules that are currently in force under the *Electricity Industry (Wholesale Electricity Market) Regulations 2004*, please refer to the Wholesale Electricity Market Rules (and any subsequent amendments) gazetted in the Western Australia Government Gazette.

The Independent Market Operator disclaims any responsibility for any liability arising from any act done or omission made in reliance on this report.

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1. Introduction

A Wholesale Electricity Market is being established for the South West Interconnected System of Western Australia. This market will facilitate greater competition and private investment by allowing wholesale purchasers of electricity, such as retailers, greater flexibility as to how, and from whom, they procure electricity. This market also includes a mechanism for ensuring that adequate generation and demand-side management capacity is available to satisfy the ever-changing demand for electricity.

This document is a summary of the market design represented by the Wholesale Electricity Market Rules. This design became fully operational in September 2006. The Reserve Capacity procurement process began in late 2004.

The objective of this document is to provide a high level description of the market sufficient to convey how the market operates without requiring the reader to work through the Market Rules themselves. However, this document should not be considered to be definitive, as only the Market Rules can provide a complete description of the market.

This report is structured as follows:

- Section 2 provides an introduction to the basic features of the market to set the context for subsequent sections.
- Section 3 provides a description of the market governance regime.
- Section 4 presents a description of the administration of the market.
- Section 5 describes the various classes or market participation as well as facility registration.
- Section 6 covers power system security and reliability issues, including outage planning.
- Section 7 describes the capacity mechanism.
- Section 8 presents a discussion of a process for procuring generation to avoid the need for transmission upgrades. This is called Network Control Service.
- Section 9 covers the energy market.
- Section 10 describes the dispatch process.
- Section 11 provides a short description of metering issues.
- Section 12 describes the settlement process.
- Appendix 1 provides additional detail on the representation of Intermittent Loads, including how meter data is allocated between the Intermittent Load, any unmetered Non-Dispatchable Load at the same site, and any surplus generation that is registered.
- Appendix 2 provides a summary of the various processes in the market, and indicates who administers and participates in each process.

2. A Brief Overview of the Market

2.1 The Market Entities

The market comprises the following entities.

- **The IMO**: The IMO is the Market Operator and Market Administrator. It also conducts long term (10 year) generation adequacy planning, amongst other things, to support the Reserve Capacity Mechanism.
- **System Management**: System Management is the "System Operator". It conducts short and medium term (up to three years) system planning, including outage planning. It schedules Electricity Generation Corporation resources, while respecting Independent Power Producer (IPP) transactions. In real-time it dispatches the power system, and can only change IPP schedules under special circumstances.
- **Network Operator**: This is a party that operates, or intends to operate, a transmission or distribution network within the SWIS and is required to be registered. Network Operators can also be Metering Data Agents - the parties that provide meter data to the IMO. The Electricity Networks Corporation is the default Metering Data Agent if another Network Operator does not fill this function.
- **Market Generator**: This is a party that operates a generating facility that must be registered if it is to provide energy to the market. Subject to some exemptions in the rules, it is expected that all generating facilities above 10 MW will register, with most smaller generators having the option to register. Market Generators are either the Electricity Generation Corporation or Independent Power Producers (IPPs).
- **Market Customer**: This is a retailer or any other party purchasing power from the market for the purpose of consumption or retail sale. The Electricity Retail Corporation is the Market Customer that supplies non-contestable retail customers and is the supplier of last resort to the retail market.
- **The Electricity Networks Corporation (Western Power)**[1]: This is a Network Operator. A ring-fenced business unit of the Electricity Networks Corporation will fill the role of System Management.
- **The Electricity Retail Corporation (Synergy)**: The Electricity Retail Corporation is the former retail business unit of Western Power and will be registered as a Market Customer. In most cases, the rules apply to the Electricity Retail Corporation as they would for any other Market Customer. The main exception is that it is the only retailer allowed to serve customers that do not have interval meters, requiring a different treatment of the load of these customers in settlement.

[1] The names "Electricity Network Corporation", "Electricity Retail Corporation" and "Electricity Generation Corporation" are defined in legislation and are the terms used in the Market Rules. The trading names for these entities are, respectively, "Western Power", "Synergy" and "Verve Energy".

- **The Electricity Generation Corporation (Verve Energy)**: The Electricity Generation Corporation is the former generation business unit of Western Power and will be registered as a Market Generator.[2] In most cases, the rules apply to the Electricity Generation Corporation as they would for any other Market Generator. The main exceptions are that:
  - Its facilities follow a different scheduling process;
  - It is required to make its capacity available to System Management to provide ancillary services; and
  - It must balance the entire system in real-time (to the extent it is able).

All these entities must be registered as Rule Participants. This is automatic for System Management and the IMO. Becoming a Rule Participant requires an entity to comply with the Market Rules. Rule Participants that trade in the Reserve Capacity or energy market are automatically Market Participants. A single Rule Participant may be registered in more than one participant class. Appendix 2 provides more information on the different functions of these and other entities.

2.2 The Trading Mechanisms

The market supports the following trading mechanisms:

- **Reserve Capacity**: The primary role of the Reserve Capacity Mechanism is to ensure that there is adequate generation and Demand Side Management (DSM) capacity available each year to meet system peak demand plus a reserve margin. Each Market Customer is required to hold "Capacity Credits" to cover their share of the total System Requirement. The IMO will assign Capacity Credits to suppliers of registered capacity, where the suppliers have the choice of trading Capacity Credits bilaterally with Market Customers, or offering them to the IMO in an auction.

  The Capacity Credits the IMO procures at auction will be used to cover the remaining requirements of Market Customers. Suppliers issued with Capacity Credits will, amongst other requirements, be obliged to make that capacity available to the market and to participate in centralised outage planning. Market Customers who do not procure sufficient Capacity Credits bilaterally will be required to fund capacity procured by the IMO. If an over-capacity situation were to arise, then the cost of the excess capacity will be shared across all Market Customers, irrespective of whether they hold bilaterally traded Capacity Credits or not.[3]

- **Bilateral Contracts**. Bilateral trades of energy and capacity occur between Market Participants and the IMO has no interest in how these trades are formed. However, Market Participants are required to submit bilateral schedule data pertaining to bilateral energy transactions to the IMO each day so that the transactions can be scheduled.

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[2] The Electricity Generation Corporation has been given ministerial approval to act as the Market Participant for a number of small loads. Consequently it may also need to register as a Market Customer but only to the extent required to serve these specific small loads.

[3] A number of special cases exist whereby a facility may obtain Capacity Credits through a different process, or can have its capacity offset against the capacity requirements of a Market Customer without actually holding Capacity Credits (see sections 7.10, 7.11 and 7.12).

- **The Short Term Energy Market (STEM)**. The STEM is a daily forward market for energy that allows Market Participants to trade around their bilateral energy position, producing a net contract position.

  Each day, the IMO collects half hour Bilateral Schedule data from Market Generators describing bilateral energy trades between producers and consumers. The IMO calculates each Market Participant's net bilateral position from this data. Each day Market Participants provide the IMO with supply and demand curves for each half hour of the Trading Day. The IMO uses the net bilateral positions and these supply and demand curves to define each Market Participant's STEM offers and STEM bids relative to its net bilateral position for each Trading Interval. A STEM Offer is an offer to increase the net supply of energy beyond the net bilateral position, while a STEM Bid is a bid to decrease the net supply of energy relative to that position. A STEM auction will be run for each Trading Interval of the next trading day, determining a STEM clearing price and clearing quantities. The combined net bilateral position and STEM position of a Market Participant describes its net contract position.

- **Dispatch/Balancing Process**. Market Participants (other than the Electricity Generation Corporation) with registered generators or dispatchable loads will be required to provide schedules called Resource Plans to the IMO that cover their net contract position. These schedules include the output of each generator and dispatchable load in each Trading Interval and the Market Participant's own load to be supplied from those facilities such that the net energy supplied matches the net contract position. Market Participants submitting resource plans must also specify pay-as-bid balancing prices to be used as the basis for compensation if asked by System Management to deviate from their Resource Plans. System Management will schedule Electricity Generation Corporation resources around those schedules, but it may issue dispatch instructions to other Market Generators and to curtailable or dispatchable loads if it cannot otherwise maintain security and reliability, or if it would have to use Electricity Generation Corporation liquid fuelled plant when non-liquid fuel capacity was still available. After the Trading Day, the IMO will determine "administrative" balancing prices to apply for unscheduled deviations from schedules, with those non-Electricity Generation Corporation facilities given Dispatch Instructions being settled (to the extent they obey) at their pay-as-bid balancing prices.

2.3 Ancillary Services

Ancillary Services are services required to support the energy market but which are not traded as part of the energy market. System Management are required to procure adequate quantities of these services, either from Electricity Generation Corporation resources (the default option) or on a contestable basis from independent providers. The requirements for each ancillary service will be proposed by System Management, but must be approved by the IMO.

2.4 Network Control Service

A Network Control Service could be thought of as an ancillary service, but is treated separately under the Rules. If a Network Operator identifies an opportunity for the placement of a generator or demand-side management option in an isolated location to mitigate the need for new transmission or distribution investment, then it must request the IMO to run a tender for such service. The IMO will run

a tender in which a transmission proposal competes against generation and demand-side options. If the winning option is something other than a transmission proposal, then the IMO will contract that capacity. The cost of funding the contract will be borne by the Network Operator. Note that the contracts are in the form of guaranteed minimum revenues for capacity and the required contract payments by the Network Operator are off-set by other revenue earned for Reserve Capacity. Energy payments to providers of a Network Control Service will be no different than for other facilities, except that the pay-as-bid prices to be used in balancing would be specified in the Network Control Service contract.

2.5 Prudential Obligations

Market Participants will have to meet prudential conditions for participating in the market. A Market Participant will have to maintain credit support to cover the IMO's estimate of the maximum amount that participant is likely to owe the IMO during any 70 day period within 48 months, allowing for expected levels of bilateral contract coverage.

If at any time a Market Participant has inadequate credit support a Margin Call will be made by the IMO, and the participant will be required to very quickly provide further credit support, potentially in the form of a cash deposit. Failure to do so may result in the Market Participant being declared to be in default. It should be noted that while the Market Rules give the IMO the power to impose extremely firm measures, this does not preclude it from informally notifying a party of problems much earlier than required by the rules so as to avoid a Margin Call being required. Use of this approach has meant that no one has been declared to be in default in the eastern states National Electricity Market.

Network Operators are not trading in the energy market, and consequently their credit support is simply security against non-payment.

2.6 The Types of Facilities

The following types of facilities can be registered in the market:

- **Scheduled Generators:** These are generators capable of being scheduled to operate at a specified level ahead of real-time, and can be dispatched by System Management up or down in real-time relative to that level. Most large generating plant falls into this category.
- **Dispatchable Loads:** A dispatchable load is a load that can be scheduled to operate at a specified level ahead of real-time, and can be dispatched by System Management up or down relative to a given load level. In effect, a dispatchable load is a load that can conform to dispatch instructions in the same manner that Scheduled Generators are required to conform to dispatch instructions. While no such load current exists, this feature is included for generality.
- **Non-Scheduled Generators**: These are generators that either cannot be scheduled to operate at a specified level ahead of real-time, e.g. a wind farm or solar generator, or are sufficiently small to not generally require central coordination by System Management. These generators can be self-scheduled by their operator, but if ever required, System Management can request them to reduce output, in which event they will be settled based on a pay-as-bid price.

- **Curtailable Loads**: A curtailable load can be interrupted on request. This demand side management option will generally be contracted, but a Market Participant can also use curtailable loads to manage its exposure to market prices. When System Management requires the curtailment of such a load in the dispatch process, a pay-as-bid price will apply to the amount of load curtailed (though Capacity Credit payments are likely to be the primary form of compensation).
- **Interruptible Loads**: An interruptible load is load that trips automatically in response to a frequency change. An Ancillary Service Contract will generally fund this demand-side-management option. Being triggered automatically and typically for short periods, there are no pay-as-bid prices associated with Interruptible Loads. They are paid in accordance with Ancillary Service contracts with System Management.

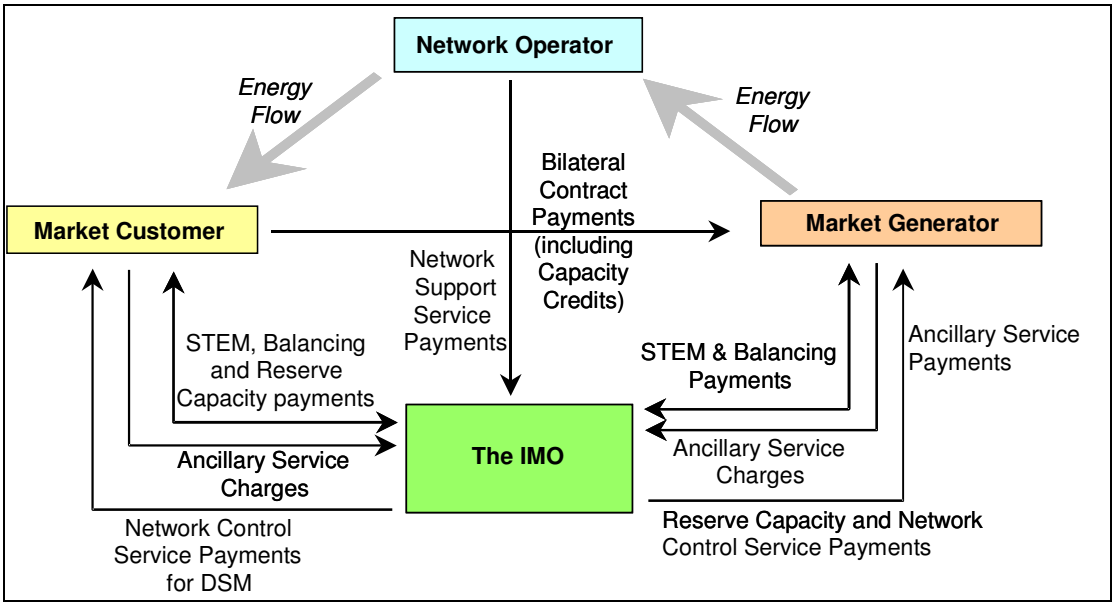
Meter data and other details are recorded for the following types of load, but these are not treated as "facilities" under the Market Rules:

- **Non-Dispatchable-Loads**: This is load that cannot be dispatched up or down by System Management (other than to not supply the load at all). Almost all load on the SWIS falls into this category.
- **Intermittent Load**: This is a load that is normally fully supplied by a generator at the same site as the load without requiring any power to be supplied from a Network registered with the IMO. In effect, it is load normally served by embedded generation. An Intermittent Load only requires power from the network when its embedded generator is not fully operational, and consequently its exposure to funding Reserve Capacity is reduced. A Curtailable Load, Interruptible Load or Non-Dispatchable Load can simultaneously be an Intermittent Load if it satisfies the required registration conditions. Under special circumstances the generator serving an Intermittent Load can be at a different location (see section 7.10)

2.7 Market Settlement

The IMO is the party with which Market Participants settle Wholesale Market transactions other than the bilateral trade of energy and capacity, with Market Participants buying energy or capacity from, or selling energy or capacity to, the IMO. The IMO will be responsible for performing settlement calculations and for invoicing and settling with Rule Participants. Exhibit 2-1 provides a simple view of the major settlement cash flows.

Exhibit 2-1. An illustration of the settlement cash flows



Most energy is traded outside the IMO administered market via bilateral contracts between Market Customers and Market Generators. These bilateral contracts can have energy and capacity components. By trading energy bilaterally Market Customers and Market Generators can reduce their exposure to the IMO administered energy market settlement processes. Where capacity is traded bilaterally the IMO reduces the market capacity charges for the relevant Market Customer and reduces the market capacity payments to the associated Market Generator.

Market Customers and Market Generators can modify their bilateral energy position through trading in the STEM. Buying or selling energy via the Balancing process is the last resort in the circumstances where actual energy supplied or consumed differs from that contracted in the day-ahead mechanisms.

While System Management is required to secure ancillary services, the costs of these services are passed on to those participating in the market.

Settlement of the STEM will occur on a weekly basis, while other transactions are settled monthly. It may take up to 30 days after the end of a month to receive all interval meter data for a month, so settlement for a trading day at the start of a month will not occur until about 70 days after that trading day. Settlement adjustments will be made at 3-month intervals (or more frequently) for up to a year, allowing for resolutions of disagreements and improved meter data.

Where there is a default in payment to the IMO and credit support is inadequate to cover it, the IMO may temporarily reduce payments in market settlement to reflect the shortfall. If the amount is not resolved quickly then the outstanding amount will be recovered by a default levy. Default is expected to be a very rare event.

3. Market Governance Bodies

3.1 The Independent Market Operator (IMO)

The Independent Market Operator, or IMO, has the following functions:

- Maintaining and developing the Market Rules.
- Maintaining and developing market procedures relating to market operation and market administration.
- Approving procedures for system operation developed by System Management.
- Registering Rule Participants and their facilities.
- Assessing generation and DSM capacity adequacy over the long term.
- Operating a Reserve Capacity mechanism.
- Administering tenders and entering contracts for Network Control Service, whereby generation or DSM capacity can negate the need for transmission capacity expansion.
- Collecting Bilateral Contract Submissions.
- Operating a Short Term Energy Market.
- Collecting Resource Plans from Market Participants that are required to submit these and forwarding them to System Management.
- Collecting pay-as-bid balancing price data from Market Participants that are required to submit these, forming dispatch merit orders based on these and forwarding the dispatch merit orders to System Management.
- Conducting market settlement.
- Monitoring Rule Participants for Rule breaches, imposing penalties for Market Rule breaches categorised as less serious, and reporting more serious breaches to the Energy Review Board.
- Commissioning audits of the IMO's and System Management's activities under the Market Rules. This relates especially to System Management's performance of the dispatch and security and reliability related processes.
- Reviewing and potentially reassessing certain decisions by System Management.
- Supporting the Economic Regulation Authority in its roles of market surveillance and monitoring market effectiveness.
- Publishing market information.

The board of the IMO consists of three independent persons who are appointed by, and report to, the Minister for Energy. The Minister has the power to give policy directions to the IMO in respect of the operation of the market. The directions would not impact on the day-to-day operations of the IMO, but would be taken into account by the IMO in its consideration of whether changes to the Market Rules

were necessary. Any directions given by the Minister are required to be transparent and to be consistent with the market objectives.

3.2 System Management

System Management is a ring-fenced entity within the Electricity Networks Corporation, and has the following functions:

- Operating the power system to maintain security and reliability.
- Developing operational procedures for the power system.
- Setting requirements for and planning emergency load reduction and system restart.
- Determining ancillary service requirements.
- Assessing system adequacy and security over short and medium term time frames.
- Coordinating planned outages for maintenance.
- Coordinating and, where applicable, conducting tests of equipment.
- Coordinating the operation of Electricity Generation Corporation facilities and issuing Dispatch Instructions to IPP generators and Market Customers with dispatchable or curtailable load.
- Monitoring Rule Participants for rule breaches relating to dispatch and power system security and reliability, and reporting its findings to the IMO.
- Providing information on power system security and reliability to the IMO.
- Providing data required for settlement to the IMO.

The Market Rules are the primary mechanism setting out the obligations of System Management. While Technical Codes, developed under the Access Regime, place limits on how the power system should be operated, the Market Rules set out System Management's specific obligations.

3.3 The Market Advisory Committee

The Market Advisory Committee is an industry group made up of Rule Participant and consumer representatives and convened by the IMO. It has the function of advising the IMO on issues pertaining to proposed market rule and procedure changes and general market operation issues. The Market Advisory Committee consists of between 11 and 12 members appointed by the IMO from nominated representatives of generators, retailers, network operators and consumers. The Minister and the Economic Regulation Authority may both appoint representatives to attend meetings of the Market Advisory Committee as observers. Where an issue to be addressed by the Market Advisory Committee is highly technical or specialised, the Market Advisory Committee may decide to form a working group of Rule Participant representatives to investigate and report back on the issue.

3.4 The Energy Review Board

The Energy Review Board (currently the Gas Review Board) is the primary appeals body, having the functions of:

- Imposing penalties for more serious categories of breaches of the Market Rules.
- Hearing appeals against IMO's decisions pertaining to rule breaches.
- Hearing claims from Rule Participants that the IMO has breached the Market Rules.
- Hearing appeals against reviewable decisions by the IMO.
- At the behest of a Rule Participant, conducting a procedural review as to whether the IMO has correctly followed the rules pertaining to rule changes, and where appropriate over-turning rule change decisions by the IMO if the IMO has failed to follow the correct process.

3.5 The Economic Regulation Authority

The Market Rules also specify certain roles for the Economic Regulation Authority, which include:

- Approving maximum prices for the reserve capacity mechanism, maximum and minimum energy prices, and the maximum compensation to be paid in respect of generator decommitment required by System Management.
- Approving efficient costs for the operation of the IMO and System Management.
- Market surveillance, including working with the IMO and reporting the outcomes to the Government.
- Monitoring and reporting to the Government on the efficiency and effectiveness of the market.

Although the Electricity Generation Corporation is expected to be the primary focus of market power monitoring, it is possible for other participants to have market power at particular times (e.g. high demand) or under particular network conditions (e.g. within a constrained region).

4. Market Administration

4.1 Market Rules

4.1.1 The IMO and Conflicts of Interest

The IMO maintains and develops the Market Rules. The IMO is an independent body charged with achieving the market objectives including through modification of the Market Rules. However, it is recognised that in some areas there are potential conflicts of interest in the IMO having administrative control of the rules that also govern its own practices and behaviour. The Market Rules include a number of features to address these issues.

Any rules that relate to issues where the IMO would face a possible conflict of interest were it to attempt to modify the rules have been identified as “protected provisions”. The IMO is not be able to change those provisions without the Minister’s approval of the amendment.

Any decision made by the IMO to amend a market rule can be appealed to the Energy Review Board on procedural grounds. The Energy Review Board is only be able to overturn a rule change if the IMO has not followed the correct market rule change process.

The IMO has an independent board to which the Minister is able to issue policy directions concerning the broad development of the market. The Minister is not able to directly influence the operation of the market or the development of rule changes, and policy directions must be consistent with the market objectives. The Minister can also direct the IMO on administrative matters.

4.1.2 The Rule Change Process

There are no limits as to who can propose a rule change. Such proposals will need to be made to the IMO in a prescribed form, along with reasons as to why the proponent thinks the rule change is desirable.

Upon receiving a rule change proposal, the IMO must decide whether it considers that the proposed change warrants further investigation. The IMO must assess requests for rule changes against the market objectives and practical considerations. The only appeal option will be to the Energy Review Board, and then only in the case of process breaches by the IMO. That is, it will not be possible to dispute the merit of the rule change. This restriction is necessary to stop so called “forum shopping” whereby parties repeatedly take the same issue to different forums.

A rule change may include an explicit wording change to the rules, or could be a more general identification of an issue with a general proposal as to how it could be addressed. In processing a rule change proposal, the IMO will develop a draft rule amendment and will consult with Rule Participants on the need and form of the rule amendment.

There is a fast track rule change process for urgent rule changes or rule changes to correct manifest errors or to address minor issues. Under the fast track process the IMO only does one round of consultation, and this process is intended to be completed within six weeks.

The normal rule change process includes two rounds of consultation, with the second round allowing consultation on a draft report published by the IMO prior to the finalisation of the report, and will usually take around 19 weeks. In consulting on a rule change proposal, the IMO may convene the Market Advisory Committee (and in certain situations must convene it), meet with interested parties, procure technical advisers, or establish a technical working group drawing on industry representatives if this is considered necessary to appropriately develop or evaluate changes.

The IMO Board will make a final decision on a rule amendment and if the rule change relates to a protected provision seek the Minister's approval. The decision of the Minister is not subject to appeal. The IMO's decision and its reasons will be published on the market website, together with a time and date when accepted rule changes will come into force. Rule changes must be published in the Government Gazette before becoming active.

4.1.3 Rule Changes Prior to Market Commencement

During the period between the initial rules being made by the Minister and energy market commencement, the IMO does not have responsibility for maintaining the Market Rules. During this interim period the Minister retains control over the Market Rules and will make any necessary rule changes. An industry consultation process similar to that used to develop the initial Market Rules will continue, with the rule changes put to the Minister reflecting a position agreed in consultation with the industry.

The ability to change the rules during this period is required to address issues arising during the course of implementing the market and the market IT systems.

4.2 Procedures

The IMO develops and changes procedures that relate to market operation and administrative market matters, while System Management develops operational procedures pertaining to short and medium system planning, security and reliability, and dispatch. However, the IMO is responsible for approving all procedures.

Procedures will have more procedural detail than the Market Rules and are expected to be subject to relatively frequent refinements and updates.

Both the IMO and System Management are subject to the same process for developing new procedures or making changes to existing procedures. Once either the IMO or System Management proposes a change, the IMO publishes a procedure change proposal, requests submissions from the public, and may convene the Market Advisory Committee. The issues addressed in the Procedures could be quite technical and specialised, so the Market Advisory Committee may decide to nominate a Working Group to study an issue. Where the change relates to the IMO's procedures, the IMO prepares a report on the Procedure Change Proposal which includes the amended wording, feedback received on the change, together with a time and date for the new Procedure to come into force. Where the change relates to System Management's procedures, System Management prepares the report, and must gain the IMO's approval for the procedure change.

The initial procedures to be used in the market are being developed under a transitional process during the implementation of the market. The full procedure change process will only commence after the energy market has commenced.

4.3 Market Parameters

The market makes use of a number of parameters, the values of which may materially change the cost and benefits of participating in the market for some Market Participants.

The IMO sets and maintains the following price caps based on principles established in the Market Rules:

- The Maximum Reserve Capacity Price (a minimum of 0 is assumed).
- The Maximum STEM Price.
- The Minimum STEM Price.
- The Alternative Maximum STEM Price, which exceeds the Maximum STEM Price and which will apply for offers pertaining to more expensive fuels, such as diesel.
- The Maximum Shut Down Price, which defines the maximum compensation to be paid to a Market Participant if System Management requests an unscheduled shut down of the facility.

These prices define the limits that participants can bid and offer as well as the most extreme market clearing prices that can occur. The Alternative Maximum STEM Price is updated monthly based on changes in oil prices, and annually for inflation, The Maximum STEM Price and the Minimum STEM Price are adjusted for inflation on an annual basis. The IMO reviews all the price caps annually and, if, after consultation with the industry, it believes changes beyond the automatic changes are required, it submits proposed new values to the Economic Regulation Authority for approval. The Economic Regulation Authority will approve these limits based on whether or not the IMO has set values in a manner consistent with requirements specified in the Market Rules.

The market price limits for market commencement are:

- Maximum Reserve Capacity Price = $122,500/MW.
- Maximum STEM Price = $153.73/MWh.
- Minimum STEM Price = –$153.73/MWh.
- Alternative Maximum STEM Price = $480/MWh.
- Maximum Shut Down Price = $56.37/MW.

Network Operators are required by the Market Rules to determine for each connection point in their network annual static loss factors reflecting average marginal losses. The IMO may audit this calculation process if a participant believes that a loss factor is incorrect.

4.4 Enforcement of the Market Rules

The classes of offences under the Regulations for breaches of the Market Rules are:

- Category A for less serious offences, such as failure to provide information when required to provide that information.
- Categories B and C for more serious rule breaches, such as those involving system security or payments.

The IMO will monitor the compliance of Rule Participants with the Market Rules and Procedures. System Management will monitor the performance of Market Participants and Network Operators in the dispatch process and in relation to short and medium term system security and reliability, and will report outcomes to the IMO. Rule Participants will also be able to report alleged rule breaches by System Management to the IMO, and alleged rule breaches by the IMO to the Energy Review Board. The latter will be done through an independent person nominated by the Minister.

When the IMO becomes aware of a rule breach by a Rule Participant, it must log the breach, warn the relevant Rule Participant that it appears to be breaching the Market Rules or Procedures, and investigate whether a breach has occurred.

For Category A breaches, the IMO will decide whether to impose any penalty but any decision can be appealed to the Energy Review Board. The IMO will investigate and report Category B and C breaches to the Energy Review Board. The Energy Review Board will decide whether a rule breach has occurred and whether to impose any penalty. Any such decision can only be appealed to the Courts on questions of law. Any penalties for breach of the Market Rules will have maximum values set in the Regulations.

4.5 Reviewable Decisions and Disputes

In the Market Rules some decisions of the IMO are designated as reviewable decisions. The reviewable decision process applies to certain areas in the rules where the IMO has some discretion in decisions that have a significant effect on Rule Participants. Some of these decisions are subject to a merits review, others – to a procedural review. If a Rule Participant wants to appeal a reviewable decision, they can apply to the Energy Review Board to have the decision reviewed. Any determination reached by the Energy Review Board will not be subject to appeal, except to the Courts on questions of law.

The dispute resolution process covers disputes between Rule Participants, but does not apply to reviewable decisions under the Market Rules. The dispute resolution process sets out two stages to be followed. Under the first stage the Rule Participants attempt to resolve disputes between themselves. A Rule Participant may send a dispute notice to another Rule Participant (which may include the IMO or System Management), and the parties to the dispute should make reasonable endeavours to meet on one or more occasions, as necessary. If they fail to resolve a dispute between themselves within 60 days, then the dispute must move to the second stage and the parties to the dispute must give consideration to using independent mediation and/or arbitration to resolve the dispute. Finally the parties may resort to litigation or other court processes.

4.6 Budgets and Fees

In the initial stages of the establishment and operation of the market the Government has determined the budget of the IMO. Once the transitional period is over, the Economic Regulation Authority will periodically determine the efficient costs of the IMO and System Management. These efficient costs effectively represent a long run view of what it will cost to run the IMO and System Management. Every year the IMO will submit a budget to the Minister, which must conform to the efficient costs set by the Economic Regulation Authority. System Management's budget, which must also conform to the efficient costs set by the Economic Regulation Authority, will be developed through a budgeting process with ministerial oversight. The IMO will provide advice to the Minister on System Management's budget proposal.

The IMO will recover its budget, System Management's costs and that portion of the Economic Regulation Authority's budget relating to its wholesale electricity market activities through a per MWh fee applied to generation and consumption in the SWIS.

5. Rule Participation

5.1 Rule Participant Classes

Anyone subject to the Market Rules is a Rule Participant. Since different rules relate to different types of participants, a number of Rule Participant classes are defined, as shown in Exhibit 5-1. A Rule Participant can belong to more than one class, except where this is explicitly restricted.

Exhibit 5-1. Rule Participant classes

Person	Registration Requirements.
Owns, controls or operates a Transmission or Distribution Network in the SWIS.	Must register as a Network Operator, except in the following situations (in which case registrations is optional): • The person is exempted because System Management does not require information about the facility, or • No Market Participant facilities are connected to it, or • The IMO has exempted the person from the requirement to register. A person who intends to own control or operate a network may also register.
Owns, controls or operates a generating facility with a rated capacity of greater than 10 MW that is connected to a network in the SWIS.	Must register as a Market Generator unless the IMO has exempted the person from the requirement to register (in which case registrations is optional): A person who intends to own control or operate such a generator may also register.
Owns, controls or operates a generating facility, with a rated capacity of less than or equal to 10 MW, but greater than 0.005 MW, which is connected to a network in the SWIS.	The person has the option to register as a Market Generator but this is not compulsory.[4] A person who intends to own control or operate such a generator may also register.
Sells or intends to sell electricity to customers in the SWIS.	Must register as a Market Customer unless the IMO has exempted the person from the requirement to register (in which case registration is optional): A person who intends to sell electricity to consumers may also register.
Any other person who sells or purchases electricity or another service contemplated by the Market Rules to or from the IMO.	Registration as either a Market Generator or Market Customer, as determined by the IMO, is compulsory, unless the IMO has exempted the person from the requirement to register (in which case registration is optional):
System Management	Automatically registered as System Management.
IMO	Automatically registered as the IMO.

[4] If such a person also has a generating facility with capacity over 10 MWh then registration is compulsory.

The rules place the obligation to register on owners, operators and controllers of facilities. If more than one person is involved, and if those people reach an agreement as to which of them will accept the obligations under the rules, then the intention is that the IMO can exempt the others from being Rule Participants under its exemption powers described in Exhibit 5-1.

It is also required that a Rule Participant must:

- Be resident in, or have a permanent establishment, in Australia.
- Not be an externally administered body corporate, or under a similar form of administration under any laws applicable to it in any jurisdiction.
- Not be immune from suit in respect of the obligations of the Rule Participant under these Market Rules.
- Be capable of being sued in its own name in a court in Australia.

A Rule Participant that participates in any aspect of the Reserve Capacity Mechanism, bilateral energy trade, the STEM, or the Dispatch/Balancing process is referred to as a Market Participant. A party that is both a Market Generator and a Market Customer is a single Market Participant.

With the exception of the IMO and System Management, it is necessary for parties wanting to become Rule Participants to apply to the IMO. In applying for Rule Participant status, a party must accept the obligation to comply with the relevant Market Rules.

5.2 Facility Registration and Deregistration

The types of facilities that can be registered are shown in Exhibit 5-2. All of these facilities must be connected to the SWIS. Facility registration will not be permitted if the applicant is not already approved to be a Rule Participant.

Exhibit 5-2. The types of facility that can be registered

Facility Type	Definition	Restrictions
Network	A transmission or distribution asset.	Cannot be any other type of facility.
Scheduled Generator	A generator that can meaningfully have its energy scheduled prior to real-time.	Must be registered if above 10 MW, but smaller generators over 0.2 MW in capacity may also register. This cannot be an intermittent generator. Cannot be any other type of facility

Facility Type	Definition	Restrictions
Non-Scheduled Generator	A generator that cannot meaningfully have its energy scheduled prior to real-time.	Must be below 10 MW or have intermittent output (e.g. wind generator). Must be above 0.005 MW in capacity. Cannot be any other type of facility
Dispatchable Load	A load that can meaningfully have its energy scheduled prior to real-time.	Must be above 0.2 MW in capacity. Cannot be any other type of facility.
Interruptible Load	A load, which while generally non-dispatchable, can be interrupted automatically under certain conditions.	Cannot be any other type of facility.
Curtailable Load	A load, which while generally non-dispatchable, can be curtailed on request under certain conditions.	Cannot be any other type of facility.

Non-dispatchable load will not be required to be registered[5], though Market Customers serving non-dispatchable load will need to register the locations at which they have load. A Curtailable Load, Interruptible Load or Non-Dispatchable Load can simultaneously be an Intermittent Load. An Intermittent Load is normally fully supplied by a generator at the same site as the load without requiring any power to be supplied from a Network registered with the IMO. In effect, it is load normally served by embedded generation. An Intermittent Load only requires power from the network when its embedded generator is not fully operational, and consequently its exposure to funding Reserve Capacity is reduced. Under special circumstances the generator serving an Intermittent Load can be at a different location (see section 7.10)

A specific facility, as registered in the market, may not correspond to a single physical generating unit. For example, a wind farm must be treated as a single facility, while a group of identical scheduled generating units at one location may be treated as a single facility. Market Participants may, at the time of registering a facility, and with the IMO's approval, aggregate facilities. The IMO would consult with System Management before approving aggregation of facilities.

When considering an application for an aggregated or disaggregated facility, the IMO will consider factors such as control and monitoring equipment, metering of separate components, outage scheduling requirements and any effects on power system reliability and security. For instance, the IMO might not allow two generating units at one location from aggregating because it needs one of those units to be explicitly schedulable for an ancillary service. Any registered aggregate facility will trade based on the net metered position of the aggregated facility, not on the separate generation and consumption of its components.

[5] Though in certain special circumstances they need to be recorded within the market systems, e.g. when associated with an Intermittent Load (see section 7.10).

The registration process for a facility involves providing information on the facility such that the IMO can determine whether the facility satisfies the criteria for being registered, and so that the IMO and System Management can adjust their databases to accommodate the facility.

A deregistration process exists where deregistration could mean the facility is closing or being transferred to another Rule Participant. A facility cannot be deregistered while providing Capacity Credits to the market though the facility, complete with its Capacity Credits, can be transferred to another Rule Participant.

5.3 Prudential Requirements

All Market Participants, and any Network Operators required to fund Network Control Service, are subject to prudential requirements as a fundamental requirement for participation in the market.

There will be two parameters associated with each Market Participant or Network Operator:

- **Credit Limit**: This limit is the maximum net amount that the Market Participant is likely to owe the IMO within the maximum two month period between being scheduled and being settled in the market, where this amount is not expected to be exceeded more than once in a 48 month period. In the case of a Network Operator, it should just reflect the maximum possible payment for any Network Control Services over that period.
- **Credit Support**: This is a guarantee of unconditional payment of a set level of funds to the IMO where the Guarantor of this payment cannot be a Rule Participant and must have a satisfactory credit rating.

Both Network Operators and Market Participants must generally[6] provide Credit Support to cover its Credit Limit. The details of prudential requirements for Market Participants are more complicated than for Network Operators. This is because the level of risk exposure for the IMO is a function of how much energy is traded by a Market Participant.

A Market Participant's Trading Limit is a prudential factor multiplied by its Credit Limit. The prudential factor is 0.84, which has been calculated by taking a ratio of the number of days before a margin call is issued to the maximum number of subsequent days before a participant would be suspended for non-payment. If the prudential factor were to equal one, then a margin call could only be made once a Market Participant's debt to the IMO reached its Credit Limit, after which the debt could continue to increase until the participant was suspended a number of days later.

If a Market Participant is getting close to its Trading Limit they may voluntarily pay a security deposit to the IMO as a guarantee against future payments. Thus, at any time, the outstanding amount that a Market Participant owes the IMO is the greater of:

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[6] Independent bodies subject to prudential supervision or central borrowing authorities of states or territories and with excellent credit ratings are allowed to be providers of financial guarantees, which can count as a Market Participant's Credit Support. If a Market Participant or Network Operator conforms to the requirements to be a provider of Credit Support then it is exempt from the need to provide Credit Support.

- Zero.
- The total net amount owed to the IMO by that Market Participant at that time less any security deposit, including amounts for which no settlement statement has yet been provided and which therefore could be an estimate.

The amount by which a Market Participant's trading limit exceeds the outstanding amount is the trading margin. If the trading margin drops to zero or below, then the IMO will issue a margin call notice to the Market Participant. The Market Participant will have 24 hours from the margin call notice being issued to either increase its security deposit or provide more credit support so that the trading margin returns to a positive value (i.e. the outstanding amount ceases to exceed the trading limit).

If need be, the IMO can draw down on a Market Participant's security deposit to settle a transaction entered into by that Market Participant.

In the event of actual settlement default, the IMO can claim a Market Participant's credit support to the extent required to cover the amount outstanding. If the problem is not remedied within five business days then the Market Participant may, at the discretion of the IMO, be fully or partially suspended from participation in the market (e.g. they may be allowed to continue activities such as the supply of energy which offsets their debts). If a Market Participant defaults on payment, such that the IMO has inadequate revenue to settle the market, then the IMO will raise a default levy from all Market Participants in accordance with the settlement rules so as to secure the funds required.

6. Power System Security and Reliability

6.1 Operating States and System Management Powers

System Management has the role of ensuring the maintenance of system security and reliability within the SWIS over the short and medium term. To achieve this, System Management must operate the power system within a technical envelope that accounts for the operating and ancillary services standards in the Market Rules and technical codes, as well as equipment and security limits provided by network operators and other participants.

The powers of System Management in operating the system are based around three operating states:

- A Normal Operating State, when the power system is in a secure and reliable state and operating within normal operating ranges. In a Normal Operating State, System Management must observe normal security standards and operating limits, while maintaining adequate ancillary services and adjusting the schedules of non-Electricity Generation Corporation generators, where necessary, based on a set merit order (to the extent allowed by network constraints).
- A High Risk Operating State exists when operating the power system in its normal operating range would expose the power system to a higher than normal probability of serious consequences in the event of a generator, transmission or other equipment failure. Some examples include a risk of interruption of gas supply, a bush fire threatening transmission lines, or a shortage of ancillary services. In a High Risk Operating State, System Management can take steps to increase the security of the power system, cancel planned outages and apply security limits appropriate to the High Risk Operating State.
- An Emergency Operating State exists when operating the power system in its normal operating range would require the involuntary curtailment of load. In an Emergency Operating State, System Management is able to cancel outages, direct Market Participants and Network Operators, and generally take whatever actions are necessary to restore the power system to a Normal Operating State.

System Management determines what operating state the power system is in, and must inform the market and the IMO of any changes in state via Dispatch Advisories described in section 10.4. System Management will provide reports to the IMO on incidents involving Emergency Operating States.

6.2 Ancillary Services

System Management proposes requirements for ancillary services, based upon standards set out in the Market Rules. The IMO will have the responsibility to approve these requirements. System Management will be required to provide ancillary services and its options for procuring them include:

- Making use of the Electricity Generation Corporation's resources.

- If the Electricity Generation Corporation lacks adequate resources, or they can be obtained at a lower cost, through contracting with third parties. Any contracting must be on a least cost basis and may involve a competitive tender.

System Management will budget the cost of procuring ancillary services, where budgeted costs must be in accordance with those approved by the Economic Regulation Authority. However, System Management will not fund Ancillary Services. Rather, the IMO will recover the costs of the ancillary services from Market Participants through the wholesale market settlement systems, and will use the revenue received to fund Ancillary Services provided by the Electricity Generation Corporation and contracted Ancillary Service providers. The details and costs of the services provided will be published on the market website.

The following ancillary services are defined in the Market Rules:

- **Load Following**. Load following is the primary mechanism in real-time to ensure that supply and demand are balanced. Load following accounts for the difference between scheduled energy and actual load and intermittent generation. Load following resources must have the ramping capability to pick up the load ramp between scheduling steps as well as maintain the system frequency. Load following may be provided by units operating under Automatic Generation Control (AGC), or through manual control.
- **Spinning Reserve**. This service holds capacity in reserve to respond rapidly should another unit experience a forced outage. The capacity would include on-line generation capacity, dispatchable loads and interruptible loads (i.e. loads that respond automatically to frequency drops).
- **Load Rejection Reserve**: This service requires that generators be maintained in a state in which they can rapidly decrease their output should a system fault result in the loss of load. This service is particularly important overnight when most generating units in the system are operating at minimum loading and have no capability to decrease their output in the time frame required.
- **Dispatch Support**. This service ensures voltage levels around the power system are maintained, and includes other services required to support the security and reliability of the power system that are not covered by other ancillary services.
- **System Restart**. This service allows parts of the power system to be re-energised by black start equipped generation capacity following a system wide black out. Unlike other generators, black start equipped generators can be started up without requiring a supply of energy from the transmission network.

In addition to managing these Ancillary Services, System Management must maintain adequate Ready Reserve. Ready Reserve is additional capacity, which may not be synchronised, that System Management can call on to provide energy in the 15 minute to four hour period following a contingency event. There is no additional payment for Ready Reserve as the cost of keeping the capacity available is funded via the Reserve Capacity Mechanism (see section 7).

There are special circumstances under which Ancillary Service and Ready Reserve Requirements may be relaxed, such as in emergency situations or where, in the case of Spinning Reserve or Ready Reserve, the reserve capacity is actually being activated to provide energy following a contingency event.

The IMO allocates the cost of ancillary services between Market Participants on the following basis:

- The monthly cost of load following will be allocated amongst Market Participants in proportion to their monthly contributing quantity, where this quantity comprises the sum of the Market Participant's metered load and metered Non-Scheduled Generation. Load following costs are not allocated to Scheduled Generation.
- The monthly costs of spinning reserve is borne by generators in proportion to the deemed risk that the generator imposes on the system, based on the output of the generator in each Trading Interval during the month.
- The monthly costs for Load Rejection Reserve, Dispatch Support and System Restart will be recovered from Market Customers in proportion to their monthly metered consumption.

6.3 Medium and Short Term Planning

6.3.1 Projected Assessment of System Adequacy (PASA)

The IMO has the duty to forecast generation adequacy over a period of 10 years and to ensure that sufficient Reserve Capacity is procured. System Management will plan capacity availability over the short and medium term.

The medium-term PASA process is an integrated assessment of system security and reliability over a rolling 36-month time horizon. The available level of generation and transmission capacity will be reported by week, with this data being updated monthly. The adequacy of this capacity will be assessed for high, medium, and low demand scenarios. This process is conducted in order to ensure that System Management, Market Participants and Network Operators are informed of projected conditions on the power system and to allow them to take appropriate actions. In particular, the information will help System Management to form a view of the power system conditions likely to apply at different times in the future, assisting it to schedule outages and plan the secure and reliable operation of the power system.

The short-term PASA is similar to the medium-term PASA, but considers a three-week horizon, with results reported for four 6-hour periods per day, and updated at least once each week, or more often if required. This finer resolution is required to support operational planning, such as determining how much ancillary service capability is required in a given part of a day and to facilitate final approval of outages.

Market Participants and Network Operators are required to provide information to System Management for each of the PASA horizons:

- Network Operators will provide information on changes to transmission capacities and ratings of equipment, proposed outage timings, access quantities at entry and exit points.
- Market Generators will update their available generating facility capacities and ancillary service capabilities, including adjustments reflecting outages or facility closure and other constraints on supply capability. Market Generators will also provide estimates of their expected energy output levels.
- Market Consumers will provide information on factors that will change the amount of energy they purchase.

The PASA results will be made available via the Market Web Site and will include:

- Load scenarios used in the PASA.
- Forecast total available generation capacity by six hour or weekly periods (as applicable).
- Information on the timing, size and duration of expected capacity shortfalls.
- Forecast transmission capacity between potentially constrained regions, under normal conditions and some contingency scenarios, and the likelihood of constraints.
- Details of planned commissioning tests.
- Possible security problems, including fuel supply problems, that could effect market or dispatch outcomes.

6.3.2 Outage Planning and Scheduling

System Management will compile a list of all equipment on the power system that is required to be subject to outage scheduling by System Management, including partial outages and de-ratings. This list will include all transmission network facilities, facilities holding Capacity Credits, and any other equipment that must be subject to System Management outage scheduling if the security and reliability of the SWIS is to be maintained. Market Participants may request that the IMO reassess the inclusion of their equipment on this list.

As part of the medium-term PASA participants will notify System Management of their outage plans for up to three years ahead. The notification will include details of the reason for the proposed outages, the timing and duration of the proposed outage, potential risks with respect to the intended duration of the outage, and contingency plans should the facility need to be returned to service prior to the scheduled outage completion time. PASA participants must also advise System Management of any changes to plans previously submitted.

Based on the outage plans and the power system security and reliability criteria, System Management will form a provisional schedule of outage plans that:

- Maintains security and reliability of the power system, or if it is not possible to achieve that, is the most prudent outage plan for managing the risks to the power system.
- Shows no bias towards a Market Participant or Network Operator in accepting outages.

Most outages are normally notified to System Management well in advance of their commencement, and typically more than a year before the event for generators. However, while participants can notify System Management of outages until a few days before the event, System Management may reject such applications if the submitting participant has allowed insufficient time for System Management to assess the impact of the outage.

Generator and demand-side facilities with capacities of less than 10 MW need only inform System Management of planned outages. System Management does not actually schedule those outages, but passes the information on to the IMO as it is required in assessing compliance with Reserve Capacity Obligations and the general availability of capacity.

Where outages are scheduled by System Management, competition between participants and the security and reliability criteria will mean that it will not always be possible to schedule a facility outage at the time its operator wants the outage. If System Management cannot determine an outage plan that accommodates the requirements of all parties, then it will first negotiate with effected parties for up to 15 business days, and if no agreement is reached, it will decide which outages are scheduled and which are not. In making such a decision, System Management must have regard for:

- Maintaining the reliability and security of the power system.
- The date and time at which System Management was notified of the outage.
- The urgency of any required maintenance.
- The implication of rescheduling the outage.

Where System Management determines that an outage cannot occur at the time the participant has requested, the participant may request that the IMO reassesses the decision. Such requests must be made within ten business days of System Management's decision but not later than five business days prior to the outage commencing. Any such requests can only be on the grounds that System Management has failed to follow the outage planning process in the Market Rules. The IMO will consult with System Management but the IMO's decision will be final.

If a Market Participant's outage plan is rejected, it and System Management must work to determine an alternative time for the outage.

Outages that are scheduled via the process in the Market Rules cannot commence until outage approval is granted. System Management is required to give final approval of an outage two days before outage commencement. This final outage approval process allows System Management to manage outages close to their commencement, and potentially delay them if the outage will endanger the power system. Given the time constraints, no reassessment of these final outage approvals is possible, but the IMO may reassess decisions after the event where participants allege that System Management has breached the outage approval process in the Market Rules. Market Participants and Network Operators will also be able to schedule opportunistic maintenance with System Management at short notice (e.g. on the day before the maintenance), provided System Management determines that such maintenance would not affect system reliability or security and provided System Management has adequate time to assess the impact of the outage.

If an outage was scheduled with System Management at least one year prior to its commencement but was delayed or cancelled by System Management within 48 hours of its commencement then the affected party can apply for compensation. Compensation will only be paid for the additional maintenance costs directly incurred by a Market Participant or Network Operator in the deferment or cancellation of the relevant maintenance, and will include labour and equipment costs specifically related to the maintenance. This compensation will be funded from Market Customers based on their monthly energy purchases. If the compensation required exceeds $50,000 then the IMO may spread the recovery of the compensation over up to six months so as to minimise the volatility of settlement payments by Market Customers.

Where outages are approved by System Management they will be designated as planned outages, and the Reserve Capacity obligations of the Market Participant will be reduced accordingly. A similar reduction will apply for consequential outages, which are due to failure of other components of the power system (e.g. transmission lines) that prevent a Reserve Capacity provider from meeting its obligations. All other outages will be forced outages. Participants will be obligated to inform System Management of forced outages as soon as practical, and to provide information concerning when the facility will return to service. Participants may need to refund Reserve Capacity payments in the event their equipment suffers forced outages (see section 7.6).

This outage scheduling process is already operating on an informal basis. Any outage scheduled with System Management under this process prior to Energy Market Commencement will, after the market has commenced, be treated as if it had been scheduled in accordance with the Market Rules.

6.3.3 Commissioning Tests

Those seeking to conduct commissioning tests on new generators, or generators returning to service from extended maintenance, must schedule those tests with System Management. System Management may also require that such tests be performed.

6.4 Other Duties of System Management

Other duties of System Management include:

- Planning and making arrangements for, and coordination of, automatic under frequency load shedding, including a priority order designed to protect high priority loads in the event of a supply shortage.
- Maintaining plans for system restart.

6.5 Performance of System Management

The IMO will coordinate investigations into major disturbances on the power system, and will require that System Management and other relevant Market Participants provide the IMO with a report explaining events and their actions soon after each event. These reports will be published on the IMO website.

Every three months System Management must provide to the IMO a report summarising all instances of involuntary load shedding, shortages of ancillary services and Emergency Operating States occurring, including details of actions taken by System Management.

System Management will assist the IMO to conduct reviews of the ancillary service requirements and procurement process and the process for scheduling outages. These reviews will take place at least every five years, but may be carried out more frequently if required. Market Participants and Network Operators will be able to make submissions to these reviews, and the results will be public.

7. The Reserve Capacity Mechanism

7.1 Overview

The Reserve Capacity Mechanism is intended to ensure that the SWIS has adequate installed capacity available from generators and demand-side management options at all times so as to:

- Cover expected system peak demand while providing adequate additional capacity to ensure demand can be meet in the event of the failure of the largest generator while maintaining some capability to respond to frequency variations.
- Remove the need for high and volatile energy prices that are required in markets like the NEM to provide adequate revenue for peaking facilities and to trigger new investment. Instead, energy prices will be capped to low levels (relative to the NEM) with the Reserve Capacity mechanism contributing to generator capital costs. The Reserve Capacity mechanism may fully fund the capital costs for peaking facilities, and will contribute towards a baseload unit's capital costs.

The IMO administers the Reserve Capacity mechanism.

The annual Reserve Capacity Requirements will be specified by the IMO based on a Statement of Opportunities Report that considers the capacity requirements of the SWIS for the next 10 years. Each Market Customer will be allocated a share of the Reserve Capacity Requirement, called its Individual Reserve Capacity Requirement, and will be required to secure Capacity Credits to cover that requirement. A Capacity Credit is effectively installed capacity or DSM registered with the IMO. A Market Customer can either procure Capacity Credits bilaterally from Capacity Credit suppliers, or it can purchase them from the IMO. The IMO may run an annual auction to procure Capacity Credits for on-sale to Market Customers if the requirement for Capacity Credits is not met through bilateral trade.

7.2 The Statement of Opportunities Report

Each year the IMO will prepare a Statement of Opportunities Report outlining projected capacity requirements for the SWIS and projected capacity shortfalls for each of the next ten years. This report will indicate opportunities for supply and demand augmentations that would improve the adequacy and security of the power system. The IMO will not consider transmission planning, as Network Operators will address this, but the Statement of Opportunities Report may make use of transmission planning information provided by Network Operators.

To develop the Statement of Opportunities Report, the IMO will be empowered to request information from Rule Participants pertaining to their expected future system usage and available generation, demand side and transmission capacities. The IMO would also take into account probable new projects where appropriate.

The IMO will determine the capacity required in each year so as to:

- Meet the forecast peak demand after the outage of the largest generation unit and while maintaining some residual frequency management capability (e.g. 30 MW), in nine years out of 10.
- Limit energy shortfalls to 0.002% of annual energy system consumption.

Both generation and demand-side options would be considered in covering these requirements.

The IMO will also determine an Availability Curve. This will determine the amount of capacity required in the SWIS that can be provided by Demand-Side Management (DSM) facilities that are only available for at least 24, 48, 72, or 96 hours per year. This information is used in the process of procuring Reserve Capacity. The capacity in each range is moderated to ensure that the total amount of DSM that could be procured for Reserve Capacity reasons is not so large as to undermine the ability of System Management to maintain the security and reliability of the SWIS.

The Statement of Opportunities report will be used to set the Reserve Capacity Requirement for the period October to September ("the Capacity Year") starting in the second year following the release of the report.

7.3 Capacity Credits and the Reserve Capacity Auction

Generation and DSM facilities capable and willing to contribute capacity must apply to the IMO for Certified Reserve Capacity applicable to the Capacity Year. This certification indicates the contribution of a facility to meeting the capacity requirement in the Capacity Year, and also bestows obligations on that facility. The primary obligations associated with Certified Reserve Capacity, which become binding only once the Certified Reserve Capacity is converted to Capacity Credits, are:

- In the case of generators other than intermittent generators, to make that capacity available to the market, in the form of bilateral contract positions, STEM submissions and capacity contracted to provide ancillary services, and to make any unscheduled capacity available in real-time if required and subject to adequate notification being given.
- In the case of DSM to make that capacity available in real-time if required and subject to adequate notification being given.
- In the case of intermittent generators, to generate to the greatest extent possible when requested by System Management to do so in real-time.

The exact quantity of capacity a facility must make available may vary with ambient temperature and the recent operation of the facility. In addition, facilities holding Capacity Credits must:

- Submit to outage scheduling by System Management.
- Submit to the Reserve Capacity testing and monitoring regime. This regime is designed to ensure that the capacity credits held by a facility accurately reflect its capabilities.
- Maintain adequate secondary fuel for 12 hours of operation (except during outages etc) if the facility claims to have a secondary fuel.

In certifying Reserve Capacity, the IMO will make use of a range of information provided by the applicant, historic performance data, and tests of the facility.

As a condition of certification of facilities that have not yet been commissioned, the IMO will require the payment of security equal to about 25% of the value of the annual payments the facility will receive if scheduled. This security will be returned if the facility fails to secure Capacity Credits or when it first reaches an output level that fully satisfies its capacity obligations. If a facility reaches 90% of the required output level on any day then the security will be returned at the end of the year. If 90% of required output is not achieved during the capacity year then the IMO will draw down on the security.

Market Participants can also secure conditional certification some years before the auction. The information required is the same as for normal certification. This conditional certification will provide potential investors with greater certainty in securing financing and when negotiating bilateral contracts. When the Market Participant applies for final certification, if no information upon which the conditional certification was based has changed and all approvals required normally for certification are provided, then it will automatically be certified.

Facilities that are covered by Network Control Service Contracts and have Certified Reserve Capacity will automatically be assigned Capacity Credits. The operators of all other facilities holding Certified Reserve Capacity will, in August of each year[7], indicate to the IMO:

- How much Reserve Capacity they want to trade bilaterally.
- How much Reserve Capacity they want to offer to the IMO via the Reserve Capacity Auction.
- Whether they want to terminate any Reserve Capacity (e.g. because they wish to decommission a facility or no longer intend to go forward with the development of a new generation project).

In determining which bilateral trades can contribute to satisfying the required Reserve Capacity, the IMO will generally accept bilateral trades in order of decreasing availability until all trades are exhausted or until the Reserve Capacity requirements are satisfied. However, there are a number of additional rules imposed on this process:

- Facilities that exist or are under construction are accepted automatically.
- The IMO can reject bilateral trades if they provide more capacity from low availability resources than is required to satisfy the minimum requirements of the Availability Curve. To illustrate this case, consider the situation where five facilities each propose to trade 5 MW of capacity that is only available for 10 hours per year when the actual amount of load that occurs for less than 10 hours is only 15 MW. If the IMO accepted all five trades then it would be accepting 25 MW of capacity when only 15 MW could be used. Thus the IMO would only accept bilateral trades from three of the facilities. In deciding from which three facilities to recognise bilateral trades, the IMO would accept facilities in order of decreasing availability. Any rejected capacity would still be allowed to participate in the auction if one is held, though if the capacity is surplus to requirement in the bilateral trade process it should also be surplus to requirements in the auction.

[7] This event occurred in September in 2005.

- If multiple facilities have the same availability but not all are required then the IMO will apply the following selection criteria to eliminate surplus capacity. The same criteria will be applied to determine which one of two or more facilities will be accepted when the facilities are mutually exclusive (e.g. because they will be constructed on the same site if accepted):
  - Facilities that can demonstrate having secured financing will be accepted first.
  - Then facilities with the greatest quantity of Certified Reserve Capacity will be accepted ahead of facilities with lower Certified Reserve Capacity
  - Then facilities identified in Expressions of Interest will be accepted ahead of other facilities
  - And finally, if the above steps have not resolved the matter, the IMO will accept facilities based on the order in which they applied for Certified Reserve Capacity, including applications for Conditional Certified Reserve Capacity.

If enough Certified Reserve Capacity is traded bilaterally to meet the Reserve Capacity Requirements of the SWIS then no Reserve Capacity Auction will be held, and all the Certified Reserve Capacity accepted through the bilateral trade process will be granted Capacity Credits. The price paid by the IMO for the Capacity Credits will be set to 85% of the Maximum Reserve Capacity Price. After 1 October 2008, if more Capacity Credits are assigned through the Reserve Capacity Mechanism than are required, the price paid by the IMO for Capacity Credits will be scaled down. The price of Capacity Credits in this case will be determined by spreading the total cost of required Capacity Credits over the number of Capacity Credits that have been assigned.

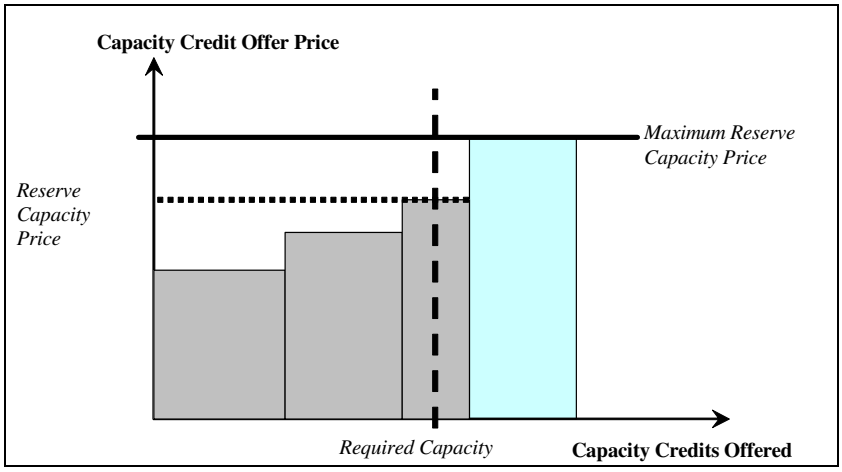
If the total capacity traded bilaterally does not fully cover the total Reserve Capacity Requirement (or there is a shortage in any Availability Class), then:

- The bilaterally traded Reserve Capacity would be granted Capacity Credits,
- The capacity difference between the Reserve Capacity Requirement and the bilaterally traded Reserve Capacity in each Availability Class would be procured via a Reserve Capacity auction.
- Any capacity procured in the auction would be granted Capacity Credits.

Each auction, where required, will be held in September and will be a simple tender to supply the IMO with Capacity Credits. An offer will be made to the IMO to provide the Capacity Credits available from a facility at a price per Capacity Credit per year. A maximum offer price will be defined at a level slightly higher than the expected cost of a new entrant peaking plant. The maximum offer price is the Maximum Reserve Capacity Price to apply in the Capacity Year for which the auction is being held.

Exhibit 7-1 illustrates the basic Reserve Capacity auction clearing process.

Exhibit 7-1. The Reserve Capacity Auction



Four offers are shown. Each offer represents that part of facility's Reserve Capacity that is being offered into the auction. The offers are scheduled in order of price until the Reserve Capacity requirement is covered. In this instance, the third block of capacity is cleared in full, meaning that more Reserve Capacity is scheduled than is required.

In Exhibit 7-1 the grey shaded area indicates the three offers scheduled. The fourth offer, which was priced at the maximum allowed price, is not scheduled and consequently will receive no payment.

Some additional rules are imposed on the auction:

- There will be limits on the amount of capacity that can be scheduled from sources that have limited availability over the year. This allows such resources to be scheduled to serve peak capacity, which has short duration, but not baseload demand. In effect, the auction is conducted to cover the requirement of the Availability Class with the highest availability first. Any surplus offers and offers for the Availability Class with the second highest availability are used to cover the requirements of the second highest Availability Class, and so forth. There are not separate prices for each Availability Class, though, with the highest priced offer scheduled from any Availability Class setting the price.
- If there are offers associated with mutually exclusive facilities (e.g. because they are yet to be built but will all be built on the same site) then the auction will be run for each permutation of such facilities, and the result used will be that which provides the capacity required at lowest cost, or, if there is shortfall of capacity, minimises that shortfall without regard for cost.
- If the reserve requirement is exceeded by more than 100 MW, because the last source of supply that could be scheduled was bigger than needed, the IMO would be allowed to accept offers from a smaller, otherwise not cleared (and hence more expensive) facility in place of a larger cleared facility if this would reduce the overall cost of Reserve Capacity. In this case, the normal price would still apply, with additional compensation being paid to the facility that offered a higher price than the clearing price but was scheduled.

Where Capacity Credits are traded bilaterally rather than being included in the auction and the bilateral arrangement ceases during the capacity year, then the IMO will still pay the facility holding the Capacity Credit the prevailing auction price. However, a Capacity Credit assigned through an auction is committed to the IMO for the entire Capacity Year, and cannot therefore be bilaterally transferred to a retailer during that Capacity Year.[8] The certification of Reserve Capacity offered into an auction, but not sold, would terminate, as the capacity either has insufficient availability or is not required for the Capacity Year.

Once issued, those who have procured Capacity Credits via the bilateral trade process are free to trade those Capacity Credits (i.e. the ability to use them to avoid funding Capacity Credits through the IMO settlement process) with others. However the obligation to provide the capacity associated with a Capacity Credit will always remain with the facility associated with the Capacity Credit. There are no plans for there to be a centralised market to facilitate these trades, though there is nothing stopping such a market developing of its own accord if there is demand for this. Capacity Credits procured by the IMO through the auction will be held by the IMO for the term of those Capacity Credits and consequently cannot be traded again.

Normally, the obligations associated with Capacity Credits will be in effect for the 12 months from October 1, starting in the second year following the year in which the Capacity Credits are granted. There are some exceptions to this:

- New facilities, that were constructed to be available for the start of the Capacity Year, will have Capacity Credit obligations that take effect from their commissioning date, which must be between 1 August and 30 November of the second year following the year in which the Capacity Credits come into being. This requirement assures that these facilities are available for the summer peak period.
- The first Capacity Credits issued in 2005 would normally take effect from late 2007, but will take effect from energy market commencement. This is required because the market design requires that capacity payments be made for generators to remain whole after the start of the energy market. Generating facilities commissioned between 2005 and late 2007 will only become subject to their Capacity Credit obligations from their commissioning dates. Capacity Credits from DSM sources developed since 2005, on the other hand, will only become active in the period 1 August, 2007 to 30 November 30, 2007, being the period for which they are actually required.
- Facilities may be decommissioned during the two months prior to the end of the Capacity Year without restricting their ability to provide Capacity Credits prior to their date of decommissioning. This requirement assures that these facilities are available for the summer peak period.

[8] This is required to prevent the operators of facilities holding Capacity Credits from bidding unreasonably high prices, in the knowledge that if they fail to be scheduled in the auction they can still secure adequate revenue through a pre-existing and confidential option to activate a bilateral trade for their Capacity Credits.

7.4 Reserve Capacity Special Price Arrangements

A new entrant facility that does not have bilateral contracts to fund its capacity but which can be funded by selling Capacity Credits to the IMO in an auction is unlikely to enter the market based on the Reserve Capacity price in a single year. While that price might be high enough to cover the facilities cost for the year, there is the risk that the Reserve Capacity price in subsequent years could be lower.

To assist new facilities entering the market in an auction situation to finance their project without bilateral contracts a Long Term Special Price Arrangement option is available. Where capital costs of not less than 10% of the maximum Reserve Capacity price per MW are incurred in supplying new capacity, either from an upgrade of an existing or a new facility, then that facility is eligible for a Long Term Special Price Arrangement. This arrangement will allow the Market Participant to receive the (inflation adjusted) auction price it earns in the first year in each year the Long Term Special Price Arrangement applies. The duration of the Long Term Special Price Arrangement can be selected by the Market Participant, but must not exceed 10 years.[9] A holder of a Long Term Special Price Arrangement (LT-SPA) will be required to apply to have its capacity re-certified each year, and the Long Term Special Price Arrangement will only be paid on the lesser of the capacity actually certified in each year and the original capacity upon which the LT-SPA was granted.

A Short Term Special Price Arrangement (ST-SPA) will also be used to address two special situations.

- The first situation is that an offer is cleared in an auction but the clearing price is less than its offer price. This could arise because a small expensive facility is accepted as providing a lower cost auction solution than accepting a low cost, but large facility. In this case, if the facility is not covered by a Long Term Special Price Arrangement, it will receive a Short Term Special Price Arrangement applicable to the Capacity Year to cover the difference between the auction price and its offer price.
- The second situation concerns facilities that participate in an auction and are commissioned up to two months before the start of the Capacity Year. A different Reserve Capacity price will apply at that time, and therefore it will be required to take up a Short Term Special Price Arrangement for those few months so that it effectively sees the price that applies in the Capacity Year in which it was scheduled. Note that a facility scheduled in the auction and which is commissioned two months prior to the start of the Capacity Year would be required to hold a Short Term Special Price Arrangement for those two months, but will then have the option to take up a Long Term Special Price Arrangement for the subsequent years.

As noted above, Capacity Credits sold to the IMO via the auction cannot be traded bilaterally for the year the IMO holds the Capacity Credits. In the case of a Long Term Special Price Arrangement the Capacity Credits can be traded bilaterally following the Capacity Year to which the original auction related. The Long Term Special Price Arrangement will be suspended if a covered facility sells the Capacity Credit bilaterally, but will resume if that bilateral arrangement ends within the term of Long Term Special Price Arrangement. Since capacity sold through the auction for one Capacity Year

[9] A term of 15 years would have been allowed for any Capacity Credits resulting an auction in 2005 but no such auction was required.

cannot be traded bilaterally, there is no need for equivalent arrangements for the Short Term Special Price Arrangements.

7.5 Supplementary Capacity Auctions

If inadequate Capacity Credits exist to cover the Reserve Capacity Requirement then the IMO will run a special Supplementary Capacity Auction close to the period of shortage. This supplementary auction will have a higher price cap than the Reserve Capacity auction, but the contracts will have a term of not more than 12 weeks. This auction will only be open to demand side management options and non-registered generators. In particular, registered generators, including embedded generators, cannot provide supplementary capacity. This restriction means that registered generators can only use the normal avenues for scheduling Reserve Capacity, and do not have any incentive to withhold capacity from the normal market so as to unnecessarily trigger a Supplementary Capacity auction.

Those participating in the Supplementary Capacity Auction would specify the availability restrictions on their capacity, an availability cost, and a usage cost reflecting costs directly incurred (e.g. a stand-by generators fuel cost). The IMO would schedule the offers so as to minimise the expected cost, based on the expected number of hours for which the Supplementary Capacity will be required.

Those providing supplementary capacity will have their rights and obligations governed by a contract with the IMO rather than the Market Rules. This allows supplementary capacity to be provided by parties that are not Rule Participants. A standard supplementary capacity contract will exist, but the IMO will be allowed to negotiate variations to the standard conditions where this is required to secure sufficient capacity or to minimise costs.

7.6 Refunds for Non-Compliance

Providers of Capacity Credits who fail to meet the obligations of Capacity Credits will have to pay a refund that reflects a measure of the value to the system of the capacity not provided.

Different refunds will apply at different times of day and at different times of year. The aim is to make refunds relatively small at times when the SWIS has abundant capacity while making them quite high at times when non-compliance creates a high risk of load curtailment.

Measures are included to cap the exposure of Capacity Credit providers. While the basic refund will be determined for each Trading Interval, limits will be imposed on the total refund required in each Trading Day, in each of three seasons (April – September, October – November, and December – March), and over the year. In addition the maximum refund over the capacity year cannot exceed the total expected payments for that year. These refunds are intended to discourage non-compliance in a Trading Interval while capping the risk if non-compliance over a long time frame is unavoidable.

These refunds will be collected in the first instance by the IMO and then rebated to all Market Customers in proportion to their Individual Reserve Capacity Requirements (see section 7.7). This effectively compensates all Market Customers for the reduction in the overall security of the system.

7.7 Funding the Reserve Capacity Auction

All Market Customers will have an Individual Reserve Capacity Requirement, which will equal the share of the Reserve Capacity Requirement allocated to them based on their expected contribution to historic system peak demand. During the course of a Capacity Year the IMO will update Individual Reserve Capacity Requirements monthly. These updates will take account of end-use customers shifting between retailers, new end-use customers entering the market, and existing end-use customers leaving the market. While the Individual Reserve Capacity Requirement of each Market Customer will change each month, the total of these quantities will add to the Reserve Capacity Requirement.

A Market Customer's Individual Reserve Capacity Requirement will typically equal its contribution to system peak load, plus an additional reserve margin. Thus a Market Customer with a load of 100 MW at times of systems peak consumption might have an Individual Reserve Capacity Requirement of 115 MW, where the additional 15 MW ensures that there is adequate generation available at peak times even if some generation capacity is unavailable. Intermittent Loads are a special case and are discussed further in section 7.10.

Market Customers who do not hold enough Capacity Credits for a given trading month will be required to fund the Targeted Reserve Capacity Cost, which comprises:

- The cost of Capacity Credits procured by the IMO, including under Special Price Arrangements, up to the Reserve Capacity Requirement. Where the IMO has procured Capacity Credits beyond the Reserve Capacity Requirement then the cost of the surplus Capacity Credits are recovered via the Shared Reserve Capacity Cost discussed below. Because of Special Price Arrangements, not all Capacity Credits cost the IMO the same amount, so the most expensive mix of Capacity Credit costs will be recovered via the Targeted Reserve Capacity Cost.
- The cost of Supplementary Capacity payments for that month to the extent that this is not offset through the IMO claiming security posted by a provider of Capacity Credits that fails to satisfy their obligations.

The Targeted Reserve Capacity Cost is allocated in proportion to each Market Customers Capacity Credit shortfall. The purpose of this Targeted Reserve Capacity Cost is to provide an incentive for Market Customers to contract bilaterally for capacity well before it is required, and to contract with reliable providers. If a provider no longer has capacity credits available at the time they must be allocated, then the Market Customer will have to purchase replacement credits from the IMO, procured through the Supplementary Capacity process, which may be significantly more expensive.

The IMO will on a monthly basis determine the Shared Reserve Capacity Cost. This cost comprises:

- The cost of Capacity Credits procured by the IMO that are surplus to the requirements of the market.
- Less any revenue beyond that required to fund Supplementary Capacity payments earned by the IMO where it has claimed the security posted by a provider of Capacity Credits that fails to ever satisfy its obligations.

- Less any refunds paid by those Capacity Credit providers who fail to satisfy their obligations.

The Shared Reserve Capacity Cost is allocated between all Market Customers in proportion to their Individual Reserve Capacity Requirement. This approach is used because the components of the Shared Reserve Capacity Cost cannot meaningfully be assigned to any individual Market Customer.

7.8 Capacity Credit Allocation Process

Capacity Credits applicable to the current Capacity Year that have been traded bilaterally between a supplier of Reserve Capacity and a Market Customer are recognised in settlement of the wholesale market. The benefit of such a transfer is that it reduces the payment required to be made by the Market Customer to the IMO, and reduces the payment required from the IMO to the Reserve Capacity supplier. This will allow the supplier and Market Customer to trade capacity at a bilaterally agreed price and will reduce prudential requirements for the Market Customer. As explained above, customers that do not have bilaterally contracted capacity are also exposed to the financial costs of procuring additional capacity.

Following each Trading Month, the suppliers of Capacity Credits will inform the IMO of which Capacity Credits are being traded bilaterally, and with whom. Because different Capacity Credits may be settled at different prices, e.g. because of Special Price Arrangements, the supplier of Capacity Credits will have to indicate which group of Capacity Credits is being used in a bilateral trade so the IMO knows how much to pay for other Capacity Credits.

The IMO will review submissions from Capacity Credit suppliers and will accept those that meet the format requirements. However, before accepting individual transactions contained in the submission it will check them to ensure that no Market Customer is allocated more Capacity Credits than it is required to provide. If the IMO finds any such cases, it will notify that Market Customer and require it to nominate which Capacity Credits it does not want to take up. This measure is designed to ensure the Market Customers do not hold on to Capacity Credits they do not need, thus preventing others from getting the benefit of them. The IMO will only confirm the transactions with the Capacity Credit suppliers once this process is completed.

7.9 Reserve Capacity and Generator Investment Strategies

The holding of Reserve Capacity auctions two years before the capacity is required is to allow time for peaking plant to enter the market based solely on the auction revenue. Base load plant is unlikely to be able to profitably enter the market solely on Reserve Capacity Revenues, so this type of plant is more likely to trade Capacity Credits bilaterally. However, should base load plant have any spare capacity that spare capacity can be offered into the auction to gain additional revenue.

Since Reserve Capacity auctions are held two years prior to the obligation commencing, if an existing facility's capacity has not been traded bilaterally and that facility fails to win a place in an auction then its owner will have two years to assess what to do. After that time it will cease receiving Reserve Capacity payments, but will be allowed to continue participating in the market. However, without a Reserve Capacity payment, either from the auction or via bilateral trade, the facility may no longer be economically viable. This is an appropriate outcome, because the fact that the facility's capacity has

not been traded bilaterally or cleared in the auction suggests that the market can acquire new capacity at a lower cost.

Pre-conditions for a new facility that is yet to be commissioned to be certified to provide Reserve Capacity will include a letter of offer for an access agreement from its Network Operator and evidence of any necessarily environmental approvals. While this may take some time to obtain, holding a bilateral contract for Capacity Credits allows Market Participants to commit to building new facilities in the knowledge that once they have secured all necessary approvals they will be able to secure the benefits of the Reserve Capacity regime.

As described in section 7.3, a process exists for conditional certification of Reserve Capacity for facilities under development so that they can have certainty as to the quantity of Capacity Credits they will hold some years prior to the normal application time. This will facilitate financing and the formation of bilateral contracts.

7.10 Intermittent Loads

The Market Customers serving Intermittent Loads will have to hold Capacity Credits for those Intermittent Loads. However, Intermittent Loads will have less impact on a Market Customer's Individual Reserve Capacity Requirement than other loads. The reason for this is that Intermittent Loads only need to purchase energy from the market when the generator supplying that intermittent load is not available. Suppose that a regular load of 100 MW contributes 115 MW to a Market Customers Individual Reserve Capacity Requirement. In the case of an Intermittent Load of 100 MW, its own generator covers the first 100 MW of capacity required[10], so the Intermittent Load is not required to contribute more than 15 MW to a Market Customer's Individual Reserve Capacity Requirement.

A Market Customer with Intermittent Load will have to pay the prevailing Reserve Capacity price for its Intermittent Load, unless it has procured the capacity bilaterally.

Operators of Intermittent Loads will nominate quantities of Intermittent Load capacity they expect they will need during a Capacity Year. This nomination will be made more than two years prior to the Capacity Year beginning so that the nominations can be factored into the Reserve Capacity Requirement. Based on these nominations the IMO will determine the additional Reserve Capacity required to cover the total requirements of Intermittent Loads and will factor these requirements into the market Reserve Capacity Requirement. However, the actual liability to pay for an intermittent load will not apply until the Intermittent Load has been registered.

A generator serving an intermittent load need not generally be registered – rather the load/generator combination is registered as a single facility. However the IMO will assess the generating facility's ability to provide capacity as if it were a reserve capacity provider, and the Intermittent Load cannot exceed the capacity that the IMO considers the generator has available. To the extent that a

[10] When assessing an application to treat a load as an intermittent load, the IMO will assess how much Certified Reserve Capacity the embedded generator supplying that intermittent load can provide. This must be enough to fully supply the intermittent load.

generator has capacity beyond that required to serve the Intermittent Load, then that extra generation capacity can be registered and can provide capacity and energy to the market beyond that required to supply the Intermittent Load. A special case concerns a generator constructed especially to serve a load of 40 MW or more – such a generator must be registered but can serve the intermittent load from a remote location until the first time it could have secured Capacity Credits through the normal process. The output of such a generator will be loss factor translated to the location of the Intermittent Load so as to produce an effective single net meter reading at that location.

Generators serving Intermittent Load are effectively providing reserve capacity, albeit without formally holding Capacity Credits. Consequently they have obligations. The generators will be subject to System Management outage planning, for instance. Further, if the generator is not operating then the metered net load will increase. When this happens, and if the generator is not on a planned outage, the Intermittent Load will be subject to Intermittent Load Refunds. These are like Reserve Capacity Refunds and reflect the fact that the generator is unavailable. An Intermittent Load should not exceed its nominated level of output (by more than a tolerance of 3%) except when its generator is on a planned outage if the load wishes to avoid Intermittent Load Refunds. To the extent that unmetered load exists at the location that is not part of the intermittent load, this can be registered as Non-Dispatchable Load and any consumption beyond the intermittent load can be associated with this load. This Non-Dispatchable Load would have to fund Capacity Credits like any other non-Intermittent Load.

Appendix 1 provides additional detail on the representation of Intermittent Loads, including how meter data is allocated between the Intermittent Load, any unmetered Non-Dispatchable Load at the same site, and any generation capacity beyond that required to serve the Intermittent Load that is registered.

7.11 Reserve Capacity and Generators of Capacity not Exceeding One MW

The standard Reserve Capacity processes provide for a 2-year timeline between the bilateral trade/auction process and the commencement of the obligations associated with capacity credits. This is done to allow time for new peaking generators to be installed if required. However, small generators can be installed much more quickly. For this reason, generators of capacity not exceeding 1 MW can secure Capacity Credits on a shorter timeline. When such a generator begins operating its operator can apply to the IMO for Capacity Credits from the start of the next Capacity Year (1 October). It can reapply for Capacity Credits each year until the commencement of the first Capacity Year for which it could have secured Capacity Credits through the normal process since the facility commenced operation.

7.12 Reserve Capacity and Demand Side Management Programs

An issue for Market Customers wishing to provide Curtailable Load to the market is that it will be difficult to get wholesale customers to contract to provide curtailability for more than about a year ahead of time. To accommodate this, the market allows a Market Customer to register a Demand Side Management (DSM) Program as if it were a Curtailable Load facility. A DSM program would be assigned capacity credits and obligations. However the DSM program is not a physical facility.

Closer to the start of the Capacity Year the Market Customer could contract for Curtailable Load and register these with the IMO (these should be of at least the same availability as the DSM program's

availability). The Market Customer could then apply to the IMO for these to be assigned the Capacity Credits of the DSM Program. The Capacity Credits and obligations of the program are shifted to individual Capacity Credits corresponding to physical facilities. As new physical facilities arise the DSM program's Capacity Credits decline, while as those physical facilities de-register the DSM program's Capacity Credits increase. At any time during the Capacity Year when a Market Customer has a DSM program for which not all Capacity Credits have been transferred to physical facilities it will be deemed to have failed to satisfy the obligations on the DSM Program and will have to pay Capacity Credit refunds (it will also have to pay refunds if any of the physical facilities fail to satisfy their obligations).

8. Network Control Service

8.1 What is Network Control Service?

Network Control Services are services provided by distributed generation or demand side management that can be substitutes for an upgrade to a transmission or distribution network. Under the Access Code, Network Operators will inform the IMO where such opportunities exist and the IMO will run a competitive tender for procurement of the services. Where the tender response of a distributed generation or demand side management option is less expensive that the transmission upgrade, the IMO will enter into a ten-year contract with the successful tender respondent, and will recover the costs of the contract from the network operator where the normal market processes do not provide sufficient revenue.

The Network Control Service contract allows System Management to issue real-time dispatch instructions to the facility as required, within the capacity and availability limits of the contract. For its part, the facility providing Network Control Service gets guaranteed minimum revenue and is not precluded from participating in the energy market. The rules do require, however, that any facility contracted to provide Network Control Service must seek certification for Reserve Capacity. The Reserve Capacity rules ensure that to the extent such a facility is certified, it will be issued Capacity Credits and settled at the prevailing Reserve Capacity price. This feature means that to the extent that Reserve Capacity payments are made to the facility, the Network Control Service payment required of the Network Operator can be reduced.

8.2 Network Control Service Requirements

Under the Access Code Network Operators must notify the IMO where there is an opportunity for distributed generation or demand side management to compete with an upgrade to a transmission network. The notification includes a specification of the services required from the facility, including active and reactive power capability, the location and the timing required.

The IMO then runs an expression of interest process to determine whether any parties other than the Network Operator could provide the services. If there is sufficient interest shown in the expressions of interest, then the IMO will announce a tender for the required Network Control Service. If sufficient interest is not shown, or other options cost more than 50% more than the transmission upgrade, then the transmission upgrade option is selected.

8.3 Network Control Service Tenders

Anyone that wishes to participate in the Network Control Service tender must be registered as a Market Participant. The Market Participant must apply to the IMO for certification of the level of the required Network Control Service that can be provided by its facility or facilities.

The IMO will release tender documents outlining the tender process, the format and content of tender responses, the Network Control Service requirements, and the contract terms. No regulated price cap is imposed on this tender as the cost of the transmission investment option effectively caps the tender

price. Tender respondents may offer to supply all or part of the requirement. The tender response includes the monthly availability payment that the tender respondent requires and the usage cost they wish to recover when called upon.

The IMO selects tender responses to achieve the lowest total cost while meeting the requirement. The total cost is based on the value for the accepted tenders of the sum of the required monthly availability payment and the usage costs of the facilities multiplied by the expected number of hours per month they will each be used. The IMO may accept more than one tender response. If the total cost of the selected tender responses is less than the cost of the transmission or distribution upgrade, then the IMO will enter into ten year contracts with the selected tender respondents. If the network upgrade is less expensive, then the IMO will inform the Network Operator of this and will not accept any of the generation or DSM tender responses.

8.4 Network Control Service Contracts and Payments

The Network Control Service Contracts will have standard terms and conditions including the services offered, the duration of the contract, the terms for System Management to call upon the services, the payment terms and testing and compliance terms.

The IMO will inform System Management of contracted Network Control Services, including details of how those facilities can be dispatched under those contracts. System Management will be able to dispatch Network Control Facilities as required for the purpose of maintaining system security and reliability, without that facility having to issue any resource plan or STEM submissions. However, the facility operator will not be precluded from participating in bilateral contracts or the STEM so that it will not be reliant on the Network Control Service contract to schedule its energy. Any dispatch instructions issued by System Management will be settled like any other real-time dispatch instruction, but settled in accordance with pay-as-bid prices specified in the Network Control Service contract.

As discussed above, it is compulsory for facilities subject to a Network Control Service contract to seek certification of their capacity as Reserve Capacity. The extent that certification is held, Capacity Credits will be issued and settled at the prevailing monthly Reserve Capacity settlement price.

Each month the IMO will calculate the payment for Network Control Service providers. This payment will equal the greater of zero and:

- The monthly availability payment.
- Less the value of Capacity Credits held by the facility, valued at the prevailing monthly Reserve Capacity settlement price.
- Less the cost of any liquidated damages stemming from non-compliance (if applied in contracts).

Note that this payment is in addition to all other market payments that the facility might receive. However, to the extent that the facility receives income for its Reserve Capacity, the Network Control Service payment is reduced accordingly. There is no restriction on a Network Control Service facility trading its Capacity Credits bilaterally (see section 7.8). To the extent this happens, its payment under the Reserve Capacity mechanism will be reduced, being replaced by a bilateral capacity payment.

The standard Network Control Service payment adjustment will still apply however. The total Network Control Service payment to the facility can never become negative, which means that like Reserve Capacity payments, the liability of the provider of the service is capped.

The usage price that is associated with a facility providing Network Control Service will be used as the pay-as-bid price paid in balancing whenever the facility is called upon.

Apart from the usage payment, which is settled in balancing, the IMO recovers the cost of the payments made under the Network Control Service contracts from the Network Operator that requested that the service be acquired.

9. The Energy Market

9.1 Introduction

The Energy Market, as used in the Market Rules, describes all mechanisms for trading energy, and includes trades via:

- Bilateral Contracts
- The Short Term Energy Market (STEM)
- Balancing

Each of these components is described in turn in this section.

9.2 Bilateral Contracts

Bilateral contracts are agreements formed between wholesale market suppliers and wholesale market consumers (i.e. retailers and directly connected loads) for the provision of energy. These Bilateral Contracts are formed on a purely commercial basis, and the market has no role or interest in how they are formed, or in the conditions they impose on the parties subject to those contracts. The IMO does not operate any secondary trading market for bilateral contracts, though there is no reason why an exchange would not develop outside the market if there were demand for this.

Whether a bilateral contract has a term of one trading interval or multiple years, a bilateral contract provides the holders with certainty over their settlement position with respect to that transaction. To the extent that one of the parties cannot conform to their contractual requirements, because of generator outage, transmission or network security constraints, low demand or some other situation, then those parties will be individually liable to settle their deviations from the contract position. This places discipline on the market to only form Bilateral Contracts that reflect a reasonable expectation of the ability of the network to facilitate the delivery of that energy. Note that there is no concept of physical, path dependent, transmission rights in the SWIS, rather each network user is granted a right to inject or withdraw up to an amount of energy specified in their access contract with their network service provider.

The holders of bilateral energy contracts must schedule that energy in the market. To schedule energy for a Trading Day, generators must make a Bilateral Submission to the IMO on the Scheduling Day, being the day prior to the day on which the Trading Day begins. These Bilateral Submissions must be balanced, in the sense that the total transmission loss adjusted energy to be supplied to the network must match the total transmission loss adjusted energy to be taken from the network. If a Market Participant is both a Market Generator and a Market Customer and wishes to cover its own load with its generation then it should include in its Bilateral Submission that it is supplying itself. The IMO will allow Bilateral Submissions to be made between 8 AM on the day being seven days prior to the start of the Scheduling Day until 8:50 AM on the Scheduling Day. The information included in Bilateral Submissions is:

- The identity of the submitter

- The total loss adjusted net energy, in MWh, to be supplied by the submitter, where energy supplied has a positive sign.
- The total loss adjusted net energy, in MWh, assigned to each Market Participant supplied by the submitter, where energy consumed has a negative sign.

The total loss adjusted net energy to be supplied (as defined in the previous point) plus the sum of the total loss adjusted net energy to be consumed by each Market Participant under that submission must equal zero. This indicates that the submission is balanced. The loss adjustments are based on static loss factors fixed for a year and reflecting average marginal losses between a fixed Reference Node and each injection or off-take point in the SWIS. These are set annually by Network Operators and published by the IMO.

Once a Bilateral Contract Submission is accepted, the energy is scheduled.

Early on the Scheduling Day, System Management will produce a demand forecast for each Trading Interval of the Trading Day and provide that to the IMO which will publish it by 8 AM. A report will also be produced at 8:30 AM allowing Market Participants to see the bilateral trades that impact them. The demand forecast and the 8:30AM report allow Market Participants to revise their bilateral contract positions (by contacting the submitting Market Generator where required) prior to the submission window closing at 8:50 AM.

An option will also be available whereby Market Participants can submit standing Bilateral Submissions. A standing Bilateral Submission comprises a Bilateral Submission for each of the seven days of a Trading Week (i.e., Sunday, Monday, Tuesday etc). If a Market Participant makes no Bilateral Submission to the IMO for a Trading Day then the IMO will use the corresponding standing Bilateral Submission corresponding to the day of the week of the Trading Day. Market Participants will be obliged to update their standing Bilateral Submissions if they become inaccurate. Alternatively, if the inaccuracy is only for a short period, the Market Participant can submit a Bilateral Submission each day during that period so that the standing Bilateral Submission is not used.

9.3 The Short Term Energy Market

The Short Term Energy Market (STEM) is an energy-only forward market operated by the IMO on the Scheduling Day to facilitate trading around bilateral contract positions. The STEM is run for every Trading Interval of the Trading Day, and determines a single clearing price for each Trading Interval as well as the quantities that sellers will sell to the IMO and that buyers will purchase from the IMO. The auction is designed so that the IMO purchases the same amount of energy it sells, so that it has no net exposure.

The STEM schedules can be viewed as bilateral contracts between suppliers and the IMO and between the IMO and consumers. If a Market Participant has made a Bilateral Submission indicating that it will supply 100 MWh of energy, and then the IMO purchases 10 MWh from it in the STEM, then the net bilateral position of the Market Participant is to supply the market with 110 MWh.

The primary role of the STEM is to provide a mechanism for economic energy trade between Market Participants. This allows those trading under Bilateral Contracts to change their position, while allowing those not trading under Bilateral Contracts to take a position.

Participation in the STEM is open to all Market Participants, but is not compulsory. However, those Market Participants operating non-intermittent generators that hold Capacity Credits are required to make adequate energy available to the market to cover their Reserve Capacity contract obligations.

To aid Market Participants in forming their STEM Submissions, the IMO will by 9 AM on the Scheduling Day report for each Trading Interval of the Trading Day: the total demand to be supplied under bilateral contract;the forecast demand;and information on the Reserve Capacity available (including information on outages).

All Market Participants may make STEM Submissions. STEM Submissions are made to the IMO between 9 AM and 9:50 AM of each Scheduling Day. Accepted submissions will be used in the STEM auctions run between 10:00 AM and 10:30 AM.

A standing STEM Submission option exists for STEM Submissions. As for standing Bilateral Submissions these apply for each of the 7 days of a Trading Week and will be used if no STEM Submission is made. Market Participants will be obliged to update their standing STEM Submissions if they become inaccurate. Alternatively, if the inaccuracy is only for a short period, the Market Participant can submit a STEM Submission each day during that period so that the standing STEM Submission is not used.

One of the features of STEM Submissions is that liquid fuelled generation can be offered at a higher price than non-liquid fuelled generation and at the same price as bids for demand. If a STEM Submission included a single offer curve to sell and a bid curve to buy relative to a Bilateral Contract position, then it would not be transparent as to what price each individual generator was offered at each level of output. To over come this, STEM Submissions contain a generation Portfolio Supply Curve and a Portfolio Demand Curve from which the IMO generates offers and bids relative to the net bilateral position of the Market Participant. In effect, Market Participants must offer their entire supply and consumption capacity in the STEM Submission, and the IMO converts this submission to an offer to buy or sell energy relative to a net bilateral position.

A STEM Submission for a Trading Day comprises the following information:

- A Portfolio Supply Curve for each Trading Interval of the Trading Day. A Portfolio Supply Curve is a supply curve made up of price-quantity pairs where the cumulative quantity offered represents all the energy being offered to the market from the Market Participant's generation resources. If the Market Participant is only a Market Customer then a zero quantity must be entered. If this portfolio is made up of X MW of facilities operating on non-liquid fuel (e.g. gas or coal) and Y MW of facilities operating on liquid fuel (e.g. distillate or oil) then the first X MW of the supply curve must contain prices less than the Maximum STEM Price (initially to be $150/MWh and adjusted annually) while the last Y MW must contain prices less than the Alternative Maximum STEM Price (initially to be $385/MWh and adjusted monthly based on oil

prices). All prices must be greater than the Minimum STEM Price (the negative of the Maximum STEM Price) and the cumulative quantity of supply offered must increase with increasing price.

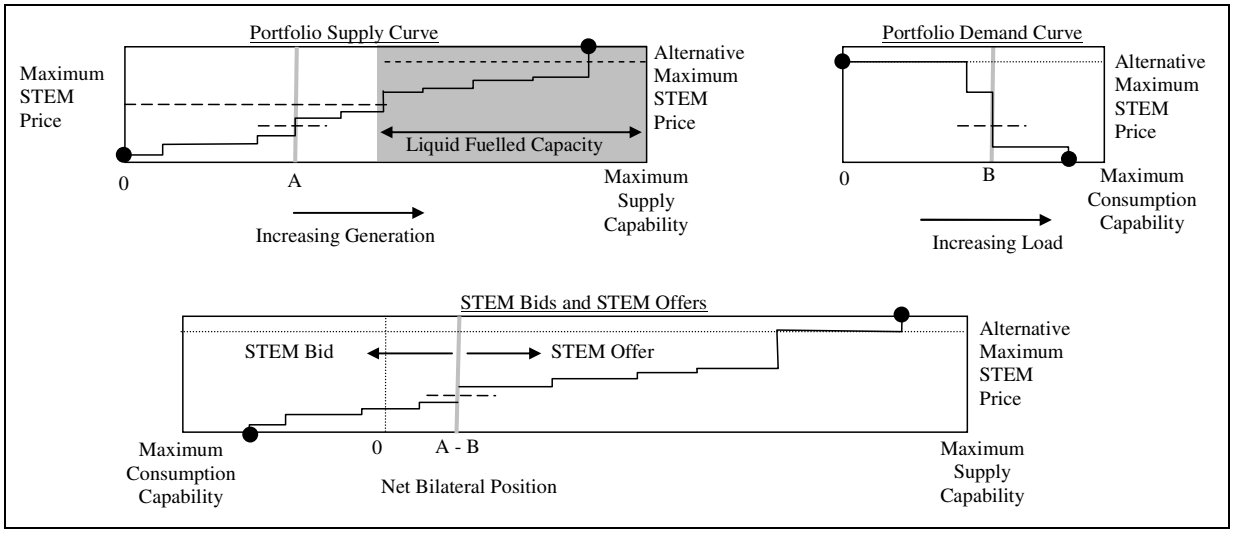
- A Portfolio Demand Curve for each Trading Interval of the Trading Day. A Portfolio Demand Curve is a demand curve made up of price-quantity pairs where the cumulative quantity bid represents all the energy that the Market Participant might potentially purchase from the market. If the Market Participant is only a Market Generator then a zero quantity must be entered. All prices must be greater than the Minimum STEM Price and less than the Alternative Maximum STEM Price and the cumulative quantity of energy consumption must increase with decreasing price.
- A Fuel Declaration. This states what fuel each dual fuelled generator was assumed to be running upon when forming the Portfolio Supply Curve. This information is used in determining which pay-as-bid price to apply in balancing, and is also required for market monitoring purposes.
- An Ancillary Service Declaration. Prior to the STEM Submission process commencing each day, System Management will advise ancillary service providers (via the IMO) of the capacity they should hold out of the STEM for each Trading Interval so as to keep that capacity available for ancillary service provision. Market Participants who are providers of ancillary services must declare for each Trading Interval how much of the required quantity is assumed to be provided by liquid fuelled generation and how much is assumed to be provided by non-liquid fuelled generation. This information serves to excuse the Market Participant from the Reserve Capacity obligation to offer capacity into the STEM.
- An Availability Declaration. If a Market Participant is not offering generation capacity to the market and there is no obvious reason for this, then the Market Participant must declare this. Situations that do not need to be declared are if the facility is known by System Management to be experiencing an outage or if the Ancillary Service Declaration can account for the reduction in capacity available. This information is used for market monitoring.

The various declarations allow the IMO and regulatory bodies to see what assumptions went into forming the Portfolio Supply Curve. To the extent that actual behaviour is observed to deviate from the declarations then this may flag the need for an investigation of the incident (though it does not mean that the Market Participant has done anything wrong).

Given a Market Participant's Portfolio Supply Curve, Portfolio Demand Curve, and Net Bilateral Position, the IMO can deduce the Market Participant's STEM Offers and STEM Bids.

The top two curves in Exhibit 9-1 illustrate a Market Participant's Portfolio Supply Curve and Portfolio Demand Curve for a Trading Interval. The bottom curve illustrates how the IMO forms the STEM Bids and STEM Offers.

Exhibit 9-1. The Portfolio Supply Curve, Portfolio Demand Curve & STEM Bids and Offers



Some points to note about the Portfolio Supply Curve and Portfolio Demand Curve in Exhibit 9-1:

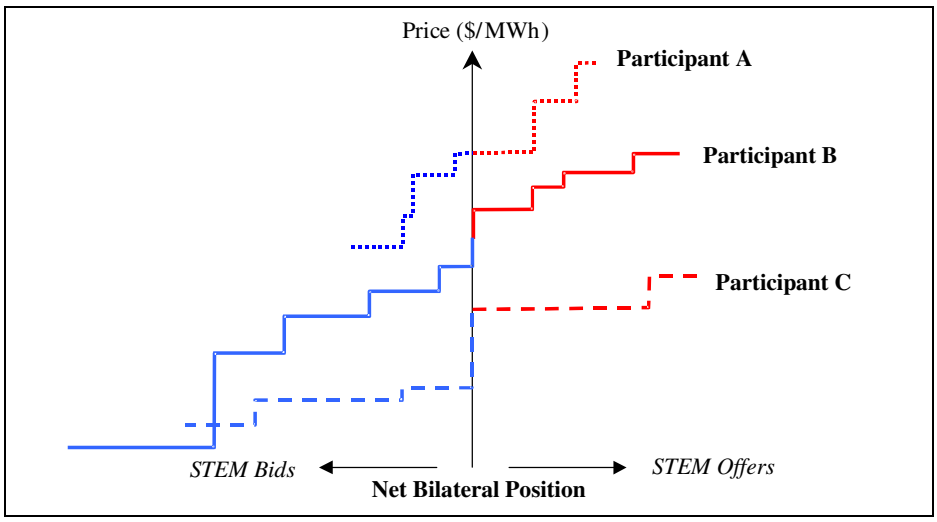
- Although not explicitly shown, the minimum price that can be offered is the negative of the Maximum STEM Price.
- The shaded area of the Portfolio Supply Curve shows the capacity that is liquid fuelled and which can therefore be offered up to the Alternative Maximum STEM Price.
- When the Market Participant formed its Portfolio Supply Curve it expected quantity A to be traded under bilateral contracts. Likewise, when it formed its Portfolio Demand Curve it expected quantity B to be traded under bilateral contracts. The Market Participant does not tell the IMO the values of A and B, but it does need to be aware of the quantity (i.e. the level of contract coverage) for each portfolio so that it can ensure that its price-quantity pairs are consistent with its net bilateral position. The short doted horizontal lines centred on points A and B indicate the price corresponding to the net bilateral position (A-B) in the bottom curve. If the IMO is to produce STEM Offers and Bids that match the Market Participant's expectation then the Market Participant must ensure that demand not traded bilaterally is bid at a price lower than that corresponding to the net bilateral position while generation not traded bilaterally must be offered at a higher price.

The bottom part of Exhibit 9-1 shows an individual Market Participant's STEM Offers and Bids relative to its Bilateral Contract.[11] The IMO forms the lower curve in Exhibit 9-1 by determining the net quantity of energy that the Market Participant is willing to provide at every possible price. Having formed such a curve, the IMO identifies the quantity corresponding to the net bilateral contract position. Relative to this point, everything with a higher price is a STEM Offer and everything with a lower price is a STEM Bid.

[11] Where a Market Participant is both a Market Generator and a Market Customer then it has only one Net Bilateral Position. It does not have a separate Net Bilateral Position as a Market Customer from that as a Market Generator. In defining its STEM Offers and Bids relative to that position it must configure its Portfolio Supply Curve and Portfolio Demand Curve to produce the desired STEM Offers and Bids.

Each Market Participant will have its own set of STEM Offers and Bids. Different Market Participants will have different prices associated with their net bilateral positions. This is illustrated for three Market Participants in Exhibit 9-2.

Exhibit 9-2. STEM bids and offers are defined relative to bilateral contract positions



The Net Bilateral Positions of the three participants shown in Exhibit 9-2 will all be different. We cannot tell from Exhibit 9-2 whether each of the participants is solely a generator, solely a consumer or some mix of the two. Thus

- Any of the participants could be a generator only with a positive bilateral contract position indicating it is a net supplier. Its STEM Bids would reflect a decrease in generation while its STEM Offers would reflect an increase in generation.
- Any of the participants could be a load only with a negative bilateral contract position indicating it is a net consumer. Its STEM Bids would reflect an increase in consumption while its STEM Offers would reflect a decrease in consumption.
- Any of the participants could be both a supplier and a consumer, in which case its bilateral contract position could be positive or negative. Its STEM Bids would reflect a combination of a decrease in generation and an increase in consumption while its STEM Offers would reflect a combination of an increase in generation and a decrease in consumption.

In the discussion that follows we assume that Participant A is a generator only. We do not need to know what the nature of Participants B and C are.

The three participants are unlikely to have exactly the same expectation as to what the STEM price will be. We see that Participant A expects a relatively high price while Participant C expects a relatively low price. Because Participant A expects a high price, it is prepared to pay a high price under its STEM Bid to buy out of its contract position, and hence avoid the need to run expensive generation. Participant C expects a lower price. Its STEM Offers are at relatively low prices because it has lots of low cost under-utilised generation capacity. It is apparent that a result of the STEM auction should be

that some of Participant A's STEM Bids are accepted, with its generation being reduced as a result, with Participant C's lower cost STEM Offers being utilised to replace that generation.

To see how the auction works, we must form all the STEM Offers into one aggregate offer, and all the STEM Bids into one aggregate bid. In Exhibit 9-2 the STEM Bids are shown as a reduction in *net supply* relative to the bilateral contract position as prices fall but in Exhibit 9-3 the bid curve is reversed as it represents an increase in *gross demand* as prices fall.

Exhibit 9-3. The STEM auction

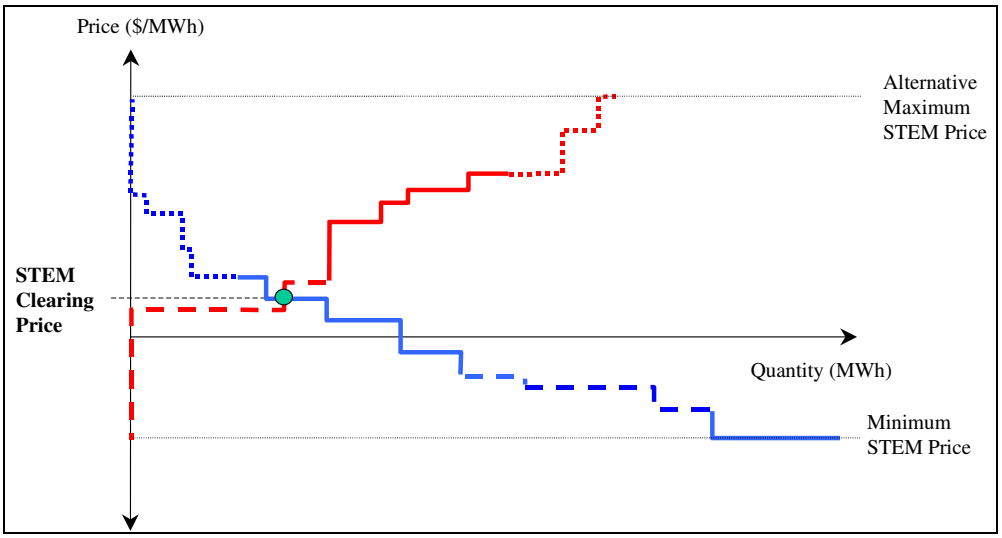


Exhibit 9-3 shows the same information as is shown in Exhibit 9-2, but the information has been re-organised to show the point where the total STEM Bids accepted equals the total STEM Offers accepted. It is apparent that the first step of Participant C's STEM Offer is fully scheduled, being used to offset the energy reduction caused by accepting all of Participant A's STEM Bids and some of Participant B's STEM Bids.

The point where the curves cross defines the market clearing STEM solution. The STEM clearing price is shown. All offers to sell with lower offer prices and all bids to buy with higher bid prices are deemed scheduled in the STEM. The STEM is designed to match supply with demand while supplying the maximum possible quantity of energy at the lowest possible price in all situations. Bids and offers with prices equal to the STEM price will be subject to additional tie breaking rules. Note that the STEM price can be negative.

The example illustrated above shows that the STEM clearing price would have a reasonable value even if no Portfolio Demand Curve were submitted to the STEM Auction. This is because, as shown in Exhibit 9-1, the supply curves for generators for levels below their bilateral contract position will be converted to STEM Bids. Even if no energy was scheduled in the STEM, the price would still have to be between the cost of the highest priced STEM Bid and the lowest priced STEM Offer, and this difference will normally only be a small amount (e.g. a few cents per MWh). The STEM auction process will select the lowest price.

Those scheduled in the STEM will be required to settle the amount they are scheduled for with the IMO at the STEM clearing price. That is, net suppliers will be paid the STEM price and net consumers must pay the STEM price.

Once the STEM has been solved, each Market Participant will have a net contract position equal to its net bilateral position as modified by its net purchase or sale in the STEM. Market Participants other than the Electricity Generation Corporation with generators and dispatchable loads must supply to the IMO a Resource Plan, which the IMO will forward to System Management for the purpose of dispatch. This is discussed more fully in section 10.1.

9.4 Balancing

Balancing refers to the settlement process to address the cost of the difference between the net contract position of Market Participants and their actual supply and consumption levels, allowing for dispatch instructions issued by System Management. The details of the dispatch process are described in section 10, and are not repeated here. However, as described in section 10.2, System Management will provide to the IMO a Dispatch Schedule for each non-Electricity Generation Corporation facility, indicating the operating level required of that facility by System Management in each Trading Interval, the fuel it ran on (if different from that given in the Fuel Declarations) and the Dispatch Instructions that gave rise to that Dispatch Schedule. In addition, there is a Dispatch Schedule reflecting the total energy supplied by Electricity Generation Corporation, this being based on operational meter and SCADA data.

The IMO will use the Dispatch Schedule information to determine balancing prices used for settling some types of deviations from Net Contract Position. In addition, IPP facilities that are issued Dispatch Instructions by System Management will be settled on a pay-as-bid basis where the prices used are specified by IPP Market Participants on the Scheduling Day or are recorded in Standing Data. Any net shortfall or surplus generated by this pay-as-bid regime will be spread across all consumers.

There will be three balancing prices determined by the IMO.

- the Marginal Cost Administrative Price (MCAP);
- the Upward Deviation Administrative Price (UDAP); and
- the Downward Deviation Administrative Price (DDAP).

The MCAP for a given Trading Interval will normally equal the STEM clearing price for that Trading Interval. However, a different balancing price will apply if the real-time effective demand deviates from the total demand expected based on the combined bilateral and STEM positions of the Market Participants by more than ±5%.

The real-time effective demand is an estimate based on real-time data collected by System Management. The total demand expected based on the combined bilateral and STEM positions equals the load scheduled to be supplied by all generators via the bilateral and STEM processes.

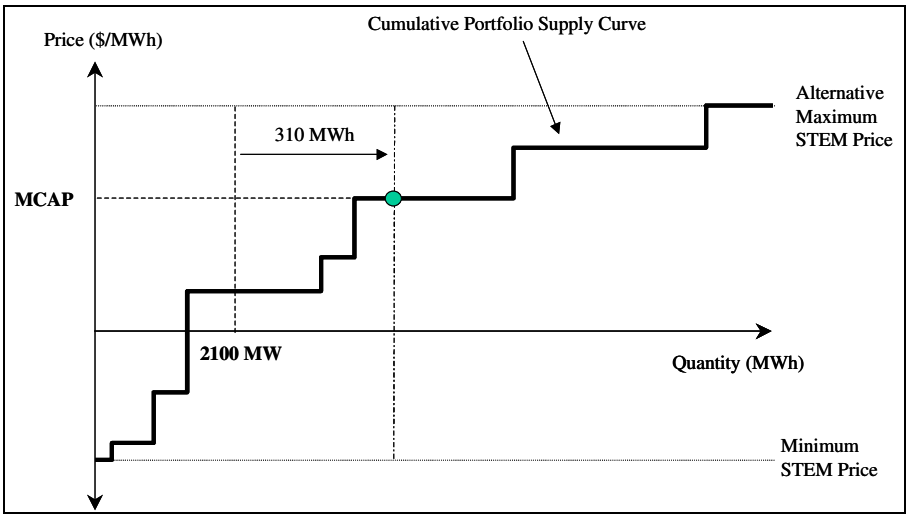
In effect, if real-time demand differs from pre-real-time expectations by less than 5% then the MCAP price equals the STEM price. Otherwise MCAP is explicitly calculated.

When required, MCAP will be calculated using the same methodology as was used to set the STEM auction price, except that an aggregate supply curve will be formed based solely on the Portfolio Supply Curves without considering the Portfolio Demand Curves. The price will be set at the point where a deemed demand quantity intersects the supply curve. This deemed demand quantity reflects the real-time demand modified upward to undo the impact of involuntary load curtailment (so as to ensure that prices are not artificially lowered because curtailment occurred) and to reflect energy that participants said they would provide via resource plans but failed to (which will have to be supplied by the Electricity Generation Corporation). Changes in the fuel that generators operate on, relative to what was declared in a Fuel Declaration, are not accounted for in this process.

To better understand this process, consider the situation where, based on the bilateral and STEM positions, we expected a demand of 2000 MWh. Now suppose that actual demand served in real-time was 2100 MWh, 10 MWh of load was involuntarily curtailed, and 200 MWh of energy scheduled under a Resource Plan was not provided due to a forced outage. The deemed demand quantity will therefore be 2310 MWh. To cover this, we require the 2000 MWh of originally scheduled energy, plus 310 MWh of additional generation to cover the 100 MWh of additional load, the 10 MWh of load curtailed, and the fact that 200 MWh of the originally scheduled energy did not materialise. By including the 200 MWh of outage of scheduled generator in this figure, we ensure that the price reflects the scheduling of more expensive generation to cover the outage. In effect, we would have to schedule 310 MWh of previously unused STEM Offers, with the last offer used setting the value of MCAP.

Exhibit 9-4 provides an illustration of the calculation of MCAP based on the example above. We see that by moving the price clearing point to the right by 310 MWh, the Marginal Cost Administered Price rises relative to the STEM. Had the demand adjustment been a large negative amount, MCAP would have fallen. Note though, that in most cases demand will not change significantly and MCAP will just equal the STEM Clearing Price.

Exhibit 9-4. The Marginal Cost Administered Price (MCAP)



The price in the STEM could be set by a Portfolio Demand Curve price-quantity step, consequently Exhibit 9-4 does not include any indication that the point where the 2100 MW line crosses the aggregate Portfolio Supply Curve corresponds to the original STEM price. However, typically the STEM price would be set at or near the price corresponding to this point.

The process used for setting MCAP only impacts on settlement prices and financial outcomes and has no impact on how facilities are scheduled in real-time, since dispatch occurs before MCAP is set.

The MCAP will be used to settle deviations from net contract position by

- the Electricity Generation Corporation in aggregate,
- Non-scheduled generators (including wind farms), other than those addressed by the first point.
- Non-dispatchable load, interruptible load and curtailable load deviations,
- IPP scheduled generators that are subject to commissioning tests or tests of their Reserve Capacity capabilities.

IPP generators that receive Dispatch Instructions from System Management (and are not subject to a test) will be settled based on pay-as-bid prices specified by the relevant Market Participant in standing data. In some cases, such as for facilities providing Network Control Service, the standing data will be set to reflect contractually agreed prices.

The Upward Deviation Price (UDAP) and the Downward Deviation Price (DDAP) are applied only to IPP scheduled generators (excluding those subject to a test) that deviate from their schedules without instruction beyond a tolerance. These deviations will be defined relative to the facilities output set by the Market Participant in a resource plan (see section 10.1) or, if a dispatch instruction is issued, to the effective schedule after modifying the resource plan schedule by the impact of that dispatch instruction. DDAP is the settlement price for deviations below scheduled quantity while UDAP is the settlement price for deviations above scheduled quantity. Since scheduled generators should not be deviating from their schedules, UDAP and DDAP are not attractive prices. The rules state that UDAP = 0.5 × MCAP during peak periods of the day (8 AM to 10 PM), and equals zero during off-peak periods (10 PM to 8 AM), while DDAP = 1.3 × MCAP during peak periods of the day and 1.1 × MCAP during off-peak periods. Additional rules ensure that DDAP and UDAP always lie between the Minimum STEM Price and the Alternative Maximum STEM Price.

A further modification is applied to the quantities to which UDAP and DDAP are applied in settlement in situations where UDAP and DDAP may not provide strong enough disincentives for deviating from schedule. Was this not to be done then a participant with a pay-as-bid price for increases that is less than MCAP may be quite happy to increase its output at a price of UDAP (which is also less than MCAP). The modification makes the effective per-unit payment for unauthorised increases equal to the pay-as-bid increase price less the amount by which MCAP exceeds UDAP, thus creating a disincentive for increasing output. Likewise, a participant with a pay-as-bid decrease price that is more than MCAP may be quite happy to pay DDAP for a decrease (since DDAP exceeds MCAP). The modification has it effectively paying a unit-price of DDAP plus the amount by which the pay-as-bid decrease price exceeds MCAP.

In practice, the IMO's settlement processes apply MCAP to all authorised deviations in the first instance. This is any deviation by Electricity Generation Corporation, Non-Scheduled Generators and Market Customer non-dispatchable loads and any deviation instructed by System Management for other registered facilities. In addition, in the case of generators other than the Electricity Generation Corporation, they then apply the applicable pay-as-bid price less MCAP to authorised deviations. Finally, UDAP or DDAP, as applicable, is applied to unauthorised deviations. These terms interact with respect to the different prices applied and the relative signs of the deviations (some quantities are positive and some are negative) to produce the net settlement payment for energy deviations.

UDAP and DDAP do not apply to the Electricity Generation Corporation because it has the obligation to follow load. Further, unlike IPPs, the Electricity Generation Corporation cannot specify pay-as-bid prices for the settlement of the Electricity Generation Corporation energy scheduled to balance the market. If the Electricity Generation Corporation deviates from its net contract position, whether for load following reasons or because it cannot match its net contract position, e.g. due to an outage, then it will be selling its surplus energy and buying its shortfall at MCAP. In other words, if the Electricity Generation Corporation does not match its contract position it is exposed to an effective "spot price" which approximates the actual cost of providing energy, regardless of whether that energy is provided by the Electricity Generation Corporation, demand-side reponse, or IPP resources.

However, if the Electricity Generation Corporation fails to comply with instructions from System Management in a significant manner, then System Management can specify a quantity of non-compliance for a given Trading Interval. This will have a non-compliance charge applied to it in settlement. The initial non-compliance charge value has been set to the Alternative Maximum STEM Price. It is expected that the non-compliance charge will be applied infrequently assuming that the Electricity Generation Corporation endeavours to follow System Management schedules and instructions.

Similarly, Market Customers are not generally exposed to UDAP or DDAP and have no pay-as-bid prices. The exceptions are that Dispatchable Loads are treated like generators, while curtailable loads may get pay-as-bid payments for decreasing output when curtailed. Non-Scheduled Generators (including Intermittent Generators) are not dispatchable so are not subject to UDAP or DDAP but, like curtailable loads, may get pay-as-bid payments when required by System Management to stop running or to decrease output.

9.5 Energy Market Settlement

The IMO will be responsible for settling the STEM and the Balancing arrangements. The key components of the STEM settlement will be:

- Those who buy energy in the STEM, whether by increasing consumption or decreasing supply, will have to pay the IMO for that energy.
- Those who sell energy into the STEM, whether by decreasing consumption or increasing supply, will be paid by the IMO for that energy.

The settlement payments for balancing will be as follows:

- The Electricity Generation Corporation will be paid MCAP if it must supply increased demand in balancing.
- The Electricity Generation Corporation will be charged MCAP if it purchases supply from IPP generators in balancing.
- If a retailer's demand exceeds its combined bilateral/STEM position then that retailer will have to pay the IMO for that energy at MCAP.
- If a retailer's demand falls short of its combined bilateral/STEM position then that retailer will be paid by the IMO for that energy at MCAP.
- With regard to Demand Side Management options, a curtailable load will be paid for any curtailment at a pay-as-bid price that is specified by the relevant Market Participant. However reserve capacity payments are likely to be the primary form of revenue for these loads. In the case of an interruptible load there is no balancing payment as it is expected to be funded under ancillary service contracts.
- If an IPP non-scheduled generator (including an intermittent generator) produces more than required by its combined bilateral/STEM position it will be paid by the IMO for that energy at MCAP.
- If an IPP non-scheduled generator (including an intermittent generator) produces less than required by its combined bilateral/STEM position it will have to pay the IMO for that energy at MCAP. A special case is where System Management instructs the IPP generator to turn off or reduce its output, any such reduction will be settled at a pay-as-bid decrease price specified by the relevant Market Participant.
- IPP generators, when rescheduled upwards by System Management will be paid by the IMO based on their pay-as-bid prices.[12]
- IPP generators, when rescheduled downwards by System Management will have to pay the IMO based on their pay-as-bid prices.
- An IPP dispatchable generator that produces more than required by its combined bilateral/STEM position, as adjusted by any dispatch instructions and after allowing for a tolerance, will be paid by the IMO for that energy at UDAP, though the payment may be further modified if UDAP is greater than the generators pay-as-bid increase price so as to ensure that the generator has a disincentive to increase its output.
- An IPP dispatchable generator that produces less than required by its combined bilateral/STEM position, as adjusted by any dispatch instructions and after allowing for a tolerance, without being instructed to do so by System Management will have to pay the IMO for that energy at DDAP, though the payment may be further modified if DDAP is less than the generators pay-as-bid decrease price so as to ensure that the generator has a disincentive to increase its output.

[12] Dispatchable Loads would be treated identically to IPP generators for the purpose of balancing, except that a payment for an increase in generation in the case of a generator becomes a payment for a decrease in load.

Settlement will not be a zero-sum process, as the UDAP and DDAP prices as well as the pay-as-bid regime will create a mismatch between income received and payments made. Given that Dispatch Instructions will not normally be issued to IPP resources, at least in the early stages of the market, and UDAP and DDAP generate income, the IMO will tend to recover more revenue than it pays out. To the extent that the Electricity Generation Corporation pays non-compliance charges then these will create surplus revenue. Further, since loss factors are based on averaged marginal losses, and marginal losses tend to exceed average losses, the application of loss factors to energy trades will tend to mean that consumers pay more than is required to fund losses. The end result of this is that some market revenue will typically need to be refunded to Market Customers each month as a non-STEM settlement payment called "reconciliation". While this is expected to be a payment to Market Customers, there may be some exceptions where additional payments must be made by Market Customers.

9.6 Market Advisories

The IMO must inform Market Participants of impending situations that could impact market outcomes. It will do this by issuing market advisories in the following situations:

- Market system outages, whereby aspects of the market cannot run normally due to systems failures; and
- Notification of suspension of any aspect of the market.

These advisories will include information on how Market Participants should respond to the situation. Note that advisories related to dispatch are called dispatch advisories, and are issued by System Management, as discussed in section 10.4.

10. Dispatch

After the STEM auction has been run, each Market Participant will have a net contract position equal to the Bilateral Submission net bilateral position as modified by their net purchase or sale in the STEM. In an ideal world, Market Participants would just follow these schedules in real-time, and would have nothing more to do but settle their bilateral transactions and STEM positions. In reality, the fact that a net contract position is held does not mean that it will be possible to physically transmit that energy in real-time. For instance, a transmission outage or a transmission line reaching the limit of its capacity could prevent all or some transactions being scheduled. Further, higher or lower demand levels, and the obligation on System Management to maintain system voltage and frequency within defined ranges, may require facilities to operate differently from the level implied by their net contract positions.

The dispatch process allows System Management to adjust schedules in real-time to ensure that power system security and reliability is maintained while, to the extent possible, facilitating trade in accordance with bilateral and STEM positions.

10.1 Resource Plans and Balancing Data

Before System Management can assess whether it needs to change the schedules of facilities, it needs to know what those schedules are. The net contract positions of Market Participants only tell it what the net supply or load of a participant will be and not what the output of each facility will be. To address this, Market Participants, other than the Electricity Generation Corporation, with generators and dispatchable loads must supply to the IMO a Resource Plan. Each Resource Plan Submission contains:

- Details of the submitting Market Participant
- For each Scheduled Generator or Dispatchable Load, details, by Trading Interval, of its MWh energy output level, its intended instantaneous output at the end of each Trading Interval[13], plus intended synchronisation and desynchronisation times.
- The total load belonging to the submitting Market Participant to be served by the facilities in the Resource Plan.
- Any known shortages, whereby the total supply by facilities, less the load of the Market Participant to be served, falls short of the net contract position. Market Participants will not be allowed to over-supply relative to their net contract position.

Market Participants other than the Electricity Generation Corporation must specify pay-as-bid prices for increasing and decreasing the output of their facilities (and for decommitting facilities including switching off intermittent generators). One set of prices will apply for the whole Trading Day. IPP Market Participants can submit energy related Balancing Data to the IMO daily or can specify it via Standing Data that applies for every day. Pay-as-bid decrease prices for non-scheduled generators

[13] This instantaneous dispatch information is required to give System Management a basis for issuing dispatch instructions and does not otherwise impact on settlement.

and decommitment price data is only recorded in facility standing data (as opposed to trading standing data) and cannot be submitted daily with energy market submissions.

Resource Plans and Balancing Data submissions can be submitted to the IMO between 11:00 AM and 12:50 PM on the Scheduling Day.

The IMO will use Balancing Data to produce a number of Dispatch Merit Orders, describing the order in which non-Electricity Generation Corporation facilities should have their output increased, decreased, or decommitted. Facilities with multiple fuel options will appear multiple times in the Dispatch Merit Order, once for each fuel.

The IMO provides the Resource Plan facility schedules, the Dispatch Merit Orders, and the Fuel Declarations to System Management by 1:30 PM. The Fuel Declarations allow System Management to know which fuel a dual fuelled generator will be using when interpreting the Dispatch Merit Orders.

The Electricity Generation Corporation does not submit a Resource Plan. Instead, System Management and the Electricity Generation Corporation will develop a schedule based on information provided monthly by the Electricity Generation Corporation. An initial schedule is developed based on the Net Contract Position data of participants, while a "final" schedule is developed once Resource Plans are available to System Management. System Management can make additional modifications to the "final" schedule if the supply and demand situation changes significantly following the end of the normal scheduling process.

Balancing Support Contracts are contracts that allow non-Electricity Generation Corporation facilities to assist the Electricity Generation Corporation in balancing the energy market. If this energy is scheduled via resource plans then it has no special treatment in the market. However, if System Management must call on energy under Balancing Support Contracts in real-time then the energy scheduled will be credited to the account of the Electricity Generation Corporation for market settlement, while the Market Participant providing the energy will not be settled by the market for that energy. This arrangement assumes that the Electricity Generation Corporation funds the provider of energy under the terms of its Balancing Support Contract.[14]

A Market Participant that submits a Resource Plan will not be able to unilaterally change the scheduling of its resources following the submission of the Resource Plan (without incurring some settlement charge for deviating from its schedule). Market Participants must communicate with System Management in situations where they cannot conform to their Resource Plan. For instance, Market Participants that submit Resource Plans must inform System Management of outages and, in the case of dual fuelled facilities, changes in the fuel they are operating on. System Management provides this information to the IMO after the Trading Day so that the IMO can factor that information into its settlement calculations.

[14] The Market Rules allow System Management to initiate the development of these contracts or for the Electricity Generation Corporation to enter into them of its own accord.

10.2 Dispatch Process

System Management will be responsible for dispatching the power system, and will have at its disposal the following information:

- Standing data on all facilities.
- Outage information.
- Resource Plans.
- Load forecasts developed by System Management.
- Ancillary Service Contracts held by System Management.
- Systems for monitoring the state of the Power System.
- Forecasts of Intermittent Generator operation (this information is to be provided directly to System Management as it is not used in any IMO processes).

System Management will schedule the Electricity Generation Corporation resources and, subject to contract conditions, ancillary service facilities in accordance with a procedure so as to match supply and demand while maintaining a secure and reliable power system.

System Management will generally not be allowed to issue dispatch instructions to non-Electricity Generation Corporation facilities (except those holding Balancing Support Contracts). Normally the Electricity Generation Corporation, capacity under Balancing Support Contracts and contracted Ancillary Services will respond to load changes and contingencies. Other than for dispatching Balancing Support Contracts the only situations where dispatch instructions could be issued would be where:

- System Management lacks the capability to maintain a secure and reliable power system using only the resources of the Electricity Generation Corporation, Balancing Support Contracts, or contracted Ancillary Services; or
- the only unscheduled Electricity Generation Corporation facilities would run on expensive liquid fuels if scheduled, while IPP suppliers have unutilised capacity from facilities that do not use expensive liquid fuels.[15]

These conditions could arise in a number of situations, but are most likely to occur in situations of exceptionally high demand, exceptionally low demand, or where network constraints apply. If System Management issues dispatch instructions to non-Electricity Generation Corporation facilities, it will be able to call on energy in accordance with the Reserve Capacity Obligations of the facility (or any further amount that the participant volunteers), subject to providing adequate time for the facilities to respond to the request.

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[15] If the situation changed so that the additional energy provided under such dispatch instructions were no longer required then the IPP facilities that had been dispatched up should be dispatched down first.

System Management will use the Dispatch Merit Order as a basis for issuing dispatch instructions to IPP Market Participants. If an IPP Market Participant changes the fuel used by one of its generators relative to the fuel it declared in its Fuel Declaration, then it must inform System Management. In dispatching a facility based on the Dispatch Merit Order, System Management will know what fuel the facility is using and hence precisely where the facility is ranked in the merit order. It should be noted that ramp rate limits and other operational constraints on facilities will mean that System Management may need to call on facilities out of merit order, or call on several facilities simultaneously, while transmission constraints may mean that System Management has no choice but to schedule particular facilities without regard for the merit order.

System Management will be able to issue dispatch instructions for a Trading Interval from 2 PM on the Scheduling Day through to the end of the Trading Day. Dispatch instructions will be issued via voice communications and other methods, but System Management will maintain a precise description of Dispatch Instructions issued, including required target outputs at the end of each Trading Interval.

The rules allow System Management to also change the unit commitment of non-Electricity Generation Corporation facilities. For each start-up or shut-down beyond the number in the Resource Plan, except as required by System Management under a contract or which is the first start up of the day for a facility holding Capacity Credits, the Market Participant will be entitled to compensation from the market equal to a pre-determined start-up or shutdown price specified in Standing Data. A Maximum Shutdown Price is defined in the rules as a measure to stop abuse of market dominance in situations where low demand requires generators to be decommitted. The Maximum Shutdown Price will initially be $55/MW. This figure has been estimated based on the expected opportunity cost of a generator during the period it is not running. The Maximum Shutdown Price will be adjusted annually based on inflation. There is no maximum price specified for generator start-up costs.

Following each Trading Day, System Management will be required to provide the IMO with a wide range of information needed by the IMO to determine balancing prices and to settle the market. This information includes:

- Dispatch Instructions issued to IPP facilities, and the reasons for those Dispatch Instructions. This will provide a means of auditing whether the instruction was appropriate, and also makes it apparent whether the Dispatch Instruction was made in accordance with a contract (e.g. for Ancillary Services or Network Control Service) or because the Electricity Generation Corporation lacked the capacity to balance the market.
- Energy output reductions requested from Non-Scheduled Generators and consumption reductions required from Curtailable Loads.
- Energy scheduled under Balancing Support Contracts.
- SCADA/Operational Meter Data pertaining to non-metered facilities and to system demand. Maximum daily on-site temperatures will also be required for some facilities where this information is used to assess the facilities Reserve Capacity obligations as a function of temperature.
- Details of each facilities outage status during the Trading Day.
- Any changes in fuel use by IPP generators relative to their Fuel Declarations.

- Details of curtailable loads and Supplementary Capacity utilised.
- The load forecasts used in real-time scheduling.
- Information on facility tests conducted during the Trading Day.

10.3 Dispatch Compliance Monitoring

System Management will be required to monitor the compliance of Market Participants with dispatch instructions and advise the IMO of any non-compliance. Apart from giving additional dispatch instructions and specifying an amount of non-compliance by the Electricity Generation Corporation to be used in settlement (see section 9.4), System Management will not be able to take any action against Market Participants who do not comply with dispatch instructions. Any action must be initiated by the IMO.

The IMO will monitor the performance of System Management. System Management will need to justify any dispatch instructions to the IMO via a periodic report.

10.4 Dispatch Advisories

System Management must inform Market Participants and Network Operators of impending or current situations that could have security ramifications for Market Participants and Network Operators. It will do this by issuing dispatch advisories in the following situations.

- Generation shortfall/load shedding occurring or expected.
- Conditions where committed generation running at minimum levels will exceed forecast load (over-generation).
- Any Ancillary service shortfalls.
- Major facility outages (generation, transmission, major loads).
- Fuel shortages that have a wide spread impact on the market.
- Dispatch or communication system outages.
- Notification of starting or ending a high risk or emergency operating state.

A dispatch advisory will include a statement of the operating state (Normal, High-Risk, or Emergency) during the period to which the advisory relates. These advisories will include information on how Market Participants should respond to the situation. The Market Rules recognise that sometimes System Management will have to react so quickly to a situation that it will not be able to issue a Dispatch Advisory until after the event.

Market Participants will be obliged to keep System Management informed of any circumstances that they become aware of that might result in System Management issuing a dispatch advisory.

11. Metering

Most of the metering processes are described outside of the Wholesale Market Rules. This is because the metering processes must address the requirements of wholesale, retailer and access metering. Hence the Market Rules focus on who must provide metering data, the process for submitting that data and the interface between the requirements of the market and the general metering regime.

A Metering Data Agent is required to maintain a registry of which meter corresponds to each Market Participant and must read meters and provide the data to the IMO for settlement purposes. Meter registry data must be provided to the IMO as required to support facility registration.

Each Network Operator has the option to be the Metering Data Agent for its own network, but if it does not take up this option then the Electricity Networks Corporation will fill this role.

The Metering Data Agent must provide meter data to the IMO on a monthly basis (though may submit data more frequently) where this data includes meter data for the previous Trading Month, and any updates to metering data previously submitted to the IMO. The Metering Data Agent must support the IMO in matters such as providing any additional data required in setting Individual Reserve Capacity Requirements for individual Market Customers.

Each Metering Data Agent must operate to a Metering Protocol. This is a generic term that means any arrangement between the Metering Data Agent and the wholesale/retail Market Participants it provides the service to. This generic term is used because some Metering Data Agents may be covered by the Access Code, while others may not be.

Any metering disputes arising in the wholesale market must be translated by the Metering Data Agent into an equivalent dispute under the Metering Protocol.

While a Metering Data Agent may have other metering duties under its Metering Protocol, these are not subject to the Market Rules.

12. Settlement

12.1 Settlement Process

The settlement process involves three main processes:

- STEM transactions are settled on a weekly basis.
- Non-STEM transactions are settled on a monthly basis.
- Any adjustments to settlement are made at least once every three months via a settlement adjustment process that corrects both STEM and Non-STEM settlements.

The Short Term Energy Market (STEM) is a forward market and no meter data is required for its settlement. For this reason the STEM market can be settled on a different timeframe from other transactions. A Trading Week is a period of seven days starting at 8 AM on Thursday and STEM transactions for that Trading Week will be summarised in daily STEM Settlement Statements and a weekly STEM Invoice. The STEM is settled on the third business day following the completion of the Trading Week.

All transactions other than STEM settlement would be included on the Non-STEM Settlement Statements issued by the IMO following each Trading Month and after meter data has been received.

Each settlement statement would include data in sufficient detail for the Market Participants to verify the accuracy of the statement.

The settlement adjustment process calculates the change in settlement position of all Rule Participants after accounting for all changes to settlement data stemming from updated data and resolutions of Notices of Disagreement and Disputes. A Notice of Disagreement is a relatively straightforward way for a Rule Participant to notify the IMO of any aspect of their settlement statements that it disagrees with. Upon receipt of such a notice, the IMO will investigate the issue itself if it relates to data developed by the IMO, or it will forward it on to the relevant Metering Data Agent or System Management. The IMO has three months to report back to a Market Participant as to whether it believes the original settlement statement was wrong. Payment of the originally invoiced amount must be made in the interim.

If the IMO issues an Adjusted Settlement Statement, a Market Participant can also issue a Notice of Disagreement up until nine months have elapsed since the original Settlement Statement was issued. This feature is included because the Market Rules do not require the IMO to retain old versions of settlement software in an operable fashion for more than 12 months (because of the cost of maintaining licenses etc).

If the IMO does not address an issue to the satisfaction of the Rule Participant through the disagreement process, the Rule Participant can dispute the matter. If the dispute is not resolved to the satisfaction of the Rule Participant, it has the option of taking the IMO to court.

12.2 Settlement Timelines

Exhibit 12-1 presents a summary of the Market Settlement timetable. In this table:

- "D" denotes the Trading Day.
- "W" denotes the Trading Week, starting on a Thursday, in which the Trading Day occurs. Trading Weeks relate to the settlement of the STEM.
- "M" denotes the Trading Month, comprising all Trading Days that commence within a calendar month, in which the Trading Day occurs. Trading Months are used for the settlement of non-STEM transactions.
- "BD" denotes a business day. Where a range of dates is presented, the IMO has discretion to choose a single date within that range, but must publish the actual dates prior to the start of each financial year.
- "SA" denotes the date on which a Settlement Adjustment process commences.

Exhibit 12-1. The Settlement Timetable

Day	Event
D	Trading Day ends.
1st BD after a Trading Week	The IMO issues a STEM Settlement Statement for each day and a STEM invoice for the preceding Trading Week in which day D occurs.
2nd BD after release of STEM Settlement Statement	Settlement date for STEM Invoice.
20th BD after release of STEM Settlement Statement	Deadline for notifying IMO of disagreement with STEM settlement statement. Any resolution of disagreements will be reflected in an Adjusted Settlement Statement (see below).
1st BD of month M+2	Generator and contestable customer meter data submitted to IMO by Metering Data Agents.
Not less than 10 BDs and not more than 5 BDs prior to non-STEM Settlement Statement issuance.	Submission of Capacity Credit transfers for the Trading Month. Between two and two BDs prior to the Non-STEM Settlement Statement issuance date the IMO will go through a process to ensure that the Capacity Credit transfers are not inconsistent with the Capacity Credits held by generators and the Reserve Capacity Requirements of the Market Customers to whom they are transferred.
Between 4th to 6th BD of month M+2	Non-STEM Settlement Statements for trading day D are issued. These are based on actual meter data for generators (the operational meter data in the case of Electricity Generation Corporation facilities that are not metered) and contestable customers, and estimates of the aggregate non-interval meter load of the Electricity Retail Corporation.
6th BD of month M+2	Invoice issued based on Non-STEM Settlement Statement for month M.
8th BD of month M+2	Settlement date for Non-STEM Invoice.

Day	Event
20th BD after issuance of Non-STEM Settlement Statement issued	Deadline for notifying the IMO of any disagreements with the Non-STEM Settlement Statement.
SA, a date set annually and occurring at least once every 3 months.	Commencement of Settlement Adjustment Process. All adjustments to settlement input data for STEM and Non-STEM transactions to be included must be provided to the IMO by this time. Changes in data will result from voluntary corrections of data by the issuing party or as a result of resolving disagreements and disputes. The issuing parties are, for metering data, the Metering Data Agents, for dispatch instruction related data, System Management, and for all other data the IMO.
By 20th BD after SA	IMO must have rerun all settlement runs to which adjustments have been made and must have issued Adjusted Settlement Statements in respect of all STEM or Non-STEM Settlement Statements originally issued.
2nd BD after issuance of Adjusted Settlement Statements	Invoice issued based on the Adjustment Settlement Statements issued as a result of the current settlement adjustment process.
2nd BD after issuance of invoices for Adjusted Settlement Statements	Settlement date for Adjusted Settlement Statement Invoice.
20th BD after issuance of invoices for Adjusted Settlement Statements	Deadline for notifying the IMO of any disagreements with an Adjusted Settlement Statement. Any adjustments will be addressed in a future adjustment process.

12.3 The Components of Settlement

Settlement Statements will include a variety of transactions. The key transactions are summarised in Exhibit 12-2.

Exhibit 12-2. The Components of Settlement

Settlement Component	Who Funds It?	On What Basis?
STEM	STEM Participants	STEM Quantities Traded
Targeted Reserve Capacity Cost. This is the cost incurred by the IMO in procuring just enough Capacity Credits (or Supplementary Capacity) to cover the difference between the Capacity Credits traded bilaterally and the total requirement of the market. Reserve Capacity security deposits drawn down by the IMO, if any, may offset any Supplementary Capacity	Market Customers	The Market Customer's Individual Reserve Capacity Requirement less the number of Capacity Credits it holds. If the customer has fully met their capacity requirement by trading Capacity Credits bilaterally, they will pay nothing.

Settlement Component	Who Funds It?	On What Basis?
cost.		
Shared Reserve Capacity Costs less the capacity component of Load Following costs. The Shared Reserve Capacity Costs are the costs of procuring Capacity Credits beyond the requirements of the market (to the extent this occurs) less any rebates and security deposits retained by the IMO as a result of non-compliance. The capacity component of Load Following is a rebate stemming from the fact that generators are fully funding these services despite consumers funding their capacity. i.e., both generators and Market Customers are paying for the capacity, so the generator payments are rebated to Market Customers.	Market Customers	In proportion to each Market Customer's Individual Reserve Capacity Requirement. Note that this will be a payment to the Market Customer if the IMO has not had to exceed the Reserve Capacity Requirement when acquiring Capacity Credits.
Spinning Reserve Cost (availability components)	Market Generators	Actual generation in each Trading Interval during a Trading Month.
Load Following	Market Customers and Market Generators	Metered MWh during the month for all loads and for Non-Scheduled Generators (but not Scheduled Generators)
Load Rejection Reserve, Commitment & Outage Compensation, Reconciliation (which may be negative)	Market Customers	In proportion to metered MWh during the month.
Non-Compliance Charge	Electricity Generation Corporation	Quantity of non-compliance
Network Control Service	Network Operators	Contract Terms
Balancing Payments (+ or -)	Market Customers and Market Generators	MWh deviation from contracts or schedules.
Market Fees These are used to fund the IMO, System Management and the Economic Regulation Authority)	Market Customers and Market Generators	Metered MWh during the month.
Default Levy (only following a default)	Market Customers and Market Generators	In the first instance, metered MWh during the month, but eventually adjusted to be relative to the metered MWh over a year.

12.4 Default

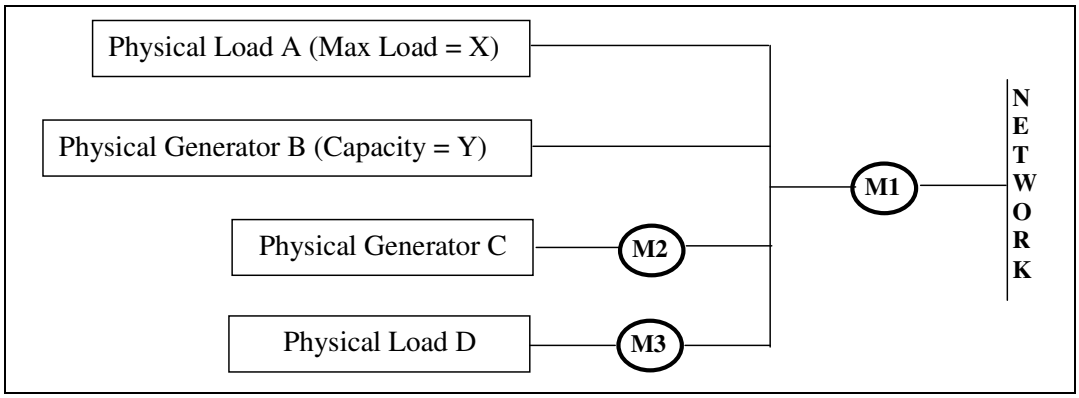
Default rules apply in the event of a Market Participant failing to meet its settlement obligations.

In the event of non-payment of bills the IMO will deem the Market Participant to be in default and may lay claim to credit support that it holds on behalf of the Market Participant. The Market Participant would be given at least 24 hours, and at the IMO's discretion, up to five business days to rectify the situation. In the event that the situation is not rectified, the Market Participant may, at the discretion of the IMO, be fully or partially suspended from participation in the market.

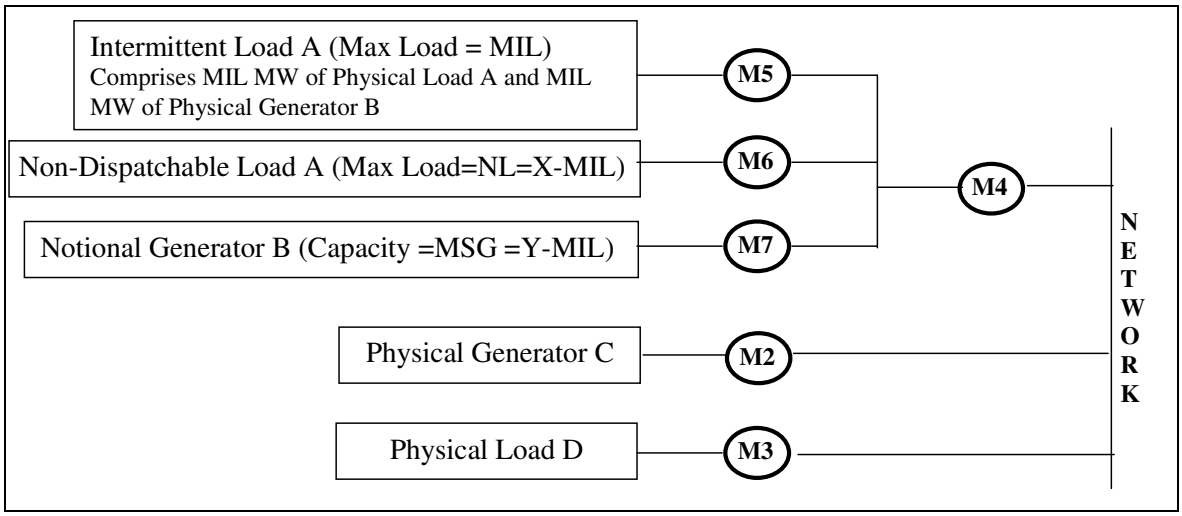
If following a default event the market lacks adequate funds to settle, then the shortfall will be funded by a levy on Market Participants. This levy will be collected a number of days after the default and will be allocated across all Market Participants based on their metered supply or consumption in the preceding month. The funds collected will be used to complete the settlement process. If the defaulting participant eventually pays its outstanding obligations, then the levy will be refunded. At the end of each financial year the default levy will be reallocated between Market Participants based on their metered supply or consumption over the year. This end of year adjustment ensures that participants do not avoid funding a default simply because they do not happen to be producing or consuming in the month in which the default occurred.

Appendix 1: Representing Intermittent Loads

This appendix describes how physical facilities are represented when an Intermittent Load is registered in the market. The following diagram describes the physical layout of generators, loads and meters associated with an Intermittent Load.



The next diagram shows how this system is represented when an Intermittent Load is registered.



The maximum intermittent load is declared to be MIL (which must be not more than the maximum load). Intermittent Load A comprises MIL MW of load from Load A and the first MIL MW of supply from generator B. This intermittent load may be non-dispatchable, curtailable or interruptible. Non-Dispatchable Load A is the remaining load of Physical Load A. Notional Generator B is the residual capacity of Physical Generator B. It will actually be registered like a normal generator except (a) it will be associated with the intermittent load and (b) its capacity figures (on each fuel) will reflect its residual capacity. Note that MSG may have a different value depending on which fuel is being used (but on each fuel the generator must have some residual capacity). Physical Generator C and Physical Load D are treated like normal generators and loads.

Where Meter M1 existed in the physical world we replace this with Meter 4, which is just Meter 1 less the metered values of Meters 2 and 3. i.e. M4 = M1 – M2 – M3. Thus M4 measures the net output of the facilities that are only metered by meter 1.

Under rules clause 2.30B.10 we must allocate the measurement for Meter 4 between Meters 5, 6 and 7 (none of which actually exist in the real world). Effectively we are allocating the measured value at Meter 4 between the three notional facilities.

The logic of allocating the M4 value is that:

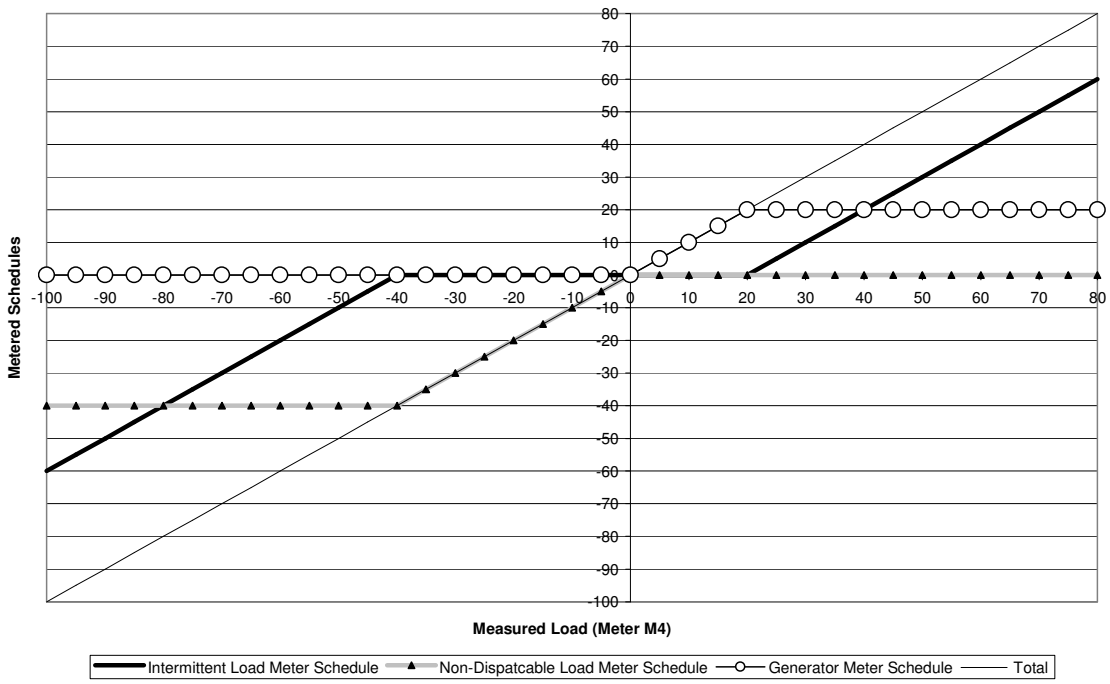
- Net supply is associated with Notional Generator B up to its capacity.
- Net consumption is associated with the Non-Dispatchable Load up to its capacity.[16]
- All other supply and consumption is associated with the Intermittent Load. This energy is settled at MCAP and Intermittent Load refunds only apply to net consumption.

Mathematically, the rules are:

- If M4 > MSG then M5 = M4 – MSG, M6 = 0, M7 = MSG
- If 0 < M4 ≤ MSG then M5= M6 = 0, M7 = M4
- If M4 = 0 then M5 = M6 = M7 = 0
- If 0 > M4 ≥ -NL then M5 = 0, M6 = M4, M7 = 0
- If –NL > M4 then M5 = M4 + NL, M6 = -NL, M7 = 0

Suppose the Physical Load A is 100 MWh (X=100), Physical Generator B can supply 80 MWh (Y=80), the Maximum Intermittent Load is 50 MWh (though this value is not actually used in the allocation), and there is no Physical Generator C or Physical Load D, we get the solutions in the following graph. The Intermittent Load Metered Schedule corresponds to meter M5, the Non-Dispatchable Load metered schedule corresponds to meter M6, and the generator Metered Schedule corresponds to meter M7.

[16] Earlier versions of the rules incorrectly associated consumption with the Intermittent Load first. This was illogical as it would mean that any Non-Dispatchable Load consumption would be seen as net consumption by the Intermittent Load, causing an Intermittent Load Refund to be applied.



The IRCR for the Intermittent Load is simply its nominated maximum intermittent load (MIL) multiplied by the system reserve margin. So if the system reserve margin is 15% then the IRCR for the Intermittent Load is 0.15 MIL. This reflects the fact that generator is covering the Intermittent Load. However, whenever Intermittent Load has net consumption beyond 3% of MIL at a time when the first MIL MW of Physical Generator B is not on planned outage the Intermittent Load must pay intermittent load refunds (because this implies that the generator may be on an outage and would be exposed to refunds if it were a normal generator with capacity credits).

The non-dispatchable load on meter M6 will have its IRCR determined in the normal fashion, with its IRCR typically being in the region of 115% of its peak summer load if the system reserve margin is 15%.

From an IRCR perspective a participant wants to maximise its intermittent load and minimise its dispatchable load. However it needs to trade off the risk of refunds if its generator is not reliable enough to cover the intermittent load.

The IMO will be monitoring registrations to ensure that the declared non-dispatchable load NL value reflects a realistic representation of the actual peak non-dispatchable load which is not Intermittent Load.

Note that under special circumstances Physical Generator B may be at an entirely different node, but for the purpose of the above processes, it must be metered (M8) and is translated by the combination of its loss factor and the intermittent load nodes loss factor to be merged into the meter value for M1. i.e. M1 = M4 – M2 – M3 – (M8 * LF_PGB / LF_IL) where LF_PGB is the loss factor for Physical Generator B's node and LF_IL is the loss factor for the Intermittent Load node. Consequently everything else works in the same way.

Appendix 2: Summary of Market Activities

Activity	Administrator of Activity		Parties to Activity					
	Independent Market Operator	System Management	Independent Market Operator	System Management	Electricity Generation Corporation	Network Operators	Market Customer	Independent Market Generator
Rule Change	x		x	x	x	x	x	x
Changes to Market Procedures relating to System Operation	x			x				
Changes to other Market Procedures.	x		x					
Registering as Rule Participant	x				x	x	x	x
Facility Registration	x				x	x	x	x
Reserve Capacity Procurement	x				x		x	x
Capacity Supplying Intermittent Loads	x						x	x
Supplementary Reserve Capacity Procurement	x						x	
Network Control Service	x					x	x	x
Bilateral Contract Data Submission	x				x			x
Short Term Energy Market	x				x		x	x

Activity	Administrator of Activity		Parties to Activity					
	Independent Market Operator	System Management	Independent Market Operator	System Management	Electricity Generation Corporation	Network Operators	Market Customer	Independent Market Generator
Resource Plan Submission to IMO	x							x
Scheduling of Electricity Generation Corporation		x			x			
Resource Plan Submission to System Management (including real-time updates)		x	x					x
Dispatch		x			x	x	x	x
Submission of Dispatch Schedules to IMO	x			x				
Balancing Pricing	x			x	x		x	x
Settlement	x				x	x	x	x
Prudential Requirements	x				x	x	x	x
Compliance Monitoring with respect to Security and Reliability		x			x	x	x	x
Compliance Monitoring other than for Security and Reliability.	x			x	x	x	x	x
Outage Planning		x	x		x	x	x	x
Commissioning Test Planning		x			x			x
10 Year Generation Planning	x				x	x	x	x
10 Year Transmission		x (Electricity			x	x	x	x

Activity	Administrator of Activity		Parties to Activity					
	Independent Market Operator	System Management	Independent Market Operator	System Management	Electricity Generation Corporation	Network Operators	Market Customer	Independent Market Generator
Planning		Networks Corp)						
3 Year Capacity Planning		x			x	x	x	x
3 Week Capacity Planning		x			x	x	x	x
Ancillary Service Requirements	x			x				
Procuring Ancillary Services		x			x		x	x
Balancing Support Contracts		x			x			x