CONSOLIDATED FINAL BUDGET AND FEES: 2014-2015

PUBLISHED: **MAY 2014**

EXECUTIVE SUMMARY

Introduction

AEMO's 2014-15 final budget provides a consolidated view of 2014-15 revenue and expenses, together with fees for 2014-15 and estimates for the following four-year period.

AEMO is aware of the pressure on energy industry businesses as a result of falling energy demand over the last four years. AEMO continues to apply commercial discipline to control its total operating expenses over this period in order to reduce the impact of AEMO fee increases on market participants where possible. As a result, AEMO has in most cases achieved fee levels below the levels forecast in prior year budgets. Further illustration of the containment of fee levels over the past four years is included in the detailed budget documents.

AEMO's total budgeted expenditure for 2014-15 is $141 million, which is $2.2 million (2%) lower than the 2013-14 budget.

Table 1 — Key points

• **<u>Lower fee levels</u> achieved compared to previous year estimates.**	↓	**Most 2014-15 fees are lower or equal to** prior years' published estimates.
• **<u>Energy</u> consumption <u>decline.</u>**	↓	Fees are **impacted** by **declining consumption** for electricity (-4%) and short term trading markets (-6%).
• **<u>Expenditure reduction</u> achieved.**	↓	2014-15 **expenditure** is budgeted to **decrease by $2.2 million or 2%** from 2013-14.

2014-15 fees

Table 2 — Key fees

Key Fees	Budget 2014-15	Prior year published estimate 2014-15	Change	Current 2013-14	Unit
NEM	0.39	0.39	0%	0.37	$/MWh
VIC TNSP - TUOS Fees	501,699	N/A	N/A	453,787	$'000
FRC - Electricity	0.060	0.066	-9%	0.060	$/MWh
VIC Wholesale Gas					
Tariff D - Industrial	0.08230	0.09464	-13%	0.06858	$/GJ
Tariff V - Domestic	0.08230	0.09464	-13%	0.10287	$/GJ
Distribution Meter	1.4208	1.4396	-1%	1.4256	$/day per meter
National Transmission Planner	0.01990	0.02814	-29%	0.01915	$/MWh
STTM - Activity Fee	0.08203	0.08091	1%	0.07218	$/GJ withdrawn
VIC FRC Gas	0.11974	0.12618	-5%	0.12875	$ per customer supply point/mth
QLD FRC Gas	0.30805	0.29908	3%	0.29908	$ per customer supply point/mth
SA FRC Gas	0.30728	0.31641	-3%	0.30424	$ per customer supply point/mth
NSW & ACT FRC Gas	2,000	2,500	-20%	2,500	$'000
Gas Statement of Opportunities	0.0283	0.03098	-9%	0.02979	$ per customer supply point/mth

Refer to Section 1 for details of each key fee.

Budgeted expenditure 2014-15

AEMO has achieved lower budgeted expenditure for 2014-15 compared to the 2013-14 budget. The total budgeted spend in 2014-15 of $141 million is $2.2 million (2%) lower than in 2013-14.

Figure 1 compares by spend category AEMO's 2014-15 budget with the 2013-14 budget.

Figure 1 – Comparison of expenditure by category

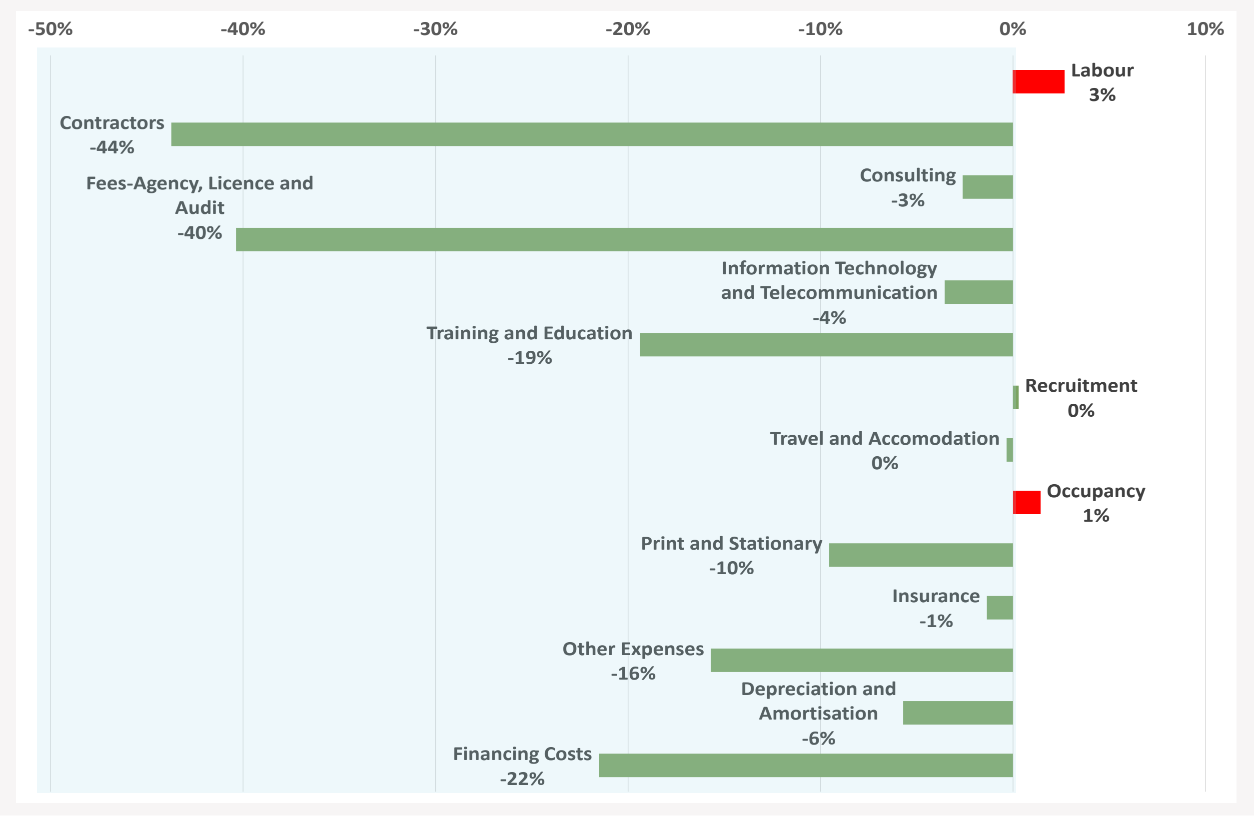


Table 3 compares 2014-15 budgeted expenditure by function with the 2013-14 budget.

Table 3 — Comparison of expenditure comparison by function

	Expenditure 2014-15 ($000)	Expenditure 2013-14 ($000)	Change
NEM	71,851	74,246	-3%
VIC TNSP - TUOS Fees	10,874	11,158	-3%
FRC - Electricity	9,416	10,122	-7%
VIC Wholesale Gas	21,296	20,401	4%
National Transmission Planner	4,207	4,909	-14%
STTM	10,769	10,078	7%
VIC FRC Gas	2,874	2,977	-3%
QLD FRC Gas	912	868	5%
SA FRC Gas	1,547	1,563	-1%
NSW & ACT FRC Gas	2,214	2,437	-9%
Gas Statement of Opportunities	1,540	1,538	0%

Declining energy consumption is impacting fees

National Electricity Market

The final forecast consumption is based on the 2014 National Electricity Forecast Report (NEFR) to be published in June 2014.

The 2014-15 budget assumes a decline in annual electricity consumption from 2013-14 mainly due to the closure of Alcoa's Point Henry plant, reductions in industrial consumption, and continued lower domestic use due to higher prices and an increase in solar PV uptake.

Liquefied Natural Gas (LNG) consumption growth is the main driver contributing to the small total NEM growth for the forward years from 2015-16 to 2018-19.

Table 4 — NEM consumption

GWh	Budget 2013-14	NEFR Update [1] 2013-14	Forecast [2] 2013-14	Budget 2014-15	Estimate 2015-16	Estimate 2016-17	Estimate 2017-18	Estimate 2018-19
NEM (excluding LNG)	179,427	177,333	175,866	170,968	171,067	171,316	171,255	171,197
LNG	664	396	3	637	4,977	7,926	8,439	8,558
TOTAL	**180,091**	**177,729**	**175,869**	**171,606**	**176,043**	**179,241**	**179,694**	**179,755**
				-4.7%	+2.6%	+1.8%	+0.3%	+0.0%

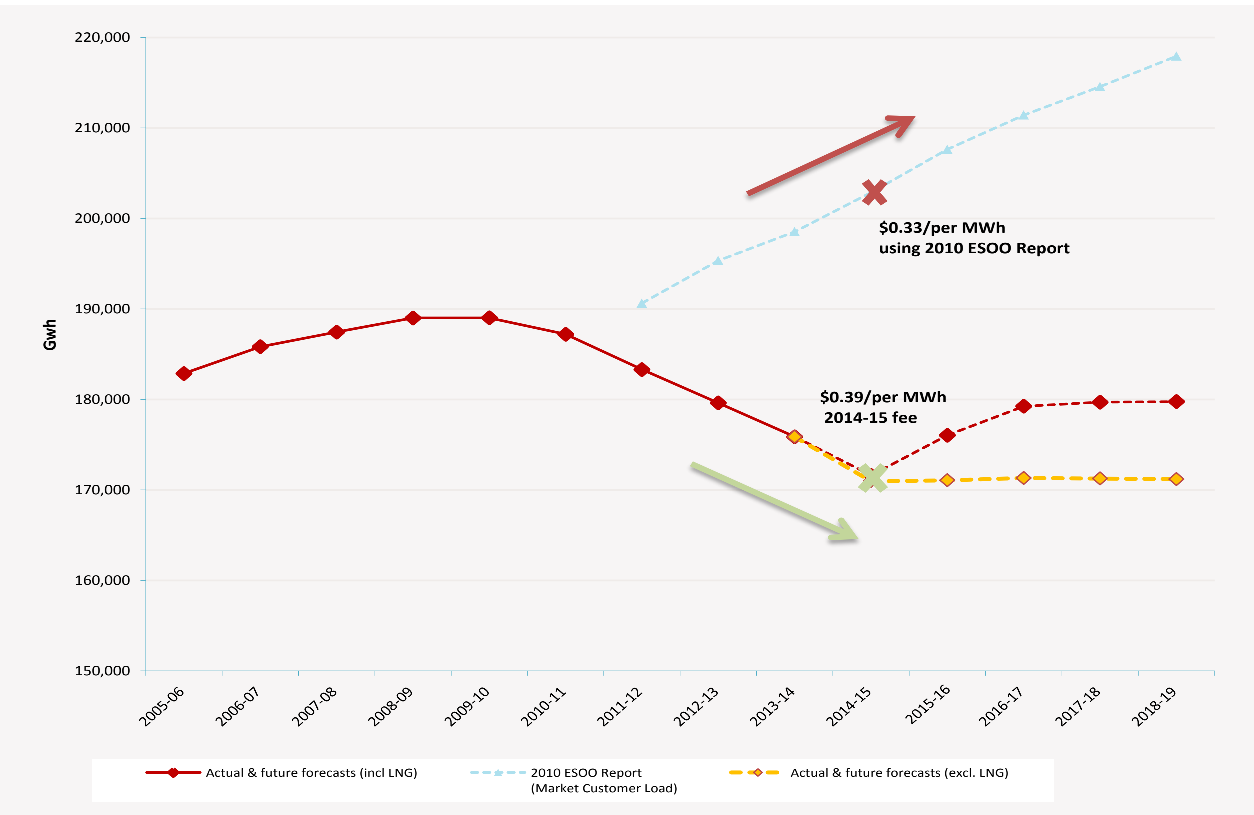
1 NEFR update released November 2013

2 Forecast annual 2013-14 consumption as at April 2014

Figure 2 demonstrates the impact of declining consumption on the NEM fee.

Note: using 2010 Electricity Statement of Opportunities (ESOO) forecast 2014-15 consumption, the 2014-15 NEM fee would have been $0.33/per MWh rather than $0.39/per MWh.

Figure 2 – Annual electricity consumption (market customer load)



Victorian Declared Wholesale Gas Market

AEMO estimates there will be flat growth in domestic consumption (1%) in 2014-15 compared to the 2013-14 budget, and declining industrial consumption. This decline is offset by a strong growth trend in Victorian exports to New South Wales.

Table 5 — DWGM consumption

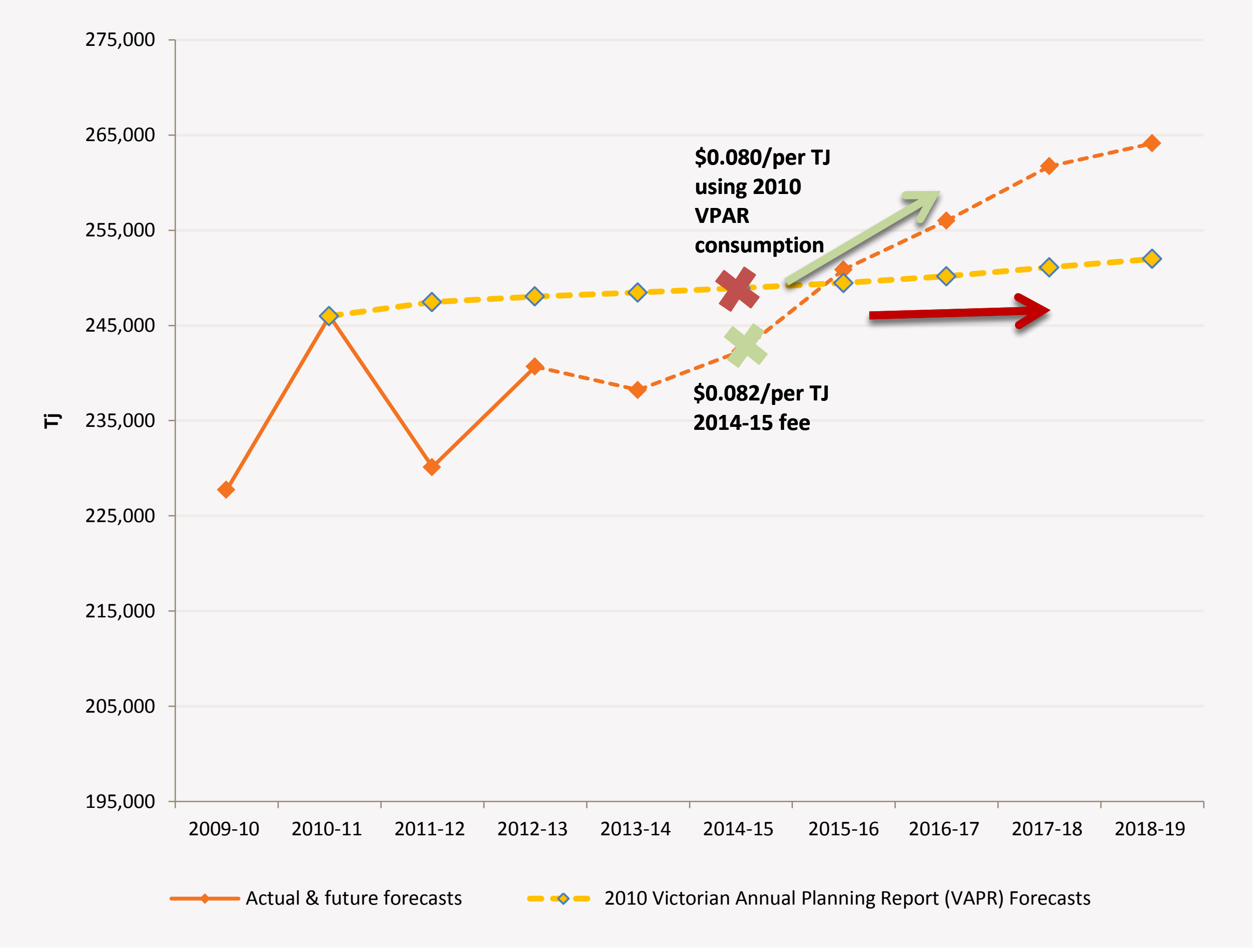
TJs	Budget 2013-14	Forecast [1] 2013-14	Budget 2014-15	Estimate 2015-16	Estimate 2016-17	Estimate 2017-18	Estimate 2018-19
Tariff V (Domestic)	126,424	121,981	125,399	126,441	127,932	129,616	131,245
Tariff D (Industrial)	77,628	72,479	70,938	70,119	70,104	70,468	70,918
Export	8,565	41,180	43,830	52,042	55,601	59,160	59,160
GPG	7,017	2,586	2,130	2,254	2,369	2,470	2,797
TOTAL	**219,635**	**238,225**	**242,296**	**250,856**	**256,006**	**261,713**	**264,120**
			+10.3%	+3.5%	+2.1%	+2.2%	+0.9%

[1] Forecast annual 2013-14 consumption as at April 2014

Figure 3 below demonstrates the impact of declining consumption on the fee.

Note: using the 2010 Victorian Annual Planning Report (VAPR) forecast 2014-15 consumption, the 2014-15 DWGM fee would have been $0.080/per TJ rather than $0.082/per TJ.

Figure 3 – Annual DWGM consumption



Short Term Trading Market

Consumption in the Short Term Trading Market (STTM) hub is expected to decline by 6% in 2014-15 and by 7.5% in 2015-16. This is mainly due to:

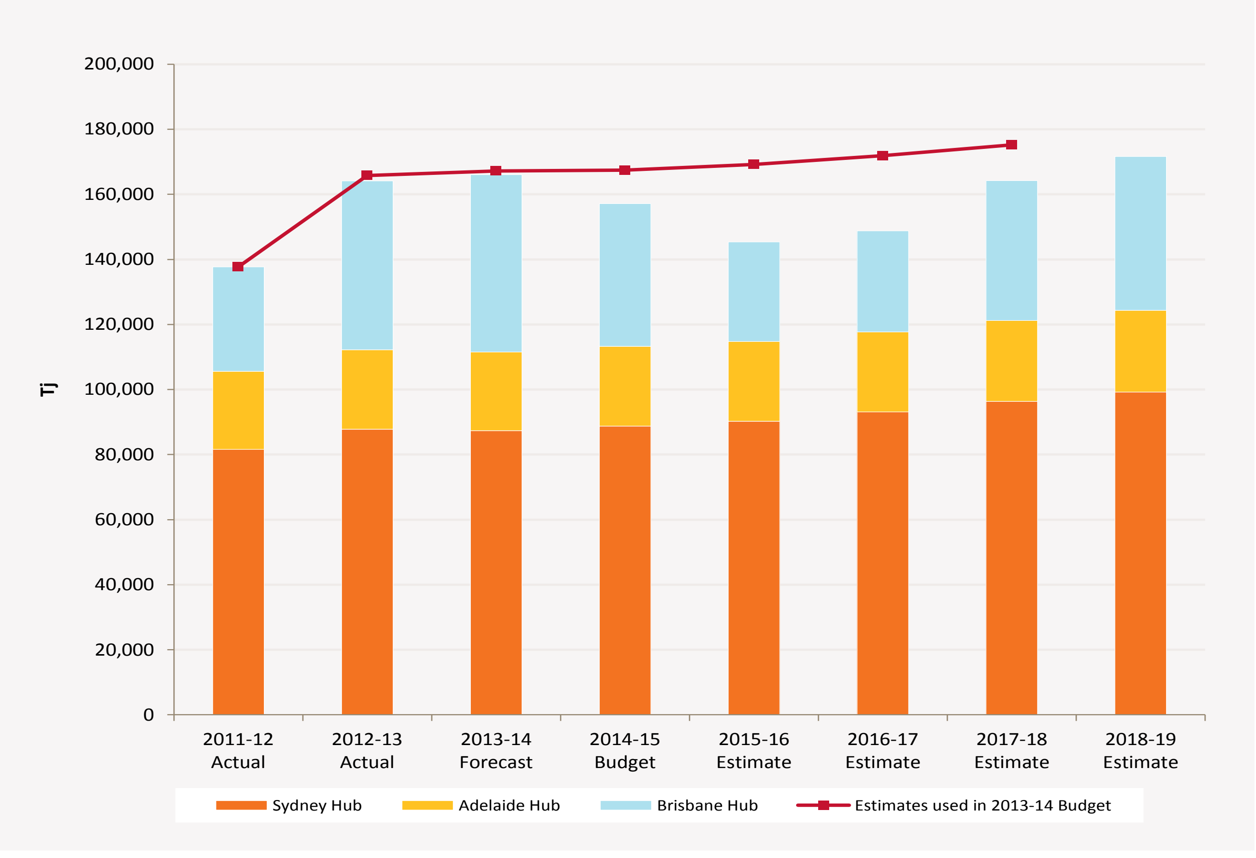
- The expected closure of Stanwell's Swanbank E plant in October 2014 for three years, which will reduce STTM annual consumption. BP's recent announcement that it will close the Bulwer refinery in mid-2015 will also impact energy consumption.

Table 6 — STTM consumption

TJs	Budget 2013-14	Forecast [1] 2013-14	Budget 2014-15	Estimate 2015-16	Estimate 2016-17	Estimate 2017-18	Estimate 2018-19
Adelaide	25,345	24,164	24,566	24,496	24,607	24,851	25,123
Brisbane	60,133	54,527	43,880	30,668	31,049	42,977	47,330
Sydney	81,666	87,358	88,723	90,236	93,119	96,368	99,202
TOTAL	**167,145**	**166,049**	**157,169**	**145,400**	**148,774**	**164,196**	**171,654**
			-6.0%	-7.5%	+2.3%	+10.4%	+4.5%

[1] Forecast annual 2013-14 consumption as at April 2014

Figure 4 – Annual STTM gas consumption



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1.1 National Electricity Market

The benchmark NEM fee will increase from $0.37/MWh to $0.39/MWh in 2014-15. This is in line with the estimate provided to stakeholders in last year's budget process.

The 2013-14 fee was reduced to return a surplus to participants and must now be increased to return a break-even position.

The 2014-15 costs for the NEM function are budgeted to decrease by 3% from 2013-14, mainly as a result of AEMO's savings from transmission network service provider (TNSP) operating agreements and a reduction in employee numbers.

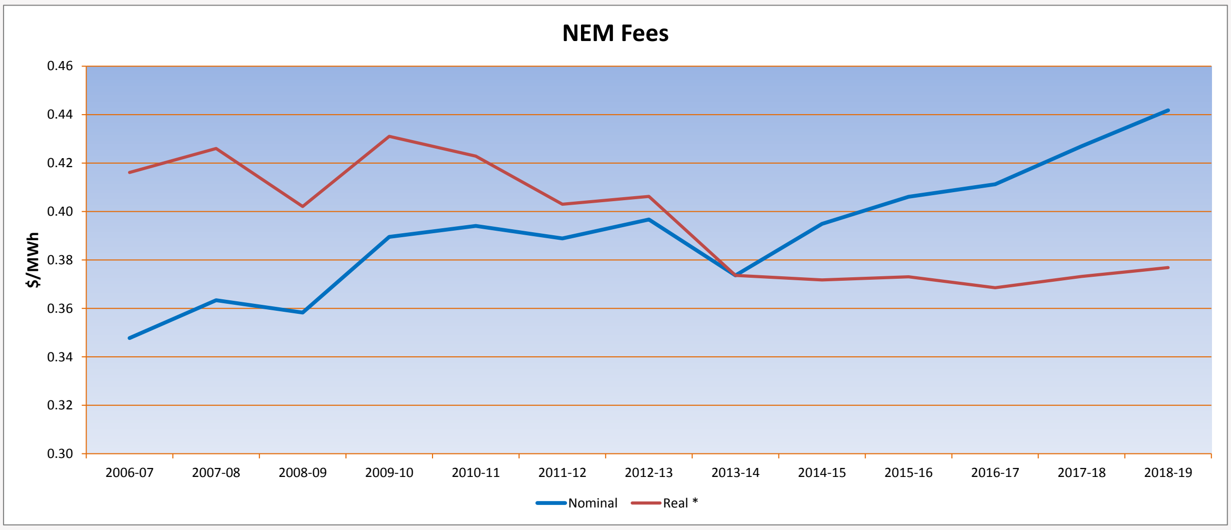
The NEM fee is expected to increase in 2015-16 to $0.41/MWh, reflecting no change to AEMO's previous estimate.

The Participant Compensation Fund (PCF) fee does not need to be charged in 2014-15 as the level of NEM PCF funds currently being held meet the Rules requirement.

Table 7 — NEM projected fees (indicative benchmark)

Fee	Actual 2013-14	Budget 2014-15	Estimate 2015-16	Estimate 2016-17	Estimate 2017-18	Estimate 2018-19
NEM fee ($/MW·h)	0.37	0.39	0.41	0.41	0.43	0.44

Figure 5 – NEM projected fees



* Real values are the nominal amounts adjusted for inflation. Prices have been calculated relative to the 2013-14 price.

1.2 Full Retail Competition Electricity

The Full Retail Competition (FRC) electricity fee will remain stable at $0.060.

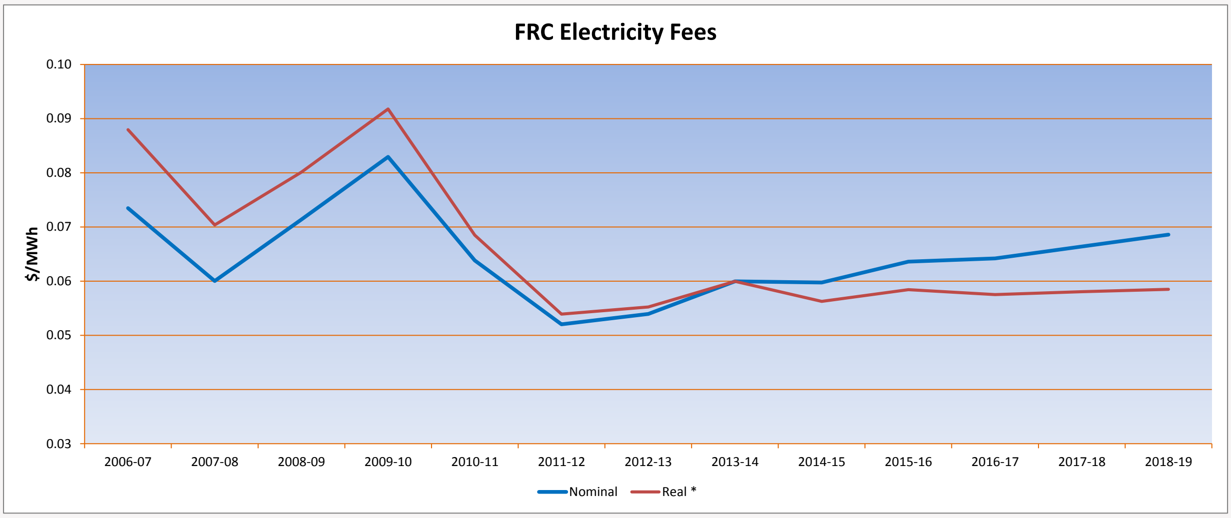
This fee is lower than the $0.066 estimate provided to stakeholders as part of last year's budget process, mainly due to a reduction in AEMO's employee numbers and lower IT costs.

The fee is expected to slightly increase over the coming years to 2018-19 due to slowing consumption growth.

Table 8 — FRC Electricity Projected Fees (Indicative Benchmark)

Fee	Actual 2013-14	Budget 2014-15	Estimate 2015-16	Estimate 2016-17	Estimate 2017-18	Estimate 2018-19
($/MW·h)	0.060	0.060	0.064	0.064	0.066	0.069
		-0%	+6%	+1%	+3%	+3%

Figure 6 – FRC electricity projected fees



* Real values are the nominal amounts adjusted for inflation. Prices have been calculated relative to the 2013–14 price.

1.3 National Transmission Planner

The benchmark National Transmission Planner (NTP) fee is budgeted to increase from $0.01915/MWh to $0.01990/MWh in 2014-15.

The 2013-14 fee was reduced to return a previous year's surplus and the 2014-15 fee needs to be increased by 4% to return to a break-even position.

The 2014-15 fee is lower than the fee of $0.02814/MWh, estimated as part of last year's budget process.

Costs for the NTP function have decreased by $0.7 million (14%) compared to the 2013-14 budget mainly due to a reduction in employee numbers and consultancy costs.

Table 9 — National Transmission Planner projected fees

Fee	Actual 2013-14	Budget 2014-15	Estimate 2015-16	Estimate 2016-17	Estimate 2017-18	Estimate 2018-19
($/MW·h)	0.01915	0.01990	0.02651	0.02439	0.02587	0.02682
		+4%	+33%	-8%	+6%	+4%

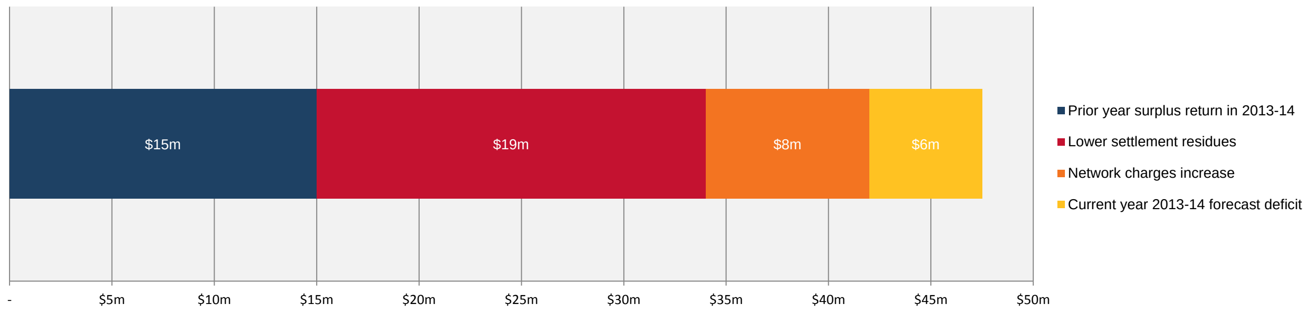
1.4 Victorian Electricity Transmission Network Service Providers

Transmission Use of System (TUOS) fees are calculated on an annual break-even basis and are predominately influenced by network charges billed by Victorian electricity transmission network owners and by estimations of settlement residue receipts.

TUOS fees are expected to increase by $48 million (11%) in 2014-15.

Table 10 outlines the key reasons contributing to this increase.

Table 10 — Revenue requirement changes reasons



- $15 million: 2013-14 current year fees are reduced to return a surplus from the prior year 2012-13.
- $19 million: Lower revenue is expected from settlement residues (39%). This is due to an assumption the carbon tax will be repealed in September 2014, with the effective abolition of the tax to be retrospective to 1 July 2014.
- $8 million: An increase in network charges in 2014-15 (1.5%) from the 2013-14 budget is mainly due to an increase in SP AusNet's regulated network charges. The Australian Energy Regulator (AER) has approved SP AusNet's revenue determination for the period 1 April 2014 to 31 March 2017.
- $6 million: The current year 2013-14 forecast deficit will be recovered in 2014-15, mainly due to an increase in SP AusNet's regulated network charges from 1 April 2014.

Table 11 — Projected TUOS revenue requirement

Fee	Actual 2013-14 ($'000)	Budget 2014-15 ($'000)	Estimate 2015-16 ($'000)	Estimate 2016-17 ($'000)	Estimate 2017-18 ($'000)	Estimate 2018-19 ($'000)
TUOS fees	453,787	501,699	490,283	492,896	TBC	TBC

1.5 Victorian Declared Wholesale Gas Market

In line with the gas market fee review undertaken in 2011-12, the Victorian Declared Wholesale Gas Market (DWGM) will transition to a single consumption fee from 1 July 2014.

Costs for this function have increased by $0.9 million (4%), primarily driven by Enterprise Bargaining Agreement (EBA) salary increases and consulting costs.

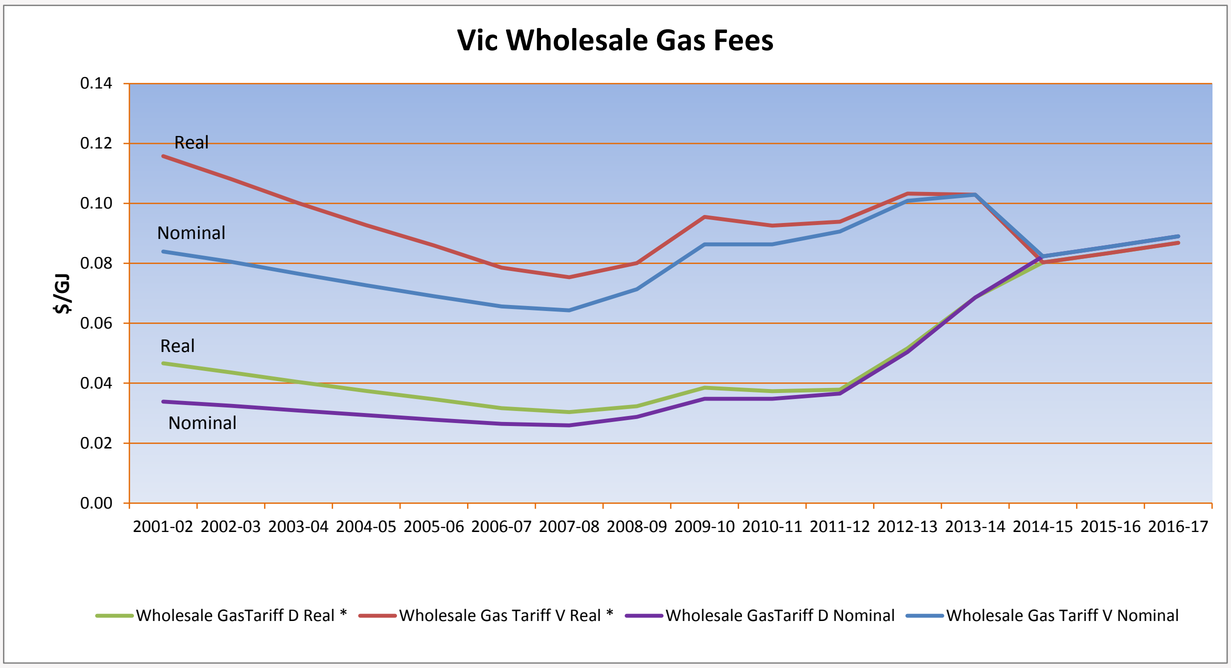
The distribution meter fee for 2014-15, which relates to metering data services, is in line with the current 2013-14 fee.

The Participant Compensation Fund (PCF) fee is not required to be changed in 2014-15 as the level of DWGM PCF funds currently being held meet the Rules requirement.

Table 12 — Summary of DWGM fees

Fee	Actual 2013/14	Budget 2014/15	Estimate 2015/16	Estimate 2016/17	Estimate 2017/18	Estimate 2018/19
Tariff D - Industrial ($/GJ)	0.06858	$0.08230 +20%	$0.08477 +3%	0.08731 +3%	0.08731 +0%	0.08731 +0%
Tariff V - Domestic ($/GJ)	0.10287	$0.08230 -20%	0.08477 +3%	0.08731 +3%	0.08731 +0%	0.08731 +0%
Distribution Meter ($/day per meter)	1.4256	$1.4208 -0%	$1.4399 +1%	1.4553 +1%	1.4793 +2%	1.5162 +2%

Figure 7 – Victorian wholesale gas projected fees



* Real values are the nominal amounts adjusted for inflation. Prices have been calculated relative to the 2013–14 price.

1.6 Short Term Trading Market

The STTM activity fee is budgeted to increase by 14% to $0.08203/per GJ.

In 2010-11, the consumption forecast for the Sydney and Adelaide hubs was significantly overestimated which resulted in a shortfall of revenue. During the 2011-12 budget process, it was agreed with stakeholders and the Board that this shortfall would be recovered by increasing the STTM fee each year from 2011-12 to 2014-15 by approximately 12%.

Fees are expected to increase again in 2015-16 by 10%, mainly due to lower consumption forecasts as a result of the announced closure of Swanbank E (Stanwell) operations in the Brisbane hub for the next three years, and BP's Queensland Bulwer Island refinery in mid-2015.

The recovery of pipeline operators' Market Operator Services (MOS) costs also impacts the STTM activity fee. AEMO is required to recover pipeline operators' MOS costs from STTM participants and pass these funds onto pipeline operators. There is a forecast over-recovery from MOS costs in 2013-14, which reduces MOS costs for 2014-15.

Costs in this function have increased by $0.7 million (6%), primarily due to labour cost increases under the current EBA, and an increased focus and effort of operational resources.

PCF fees are required to be collected for the Brisbane hub only in 2014-15, following the February 2013 Rule change to increase the fund balance from $0.1 million to $0.45 million. There is no requirement to collect PCF funds for the Sydney and Adelaide hubs as the level of funds currently being held for these hubs meets the Rules requirements.

Table 13 — Short Term Trading Market projected fees

Fee	Actual 2013-14	Budget 2014-15	Estimate 2015-16	Estimate 2016-17	Estimate 2017-18	Estimate 2018-19
Operating Component	0.07033	0.08158 +16%	0.08822 +12%	0.07234 -18%	0.05932 -18%	0.04864 -18%
MOS Component	0.00185	0.00045 -76%	0.00230 +417%	0.00231 +0%	0.00214 -7%	0.00210 -2%
Activity Fee ($/GJ withdrawn)	**0.07218**	**0.08203** **+14%**	**0.09052** **+10%**	**0.07465** **-18%**	**0.06146** **-18%**	**0.05074** **-17%**
Fixed Fee ($/day per hub per ABN)	30	30	30	30	30	30
PCF Fee - Syd ($/GJ withdrawn per hub per ABN)	0	0	TBC	TBC	TBC	TBC
PCF Fee - Adel ($/GJ withdrawn per hub per ABN)	0.00268	0	TBC	TBC	TBC	TBC
PCF Fee - Bris ($/GJ withdrawn per hub per ABN)	0.00374	0.00262 -30%	TBC	TBC	TBC	TBC

1.7 Gas Statement of Opportunities

Gas Statement of Opportunities (GSOO) costs are recovered via charges to retailers in AEMO's FRC gas markets on a fee per meter basis.

A reduction in the fee is expected in 2014-15, mainly due to a forecast carry forward surplus from 2013-14, and also a reduction in operational costs for this function relating to labour and consultancies.

Table 14 — Gas Statement of Opportunities projected fees

Fee	Actual 2013-14	Budget 2014-15	Estimate 2015-16	Estimate 2016-17	Estimate 2017-18	Estimate 2018-19
Gas Statement of Opportunities	0.02979	0.02830	0.02689	0.02823	0.02964	0.03112
($ per customer supply point per month)		-5%	-5%	+5%	+5%	+5%

1.8 Victorian Full Retail Competition Gas

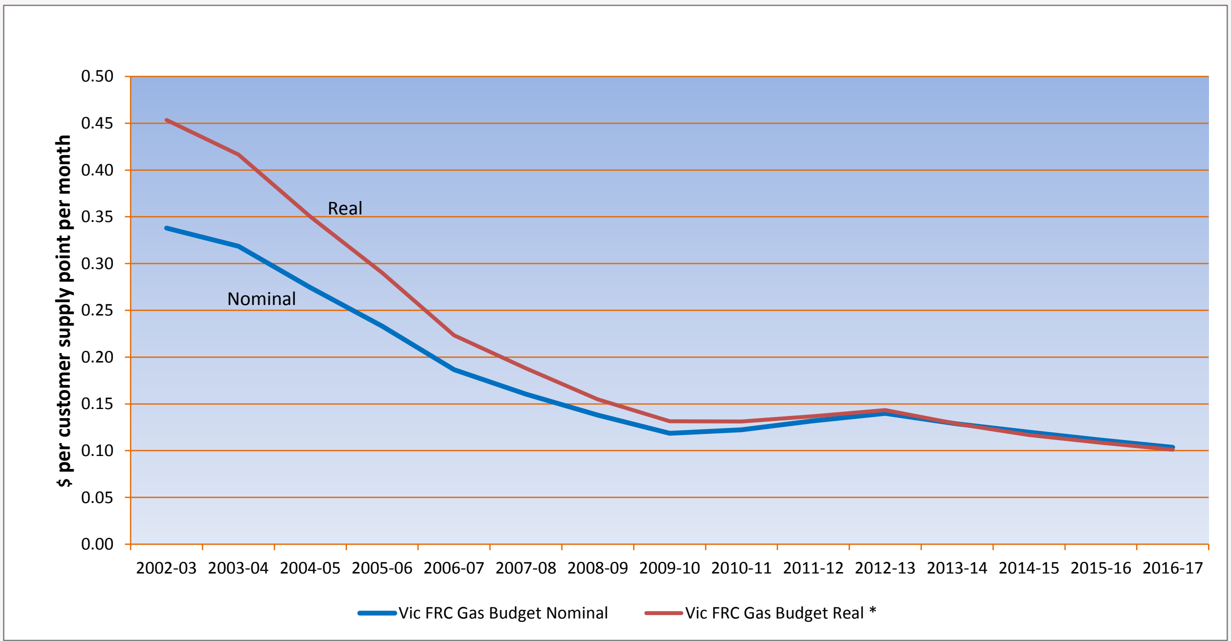
The Victorian Full Retail Competition (FRC) gas fee will reduce by approximately 7% in 2014-15 and by a further 7% in the following two years due to a prior-year surplus in the function.

Costs for this function have decreased by 3%, mainly due to a reduced number of employees.

Table 15 — Victorian FRC Gas projected fees

Fee	Actual 2013-14	Budget 2014-15	Estimate 2015-16	Estimate 2016-17	Estimate 2017-18	Estimate 2018-19
FRC Gas Tariff ($ per customer supply point per month)	0.12875	0.11974 -7%	0.11136 -7%	0.10356 -7%	0.10874 +5%	0.11418 +5%
Initial Registration Fee ($ per participant)	5,760	5,760	TBC	TBC	TBC	TBC
Gas Statement of Opportunities ($ per customer supply point per month)	0.02979	0.0283 -5%	0.02689 -5%	0.02823 +5%	0.02964 +5%	0.03112 +5%
Gas Advocacy Panel pass-through ($ per customer supply point per month)	0.01910	0.01110 [1] -42%	TBC	TBC	TBC	TBC

Figure 8 – Victorian FRC Gas projected fees



* Real values are the nominal amounts adjusted for inflation. Prices have been calculated relative to the 2013–14 price.

1 This fee relates to the recovery of costs for the gas Consumer Advocacy Panel. The costs and fees associated with the new Energy Consumers Australia are yet to be finalised

1.9 Queensland Full Retail Competition Gas

The Queensland Full Retail Competition (FRC) gas 2014-15 fee is proposed to increase gradually from 2014-15 to 2016-17 and increase more sharply in 2017-18 and 2018-19.

This function has a small cost base; relatively minor increases in costs can therefore result in large percentage fee increases.

The costs in this function have increased, however there is currently a carried forward surplus that limits the impact of the cost increases on the fee for the next three years.

Table 16 — Queensland FRC Gas projected fees

Fee	Actual 2013-14	Budget 2014-15	Estimate 2015-16	Estimate 2016-17	Estimate 2017-18	Estimate 2018-19
FRC Fee ($ per customer supply point per month)	0.29908	0.30805 +3%	0.31729 +3%	0.32681 +3%	0.3693 +13%	0.41731 +13%
Initial Registration Fee ($ per participant)	5,760	5,760	TBC	TBC	TBC	TBC
Gas Statement of Opportunities ($ per customer supply point per month)	0.02979	0.0283 -5%	0.02689 -5%	0.02823 +5%	0.02964 +5%	0.03112 +5%
Gas Advocacy Panel pass-through ($ per customer supply point per month)	0.01910	0.01110 [1] -42%	TBC	TBC	TBC	TBC

1.10 South Australia Full Retail Competition Gas

The South Australia Full Retail Competition (FRC) fee is expected to increase by 1% in 2014-15 and remain flat over the following two years, with a reduction forecast from 2017 to 2019.

Table 17 — South Australia FRC Gas projected fees

Fee	Actual 2013-14	Budget 2014-15	Estimate 2015-16	Estimate 2016-17	Estimate 2017-18	Estimate 2018-19
FRC Fee ($ per MIRN per month)	0.30424	0.30728 +1%	0.30728 +0%	0.30728 +0%	0.30113 -2%	0.29511 -2%
Initial Registration Fee ($ per participant)	11,300	11,300	TBC	TBC	TBC	TBC
Gas Statement of Opportunities ($ per customer supply point per month)	0.02979	0.0283 -5%	0.02689 -5%	0.02823 +5%	0.02964 +5%	0.03112 +5%
Gas Advocacy Panel pass-through ($ per customer supply point per month)	0.01910	0.01110 [1] -42%	TBC	TBC	TBC	TBC

1 This fee relates to the recovery of costs for the gas Consumer Advocacy Panel. The costs and fees associated with the new Energy Consumers Australia are yet to be finalised.

1.11 NSW Full Retail Competition Gas

Unlike AEMO's other Full Retail Competition (FRC) gas markets, the NSW FRC market does not have a fee per meter charge. NSW FRC fees are predominantly charged on a market share basis and a meter churn basis.

AEMO's costs in providing this service have decreased slightly in 2014-15 and remain relatively stable in the forward years to 2018-19.

Table 18 — NSW FRC Gas Projected Fees

	Actual 2013-14 ($'000)	Budget 2014-15 ($'000)	Estimate 2015-16 ($'000)	Estimate 2016-17 ($'000)	Estimate 2017-18 ($'000)	Estimate 2018-19 ($'000)
Total Participant Revenue	2500	2000	2000	2000	2400	2400
Total Expenditure	2,437	2,214	2,278	2,343	2,411	2,481
Gas Statement of Opportunities (total to be recovered from NSW FRC participants)	484	475	461	494	567	597
Gas Advocacy Panel pass-through (total to be recovered from NSW FRC participants)	310	186 [1]	TBC	TBC	TBC	TBC

1 This fee relates to the recovery of costs for the gas Consumer Advocacy Panel. The costs and fees associated with the new Energy Consumers Australia are yet to be finalised.

1.12 Gas Supply Hub

The Wallumbilla Gas Supply Hub project was approved by the Board at $1.7 million in December 2012. The go-live date for this market was late March 2014.

The gas supply hub is a voluntary market, and fees have been set at $0.03/GJ for day-ahead and on-the-day products, and $0.02/GJ for weekly products.

Estimates of trade volumes for 2014-15 and beyond are based on a "low" scenario.

Trade volumes are forecast to increase from 2016 as LNG exports increase and additional hub services are created at the Wallumbilla gas supply hub.

Table 19 — Gas Supply Hub fees

Fee		Budget 2014-15
Trading participants	Fixed Fee - one licence per annum	$ 14,500
	Fixed Fee - additional licence per annum	$ 5,500
	Variable transaction fee	
	- Daily product fee ($/GJ)	$ 0.03
	- Weekly product fee ($/GJ)	$ 0.02
Reallocation participants	Fixed fee per annum	$ 9,000
Viewing participants	Fixed fee per annum	$ 5,500

1.13 Other budgeted revenue requirements

AEMO also collects revenue to recover the costs of the following functions:

Table 20 — Other revenue requirements

Key Fees	Budget 2014-15	Actual 2013-14
Gas B2B	139	125
Gas Bulletin Board	471	224
South Australia Planning	1,000	1,030
Settlement Residue Auctions	275	300

1.14 Energy Consumers Australia and Consumer Advocacy Panel fees

The Standing Council of Energy and Resources (SCER) has approved the establishment of the Energy Consumers Australia (ECA) by 1 July 2014, to provide a focus on national energy market matters of strategic importance for energy consumers, and residential and small business consumers in particular. AEMO is required to collect funds for the operation of the ECA, which will need to be incorporated into the participant fee process we operate with gas and electricity market stakeholders.

The funding arrangements for ECA are proposed to be similar to that of the existing Consumer Advocacy Panel (CAP) whose functions will be absorbed by the ECA, however fees will be collected on a per supply point basis for both gas and electricity (the CAP is currently recovered as a per MWh rate from electricity customers). AEMO is also expected to manage the over/under-recovery through its annual budget process.

SCER officials are progressing an ECA implementation plan, which will put in place the necessary provisions for AEMO to collect revenue on behalf of ECA. An update is provided on the SCER website: **https://scer.govspace.gov.au/files/2011/12/Energy-Consumers-Australia-Implementation-Plan-Synopsis.pdf**. A transitional funding arrangement is expected to be in place until 1 January 2015. From 1 January 2015, permanent funding is expected to be in place, and CAP functions to be absorbed by the ECA.

Table 21 reflects the CAP fees to be collected in electricity and gas for 2014-15 until further developments are made with the CAP being absorbed under ECA. The costs and fees associated with the ECA are yet to be finalised.

Table 21 — Consumer Advocacy Panel requirements

CAP Fees	Budget 2014-15	Actual 2013-14
Electricity ($/MWh)	0.01069	0.01399
Gas ($ per customer supply point per month)	0.01110	0.01910

2 AEMO FINANCIALS

2.1 Financials

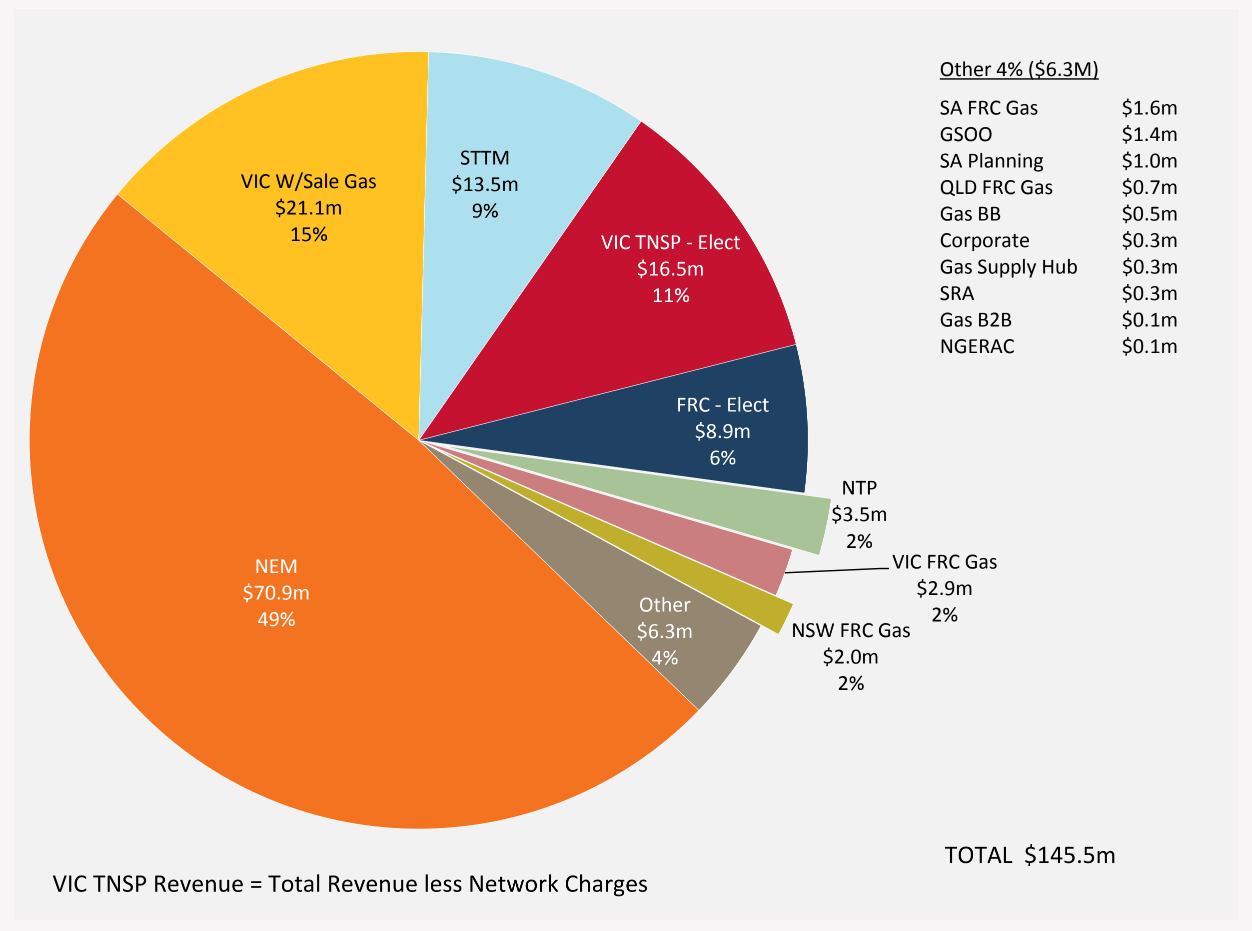
Table 22 — Consolidated Profit and Loss 2014-15

Annual	AEMO (excluding Vic TNSP)				Victorian TNSP				Total AEMO			
	Budget 2013-14 $'000	Forecast 2013-14 $'000	Budget 2014-15 $'000	Variance to Budget $'000	Budget 2013-14 $'000	Forecast 2013-14 $'000	Budget 2014-15 $'000	Variance to Budget $'000	Budget 2013-14 $'000	Forecast 2013-14 $'000	Budget 2014-15 $'000	Variance to Budget $'000
REVENUE												
Fees and Tariffs	124,087	122,831	124,363	276	-	-	-	-	124,087	122,831	124,363	276
TUoS Income	-	-	-	-	453,787	454,694	501,699	47,912	453,787	454,694	501,699	47,912
Establishment Fees	-	-	-	-	-	-	-	-	-	-	-	-
PCF Fees	893	893	115	(778)	-	-	-	-	893	893	115	(778)
Settlement Residue	-	-	-	-	49,958	47,558	30,792	(19,166)	49,958	47,558	30,792	(19,166)
Other Revenue	3,793	4,127	4,490	697	24,370	23,543	24,880	510	28,163	27,670	29,370	1,207
TOTAL REVENUE	**128,773**	**127,851**	**128,967**	**194**	**528,115**	**525,795**	**557,372**	**29,257**	**656,888**	**653,646**	**686,339**	**29,451**
NETWORK CHARGES	-	-	-	-	532,349	540,351	540,843	8,494	532,349	540,351	540,843	8,494
NET REVENUE	**128,773**	**127,851**	**128,967**	**194**	**(4,234)**	**(14,556)**	**16,528**	**20,763**	**124,539**	**113,295**	**145,496**	**20,957**
EXPENDITURE								-				
Total Labour~	80,019	79,262	82,544	2,526	5,476	4,528	5,239	(237)	85,495	83,791	87,783	2,289
Contractors	1,270	849	614	(655)	-	-	100	100	1,270	849	714	(555)
Consulting	6,975	5,825	7,219	243	1,290	615	831	(460)	8,266	6,440	8,049	(217)
Fees-Agency, Licence and Audit	2,860	2,552	1,706	(1,155)	-	-	-	-	2,860	2,552	1,706	(1,155)
Information Technology and Telecommunication	15,295	14,487	14,752	(544)	-	-	-	-	15,295	14,487	14,752	(544)
Occupancy	4,995	4,747	5,065	71	-	-	-	-	4,995	4,747	5,065	71
Training & Recruitment	2,036	1,705	1,731	(305)	34	31	47	13	2,071	1,736	1,778	(293)
Travel & Accommodation	1,923	1,799	1,879	(44)	33	33	70	38	1,956	1,832	1,949	(7)
Other Expenses from Ordinary Activities	7,269	6,687	6,533	(736)	15	15	13	(1)	7,284	6,702	6,546	(738)
TOTAL EXPENDITURE (excl Financing & Depreciation)	**122,643**	**117,915**	**122,043**	**(600)**	**6,848**	**5,221**	**6,300**	**(548)**	**129,491**	**123,136**	**128,343**	**(1,148)**
Depreciation and Amortisation	15,264	14,756	14,386	(878)	36	39	42	6	15,300	14,795	14,428	(873)
Financing Costs	2,474	2,622	2,024	(451)	104	-	-	(104)	2,579	2,622	2,024	(555)
Capitalised internal labour	(3,786)	(4,495)	(3,390)	396	-	(4)		-	(3,786)	(4,499)	(3,390)	396
TOTAL OPERATING EXPENDITURE	**136,596**	**130,798**	**135,063**	**(1,533)**	**6,988**	**5,256**	**6,342**	**(646)**	**143,584**	**136,054**	**141,405**	**(2,179)**
SURPLUS / (DEFICIT)	**(7,822)**	**(2,947)**	**(6,095)**	**1,727**	**(11,222)**	**(19,812)**	**10,186**	**21,409**	**(19,045)**	**(22,759)**	**4,091**	**23,136**
Corporate Recovery	4,169	3,621	4,532	362	(4,169)	(3,621)	(4,532)	(362)	-	-	-	-
Transfer to Reserves / Recoveries	3,005	2,471	4,070	1,065	(4,169)	(3,621)	(4,532)	(362)	(1,164)	(1,150)	(461)	703
Brought Forward Surplus / (Deficit)	7,177	12,204	11,728	4,551	14,423	17,941	(5,493)	(19,916)	21,600	30,144	6,236	(15,364)
ACCUMULATED SURPLUS / (DEFICIT)	**2,361**	**11,728**	**9,703**	**7,343**	**(969)**	**(5,493)**	**162**	**1,131**	**1,392**	**6,236**	**9,865**	**8,474**
Contributed capital relating to Vic Wholesale gas market	(8,704)	(8,704)	(8,704)	-	-	-	-	-	(8,704)	(8,704)	(8,704)	-
ADJUSTED ACCUMULATED SURPLUS / (DEFICIT)	**(6,343)**	**3,025**	**1,000**	**7,343**	**(969)**	**(5,493)**	**162**	**1,131**	**(7,311)**	**(2,468)**	**1,162**	**8,474**

~ Total Labour includes both opex and capex labour.
Note the Budget 2014-15 accumulated surplus includes $8.7M of contributed capital relating to the Vic Wholesale Gas market.

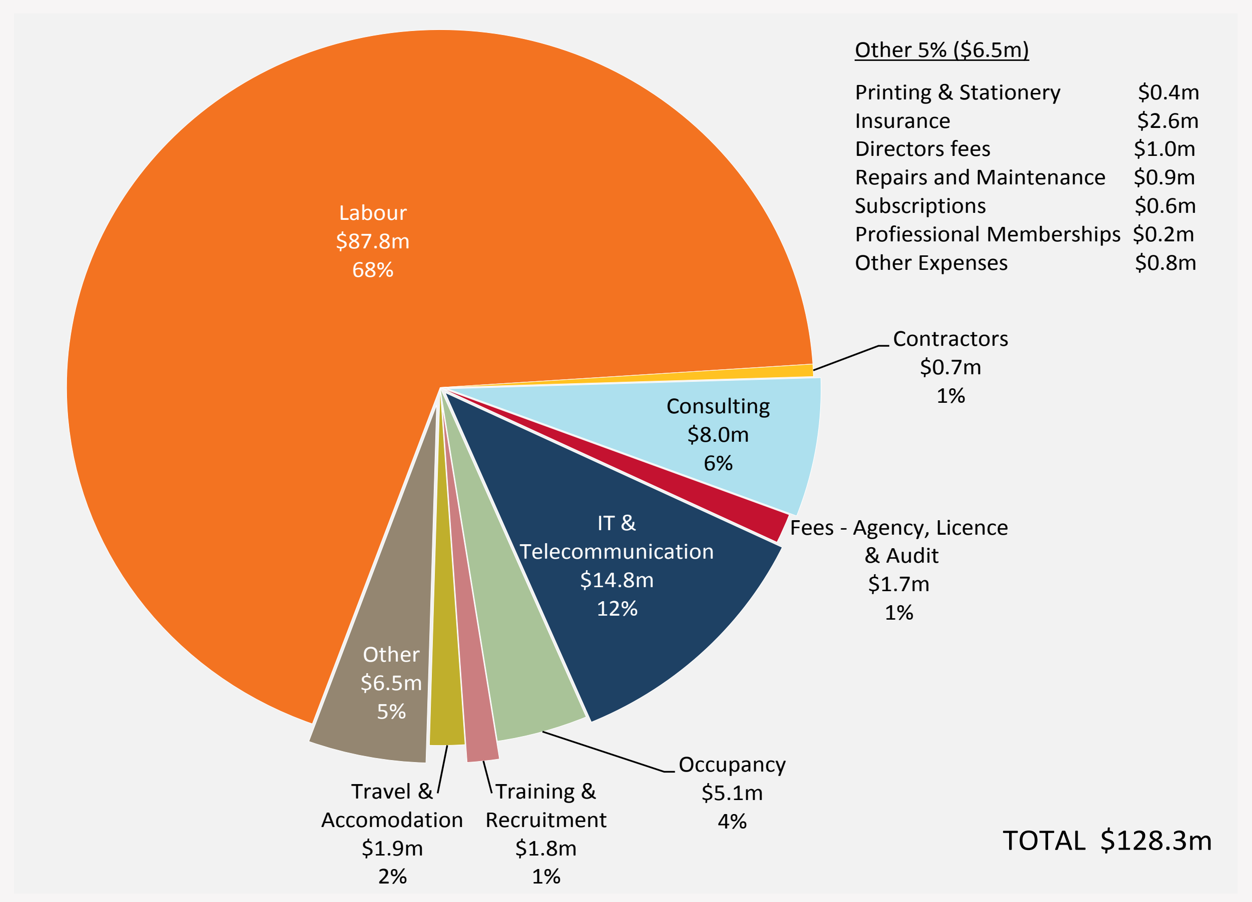
2.2 Net revenue

Figure 9 – Net revenue by function



2.3 Expenditure

Figure 10 – Total expenditure by category (excluding depreciation and finance costs)



2.3.1 Expenditure commentary

Total budgeted expenditure (excluding financing costs and depreciation) is $128.3 million.

This is a decrease of $1.1 million (1%) from 2013-14 budgeted expenditure.

Key variances in expenditure between the 2014-15 budget and the 2013-14 budget are:

- **Labour costs**
  Labour costs are budgeted to increase by $2.3 million (2.7%) compared to the 2013-14 budget.

  Key points of the 2014-15 labour budget are:
  - The number of budgeted full-time equivalent (FTE) positions for 2014-15 is 489.
  - Budgeted positions in 2014-15 include 11 new positions. Ten of these positions reflect the February 2015 graduate intake.
  - A provision that EBA increases for employee and management increases has been assumed.
- **Contractor costs**
  Contractor costs are budgeted to decrease by $0.6 million (44%) compared to the 2013-14 budget, predominately due to the conclusion of works on TNSP operating agreements.

- **Consulting costs**

  Consulting costs are budgeted to decrease by $0.2 million (3%) compared to the 2013-14 budget.

  The major consulting items in the 2014-15 budget relate to:

  – National Energy Forecasting Report ($0.7 million).

  – National gas forecasts ($0.4 million).

  – Electricity connection point forecasting ($0.5 million).

  – Electricity value of customer reliability project ($0.2 million).

  – Energy markets for a changing environment (NEM resilience) ($0.2 million).

  – Optional Firm Access (future offset arrangements) ($0.2 million).

- **Fees – Agency Licence and Audit**

  Fees for agency, licence and audit costs are budgeted to decrease by $1.2 million (40%), mainly due to TNSP Operating Agreement annual savings. This is also a permanent saving for the future years.

- **IT and telecommunications**

  IT and telecommunication costs are budgeted to decrease by $0.5 million (3.5%) compared to the 2013-14 budget.

  Key changes relate to:

  – Lower telecommunication costs ($0.3 million) from the 2013-14 budget due to savings from renegotiating contracts.

  – Lower number of software upgrades and purchases ($0.5 million).

  – A net increase to IT Service Level Contracts costs ($0.3M) as a result of:

  ⇒ New Wallumbilla Gas Supply Hub licence costs ($0.2 million).

  ⇒ New support costs for Microsoft datacentres and SQL, Gas SCADA support, and a new weather service contract ($0.6 million).

  ⇒ An annual productivity target of $0.5 million has been set for IT service level contract negotiation opportunities to be found during 2014-15 with existing suppliers.

- **Occupancy**

  Occupancy costs are budgeted to increase by $0.1 million (2%) compared to the 2013-14 budget, mainly due to contracted consumer price index increases for office leases.

- **Other expenses**

  Other expense costs are budgeted to decrease by $0.7 million compared to the 2013-14 budget mainly due to reduced costs in communication tools, subscriptions and research data, professional fees, and repairs and maintenance.

- **Financing costs**

  Financing costs are budgeted to decrease by $0.6 million (22%) compared to the 2013-14 budget, mainly due to lower interest paid on the STTM and Norwest loans as the principal outstanding reduces by $6 million in 2014-15.

- **Depreciation costs**

  Depreciation costs are budgeted to decrease by $0.9 million (6%) compared to the 2013-14 budget, mainly due to:

  - A reduction of $0.2 million as the Australian Wind Energy Forecasting System (AWEFS) is fully depreciated in 2014-15.
  - A reduction of $0.8 million in various hardware and system software releases being fully depreciated in NEM, Electricity FRC, and Corporate.
  - A reduction of $0.3 million for current year 2013-14 capital projects that were due to depreciate in 2014-15.
  - An offset in new depreciation costs, mainly for Wallumbilla Gas Supply Hub project and new capital expenditure items ($0.4 million).

2.4 Balance sheet 2014-15

Table 23 — Balance sheet 2014-15

	Budget 2013-14 $'000	Forecast 2013-14 $'000	Budget 2014-15 $'000	Variance Budget 2014-15 to Budget 2013-14 $'000	%
ASSETS					
Current Assets					
Cash and Short Term Deposits	21,763	29,256	26,753	4,990	+23%
Receivables	68,097	67,176	70,911	2,814	+4%
Other Current Assets	3,191	2,532	2,672	(519)	-16%
Total Current Assets	93,051	98,964	100,336	7,285	+8%
Non - Current Assets					
Intangible Assets - Software	31,168	29,995	28,090	(3,078)	-10%
Property, Plant and Equipment	27,875	28,545	25,069	(2,806)	-10%
Total Non Current Assets	59,043	58,540	53,159	(5,884)	-10%
TOTAL ASSETS	152,095	157,504	153,495	1,401	+1%
LIABILITIES					
Current Liabilities					
Payables	58,394	65,194	61,396	3,002	+5%
Borrowings	5,357	5,357	5,357	(0)	-0%
Provisions	18,668	18,391	20,188	1,520	+8%
Other Current Liabilities	16,059	10,744	10,611	(5,448)	-34%
Total Current Liabilities	98,478	99,686	97,552	(925)	-1%
Non - Current Liabilities					
Borrowings	27,986	27,986	22,629	(5,357)	-19%
Provisions	2,335	1,920	2,002	(333)	-14%
Lease Liability	2,720	2,720	2,032	(687)	-25%
Total Non Current Liabilities	33,040	32,625	26,663	(6,378)	-19%
TOTAL LIABILITIES	131,518	132,311	124,215	(7,303)	-6%
NET ASSETS / (LIABILITIES)	20,576	25,193	29,280	8,704	
EQUITY					
Capital contribution	7,093	7,093	7,093	-	+0%
Participant compensation fund reserve	9,974	9,822	10,283	310	+3%
Australian Wind Energy Forecasting System reserve	248	230	-	(248)	-100%
Land reserve	1,869	1,813	2,039	170	+9%
Accumulated surplus/(deficit)	1,392	6,236	9,865	8,472	+609%
TOTAL EQUITY	20,576	25,193	29,280	8,704	

2.5 Cash flow statement 2014-15

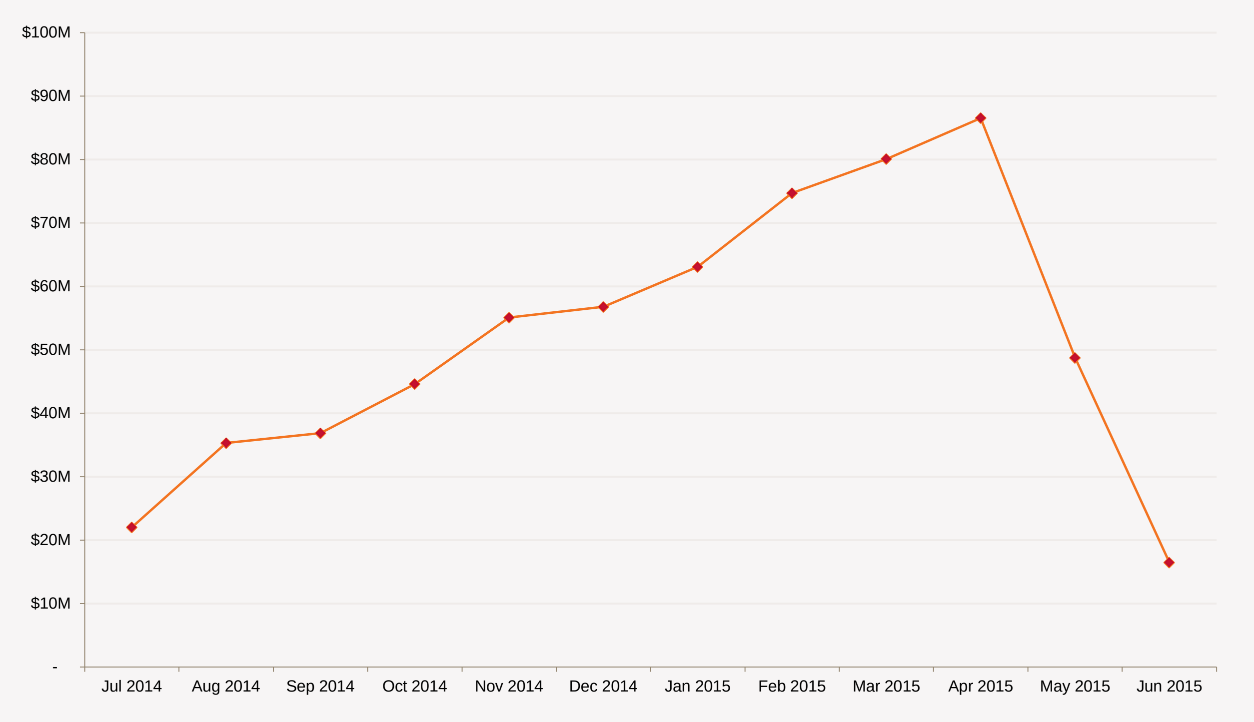
Table 24 — Cash flow for 2014-15

	Budget 2014-15 $'000
Cash flows from operating activities	
Receipts	
Receipts from customers (inclusive of GST)	741,439
Interest received	1,201
Total Receipts	**742,640**
Payments	
Payments to suppliers and employees (inclusive of GST)	(726,675)
Interest and other costs of finance paid	(2,199)
Total Payments	**(728,874)**
Net cash provided by operating activities	**13,766**
Cash flows from investing activities	
Payments for non-financial assets	(10,912)
Net cash used in investing activities	**(10,912)**
Cash flows from financing activities	
Proceeds from borrowings	-
Repayments of borrowings	(5,357)
Net cash used in financing activities	**(5,357)**
Net increase in cash held	**(2,503)**
Cash at the beginning of the period (including PCF) at 1 July 2014	29,256
Cash at the End of Period (including PCF) at 30 June 2015	**26,753**
Less: PCF Funds	(10,283)
Cash at the End of Period (excluding PCF) at 30 June 2015	**16,469**

Figure 11 reflects the monthly expected cash balance (excluding PCF) for 2014-15.

No new borrowings are budgeted for 2014-15.

Figure 11 – Expected closing cash balance (excluding PCF) for 2014-15



3 CAPITAL EXPENDITURE

AEMO's budgeted capital expenditure for 2014-15 is $9.0 million.

This represents a $0.4 million (4%) reduction on the 2013-14 budget.

Table 25 — 2014-15 budgeted capital expenditure summary

	Budget 2013-14 $M	Forecast 2013-14 $M	Budget 2014-15 $M	Change	
Total Capital Expenditure	9.4	8.6	9.0	-0.4	-4%

A list of major capital projects is shown in Table 26. It outlines the key individual projects planned to be delivered in the 2014-15 year.

Table 26 — Major Capital Projects

Major Projects	Budget 2014-15 $'000
Foundation universal HUB	1,405
Automating MVar dispatch	1,021
Technology platform stream	680
IT licensing upgrade	400
Renewal of SA/NSW gas retails systems	400
Multiple trading relationships and embedded networks (MTREN)	394
IT backup infrastructure	375
IT domain consolidation	350
Control room operational phones	350
Solar forecasting	334
Implement selected monitoring platform	238
Migrate market systems to scheduling tool	228
MSATS renewal and upgrade of NEM retail database	200
VMware ESX hardware renewal	195
Implement selected scheduling platform	186
Enterprise porfolio management (EPM) tool	150
Futures offset arrangement	115
Real time transient stability	108
Property - general	100
Intranet upgrade	100
Settlement residue auction unit transfer graphical user interface (GUI)	100
DWGM - portfolio rights trading	98
Gas reporting solution stream	94
Forecasting solution stream	94
Compellent - IT storage extensions	80

LIST OF SYMBOLS AND ABBREVIATIONS

Term	Definition
AER	Australian Energy Regulator
AWEFS	Australian Wind Energy Forecasting System
B2B	business-to-business
DWGM	Declared Wholesale Gas Market
FRC	Full Retail Contestability
GJ	gigajoule
GSOO	Gas Statement of Opportunities
ESOO	Electricity Statement of Opportunities
LNG	liquefied natural gas
MOS	Market Operator Service
MW·h	megawatt hour
NA	not applicable
NEM	National Electricity Market
NGERAC	National Gas Emergency Response Advisory Committee
NGR	National Gas Rules
NSM	National Smart Metering
NTP	National Transmission Planner
PCF	Participant Compensation Fund
STTM	Short Term Trading Market
TNSP	Transmission Network Service Provider
TUOS	Transmission Use of System