REPORT – FINAL (REDACTED)

27 FEBRUARY 2017

REVIEWING ENERGY COSTS FOR SYDNEY DESALINATION PLANT (SDP)

Report prepared for the Independent Pricing and Regulatory Tribunal (IPART)

MARSDEN JACOB ASSOCIATES

Marsden Jacob Associates
Financial & Economic Consultants

ABN 66 663 324 657
ACN 072 233 204

Internet: http://www.marsdenjacob.com.au
E-mail: economists@marsdenjacob.com.au

Melbourne office:
Postal address: Level 4, 683 Burke Road, Camberwell
Victoria 3124 AUSTRALIA
Telephone: +61 3 9882 1600
Facsimile: +61 3 9882 1300

Perth office:
Level 1, 220 St Georges Terrace, Perth
Western Australia, 6000 AUSTRALIA
Telephone: +61 8 9324 1785
Facsimile: +61 8 9322 7936

Sydney office:
119 Willoughby Road, Crows Nest
New South Wales, 2065 AUSTRALIA
Rod Carr 0418 765 393
Ken Harper 0412 318 324

Brisbane office:
Rick Stankiewicz 0412 314 818

Authors: Andrew Campbell
Ken Harper

MARSDEN JACOB ASSOCIATES

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Glossary

AEMC	Australian Energy Market Commission
AEMO	Australian Energy Market Operator
AER	Australian Energy Regulator
CCGT	Combined cycle gas turbine
DWP	Dispatch Weighted Price
EnAM	Energy Adjustment Mechanism
ESA	Electricity Supply Agreement
ESS	Energy Savings Scheme
GJ	Gigajoule
GW	Gigawatt
GWh	Gigawatt hour
kWh	Kilowatt hour
LGC	Large-scale generation certificates
LRET	Large-scale Renewable Energy Target
MPC	Market Price cap
MW	Megawatt
MWh	Megawatt hour
NEM	National Electricity Market
NSW	New South Wales
OCGT	Open Cycle Gas Turbine
OTC	Over-the-Counter
PPA	Power Purchase Agreement
PJ	Petajoule
PV	Photovoltaic
RET	Renewable Energy Target
RSA	Renewable Energy Supply Agreement
SDP	Sydney Desalination Plant
SRES	Small-scale Renewable Energy Scheme
STC	Small-scale technology certificate

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Executive Summary

Key Study Findings

Review Period

SDP operated in the water security shutdown mode for the entire Review Period (2012/13 to 2015/16). During this period its demand level averaged 0.3 MW lower than had been projected which resulted in electricity costs decreasing by $2.3M.

The low demand and minimum take obligations SDP has in place meant that there was a large surplus of electricity and LGCs that needed to be sold. [Redacted]

Outlook Period

A Benchmark Price was developed for each of the eight potential SDP operating modes, of which there were only three different demand profiles. This was based on the current forward market for energy and LGCs, current and projected prices for STCs and ESCs, efficient C&I retail margin, and historical and projected costs associated with ancillary services, metering/data charges and market fees. LRMC modelling was used to develop trends for the last 2 to 3 years of the Outlook Period where forward markets are unreliable.

The Benchmark Price accounted for the contracts types and volumes available and the resulting over-contracting that would result. This has the Benchmark Price slightly varying between the full operating mode, ramping modes and shutdown modes. Benchmark Prices for these cases were also determined based on no over-contracting (termed No Over-contracting). With over-contracting included the Benchmark Prices were almost identical for the ramping and shutdown modes, while with over-contacting excluded the Benchmark Prices were almost identical for the full operation and ramping modes. [Redacted]

Infigen Contracts

Marsden Jacob did not consider having SDP uncontracted would be appropriate, and that the arrangements and prices provided by the ESA and RSA are a reasonable solution. However it remains to be seen over the twenty year term of the agreements whether they are prudent. [Redacted]

EnAM Application and Structure

Application of the EnAM over the period 2012/13 to 2015/16 showed a total loss of $34.038M from the sale of surplus energy and LGCs. The EnAM sharing mechanism had $24.525M of this passed through to customers.

The current EnAM arrangement was observed to provide different proportional shares between SDP and customers of losses and gains, and to provide only modest incentives to SDP to obtain greater value from the sale of surplus energy. To address these issues three alternative EnAM arrangements were presented.

This report presents the findings of an independent study undertaken by Marsden Jacob Associates on the management and purchases of electricity by Sydney Desalination Plant Pty Limited (SDP) in its drought response role. The study was divided into two parts:

- Reviewing the period 1 July 2012 to 30 June 2017 (the Review Period) in terms of how electricity purchase costs varied from that projected and the prudency of SDP trading of spare contracted energy and spare contracted LGCs during that period (as the Review Period is not yet finished this was undertaken over the period 1 July 2012 to 30 June 2016); and

- Projecting the electricity purchase prices for the period 1 July 2017 to 30 June 2022 (the Outlook Period) for the purpose of developing a Benchmark Price that would define the electricity purchase costs that can be passed through to customers.

The Review Period: 1 July 2012 to 30 June 2016

SDP did not operate during the Review Period and remained in water security shutdown mode throughout the entire Review Period. This low demand level was further reduced due to a tornado in December 2015 that resulted in widespread damage to the plant and further reduced electricity demand.

Electricity purchase costs (to SDP) were less than projected due to the level of demand being about half of what had been assessed for operation in the water security shutdown mode. The reduction in demand and the total savings over the period 2012/13 to 2015/16 are shown in Table ES1 below.

Table ES1 Electricity Cost Savings in the Review Period (Nominal dollars)

	2012/13	2013/14	2014/15	2015/16
Reduced Demand (MWh)	3,313	4,794	5,135	6,918
Cost Saving	$372,404	$552,321	$590,836	$806,208

[Redacted]

A 5% improvement in the sales price for the total amount of spare contract energy in the water security shutdown mode could be worth between $0.5M and about $1M per year. It could be suggested that forward selling more volume and for longer durations could be potentially undertaking by SDP but, in light of potential drought operation, a very conservative position of only trading the month before for the next forward quarter was considered prudent.

It was the view of Marsden Jacob that this less passive strategy of forward selling electricity could be accomplished under the existing contractual arrangements with Infigen and with little, if any, increase in the risk of being short against contracted maximum capacity as only SDP's operation associated with drought response was relevant, and that the probability of dam levels reducing to 70% over the next quarter (requiring the plant to commence start-up) during most of this period was practically zero.

On the basis that SDP sold only 50% of the surplus contracted energy for the next forward quarter during this period, electricity purchase costs would have reduced by $391,161 (if 100% of surplus energy had been sold this would have equated to $770,028), excluding any internal costs to SDP in undertaking this function. If reasonable internal costs of $75,000 per annum are included of undertaking a less passive position management strategy, a net benefit of between $0.1m and $0.5m could have been reasonably obtained by SDP over the Review Period. The net benefit over the Review Period was limited/reduced by high spot prices in Q2 2016 against the prevailing forward curve.

Over the long run, the net benefit of this less passive position management approach is estimated to be approximately $0.5m per annum on average (ie $2 million over four years).

The Outlook Period: 1 July 2017 to 30 June 2022

Projecting the (prudent) electricity purchase price (the Benchmark Price) to apply in the Outlook Period for each operating mode required identifying the associated SDP demand profile, the prudent hedging strategy for the operating mode, and from this determining the Benchmark Price to apply.

In developing the Benchmark Price three matters were addressed:

- Marsden Jacob concurred with SDP that a prudent hedging strategy would have the SDP demand in all operating modes fully contracted (i.e. no spot exposure on the purchase of energy);
- The Benchmark Price for each operating mode was developed accounting for any over-contracting that would result from using the contracts available, and also under the idealised assumption of no over-contracting. (The later cases were distinguished through adding "No over-contracting" to the case name);
- Marsden Jacob interpreted the requirement that supply to SDP be 100% renewable as STCs being supplied to the Small-scale Renewable Percentage and LGCs being supplied for the remainder of the demand;
- The exact definition of the Benchmark Price was established as the price that would be paid for energy used in an operating mode that would cover all electricity purchase costs (excluding network), including any contract/demand mismatch. Given that the SDP demand was to be fully contracted this related to also considering over-contracting costs.

With over-contracting included, the optimum hedging strategy was that provided by the closest match of a flat NSW swap contract to the relevant SDP demand profile. This resulted in a 40% amount of over-contracting in the shutdown mode (due to the smallest swap contract being 1 MW), a 50% level of over-contracting in the ramping mode, and about 2% over-contracting level in the full operating mode (post 2017/18). While the over-contracting appeared high in the shutdown and ramping modes, the amount of energy involved was noted as small.

The price of flat NSW swap contracts and LGCs was assessed through the most recent forward curves and Long Run Marginal Cost (LRMC) modelling of supplying electricity to NSW. The LRMC modelling was used to extend the forward curves past the date they were considered reliable (i.e. 2019). The integration of these approaches was done by having the developed swap prices / LGC prices being consistent with the forward curve in the first two to three years, and with the annual price profile established by the LRMC modelling in the last 2 to 3 years.

The other components of the Benchmark Price, namely the NSW Energy Saving Scheme, the retail margin of a competitive retailer, ancillary services, metering/data charges and market fees were established through a review of historical outcomes (and budget where available) and then determined what was considered efficient. The Marginal Loss Factor applicable to SDP was that most recently published.

The results of this analysis showed the Benchmark Price to be different for the full operating, ramping, and shutdown modes, and also different between the "with over-contracting" and "no over-contracting" cases. This is shown in Table ES2 below.

Table ES2 Benchmark Price $/MWh (1 July 2016 Real Dollars)

	2017/18	2018/19	2019/20	2020/21	2021/22
Full Operation	152.5	148.3	144.1	143.4	143.1
Ramping	155.5	151.2	146.9	146.3	146.0
Shutdown	155.5	151.2	146.9	146.3	146.0
Full Operation: No Over-contracting	152.4	148.2	144.0	143.4	143.1
Ramping: No Over-contracting	152.4	148.2	144.0	143.4	143.1
Shutdown: No Over-contracting	153.2	149.0	144.7	144.1	143.8

The component costs for the Benchmark Prices for 2017/18 are shown in Table ES3. These costs are close to the costs in the other years over the Outlook Period.

Table ES3 Benchmark Price Component Costs for 2017/18 $/MWh (1 July 2016 Real Dollars)

	Full	Ramping	Shutdown	Full No over-cont..	Ramping No over-cont.	Shutdown No over-cont..
Energy	63.55	66.54	65.79	63.51	63.51	63.51
LGC	77.06	77.06	77.06	77.06	77.06	77.06
STC	3.38	3.38	3.38	3.38	3.38	3.38
ESS	1.94	1.94	1.94	1.94	1.94	1.94
Retail margin	5.00	5.00	5.00	5.00	5.00	5.00
Market fees	0.30	0.25	0.30	0.30	0.30	0.30
Metering /data	0.01	0.02	0.73	0.01	0.02	0.73
Ancillary services	0.25	0.25	0.25	0.25	0.25	0.25
Losses	0.98	1.02	1.01	0.98	0.98	0.98
TOTAL	**152.47**	**155.46**	**155.46**	**152.43**	**152.44**	**153.15**

Prudency of the Infigen Contact over the Outlook Period

The Benchmark Price(s) established for the Outlook Period were compared to the Infigen contract prices. This comparison is shown in Table ES4 below for the Full operating mode (with and without over-contracting) expressed in 1 July 2016 dollars.

Table ES4 Infigen Contract Price and Benchmark Price (in $/MWh) for Operating Mode (Real 1 July 2016 Dollars)

[Table: Infigen Contract - Operating Mode values redacted]

	2017/18	2018/19	2019/20	2020/21	2021/22
Infigen Contract - Operating Mode					
Benchmark Price - Full Operation	$152.5	$148.3	$144.1	$143.4	$143.1
Benchmark Price - Full Operation No over-contracting	$152.4	$148.2	$144.0	$143.4	$143.1

Marsden Jacob considers having the SDP uncontracted would not be appropriate, and that medium to long term contracting for electricity and renewable requirements is prudent. While medium term contracting for periods of 1 to 3 years may be considered suitable for some customer and loads (including potentially for SDP) [Redacted]

Accordingly it remains to be seen over the twenty year term of the agreements whether they are prudent over the entire contract term.

While other contracting arrangements could be considered, the arrangements provided by the ESA and RSA by Infigen to SDP and the prices obtained are considered to be a reasonable solution. [Redacted]

Application of the EnAM

Application of the EnAM over the period 2012/13 to 2015/16 showed a total loss of $34.038M from the sale of surplus energy and LGCs. The EnAM sharing mechanism had $24.525M of this passed through to customers. There were no losses that were excluded from the EnAM.

On this basis the EnAM losses that can be passed through to customers are shown in Table ES5 below.

Table ES5 EnAM: Losses that can be passed through to Customers Nominal Dollars

[Table values redacted]

	2012/13	2013/14	2014/15	2015/16
Combined energy adjustment				

Identified Issues with the Current EnAM Arrangements

Two issues were observed in relation to the structure of the current EnAM:

- [Redacted]
- On the margin when markets prices are low or extremely high, SDP is subject to only 10% of any contract losses or gains.

This suggests an EnAM profile that provides improved symmetry of the proportion allocation or gains and losses, and that provides improved incentives for SDP to maximise the value of surplus energy sales. To this end three alternative arrangements were presented:

- Option 1 - Two Band Sharing: 50% to $2M and then 15% sharing;
- Option 2 - Two Band Sharing: 50% to $3M and then 20% sharing; and
- Option 3 - Single Band 25% Sharing.

1. Introduction

Marsden Jacob Associates (Marsden Jacob) was commissioned by the Independent Pricing and Regulatory Tribunal (IPART) to review the management and purchases by the Sydney Desalination Plant (SDP) of electricity and LGCs over the Review Period (2012/13 to 2016/17 – noting that 2016/17 actuals are not yet finalised so this review looked at the period ending 30 June 2016) and for the Outlook Period (2017/18 to 2021/22) by reviewing SDP's proposal and independently forecasting electricity (including all relevant components) and LGC Benchmark Prices. The study also involved the application and assessment of the Energy Adjustment Mechanism (EnAM). This report presents the findings of that study.

1.1 Background

IPART is conducting a review of Sydney Desalination Plant Pty Limited (SDP) maximum prices for its declared monopoly services to apply from 1 July 2017 for a period up to five years (the 2017 Determination).

IPART released its first determination of SDP's prices in December 2011 for the period from 1 July 2012 to 30 June 2017 (the 2012 Determination).

IPART has the role to set prices which reflect the efficient costs of delivering SDP's monopoly services. The 5 yearly price reviews seek to protect customers from paying for inefficient or unnecessary expenditure, while ensuring SDP raises adequate revenue to cover the efficient costs required to deliver its monopoly services.

1.2 Scope of Work

The scope of work as presented to Marsden Jacob is presented in Appendix 1. A summary of the scope of work, together with labels for the individual work items is presented in Table 1 below.

Table 1 Summary of Scope of Work

Task Label		Description
Task 1.1a	Past Energy	Review energy purchase cost management over the Review Period.
Task 1.2a	Past REC	Review LGC purchase cost management over the Review Period.
Task 1.1b	Future Energy	Develop Benchmark energy cost to apply over the Outlook Period.
Task 1.2b	Future LGC	Develop Benchmark LGC cost to apply over the Outlook Period.
Task 1.3	Infigen Contract	Assess the prudency of the Infigen contracts with SDP.
Task 2a	Apply EnAM	Application of the EnAM over the Review Period.
Task 2b	Review EnAM	Suggested improvements to the EnAM.

1.3 Outline of this Report

The report is structured as follows.

Chapters 2 and 3 present the concepts and factors in supplying wholesale demand in the NEM. This is fundamental background material in order to introduce and explain concepts that support the analysis and findings presented in later chapters of this report. The prudent ways that wholesale energy purchases and risks are managed in the NEM are then discussed in Chapter 4 and this is compared to the approach by SDP.

Chapter 5 reviews SDP's electricity purchase costs over the Review Period (defined in Section 1.4 below), the reasons for differences from projected, and the impact of not forward selling spare contract energy during this period.

Chapters 6 examines the modes of operation that SDP may operate in over the Outlook Period (defined in Section 1.4 below) and what this means for matching hedging contracts to the associated SDP demand profiles.

Including the impact of demand / hedging contract match, Chapter 7 develops the Benchmark Price for the Outlook Period. This utilises forward market curves and LRMC modelling in order to develop the Benchmark Price for the Outlook Period.

Chapter 8 presents the key terms of the contracts between SDP and Infigen. Based on the established Benchmark Price(s), Chapter 9 compares this to the Infigen contracts and comments on the prudency of these contracts.

The report concludes in Chapters 10 and 11 by applying the EnAM for the Review Period and makings recommendations of how the EnAM could be improved to encourage more efficient outcomes.

1.4 Definitions used in this Report

<u>The following definitions apply in this report:</u>

Review Period	1 July 2012 to 30 June 2017.
Outlook Period	1 July 2017 to 30 June 2022.
Infigen	Refers to that party that is the counterparty to the ESA (Infigen Energy Markets Pty Limited) and RSA (Renewable Power Ventures Pty Limited).
Infigen Contract	This refers to the two contracts of the ESA and RSA.
SDP	This is used interchangeably to refer to: - The legal entity Sydney Desalination Plant Pty Limited - The physical desalination plant.

1.5 Dollars and Escalation used in this Report

This report refers to numbers that were presented in nominal dollars, real 2011/12 dollars, real 1 July 2016 dollars, and real 1 January 2017 dollars. This required conversion of dollars between these various definitions.

The basis of dollars presented in this report is as follows:

- All dollars are real 1 July 2016 Australian dollars unless otherwise specified.
- Forward curves of energy and LGC prices are published in nominal dollars and forward prices are presented as published.
- Historical SDP costs were presented to Marsden Jacob in 2011/12 dollars and in nominal dollars. These are presented in these respective dollars.

The CPI used in the Review Period and Outlook Period are shown in the table below. For clarity, the conversion used in moving from one year to the next is shown in Table 2 below.

Table 2 CPI Assumed in this Report.

Financial Year	CPI
2011-12 into 2012-13	2.4%
2012-13 into 2013-14	3.0%
2013-14 into 2014-15	1.5%
2014-15 into 2015-16	1.0%
2015-16 into 2016-17	2.2%
2016-17 into 2017-18	2.5%
2017-18 into 2018-19	2.5%
2018-19 into 2019-20	2.5%
2019-20 into 2020-21	2.5%
2020-21 into 2021-22	2.5%

1.6 Redactions

This report has been developed for the public domain from a confidential report. As such there are various text, tables and figures redacted due to confidentiality. Where this occurs is indicated in the report as “[Redacted]” or is explained.

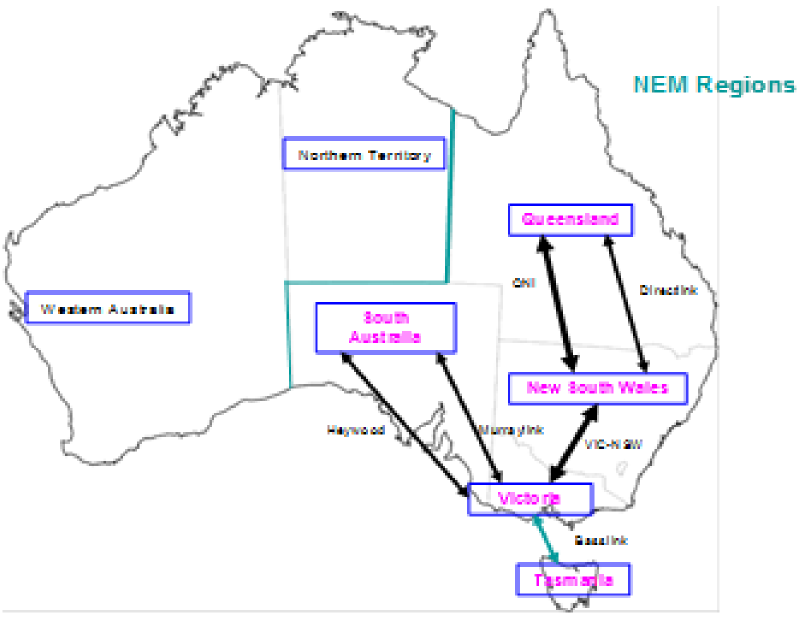
2. Buying Wholesale Electricity in the NEM

The analysis and discussion presented in this report relies on an understanding of the operation of the National Electricity Market (NEM). This is fundamental background to support the analysis and findings presented later in this report. Key concepts are:

- Spot and contract prices;
- Hedging spot prices and the reasons this is undertaken;
- The Large-scale Renewable Energy Target scheme and how this functions; and
- Other environmental products such as the Small-scale Renewable Energy Scheme.

The NEM is a competitive electricity market for the supply and purchase of wholesale electricity run by the market operator (Australian Energy Market Operator or AEMO) which covers the Australian states of Queensland, New South Wales (NSW), Victoria, South Australia (SA), Tasmania and the Australian Capital Territory (ACT). Western Australia and the Northern Territory are not connected to the NEM Grid and are not part of the NEM.

Figure 1 Diagrammatic View of the National Electricity Market



The diagram opposite shows the NEM regions that closely align with State boundaries and the interconnectors between regions (shown as black arrows).

The arrows are not drawn to scale.

Like many electricity markets the NEM operates on the concept of a virtual electricity pool. Under this concept, all electricity generated is traded through the electricity spot market. The electricity pool forms the basis of the “spot” electricity market where generators are paid for electricity they sell into the electricity pool and wholesale customers (mainly retailers who on-sell to retail customers) pay for electricity they purchase from the electricity pool. Technically the NEM is an energy only, gross electricity market. There are no payments for capacity and no requirements for electricity suppliers[1] to obtain capacity[2].

The NEM is divided into regions that correspond very closely to the State boundaries. Each region has a separate spot price calculated (in each 30-minute period called a settlement period) which is referenced to the Regional Reference Node (RRN) of that region (the location of the largest load centre). The regional spot prices are related to each other by the transmission losses and power flow limits on the interconnectors that join the regions together.

The market or pool works on a half hourly basis. For each 5-minute period generators offer to sell electricity into the pool by submitting price ($/MWh) and volume (MW) bands (up to 10 price/volume bands for each individual generating unit is allowed) to AEMO. Using sophisticated computer systems AEMO selects the lowest priced offers (from all generators) to supply the electricity demand for the 5-minute period across all the NEM participating States, accounting for interstate electricity flows on the interconnectors[3]. The highest priced band used sets the spot price for that 5-minute period[4].

The market is settled on a half hour period known as a trading interval by taking the average of the six 5-minute dispatch intervals.

Payments by retailers and revenues to generators (known as settlements) are calculated as the measured quantity of electricity bought or sold each half hour (using special meters) multiplied by the spot price in that region for that half hour period and multiplied by the Marginal Loss Factor[5] (MLF) at the location of the party selling or buying.

As spot prices are not known in advance, parties enter into hedging contracts that have an agreed price for the purchase and sale of wholesale electricity (this is discussed further below).

2.1 Spot Price Outcomes

In any half hour period, regional spot prices generally reflect the current state of supply (being offered by generators) and demand (being taken by customers). Prices are typically high at times of high demand and/or low available generation capacity, and low at times of low demand and/or high available generation[6] capacity. Spot prices can also vary due to power flow constraints on the interconnectors (between regions) or generators behaving in a manner to encourage high price outcomes (i.e. oligopoly behaviour).

Spot prices set each 30 minutes can range from and between the Market Price Cap (MPC)[7] at $14,000/MWh and the Market Floor Price (MFP) of -$1,000/MWh.

[1] An electricity supplier is a party such a retailer that supplies electricity to customers.

[2] The NEM is a "gross" pool unlike the electricity market in Western Australia's South West Interconnected System (SWIS) which is a "net" pool.

[3] The dispatch process also accounts for transmission constraints within each region.

[4] The dispatch engine used by AEMO is a linear program that determines the least cost solution to supply demand based on the bids submitted. The regional spot price for each region is the marginal cost of supplying an additional MW of load at that regional reference node.

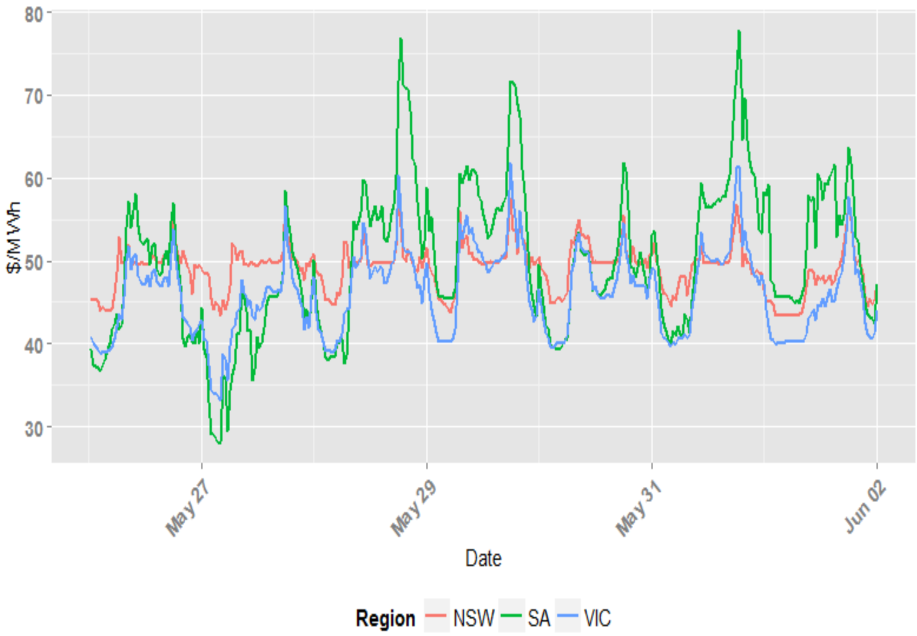
[5] MLF's represent the transmission loss from the point of connection to the regional reference node.

[6] Assuming all available generation is bid into the market at competitive prices.

[7] The Market Price Cap can change annually.

Figure 2 shows an example of half hourly spot price outcomes in some NEM regions, namely NSW, South Australia and Victoria (excluding Tasmania[8]). This shows the variation in spot prices in a typical week during the Review Period that reflects the level of demand and the separation of spot prices between regions due to transmission losses and constraints.

Figure 2 Regional Spot Prices for the Week commencing 26th May 2014



2.2 Hedging Contracts

The uncertain and variable nature of future spot prices (half hourly to annual average) introduces significant risk to both the sellers of wholesale electricity (mainly generators) and the purchasers of this electricity (mainly retailers). For generators these risks arise from uncertain future revenues, while for retailers these risks are associated with uncertain costs while offering their customers fixed priced tariffs.

For this reason NEM participants typically seek to hedge a large proportion of their exposure to spot prices through buying or selling financial contracts. The most commonly traded electricity contract in the NEM is the so called swap contract[9]. A swap contract works as follows. For a nominated quantity of power or energy (MW or MWh[10]), the seller of the swap, usually but not necessarily a generator, agrees to pay a specified floating price (a nominated regional reference spot price) in exchange for receiving from the buyer of the swap, the agreed fixed price.

Assuming that the seller is a base-load generator and generates an amount equal to the notional swap quantity every trading interval, the swap has the effect of providing a generator with a

[8] Tasmania is connected by a DC link from Victoria and is dominated by Hydro Tasmania which operates virtually all generation in Tasmania.

[9] Full name is a "fixed for floating price swap".

[10] Contracts can be written either in terms of capacity (MW) or energy (MWh).

fixed (hedge) price for its generation and a retailer (the buyer of a swap contract) with a fixed (hedge) price for the purchase of wholesale energy.

For a generator, selling a swap contract has the risk that the generator may have an outage when spot prices are high and above the fixed price[11] or else be generating insufficient volumes to cover its sold position. For this reason, generator portfolios usually do not contract to the full capacity of their portfolio.

Wholesale electricity contracts are traded on the Australian Stock Exchange (ASX), directly between market participants and through brokers in the Over-the-Counter (OTC) market.

2.3 Contract Premium over Spot

Contract premiums refer to the price difference between contracts and spot.

Reviews of historical contract and spot prices have consistently shown that in all regions, contract prices have for most of the time been priced above spot prices, usually by about $2 to $5/MWh. The reasons for this relate to the "generator outage" risk to the buyer, and that contract prices incorporate an allowance for extreme and unexpected spot prices that may occur only once every say 5 to 10 years.

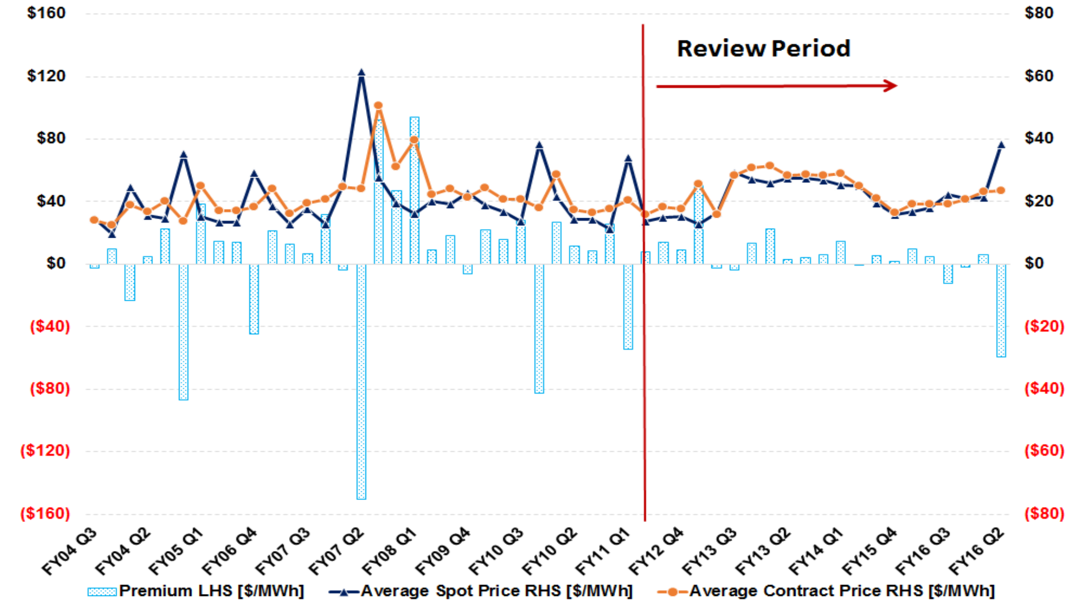
In relation to a flat MW profile over a defined period and region (say a year), this is taken to be the price difference between a swap contract and the average spot price. This is expressed either as a $/MWh value or as a percentage. Percentage is often preferred as it is considered to 'scale" better with changing price levels.

To assess the "contract premium" that has been associated with the NSW NEM region, Figure 3 presents for each financial year, the swap contract price (taken the month before the year), the average spot price, and the price difference each year between the swap contract and average spot price (shown as the bars on the graph). Over the period the contract premium was $2.2/MWh or 4.9%.

A contract premium of 5% was taken to be what could be expected over the Outlook Period. Further details in relation to historical spot prices in NSW, Victoria and Queensland and contract premia is included in Appendix 6. The material included in this appendix further illustrates that on average there is a contract premium over spot in NSW and even higher contract premia available the further in advance of the relevant quarter a NSW flat quarterly contract was sold.

[11] When a generator is off line it is not receiving spot payments.

Figure 3 NSW Swap Contract and Average Pool Price Differences: 2004 to 2016



2.4 Ancillary Services

In order to operate the NEM safely, securely and reliably, the market operator (AEMO) needs to dispatch or procure ancillary services (including frequency control[12], network/voltage control and system restart).

All frequency control ancillary services (FCAS) are provided by competitive spot market arrangements that work in a similar manner to the energy market. Generators bid in to supply these services and a spot price is set based on the market needs and bids. The volumes required are very much less than in the energy market (in the hundreds of MWs) and the prices are usually very low (sub $4/MWh).

Both generators and retailers are liable according to defined market rules to pay for ancillary service charges from AEMO.

2.5 The Large-scale / Small-scale Renewable Energy Targets

Renewable energy certificates (RECs) were the primary commodity in the Renewable Energy Target (RET) prior to 1 January 2011. From 1 January 2011 RECs were split into types:

- The Large-scale Renewable Energy Target (LRET) that traded Large-scale Generation Certificates (LGCs); and
- The Small-scale Renewable Energy Scheme (SRES) that traded Small-scale Technology Certificates (STCs).

The LRET operates to have large renewable generators create Large-scale Generation Certificates (LGCs) and to require wholesale energy purchasers (mostly retailers) to purchase their liable amount of LGCs for that calendar year. This liable amount is calculated by the

[12] This is also referred to as load following ancillary service in some markets.

product of the Large-scale Renewable Percentage and the retailers' wholesale demand that is supplied.

This LRET target has a profile that will increase each calendar year and will reach 33,000 GWh in 2020, after which time the target remains at that level to 2030. Individual obligations are determined by prorating in proportion to energy purchase levels.

Large buyers and sellers of Large–scale Generation Certificates (LGCs) (as well as Small-scale Technology Certificates (STCs) and New South Wales Energy Saving Certificates (ESCs)) trade through the wholesale market or through various brokers/trading platforms with minimum parcel sizes generally of 5,000 certificates. The price for a parcel of certificates is called the 'spot price'.

If a wholesale energy purchaser does not buy enough LGCs then that entity pays a penalty for each LGC that should have been purchased. The penalty per LGC is called the Shortfall Penalty Price, and is set at $65 per LGC, non-tax-deducible and constant in nominal terms over the life of the scheme.

If not enough renewable generation is developed and there are not enough LGCs then the LGC price would be expected to be at the Shortfall Penalty Price. However if there were more LGCs than required, the LGC price would be expected to be less than the Shortfall Penalty Price.

2.5.1 LGC Spot and Contract Prices

The design of the LRET, with the flat target post 2020 and ending in 2030, has resulted in two recognised pricing phases, these being:

- The investment phase – development to the 33,000 GWh target; and
- The post investment phase – uncertain nature of LGC production post 2020 (when the 33,000 target is flat) that may result in more or less than the expected number of LGCs being produced.

During the investment phase a significant amount of entry would be expected to be through Power Purchase Agreements (PPAs) for both energy and LGCs created (from which can be inferred an LGC price). This is likely to be the main source of supply during the period of development as the target ramps up.

Once sufficient renewable generation has been developed to satisfy the 33,000 GWh LRET target (estimated to be by about 2022), LGC purchases would not be associated with new renewable generation build (and associated costs), but would be subject to the prices associated with purchasing LGCs from developed renewable generators. Under this condition prices are determined by the projection of how many LGCs will be produced compared to the demand for LGCs. With the amount of LGC produced uncertain, LGC prices, spot and contract, have the potential to be highly volatile during this phase.

During these different phases the relationship between spot and contract prices may change. LGC forward prices, which would (theoretically) converge to spot prices at the time of delivery, would be subject to a "cost of carry" (related to the opportunity cost of invested in say risk free bonds) and a "Convenience Yield" (pertaining to the requirement to surrender a certain number of LGCs each year if shortfall penalties or borrowing forward are to be avoided). This would likely have contract prices upward sloping in the investment phase when there may be a surplus of LGCs and downward sloping in the post investment phase (when a surplus of LGC is unsure).

With a shortfall of LGCs projected by about 2019, the pricing dynamics of the LRET is as follows:

- An increasing LGC price representing the discounted price from the year there is a shortfall of LGCs (projected to be 2019);
- Prices at the shortfall penalty price during the LGC shortfall period. This can be reduced slightly through borrowing forward (limited to 10% of LGC liabilities); and
- On the basis there become sufficient LGCs and investment is complete, LGC spot prices are then determined by the supply and demand of the LGCs. LGCs "locked in" through PPA contracts are effectively out of the market".

Over the Outlook Period the LRET is expected to be in the investment phase during which least cost modelling will recognise the dynamics of the LRET.

While there are a number of merchant renewable generators in the NEM, the vast majority of LGCs are sold under long-term bilateral contracts and prices in many cases of either the transaction or the individual components of energy and LGC within that transaction are not that transparent to parties outside of those contracts. Sources of certificate supply therefore include existing renewable energy projects which are eligible to create certificates and certificates that were created in previous years but have been banked rather than being surrendered.

2.5.2 STCs

The Clean Energy Regulator estimates the demand for STCs each calendar year and sets the small-scale technology percentage for STCs on this basis. There is a penalty of $40 (nominal) for non-compliance and liable entities have to acquit their liability through the purchase and surrender of small-scale technology certificates (STCS) each quarter, or through payment of a small-scale technology shortfall charge. STC prices have been near the $40 level for a number of years.

2.6 The NSW Energy Savings Scheme

The NSW Energy Saving Scheme (ESS) is an energy efficiency scheme administrated and regulated by the Independent Pricing and Regulatory Tribunal (IPART).

An energy saving certificate (ESC) represents the equivalent of MWh of energy saving (changed from 1 tonne of CO_2-equivalent avoided) as a result of projects and initiatives that save energy through installing, improving or replacing energy savings equipment. The ESS certificates may be sold at the time of implementation of the energy savings activity, for the energy savings that will occur over the deemed lifetime for the activity (upfront financing). The ESS is legislated to continue to 2025.

Each Scheme Participant must meet an individual energy savings target calculated as a percentage of their demand in NSW. The energy savings targets in the Outlook Period are 2017 – 7.5%, 2018 8.0%, 2019 to 2025 8.5%.

The Energy Saving Certificate (ESC) spot price has been historically quite volatile and ESCs have traded at prices between $14 and $32 since the start of the scheme in 2009. During the 2016 calendar year spot ESC prices have generally been around the $25/certificate level, noting that in recent weeks they have fallen to just under $20/certificate (as at 3 December 2016 spot ESC prices were reportedly at $19.20/certificate).

3. Purchasing Wholesale Demand

The purchase of wholesale electricity in the NEM involves the purchases of many products and the management of price risk. These products include the main supply chain components, market overheads, and a number of environmental products. The management of this activity is highly technical and complex. Depending upon risk appetite, size of energy book and resourcing levels, risk management can range from very conservative right through to much higher levels of risk (eg to pool price exposure) but in return for potentially increased gains and/or losses.

This chapter describes this process, the guidelines used by retailers in the NEM, and those established by SDP.

The obligation for SDP to purchase LGCs and STCs equal to its total demand is described.

3.1 Components of Electricity Costs

The components of wholesale electricity purchase are described and listed in Table 3 below. The sections that follow describe what these are, the risks involved in purchasing wholesale electricity, and how these risks can be managed.

Table 3 Components of Electricity Supply

Component	Comments
Energy	Volume weighted average (VWA) wholesale electricity price reflecting the load shape needed to be managed. Units are $/MWh.
Ancillary Services	Are those services used by AEMO to manage the power systems, safely, securely and reliably. This includes frequency control, network control and system restart.
LGCs	Large scale generation certificates needing to be procured and/or surrendered to meet calendar year scheme liabilities.
STCs	Small scale generation certificates needing to be procured and/or surrendered to meet calendar year scheme liabilities.
ESS (Energy Saving Scheme)	NSW scheme applicable to all demand. Retailers must surrender an appropriate number of Energy Saving Certificates (ESCs) to meet their annual energy savings targets.
Network	Transmission and distribution charges.
Retail Margin	The reasonable estimated cost in $/MWh of running an electricity retail operation.
Metering and Data Costs	Charges imposed by a service provider for metering and data forwarding services.
Market fees (AEMO)	Charges imposed by AEMO on a per MWh basis to cover the costs of operating the NEM.

The network component costs applicable to SDP are directly passed through and are thus not considered in this report.

3.2 Managing Energy Purchase

The principle component of wholesale energy purchase cost is wholesale energy. As described in Chapter 2, as this can involve high risk when purchased on the spot energy market hedging products are used to manage this risk.

The risks of energy purchase are often separated into two components:

- Volume risk: Unless it is a whole of meter contract (refer Appendix 3), hedging contracts typically do not provide an exact match to demand which can result in over-contracting and or under-contracting. Spot exposure refers to load that is not contracted and is exposed to spot prices;
- Price risk: This can result from unexpected extreme price volatility and/or sustained high pool prices when there is spot exposure.

The sections that follow describe "shape risk" and the most common hedging contracts used to manage these risks. These are the contracts used later in the report to assess the costs of prudent risk management of the SDP demand profile.

3.2.1 Load Shape, Uncertainty and Mismatch

Driven by a range of factors including weather, processes and operating hours, one of the significant challenges facing retailers and customer loads is that the electricity load for that same customer can and does vary from one half hour to the next as well as by day type and season throughout the year. A retailer will seek to manage the risk associated with changes to its customer loads on a regional basis using a variety of products (most of which are detailed later in section 3.2.2 and Appendix 3).

While customer load varies on a half hourly basis, most wholesale electricity hedging products available are generally flat structures, with the same volume in each relevant time period be they flat (all time periods) or peak (7 am to 10 pm on working weekdays). Accordingly there will be periods of under and over hedging of load compared with the hedging structure that has been put in place.

A hypothetical example for a typical day and load profile with a simple hedging structure to managing the risk associated with a typical load profile is shown in Figure 4 below. In the figure, the dotted lines represent the range of electricity demand from customers that the retailer must provide and the shaded areas represent the coverage provided by different hedging instruments.

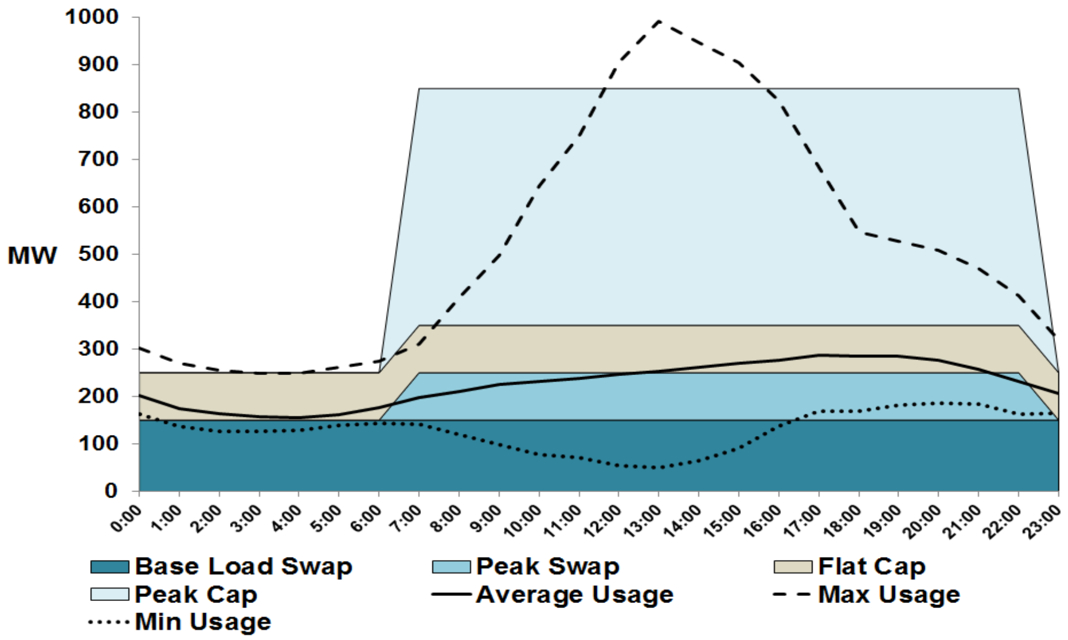
Due to the shape of the load, the correlation of its demand to spot price and the mismatch between the block structured hedging instruments and the out turned load there will be associated risks that need to be priced or allocated between the buyer and seller of the hedging contracts for the electricity load.

In particular if the electricity load shape needing to be hedged has a high correlation with peak electricity prices (such as a commercial building with a peak air conditioning and business usage profile) a premium will be charged to manage this risk whilst if the load (such as a water pumping load) is inversely correlated to pool prices and risk, a discount to the flat contract or pool prices may be plausible.

Due to the mismatch between actual and forecast load as well as mismatch between block hedging structures and the load itself there will be cost of under or over-hedging (ie the risk of under hedging and the additional cost of over-hedging) that will need to be borne either by the customer directly or else that assessed charge will be incorporated as an additional premium to cover the whole of meter load shape.

The total wholesale cost of supply for the electricity load shape is therefore considered to be the cost of the hedged component plus the cost of unhedged demand and over-hedged sales.

Figure 4 Illustration of Hedging a Load Profile in the NEM



3.2.2 Hedging Products Available

With increased vertical integration and consolidation occurring across the NEM, hedging a retail load profile with load uncertainty is increasingly being undertaken through retailers owning or contracting directly with generation, with supporting derivative contracts, most notably swaps and caps. A range of hedging products exist to allow buyers and sellers to trade electricity in quantities that vary throughout the day and that are unpredictable. The products identified below are generally structured around calendar quarters so there can be mismatch between months and day types that needs to be considered or else managed through more tailored products.

The section below presents the main products that are available from various counterparties in New South Wales in order to build up and prudently manage a relatively small wholesale contract position. Depending on the size and complexity of the electricity load needing to be hedged a portfolio of contracts may be necessary to managing associated risk exposures. These portfolios can range from very simple structures to an extremely complex portfolio including generation and demand side management.

In the exchange traded electricity market, the standard contract size is 1 MW but volume trades in parcels of 5 MW as well. Standard contract sizes in the over-the-counter (OTC) market are even larger, at 5 MW or much more.

The main products are:

- Swaps (capped, flat, peak period); and
- Caps (flat and peak period)

These are discussed below. Additional products that are used are presented in Appendix 3.

Flat Swaps

Flat swaps, bought or sold on a quarterly or annual basis, are a readily accessible and anonymous channel through which any NSW retailer or wholesale market participant can gain exposure to the market and manage risk. The best and most prudent approach is to build up positions slowly in small volumes for example, by buying or selling in forward volume on a quarterly basis. In addition to trading with generic ASX electricity futures products, flat swap products can also be traded over the counter (OTC) as well. Electricity futures and options contracts are listed by the Australian Stock Exchange (ASX) on the 4 major regions (VIC, SA, QLD and NSW).

Capped swaps

Buy swap/sell cap or sell swap/buy cap (either futures or OTC). These products are used extensively by market participants to manage electricity price risk up to and including a cap of $300/MWh.

Peak Swaps (or 7 day peak swaps)

Either futures or OTC these products capture or protect premium peak contract revenue but doesn't provide price protection during off peak (particularly around the nightly hot water load and price spike) or on weekends when prices can be high (especially on hot summer afternoons and winter morning and evening peaks and ramping). Peak periods are generally defined as 7 am to 10 pm Eastern Standard Time on working weekdays.

Caps (futures or OTC)

Buying or selling of cap products (generally with strike prices of $300/MWh) through OTC or futures markets as a potential revenue source for generators and price protection for retailers. A range of commercial and industrial customers as well have shown interest in purchasing cap type products to protect against pool price outcomes where they are taking on spot exposures.

3.3 LGCs and STCs Purchase and Requirements

In addition to the creators of LGCs and STCs there are a great number of installer aggregators and financial intermediaries that have emerged over recent years that also operate in these renewable energy and energy efficiency certificate markets. A number of firms such as TFS, Green Energy Trading, ICAP and GFI operate platforms or services to facilitate certificate trading and, for a service fee, help match buyers and sellers of relevant certificates.

3.4 SDP Renewable Energy Obligation

SDP has an obligation to be 100% renewable. This obligation was instigated before the RET was separated into the LRET and SRES.

The liability of SDP to purchase LGCs and STCs is contingent on the meaning of 100% renewable in this context. To assist in this we note the following:

- SDP is not Green power accredited and does not operate under Green power rules.

  (Green power has the obligation to have 100% of demand covered by LGC and still remains an STC obligation which has to be met even if the electricity load is 100% covered by LGCs. Green power requirements were established prior to the separation of the RET into the LRET and SRES.)

- The calculation of the percentage of demand supplied by renewable generation, and that is used in the specification of renewable energy targets, incorporates pre-1997 renewable generation, renewable generation under the LRET, and renewable supply under the SRES.

- Clause 5.1 of the RSA States:

  [Redacted]

For the SDP load and irrespective of whether or not SDP uses renewable energy STCs have to be surrendered to the Clean Energy Regulator reflecting the relevant small scale technology percentage (circa 10%). An alternative of view of 100% renewable energy could be to consider the SDP load is covered 100% by LGCs and ignore the STC liability but this is inconsistent with the renewable energy regulatory framework. Similarly as there appears to be no legislative requirement to have SDP 100% backed by Green power there is no requirement to model the case of 100% LGCs plus 10% STCs.

The above supports the position that the meaning of SDP being 100% renewable is that **submitted LGCs plus STCs must equal SDP plant load.**

The above was taken to be the meaning of the plant being supplied by 100% renewable generation, with STCs only required up to the extent of the annual small-scale technology percentage (circa 10%) and the balance of renewable energy needed (circa 90%) for SDP supplied through LGCs.

3.5 Other Components

The other components of energy purchase are Ancillary Services, Retail Margin, AEMO fees, Metering and Data Costs. These are relatively small cost components and are addressed later in this report.

4. Prudent SDP Trading Strategy

The energy purchase decisions of SDP in principle share the same issues of many NEM retailers, which involve balancing risk and opportunity. Retailers need to ensure risk is contained while acting to minimise purchase costs.

This chapter reviews the SDP trading policy and compares this to "best practice" in the NEM, while noting the differences in circumstances between the two. From this a prudent trading strategy for SDP is presented.

4.1 Managing Energy Purchase and Trading Risk

As stated previously desalination is a very energy intensive process. In managing the energy risks associated with the SDP electrical load it is important to understand the nature of the electrical load needing to be hedged, associated renewable energy schemes (LGCs and STCs) and energy efficiency obligations and all other energy cost components. Section 3.1 of this report identified the energy cost components applicable to SDP.

The NEM is generally characterised by fixed-rate variable-quantity sales contracts on the demand side and floating rate commodity prices on the supply side. Due to the obvious need to manage the potential mismatch between these two important profit determinants, participants hedge exposures through the transaction of wholesale physical and financial instruments (derivatives). These characteristics present risks which are not necessarily unique to the energy market, but which are generally categorised as Energy Risk.

It is normally the role of the Wholesale Energy or Trading Group to manage a portfolio of such instruments, with the aim of maximising gross margin, within the risk parameters contained within an Energy Risk or Trading Policy and, if appropriate, a separate Wholesale Energy Markets Credit Policy.

4.2 Standard Retailer Trading / Risk policy

As part of prudent management and in meeting the requirements of holding a financial services licence, electricity retailers will normally have in place robust energy risk management policies that may report to a separate Board Sub-Committee and/or management committee specifically on energy risk. Typically these energy risk policies are reviewed at least annually, show version numbers, date approved and high level detail of changes from the prior policy version.

The document would be comprehensive and contain a range of areas including:

- Organisation's risk appetite;
- List of energy risks;
- How risk is measured;
- Risk and position limits;
- List of approved energy products (eg electricity, gas, renewable energy certificates), approved markets, etc;
- How breaches are managed and reported;

- Wholesale energy credit policy (can either be in the energy trading policy or in a separate policy document);
- Delegations – who is authorised to trade on the organisation's behalf (sometime also in a separate document);
- Segregation of duties (front, middle and back office reporting lines to ensure ring fencing of duties and responsibilities).

The energy risk framework developed would normally:

- Identify the risks;
- Measure the risks;
- Manage the risks; and
- Monitor and communicate the risks to management.

Risks, as they related to energy risk, are typically characterised as:

- Market Risk;
- Credit Risk;
- Liquidity/ Funding Risk; and
- Operational Risk, Legal and Regulatory Risk.

The Trading/Energy Risk Policy would normally provide detailed guidance on the metrics used to calculate market, credit, and liquidity/funding risks, the processes to review the methodologies and methods, and the estimation of the risk parameters used in calculating them.

Appendix 2 presents additional detail on energy risks and management.

4.3 SDP Energy Trading Policy

The SDP Electricity and LGC Trading Policy was reviewed by Marsden Jacob.

[Redacted.]

4.4 Assessment of SDP Trading Policy

This section reviews the stated SDP trading policy.

[Redacted]

4.4.1 SDP Trading and Risk

[Redacted]

4.4.2 LGC Trading

[Redacted]

The SDP policy of selling LGCs is considered sensible and prudent.

4.4.3 Processes to support improved electricity and LGC position management

[Redacted]

It is usual practice where sales can be made on the forward market without incurring additional risk for this to be undertaken. The reasons for this are securing a revenue stream and obtaining an expected higher revenue stream.

[Redacted]

4.5 Prudency of SDP Energy Trading Policy

[Redacted]

In relation to the risk of spot exposure we note the following:

- There will be many quarters where there is assurance that operation under the 70/80 drought rule will not be required the following quarter. In the event there is a possibility, the maximum electricity demand would be well below the minimum contract level the following quarter;
- The risk of SDP demand due to an emergency operation request is discounted for two reasons:
  - the probability of such a request is considered extremely remote (particularly given where SDP injects water into the system); and
  - the start-up profile is likely to be such that the maximum electricity demand for SDP that would be associated with such a request would be considerably below the maximum contract level over the following quarter. There is no understood basis as to why this would be markedly different than for start-up under a drought trigger.

Without being prescriptive of how such a policy change would be implemented, this would be expected to include activities such as:

- Monitoring the SDP maximum demand that can occur for at least the next quarter (as during the month prior to the next quarter) as a metric to the amount of energy that can be forward sold the next quarter with extremely low or negligible risk that SDP will be short contracted energy for electricity purchases. This would involve activities such as:
  - reviewing actual load data, dam outlook, reforecasting SDP electricity load if necessary and assessing preferably monthly but no less than quarterly the expected SDP electricity demand levels for the next quarter;
  - ascertaining the MW gap between expected quarterly SDP maximum demand and the minimum annual volume level on a MW basis;
  - reviewing and monitoring forward electricity futures contract prices; and
  - developing and operating to a formal sale process for electricity as per LGCs.
- Monitoring contract premiums in order that confidence remains that contracts are being sold at a premium;
- Obtaining a number of broker quotes ...[Redacted]… for each quarter;

- Reducing the exposure to NSW pool price variability by selling a prudent level (say between 50 and 100% of surplus energy ...[Redacted]…) for at least the next forward calendar quarter; and
- Recording/documenting at the time any electricity transaction was undertaken (as already done by SDP for LGCs) the prevailing market conditions and therefore supporting the prudency of the trading decision(s) made.

5. Review of Past Purchase Costs

SDP purchase costs for electricity were less than estimated for the Review Period due to using less electricity in the shutdown mode and having a price on carbon emissions removed. The total saving was about $2.3M over the period 2012/13 to 2015/16.

[Redacted]

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This chapter reviews the electricity purchase costs of SDP over the Review Period. The costs consist of:

- The original estimate of electricity purchase costs;
- The change in costs due to a reduced demand level in the shutdown mode and the removal of a price on carbon emissions (that resulted in lower energy prices); and
- The forgone value of not forward selling energy.

5.1 Benchmark Price for the Review Period

In the 2012 Determination IPART considered a range of issues in relation to determining the efficient cost of purchasing energy to be reflected in SDP's water prices.

At the time the Benchmark Price was developed, the Carbon Pollution Reduction Scheme (CPRS) was due to commence on 1 July 2012, and a projected price of carbon emission was included in the Benchmark Price. Subsequent to this the CPRS was repealed and the scheme was terminated on 1 July 2014. In its 2012 Determination, IPART accordingly developed two Benchmark Prices (with and without carbon). As a result of this, IPART removed the carbon price component from the Benchmark Price and a "non-carbon" Benchmark Price applied from 1 July 2014.

The Benchmark Price with and without a carbon price and on a real (1 July 2012) are shown in Table 4 below. With the carbon price repealed from July 2014, the relevant Benchmark Price is with a carbon price for 2012/13 and 2013/14 and the without a carbon price for 2014/15, 2015/16 and 2016/17. The energy costs reflect the impact of removing the carbon price and the impact on "green costs".

Table 4 Benchmark Price for the Review Period ($/MWh) (Real dollars shown are 1 July2012)

	Dollars	FY12/13	FY13/14	FY14/15	FY15/16	FY16/17
Energy costs including carbon	Real $ #	$ 112.41	$ 115.21	$ 117.61	$ 121.38	$ 128.13
Energy costs excluding carbon	Real $ #	$ 109.38	$ 111.62	$ 115.06	$ 116.54	$ 118.55

Table 5 below shows the original IPART determination of wholesale and renewable energy costs (with the introduction a carbon pricing scheme). IPART also determined a cost pass through mechanism for actual fixed and variable network costs that will take effect on an annual basis over the determination period.

Table 5 2012 IPART determination efficient energy costs for SDP (including carbon)

Table 7.1 IPART decision on energy costs ($/MWh, $2011/12)

	2012/13	2013/14	2014/15	2015/16	2016/17
Variable energy costs					
Wholesale Electricity ($/MWh)	60.47	63.99	64.48	66.27	70.94
REC ($/MWh)	44.29	46.06	47.9	49.82	51.82
SRES and other costs ($/MWh)	7.65	5.17	5.22	5.29	5.37
Total Efficient Energy Cost ($/MWh)	112.41	115.22	117.6	121.38	128.13
Network costs					
Fixed	Actual costs past through via a methodology	Actual costs past through via a methodology	Actual costs past through via a methodology	Actual costs past through via a methodology	Actual costs past through via a methodology
Variable	Actual costs past through via a methodology	Actual costs past through via a methodology	Actual costs past through via a methodology	Actual costs past through via a methodology	Actual costs past through via a methodology

Note: A detailed explanation of the methodology for the pass through of network charges can be found at Box 7.1.
Source: IPART Analysis.

Source: IPART 2012 SDP Final Report, page 58

5.2 SDP Demand over the Review Period

For the Review Period IPART commissioned Halcrow (refer IPART 2012 SDP Final Report, page 62) to ascertain the demand profile of SDP under the various operating modes.

Halcrow determined that:

- In a water security shutdown period the desalination plant will consume 9.64 GWh a year;[13] and
- When or if SDP was in full operation the expected consumption would be around 360GWh year.

During the Review Period SDP remained in water security shutdown mode.

Half hourly electricity consumption data for the Sydney Desalination Plant over the Review Period was provided by SDP to Marsden Jacob. Table 6 below presents this data in terms of month electricity consumption (MWh). This data shows the following:

- SDP used 4.8 to 5 GWh per annum. This is about 50% of the level indicated by Halcrow and allowed by IPART in its 2012 Determination.
- For the period July 2012 to September 2012 electricity consumption was slightly higher than other periods during the Review Period. This was associated with the transition by SDP out of full operation mode into water security shutdown mode.

13 Halcrow therefore proposed and IPART accepted that, on the basis of information available at that time for the no production mode, the energy costs coinciding with the expected annual usage of 9.64 GWh (and excluding potential gains or losses on mark to market) be classified as fixed costs.

- The Kurnell tornado that hit SDP in December 2015 resulted in electricity load consumption being lower than had been previously observed (in the water security shutdown mode). This lower energy consumption from December 2015 was due to the extensive damage sustained at the plant. As repairs are being carried out Marsden Jacob understands that the normal load level seen previously at SDP in water security shutdown mode will be progressively restored over an extended timeframe to the 4.5 to 5 GWh per annum level.

Table 6 Monthly SDP electricity consumption for July 2012 to June 2016 (MWh)

Electricity consumed by SDP (MWh)	2012/13	2013/14	2014/15	2015/16
July	988	367	407	367
August	842	399	384	344
September	861	413	375	354
October	471	416	404	393
November	418	392	404	350
December	453	425	333	196
January	476	435	331	35
February	364	393	398	131
March	416	426	384	146
April	362	384	348	124
May	344	400	372	134
June	332	396	365	148
Total	6,327	4,846	4,505	2,722

5.3 SDP Energy Purchase Costs over the Review Period

As a result of the lower electricity demand electricity purchase costs were lower than projected for the Review Period. Table 7 shows on an annual basis (real 2011/12 dollars):

- The original estimated costs based on the 9.64 GWh p.a. and the Benchmark Price (which includes a carbon price for the years 2012/13 and 2013/14);
- The reduction in demand from the annual 9.64 GWh "benchmark level" in shutdown mode and associated cost savings (based on the relevant Benchmark Price);
- The cost saving associated with the reduction in the Benchmark Price;
- Total savings.

The total saving of the period 2012/13 to 2015/16 was $2,321,768 (real 2011/12 dollars).

Table 7 Reduced Costs from that Projected (Real 2011/12 Dollars))

	2012/13	2013/14	2014/15	2015/16
"Benchmark Demand" shutdown MWh	9,640	9,640	9,640	9,640
Determined Cost	$1,083,601	$1,110,633	$1,109,183	$1,123,423
Actual Demand MWh	6,327	4,846	4,505	2,722
Actual Cost	$711,198	$558,312	$518,347	$317,216
Saving due to reduced demand	$372,404	$552,321	$590,836	$806,208

5.4 Trading Benefits Foregone

As described in the previous chapter, it is usual practice to forward sell energy if such sales can be undertaken within risk limits. The analysis presented in Appendix 6 further notes that the contract premium for selling forward a NSW flat quarterly contract in the month prior to the next quarter is still material but that a higher contract premium may potentially be obtainable if any quarterly contract was sold with an even greater lead time between the selling decision and the relevant quarter. A policy of forward selling quarterly the month before was described (in Section 4.5) as a prudent strategy for SDP to undertake.

The value that such a policy would have provided over the period 2012/13 to 2015/16 was ascertained based on historical contract prices (recorded on the 15th day of the month before the quarter commenced) and the corresponding NSW spot prices. The result of this under the assumption SDP sold only 50% of its available surplus energy against the minimum contract volume is shown in Figure 5. Figure 6 shows this on a cumulative basis. The figures for selling 100% of available energy would be twice the values shown.

Figure 5 Trading Profit through Forward Selling Quarterly 50% of Available Energy (Nominal $)

[Figure 5 Redacted]

The profile shows the majority of months recorded as trading profit excluding any SDP internal costs. Of the 16 quarters in this period 13 had a positive trading profit and 3 had a negative trading profit. The typical trading profit each quarter from selling only 50% of surplus contracted energy was about $100,000.

The relatively low cumulative value over the four years was due to the last quarter (Q2 2016) having a loss of almost $1.3M (based on selling 50% of available energy). This was due to extremely high pool prices occurring in NSW in Q2 2016 that were not forecast or factored into the prevailing Q2 2016 NSW contract swap curve as at 15 March 2016. We note that this is the nature of the spot market, where very high value and risk can be gained or alternatively lost when spot prices are high, and that selling in selected months could have resulted quite different outcomes.

Figure 6 Cumulative Trading Profit by Forward Selling Quarterly 50% of Available Energy (Nominal $)

[Figure 6 Redacted]

The total profit and net of considered reasonable internal SDP costs that would be associated with selling available energy over the period 2012/13 to 2015/16, for sales of 25% to 100% of the surplus contracted energy, is shown in Table 8. This shows that the inclusion of internal costs practically reduces any profit based on forward selling 50% of available energy over this period to zero or a loss. There would have expected to have been a profit in the order of $470,000 (or $770,000 excluding any additional costs) had 100% of available energy been forward sold.

Table 8 Assessed Profit to SDP from Forward Selling Available Contract Volume 2012/13 – 2015/16 (Nominal $)

[Table values redacted]

	25%	50%	75%	100%
Trading Profit				
SDP Cost				
Net				

The analysis above supports the contention that forward selling energy would be expected to increase the value of the surplus energy that exists when SDP is operating in the shutdown mode. It is noted that a 5% increase in the value of energy sold in the water security shutdown mode is about $1M per year.

6. Future SDP Demand and Hedging Contract Match

As for any large load in the NEM, the profile of the SDP demand is a key factor in the appropriate supply/hedging strategy to be undertaken by SDP.

SDP operates in a number of defined modes relating to full operation, shutdown, testing, and moving between these states.

Each of these states needs to have electricity purchases fully hedged. With the products available to do this there is an inevitable mismatch of demand and contract shape. This is important as it defines the amount of over-contracting to be accounted for in assessing prudent electricity purchase costs.

SDP is required to operate the desalination plant in line with a variable regime stipulated in the 2010 Metropolitan Water Plan and requires roughly 46 Megawatts at full production. The requirement for desalination is based on the 70/80 rule (desalination required when the water storage level drops below 70% and desalination would cease when this level reached 80%).

Within this requirement the desalination plant can operate in a number of modes depending on its operating status:

- When not operating the plant may be required undergo testing for a period of days or week;
- When operating it may be necessary to shut the plant down from a number of days to months; and
- The plant may need to transition between operating and non-operating states.

This chapter:

- Reviews the historical operation of the plant;
- Identifies and characterises the operating modes of the plant; and
- Identifies the appropriate match between hedging contracts and SDP demand profile.

6.1 Review of Past Operation and Electricity Demand

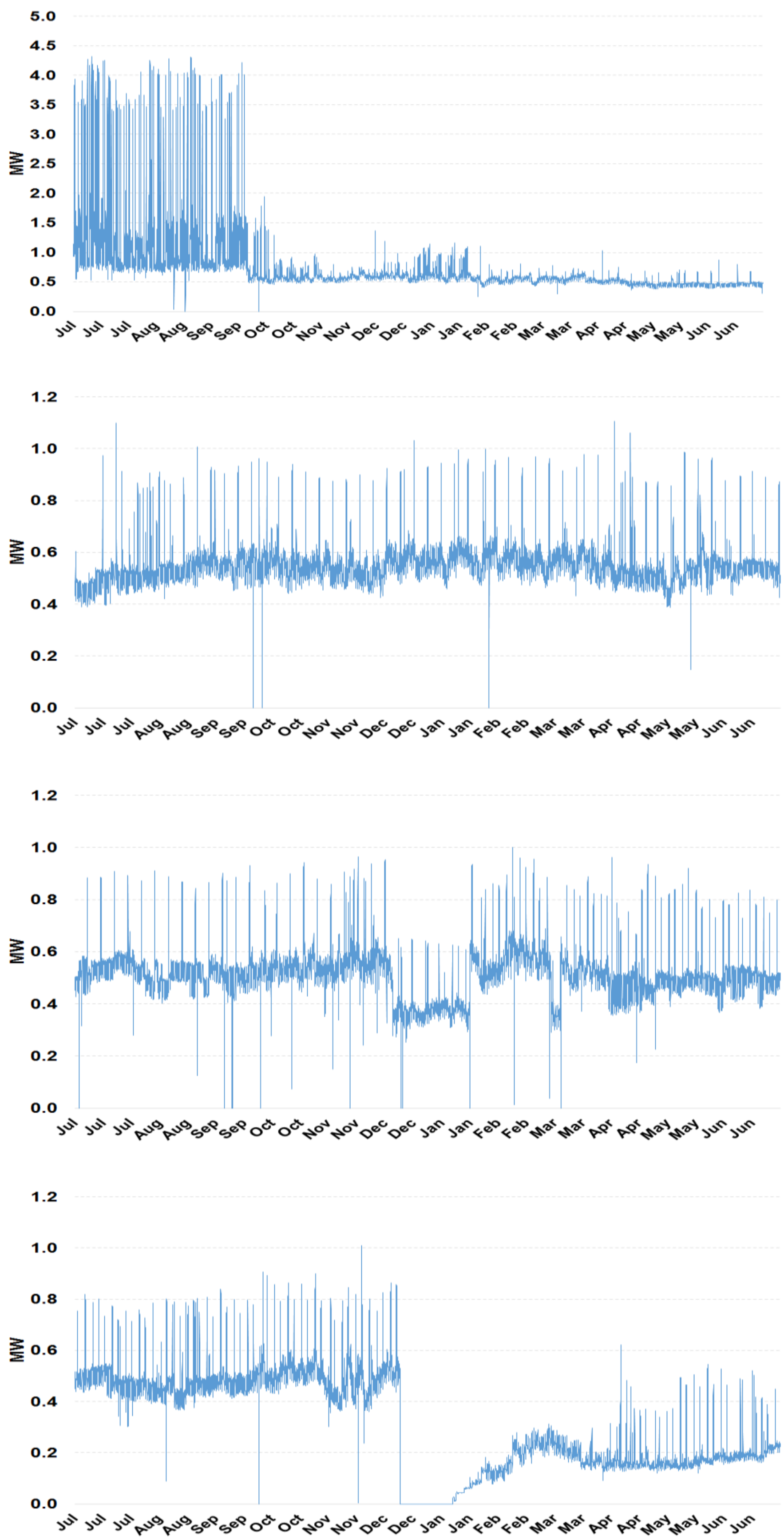
Historical operation provides information on the nature of the SDP demand in its various modes of operation. Figure 7 presents the half hourly SDP demand profiles for the financial years 2012/13 to 2015/16. The plant was not operating through this period.

The profiles illustrate the variation that can occur in the non-operating modes.

These graphs can be summarised by Figure 8 which shows for each quarter:

- The average demand; and
- The maximum 30 minute demand recorded in that quarter.

Figure 7 Historical SDP Demand – 30 Minute profiles by Year



2012/13

Operation was reducing from full operation in 2012.

2013/14

Operation was in shutdown mode. This has electricity averaging about 0.6MW with spikes to 1 MW or very slightly over.

2014/15

Operation was in shutdown mode. Electricity use very similar to the year prior.

2015/16

Operation was in shutdown mode with demand at about 0.6MW. In December 2015 a tornado destroyed much of the plant (which is now being repaired). The drop in demand and recovery is seen post December 2015.

Figure 8 Historical SDP Demand – Average Quarterly and Maximum Half Hourly Demand (MW)

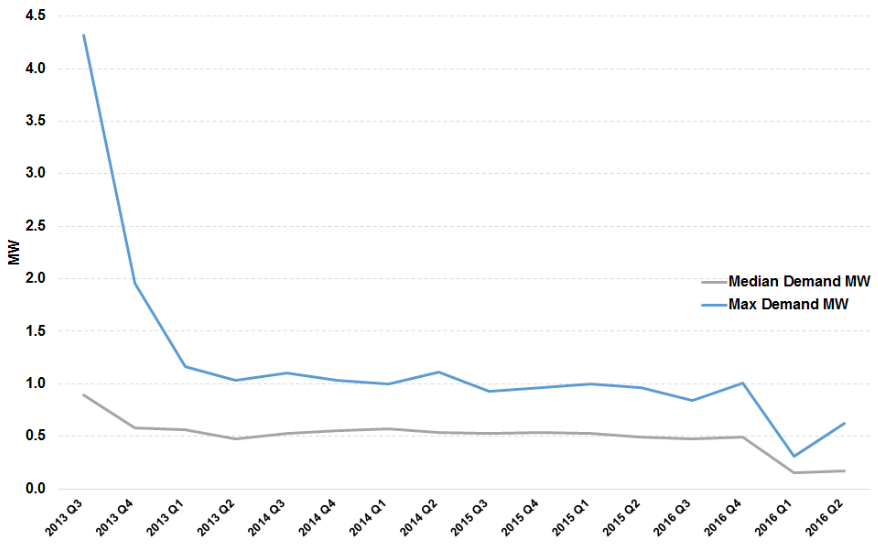


Figure 8 illustrates that when SDP is in the water security shutdown mode the demand profile contains short demand spikes that result in periods when demand is close to 1 MW.

6.2 SDP Operating Modes

Eight operating states were identified and characterised by Atkins as part of a review of plant operation. Table 9 presents list of operating modes and a brief description of each. Their characterisation is described as the MW profile when in that state.

Table 9 SDP Operating Modes

Operating Mode	Comment
Full Operation	Flat operation
Ramp up	May take 8 months from water security shutdown mode, and less time from other modes.
Ramp down	Ramping down may take several weeks.
Short-term shutdown (for 2 to 10 days)	Small load while shutdown. Plant can be restarted quickly.
Medium-term shutdown (for 11 to 90 days)	Small load while shutdown. Plant can be restarted within weeks.
Long-term shutdown (for 91 days to 2 years)	Small load while shutdown. About 3 months required to restart the plant.
Water security shutdown (for more than 2 years)	Minimum load. A significant amount of work required to restart the plant.
Testing	Uncertain demand and depends on the testing to be undertaken.

Their characterisation did not specify how long the plant would be in each operation mode or the mode it may have previously been operating in.

This meant that no consideration was given to the sequence of operating modes.

6.3 Matching of Hedging Contracts to Demand

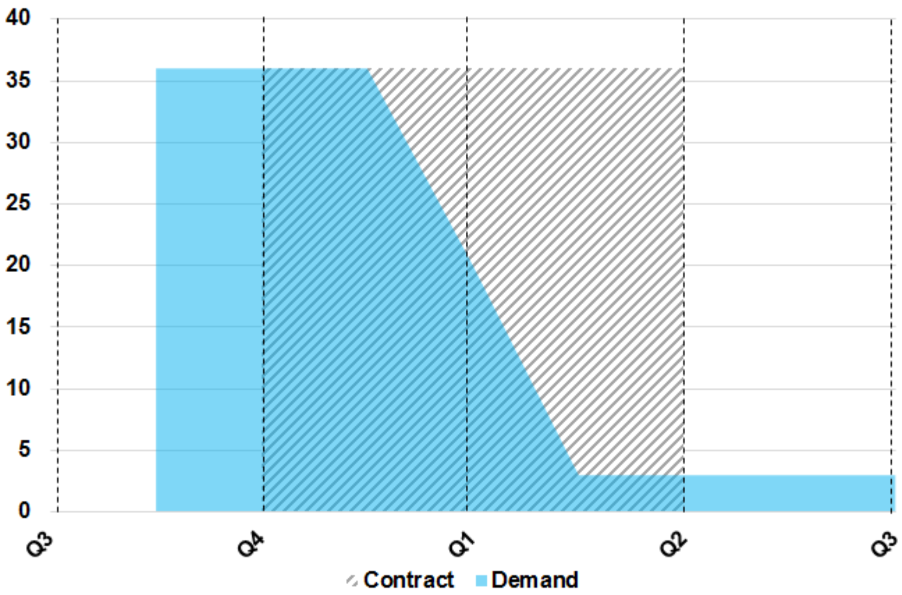
As previously described, hedging arrangements were based on the following:

- The "flat" demand profiles (operating and shutdown) for the purposes of contract supply were assumed to be operating indefinitely.
- The most appropriate contract type for hedging flat demand is a flat swap. This meant that the only contact demand mismatch was associated with the size of the flat swap compared to the demand profile. With swap contracts available in 1 MW quantities, the size mismatch was that associated with contracting in 1 MW increments compared to the SDP operating mode demands.

  For example, an operating mode with a demand of 0.6 MW would require a swap contract of 1 MW, resulting in an over-contract quantity of 0.4 MW, or expressed as a percentage of the demand 66%. However a 1 MW contract would cover the frequent demand spikes that reach a demand level of about 1 MW
- The ramping profiles needed to include any over-contracting associated with when the ramping commenced started and ended with respect to the start and end dates of quarterly contracting.

  This is illustrated in Figure 9 which shows how a 90 day ramping profile would need to be contracted in quarterly swap contracts.

Figure 9 Contracting a 90 day ramping Profile in Quarterly Blocks



Unless the ramping profile commenced at the exact start of the quarter, the ramping profile would extend into two quarters. This would increase the mismatch between contract volume and the demand profile association with that portion of the demand profile that is at minimum level (and contracted to the maximum SDP demand).

Based on the above and for each operating mode, Table 10 presents the SDP demand profile, associated contract quantity that has the demand fully contracted, and the corresponding amount of over-contract energy (expressed as a percentage the demand to be supplied). For the ramping modes this is assumed to require two quarters of contracting (making the slope irrelevant to the amount of contract oversupply).

The demand profiles for each operating mode were characterised by Atkins.

Table 10 Contract Match for the Various Operating Modes

Operating Mode	SDP MW	Contract Demand MW[14]	Percentage of over-contracted energy
Full Operation : 2017/18	37.50	38.00	1.33%
Full Operation : 2018/19 – 2021/22	37.25	38.00	2.02%
Ramp up	0.5 to 37.5	38.00	100.00%
Ramp down	37.5 to 0.5	38.00	100.00%
Short-term shutdown	0.571	1.00	75.20%
Medium-term shutdown	0.57	1.00	75.20%
Long-term shutdown	0.57	1.00	75.20%
Water security shutdown	0.57	1.00	75.20%

In addition to the operating modes and associated volumes of over-contracting shown in Table 10, each of the modes was modelled based on having the contracts exactly match the demand profiles. These cases were labelled with the mode name finishing with the term “No Over-contracting”.

The reason each of the modes were modelled in the No Over-contracting cases is that the “metering and data” costs (presented later in this report) are a fixed annual cost (independent of the level of demand) and thus on the $/MWh basis are lower the higher the demand level.

[14] volume of forward contracts required to meet SDP’s efficient energy volumes for each mode of operation

7. The Benchmark Price

The Benchmark Price is the price that SDP can pass-through to customers for electricity used by the plant (whether in shutdown, standby or operating mode). It is a price that:

- Covers all electricity purchase components except network costs which are passed through;
- Is considered prudent and efficient for the demand profile being supplied; and
- Provides for the total electricity purchase costs to be paid including that associated with any mismatch between the SDP demand profile and the contract profile.

The key issues in the establishment of the Benchmark Price were assessing the future price of contracts, the contract match to the SDP demand profile and the revenue that can be achieved for the sale of surplus contracted energy and LGCs.

The basis of future energy costs were the recent forward curves and LRMC modelling.

This chapter:

- Articulates the definition of the Benchmark Price;
- Presents the components of the Benchmark Price;
- Presents Marsden Jacob's modelling of the LRMC for the Outlook Period;
- Presents Marsden Jacob's assessment of the forward price outlook, ESS, retail margin, ancillary services, metering /data charges and market fees; and
- Presents the development of the Benchmark Price from the above analysis.

7.1 Definition of the Benchmark Price

What is it used for?

The Benchmark Price is the price that SDP can levy customers for electricity used to power the desalination plant. It applies only to electricity used for that purpose.

What is the regulatory process?

The Benchmark Price is established through a regulatory process at each five year review for the following five financial years.

What is the basis of the Benchmark Price?

The Benchmark Price:

- Is an independent assessment of the wholesale electricity price for electricity supply to the Sydney Desalination Plant (SDP) that is considered prudent[15] and efficient[16] for each of the established operating mode demand profiles;

[15] Well advised, showing good judgment, wise.

[16] Well planned, cost effective.

- It represents the price (paid for electricity used) that covers the total cost of electricity purchase, including any "mismatch" costs that can result through the electricity contract shape not exactly matching the SDP demand shape;
- Is a price that includes all the components associated with the procurement of electricity excluding network charges (that are passed through);
- Has the demand supplied by 100% renewable energy. This is defined as LGCs plus STCs equalling 100% of the electricity load requirements, with STCs at the mandatory small-scale technology percentage[17] (this was discussed in Section 3.4);
- Is calculated for each SDP demand profile that relates to a particular mode of operation which is assumed known in advance. Benchmark Prices were also determined for the No Over-contracting cases;
- Is independent of any contracts or arrangements that may have been established for supply to SDP (i.e. ***The Benchmark Price is independent of the Infigen Contracts***) ; and
- Can vary by year and mode of operation.

7.1.1 Components of the Benchmark Price

The components of the Benchmark Price, requirements in respect of the SDP demand profile, and the approaches to the estimation of the components are presented in Table 11 below.

Table 11 Components of the Benchmark Price

Component	Comments	Assessment Approach
Energy	Hedging a known demand profile.	Forward energy prices of swap, capped swap, $300 cap contracts. LRMC assuming existing plant is established (incremental approach). LRMC assuming only NSW and that no existing plant is established (stand-alone approach).
LGCs	Requires LGC to cover the SDP demand less that supplied by STCs.	LRMC (incremental approach) Forward LGC Prices
STCs	Required to the small-scale renewable percentage.	Market outlook.
Energy Saving Scheme	Required to the level required by the ESC scheme.	Market outlook.
Retail Margin	Observed competitive margins.	Historical margins.
Ancillary Services	Regulation Causer pays payments.	Review of historical payments.
Losses (MLF)	MLF = 1.0154	Assumed to remain constant.
Market fees (AEMO)	AEMO publication of fees	Review of historical payment and AEMO budget.
Metering and data forwarding charges	Fixed cost (independent of demand)	Historical payment by SDP.

[17] The Clean Energy Regulator publishes the small-scale technology percentage by 31 March each year for the current calendar year. The small-scale technology percentage is calculated based on the estimated value (in megawatt hours) of small-scale technology certificates that will be created for the year.

7.2 Approach to Developing the Benchmark Price

The approach to the development of the Benchmark Price involved the following steps:

- The modes of SDP operation and the associated electricity supply profiles were identified. These have been described in Table 9;
- No demand-side management was assumed as this is understood to be in violation of the SDP requirement to operate fully when requested to do so;
- The optimum hedging strategy that minimises the total electricity purchase costs accounting for any contract / demand shape mismatch;
- The contract prices over the Outlook Period were assessed through a review of the forward curve and LRMC modelling;
- The costs of over-contracting demand (and selling back into the market) were developed through use of the historical contract premium and the level of over-contracting as a percentage of the demand supplied;
- The prices over the Outlook Period for each of the identified components of the Benchmark Price were assessed; and
- The summation of component prices accounting for the required volume of the components to be purchases was undertaken.

The approach to the calculation of the individual components is described below.

7.2.1 Energy Price and LGC Price

Energy and LGC prices were developed as follows:

- With the optimum hedging contract structure being flat firm contracts it was not necessary to develop contract prices for above and below $300/MWh;
- Contracts were calendar quarterly flat swaps. One of the key advantages of these contracts was that they are the most liquid of all the contracts traded in the NEM and the best match for the residual gap between SDP actual consumption and the minimum annual quantity requirements under the ESA;
- Forward prices were established based on data as of Friday 25 November 2016. Depending on the source these contracts went out two to three years. It was noted that forward prices have a relationship to spot prices and a weaker relationship to LRMCs;
- LRMC modelling was undertaken to establish the cost of providing energy, capacity and LGCs in each year of the Outlook Period. This was in the context of pricing contracts that could be purchased for NSW over the Outlook Period, particularly in the later years of the Outlook Period.

  The assumptions of fuel and capital costs were critical inputs and these were also compared to "in market" prices.

  Two approaches to the modelling are undertaken:

  - ***LRMC Approach 1:***
    - total NEM modelled

    - existing generators were taken to be in service with their capital costs sunk. With excess capacity LRMC prices in the early years the capacity price was zero.
  - ***LRMC Approach 2:***
    - NSW only modelled
    - no existing plant was assumed in operation (i.e. existing generators were assumed not in service)
    - generator plant used the most efficient technology based on current policy. Black coal plant was included in the generation options available
    - the results provided the LRMC of an efficient energy market including a non-zero capacity price. The LRMC could be taken as the new entry limiting price;
- The price of the various contract types was developed based on the forward and LRMC modelling. The issues addressed in this integration were:
  - the liquidity of the forward contracts over the Outlook Period
  - the basis of LRMC model results to the pricing of contracts over the Outlook Period.

  (The assumption is not an efficient market, but efficient supply arrangements within the market.)
- A risk management framework that has no "spot price exposure" for each of the operating modes;
- For each mode of operation, a level of swap contract capacity was assigned that resulted in no spot exposure (and also that represented the least cost arrangement):
  - the amount of "over-contracted" supply depended on the operating mode
  - the price received for the over-contracted portion was the assumed swap contract price established in that year less the expected contract premium over spot price.
- Any losses associate with over-contracting were incorporated in a calculation of the Benchmark Price, such that all electricity purchase cost were covered. This meant that the Benchmark Price was slightly higher than the contract costs to "compensate" for over-contracting associated with any contract / demand profile mismatch;
- The Benchmark Price was then presented in a matrix of year and operating mode.

7.2.2 STC and ESS and Other Component Prices

STCs

The manner the STC market operates is that the demand for STCs are calculated each calendar year and the price reflects the supply and demand. Typically prices have been near the price cap of $40 (nominal).

The historical prices over the past several years as well as considering the current STC forward prices available were taken as the price of STCs.

ESS

During most of the 2016 calendar year ESC prices have been at or around the $25/certificate level for spot ESCs. It is observed that the price for ESCs has fallen from this level from around the end of September 2016 and as at 3 December 2016 spot ESC prices are $19.20/certificate. Despite the recent drop in ESC prices, based on recent trading data over the

2016 calendar year a reasonable estimate of $25/certificate has been used for the Outlook Period.

Retail Margin

Retail margins vary significantly. However the margin in a competitive market for large loads (rather than mass market) is considered to be about 3%. This was the margin assumed.

Ancillary services, Market fees, Metering and data forwarding charges

Historical data is generally the best estimator of these costs. The costs for the previous year were taken (except for market fees which were taken from AEMO budget data as these are more representative of charges for an efficient retailer/energy business).

7.3 Price Projection - Energy

This section presents the results of the forward market and LRMC modelling as indicators of future swap and LGC prices, and the Marsden Jacob projection of swap contract and LGC prices. Additional information is provided in the noted appendices.

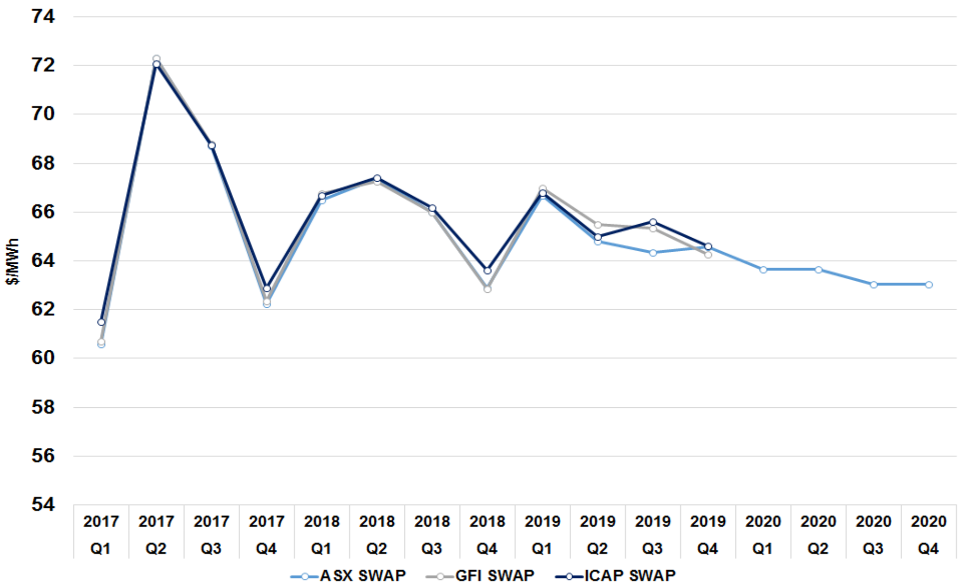
7.3.1 Energy - Forward Prices

The forward energy prices were taken from the following sources for the quarters in the Outlook Period:

- Published by GFI Australia Pty. Ltd. on Friday 25 November 2016;
- Published by ICAP. on Wednesday 16 November 2016;
- Published by ASX on Friday 25 November 2016.

The results of the forward prices for NSW swap contracts are shown in Figure 10 below.

Figure 10 NSW Forward Contract Quarterly Swap Prices (Nominal $)



We note that the various sources show a close matching of prices (which would be expected). The prices are very recent and are considered reliable in relation to future NSW quarterly swap prices. The level and shape of the forward price curve reflect the seasonal pattern of prices and the price risk expected each year. Issues impacting the outlook are the closure of Hazelwood Power Station and increasing renewable generation development.

7.3.2 LGC Prices – Forward Prices

The impending shortage of LGCs has resulted in LGC prices rising substantially over the past year and are now near the Shortfall Penalty Price (non tax deductable price of $65/MWh nominal, or $92.5/MWh).

Table 12 shows the forward LGC prices as published by GFI Australia Pty. Ltd. on Friday 25 November 2016. While an upward sloping LGC price curve may be expected (reflecting the cost of carry of LGCs), the slightly decreasing level reflects the uncertainty regarding the quantity of renewable generation that will be developed over the next two to five years. Increased LGC supply would result in LGC prices decreasing as the date when a shortfall eventuates is pushed out.

Table 12 Forward LGC Prices ($/LGC) (Nominal $)

	2017/18	2018/19	2019/20	2020/21	2021/22
LGC Price	88.5	85.75	83.5	83.5	Not published

7.3.3 Energy and LGCs - LRMC Prices

LRMC modelling was undertaken using the two approaches previously described, these being the “incremental approach” and the “stand-alone” approach. The assumptions used were the most recent on demand, fuel costs and capital costs. The assumptions are presented in Appendix 5. The results of this modelling are shown in Table 13 below (real 2016 dollars). The details of the modelling are presented in Appendix 4.

Table 13 Results of LRMC Modelling (Real 2016 $)

	2017/18	2018/19	2019/20	2020/21	2021/22
Incremental					
Energy ($/MWh)	$36.71	$34.83	$32.16	$35.67	$40.14
Capacity ($/MWh)					
Total Energy ($/MWh) **	$36.71	$34.83	$32.16	$35.67	$40.14
LGC ($/LGC)	$81.37	$83.40	$83.43	$81.44	$79.50
Stand-alone					
Energy ($/MWh)	$72.20	$72.72	$71.87	$70.61	$69.00
Capacity ($/MWh)	$12.8	$12.8	$12.8	$12.8	$12.8
Total Energy ($/MWh) **	$85.00	$85.52	$84.67	$83.41	$81.80
LGC ($/LGC)	$70.56	$72.68	$74.86	$77.11	$79.42

** Based on a flat demand.

7.3.4 Price Projection - Annual Swap Contract and Energy Component

Swap Contract Price Projection

The results of the forward curve and LRMC modelling for future annual NSW swap contract prices are shown in Figure 11, together with the projection of annual NSW swap contract prices. The projection is based on the following:

- The forward curve for the first two years;
- Maintaining the relationship between the LRMC modelling results and the swap contract price projection over the Outlook Period. As the swap contract price projection is equal to the forward curve over the first two years, this was also equivalent to maintaining the relationship between these values. We note that this resulted in the projection being very close to the forward price projection for the 2019/20 year.

The NSW swap contract projection is shown in tabular format in Table 14. This is represented in both real 2016 and nominal dollars.

Figure 11 Forward, LRMC and Projected Swap Contract Prices (Nominal $)

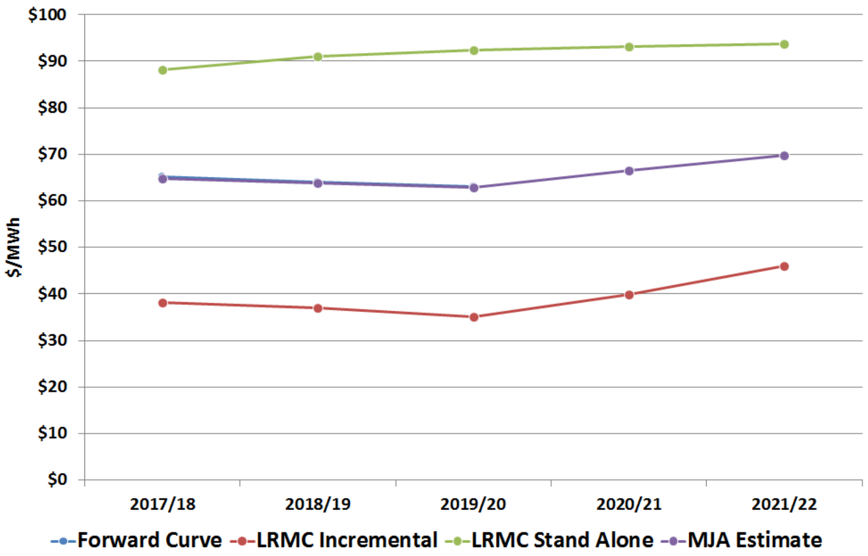


Table 14 Projection of NSW Swap Contract Price $/MWh (Real 2016 and Nominal $)

	2017/18	2018/19	2019/20	2020/21	2021/22
Nominal $/MWh	65.10	64.05	63.06	67.06	69.82
Real $/MWh	63.51	60.96	58.56	59.69	61.12

Energy Component in the Benchmark Price

The energy component in the Benchmark Price needs to account for the amount of over-contracting presented in Table 10. As previously described, this level of over-contracting cannot be avoided if the electricity purchases are to be fully hedged. The cost of the over-contracting is associated with selling the over-contracted energy at a discount equal to a price 5% lower than the swap contract price.

The resulting cost for the energy component (at the location of the plant[18]) of the Benchmark Price for each of the operating modes (including the no over-contracting cases) is shown in Table 15 below (real 2016 dollars). We observe the following:

- The demand for Full Operation was 37.5 MW in 2017/18 and 37.25 MW in all the years after 2017/18;
- As the shutdown modes all had the same level of demand, the over-contracted amounts were the same and the resulting energy component of the Benchmark Price is the same. This is about 2% higher than the associated swap contract price;
- As the ramping model over-contracted amount was slightly higher than for the shutdown modes, the resulting energy component of the Benchmark Price was marginally higher than for the shutdown modes;
- The energy component of the Benchmark Price for the full operating mode had very little over-contracted quantity and thus had the lowest cost of energy for the Benchmark Price;
- All the "no-over-contracting" cases are the same as the differences between the modes in this table is due only to the level of over-contracting.

Table 15 Assessment of the Annual Benchmark Price – Energy (includes losses) (Real 2016 Dollars)

	2017/18	2018/19	2019/20	2020/21	2021/22
Full Operation	64.53	61.96	59.52	60.66	62.12
Ramp up	67.56	64.85	62.29	63.49	65.01
Ramp down	67.56	64.85	62.29	63.49	65.01
Short-term shutdown	66.80	64.12	61.59	62.77	64.28
Medium-term shutdown	66.80	64.12	61.59	62.77	64.28
Long-term shutdown	66.80	64.12	61.59	62.77	64.28
Water security shutdown	66.80	64.12	61.59	62.77	64.28
Full Operation: No Over-contracting	64.49	61.90	59.46	60.60	62.06
Ramping: No Over-contracting	64.49	61.90	59.46	60.60	62.06
Shutdown: No Over-contracting	64.49	61.90	59.46	60.60	62.06

7.4 Price Projections - LGCs

The results of the annual LGC price based on the forward curve and LRMC modelling are shown in Figure 12, together with the projection of annual LGC prices. The projection was LGC prices being $86.5/LGC in all years of the Outlook Period.

What is noticeable in the profile of prices is that the forward curve has LGC prices reducing from the current level whereas the LRMC modelling has LGC price increasing (based on the cost of carry of LGCs). The difference arises from the LRMC modelling having perfect

[18] i.e. Includes the MLF of 1.0154.

foresight of the future whereas the forward curve reflects uncertainties about how much new renewable generation will be developed over the Outlook Period (and beyond).

Because of this, the LGC projection was based on the following:

- An LGC price in 2017/18 at the mid-point between the current forward curve and the Incremental LRMC modelling. The Incremental LRMC was selected as this best represents the current LGC position of an impending shortfall over the Outlook Period;
- LGC prices remaining constant over the Outlook Period. This recognised that the forward curve would likely lift based on the underlying dynamics illustrated through the LRMC modelling and the uncertainty of how much renewable generation would be developed over the Outlook Period.

Figure 12 Forward, LRMC and Projected LGC Prices (Nominal)

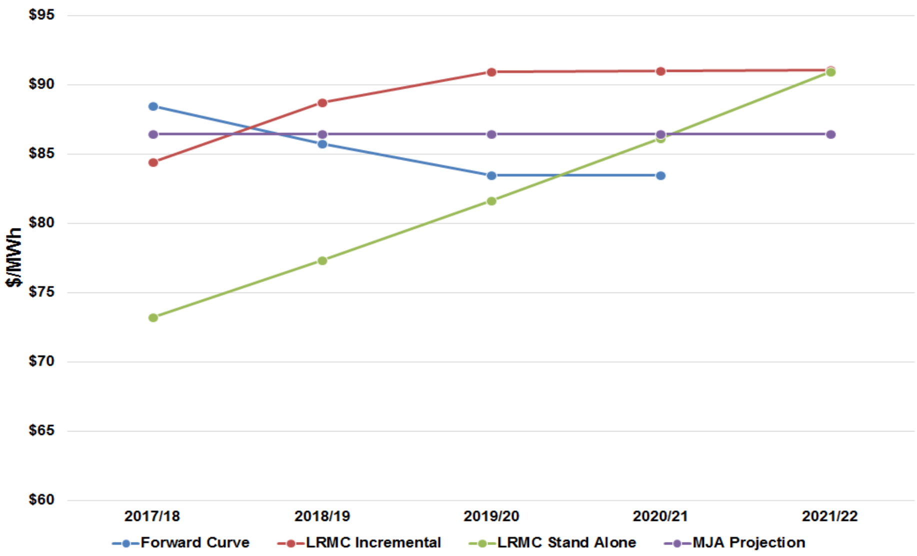


Table 16 LGC Price Projection $/LGC (Real 2016 and Nominal Dollars)

	2017/18	2018/19	2019/20	2020/21	2021/22
Nominal $/LGC	86.50	86.50	86.50	86.50	86.50
Real $/LGC	84.39	82.33	80.32	78.36	76.45

7.5 Price Projection - Other Component Projections

As previously described the best guide to the future costs of the ESS, retail margin, ancillary services, metering/data forwarding charges and market fees are historical outcomes or published budget values where available. Table 17 presents the approach and information sources used to assess the future prices of these components. Table 18 then presents the projected values (Real 2016 dollars).

Table 17 Estimated Other Costs

Component	Basis
STCs ($/certificate)	Historical and current price. STC price remains at $39/STC and the small scale percentage remains at the 2016 percentage level.
Energy Saving Scheme ($/certificate)	Certificates are $25 nominal over the Outlook Period and the target (% savings) is as specified by IPART.
Retail Margin ($/MWh)	Assessed by MJA based on understood competitive margins and as per the ERM FY 2015/16 accounts.
Ancillary Services ($/MWh)	Based on the most recent completed financial year (FY15/16) of ancillary service charges paid by SDP to Infigen. Reasonable forward estimate of efficient ancillary service charges given recent reductions in system restart charges.
Market fees (AEMO) ($/MWh)	From AEMO budget fees for FY16/17. Charges applicable to large retail loads (and Market Customers) only.[19]
Metering and data forwarding charges ($/pa)	Advised by SDP on 30/11/16
Losses	Refers to MLF published by AEMO. The MLF is assumed to remain constant over the Outlook Period.

Table 18 Assessment of the Annual Benchmark Price - Non Energy Components (Real 2016 $)

		2017/18	2018/19	2019/20	2020/21	2021/22
STCs	$/MWh	3.38	3.24	3.24	3.24	3.24
Energy Saving Scheme	$/MWh	1.94	2.06	2.13	2.13	2.13
Retail Margin	$/MWh	5.0	5.0	5.0	5.0	5.0
Ancillary Services	$/MWh	0.25	0.25	0.25	0.25	0.25
Losses (MLF)	Scalar	1.0154	1.0154	1.0154	1.0154	1.0154
Market fees (AEMO)	$/MWh	0.30	0.30	0.30	0.30	0.30
Metering and data	$/Year	3,655	3,655	3,655	3,655	3,655

On a $/MWh basis the metering costs in 2017/18 varied between $0.01/MWh when in full operation to $0.76/MWh when in shutdown mode.

[19] http://www.aemo.com.au/-/media/Files/PDF/AEMO-FINAL-Electricity-Revenue-Requirement-and-Fee-Schedule-201617.pdf

7.6 Construction of the Benchmark Price

The Benchmark Price was calculated by adding the individual components calculated above on a $/MWh basis. The results for each of the operating modes that had different Benchmark Price are shown in Table 19 below (real 2016 dollars). In this table:

- Ramping refers to either Ramping up or Ramping down;[20]
- Shutdown refers to either of the following: Short-term shutdown, Medium term shutdown, Long-term shutdown, or Water security shutdown[21].

Table 19 Benchmark Price for each Operating Mode $/MWh (Real 2016 Dollars)

	2017/18	2018/19	2019/20	2020/21	2021/22
Full Operation	152.5	148.3	144.1	143.4	143.1
Ramping	155.5	151.2	146.9	146.3	146.0
Shutdown	155.5	151.2	146.9	146.3	146.0
Full Operation: No Over-contracting	152.4	148.2	144.0	143.4	143.1
Ramping: No Over-contracting	152.4	148.2	144.0	143.4	143.1
Shutdown: No Over-contracting	153.2	149.0	144.7	144.1	143.8

From Table 19 the following are observed are made:

- The differences between Full operation, Ramping and Shutdown modes are due to metering and data costs being a fixed annual amount and the different level of over-contracting associated with each of the modes;
- The difference between Full Operation and Ramping in the "with over-contracting" included cases is due to the different levels of over-contracting. This difference is not present in the "No Over-contracting" cases;
- With "over-contracting" included the Benchmark Price for the Ramping mode and Shutdown mode are almost identical. This is due to the higher $/MWh "metering and data" costs in the Shutdown mode being almost exactly compensated by the lower over-contracting costs in the Ramping mode.

Table 20 and Table 21 respectively presents the components of the Benchmark Price for the ***including*** and ***excluding*** "over-contracting" cases for the Full, Ramping, and Shutdown modes. The following are noted in these tables.

- The energy costs exclude losses (energy costs + losses equals the energy costs shown in Table 15);

[20] Ramping up and ramping down cases had the same Benchmark Price.

[21] Short-term shutdown, medium term shutdown, long-term shutdown or water security shutdown modes had the same Benchmark Price.

- Each component is expressed as a $/MWh figure where MWh refers to the total SDP demand[22]. This means the costs of LGCs, STC, and ESS expressed on a per MWh of SDP demand are lower than the published costs of these components.

Table 20 Component Costs of the Benchmark Prices – INCLUDES Over-contracting (Real 2016 dollars)

Full Operation

	2017/18	2018/19	2019/20	2020/21	2021/22
Energy (excluding losses)	63.55	61.02	58.61	59.74	61.18
LGC	77.06	75.47	73.63	71.84	70.08
STC	3.38	3.24	3.24	3.24	3.24
ESS	1.94	2.06	2.13	2.13	2.13
Retail margin	5.00	5.00	5.00	5.00	5.00
Market fees	0.30	0.30	0.30	0.30	0.30
Metering and Data	0.01	0.01	0.01	0.01	0.01
Ancillary Services	0.25	0.25	0.25	0.25	0.25
Losses	0.98	0.94	0.90	0.92	0.94
TOTAL	**152.47**	**148.29**	**144.08**	**143.43**	**143.13**

Ramping

	2017/18	2018/19	2019/20	2020/21	2021/22
Energy (excluding losses)	66.54	63.86	61.35	62.53	64.03
LGC	77.06	75.47	73.63	71.84	70.08
STC	3.38	3.24	3.24	3.24	3.24
ESS	1.94	2.06	2.13	2.13	2.13
Retail margin	5.00	5.00	5.00	5.00	5.00
Market fees	0.25	0.25	0.25	0.25	0.25
Metering and Data	0.02	0.02	0.02	0.02	0.02
Ancillary Services	0.25	0.25	0.25	0.25	0.25
Losses	1.02	0.98	0.94	0.96	0.99
TOTAL	**155.46**	**151.14**	**146.82**	**146.22**	**145.99**

Water Security Shutdown

	2017/18	2018/19	2019/20	2020/21	2021/22
Energy (excluding losses)	65.79	63.14	60.65	61.82	63.30
LGC	77.06	75.47	73.63	71.84	70.08
STC	3.38	3.24	3.24	3.24	3.24
ESS	1.94	2.06	2.13	2.13	2.13
Retail margin	5.00	5.00	5.00	5.00	5.00
Market fees	0.30	0.30	0.30	0.30	0.30
Metering and Data	0.73	0.73	0.73	0.73	0.73
Ancillary Services	0.25	0.25	0.25	0.25	0.25
Losses	1.01	0.97	0.93	0.95	0.97
TOTAL	**155.46**	**151.17**	**146.87**	**146.26**	**146.02**

[22] For example, in 2017/18 the cost of LGCs was $86.48/LGC and 91.34% of SDP demand was required to be supplied by LGCs. The cost of LGCs for SDP is then $86.48 x 91.24% which equals 78.98 nominal dollar or $77.06 Real 1 July 2016.

Table 21 Component Costs of the Benchmark Prices – EXCLUDES Over-contracting (Real 2016 dollars)

Full Operation: No Over-contracting

	2017/18	2018/19	2019/20	2020/21	2021/22
Energy (excluding losses)	63.51	60.96	58.56	59.69	61.12
LGC	77.06	75.47	73.63	71.84	70.08
STC	3.38	3.24	3.24	3.24	3.24
ESS	1.94	2.06	2.13	2.13	2.13
Retail margin	5.00	5.00	5.00	5.00	5.00
Market fees	0.30	0.30	0.30	0.30	0.30
Metering and Data	0.01	0.01	0.01	0.01	0.01
Ancillary Services	0.25	0.25	0.25	0.25	0.25
Losses	0.98	0.94	0.90	0.92	0.94
TOTAL	**152.43**	**148.23**	**144.02**	**143.37**	**143.07**

Ramping: No Over-contracting

	2017/18	2018/19	2019/20	2020/21	2021/22
Energy (excluding losses)	63.51	60.96	58.56	59.69	61.12
LGC	77.06	75.47	73.63	71.84	70.08
STC	3.38	3.24	3.24	3.24	3.24
ESS	1.94	2.06	2.13	2.13	2.13
Retail margin	5.00	5.00	5.00	5.00	5.00
Market fees	0.30	0.30	0.30	0.30	0.30
Metering and Data	0.02	0.02	0.02	0.02	0.02
Ancillary Services	0.25	0.25	0.25	0.25	0.25
Losses	0.98	0.94	0.90	0.92	0.94
TOTAL	**152.44**	**148.25**	**144.03**	**143.38**	**143.08**

Shutdown: No Over-contracting

	2017/18	2018/19	2019/20	2020/21	2021/22
Energy (excluding losses)	63.51	60.96	58.56	59.69	61.12
LGC	77.06	75.47	73.63	71.84	70.08
STC	3.38	3.24	3.24	3.24	3.24
ESS	1.94	2.06	2.13	2.13	2.13
Retail margin	5.00	5.00	5.00	5.00	5.00
Market fees	0.30	0.30	0.30	0.30	0.30
Metering and Data	0.73	0.73	0.73	0.73	0.73
Ancillary Services	0.25	0.25	0.25	0.25	0.25
Losses	0.98	0.94	0.90	0.92	0.94
TOTAL	**153.15**	**148.95**	**144.74**	**144.09**	**143.79**

8. SDP and Infigen Financial Relationship

[Redacted]

The terms and conditions in these contracts are fundamental to the costs of energy and environmental products to SDP associated with the desalination plant electricity load.

This chapter presents the key terms of these contracts and the cash flows of Infigen and SDP associated with electricity and LGC purchases by SDP.

The contracts SDP has entered into for the supply of electricity and the necessary LGCs comprise the ESA and RSA. The main terms of these contracts are described in the sections that follow.

8.1 Electricity Supply Agreement

[Redacted]

Table 22 Electricity Supply Agreement Terms [Redacted]

8.2 Renewable Energy Supply Agreement

[Redacted]

Table 23 Renewable Supply Agreement Terms

[Redacted]

8.3 SDP Cash Flows

The operation of the contracts has SDP cash flows operating as shown in Figure 13 below.

[Redacted]

Figure 13 SDP and Infigen Energy Sale and Purchase Cash Flows

[Redacted]

[Redacted]

Figure 14 SDP Demand Level and Electricity Purchase

[Redacted]

8.4 Infigen Contract Prices

[Redacted]

9. Prudency of the Infigen – SDP Contracts

Two aspects of the Infigen contracts are reviewed, firstly the benefits and risk the long term structure and terms provides to SDP, and secondly how the Infigen contract prices have compared to historical market outcomes and what the projection is over the next 5 years.

The review highlights the number of issues involved. [Redacted]

This chapter reviews the prudence of the ESA and RSA contracts ("Infigen contracts"). Two aspects were considered in this review:

- The structure of the contracts in terms of volume, term and the other contract conditions;
- The contracts prices over the Outlook Period and over the remaining contract term.

[Redacted]

9.1 Review of Contract Structure

[Redacted]

9.2 Past and Future Contract Performance

The performance of the Infigen Contract relates to the price paid for electricity used, which is determined by the matching of contract volume and actual SDP demand, and contract prices compared to actual. This is presented for the Review Period and the projection for the Outlook Period.

SDP contract volume and the SDP demand for the Review Period and that likely for the first 3 years (at least) of the Outlook Period have been discussed.

[Redacted]

9.2.1 Infigen Contract, Benchmark and Actual Prices

Figure 15 presents in real 2016 dollars for the Review Period (historical outcomes) and the Outlook Period (using the Benchmark Price developed in this report):

- Actual prices – this is spot energy, LGC and other components provided by the Infigen Contract;
- Infigen Contract Price (energy plus LGCs);
- Infigen Contract Price (energy plus LGCs) including losses from sales of surplus energy; and
- The Benchmark Price.

From this graph we note the following:

Review Period

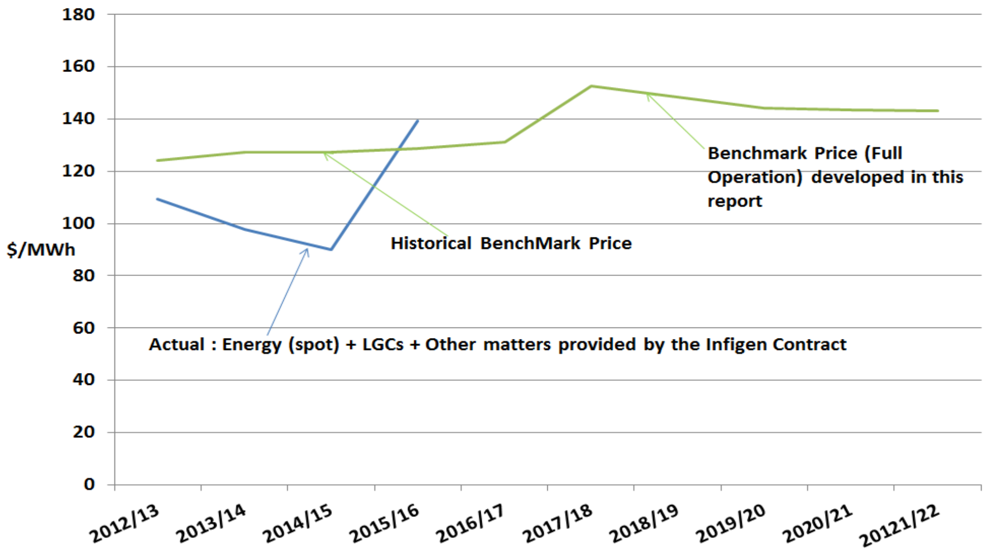
- The Benchmark Price was slightly lower, reflecting an expectation that actual prices would be slightly lower;

- For the period 2012/13 to 2014/15 energy prices were low. This was due to oversupply that principally occurred through energy efficiency, rooftop PV solar development and lower economic growth. The degree to which "scheduled demand[23]" would flatten was not foreseen by most of the market investors. Energy prices in 2015/16 have recovered due to coal plant closures and high gas prices;

Over the past 5 year there have been long periods when LGC prices have been low, principally due to renewable energy policy uncertainty. Under the Abbott government the Warburton review of the LRET recommended a substantial reduction in the LRET. [Redacted]

Figure 15 Infigen Contract Prices, Benchmark Prices and Actual Prices (Real 2016 dollars)

[Infigen contract price redacted from the figure below]



- The agreement of the 33,000 GWh LRET target by both sides of politics and the shortage of renewable generation to meet this target has resulted in LGC prices increasing to be near the Shortfall Penalty Price;
- [Redacted]

Outlook Period

- The outlook for energy prices is substantially higher than the previous 5 years. This is due to the factors previously mentioned plus additional generation plant closure plus further increase in gas prices. The forward curve for NSW flat contracts have contract energy prices higher than the prices contained in the ESA;
- As mentioned, the outlook is for LGC prices to be near the Shortfall Penalty Price over the Outlook Period. Looking further ahead, the dynamics of the renewable energy market is complex and the price and availability of renewable energy is uncertain;
- The Benchmark Price developed in this report reflects this changed dynamics.

[23] Scheduled demand is the demand supplied by the main grid power stations.

9.3 Evaluation of Infigen Contracts

The above discussion has illustrated the number of issues involved in the suitability of the Infigen contract in supply the uncertain SDP demand profile.

Marsden Jacob does not consider having the SDP uncontracted would be appropriate. The situation of a number of large industry demands in recent years has illustrated the risks of being uncontracted and attempting to secure contracts when required. The risk for SDP also includes the need to be 100% renewable before it can operate. Therefore medium to long term contracting for electricity and renewable requirements for the energy needs of SDP is considered prudent.

[Redacted]

On this basis the Infigen contracts are considered to be prudent.

10. Application of the EnAM over the Review Period

The Energy Adjustment Mechanism (EnAM) provides for the sharing between SDP and customers of the gains and losses associated with the sale of surplus electricity and LGCs.

The gains and losses are calculated as the sales price compared to the Infigen contract price for the volume sold. The calculation excludes the pass-through of imprudent transactions associated with trading surplus electricity contract supply or LGCs (Infigen contract).

The assessment did not exclude any losses from the EnAM due to imprudent trading.

The EnAM pass-through was calculated to be a loss of $24,525,245 over the period 2012/13 to 2015/16.

This chapter describes the Energy Adjustment Mechanisms (EnAM) and how it works, and then applies to EnAM to the period 2012/13 to 2015/6 (the 2016/17 year is not complete). The following chapter considers potential changes to the EnAM based on observations over the Review Period.

10.1 Description of the EnAM

IPART has implemented an Energy Adjustment Mechanisms (EnAM), contained within the current regulatory framework, to provide for the pass-through to SDP's customers of the financial gains or losses each year associated with the sale of surplus contracted energy and LGCs. As surplus energy and LGCs are only available in the shutdown modes, application of the EnAM is restricted to these periods.

IPART's current specification of the EnAM for the Review Period is as follows:

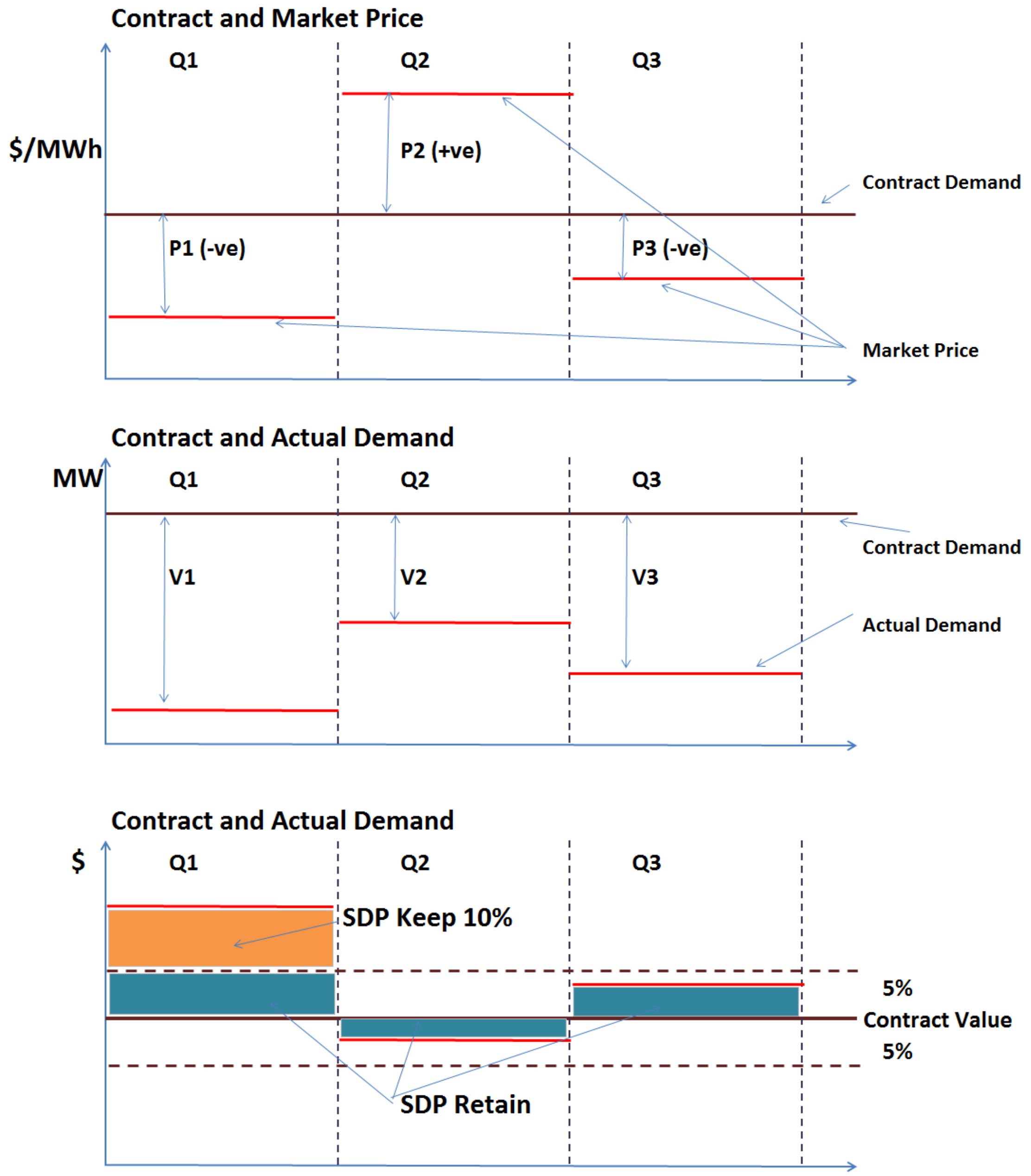
- For each year determine the net gain or loss from the sales of energy and LGCs[24] (i.e. operates on the summation of energy and LGC gains or losses);
- For each year determine a threshold band equal to 5% the total minimum purchase cost of energy plus LGCs;
- SDP retains all gains and losses within the threshold band;
- Gains and losses outside of the threshold band are shared 90% to customers and 10% to SDP;
- There is a requirement that SDP must act prudently to minimise its exposure to losses on the resale of surplus electricity and LGCs. This includes negotiating any consideration for the assignment of its long-term energy contracts. Where there is manifest imprudence that may arise on the part of SDP, those affected transactions may be excluded in whole or in part from the energy adjustment mechanism; and

[24] For the purpose of the EnAM calculation the spot price of RECs is defined as the time weighted average of the "last / mkt" prices specified in A$/MWh for "all spot T+3" transactions of "LGCs (LRETs)" occurring in the final month of each calendar quarter, as published in the Greenroom report (or equivalent).

- Does not apply if the Infigen contracts are assigned to a third party or terminated.

Box 1 below presents a visual presentation of the operation of the EnAM.

Box1: Explanation of EnAM Operation



EnAM Calculation

Q1	**P1 x V1**	**Negative - Additional cost**
Q2	**P2 x V2**	**Positive - Additional revenue**
Q3	**P3 x V3**	**Negative - Additional cost**

To clarify the operation of the EnAM the Minister[25] advised that:

".... the intention of the proposed energy adjustment mechanism is that:

> *1. It would only apply to electricity and RECs that are not required by SDP when the desalination plant is not in full operation mode when complying with the plant's operating rules, as established by the Metropolitan Water Plan and subsequently included in SDP's Network Operators Licence under the Water Industry Competition Act.*
>
> *2. It would ensure that SDP customers for water (in Sydney Water's Area of Operations) receive the benefit of significant gains and bear significant losses incurred as a result of the difference between the cost of electricity and RECs under SDP's contracts with Infigen and the market price for electricity and RECs arising from the sale of SDP's surplus electricity and RECs (in the circumstances described in point 1).*
>
> *3. For electricity, the mechanism would mirror the 'Calculation of Shortfall Adjustment' in SDP's Electricity Supply Agreement with Infigen, with the 'market price' defined as the half-hourly spot price and/or the price of a contracted 'available block'.*
>
> *4. For RECs, the 'market price' would be the price shown in the Nextgen Greenroom Report, or another equivalent report."*

10.2 Application of the EnAM

This section applies the EnAM to the period 2012/13 to 2015/16. Presented are:

- The calculation approach;
- The identification of any imprudent trading losses to be excluded; and
- The calculation of the EnAM amount.

10.2.1 Calculation Approach

As SDP was in water security shutdown mode over the entire Review Period all days (and sales) were included in the calculation. This meant that there was excess electricity equal to the difference between the minimum annual contract level and the demand level associated with the operation in the shutdown mode.

The calculation was undertaken on a quarterly basis as follows:

- Electricity Resale Gain or Loss = (minimum contract volume less actual volume) x (market price less contract price);
- RECs/LGCs Resale Gain or Loss = (minimum contract volume less actual volume) x (market price less contract price);
- The Combined Energy Resale Gain or Loss was then calculated by summing the resale gain or loss for electricity and LGCs to give the total annual gain or loss;
- All trades (or lack of trades) were reviewed and any losses were excluded if considered imprudent;

[25] https://www.ipart.nsw.gov.au/files/sharedassets/website/trimholdingbay/methodology_paper_-_sydney_desalination_plant_-_efficiency_and_energy_adjustment_mechanisms_-_april_2012.pdf, page 21

- The annual gains or losses were allocated to SDP and customers using the 5% threshold and 90% above the threshold sharing arrangements; and
- This was then summed over the four years to give a total value.

10.2.2 Imprudent Trading

[Redacted]

Section 5.4 presented the assessment of the gains that could have been obtained over the Review Period and Table 8 showed the results of this. On the basis that undertaking the work required would have a cost of $75,000 per year, the gains from forward selling 50% of available contracted energy each month over the Review Period would have been $91,000. Given the uncertainty in costs and actual forward prices that would have been achieved, this is taken to represent only relatively small potential trading gains over the Review Period.

The conclusion to this is that there are no losses to be excluded from the EnAM due to imprudent action.

10.2.3 Calculation of EnAM Amounts

Table 24 below presents the working of the application of the EnAM.

Shown are:

- The ESA and RSA contract values of electricity and LGCs ;
- The 5% threshold level;
- The amount subject to the 10%/90% sharing;
- The 90% rule to determine the losses passed through to customers.

These values have been calculated on the basis that no losses have been excluded from the EnAM.

The total EnAM over the four years (FY12/13 to FY15/16) using this approach is $(24,525,245).

Table 24 Application of the EnAM

[Table 24 Redacted]

	2012/13	2013/14	2014/15	2015/16
Elec contract value $				
Elec materiality threshold $				
REC contract value $				
REC materiality threshold $				
Elec + LGC materiality threshold $				
Resale gain or loss				
Resale gain or loss outside threshold $				
Combined energy adjustment pass through $ under EnAM				

11. Assessment of the EnAM

In its current form the EnAM was considered by Marsden Jacob to have two potential shortcomings. Firstly it is silent on whether a reasonable forward energy sale that resulted in a loss would necessarily be considered prudent, and the 90% sharing rate limits the incentive of SDP to take a greater interest in forward selling spare energy for potential profit and/or limiting losses. These two issues form the basis of the recommendations in relation to any changes to the EnAM.

As previously described the EnAM calculates the share between SDP and customers of the gains and losses associated with the sales of surplus energy and LGCs.

The design of the EnAM should recognise that SDP is acting on the behalf of its customers. As such the EnAM should provide sufficient incentives for SDP to maximise the value of the sale of surplus energy while providing the remaining gains or losses to customers.

Recognising the above, this chapter:

- Reviews the issues associated with the sale of surplus contract energy and LGCs;
- Review the sharing arrangements (i.e. 5% threshold and 10%/90% sharing); and
- Proposes alternative sharing arrangements.

11.1 Selling Surplus Contract Energy and LGCs

Energy - Available Contract Volume

With no action surplus energy is sold half hourly on the spot market. [Redacted] The fact that this occurs without action suggests that the same approach would occur without the EnAM.

The alternative to sales on the spot market is to take action to forward sell via derivative contracts. The sale of derivative contracts can result in trading gains or losses. There is no option to put "contract energy" in inventory and sell at a later time.

The expected gain to be made on the sale of forward contracts is non-trivial and the existing excess energy position of SDP when in shutdown mode compared with the minimum annual contracted volume in the ESA is large. For example, based on SDP being in the water security shutdown mode, the forward market at $65/MWh and obtaining a 5% premium over spot prices, selling all available surplus energy would result in a trading gain of about $1M per year. This is proportionally decreased as the amount of surplus energy is decreased.

The sale of derivative contracts (i.e. forward sales) that result in a loss (arising from the average spot price being higher than the contract quantity) raises the question of prudency and the exclusion of such trades in the EnAM (with the full transaction loss being allocated to SDP).

However it is the view of Marsden Jacob that if forward electricity demand for SDP for the next quarter is prudently assessed, transactions are then entered into to reduce the exposure to NSW pool prices [Redacted], and those transactions are struck at or near the prevailing market prices then it would be unreasonable to exclude those transactions from the EnAM in the event of losses. In relation to a transaction that results in a gain, it is not clear that such a transaction could ever be considered imprudent.

LGCs

Unlike energy LGCs can be placed in inventory and sold at a later time. The sale of LGCs is not via a derivative contract that can result in a trading gain or loss. Sales of LGCs do require a decision to sell and to undertake this activity.

[Redacted]

It is noted that due to the changing renewable regulatory environment references in relation to EnAM to RECs should be changed to LGCs and any references to markets and market prices sources should be made more flexible to allow for the development of new price sources that can be used to establish or support the prudence of forward or spot sale transactions taken by SDP in either electricity or LGCs.

11.2 EnAM Sharing Arrangements

The design of the sharing arrangements and their consistency to the objectives of the EnAM is discussed below.

Combined treatment of energy and LGCs

The approach used in this report is that gains and losses from the sale of surplus energy and surplus LGCs should be treated on a combined basis. If this were not the case then a loss of say energy within its 5% band would not cancel a gain of LGCs above its 5% band. This also recognises that it is the gains and losses of electricity purchases that are being addressed, and not the individual components.

5% threshold band

This band represents a value within which SDP retains all gains and losses.

In relation to the 5% band the following are noted:

- For energy and based on the 2015/16 ESA energy price, the size of this threshold is [Redacted]. The total threshold for energy plus LGCs combined in 2015/16 is [Redacted].
- On the assumption that the spot price averaged the contract price, this would closely approximate the trading profits if all energy were forward sold and obtained a 5% premium over the spot price (the level the premium has averaged since 2001). It is not considered reasonable that SDP should retain the total profits in this situation.

It is observed that “thresholds bands” are often used as a balance between administrative costs associated with including small transactions (in payments) and the value of including such transactions. However in this situation, the threshold band does not provide any savings in administrative work (in fact quite the opposite).

There appears to be no apparent value in retaining the use of a 5% threshold.

10% /90% sharing

The 90% pass-through of gains and losses outside of the threshold band shields SDP from the vast majority of the potential gains and also the vast majority of prudent losses. The limited upside available from gains and potentially larger downside would potentially act as a deterrent to any rational business to invest in less passive management of the surplus energy (especially) and LGC sales.

Increasing the sharing percentage (from 10%) would potentially provide SDP with a stronger incentive to less passively manage their excess energy and LGC positions whilst not in full operation mode, while not exposing SDP to materially more risk that it could prudently manage.

Symmetry of Sharing

While appearing symmetrical, the current EnAM arrangements are highly likely to be asymmetrical in relation to the proportional sharing (between SDP and customers) of losses and gains. The reason for this asymmetry is as follows:

- The 5% Threshold (energy plus LGCs) is sized at about [Redacted];
- The Infigen contracts includes costs that are not included in the surplus energy or LGCs sold (retail margin, ancillary services etc.);
- Historically NSW spot prices (in real 2016 dollars) [Redacted]. The introduction of a price on carbon emissions could increase energy prices but no such policy is currently planned;
- [Redacted].

This indicates that there is a far greater potential for the sum of energy and LGC prices to be significantly lower than the combined Infigen contract price than for the sum of energy and LGC prices to be significantly higher than the combined Infigen contract price. As noted above, this is because the Infigen contract prices implicitly include other components and the Infigen contract price levels are near new entry levels.

11.3 Revised Sharing Arrangements

From the above the following observations are made regarding the current EnAM:

- Increased incentives for a less passive management of the energy surplus when SDP is in the water security shutdown mode could have potential benefits to customers;
- The nature of the sale of LGCs has not and is unlikely to be influenced by the EnAM or changes to its design;
- Greater clarity may be required in relation to the prudency of forward trades, undertaken in adherence to good trading practice, that results in a trading loss;
- The asymmetry of potential gains and losses means that on a percentage basis, SDP would be expected to keep the majority of gains (in years where there is a gain) while customers would be expected to be allocated the majority of losses (in years where there are losses); and
- There is no evidence that the threshold bands provide any useful purpose.

Any proposed modification to the EnAM should attempt to address the issues of incentives to maximise the value of energy sold and also providing an equitable sharing of both gains and losses.

This suggests modifications to the EnAM as follows:

- Modify the threshold band to provide sharing to customers. This can be done by decreasing its size and/or provide sharing within the band;
- Outside the Threshold Band provide an increased allocation to customers; and

- Introduce a different profile for gains as opposed to losses.

If there were to be material changes made to the EnAM it would be reasonable for these changes to only take effect on and from 1 July 2017 and that the existing EnAM rules remain in place for the 2016/17 financial year.

If there were to be material changes made to the EnAM it would be reasonable for these changes to only take effect on and from 1 July 2017 and that the existing EnAM rules remain in place for the 2016/17 financial year.

Figure 16 presents three alternative options for the EnAM:

- Option 1 - Two Band Sharing: 50% to $2M and then 15% sharing:
  - the Threshold band is sized lower than the conceivable annuals gains
  - above this SDP has increased incentives to manage the surplus energy;
- Option 2 - Two Band Sharing: 50% to $3M and then 20% sharing:
  - the Threshold band is sized about the size of the conceivable annuals gains
  - above this SDP has higher incentives to manage the surplus energy than in Option 1;
- Option 3 - Single Band 25% Sharing:
  - this is the simplest and is totally symmetrical
  - it provides a lower sharing of gains (in years where there are gains) to customers.

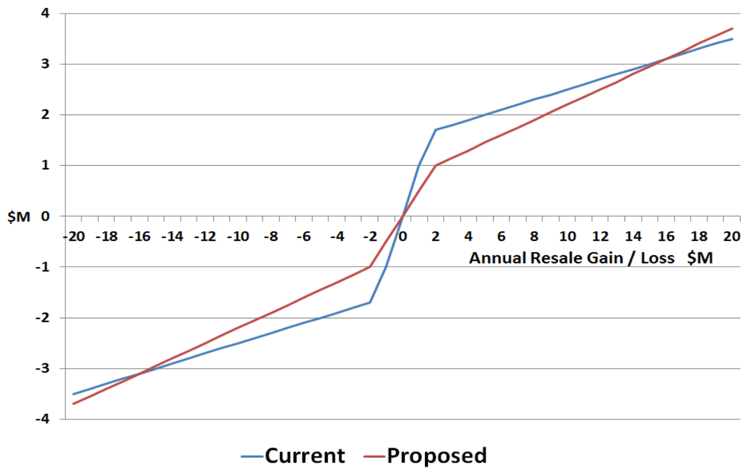
All these options address the asymmetry of gains and losses allocation and the incentives for greater management of surplus energy sales.

In these options for EnAM:

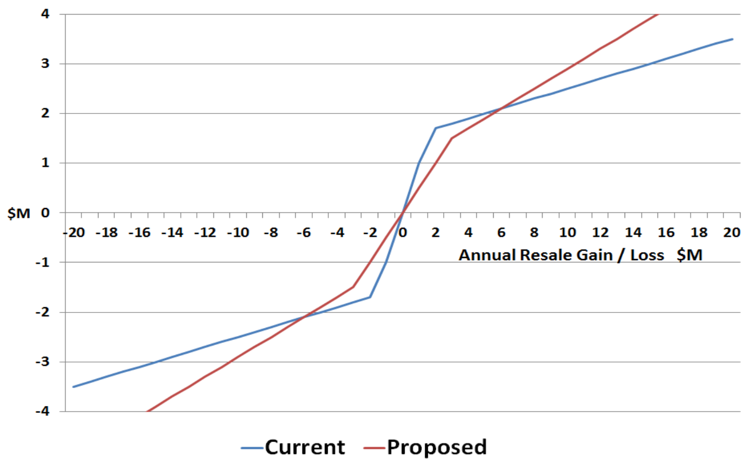
- Gain and losses to be based on the total of energy + LGC gains/losses; and
- Clarity on the circumstances under which transaction losses would be considered prudent.

If there were to be material changes made to the EnAM it would be reasonable for these changes to only take effect on and from 1 July 2017 and that the existing EnAM rules remain in place for the 2016/17 financial year.

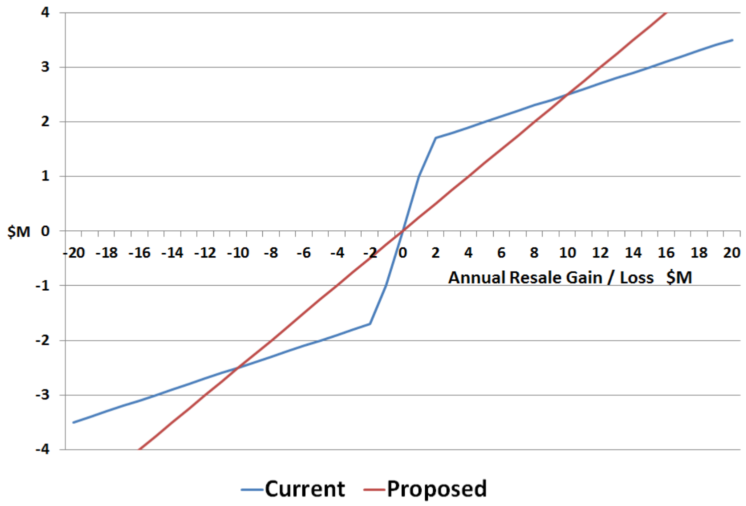
Figure 16 Current and Proposed EnAM Sharing Models – SDP Allocation of Gains and Losses



Two Band Sharing : 50% to $2M and then 15% sharing



Two Band Sharing : 50% to $3M and then 20% sharing



Single Band 25% Sharing

12. Appendix 1 Scope of Work

The scope of work as presented to Marsden Jacob is presented below.

DESCRIPTION OF SERVICES

The consultant must undertake an energy expenditure review, including the following tasks:

- **Task 1**. A detailed review of SDP's past and proposed energy costs (including electricity and Renewable Energy Certificates (RECs))
- **Task 2**. Provide inputs into application of the Energy Adjustment Mechanism (EnAM) in the 2017 Determination of SDP's prices, and into the review of the Methodology Paper on EnAM for the future determination period(s).

IPART requires the consultant to provide the following services:

Task 1. A detailed review of SDP's past and proposed energy costs

As part of the price review, IPART makes decisions on SDP's operating and capital expenditure allowances over the 2017 Determination. To do so, IPART examines:

- actual expenditure incurred since the last price determination (the 2012 Determination), and
- forecast expenditure for the next determination period (2017 Determination).

Energy costs are one of the components of total operating costs. To assist IPART in this task, the consultant must assess, report and provide recommendations on SDP's:

Task 1.1 Electricity costs: the prudence and efficiency of past and proposed electricity expenditure for the period from 1 July 2012 to 30 June 2022

Task 1.2 Renewable Energy Certificates (RECs) costs: the prudence and efficiency of past and proposed RECs expenditure for the period from 1 July 2012 to 30 June 2022.

This consultant should review the efficiency of energy (electricity and RECs) costs for the current determination period (2012-13 to 2016-17), and recommend the prudent and efficient forward costs of purchasing energy over the range of plausible operating scenarios for the new determination period (2017-2018 to 2021-22). Forward costs of purchasing energy include values for RECs and an allowance for electricity.

Network energy costs payable by SDP are currently included as a pass-through into its prices in line with the annual changes to network charges as approved by the Australian Energy Regulator (AER). IPART may continue using a pass-through mechanism for network costs and therefore this component of energy costs may be excluded from this consultancy.

In undertaking the review of historical energy costs in Tasks 1.1 and 1.2, the consultant must:

a) Assess efficiency of actual energy costs from 2012-13 to 2016-171, including

i. Report on the historical expenditure for each year of the current determination period (ie from 2012-13 to 2016-17)

ii. Review the variations in energy expenditure from what was allowed in the 2012 Determination for SDP and, where assessed as material, comment on the reasons for this variation including the extent to which these variations are justified

iii. Review any cost sharing of energy savings between SDP and its operator, Veolia, achieved over 2012-13 to 2016-17

iv. Review the history of trades of surplus energy, including the prudence of SDP's RECs trades over the 2012 determination period, and provide recommendations on the amount of gains or losses to be excluded for the purposes of applying the EnAM (Task 2).

In undertaking the review of forward energy costs in Tasks 1.1 and 1.2, the consultant must:

a) Recommend efficient annual energy costs with respect to SDP's load shape (per MWh of energy used) for the period from 1 July 2017 to 30 June 2022 (ie, 2017-18 to 2021-22), based on the:

   i. benchmark estimates of energy costs (RECs and electricity) using both:

   – A market-based forecast using the futures trade in electricity and RECs contracts on the ASX (eg ASX Energy), and

   – A market-based forecast using Long Run Marginal Costs (LRMC) of generation as a long term proxy for wholesale market spot and contract electricity prices, and LRMC of meeting the Renewable Energy Target (RET) as a proxy for REC market prices.

b) Assess and provide recommendations as to the efficiency of SDP's proposed level of energy costs for each year, including

   ii. Review of the prudence and efficiency of the actual electricity and REC prices payable by SDP under its long-term contracts.

An explanation of the efficiency and prudence tests that the consultant is required to undertake is provided at Appendix B.

Task 2: Input to application and review of Energy Adjustment Mechanism

Under the ToR, IPART is required to implement an Energy Adjustment Mechanisms (EnAM). The EnAM is to provide for the carryover and pass-through to SDP's customers of gains or losses, outside a core band, associated with the sale of surplus electricity and RECs when the plant is in Shutdown and Restart modes only.

SDP incurs these gains and losses, not as the result of our price structures, but because of the avenues available to SDP to deal with surplus electricity and RECs within the constraints of its Infigen (energy) contract arrangements.

SDP must act prudently to minimise its exposure to losses on the resale of surplus electricity and RECs, including in negotiating any consideration for the assignment of its long-term energy contracts. In the case of any manifest imprudence that may arise on the part of SDP, IPART may exclude the affected transactions (in whole or in part) from the EnAM.

Appendix A provides detail on EnAM as background for this task.

Task 2.1 Application of EnAM in the 2017 Determination

To assist IPART in this task, the consultant must assess and report:

a) gains and losses resulting from the difference between SDP's costs of electricity and RECs under its contracts and revenues from the sale of surplus electricity and RECs, from 2012-13 to 2015-16

b) Amount of gains or losses to be excluded for the purposes of applying the EnAM as being imprudent, based on findings of Task 1

c) Recommended EnAM pass through amounts to include in the 2017 Determination.

In undertaking this task the consultant must follow IPART's 2012 Methodology Paper, where appropriate.

Task 2.2 Review of Methodology Paper on EnAM for future regulatory period

As part SDP's price review, IPART is reviewing and if necessary updating the EnAM methodology. Any updates to the methodology would apply at future reviews (ie, the revised 2017 Methodology Paper will be used to implement the EnAM over the 2017 determination period in prices from 1 July 2022).

The consultant must:

a) Undertake an assessment of the EnAM, informed by Tasks 1 and 2.1, and identify areas of the current methodology that could be improved. In particular, the consultant should identify any ambiguities, redundancies and unnecessary complexities in our EnAM.

b) Provide advice on amending the EnAM based on the consultant's assessment and stakeholder submissions on the EnAM

13. Appendix 2 Energy Risk

This appendix presents a review of the types of risk that are associated with energy trading in the NEM and approaches that are adopted to manage such risks.

Four major components of Energy Risk are addressed individually below.

13.1 Market Risk

Market risk is defined as the risk of loss resulting from the adverse fluctuation in market factors. Market factors refer to energy and environmental/carbon commodity volumes, as well as their respective prices. The management of market risk is reflected in:

- position reporting;
- limit structures;
- limit monitoring and reporting; and
- limit violation and loss notification.

Market Risk is defined as the risk that the value of your portfolio will move adversely, due to movements in market variables. More specifically, Market Risk arises, as a result of changes in market prices (Price Risk) or changes in underlying exposures (Volume Risk). Whilst these features are certainly not unique to the energy market, the volatility of spot electricity prices (for example) and the variable nature of customer energy requirements, makes the management of Market Risk in energy markets particularly challenging.

The two main causes of Market Risk are the potential mismatches between:

- Retail selling prices relative to the underlying wholesale purchase costs; and
- Customer load and the corresponding hedge position relative to the forward curves at any point in time.

Generally, such exposures arise through:

- Unexpected changes in customer consumption patterns.
- Mismatches between retail and wholesale contract optionality.
- Inadequate risk transfer in retail sales contracts.
- Load forecasting errors.
- Lack of flexibility in the wholesale hedge position.
- Unexpected changes in the wholesale hedge position.
- Unexpected changes to the wholesale or retail forward curves.
- Pricing anomalies between wholesale and retail operations.

How is Market Risk typically measured?

The level of Market Risk can be measured via a combination of the following three components.

Earnings at Risk:

This is fairly standard and primary measure of market risk and is designed to simulate the potential economic loss that a particular set of market variables will create. This measure is a probabilistic or statistical measure and uses historical load and spot prices to simulate future outcomes. The *E@R* exposures are measured relative to Board approved Earnings at Risk Limits. Details of these limits and the methodology employed can vary between organisations and the risk appetite and capability of an organisation.

Earnings Stress Tests:

Stress tests are a supplementary measure of market risk and are designed to quantify the financial outcome of a severe but plausible scenario. By definition, such scenarios are unlikely to appear in historical observations, so the results of these tests assist in understanding the potential risk outcomes, over and above the bounds of the probabilistic earnings at risk measures.

Portfolio Performance Analysis:

Historical portfolio performance is the third component of market risk that should be utilised. The financial results of the wholesale portfolio versus both budget and the transfer price on a monthly basis as part of a performance report. This backwards looking analysis is used as a proxy indicator of how the forward portfolio might perform under similar structuring and conditions and complements the two aforementioned market risk measures.

In addition to the three measures outlined above, participants will use substantive graphical representation to assist in understanding the combined portfolio position that is driving any reported market risk exposures.

How is Market Risk Generally Reported?

Market Risk exposures are calculated and reported (relative to limits) to a management and/or board sub-committee on a monthly basis by an independent part of an organisation.

How is Market Risk Generally Managed?

Market Risk associated with an energy business is generally managed through the application of appropriate controls and limits. These include:

- Limits on earnings at risk exposures;
- Limits on portfolio positions;
- Dealing only in authorised instruments and markets; and
- Regular reporting of forecasting performance results.

13.2 Credit Risk

Credit risk is defined as the risk of loss from counterparties or customers defaulting on their financial obligations. The management of credit risk is reflected in:

- Credit exposure assessment;
- Counterparty credit worthiness assessments;
- Counterparty limit matrix;

- Credit risk administration (including documentation approval, credit enhancements and counterparty credit files);
- Limit monitoring and reporting of limit violations;
- Loss notification and recovery administration.

Participation in the energy market may expose a participant to credit risk via both the wholesale energy market and the retail sales market. Each of these credit risk exposures can be managed by separate policies (or else incorporated into a Group Credit Policy or on occasion into the Wholesale Energy Trading Policy) such as:

- The Wholesale Energy Markets Credit Policy; and
- The Retail Commercial Credit and Debtor Policy.

Both of the policies would normally fall within the umbrella of a Group Credit Policy.

13.3 Liquidity/Funding Risk

Liquidity/Funding risk is the risk that a company cannot access sufficient liquidity to meet financial obligations arising from energy market positions when they fall due. The policy specifies measurement processes, roles and responsibilities.

13.4 Operational Risk, Legal and Regulatory Risk

Operational risk is defined as the risk of loss resulting from inadequate or failed internal processes and controls, people and systems, or from external events. Operational risk includes failure of compliance processes.

Operational risk arises from the execution of trading, market, and marketing operations, as well as the market risks associated with the delivering, producing, and storing of physical energy. The management of operational risk is reflected in:

- Guidelines in policies and procedures (including segregation of duties, operating standards, code of ethics, information systems support, and business continuity planning); and
- Administration and reporting.

Operational Risk is a very difficult risk to quantify. Rather than attempting to prescribe arbitrary measures for compliance purposes, Operational Risk would normally be assessed as part of an annual risk review. Through a prescribed framework of analysis the various components of Operational Risk are assessed in terms of consequence and likelihood. Whilst the consequences of Operational Risk are generally assessed to be within the "Major" or "Catastrophic" categories, the likelihood of such events is generally assessed as "Rare" or "Unlikely". These assessments are made at least annually, after consideration of the Operational Risk controls that has been employed.

Operational Risk associated with an energy business is normally managed through the application of appropriate controls and standards. These can include:

- Dealing only in Authorised Instruments and Markets.
- Strict Internal Delegations of Authority covering the magnitude and duration of transactions that may be entered into by staff.

- Delegations of authority for the execution of ISDA Master Agreements and confirmations for non-Master Agreement transactions.
- Maintenance and issuance of delegated authorities and specimen signatures
- Maintenance of counterparty delegated authorities and specimen signatures.
- Clear segregation and documentation of the wholesale transaction execution, confirmation, settlement and reporting processes.
- Observation of standard confirmation conventions, including the issuance and maintenance of Standard Settlement Instructions.
- Minimum levels of staff qualifications.
- Business Continuity Plans for major systems.
- The use of Austraclear or similar settlement system for wholesale transaction settlement. This ensures the two-way confirmation of transactions.
- Independent risk reporting.
- An (at least) annual Internal Audit compliance program and review of the internal control systems and associated documentation.

Legal Risk is defined as the risk that a counterparty's performance obligations may not be legally enforceable. In relation to participation in the energy market, this concept can relate to both wholesale energy transactions and retail sales transactions. The potential impacts of the Legal Risk that such transactions may introduce, can be categorised as follows:

- ***Impacts on Overall Portfolio Position:*** From a wholesale trading perspective, the legal enforceability of hedge contracts is paramount to knowing how the portfolio is positioned at any point in time. From a retail contract perspective, the legal enforceability of transactions will not only effect the expected revenue from customers, but will also impact on the relative position of the underlying wholesale portfolio against committed load.
- ***Impacts on Margins:*** The legal certainty associated with both wholesale and retail transactions is also important from a cost pass through perspective.

14. Appendix 3 Hedging Contracts

This appendix presents a review of the products that are available to manage wholesale electricity purchase cost risk in the NEM.

Flat Swaps

Whilst monthly electricity futures products do exist, unlike South Australia liquidity in the NSW electricity market remains relatively high. This means it is theoretically possible but difficult to adjust positions to a monthly resolution through over the counter derivatives or futures contracts. Standard swap products are generally calendar quarters or annual periods.

Flat swaps, bought or sold on a quarterly or annual basis, are a readily accessible and anonymous channel through which any NSW retailer or wholesale market participant can gain exposure to the market and manage risk. The best and most prudent approach is to build up positions slowly in small volumes for example, by buying or selling in forward volume on a quarterly basis. In addition to trading with generic ASX electricity futures products, flat swap products can also be traded over the counter (OTC) as well. Electricity futures and options contracts are listed by the Australian Stock Exchange (ASX) on the 4 major regions (VIC, SA, QLD and NSW).

Capped swaps

Buy swap/sell cap or sell swap/buy cap (either futures or OTC). These are good products and popular for the buying and selling energy capped at $300/MWh and managing the risk associated with high price volatility.

Peak Swaps (or 7 day peak swaps)

Either futures or OTC these products capture or protect premium peak contract revenue but doesn’t provide price protection during off peak (particularly around the nightly hot water load and price spike) or on weekends when prices can be high (especially on hot summer afternoons and winter morning and evening peaks and ramping). Peak periods are generally defined as 7 am to 10pm Eastern Standard Time on working weekdays.

Caps (futures or OTC)

Buying or selling of a caps (generally with strike prices of $300/MWh) through OTC or futures markets as a potential revenue source for generators and price protection for retailers. A range of C&I customers have shown interest in purchasing cap type products to protect against pool price outcomes where they are taking on spot exposures.

Intermittent Generation (non-firm energy)

Many wind farms have been developed in the NEM since around 2008. Some of these windfarms (e.g. Hallett) are either owned by major participants or contracted to them (e.g. Trustpower’s Snowtown windfarms) but a number of windfarms are operating as merchant plant, with production output in excess of their contracted wholesale and retail positions. Whilst not a perfect match for the retail load that needs to be hedged, the energy output from wind farms can either be contracted on a firm basis or non-firm metered basis. The levels of discount for buying the non-firm energy from any intermittent source such as a windfarm should be negotiated and linked to the perceived discount of the wind farm to its ability to capture the flat regional reference pool price and/or the cost of firm up the non-firm energy (either through buying caps, allocation of existing generation assets or other weather hedging products).

Wind Firming Products

These can be structured in a variety of ways but generally are premium cap type revenue structures where volumes can change as wind farm production alters. This type of product takes generally weeks to months to negotiate and finalise documentation (particular if a new product approval is required)

Inter-regional Swaps

Many wholesale participants (both physical market participants and well as financial institutions) will trade inter-regional swaps on the basis of a spread between two NEM regions in 5 MW parcels or 25 MW blocks on a quarterly or annual basis. These transactions can be done either through futures or bilaterally.

Quarterly Asian Collars (sell cap, buy floor) (either traded through futures or OTC)

In return for buying a floor to protect downside revenue in the spot market, would need to sell an offsetting cap (or vice versa depending on whether a seller or buyer). This type of transaction has been done many times previously on a costless or low cost basis, most normally on quarterly basis to provide a revenue collar in up to 25 MW block trades and is a good product to manage outage and revenue risk. However, if it becomes necessary to try and reverse an Asian collar position it can be exceedingly difficult to do so.

Annual options (financial or calendar year put/calls)

These products can also be transacted through futures or OTC markets. Striking appropriate price levels for this type of product can be challenging as there tends to be many interested parties wanting to buy the call for risk mitigation purposes but the buyers have much less interest in selling the associated put. It is the floor and its level in the collar arrangement which has real value to generator providing larger volumes of energy into the spot market. As with the Asian collar product discussed above this is can be a difficult product to get out of (reverse) in the market if circumstances change.

Non-firm swaps

These are OTC products that reduce in volume if there are pre-agreed generally output driven restrictions. Effectively this transfers outage or production risk to the buyer so generally only those buyers with larger amounts of peaking plant or ability to curtail load would be interested in buying these type of products. Reflective of the risk transfer to the counterparty, these products are sold at a negotiated discount to the prevailing swap curve.

Progressive purchase or book build arrangement

A service offered by a number of retailers and requested by major customers allows for progressive position adjustment to managing their electricity costs within defined parameters (such as timing, minimum hedging level, shape uplift premium to reflect that the load shape may shaped and therefore at a premium or discount compared with the flat product being purchased, quantity, number of requests per quarter, etc) and offered on a fee for service basis. This type of product allows a customer to choose what level of load can be hedged at price level and timing of their own choosing.

Spot Exposure

Either in conjunction or as an alternative to hedging, customers, retailers and generators may take on varying levels of spot exposures. Where customers or retailers have the ability to manage their consumption profile (such as an interruptible process) this may mean they can take advantage of lower pool prices in the NEM but when periods of high spot prices occur they can reduce demand, start generation and/or be covered by cap contracts above a predetermined strike price level.

Whole of meter contracts

Whole meter contracts are typically structured between electricity retailers and customer loads as well as between intermittent generators and buyers of that generation output. These type of contracts shift the volume risk associated with the electrical load or generation output to the other counterparty. Depending upon the expected degree of load variability and particularly its correlation to price and risk, a significant premium will normally be charged (if being sold) or deducted (if output is being purchased) when compared with a standard product. This premium or discount is reflective of the allocation of risk between the buyer and the seller of such a structure whereby the volume risk is shifted entirely from one party to the other...

Settlement residue auction (SRA) units

Due to the extreme levels of high and low prices regularly observed between regions, many market participants consider accessing the revenues associated with binding interconnector flows between adjacent regions. In order to not materially move the quarterly settlement residue auctions conducted by AEMO that occur for three years forward (i.e. 12 forward quarters), a participant would look at building up their SRA positions over many quarterly auctions. It is noted that if the relevant interconnector is limited, unavailable or being forced flow in the wrong direction then SRAs may have limited value and therefore any premium paid for SRAs should be reflective of its perceived hedging effectiveness.

Reallocation services

Many second tier retailers do not any hold sufficient generation in the NEM to meet their AEMO prudential obligations. Especially for generally smaller and lower credit quality participants, these participants will investigate other prudential alternatives rather than just provide large and costly bank guarantees to AEMO. If needed to reduce AEMO prudential requirements due to participation in the retail market reallocation can be purchased on its own from banks, wind generators, first tier retailers or as part of a bundled hedge offering.

15. Appendix 4 LRMC Modelling

This appendix presents the approach used to undertake the Long Run Marginal Cost (LRMC) modelling presented in this study. The approach used is first compared to that used by Frontier Economics in the development of the Benchmark Price in the previous review.

15.1 Previous LRMC Approach

The basis for the Benchmark Price established in the previous review was a LRMC of energy and LGCs. This was undertaken by Frontier Economics using their least cost model WHIRLYGIG.

The reasons Frontier provided in their 2011 report as to why this approach was preferred over the other common approaches of forward market prices and simulation modelling were that trade in derivative contracts beyond the next year or two tends to be illiquid, and simulation modelling tends to be increasingly reliant on assumptions about industry structure.

The *WHIRLYGIG* model was briefly described in the 2011 report as:

> "optimises total generation cost in the electricity market, calculating the least cost mix of existing generation plant and new generation plant to meet energy demand".
>
> "can be used to calculate both the LRMC of energy (the additional costs associated with an increase in energy demand) and the LRMC of LGCs (the additional costs associated with an increase in target under the LRET)".

The 2011 report also explained that *WHIRLYGIG:*

- Included all the environmental schemes at the time "LRET, NGAC;
- Used the latest assumptions of demand forecasts and generator availability.

The 2016 report by Frontier and response to question by Marsden Jacob provided additional explanation (noting the same approach was used). The matter of gas prices used was a noted issue as the gas prices used in the Frontier modelling were developed via a LRMC approach that did not reflect the current dynamics in the market. Frontier noted that "relatively moderate gas price increases, particularly when compared with some other public forecasts".

In regard to the above Marsden Jacob noted the following:

- The LRMC estimate is substantially lower than both the average NSW spot price over the past year and the current forward curve, which is despite prices being insufficient for any new thermal generation;
- The LRMC estimate does not reflect a contract price that would provide a flat firm contact volume – excludes the premium associated with firm capacity.

15.2 Marsden Jacob Approach

Marsden Jacob used the Prophet least cost planning module[26] to develop the LRMC of electricity supply in NSW. The box below presents a description of the basis of least cost generation investment models.

Box Power Generation Least Cost Model

- Minimises NPV over Model Period of generator capital costs + operating costs + environmental product costs
- Model Period is Start Year to Finish Year
- Each year comprised of "n" time segments (e.g. Month, 10 step demand duration curve)
- In each time segment:
  - total generator dispatch = demand + losses (energy balance constraint)
  - for each transmission line / interconnector: power flow < flow limit
- Each year:
  - region generation reserve > a specified level (capacity balance constraint)
  - The annual target of LGC needs to be supplied accounting for the rule of the LRET such as banking surplus LGCs (LGC balance constraint)
  - for each hydro generation system: total generation < annual generation limit
- Prices (shadow price of the corresponding constraint)
  - Energy Price: Cost of meeting 1 additional MWh of demand in that year. In each time segment this is effectively the SRMC of the generator clearing that region
  - Capacity Price: Cost of meeting 1 additional MW of maximum demand in that year. This is zero in all annual time segments except the maximum demand segment.
  - LGC Price: Cost of meeting 1 additional LGC in that year.
- Generator revenues

$\sum^{\text{All time segments}}$ Energy price x Generation + LGC Price x Generation (LGC apply to renewable gen only).

Each year the LRMC model provides energy, capacity and LGC costs. For each of these the cost is the shadow price of the corresponding balancing constraint. Being an energy only market the NEM spot price can be thought of as the sum of the energy and capacity cost. We note the following:

- If a region has sufficient generation reserve then the capacity cost is zero;
- The energy cost is equivalent to the spot price that would be obtained with all available generation bidding SRMC;
- Unless renewable generation is economic with no LRET revenue, the LRMC model will only develop sufficient renewable generation to satisfy the LRET target. The LGC cost if the marginal cost of developing additional renewable generation to supply that increment of LGC demand.

[26] This is a least cost linear program model and is similar to that used by Frontier Economics.

Each year the average annual LRMC is the time weighted energy plus capacity cost. There is only one LGC price each year.

The LRMC derived says nothing about the firmness of supply and whether any additional cost should be included for firm contract supply.

The LRMC modelling undertaken by Marsden Jacob used two approaches labelled the Incremental Approach and Stand Alone Approach. These are described in the main body of the report and are not repeated here.

The assumptions used are presented in Appendix 5.

16. Appendix 5 LRMC Modelling Assumptions

This chapter presents the assumptions used in the LRMC modelling presented in this report. The assumptions are restricted to the Outlook Period that concludes on 1 July 2022. The assumptions are presented in terms of:

- Inflation and foreign exchange;
- Discount rate;
- Demand outlook;
- Generator entry and closures;
- New generator costs (thermal and renewable);
- Fuel costs (coal and gas);
- Renewable energy schemes and carbon emission pricing;
- Transmission.

16.1 Discount Rate and Economic Outlook

Inflation and FX assumptions were taken from a review of projections including the Commonwealth Budget Papers, nab publications and Trading Economics. The conclusions were as follows:

- CPI will average 2.5% (mid-point of the Reserve Bank inflation target rate). The outlook for the years 2017 and 2018 is CPI lower than 2.5%;
- The AUD/US exchange rate may decline from its current level of 0.75 but there is uncertainty in this. The current level was assumed to continue;
- The risk free rate was assumed to be 4.75% (nominal), which is the yield on 10 year Commonwealth Government Bonds up to 14 October 2016.

16.2 NEM Demand Outlook

16.2.1 Assumptions and Development - GWh

The scheduled demand[27] growth scenarios were developed from undertaking separate projections of the following components:

- Electricity consumption excluding Electric Vehicles (EVs);
- Rooftop solar (that reduces scheduled demand);
- Smelter demand;
- EV electricity consumption (the use of storage is addressed in the demand profile).

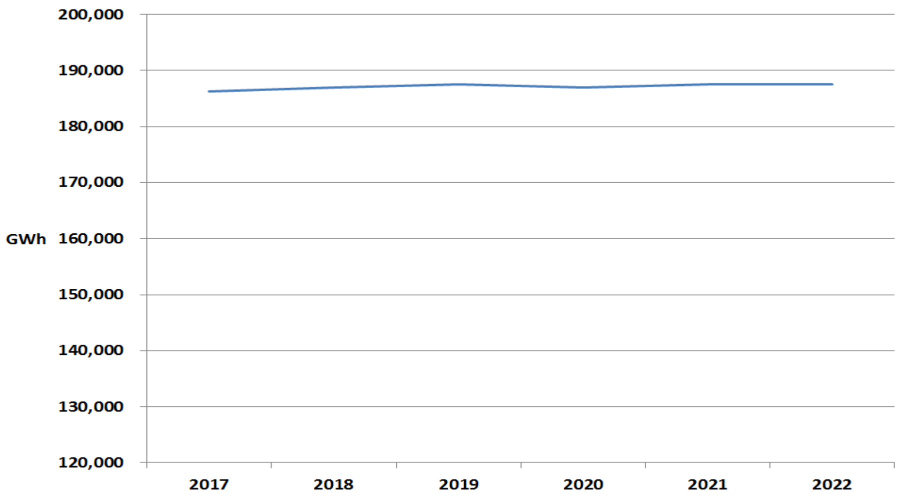
The demand assumptions were as follows:

[27] Scheduled demand is the generation required to be supply by all scheduled and semi-scheduled generators. It excludes the demand supply by rooftop PV.

- The electricity consumption excluding EVs was based on the AEMO National Electricity Forecasting Report (NEFR) 2016 Neutral[28] demand projections.
- Rooftop PV:
  - for all States other than Queensland was taken to be the AEMO projections corresponding to the Neutral scenario
  - for Queensland the AEMO Qld projection of rooftop PV development was modified to account for the 3,000 MW rooftop PV target by 2020 that has been set by the Queensland government. This modification was to have the Queensland rooftop PV target fall midway between the AEMO projection for Queensland and the Queensland rooftop PV target.
- The Portland smelter was assumed to close on 1 July 2021. This was 3 years after the closure of Hazelwood Power Station PS and was based on a level of government support that would be required over the period after its supply contract with AGL terminates in 2017.
- A slight increase in EV penetration model was assumed based on Marsden Jacob modelling. However over the Review Period this was very minor (EV penetration does not significantly increase until post 2030 in this modelling).

The outlook of scheduled demand (i.e. that includes the impact of EVs, rooftop PV and smelter closures) is shown for the total NEM (scale is from 120,000 to 200,000 GWh p.a.) is shown in Figure 17 below.

Figure 17 Total NEM Scheduled Demand Scenarios (GWh)



16.3 Generator Entry and Closures

In the Review Period the only generator closure was Hazelwood Power Station in April 2017. This was announced by the owners of HPS (Engie) in late 2016.

Entry of new generation over the Review Period was an output of the modelling. However this was limited to renewable generation under the LRET and State renewable generation schemes.

[28] The Neutral outlook is the middle projection presented in the NEFR 2016 report and is considered the most likely.

16.4 Generation Costs

Generator costs are comprised of capital costs (i.e. the construction costs), operating costs (the costs incurred when the plant is operating) and fuel costs (in the NEM associated with gas, black coal and brown coal). These costs determine the economics of developing generators and how new and existing generators are used when operating. These assumptions are presented in turn below.

16.4.1 Capital Costs

Table 25 below presents indicative capital costs for CCGT, OCGT, large-scale wind and large-scale solar generators. The wind cost shown also depends on factors such as the quality of the wind resource. These costs determine the economics of generator entry.

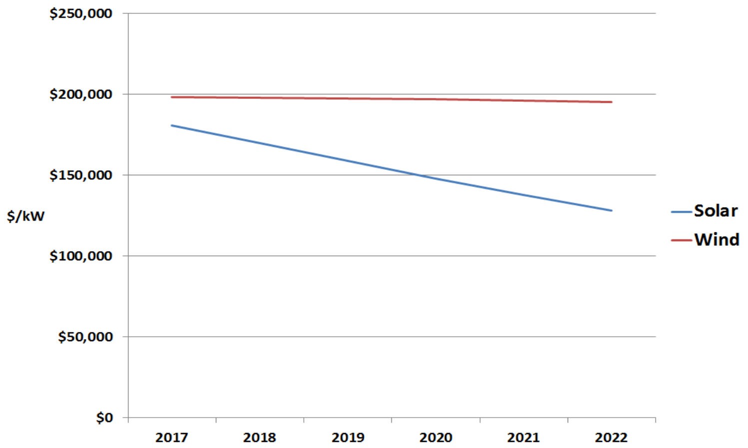
Table 25 New Generator Capital Costs ($/kW)

Technology	Capital $/kW	VOM $/MWh	Future Costs
CCGT	1250	4	Stay constant in real terms
OCGT	850	10	Stay constant in real terms
Solar	2,300		Decline
Wind	2,200	13	Slight decline

Source: Marsden Jacob

While non-renewable generation costs are assumed to remain constant in real terms, renewable generation costs are projected to decline. This decline is projected by a number of parties such as Bloomberg and renewable generation developers. The assumed profile of large scale wind and solar capital costs (real 2016 AUD) is shown in Figure 18 below.

Figure 18 Capital Costs of Large-scale Wind and Solar Plants



16.4.2 Operations and Maintenance Costs

Operations and maintenance costs relate to the costs of maintaining people to run a power station and the additional costs incurred when generators are operated. Every two years AEMO publishes information on the SRMC, fixed operating and maintenance costs (FOM), and variable operating and maintenance costs (VOM) of the NEM generators based on certain assumptions and using public domain information. A summary of this information based on technology type is presented in the table below. These costs are considered reasonable.

Table 26 Generator Fixed and Variation Operating and Maintenance Costs

Technology	FOM $/MW/Year		VOM $/MWh	
	Min	Max	Min	Max
Black Coal	52,828	71,538	1.31	1.57
Brown Coal	56,350	92,482	1.31	3.30
CCGT	27,515	34,118	1.15	5.60
Distillate	14,308	14,308	9.96	10.58
Hydro	57,230	57,230	6.77	7.87
OCGT	14,308	44,023	2.48	10.98

Source: AEMO 2014

16.5 Fuel Costs

16.5.1 Black Coal

The NSW black coal power stations are the principle price setting generators in NSW (and Victoria, and to a lesser extent SA). A number of these power stations have coal supply that is subject to international price linkage.

The recent increase in coal costs (thermal coal costs have increased over the last 6 months to about USD 90/tonne) is not seen as permanent with most analysts projecting China will increase the operating days of the mines in order that coal prices return to the previous level.

The outlook is that long term coal prices will remain at the current levels. The projected coal prices are presented in Figure 19 below.

16.5.2 Gas Costs

Currently east coast gas prices and availability are being influenced by the tightening domestic gas market due to a move to 6 LNG train operation in Queensland, Moomba gas decline, the moratorium on fracking (non-conventional gas development), and the increasing supply being required from Gippsland gas.

Future gas costs will be determined by many factors that include:

- Oil prices (through international price linkage);
- Cost of producing gas (which is increasing);
- Gas availability (which is reducing);
- Competition (which is decreasing.

Netback prices[29] are considered to provide an appropriate indicator of future gas prices. The outlook for gas delivered to power stations is shown in Figure 20 below.

Figure 19 NSW Black Coal Power Station Costs ($/GJ Delivered)

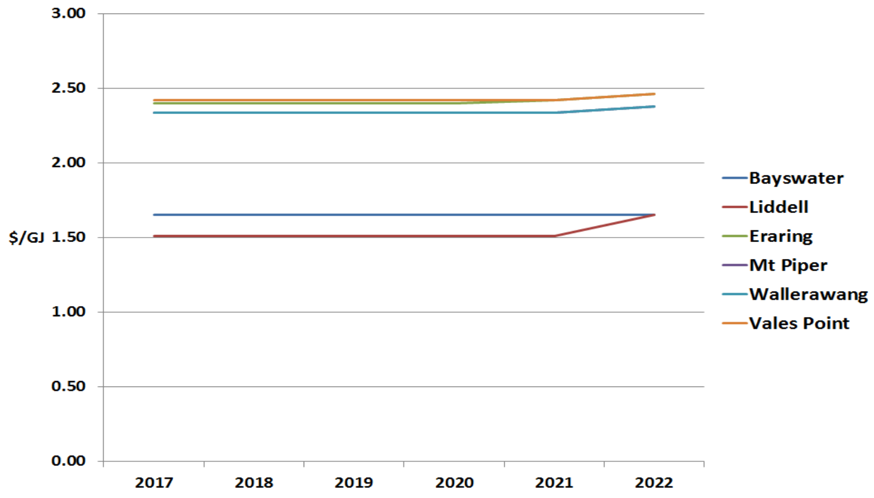
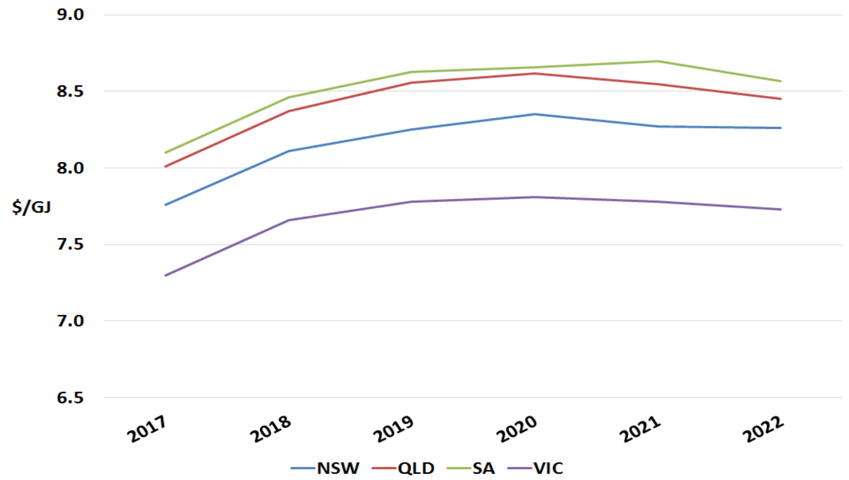


Figure 20 Australian Wholesale Gas Costs ($/GJ)



16.6 Renewable Generation

16.6.1 LRET

The LRET is assumed to remain unchanged over the Outlook Period.

The LRET is a very different market than the NEM, being structured as:

- A target that sets total LGC purchase obligations by retailers (and very large customers);
- Prorating of obligations based on energy consumed;
- A penalty price (non-tax deductable) for not submitting required LGCs; and

[29] This is the Free on board gas price or export less the variable costs associated with liquefaction and transport. As capital is sunk capital costs are excluded. This is often referred to as "Short Run Netback Price".

- A created LGC can be used at any time over the life of the LRET which (currently) terminates 31 December 2030.

The design of this scheme has renewable generators developed to meet the 2020 target, after which they supply a constant annual target of 33,000 GWh to 2030.

16.6.2 State Based renewable Schemes / Announcements

Victoria and Queensland have proposed to introduce their own renewable generation schemes to provide for a renewable energy target that continues to increase post 2020. These schemes have not yet been implemented. As there are no operating State schemes (other than in the ACT) there is uncertainty in regard to how these should be treated. At a national level there is a desire to have a consistent and uniform policy.

The assumptions regarding the amount of generation that would be provided by each of the State schemes (for each of the two scenarios) are presented in Table 27 below.

Table 27 State Based Renewable Generation Schemes

State	Energy (GWh) Target	Proposed Assumptions
Queensland (QRET)	50% by 2030	Will be partially met. Limit of 100 MW p.a. outside of the LRET to 2022.
NSW	-	LRET only
Victoria (VRET)	Target of: 25% by 2020 40% by 2025	Will be partially met. Limit of 100 MW p.a. outside of the LRET to 2022.
South Australia	50% by 2025	Aspirational only Will be (closely) achieved through the LRET
Tasmania	-	LRET only

16.7 Carbon Pricing

There is no carbon price announced for introduction during or after the Review Period.

16.8 Transmission

The assumption regarding transmission is that no new interconnectors are developed over the Review Period.

17. Appendix 6 Contract Premium Analysis

The purpose of this Appendix is to review the relationship between forward contract prices and the associated spot prices. This is presented in the context of the expected margin ($/MWh) that can be obtained from forward contracting and the likelihood that the forward price obtained over a period will be higher than the average spot price that outturns over that period.

This appendix is restricted to ***quarterly forward flat swap contracts*** (i.e. contract period is a 3 month quarterly period and the forward contract is a flat swap).

This appendix presents the following:

- The definition of contract premium;
- The basis for an expectation that contract premiums will be positive;
- Recorded contract premiums in NSW;
- How contract premiums change with the time between contracting and the contract period; and
- An analysis of the probability of obtaining a positive contract premium.

Definition of Contract Premium

Before presenting the analysis we define the term “contract premium” that is used in this appendix and in the report:

A contract premium over a period of time (in this appendix a 3 month period) is the difference between the contract price for that period and the average spot price that outturns over that period. This can be expressed as a$/MWh or as a % of the spot price. A positive contract premium means that the contract price was higher level than the average spot price over the period, and vice versa for negative contract premiums.

Basis for Contract Premiums to be Positive

Without contracts generators have uncertain revenues and retailers have both uncertain costs and high risk. The risk to retailers is associated with selling at fixed tariff costs while purchasing wholesale energy where prices can exceed average levels by over a factor of 100. When generators sell contracts the risk retailers face (when uncontracted) is transferred to generators who face risks associated with generator failures or generating insufficient volumes to cover their sold contract positions at the time of high pool prices.

This asymmetry of risk means that a risk premium has been associated with selling contracts. The expected occurrence of price spikes or event uncertainty can also have a significant impact on the magnitude of the contract risk premium.

Observed Contract Premiums in NSW

The NSW contract premiums associated with quarterly contracts entered into the month before the quarter over the period 2004 to 2016 are shown in Figure 21 below. The box highlights the contract premiums in the Review Period which were the basis of the trading benefits shown in Figure 5 of the main report.

To illustrate how the benefits of contract sales would accumulate over time, Figure 22 shows the sum of the contract premiums presented in Figure 21. This shows an increasing trend but with volatility associated with quarters of negative premiums.

Figure 21 NSW Quarterly Contract Premiums Contracting the Month Prior over the period Q2 2004 to Q4 2016 (Nominal dollars)

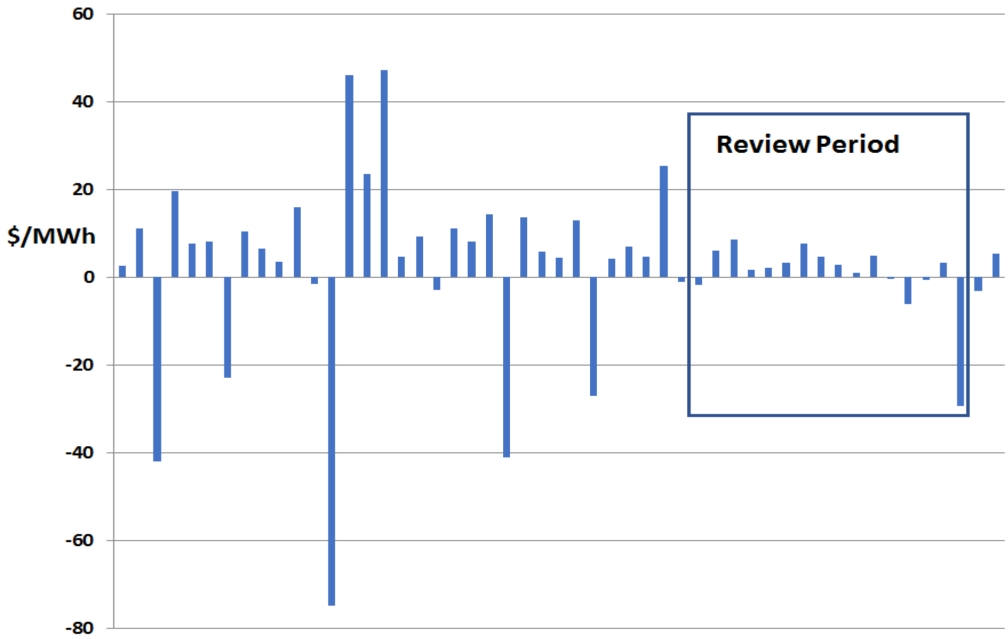


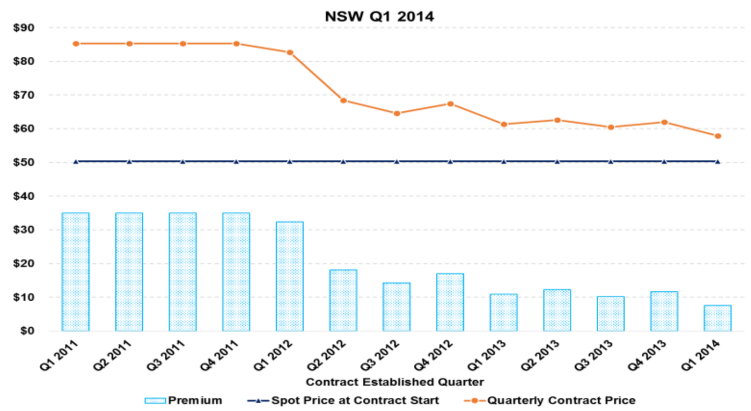
Figure 22 Cumulated sum of Quarterly Premiums shown in the figure above.

Quarterly NSW Contract Premiums when Contracted before the Month Prior

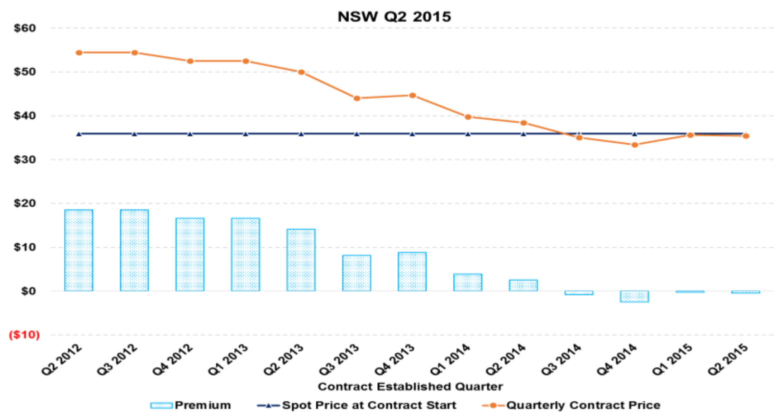
The above analysis has been based on forward contracts entered into the middle of the month prior to the quarter. As previously noted forward contracts for a quarter can be entered into a number of years prior to the quarter, and over this period the contract price and thus the premium obtained can change. To illustrate this, Figure 23 shows for three sample quarters (Q1 2014, Q2 2015 and Q3 2015) how the contract price and therefore contract premium changed when contracts for these quarters were entered into further back in time:

- The x axis of each graph is the quarter the contracted was entered into;
- The spot price is independent of when the contract was written (and this is the same for all the contracts).

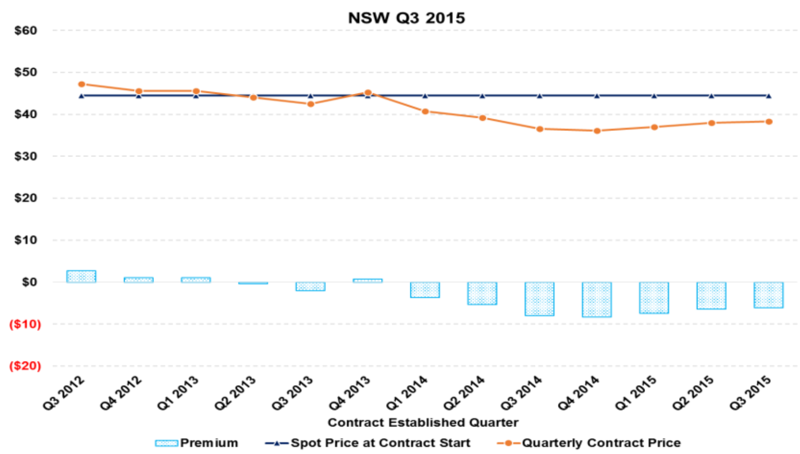
Figure 23 Historical contract price versus spot price for three quarters during the Review Period



Large contract premium for Q1 2014 over realised spot observable for this quarter for all prior periods



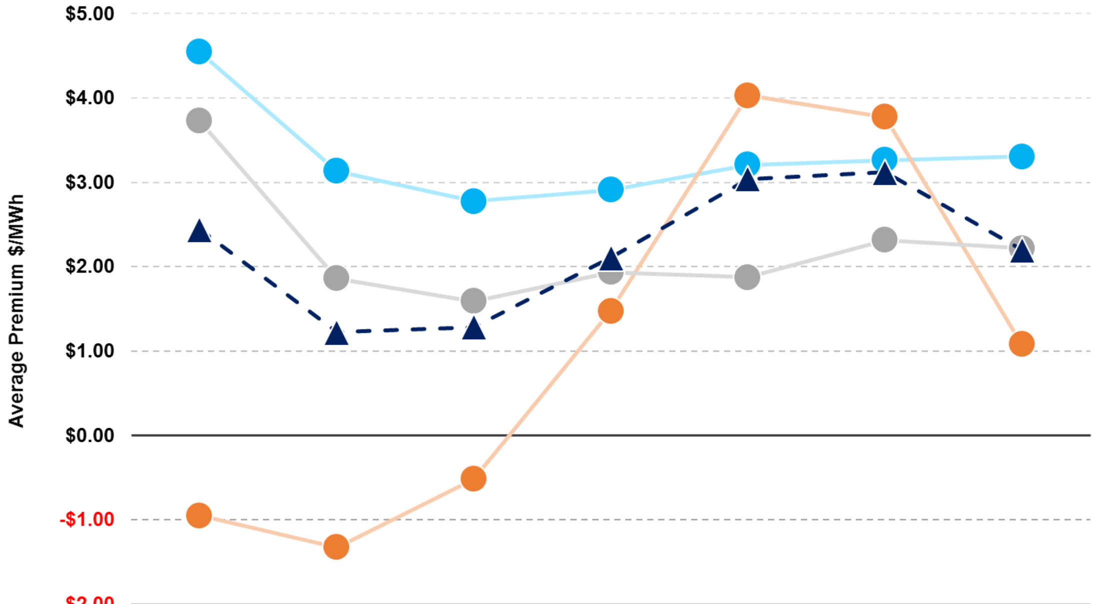
Large contract premium one to two years out due to CPRS. After carbon repeal contract price for Q2 15 at or near realised spot price



One to two years in advance contract level for Q315 close to realised spot but closer to relevant quarter contract price below

This analysis was generalised to examine how contract premiums changed in NSW, Victoria and Queensland (note South Australia and Tasmania were excluded due to their extremely low contract liquidity) when contracts were entered into further back from the quarter being contracted. The result of this analysis is shown in Figure 24 below. This shows for each State how quarterly contract prices over the period 2004 to 2016 varied when contracts were entered into one month to two years prior. The profile suggest that contracts premiums do not vary significantly for up to a year prior to the quarter but in the longer term can be higher.

Figure 24 Average contract premium over spot by contracting earlier



	2 Years	1.5 Years	1 Year	6 Months	3 Months	1 Month	Average 10 Years
NSW	$4.54	$3.13	$2.78	$2.91	$3.21	$3.26	$3.31
QLD	-$0.95	-$1.33	-$0.52	$1.47	$4.03	$3.77	$1.08
VIC	$3.73	$1.86	$1.59	$1.93	$1.88	$2.31	$2.22
Average	$2.44	$1.22	$1.28	$2.11	$3.04	$3.12	$2.20

Probability of Obtaining a Positive Contract Premium

The basis of a trading strategy that favours forward selling should be that greater returns can be obtained with no material increase in risk.

To assess the likelihood of forward selling resulting in positive premiums and increased revenue, the contract premiums associated with forward selling a quarterly contract the month before for all NSW, Victoria and Queensland over the period 2004 to 2016 were calculated and presented as a histogram. This is shown in Figure 25 below. The x axis shows the "bucket" of premium values (such as $10 to $20) and the y axis shows the number of occurrences over the period[30]. Note that the end buckets are not of equal size.

We note that the likelihood of large positive and negative premiums is significant. The greater frequency of large negative premiums is due to the market floor price of -$1,000/MWh compared to the price cap of about $14,000/MWh, and the reluctance of generators to have negative spot prices.

From this histogram a probability distribution was constructed and this is shown in Figure 26. This shows the probability of the Contract Premium being less than that on the x axis. This

[30] When all "buckets" are of equal size the area can be scale to 1 to produce a probability density function.

shows that the probability that the contract premium is less than zero is 32% (and thus a 68% probability that a contract premium is positive).

Figure 25 Histogram of Quarterly Contract Premiums for NSW, Vic and QLD.

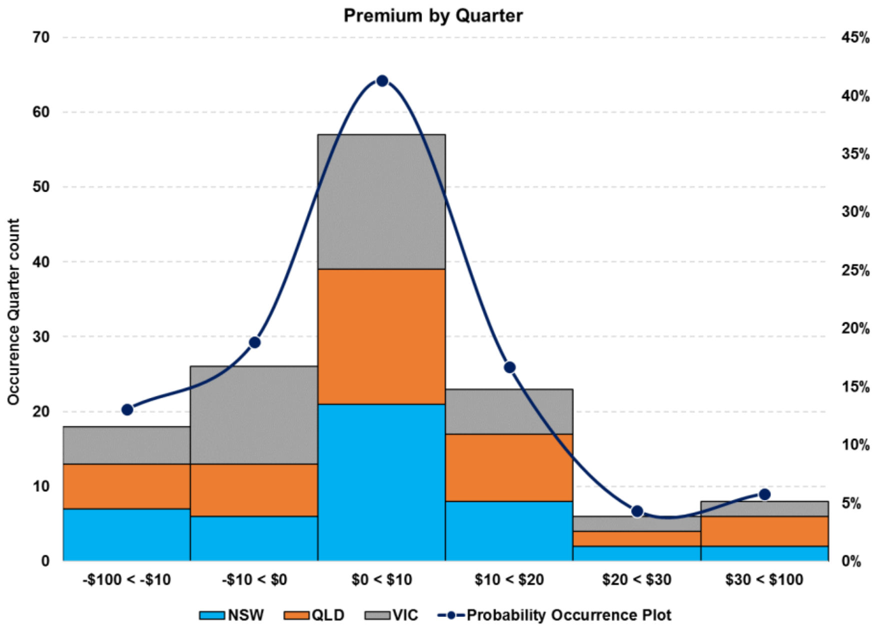
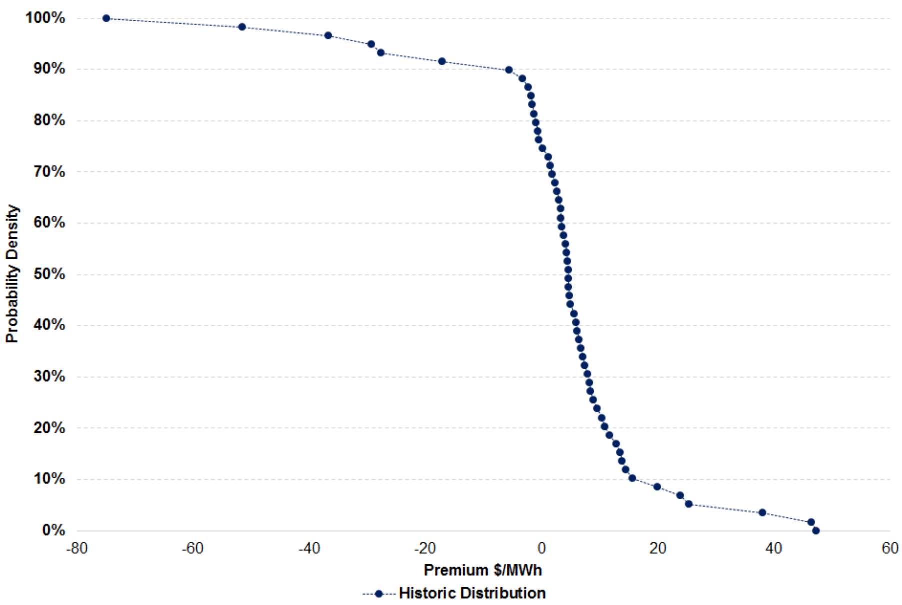


Figure 26 Probability Distribution of Quarterly Contract Premiums (Entered the month Prior)



However, a trading strategy should be evaluated through how it would perform over time. For SDP this would be equivalent to the expected average premium obtained if forward selling was done for each quarter over a 5 year period. This corresponds to the expected premium that would be obtained over 20 quarterly sales.

This was done by sampling the probability distribution 20 times and recording the average premium obtained, and then sampling another 20 times and recording the average premium obtained. This was repeated 1000 times and the results plotted in a histogram shown in Figure 27. This figure also shows the probability of each bucket occurring.

This shows that over 20 contract sales the probability of obtaining a positive contract premium, equal to the average premium expected significantly increases.

The probability is reduced to 16% that the sales will result in a net loss (compared to selling on the spot market). However if a negative average premium was obtained, then the expected premium would be about -$0.4/MWh.

Figure 27 Histogram of Average Premium from 20 Contract Sales