



Office of Energy
Government of Western Australia

Wholesale Electricity Market Design Summary

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1. Introduction

A new Wholesale Electricity Market is being established for the South West Interconnected System (SWIS) of Western Australia. The establishment of the new market is a key component of Western Australia's electricity reform program. The market will facilitate competition, and encourage private investment in the generation and retail sectors of the electricity industry. The market will also include a mechanism for ensuring that adequate generation and demand side management capacity is available to maintain reliability and security of electricity supply. The ultimate objective of the Wholesale Electricity Market is to provide benefits to the community by facilitating competition and minimising the cost of electricity supplied to consumers in the SWIS.

This document is a summary of the market design represented by the Wholesale Electricity Market Rules, Version 1.0. This design is projected to be fully operational by mid-2006, but the Reserve Capacity procurement process will begin 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 is provided for general information only and should not be considered to be definitive, as only the Market Rules can provide a complete and fully reliable 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 of 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 Support Service.
- Section 9 covers the energy market rules.
- Section 10 describes the dispatch process.
- Section 11 provides a short description of metering issues.
- Section 12 describes the settlement process.

A number of appendices are also included.

- Appendix 1 provides a table of key events during the course of market implementation, as well as key milestones of market operation. These dates are provisional.

- Appendix 2 provides a summary of the various processes in the market, and indicates who administers the process and who participates in that 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 Market.
- **System Management:** System Management is the “System Operator”. It conducts short and medium term (up to 3 years) system planning, including outage planning. It schedules Western Power’s resources to met Western Power’s contractual requirements, while respecting Independent Power Producer (IPP) transactions. In real-time it dispatches the power system, but can only change IPP schedules under special circumstances.
- **Network Operators:** This is a person who operates, or intends to operate, a transmission or distribution network within the SWIS that is required to be registered. Network Operators can also be Metering Data Agents, these being the parties that provide settlement data to the IMO. The network business unit of Western Power is the default Metering Data Agent if another Network Operator does not want to fill this function.
- **Market Generator:** This is a person who 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 be required to register, with most smaller generators having the option to register.
- **Market Customer:** This is a retailer or any other person purchasing power from the market for the purpose of consumption or retail sale. The retail business unit of Western Power is the Market Customer that supplies non-contestable retail customers and is the supplier of last resort for the retail market.
- **Western Power:** Western Power will be registered as a Market Generator, a Market Customer, and as a Network Operator. Western Power will also fill the role of System Management. In most cases, the rules apply to Western Power’s Market Generator, Market Customer, and Network Operator functions as they would for any other Market Participant. The main exceptions to this are that:
 - Western Power facilities follow a different scheduling process;
 - Western Power, via System Management, is required to provide ancillary services; and
 - Western Power must balance the entire system in real-time.

All these entities must be registered as Rule Participants, though 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 capacity available each year to meet system peak demand plus a reserve margin. Each Market Customer will be 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 through the Reserve Capacity auction. If an over-capacity situation were to arise, then the cost of the over supplied capacity will be shared across all Market Customers, irrespective of whether they hold Capacity Credits.
- **Bilateral Contracts.** Bilateral trades of energy and capacity occur between Market Participants and the market has no interest in how these trades are formed. However, Market Participants will be required to submit Bilateral Scheduled data pertaining to bilateral energy transactions to the IMO each day so that the transactions can be physically scheduled.
- **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, effectively producing a new net bilateral contract position. The IMO will collect supply and demand price curves from Market Participants once a week to apply for the next week. Different supply and demand curves can be specified for each half hour Trading Interval. Each day, the IMO will collect half hour Bilateral Schedule data from Market Participants, and use these and the weekly supply and demand curves to define STEM offers and STEM bids relative to the contract position for each Trading Interval. A STEM Offer is an offer to increase the net supply of energy beyond the Bilateral Schedule 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 bilateral and STEM position of a Market Participant describes its net contract position.
- **Dispatch/Balancing Process.** Market Generators other than Western Power 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 in each Trading Interval and the total load to be supplied by a participant. System Management will schedule Western Power resources around those schedules, but it may issue dispatch instructions to other Market Generators if it cannot otherwise maintain security and reliability, or if it would have to use expensive liquid fuelled plant while other Market Generators have non-liquid fuel capacity available. After the Trading Day, the IMO will determine "administrative" balancing prices to apply for unscheduled deviations from the schedules, with those IPPs who were given Dispatch Instructions being settled on a pay-as-bid basis.

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. Under the Market Design, Western Power will be required to provide these services, either from its own resources or by procuring them 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 location of a generator or demand-side management option in an isolated location to mitigate the need for new transmission or distribution investment, then it can request the IMO to run a tender for such service. The IMO will run a tender in which a transmission proposal competes with other proposals. 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 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 and, in the case of the Network Support Service, Network Operators will have to meet prudential conditions for participating in the market. A Market Participant will have to provide 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. A Network Operator will need to provide credit support to cover the maximum amount that could be owed under a Network Support Service contract over that same period.

If at any time a Market Participant has inadequate credit support, it will be given a Margin Call, and is required to very quickly provide more 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 ever been declared to be in default in the National Electricity Market operating in the eastern states.

Network Operators are not subject to Margin Calls as they 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:

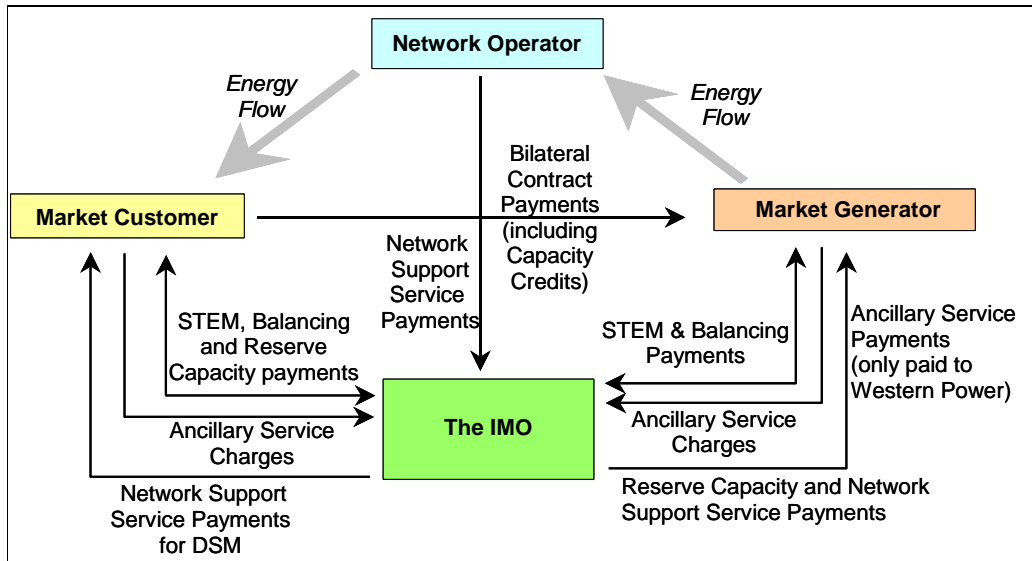
- **Scheduled Generators:** These are generators capable of being scheduled to operate at a specified level ahead of real-time, and can be dispatched by System Management up or down in real-time relative to that level. Most large generating stations fall into this category.
- **Dispatchable Loads:** 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.
- **Curtable and Interruptible Loads:** A curtable load can be interrupted on request, while an interruptible load is interrupted automatically in response to a frequency change. An interruptible load is effectively also a curtable load, but a curtable load is not necessarily an interruptible load. These demand side management options will generally be contracted, but a Market Participant can also use them to manage its exposure to market prices.
- **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.
- **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.

There is no requirement to register Non-Dispatchable Loads as “facilities”. However, the IMO requires some information with respect to them, such as meter information.

2.7 Market Settlement

The IMO is the party with which Market Participants trade, 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 via bilateral contracts between Market Customers and Market Generators. These bilateral contracts can have energy and capacity components. Reserve Capacity payments can be accounted for by reducing bilateral contract payments.

Market Customers and Market Generators can modify their bilateral position via trading in the STEM or, if they have inadequate coverage by real-time, by buying or selling energy via the Balancing process.

While Western Power is required to secure ancillary services, it will be able to pass on some of the costs of these services to the market.

Settlement of the STEM will occur on a weekly basis, while other transactions will be settled monthly. It may take up to 30 days after the end of a month to receive interval metering data for a month, so preliminary settlement for a trading day at the start of a month is not expected to occur until about 70 days later. Settlement adjustments will be made at 3 month intervals for up to a year, allowing for resolutions of disagreements and improved meter data.

In the event a Market Participant, or a Network Operator funding Network Support Service, defaulting on payments to the IMO and inadequate credit support is available to cover the shortfall, then the IMO will, in the first instance, reduce payments it makes in market settlement to reflect the funds it actually receives. If the over-due payment is not resolved, or if credit support for the defaulting party is inadequate, such that the IMO cannot complete settlement of the amounts it owes, it will be empowered to raise a default levy from all Market Participants and Network Operators funding Network Support Service so as to recover the shortfall. It should be noted that default is expected to be a very rare event. For instance there has been no case of default in the National Electricity Market operating in the eastern states since its establishment in 1998.

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 other than Western Power and forwarding these 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.
- 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 will be appointed by, and will report to, the Industry Minister. The Industry 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 Industry 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 Network business unit of Western Power, 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
- Conducting tests of equipment
- Coordinating the operation of Western Power facilities and issuing Dispatch Instructions to non-Western Power facilities
- Monitoring Rule Participants for rule breaches relating to dispatch and power system security and reliability, and reporting 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 Participants 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. 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 Participants to undertake a study.

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 Western Power 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 will maintain and develop the Market Rules. The IMO is an independent body, and generally will not have any incentive to modify the Market Rules to in a way that is detrimental to the market. However it is recognised that in some areas there are potential conflicts of interest in the IMO having administrative control of the rules that govern its own practices and behaviour. The Market Rules include a number of features to address these issues.

Any market rules that relate to issues where the IMO would face a possible conflict of interest were it to attempt to modify the rules are “protected provisions”. Protected provisions will be identified in the rules, and the IMO will not be able to change those provisions without the Industry Minister’s approval of the amendment.

Any decisions made by the IMO to adopt a market rule change can be appealed to the Energy Review Board on procedural grounds. The Energy Review Board will only be able to overturn such rule changes if the IMO has not followed the correct market rule change process.

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

Finally, the Economic Regulation Authority will approve the costs of the IMO.

4.1.2 The Rule Change Process

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

Upon receiving a rule change proposal, the IMO must decide whether it considers a 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 should 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 6 weeks. The normal rule change process includes two rounds of consultation, with a draft report published by the IMO, and would usually takes 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 properly develop or evaluate changes.

The IMO 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 will not have responsibility for maintaining the market rules. During this interim period the Minister will retain 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.

It is not anticipated that there will be fundamental design changes to the market during this interim period. However, the ability to change the rules is required to address issues arising during the course of implementing the market and the market IT systems in particular.

4.2 Procedures

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

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

Both the IMO and System Management will be subject to the same process for developing new procedures or changes to existing procedures. Once either the IMO or System Management proposes a change, the IMO will publish a procedure change proposal, request submissions from the public and 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 will prepare a report on the Procedure Change Proposal, including the amended wording, feedback it has received, together with a time and date for the new Procedure to come into force. Where the change relates to

System Management's procedures, the System Management will prepare the report, and must gain the IMO's approval for the procedure change.

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

4.3 Market Parameters

The market makes use of a number of parameters, the value of which will materially change the cost and benefits of participating in the market.

The IMO will propose 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 very 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 limits define the most extreme prices that participants can bid and offer as well as the most extreme market clearing prices that can occur. The Alternative Maximum STEM Price will be updated monthly based on changes in oil prices, while the Maximum STEM Price and the Minimum STEM Price will be adjusted automatically for inflation on an annual basis. The IMO will review all the price caps annually and, if, after consultation with industry, it believes changes beyond the automatic changes are required, it will submit 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 initial market price limits are:

- Maximum Reserve Capacity Price = \$150,000/MW
- Maximum STEM Price = \$150/MWh
- Minimum STEM Price = \$150/MWh
- Alternative Maximum STEM Price = \$385/MWh
- Maximum Shut Down Price = \$55/MW

It should be noted that the market rules include inflation and oil price adjustments that may cause some of these price limits to be slightly modified by the time of energy market commencement.

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 will audit the calculation process.

4.4 Enforcement of the Market Rules

The classes of offences under the Regulations for breaches of the market rules will be:

- Category A for less serious offences, such as failure to provide information when required to; and
- 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 Industry Minister.

When the IMO becomes aware of a rule breach by a Rule Participant, it must log the breach, warn the relevant Rule Participants that they appear 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 such 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 affect on Rule Participants. 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 will determine 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 Industry 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 Western Power's budgeting process which is overseen by the Government Enterprises Minister. The IMO will provide advice to the Industry 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 on metered 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.	<p>Must register as a Network Operator, except in the following situations (in which case registrations is optional):</p> <ul style="list-style-type: none"> • 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. <p>A person who intends to own control or operate a network may also register.</p>
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.	<p>Must register as a Market Generator unless the IMO has exempted the person from the requirement to register (in which case registrations is optional):</p> <p>A person who intends to own control or operate such a generator may also register.</p>
Owns, controls or operates a generating facility, with a rated capacity of less than or equal to 10 MW, but greater than 0.2 MW, which is connected to a network in the SWIS.	<p>The person has the option to register as a Market Generator but this is not compulsory.</p> <p>A person who intends to own control or operate such a generator may also register.</p>
Sells or intends to sell electricity to customers in the SWIS.	<p>Must register as a Market Customer unless the IMO has exempted the person from the requirement to register (in which case registration is optional):</p> <p>A person who intends to sell electricity to consumers may also register.</p>
Any other person who sells or purchases electricity or another service contemplated by the Market Rules to or from the IMO.	<p>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):</p>
System Management	Automatically registered as System Management.
The IMO	Automatically registered as the IMO.

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; and
- be capable of being sued in its own name in a court in Australia.

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

With the exception of the IMO and System Management, it will be 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 the 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 allowed to occur 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
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 0.2 MW in capacity. Cannot be any other type of facility

Facility Type	Definition	Restrictions
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.
Curtaileable 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, though Market Customers serving non-dispatchable load will need to register the locations at which they have load.

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 forbid two generating units at one location from aggregating because it needs one of those units to be scheduled 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.

The registration process for a facility would involve 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 unless the facility, and its Capacity Credits, is transferred to another Rule Participant.

5.3 Prudential Requirements

All Market Participants, and any Network Operators required to fund Network Support Service, will be 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 2 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 the Network Support Service over that period.
- **Credit Support:** This is a guarantee of unconditional payment of a set level of funds to System Management 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 provide Credit Support to cover its Credit Limit. For a Network Operator this is the only prudential requirement. 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. If the prudential factor were to equal one, then, as discussed, below, a margin call could only be made once a Market Participant's debt to the IMO reached its Credit Limit. Given that it takes some time to resolve a margin call, a prudential factor of one would pose a risk to the market. Instead, the prudential factor will have a value less than one, ensuring that when a margin call is made, there is still Credit Support available to cover the period until the margin call is addressed.

If a Market Participant is getting close to its Trading Limit it 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:

- zero; and
- 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 that Market Participant's security deposit to settle a transaction entered into by the 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 5 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 this is addressed under the settlement rules.

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 will be 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-Western Power generators, where necessary, based on a set merit order
- 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 will determine what operating state the power system is in, and must inform the market of any changes in state as soon as possible, but ideally within 15 minutes of the state commencing. System Management periodically 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 Western Power resources; and

- If Western Power lacks adequate resources, through contracting with third parties. Any contracting must be on a least cost basis and may involve a competitive tender.

Western Power's budget will include the cost of procuring ancillary services, where budgeted costs must be in accordance with those approved by the Economic Regulation Authority. The IMO will recover the costs of the ancillary services from Market Participants through the wholesale market settlement systems, and will pass the payments to Western Power.

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. In effect, 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).
- **Fifteen Minute Reserve.** This service holds capacity in reserve to respond over a longer timeframe than spinning reserve. The capacity would include on or off-line generation capacity, dispatchable loads and curtailable loads.
- **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 so that the power system can be re-energised following a system wide black out.

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, metered Non-Scheduled Generation, and the first 7200 MWh per month of output from Scheduled Generators. The 7200 MWh figure corresponds to an average consumption of 10 MWh for 24 hours per day for 30 days, and is set so that Scheduled Generators are settled on the same basis as non-intermittent Non-Scheduled Generators (which must have an energy output of not more than 10 MWh).

- The monthly costs of spinning and fifteen minute reserve are borne by generators in proportion to the deemed risk that the generator imposes on the system, based on the capacity and reliability of the generator. A generator that has been more reliable over recent years will pay less than an equally sized but less reliable generator. This gives investors in new generation capacity a strong incentive to manage the risks they impose on the system.
- 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 will have 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 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 6 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.
- Possible security problems that could affect market or dispatch outcomes, including fuel supply problems.

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 reassesses the inclusion of their equipment on this list to the IMO.

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; and that
- shows no bias towards a Market Participant or Network Operator in accepting outages.

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 negotiated with affected 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 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; and
- 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 10 business days of System Management's decision but not later than 5 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 2 days before the outage commencement, so that it can ensure it has adequate capacity available. 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, 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 outages other than those for opportunistic maintenance are delayed or cancelled by System Management within 48 hours of their commencement then the affected party can apply for compensation. Compensation will only be paid for the 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 energy purchases. If the compensation required happens to exceed \$50,000 then the IMO may spread the recovery of the compensation over up to 6 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. Reserve Capacity penalties may apply as a result of forced outages.

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.

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 5 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 plus adequate additional capacity to ensure demand can be met 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. While the Reserve Capacity mechanism may fully fund the capital costs for peaking facilities, it may only cover some of a baseload unit's capital costs.

The IMO will administer 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 will run an annual auction to procure Capacity Credits for on-sale to Market Customers.

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 9 years out of 10; and to

- 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 would 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 and STEM Offers, 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 wide 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 once it first satisfies its obligations (defined as providing at least 90% of the energy it is obliged to provide on a day when its obligation has not been reduced to zero because of outages).

The IMO will, for an administration fee, offer a service whereby Market Participants can 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 none of the information upon which the conditional certification was based has changed, and all necessary approvals 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.

In September 2005 and in August of each subsequent year, the operators of all other facilities holding Certified Reserve Capacity will 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 no longer ahead 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 requirements are satisfied. However, there are a number of additional rules imposed on this process:

- 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 5 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 5 trades then it would be accepting 25 MW of capacity when only 15 MW could be used. Thus the IMO should only accept bilateral trades from 3 of the facilities. In deciding from which 3 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.
- If multiple facilities have the same availability but are not all required then the IMO will apply the following selection criteria until the require capacity is accepted. 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 are operational or are under construction will be accepted first.
 - Facilities that can demonstrate having secured financing will then be accepted.

- Facilities with the greatest quantity of Certified Reserve Capacity will be accepted ahead of facilities with lower Certified Reserve Capacity
- 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.

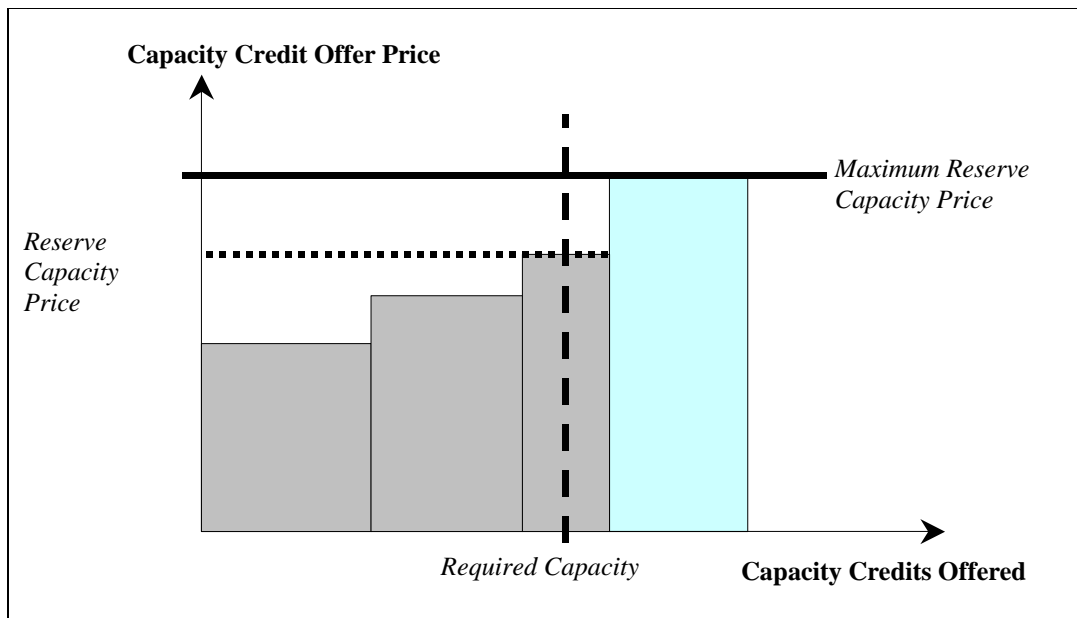
If enough Reserve Capacity were traded bilaterally to meet the Reserve Capacity Requirements of the SWIS then no auction would be held, and all the bilaterally traded Reserve Capacity would be converted to Capacity Credits.

If the total bilateral trade did not fully cover the total Reserve Capacity Requirement, then the bilaterally traded Reserve Capacity would become Capacity Credits, and the remainder procured to cover the shortage would become Capacity Credits only as a result of the auction.

Each auction will be held in September, except in 2005 when it will be held in October, 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 for the first auction is \$150,000/MW per year.

Exhibit 7-1 illustrates the 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. 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.
- 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.

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.

Capacity Credits not offered into the Reserve Capacity auction can be assigned by the operators of the facilities holding them to Market Customers, providing Market Customers with an exemption from funding the Reserve Capacity auction. In effect, this capacity is funded bilaterally. If the bilateral arrangement ceases at any time, then the IMO will still pay the facility holding the Capacity Credit the prevailing auction price. However, a Capacity Credit offered into the auction will be held by the IMO for the entire Capacity Year, and cannot then be bilaterally transferred to a retailer during that Capacity Year.¹ Capacity Credits offered into an auction, but not sold, would terminate, as such Capacity Credits are not required for the Capacity Year.

Once issued, those who have procured Capacity Credits via the bilateral trade process are free to trade them 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 come into being. There are some exceptions to this:

¹ 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.

- 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 market commencement, which will be no earlier than mid-2006. 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. DSM Capacity Credits, on the other hand, will only become active in the period 1 August, 2007 to 30 November 30, 2007 as we do not want to encourage them to be available earlier than 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.

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 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. This leaves a new entrant facility that cannot secure bilateral contracts with a bankability problem.

To address this concern 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 if it is scheduled in a Reserve Capacity Auction. This arrangement will allow the Market Participant to receive the auction price it earns in the first year in each year the Long Term Special Price Arrangement applies, though inflation adjusted. The duration of the Long Term Special Price Arrangement can be selected by the Market Participant, but must not exceed 10 years, except for the first auction where it cannot exceed 15 years. 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 capacity actually certified.

A Short Term Special Price Arrangement 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 2 months before the start of the Capacity Year. A different Reserve Capacity price will apply at that time, and therefore they will be required to take up a Short Term Special Price Arrangement for those few months so that they effectively see the price to apply in the Capacity Year for which they were scheduled. Note that a facility scheduled in the auction and which is commissioned 2 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 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 and Supplementary Capacity 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 will be included to cap the exposure of Capacity Credit and Supplementary Capacity 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 term of the obligations cannot exceed the value of the original payments over the term of the contract. 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 rebated to all Market Customers who have either secured Capacity Credits through bilateral trade or from the IMO. These rebates will not just be focused on those funding the auction, as only a subset of Capacity Credits will be traded through the auction, and in some years there may not need to be an auction if retailers hold adequate Capacity Credits.

7.7 Funding the Reserve Capacity Auction

All Market Customers, being consumers or retailers purchasing from the wholesale market, will have an Individual Reserve Capacity Requirement set, which will equal a share of the Reserve Capacity Requirement, allocated to them based on their expected contribution to system peak demand. The allocation of Reserve Capacity will be reviewed monthly and if market shares have changed significantly then the share of Reserve Capacity Requirements will be re-allocated.

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 Special Price Arrangement payments for that month.

The Targeted Reserve Capacity Cost is allocated in proportion to each Market Customers Capacity Credit shortfall.

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 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 Allocations

Capacity Credits applicable to the current Capacity Year that have not been sold to the IMO in the Reserve Capacity auction can be allocated from the supplier of Reserve Capacity to a Market Customer, with this transfer being 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, while allowing the supplier and Market Customer to trade capacity at a bilaterally agreed price.

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, as exceeding the amount it is allowed to hold. 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.

Note that there is nothing preventing parties to a trade of Capacity Credits from settling the transaction without involving the IMO. The IMO only provides this settlement service as a means of reducing prudential requirements in the market.

7.9 Reserve Capacity and Generator Investment Strategies

The idea of holding Reserve Capacity auctions 2 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 based 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 there is nothing stopping that spare capacity being offered into the auction to gain additional revenue.

Since Reserve Capacity auctions are held 2 years prior to the obligation commencing, if an existing facility fails to win a place in an auction then its owner will have 2 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 has not been cleared in the auction suggests that the market can acquire new capacity at a lower cost.

A pre-condition for a new facility that is yet to be commissioned to be certified to provide Reserve Capacity will be a letter of offer for an access agreement from its Network Operator and evidence of environmental approval. 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 noted above, a process exists for conditional certification of Reserve Capacity for facilities under development so that they can have certainty as to the amount of Capacity Credits they can hold some years prior to the normal application time. This will facilitate financing and the formation of bilateral contracts.

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 than 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.

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, without the facility having to offer that energy into the market. 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.

8.3 Network Control Service Tenders

Anyone that wishes to participate in the Network Control Service tender must be registered as a Market Participant. It 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 Payment Guarantee that the tender respondent is offering and the usage cost they wish to recover when called upon.

The IMO selects tender responses to achieve the lowest total cost while covering the requirement. The total cost is based on the value for the accepted tenders of the sum of the required Monthly Payment Guarantees 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 Monthly Payment Guarantees for 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 Network Control Service 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 Payment Guarantee;
- less the value of Capacity Credits held by the facility, valued at the prevailing monthly Reserve Capacity settlement price; and
- less the cost of any liquidated damages stemming from non-compliance.

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. To the extent this happens, its payment under the Reserve Capacity mechanism will be reduced, being replaced by a bilateral 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 market 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 contract with their network service provider.

The holders of bilateral contract energy 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. The IMO will allow Bilateral Submissions to be made between 8 AM and 8:30 AM on the Scheduling Day. It then validates these submissions, with submitters having until 9:30 AM to resubmit any submissions that the IMO rejects as being inconsistent with the requirements of the rules. 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.
- In the case of Western Power, the total loss adjusted Western Power load, in MWh, to be supplied by Western Power.

The information on Western Power load is required because the other information only relates to net sales and purchases from each Market Participant, and does not give the market any information as to how much of its own load a Market Participant will supply. The market does not require this information for independent generators because they will specify it as part of their Resource Plan data later in the process. Since Western Power does not issue Resource Plans, it must provide the data so we have a basis of determining deviations from its contract position by loads.

The loss adjustments described above are based on static loss factors fixed for the 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.

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, and 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 loads. 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. Because bids and offers are based on net supply, those bids alone cannot define compliance with

Reserve Capacity obligations. Instead, compliance with the obligations is based on the total energy supplied under Resource Plans, plus the STEM Offers.

To reduce the potential for the exercise of market power, the bid and offer information used in the STEM must be specified weekly, and cannot be revised during the week. This was seen as a means of allowing Western Power to participate in the STEM in a way that minimises the risk to other Market Participants that Western Power will abuse its dominant position.

While STEM Submissions are made weekly, the STEM market is still cleared daily, based on the weekly STEM Submissions and the daily Bilateral Submissions.

All Market Participants may make Weekly STEM Submissions. Weekly STEM Submissions must be made to the IMO between 8 AM and 10 AM on Tuesday of each week. The IMO will review and approve or reject these submissions by 2 PM, with Market Participants having an opportunity to address errors through to 5 PM on Tuesday. Accepted submissions will be first used in the STEM Market run on Wednesday for the Trading Day (and Trading Week) starting at 8 AM on Thursday.

The Weekly STEM Submissions cannot include offers to sell and bids to buy relative to a Bilateral Contract position, as the Bilateral Submissions are not made until later. Instead, the Weekly STEM Submissions contain information that will allow the IMO to generate offers and bids once the Bilateral Submission has been received. In effect, Market Participants must offer their entire capacity in the Weekly STEM Submission, and the IMO will subsequently convert this submission to an offer to buy or sell energy relative to a bilateral contract position.

A Weekly STEM Submission comprises the following information:

- The identity of the Market Participant to whom the submission applies.
- For each Trading Interval of the Trading Week, a price-quantity curve covering the entire range of a facilities output with two prices specified in each block.
- The “Energy Supplied” part of the curve can have at least 10 blocks but not more than the total MW supply capability of the Market Participant divided by 30 MW.
- The “Energy Consumed” part of the curve can have at least 10 blocks but not more than the total MW consumption capability of the Market Participant divided by 30 MW
- Prices must be between the minimum and maximum STEM prices.

To minimise the risks to Market Participants of changes in fuel cost during the week, the Weekly STEM Submission process includes some features that allow offer prices to effectively be changed if a generator changes fuel. To achieve this, the generation capability of a Market Participant is divided into three classes:²

- The first class is all the generation that cannot run on liquid fuel (e.g. coal or gas-only fuelled plant). This is “Non-Liquid Capacity”.

² Demand side capacity should be offered via the Gross Demand Curve described later.

- The second class includes generation that can be operated on low cost fuel or liquids. In special circumstances other high cost fuel arrangements can be included in this class. This is “Duel Fuel Capacity”.
- The third class comprises all the generation that is only fuelled by liquids. This is “Liquid Capacity”.

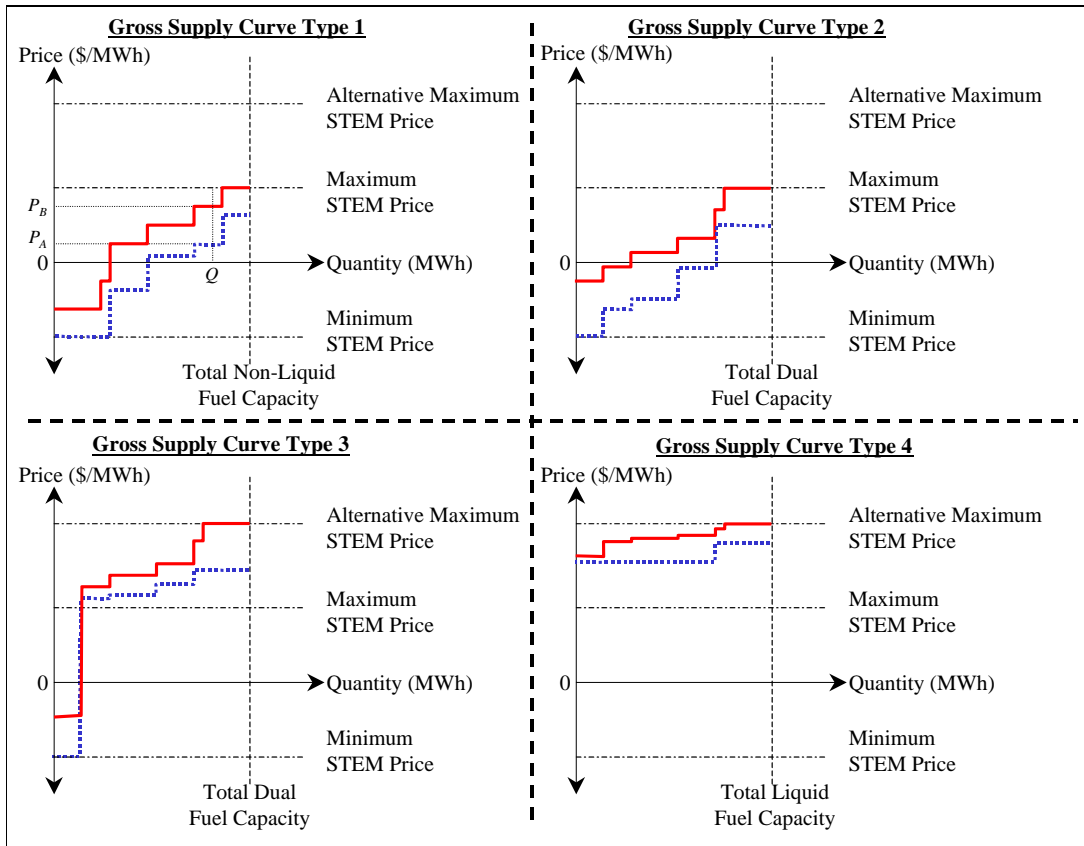
A Market Participant with capacity in all three classes must submit 4 “Gross Supply Curves” for each half-hour during the week (though the curves could be the same in each half-hour). One curve will be associated with the Non-Liquid Capacity, one curve will be associated with the Liquid Capacity, and the remaining two curves are associated with the Duel Fuel Capacity, with one applying to the capacity while not using liquids, the other to the capacity if it uses liquids.

As an additional market power measure, different maximum offer prices apply to each of these Gross Supply Curves. The curves for Non-Liquid Capacity and Duel Fuel Capacity not operated on liquids must have prices not exceeding the Maximum STEM Price (initially to be \$150/MWh and adjusted annually). The curves for Duel Fuel Capacity operated on liquids, and for Liquid Capacity must have prices not exceeding the Alternative Maximum STEM Price (initially to be \$385/MWh and adjusted monthly based on oil prices). Offer price can be negative, but all four curves must have prices greater than the Minimum STEM Price, which is just the negative of the Maximum STEM Price.

Exhibit 9-1 illustrates the Gross Supply Curves submitted for each type of capacity. These are portfolio offers covering ALL of a Market Participants generators of that class. Note that there are actually two curves associated with each Gross Supply Curve. The upper (solid) curve represents the price that the participant wants to be paid to increase its output relative to any level of generation, while the lower (dotted) curve represents the price at which the participant will decrease its generation relative to any level of generation. This allows the Market Participant to define a range of prices within which they will not be rescheduled relative to a Bilateral Position. Thus, for Gross Supply Curve Type 1, if the Market Participant plans to supply a quantity Q during the particular half hour the offer relates to, then it:

- will increase its output for a STEM price exceeding P_B ; and
- will decrease its output if the STEM price is less than P_A .

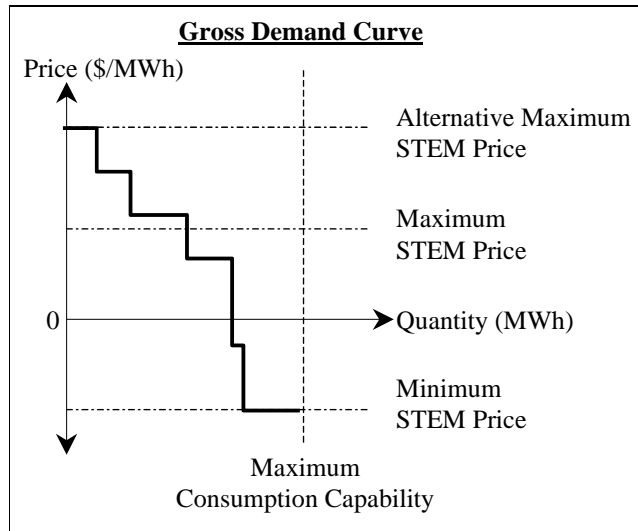
Exhibit 9-1. The Four Types of Gross Supply Curve



Note that some of the offer curves include ranges where generation is offered at negative prices. This is typically done to indicate the minimum output level of generators. Thus if a 100 MW generator can only reduce its output down to 20 MWh before needing to be decommitted, it might offer the first 20 MWh of capacity at a negative price to ensure it is scheduled. Negative prices may also be used to ensure that co-generators and other forms of must-run generation are scheduled.

Market Participants may also submit a single Gross Demand Curve indicating the STEM price at which they wish to adjust their consumption levels. This curve is shown in Exhibit 9-2. The Gross Demand Curve can have prices ranging between the Alternative Maximum STEM Price and the Minimum STEM Price. Unlike generators, only a single curve is included.

Exhibit 9-2. The Gross Demand Curve



The Gross Demand Curve can be used in the following situations:

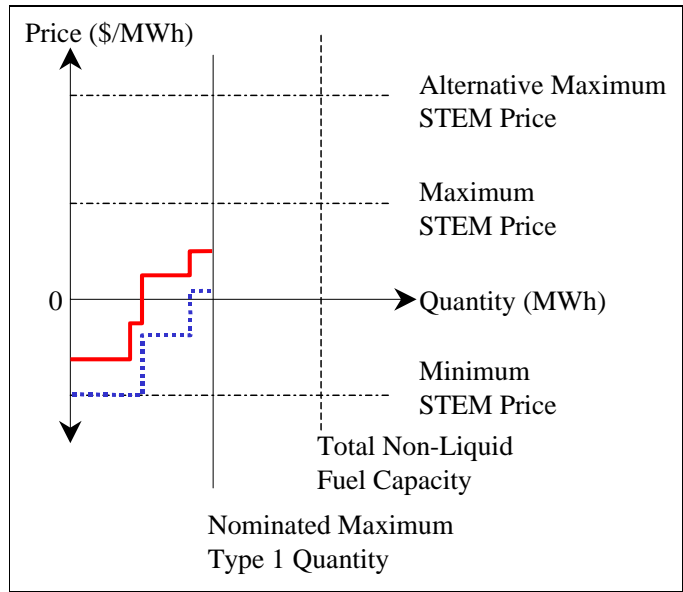
- A Market Customer who has purchased too much energy under a bilateral contract can specify a low bid price for the excess energy so as to sell that energy to the IMO in STEM.
- A Market Customer who has not purchased enough energy bilaterally can specify a high bid price so as to secure the additional energy.
- A Market Customer with a demand-side management/curtailable load capability can specify STEM prices above which they will reduce consumption (and hence make a profit).

The number of price-quantity steps allowed in each Gross Supply Curve or Demand Curve is the greater of 10 and one-thirtieth of the total MW supply or consumption capability associated with the capacity represented in that curve. Thus if a Market Participant has 200 MW of Non-Liquid Fuel Capacity, it can have between 1 and 10 price-quantity steps in its Gross Supply Curve Type 1. But if it had 600 MW of capacity, it would be allowed between 1 and 20 price-quantity steps.

On the Scheduling Day, being the day prior to the Trading Day, Market Participants can modify their effective STEM submission for the Trading Day by submitting STEM Quantity Nomination Data. This data, which must be submitted between 8 AM and 9.30 AM on the Scheduling Day, allows Market Participants to modify the quantities in their STEM submissions, as well as the fuels to be used. Some examples of this data follow.

With respect to Gross Supply Curves of types 1 and 4, each Market Participant can indicate a Nominated Maximum Quantity for that curve type. As shown in Exhibit 9-3 for the case of Gross Supply Curve Type 1, this quantity truncates the offer curve at the specified quantity. This feature can be used to modify a participant's offer if one or more of its generators has become unavailable since submitting the Weekly STEM Submission. Note, however, that since the Gross Supply Curves are on a portfolio basis, rather than a facility basis, if the lowest cost 10 MWh of generation is unavailable, all the Market Participant will be able to do is truncate the most expensive 10 MWh of its portfolio.

Exhibit 9-3. The Nominated Maximum Type 1 Quantity

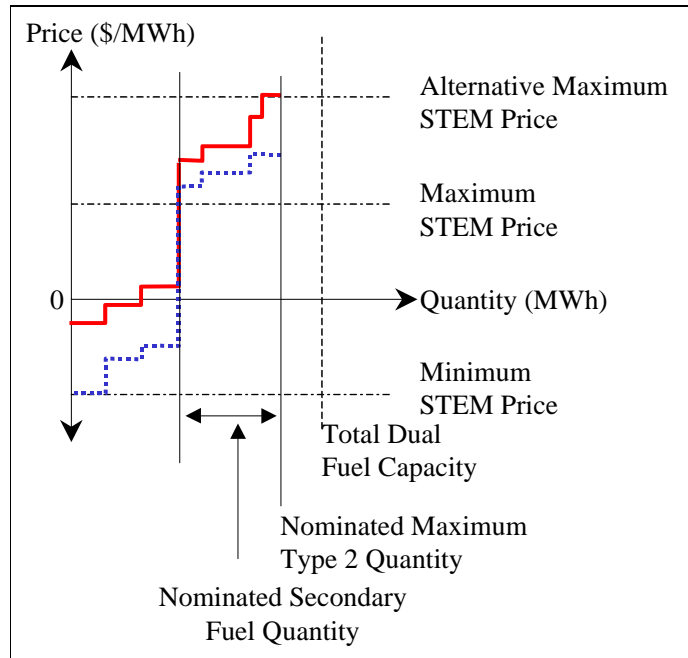


The STEM Quantity Nomination Data for dual fuel capacity is slightly more sophisticated. Recall that the Gross Supply Curves of type 2 and 3 are associated with this capacity. Note only can a Market Participant specify a Nominated Maximum Quantity (associated with the type 2 curve), but it can also specify a Nominated Secondary Fuel Quantity indicating how much of its capacity will be running on liquids.

Before a Market Participant can submit a non-zero Nominated Secondary Fuel Quantity it must have provided the IMO with a “Fuel Constraint Notification” indicating that a genuine constraint is preventing it from operating on its primary fuel. While the IMO will not reject a Fuel Constraint Notification, it can ask for more information, will make public the fact that the participant has provided such a notification, and will periodically report such notifications to the Economic Regulation Authority.

Having provided the IMO with a Fuel Constraint Notification, a Market Participant can submit a Nominated Secondary Fuel Quantity within its STEM Quantity Nomination Data for a half-hour. The effect of a Nominated Secondary Fuel Quantity is to have part of the Gross Supply Curve Type 3 used in place of part of the Gross Supply Curve Type 2. This is illustrated in Exhibit 9-4, which shows a composite Gross Supply Curve formed from the Type 2 and Type 3 curves shown in Exhibit 9-1.

Exhibit 9-4. Nominated Maximum Type 2 Quantity & Nominated Secondary Fuel Quantity



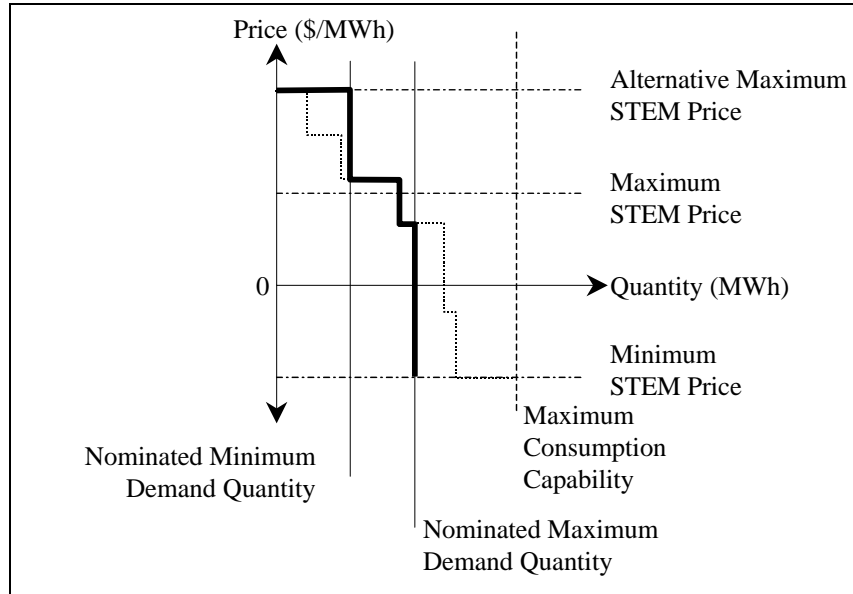
To understand Exhibit 9-4, suppose that the Total Dual Fuel Capacity of a Market Participant was 100 MWh. That Market Participant would have submitted Gross Supply Curves of type 2 and 3 for that 100 MWh of energy in its Weekly STEM Submission (see Exhibit 9-1). Now suppose that 10 MWh of capacity is unavailable for a given half-hour during to outage, while 30 MWh of the remaining capacity had to be run on liquids. The Market Participant would submit a Nominated Maximum Type 2 Quantity of 90 MWh indicating that it is only capable of generating that much energy. In addition, it would specify a Nominated Secondary Fuel Quantity of 30 MWh. In the STEM Auction, the IMO would use a composite Gross Supply Curve comprising the first 60 MWh of Gross Supply Curve Type 2 offer (non-liquid fuel) and the Gross Supply Curve Type 3 in the range between 60 MWh and 90 MWh (for the liquids capacity).

STEM Quantity Nomination Data can also be submitted in respect of the Gross Demand Curve. Exhibit 9-2 shows the weekly demand curve as it relates to a particular half-hour. By the scheduling day the Market Participant may want to modify this curve to reflect better information about its expected consumption. Exhibit 9-5 demonstrates how the Gross Demand Curve can be modified by STEM Quantity Nomination Data. The Market Participant can specify:

- A Nominated Minimum Demand Quantity, indicating that the Market Participant wishes to purchase at least this amount of energy irrespective of what the price is.
- A Nominated Maximum Demand Quantity, indicating that the Market Participant does not want to purchase any energy beyond this quantity irrespective of what the price is.

In effect, the original Gross Demand Curve applies between these two quantities while the Market Participant is a price-taker for consumption below the Nominated Minimum Demand Quantity and does not participate beyond the Nominated Maximum Demand Quantity.

Exhibit 9-5. The Nominated Maximum Demand Quantity



Having applied STEM Quantity Nomination Data and formed the final effective Supply Curves and Demand Curves for each half-hour, the IMO must convert these into STEM Bids and STEM Offers.

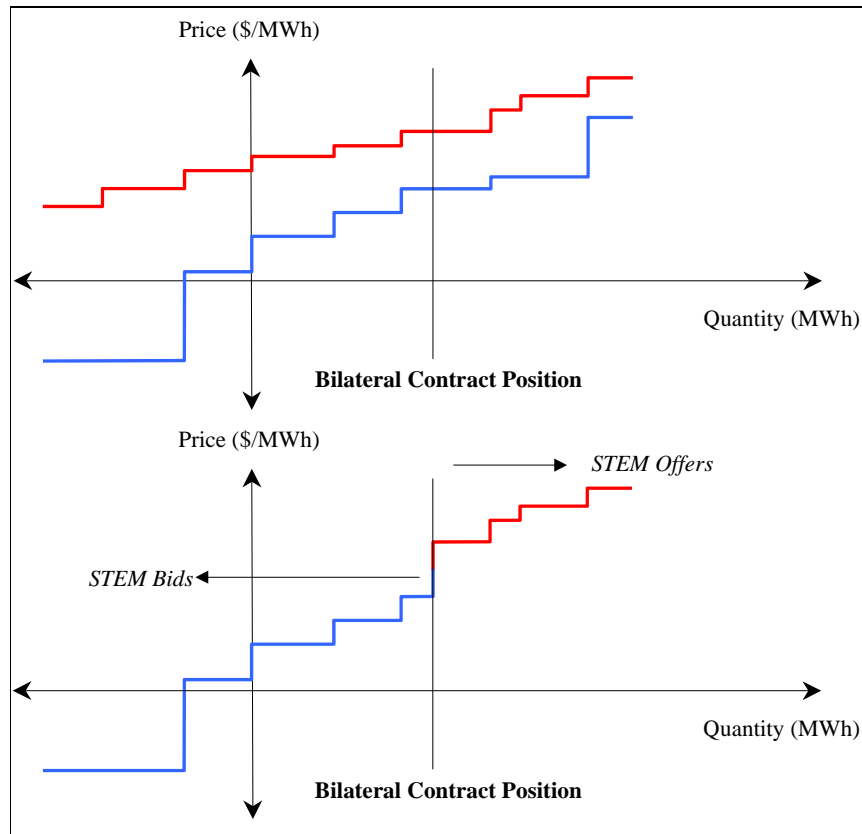
The first step to generating STEM Bids and Offers is to merge all of a Market Participant's various Supply Curves and its Demand Curve into a single curve. The IMO does this, at least conceptually, by asking what the Market Participants net supply would be at each price level. Thus if at price of \$22.13/MWh a Market Participant is:

- offering to supply 10 MWh from its Non-Liquid Capacity;
- offering to supply 15 MWh from its Dual Fuel Capacity,;
- offering to supply 0 MWh from its Liquid Capacity; and
- bidding to consume 7 MWh as a load.

Then the net supply at \$22.13/MWh for that Market Participant will be 18 MWh. Conceptually, the IMO repeats this process for all prices between the Minimum STEM Price and the Alternative Maximum STEM Price, and for both price curve for increased net supply and the price curve for decreased net supply. This produces the two net supply curves shown in the top of Exhibit 9-6. The upper line describes the price required to increase net supply, the lower curve the price below which net supply will be reduced.

The lower part of Exhibit 9-6 shows what happens when the IMO superimposes the bilateral contract quantity on to the top curve. The STEM Offers are defined by the price curve for increased net supply while the STEM Bids are defined by the price curve for decreased net supply.

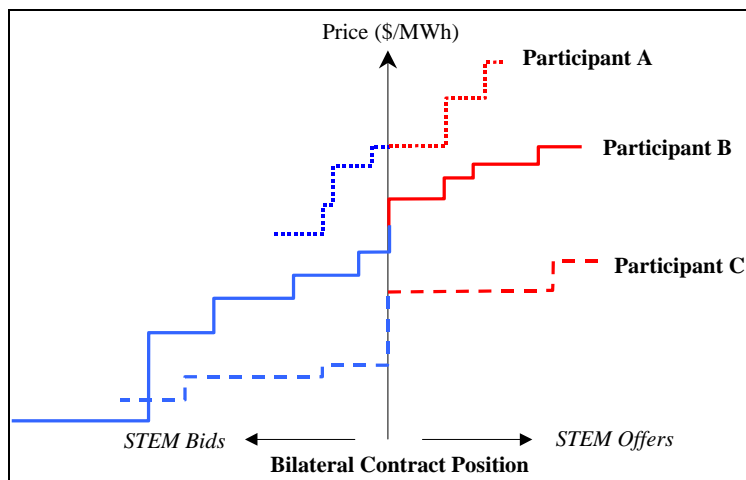
Exhibit 9-6. Forming Stem Bids and Stem Offers



Note that a STEM Bid is effectively a bid to decrease net supply and as such a STEM Bid could be associated with a generator decreasing output rather than necessarily with a demand increase. Likewise, a STEM Offer could be associated with a reduction in load as demand increases rather than necessarily with an increase in supply.

Exhibit 9-6 shows an individual Market Participant's STEM Offers and Bids relative to its Bilateral Contract. Each Market Participant will have their own set of STEM Offers and Bids. This is illustrated for the case of 3 Market Participants in Exhibit 9-7.

Exhibit 9-7. STEM bids and offers are defined relative to bilateral contract positions



The Bilateral Contract Positions of the 3 participants shown in Exhibit 9-7 will all be different. We cannot tell from Exhibit 9-7 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 for expensive generation. Participant C expects a lower price, and has undersold its capacity. 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 9-7 the STEM Bids are shown as a reduction in *net supply* relative to the bilateral contract position as prices fall but in Exhibit 9-8 the bid curve is reversed as it represents an increase in *gross demand* as prices fall.

Exhibit 9-8. The STEM auction

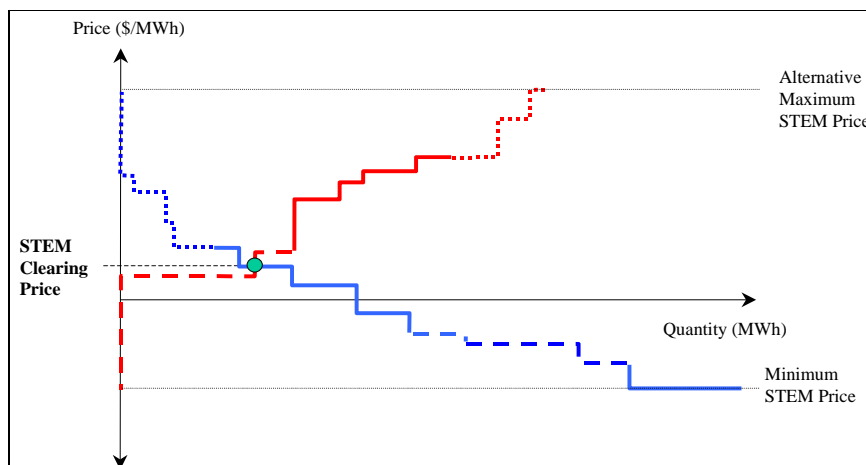


Exhibit 9-8 shows exactly the same information as is shown in Exhibit 9-7, but the information has been re-organised to show the point where the total STEM Bids accepted equals the total STEM Offers accepted. It is apparent that the first step of Participant C's STEM Offer is fully scheduled, being used to offset the energy reduction caused by accepting all of Participant A's STEM Bids and some of Participant B's STEM Bids.

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 demand bids were submitted to the STEM Auction. This is because, as shown in Exhibit 9-6, 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).

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.

Having solved the STEM, each Market Participant will have a net contract position equal to the Bilateral Submission net contract position as modified by their net purchase or sale in the STEM.

Market Participants other than Western Power 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-Western Power facility, indicating the operating level required of that facility by System Management in each Trading Interval, and the Dispatch Instructions that gave rise to that Dispatch Schedule. In addition, there is a Dispatch Schedule reflecting the total energy supplied by Western Power, this being based on operational meter 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 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 Administered Price (MCAP);
- the Upward Deviation Price (UDP); and
- the Downward Deviation Price (DDP).

The Marginal Cost Administered Price (MCAP) for a given Trading Interval will normally equal the STEM clearing price for that Trading Interval. However, a different balancing price will apply in each of the following situations:

- If the real-time dispatch conditions require the use of liquid fuels, when this was not expected at the time the STEM auction was solved.
- 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 $\pm 5\%$ or if involuntary load curtailment occurs.
- If a total of 5% of the scheduled of the scheduled generation was unavailable due to an outage during the Trading Interval.

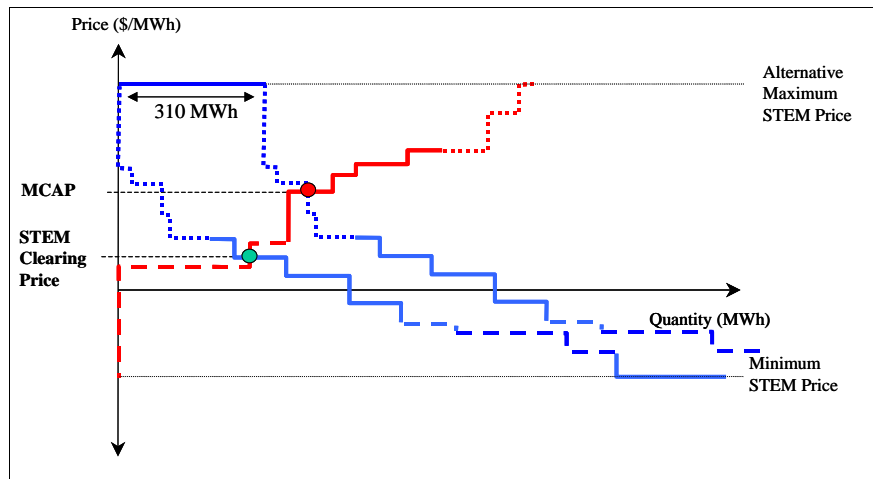
In these situations MCAP will be calculated using the same methodology as was used to set the STEM auction price, except:

- If liquid fuels were used in real-time, but liquid fuel STEM data was not used in the STEM auction, then liquid fuel STEM data corresponding to the facilities that actually ran on liquid fuels will be used instead of their normal STEM data in setting MCAP.
- An aggregate supply curve will be formed based solely on the Gross Supply Curves without considering the Gross 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 to exclude involuntary load curtailment and to reflect outages of facilities that have suffered forced outage since being scheduled.

To better understand the second point, 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 scheduled energy 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 9-9 provides an illustration of the calculation of MCAP based on the example above. We see that by moving the demand curve 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 9-9. The Marginal Cost Administered Price (MCAP)



It is important to realise that 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 would be used to settle deviations from net contract position by

- Western Power in aggregate (i.e. combined deviation of the generation and retail business units).
- Non-scheduled generators (including wind farms), other than those addressed by the first point.
- Non-dispatchable load, interruptible load and curtailable load deviations, other than those addressed by the first point.

IPP generators that receive Dispatch Instructions from System Management 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 that deviate from their schedules without instruction beyond a tolerance. These deviations can be to the net contract position when no dispatch instruction is received, or to the effective schedule after a dispatch instruction has been received. 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 $UDAP = 0.5 \times MCAP$ during peak periods of the day, and equals zero during off-peak periods, while $DDAP = 1.3 \times MCAP$ during peak periods of the day and $1.1 \times MCAP$ during off-peak periods. Additional rules ensure that DDAP and UDAP always lie between the Minimum STEM Price and the Alternative Maximum STEM Price.

UDAP and DDAP do not apply to Western Power because it has the obligation to follow load. Further, unlike IPPs, Western Power cannot specify pay-as-bid prices for the settlement of Western Power energy scheduled to balance the market. If Western Power 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 Western Power 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 Western Power or IPP resources.

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:

- Western Power will be paid MCAP if it must supply IPP load in balancing.
- Western Power 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.
- If an IPP 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 intermittent generator produces less than required by its combined bilateral/STEM position it will have to pay the IMO for that energy at MCAP.
- IPPs, when rescheduled upwards by System Management will be paid by the IMO based on their pay-as-bid prices.
- IPPs, 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.
- 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.

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. 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 loads each month as a settlement payment called "reconciliation". While this is expected to be a payment to loads, there may be some exceptions where additional payments must be made by loads.

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.
- 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 contract 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 bilateral 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

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 Western Power, 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 Loads, details, by Trading Interval, of its MWh energy output level, its intended instantaneous output at the end of each Trading Interval³, plus intended synchronisation and desynchronisation times.
- For each Non-Scheduled Generator, by Trading Interval, its intended MWh energy output level to cover the net contract position. Non-Scheduled Generators can optionally operate without being included in Resource Plans.
- 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.

Resource Plans must in the first instance be supplied to the IMO between 11:00 AM and noon on the Scheduling Day. The IMO's checking process and the possibility of re-submissions to address errors mean that the Resource Plans are only finalised at 1 PM. The IMO then forwards on these facility schedules to System Management by 1:30 PM.

³ This instantaneous dispatch information is required to give System Management a basis for issuing dispatch instructions and does not otherwise impact on settlement.

Western Power does not need to provide a Resource Plan. Instead, System Management will schedule Western Power's resource. Upon running the STEM auction, and based on the STEM results, the IMO will provide System Management with an indicative net supply or demand expected to be provided in aggregate by participants other than Western Power. This will allow System Management to develop a relatively advanced schedule for Western Power early in the Scheduling Day so as to serve the expected demand allowing for the contribution of other Market Participants. Then, once the IMO provides System Management with Resource Plans for facilities other than Western Power facilities, System Management can finalise its schedule for the full 24 hours of the Trading Day.

A Market Participant that submits a Resource Plan will not be able to change the scheduling of its resources following the submission of the Resource Plan, except that it will be compulsory for it to inform System Management of outages. Operators of facilities capable of operating on liquid fuels would also have to notify System Management if any situation arose forcing them to operate the facility on liquid fuels, which will impact both on when the facility might be dispatched relative to other facilities, and settlement.

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

System Management will be free to schedule Western Power resources and, subject to contract conditions, ancillary service facilities as it sees fit 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-Western Power facilities (other than those that are effectively part of Western Power's portfolio as a result of contracts held with Western Power). Instead, Western Power and contracted Ancillary Services will respond to load changes and contingencies. The only situations where such dispatch instructions could be issued would be where:

- Western Power lacks the capability to maintain a secure and reliable power system using only the resources of Western Power or contracted Ancillary Services; or
- the only unscheduled Western Power facilities must run on expensive liquid fuels if scheduled, and IPP suppliers have unutilised capacity from facilities that do not use expensive liquid fuels.

These conditions might occur in situations of exceptionally high demand, exceptionally low demand, or where network constraints apply. If System Management issues dispatch instructions to non-Western Power facilities, it will be able to schedule capacity up to the maximum amount specified in the facilities' Reserve Capacity contract, subject to providing adequate time for the facilities to respond to the request.

The IMO will provide System Management with a Dispatch Merit Order, describing the order in which non-Western Power facilities should be scheduled, or removed from the schedule, subject to network constraints. The Dispatch Merit Order to apply for the week commencing Thursday will be determined by the IMO on Wednesday based on pay-as-bid prices recorded in Standing Data as at that date. Facilities with multiple fuel options will appear multiple times in the Dispatch Merit Order, once for each fuel. When dispatching a facility based on the Dispatch Merit Order, System Management will know what fuel it 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 it can only schedule one facility irrespective of cost.

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 Interval. Dispatch instructions will be issued via voice communications and other traditional methods, but System Management will have to 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-Western Power facilities. For each start-up or shut-down beyond the number in the Resource Plan, or allowed under an Ancillary Service Contract, 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 to the IMO the following information required by the IMO to determine balancing prices and to settle the market:

- Dispatch Schedules for each IPP facility.
- 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 Western Power lacked the capacity to balance the market.
- Operational Meter Data pertaining to Western Power facilities and to system demand.

- Revised supply and consumption capability data for all facilities reflecting their capabilities in real-time during each Trading Interval (so that outages can be accounted for in determining Balancing prices).
- Details of curtailable loads and Supplementary Capacity utilised.

10.3 Dispatch Compliance Monitoring

System Management will be required to monitor the compliance of Market Participants with dispatch instructions. Apart from giving additional dispatch instructions, System Management will not be able to take any action against such Market Participants, with this power lying with 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 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

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. These advisories will include information on how Market Participants should respond to the situation.

11. Metering

Much of the metering regime will be addressed outside of the Wholesale Market Rules as the metering regime must address rules for 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.

It is proposed that 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 Western Power Networks will fill this role.

The Metering Data Agent must provide settlement ready meter data to the IMO once each month where this data includes meter data for the previous Trading Month, and any updates to early metering data. The Metering Data Agent must support the IMO in matters such as 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 too. This generic term is used as a permanent metering regime may or may not be in place at the start of the wholesale electricity market, and 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 3 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 3 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 most other transactions. A Trading Week is a period of 7 days starting on Thursday and STEM transactions for that Trading Week will be summarised in a STEM Settlement Statement and 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 uses all changes to settlement data stemming from 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 they disagree 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 3 months to report back to a Market Participant as to whether it believes the original settlement statement was wrong.

If the IMO issues an Adjusted Settlement Statement, a Market Participant can also issue a Notice of Disagreement up until 9 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, its only remaining option is to take 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 Friday, 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.
1 st BD after a Trading Week	The IMO issues a STEM Settlement Statement and a STEM invoice for the preceding Trading Week in which day D occurs.
2 nd BD after release of STEM Settlement Statement	Settlement date for STEM Invoice.
20 th 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).
1 st 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 5 and 2 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 4 th to 6 th 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 Western Power) and contestable customers, and estimates for non-contestable customer retailers.
6 th BD of month M+2	Invoice issued based on Non-STEM Settlement Statement for month M.
8 th BD of month M+2	Settlement date for Non-STEM Invoice.
20 th BD after issuance of Non-STEM Settlement Statement issued	Deadline for notifying the IMO of any disagreements with the Non-STEM Settlement Statement.
1 st BD of month M+4	Final meter data for Trading Month M issued to IMO by Metering Data Agents.

Day	Event
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 20 th 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.
2 nd 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.
2 nd BD after issuance of invoices for Adjusted Settlement Statements	Settlement date for Adjusted Settlement Statement Invoice.
20 th 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.	Market Customers	The Market Customer's Individual Reserve Capacity Requirement less the number of Capacity Credits it holds. If the customer is fully covered by Capacity Credits, it will pay nothing.

Settlement Component	Who Funds It?	On What Basis?
<p>Shared Reserve Capacity Costs less the capacity component of Spinning & 15 Minute Reserve and Load Following costs.</p> <p>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.</p> <p>The capacity component of Spinning & 15 Minute Reserve and 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.</p>	Market Customers	<p>In proportion of each Market Customer's Individual Reserve Capacity Requirement.</p> <p>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.</p>
Spinning Reserve & 15 Minute Reserve Cost (capacity & availability components)	Market Generators	Generator Capacity, Utilisation & Forced Outage Rate
Load Following	Market Customers and Market Generators	Metered MWh during the month, though capped at 7200 MWh for scheduled generators (see section 6.2)
Load Rejection Reserve, Commitment & Outage Compensation, Reconciliation (which may be negative)	Market Customers	In proportion to metered MWh during the month.
Network Control Service	Network Operators*	Contract Terms
Balancing Payments (+ or -)	Market Customers and Market Generators	MWh deviation from contracts or schedules.
<p>Market Fees</p> <p>These are used to fund the IMO, System Management and the Economic Regulation Authority)</p>	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 any 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, 5 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 up, 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: Market Implementation & Events Timeline

The following table indicates the schedule for market implementation and key events during that period.

By 15 October 2004	Publish an information package on the Reserve Capacity auction and seek Expressions of Interest.
10 December 2004	Last day for submission of Expressions of Interest.
23 December 2004	Announce results from the Expressions of Interest process.
During December 2004	Establish the Independent Market Operator.
During 2005 and early 2006	Work continues on developing market procedures, implementing systems, and making any changes required to Market Rules.
4 January 2005	Lodgements of applications for Certified Reserve Capacity commence.
1 July 2005	Statement of Opportunities Report released by IMO A Reserve Capacity Information Package, specifying the exact quantities to be procured, is released by the IMO to those who responded to the Expression of Interest.
15 July 2005	The Reserve Capacity Information Package is made public.
20 July 2005	Lodgements of applications for Certified Reserve Capacity cease.
5 August 2005	IMO notifies applicants for Certified Reserve Capacity of the amount of capacity they are certified to hold.
10 August 2005	Deadline for providing security to the IMO in respect of facilities holding Certified Reserve Capacity that are yet to be commissioned.
9 September 2005	Deadline for notifying IMO of whether Reserve Capacity will be traded bilaterally or offered into auction.
12 September 2005	IMO notifies participants of accepted bilateral trades.
16 September 2005	IMO notifies participants as to whether an auction will be held and the quantities to be auctioned (after allowing for bilateral trade).
20 September 2005	Reserve Capacity auction offer submission commences.
29 September 2005	Reserve Capacity auction offer submission ceases.
3 October 2005	Reserve Capacity Auction conducted by the IMO.
20 December 2005	Capacity Credits issued. Long Term Special Price Arrangements must be taken up by this date.
23 December 2005	Security of unsuccessful bidders returned.
1 July 2006 (or market start if later)	Commencement of Reserve Capacity payment regime. Normally payments would not begin until late 2007 but an earlier date is used to bridge the period from energy market start.

Appendix 2: Summary of Market Activities

Activity	Administrator of Activity		Parties to Activity					
	Independent Market Operator	System Management	Independent Market Operator	System Management	Western Power	Independent Network Operators	Independent 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
Supplementary Reserve Capacity Procurement	x				x (retail)		x	
Network Control Service	x					x	x	x
Bilateral Contract Data Submission	x				x			x
Short Term Energy Market	x				x		x	x
Resource Plan Submission to IMO	x							x

Activity	Administrator of Activity		Parties to Activity					
	Independent Market Operator	System Management	Independent Market Operator	System Management	Western Power	Independent Network Operators	Independent Market Customer	Independent Market Generator
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
10 Year Generation Planning	x				x	x	x	x
10 Year Transmission Planning		x (WP networks)			x	x	x	x
3 Year Capacity Planning		x			x	x	x	x
3 Week Capacity Planning		x			x	x	x	x
Ancillary Service	x			x				

Activity	Administrator of Activity		Parties to Activity					
	Independent Market Operator	System Management	Independent Market Operator	System Management	Western Power	Independent Network Operators	Independent Market Customer	Independent Market Generator
Requirements								
Procuring Services	Ancillary	x			x		x	x (at discretion of Western Power)