2019-20 AEMO Final Budget and Fees

June 2019

Executive summary

The energy industry continues to transform rapidly, posing challenges and opportunities related to changing supply sources and consumer preferences, new service models, aging infrastructure, weather and climate changes, and cybersecurity.

The changing energy environment has a direct impact on AEMO's day-to-day operations and investment requirements. AEMO must respond to an increasingly complex operating environment, increased regulatory requirements and high stakeholder expectations at a time where there is significant competition for skilled resources.

AEMO continues to focus on managing costs, operating efficiently, and minimising the impact on participant fees of increased operating requirements, however these growing demands are reflected in additional budgeted spending in 2019-20.

Operating costs

Excluding depreciation, operating costs are budgeted to increase in 2019-20 by $28m compared to the 2018-19 budget. This increase comprises:

- An additional $18m for compliance requirements and prudent initiatives.
  - Compliance requirements include integrated system planning uplift, increased cyber security requirements, the management of distributed energy resources, increased reporting and regulatory requirements and a more complex operating environment.
  - Prudent initiatives include investment in our systems through the digitisation program, and the uplift of our organisational capability.
- An additional $10m due to growth and committed costs, less targeted efficiency gains.
  - Includes recoverable costs increasing due to growth and cost pass-through, impacts including CPI and labour escalations, and additional costs as a result of increasing market and regulatory complexities.
  - Increases have been partially offset by targeted efficiencies in the 2019-20 budget totalling $7m.

Capital program

The capital expenditure budget for 2019-20 is $181.2m.

The digital replacement program is the largest investment over the budget period.

AEMO's current technology infrastructure was developed in an era where energy markets were stable and the use of data was predictable and limited.

Taking into account the exponentially faster rates of digital change and the technology requirements to deliver significant initiatives including the 5 Minute Settlement (5MS) Program and WA Market reform, AEMO conducted an assessment of its technology requirements and concluded that the prudent option is to replace the current ageing infrastructure.

Ultimately, this investment will deliver a new platform and services that will reduce operating costs for both AEMO and the industry and provide services that support the transition to a new energy environment. AEMO's 10-year projections show lower overall Totex (combination of operating and capital costs) if the digital investment is made now, while not investing will incur a significant cost burden over time as AEMO's ageing infrastructure becomes more costly to maintain.

Impact on fees

AEMO has a number of separate functions, of which operating the grids and markets in the National Electricity Market (NEM) is the largest (47% of total revenue). Each function has its own fees, which are set in accordance with published fee structures. Fees are set on a cost recovery basis, and new initiatives and any under-recovery is funded via a debt facility.

As projected in last year's budget process, the need for additional investment will result in the NEM fee increasing by 12% in 2019-20, with similar increases projected for the next three years. The fee is then expected to increase in line with inflation.

The Declared Wholesale Gas Market (DWGM) fee is increasing by 3% as a result of lower consumption, and the majority of other gas fees are reducing or have minor increases.

There is a step increase in the National Transmission Planner fee to provide for the continued enhancement of the Integrated System Plan.

AEMO is minimising the impact on participant fees by, firstly:

- Managing its cost base to reduce current year costs by 6% compared to budget.
- Establishing strategic partnerships with CSIRO and the Bureau of Meteorology to utilise expertise without needing to develop it or bring it in-house.
- Seeking funding from other sources including government and the Australian Renewable Energy Agency (ARENA).

In addition to these immediate steps AEMO will also:

- Propose a long-term pricing approach in the NEM, where costs are recovered over a 10-year period rather than the current five-year period. This is discussed in more detail in Section 1 of the document.
- Review the fees associated with each new development/service to ensure those costs are allocated to the beneficiaries (user pays). For example, AEMO is proposing a consultation to seek views on whether 5MS should become a declared NEM Project. If so, a further consultation would be conducted on how fees would be allocated.
- Commence an assessment of the fee allocation for our current services, taking into account the transformation of the industry. This will involve significant engagement with stakeholders throughout this process in the lead-up to the next fee determination.

Financial summary

The table below provides a financial summary of the final 2019-20 profit and loss, and accumulated surplus/(deficit) position in comparison to the current budget 2018-19.

Table 1 **Financial summary**

	AEMO (excl. Vic TNSP)			Victorian TNSP			AEMO		
	Budget 2018-19 $m	Budget 2019-20 $m	Variance $m	Budget 2018-19 $m	Budget 2019-20 $m	Variance $m	Budget 2018-19 $m	Budget 2019-20 $m	Variance $m
NET Revenue	**179**	**198**	**19**	**(22)**	**19**	**41**	**158**	**217**	**60**
Total Operating Expenditure	**208**	**242**	**34**	**14**	**16**	**2**	**222**	**258**	**36**
Annual Surplus/ (Deficit)	**(28)**	**(43)**	**(15)**	**(36)**	**3**	**38**	**(64)**	**(41)**	**24**
Transfer to Reserves / Recoveries	5	4	(0)	(6)	(6)	0	(1)	(1)	(0)
Brought Forward Surplus	6	(3)	(9)	42	3	(39)	48	(0)	(49)
Accumlated Surplus/ (Deficit)	**(17)**	**(42)**	**(25)**	**0**	**(0)**	**(0)**	**(17)**	**(42)**	**(25)**

Contact for inquiries

For all queries on budget and fees, please contact 2019-20budget@aemo.com.au

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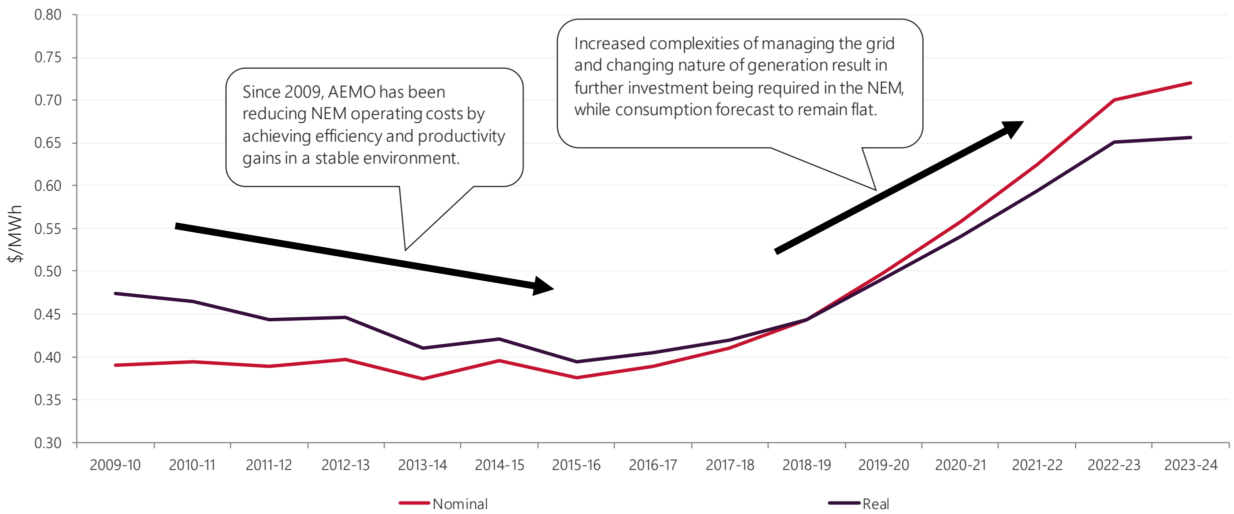
1. Fees

1.1 National Electricity Market

Purpose of this function	**Power system security and reliability.** **Market operations and systems.** **Wholesale metering, settlements and prudential supervision.** **Longer-term energy forecasting and planning services.** **(for the eastern and southern Australian states)**
Fees	The current NEM fee is $0.44/MWh. The final NEM fee for 2019-20 is $0.50/MWh (+12%). As projected in last year's budget process, the need for additional investment will result in the NEM fee increasing by 12% in 2019-20, with similar increases projected for the following three years. The fee is then expected to increase in line with inflation. The NEM fees have been calculated on the basis of AEMO recovering all of its costs (i.e. reaching a break-even position) over a 10-year period rather than the current five-year period. This approach: • Better aligns with the 'reflective of involvement' (user pays) test under the NER. In a period where there is significant investment for longer-term future gain, it reflects that participants paying the NEM fees in the future will be receiving some of the benefits of the expenditure being incurred in the next few years. • Reduces volatility and contributes to a smoother pricing impact to end consumers. If this approach wasn't adopted and the costs were continued to be recovered over five years, the NEM fees would be increasing by more than 17% per annum for the next five years, rather than the current approach of an increase of 12% for each of the next four years and then increases in line with inflation. The recovery of costs associated with the 5MS project are expected to commence in 2022-23 following consultation in how these fees should be recovered. As such, these costs are not factored into the fees outlook in this document. AEMO is planning to undertake a consultation process in July 2019 to ascertain whether 5MS should become a declared NEM project. If deemed to be declared, further consultation will be conducted to determine an appropriate fee recovery mechanism.

Figure 1 Projected NEM fees



Note: Real values are the nominal amounts adjusted for inflation. Prices have been calculated relative to the 2018-19 price.

Table 2 **Projected NEM fees (indicative benchmark)**

Fee	Actual 2018-19	Budget 2019-20	Estimate 2020-21	Estimate 2021-22	Estimate 2022-23	Estimate 2023-24
NEM fee ($/MWh)	0.44	0.50	0.56	0.62	0.70	0.72
		+12%	+12%	+12%	+12%	+3%

1.1.1 NEM energy consumption

The budgeted consumption for 2019-20 is based on available data estimates used in the 2019 NEM Electricity Statement of Opportunities.

The 2019-20 consumption is expected to stay flat in the next five years mainly due to increased solar photovoltaic (PV) uptake and energy efficiency being offset by population and economic growth.

Figure 3 below demonstrates the budget energy consumption used to calculate the NEM fee.

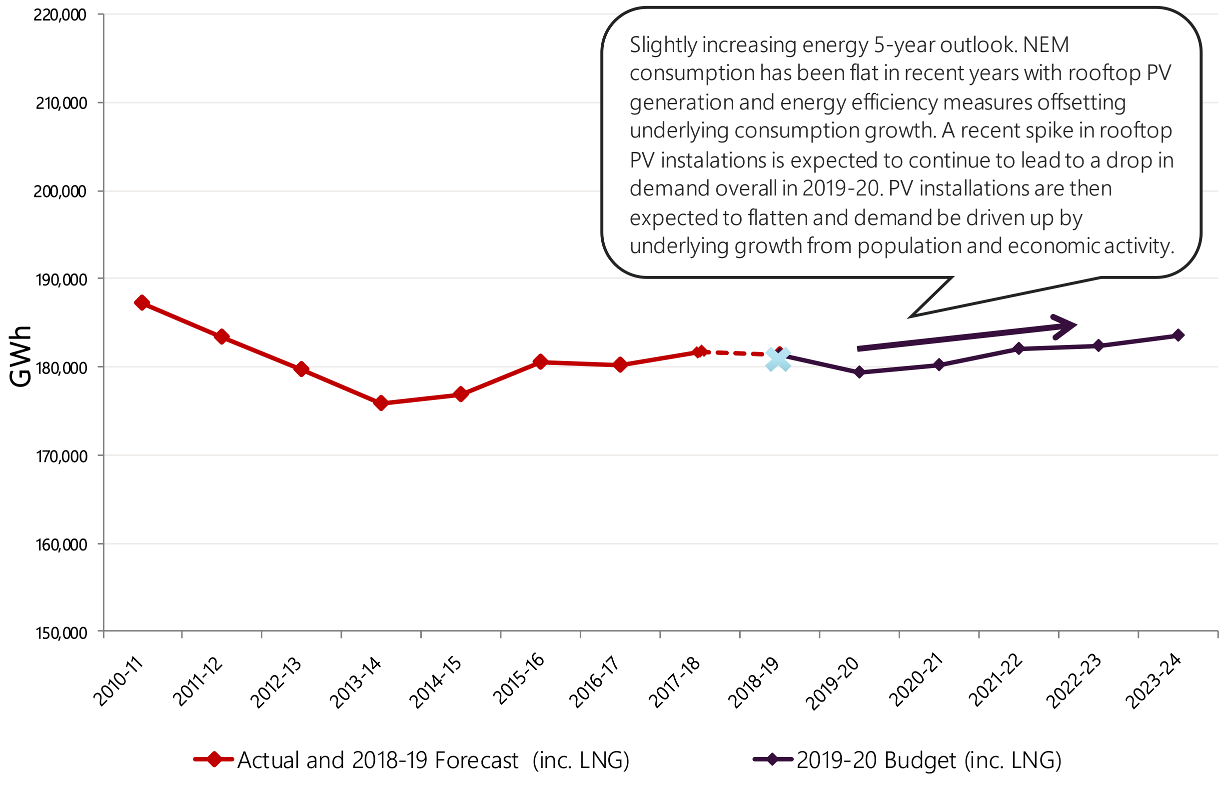
For market customers, the **NEM fee methodology** levies fees on a **$ per MWh consumption basis**. An energy forecast is factored into the calculation of the AEMO fees. For generators, the **NEM fee methodology** levies fees on a **$ per day** based on capacity and energy produced.

Table 3 **NEM consumption**

GWh	Budget 2018-19	Forecast * 2018-19	Budget 2019-20	Estimate 2020-21	Estimate 2021-22	Estimate 2022-23	Estimate 2023-24
NEM	178,650	181,407	179,387	180,134	182,031	182,346	183,542
		+1.5%	+0.4%	+0.4%	+1.1%	+0.2%	+0.7%

* Forecast annual consumption at February 2019.

Figure 2 Annual electricity consumption (market customer load)



1.2 Full Retail Contestability (FRC) Electricity

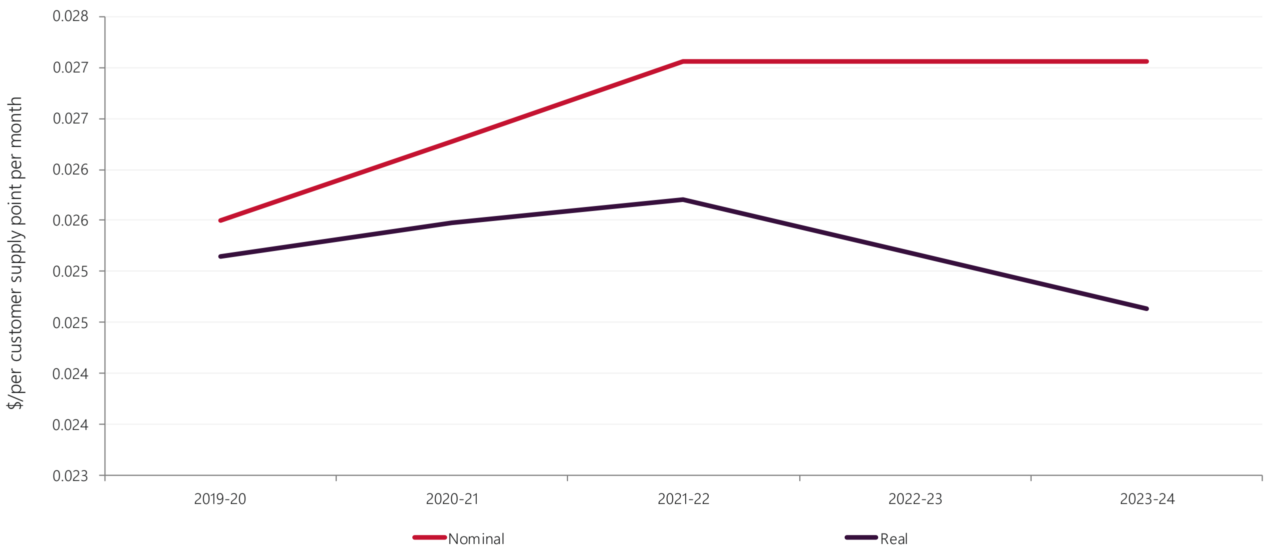
Purpose of this function	**To facilitate retail market competition in the east coast and southern states of Australia by managing and supporting:** • **Data for settlement purposes.** • **Customer transfers.** • **Business to business processes.** • **Market procedure changes.**
Fees	From 1 July 2019, fees will be collected on a per connection point basis. The final 2019-20 FRC Electricity fee is $0.02550 per connection point per week. This fee will increase by 3% in 2019-20 and for the following two years and then remain flat for the periods shown.

Table 4 **Projected FRC electricity fees**

Fee	Estimate * 2018-19	Budget 2019-20	Estimate 2020-21	Estimate 2021-22	Estimate 2022-23	Estimate 2023-24
$ per connection point per week	0.02476	0.02550	0.02627	0.02706	0.02706	0.02706
		+3%	+3%	+3%	+0%	+0%

* Conversion of 2018-19 fee from $0.077 per MWh to $0.02476 per connection point per week for comparison purpose.

Figure 3 Projected FRC electricity fees



Note: Real values are the nominal amounts adjusted for inflation. Prices have been calculated relative to the 2018-19 price.

1.3 National Transmission Planner (NTP)

Purpose of this function	• **Delivering the annual National Transmission Network Development Plan (NTNDP).** • **Other activities involve preparing the Independent Planning Reports for New South Wales, Tasmania and Queensland, Connection Point Forecasts and work on the Network Capability Incentive Performance process.**
Fees	The current NTP fee is $0.02339/MWh. This fee will increase to $0.03040/MWh in 2019-20 (+30%). The increase in 2019-20 and future years reflects additional resources and investment to uplift forecasting and planning and preparation of the Integrated System Plan (which incorporates the National Transmission Development Plan).

Table 5 **Projected National Transmission Planner fees**

Fee	Actual 2018-19	Budget 2019-20	Estimate 2020-21	Estimate 2021-22	Estimate 2022-23	Estimate 2023-24
($/MWh)	0.02339	0.03040	0.03952	0.05138	0.06679	0.08683
		+30%	+30%	+30%	+30%	+30%

1.4 Victorian Electricity Transmission Network Service Provider (TNSP)

Purpose of this function	• **AEMO provides shared transmission network services to users of the Victorian Transmission System (DTS).** • **These services include the planning of future requirements and procuring of augmentations in the DTS.**
Fees	Transmission Use of System (TUOS) fees are calculated on an annual break-even basis and are predominately influenced by network charges billed by the Victorian electricity transmission network owners and by estimations of settlement residue receipts. The 2019-20 fees are 19% higher than the 2018-19 fees mainly due to higher inter-regional TUOS costs, higher network charges and a smaller brought forward surplus from the prior year. Forward year estimates have not been made due to the volatility of the factors listed above.

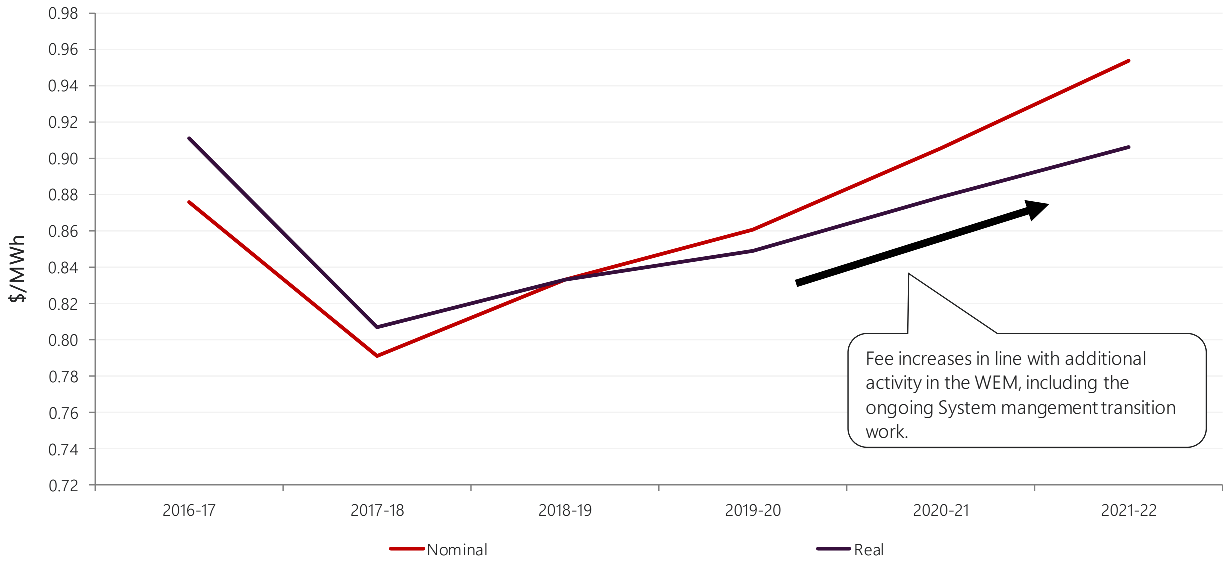
Table 6 **Projected TUOS revenue requirement**

Fee	Actual 2018-19	Budget 2019-20	Estimate 2020-21	Estimate 2021-22	Estimate 2022-23	Estimate 2023-24
TUOS fees ('000)	462,312	549,555	TBC	TBC	TBC	TBC
		+19%				

1.5 Western Australia Wholesale Electricity Market (WEM)

Purpose of this function	• **Power system security and reliability.** • **Market operations and systems.** • **Wholesale metering, settlements and prudential supervision.** • **Preparing for and implementing WA Government's WEM and Constrained Access Reforms.** • **Longer-term energy forecasting and planning services (for the South West Interconnected System of Western Australia).**
Fees	The current WEM fee is $0.833/MWh. This fee will increase to $0.861/MWh (+3%) in 2019-20. The fee has increased in line with additional activities and complexity in the WEM including the on-going system management transition work, inflation and an increase in depreciation and amortisation.
Other notes	On 14 June 2019, the ERA approved and released its final determination on the AEMO Allowable Revenue and Forecast Capital Expenditure for 2019/20 to 2021/2022 to be effective from 1 July 2019. For further information, please refer to the AEMO Allowable Revenue and Forecast Capital Expenditure 2019/20 to 2021/2022 final determination on the ERA website.

Figure 4 WEM fees in real and nominal terms



Note: Real values are the nominal amounts adjusted for inflation. Prices have been calculated relative to the 2018-19 price

Table 7 WA WEM fees

Fee	Actual 2018-19	Budget 2019-20	Estimate 2020-21	Estimate 2021-22
AEMO WEM Market Operator fee ($/MWh)	0.350	0.362	0.387	0.414
	-2%	+4%	+7%	+7%
AEMO WEM System Management fee ($/MWh)	0.484	0.499	0.519	0.540
	+11%	+3%	+4%	+4%
AEMO WEM fee ($/MWh)	0.833	0.861	0.906	0.954
	+5%	+3%	+5%	+5%
AEMO WEM fee (indicative benchmark) * ($/MWh)	1.667	1.722	1.812	1.908

* The fee listed above is a benchmark fee calculated by dividing the total cost of the WEM functions by the total forecast consumption. The actual fee charged to both Market Customers and Generators is $0.362/MWh and $0.499/MWh for the Market Operator and System Management functions respectively. The isolated grid, different regulatory and market arrangements are a key driver of costs.

1.5.1 WEM energy consumption

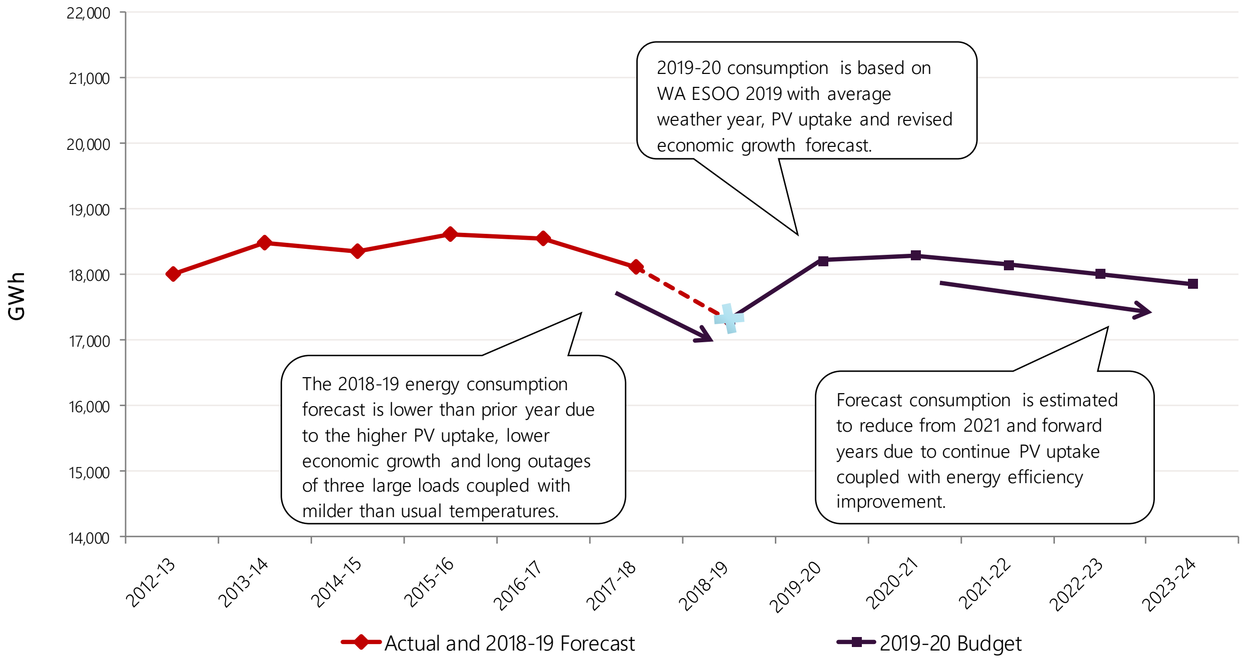
The budgeted consumption for 2019-20 is based on data estimates used in the WA 2019 ESOO, published on 14 June 2019. Consumption is expected to increase by 1.1% in 2019-20 and with small increase in 2020-21 before trending downward in forward years due to declining residential consumption as a result of rapid uptake of rooftop PV coupled with energy efficiency improvements.

Table 8 **WEM consumption**

GWh	Budget 2018-19	Forecast * 2018-19	Budget 2019-20	Estimate 2020-21	Estimate 2021-22	Estimate 2022-23	Estimate 2023-24
Load forecast	18,029	17,319	18,221	18,289	18,151	18,008	17,864
		-3.9%	+1.1%	+0.4%	-0.8%	-0.8%	-0.8%

Figure 5 below outlines the forecast energy consumption used to calculate the WEM fee.

Figure 5 WA annual electricity consumption



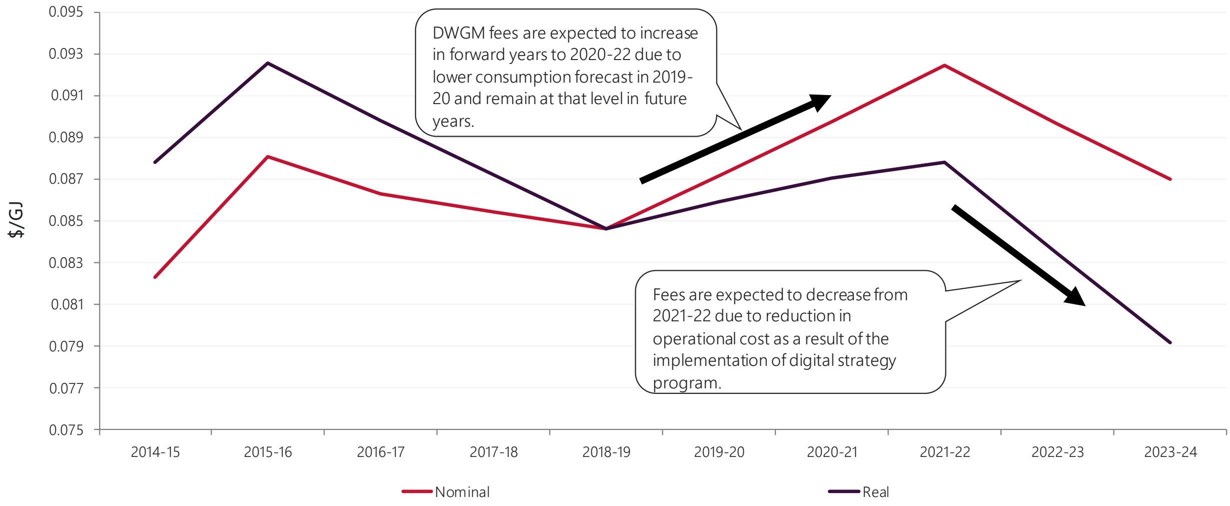
1.6 Declared Wholesale Gas Market (DWGM)

Purpose of this function	**To enable competitive dynamic trading based on injections and withdrawals from the transmission system that links producers, major users and retailers.** **This market provides the following broad services:** • **Gas system security, market operations and systems.** • **Gas system reliability and planning.** • **Wholesale metering and settlements.** • **Prudential management.**
Fees	**Energy tariff** The current energy tariff is $0.08459/GJ. This fee will increase to $0.08713/GJ (+3%) mainly driven by lower forecast energy consumption in 2019-20. **Distribution meter fee** The distribution meter fee is paid by each market participant connected to a Declared Distribution System, or whose customers are connected to a Declared Distribution System, at a connection point which there is an interval metering installation. The distribution meter fee relates to metering data services and is expected to decrease by 8% to $1.36970/per meter per day in 2019-20. The 2018-19 fee was temporarily higher to recover a deficit from previous years. **Participant Compensation Fund** The Participant Compensation Fund fee is not required to be charged in 2019-20 as the current level of DWGM PCF funds being held meets the rules requirement. Estimates of future PCF fees are not provided as they are mainly impacted by future events that may arise from time to time.

Table 9 **Projected DWGM fees**

Fee	Actual 2018-19	Budget 2019-20	Estimate 2020-21	Estimate 2021-22	Estimate 2022-23	Estimate 2023-24
Energy tariff ($/GJ)	0.08459	0.08713	0.08974	0.09243	0.08966	0.08697
	-1%	+3%	+3%	+3%	-3%	-3%
Distribution Meter ($/day per meter)	1.48584	1.36970	1.37052	1.38165	1.41428	1.44256
	+28%	-8%	+0%	+1%	+2%	+2%
PCF Fee ($/GJ)	0	0	TBC	TBC	TBC	TBC

Figure 6 Projected DWGM fees trend in nominal and real terms



Note: Real values are the nominal amounts adjusted for inflation. Prices have been calculated relative to the 2018-19 price.

1.6.1 DWGM energy consumption

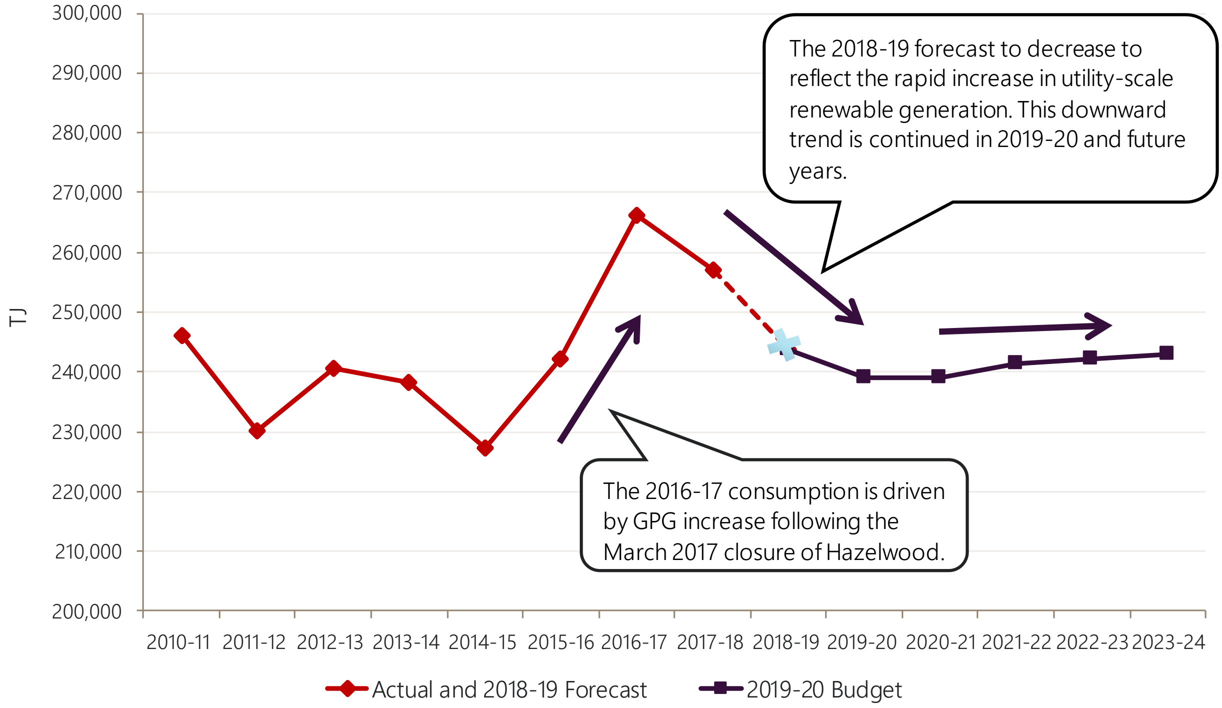
The budgeted consumption for 2019-20 and forward years is based on data estimates used in the March 2019 Gas Statement of Opportunities. Consumption in DWGM is forecast to fall from 2019-20 to reflect the rapid increase in utility-scale renewable (wind and solar) generation. Consumption for forward years is estimated to be mostly flat reflecting a forecast increase in residential load as a result of population growth that is expected to be offset by the continuation of growth in renewable generation.

Table 10 **DWGM energy consumption**

TJ	Budget 2018-19	Forecast * 2018-19	Budget 2019-20	Estimate 2020-21	Estimate 2021-22	Estimate 2022-23	Estimate 2023-24
Domestic	129,287	127,449	126,870	127,169	127,691	128,733	129,532
Industrial	68,220	66,143	65,609	65,543	66,244	66,072	66,053
Export	47,825	40,830	41,982	41,982	41,982	41,982	41,982
GPG	16,906	9,220	4,519	4,267	5,525	5,485	5,485
Total	262,238	243,643	238,980	238,961	241,442	242,272	243,052
		-7.1%	-8.9%	-0.0%	+1.0%	+0.3%	+0.3%

* Forecast annual 2018-19 consumption at February 2019.

Figure 7 DWGM energy consumption



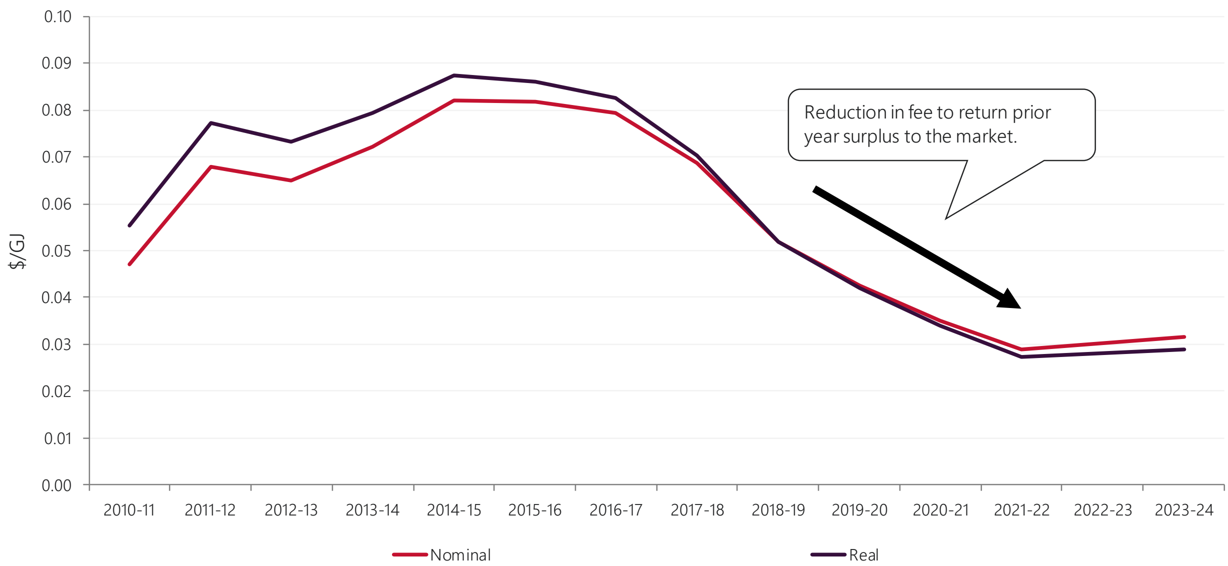
1.7 Short Term Trading Market (STTM)

Purpose of this function	**The purpose of the STTM is to enable a wholesale market gas balancing mechanism at the gas hubs – Sydney, Adelaide and Brisbane.** **The market is a day ahead market for each hub, and the market sets a daily market price.** **The STTM function provides the following broad services:** • **Market operations and systems.** • **Market Operator Service (MOS) – AEMO recovers the pipeline operators' service costs for their portion of operating costs in relation to the STTM and recovers this from participants.** • **Wholesale metering and settlements.** • **Prudentials management.**
Fees	The current STTM fee is $0.05192/GJ. This fee will decrease to $0.04258/GJ in 2019-20 (-18%) to return a prior year surplus.

Table 11 **Projected STTM fees**

Fee	Actual 2018-19	Budget 2019-20	Estimate 2020-21	Estimate 2021-22	Estimate 2022-23	Estimate 2023-24
Activity Fee ($/GJ withdrawn)	0.05192 -25%	0.04258 -18%	0.03495 -18%	0.02879 -18%	0.03018 +5%	0.03161 +5%
PCF Fee – Syd ($/GJ withdrawn per hub per ABN)	0	0	TBC	TBC	TBC	TBC
PCF Fee – Adel ($/GJ withdrawn per hub per ABN)	0	0	TBC	TBC	TBC	TBC
PCF Fee – Bris ($/GJ withdrawn per hub per ABN)	0	0	TBC	TBC	TBC	TBC

Figure 8 Projected STTM fees trend in nominal and real terms



1.7.1 STTM energy consumption

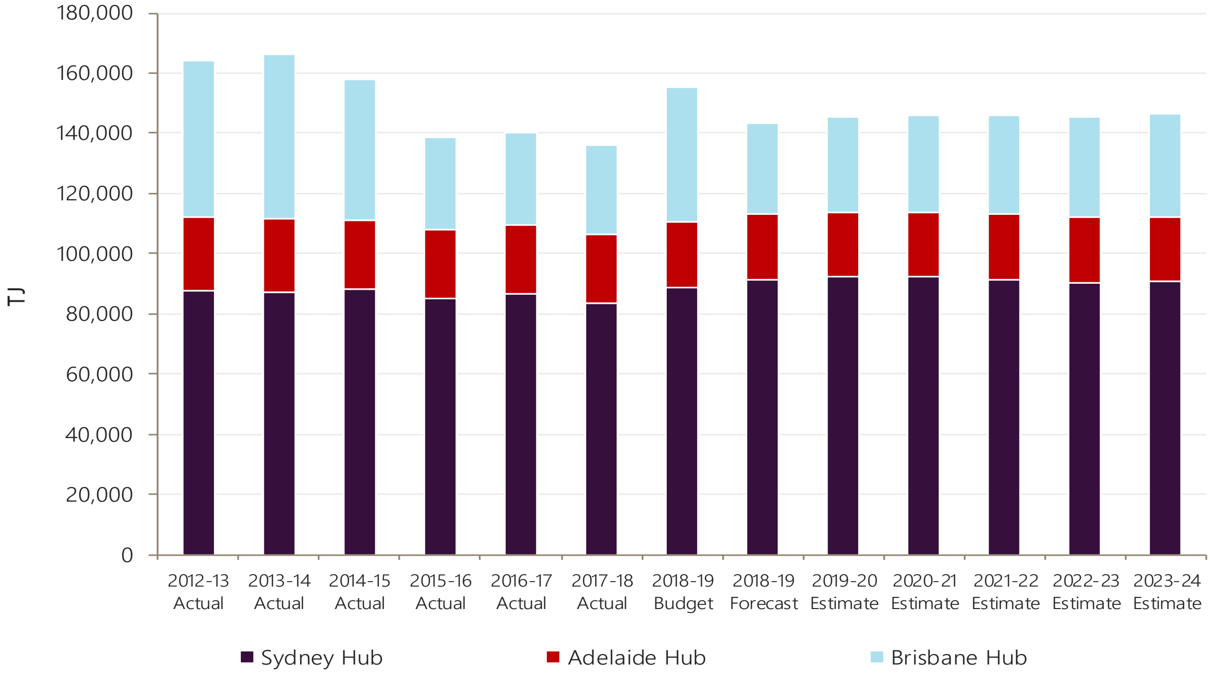
STTM energy consumption is forecast to decrease in 2019-20 then stabilise in the forward years due to alignment with recent history on industrial load (the mothballed Swanbank E GPG in Queensland – Brisbane hub), coupled with expected high gas prices and no apparent drivers for additional growth

Table 12 **STTM energy consumption**

TJ	Budget 2018-19	Forecast * 2018-19	Budget 2019-20	Estimate 2020-21	Estimate 2021-22	Estimate 2022-23	Estimate 2023-24
Adelaide	22,576	21,720	21,543	21,536	21,544	21,492	21,464
Brisbane	29,584	29,955	31,489	32,165	33,083	33,743	34,262
Sydney	83,692	91,549	92,239	92,390	91,512	90,473	90,897
Total	135,852	143,224	145,272	146,091	146,139	145,708	146,622
		+5.4%	+6.9%	+0.6%	+0.0%	-0.3%	+0.6%

* Forecast annual 2018-19 consumption at February 2019.

Figure 9 STTM energy consumption



1.8 FRC Gas Markets

Purpose of these functions	**AEMO operates FRC gas markets in Victoria, Queensland, South Australia, New South Wales and Western Australia.** **The purpose of the FRC gas markets are to provide the services and infrastructure to allow gas consumers to choose their retailer while also providing the business to business interactions to support efficient operation of the market.** **The following broad services are provided:** • **Support retail market functions and customer transfers.** • **Manage data for settlement purposes.** • **Implement market procedure changes.** • **Operate the central IT systems that facilitate retail market services.**

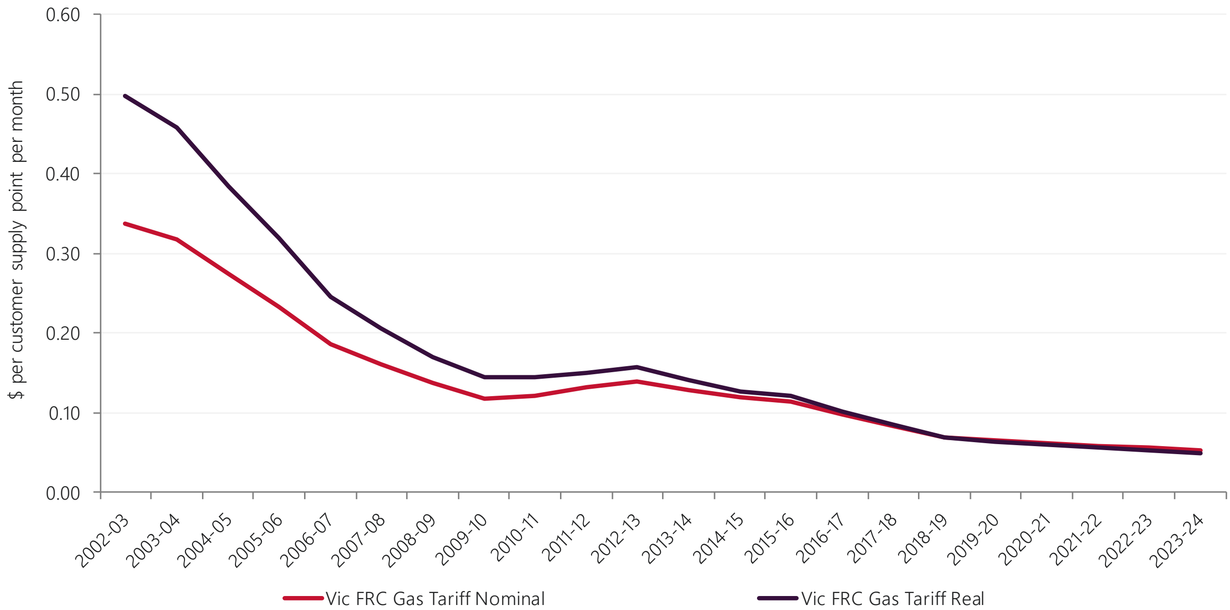
1.8.1 Victorian FRC Gas

Fees	The current Victorian FRC Gas fee is $0.06893 per customer supply point/month. This fee will decrease to $0.06548 in 2019-20 (-5%) and is estimated to reduce by similar amounts in future years as the operating costs for the function remain flat. The initial registration fee has now been updated for the first time since AEMO's inception to reflect the estimated costs in facilitating registrations.

Table 13 **Projected Victorian FRC gas fees**

Fee	Actual 2018-19	Budget 2019-20	Estimate 2020-21	Estimate 2021-22	Estimate 2022-23	Estimate 2023-24
FRC Gas Tariff ($ per customer supply point per month)	0.06893 -17%	0.06548 -5%	0.06221 -5%	0.05910 -5%	0.05615 -5%	0.05334 -5%
Initial Registration Fee ($ per participant)	5,760 +0%	19,000 +230%	TBC	TBC	TBC	TBC

Figure 10 Projected Victorian FRC gas fees



Note: Real values are the nominal amounts adjusted for inflation. Prices have been calculated relative to the 2018-19 price.

1.8.2 Queensland FRC Gas

Fees

The current Queensland FRC Gas fee is $0.22256 per customer supply point/month.

This fee will increase to $0.24482 (+10%) in 2019-20 and in the future four years in line with the prior year published estimates. This fee has been reduced over recent years to return an accumulated surplus to participants and the planned increases reflect the fee returning to its base level.

The initial registration fee has now been updated for the first time since AEMO's inception to reflect the estimated costs in facilitating registrations.

Table 14 **Projected Queensland FRC gas fees**

Fee	Actual 2018-19	Budget 2019-20	Estimate 2020-21	Estimate 2021-22	Estimate 2022-23	Estimate 2023-24
FRC fee ($ per customer supply point per month)	0.22256 +0%	0.24482 +10%	0.26930 +10%	0.29623 +10%	0.32585 +10%	0.35844 +10%
Initial Registration Fee ($ per participant)	5,760 +0%	17,000 +195%	TBC	TBC	TBC	TBC

1.8.3 South Australia FRC Gas

Fees

The current South Australian FRC Gas fee is $0.21484 per customer supply point/month.

This fee will decrease to $0.20839 (-3%) in 2019-20. Similar decreases are then expected for the following two years.

The operating costs remain stable in this function.

The initial registration fee has now been updated for the first time since AEMO's inception to reflect the estimated costs in facilitating registrations.

Table 15 **Projected South Australia FRC gas fees**

Fee	Actual 2018-19	Budget 2019-20	Estimate 2020-21	Estimate 2021-22	Estimate 2022-23	Estimate 2023-24
FRC fee ($ per customer supply point per month)	0.21484 -13%	0.20839 -3%	0.20214 -3%	0.19608 -3%	0.19608 +0%	0.19608 +0%
Initial Registration Fee ($ per participant)	11,300 +0%	16,000 +42%	TBC	TBC	TBC	TBC

1.8.4 New South Wales FRC Gas

Fees

The current New South Wales FRC Gas fee is $0.16410 per customer supply point/month.

This fee will decrease to $0.15097 (-8%) in 2019-20 and will continue to decrease in future years due to system costs being fully amortised by end of 2020-21.

Table 16 **Projected New South Wales FRC gas fees**

Fee	Actual 2018-19	Budget 2019-20	Estimate 2020-21	Estimate 2021-22	Estimate 2022-23	Estimate 2023-24
FRC fee ($ per customer supply point per month)	0.16410 +1%	0.15097 -8%	0.13889 -8%	0.12778 -8%	0.11756 -8%	0.10816 -8%

1.8.5 Western Australia FRC Gas

Fees

The current Western Australia FRC Gas fee is $0.13485 per customer supply point/month.

This fee will decrease to $0.12811 (-5%) in 2019-20 to return a prior year surplus.

Table 17 **Projected Western Australia FRC gas fees**

Fee	Actual 2018-19	Budget 2019-20	Estimate 2020-21	Estimate 2021-22	Estimate 2022-23	Estimate 2023-24
FRC fee ($ per customer supply point per month)	0.13485 +0%	0.12811 -5%	0.12171 -5%	0.11562 -5%	0.11793 +2%	0.12029 +2%
Initial Registration Fee – member	12,951	13,163	13,375	13,587	13,799	14,011
Initial Registration Fee – associate member	2,590	2,632	2,675	2,717	2,760	2,802
Annual Fee - Member	19,905	20,231	20,562	20,898	21,240	21,588
Annual Fee - Associate Member	3,881	3,945	4,009	4,075	4,141	4,209

Note: associate members are self-contracting users that are party to the WA Gas Retail Market Agreement.

1.9 Eastern and South Eastern Gas Statement of Opportunity (GSOO)

Purpose of this function	**The purpose of the GSOO is to report the supply adequacy of eastern and south-eastern Australian gas markets to meet energy needs. AEMO reports on demand and supply, and delivery constraints projected for the next 20 years.** **Retailers across the FRC gas market jurisdictions are currently charged for GSOO costs at a flat rate per customer supply point.**
Fees	The current GSOO fee is $0.03799 per customer supply point/month. This fee is will increase to $0.03989 (+5%) in 2019-20 and the following two forward years due to the continued uplift of long-term forecasting capability along with additional insight reports to stakeholders.

Table 18 **Projected GSOO fees**

Fee	Actual 2018-19	Budget 2019-20	Estimate 2020-21	Estimate 2021-22	Estimate 2022-23	Estimate 2023-24
Gas Statement of Opportunities ($ per customer supply point per month)	0.03799 +8%	0.03989 +5%	0.04188 +5%	0.04398 +5%	0.04398 +0%	0.04398 +0%

1.10 Gas Supply Hub (GSH)

Purpose of this function	**AEMO implemented a Gas Supply Hub (GSH) at Wallumbilla in March 2014, at the request of the Government.** **The GSH provides an exchange for the wholesale trading of natural gas to enable improved wholesale trading for an east coast gas market affected by significant liquefied natural gas (LNG) exports in Queensland. Through an electronic platform, GSH participants can trade standardised, short-term physical gas products at each of the three foundation pipelines connecting at Wallumbilla.** **AEMO centrally settles transactions, manages prudential requirements and provides reports to assist participants in managing their portfolio and gas delivery obligations.** **In June 2016 a trading location at Moomba was established.** **In March 2017 the three trading locations at Wallumbilla were replaced with a single Wallumbilla location, through what is known as the Optional Hub Services (OHS) model.**
Fees	Fees are determined outside of AEMO's budget and fee setting process and is set within the Gas Supply Hub exchange agreement with consultation with stakeholders when changes are made. The GSH fee schedule is included in this report for information purposes.

Table 19 **Projected GSH fees**

Fee	Fee type	Actual 2018-19	Budget 2019-20
Trading participants	Fixed Fee - one licence per annum	12,000	12,000
	Fixed Fee - additional licence per annum	12,000	12,000
	Variable transaction fee		
	- Daily product fee ($/GJ)	0.03	0.03
	- Weekly product fee ($/GJ)	0.02	0.02
	- Monthly product fee ($/GJ)	0.01	0.01
Reallocation participants	Fixed fee per annum	9,000	9,000
Viewing participants	Fixed fee per annum	3,600	3,600

1.11 Gas Capacity Trading (CTP)

Purpose of this function	**The purpose of the Capacity Trading Platform is to facilitate the secondary trading of pipeline capacity.** **The following broad services are provided:** • **Settlement and prudential management of capacity transactions.** • **Exchange transaction information with facility operators to facilitate the delivery of capacity transactions.** • **Update STTM contract rights and DWGM accreditations in accordance with transactions in integrated products.**
Fees	The CTP market went live 1 March 2019. AEMO's fees are calculated in accordance with the Structure of Participant Fees for Capacity Trading Platform, Day-ahead Auction, Operational Transportation Service Code Panel, consulted on and published 12 February 2019. There is minimal change to the fees for 2019-20. Registration fees apply from 1 July 2019, as per the published Structure of Participant Fees document.

Table 20 **Projected CTP fees**

Fee	Fee type	1 March - 30 June	Budget 2019-20	Estimate 2020-21	Estimate 2021-22
Capacity Trading Platform (CTP)	Fixed Fee - one licence per annum (commodity & capacity)	12,000	12,000	12,000	12,000
	Fixed Fee - one licence per annum (capacity only)	7,000	7,000	7,000	7,000
	Variable transaction fee				
	- Daily product fee ($/GJ)	0.043	0.044	0.045	0.046
	- Weekly product fee ($/GJ)	0.033	0.034	0.035	0.036
	- Monthly product fee ($/GJ)	0.023	0.024	0.025	0.026
	Initial Registration Fee – Part 24 Facility Operators ($ per participant)	Nil	15,000	TBC	TBC

Note: the variable transaction fees for CTP are including a fee of $0.003 relating to OTS code panel.

1.12 Day Ahead Auction (DAA)

Purpose of this function	**The purpose of the Day-ahead Auction is to reallocate contracted but unnominated transportation capacity to shippers that value it the most.** **The following broad services are provided:** • **Auction platform to allocate capacity to shippers.** • **Settlement and prudential management of auction transactions.** • **Provide auction results to facility operators to facilitate the delivery of auction transactions.** • **Update DWGM accreditations in accordance with transactions to a DWGM interface point.**
Fees	The Day ahead Auction market went live 1 March 2019. AEMO's fees are calculated in accordance with the Structure of Participant Fees for Capacity Trading Platform, Day-ahead Auction, Operational Transportation Service Code Panel, consulted on and published 12 February 2019. There is minimal change to the fees for 2019-20. Registration fees apply from 1 July 2019, as per the published Structure of Participant Fees document.

Table 21 **Projected DAA fees**

Fee	Fee type	1 March - 30 June	Budget 2019-20	Estimate 2020-21	Estimate 2021-22
Day ahead Auction (DAA)	Variable fee ($/GJ)	0.033	0.034 3%	0.035 3%	0.036 3%
	Initial Registration Fee - Auction participants ($ per participant)	Nil	15,000	TBC	TBC

Note: the variable fee for DAA is including a fee of $0.003 relating to OTS code panel.

1.13 Operational Transportation Service (OTS) Code Panel

Purpose of this function	**To assess and consult on proposals to amend the Operational Transportation Service Code and develop proposals to amend the Code, prepare impact and implementation reports on proposals, make recommendations in relation to proposals, report to the AER on proposals, develop proposals at the request of the AER and other related functions.**
Fees	OTS code panel fee of $0.003 per GJ is levied on all CTP and DAA trades.
Other notes	AEMO is permitted to recover costs incurred in relation to the OTS Code Panel including establishing and operating the OTS Code Panel, the participation of the AEMO member of the OTS Code Panel and providing services to facilitate the functioning of the OTS Code Panel.

Table 22 **Projected OTS Code Panel fees**

Fee	Fee type	1 March - 30 June	Budget 2019-20	Estimate 2020-21	Estimate 2021-22
OTS Code Panel ($/GJ)	Variable fee ($/GJ)	0.003	0.003	0.003	0.003

1.14 Gas Bulletin Board (GBB)

Purpose of this function	**The Gas Bulletin Board (GBB) is a communications system that provides information relating to gas production, transmission, storage and usage for facilities that are connected to the east coast gas market.** **GBB provides market participants timely data to assist in decision making. This includes capacity outlooks, nominations and forecasts, actual flows, linepack adequacy and additional information for maintenance planning.**
Fees	The 2019-20 fee is $0.00054/GJ for Producers and $0.00268/GJ for Participants in Wholesale Gas Markets. These fees have increased by 7% in 2019-20 and 8% per year for the following two years to recover the system investment costs relating to the AEMC rule changes.

Table 23 **Projected GBB fees**

Fee	Actual 2018-19	Budget 2019-20	Estimate 2020-21	Estimate 2021-22	Estimate 2022-23	Estimate 2023-24
Producer ($/GJ)	0.00050	0.00054 7%	0.00057 8%	0.00058 8%	0.00051 -10%	0.00052 -10%
Participants in Wholesale Gas Market ($/GJ)	0.00250	0.00268 7%	0.00289 8%	0.00312 8%	0.00312 0%	0.00312 0%

1.15 Western Australian Gas Services Information (GSI)

Purpose of this function	**The GSI function includes the GBB (WA) and WA GSOO. The objectives of the GBB (WA) and WA GSOO is to ensure:** • **Security, reliability and availability of the supply of natural gas.** • **Efficient operation and use of natural gas services.** • **Efficient investment in natural gas services.** • **Facilitation of competition in the use of natural gas services.** **Similar to the GBB on the East Coast, the WA GBB is an information website hub to provide flow information on gas, transmission, storage, emergency management with supply disruptions, and demand in WA.** **The WA GSOO is an annual planning document providing medium to long-term outlook of WA gas supply and demand and transmission and storage capacity.**
Fees	The current GSI recovery is $1.520m. The recovery fee has increased to $1.708m (+12%) in 2019-20 due to an increase in operational costs which was approved by the ERA on the 14 June 2019. For further information, please refer to the AEMO Allowable Revenue and Forecast Capital Expenditure 2019/20 to 2021/2022 final determination on the ERA website.

Table 24 **Projected GSI fees**

Revenue requirement	Actual 2018-19	Budget 2019-20	Estimate 2020-21	Estimate 2021-22
AEMO GSI revenue requirement ($'000)	1,520	1,708 +12%	2,005 +17%	2,006 +0%

1.16 Other budgeted revenue requirements

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

Table 25 **Other Revenue Requirements**

Other revenue requirement	Actual 2018-19	Budget 2019-20
SA Planning ($'000)	1,000	1,000
Settlement Residue Auctions ($'000)	295	718

The Settlement Residue Auctions revenue requirement has increased to $718k in 2019-20 reflecting both amortisation of system enhancements and costs incurred in facilitating a secondary trading market, including the design work, rule changes and scoping of a capital investment project that were previously not included in the 2018-19 fee. This project was approved to be commenced in August 2018 and the secondary trading market is scheduled to go live on 1 October 2019.

1.17 Energy Consumers Australia (ECA)

Purpose of this function	**To promote the long-term interests of energy customers, residential and small business customers.**
Fees	AEMO is required to recover the funding for the ECA from market participants (i.e. pass through recovery). Total expenditure budgeted by the ECA to be recovered in 2019-20 is $7.6m (2018-19: $7.3m). The electricity ECA fee is $0.01082 per connection point per week in 2019-20 (10% increase). The 2018-19 fee was reduced to return a prior year surplus, fee increases in 2019-20 reflect the ECA budgeted revenue requirement. The gas ECA fee is $0.03556 per customer supply point per month in 2019-20 (0% increase).
Other notes	For any questions on the ECA budgeted revenue requirement, contact Elizabeth Lawler, Associate Director, Operations (Elizabeth.Lawler@energyconsumersaustralia.com.au).

Table 26 **ECA fees**

AEMO's ECA fees	Actual 2018-19	Budget 2019-20
Electricity ($ / connection point for small customers per week)	0.00985 +1%	0.01082 +10%
Gas ($ / customer supply point per month)	0.03547 +11%	0.03556 +0%

1.18 Economic Regulation Authority (ERA)

Purpose of this function	**To ensure that WA has a fair, competitive and efficient environment for consumers and businesses.**
Fees	AEMO is required to recover the funding for the ERA from WEM market customers and generators and gas shippers (i.e. pass through recovery). Total expenditure budgeted by the ERA to be recovered in 2019-20 is $6.66m (+33% increase) (2018-19: $5.03m). The WEM ERA fee is $0.179 per MWh in 2019-20 (31% increase).
Other notes	For any questions on the ERA budget in 2019-20, contact Pam Herbener, Director, Corporate Services at pam.herbener@erawa.com.au

Table 27 **ERA revenue requirements**

ERA revenue requirement	Actual 2018-19	Budget 2019-20
WEM regulator fee ($'000)	3,948	5,021
Rule change panel ($'000)	1,008	1,561
GSI ($'000)	70	80

Table 28 **ERA WEM fee**

ERA WEM fee	Actual 2018-19	Budget 2019-20
ERA WEM fee ($/MWh)	0.137 11%	0.179 +31%

2. AEMO financials

2.1 Final Consolidated Profit and Loss 2019-20

	AEMO (excl. Vic TNSP)			Victorian TNSP			AEMO			Note
	Budget 2018-19 $'000	Budget 2019-20 $'000	Variance $'000	Budget 2018-19 $'000	Budget 2019-20 $'000	Variance $'000	Budget 2018-19 $'000	Budget 2019-20 $'000	Variance $'000	
REVENUE										
Fees and Tariffs	172,646	186,896	14,251	-	-	-	172,646	186,896	14,251	A
TUoS Income	-	-	-	462,312	549,555	87,243	462,312	549,555	87,243	B
Establishment Fees	-	-	-	-	-	-	-	-	-	
PCF Fees	1,000	1,000	-	-	-	-	1,000	1,000	-	
Settlement Residue	-	-	-	56,771	63,000	6,229	56,771	63,000	6,229	
Other Revenue	5,655	10,461	4,806	42,713	59,884	17,171	48,368	70,345	21,977	C
TOTAL REVENUE	**179,301**	**198,357**	**19,056**	**561,796**	**672,439**	**110,643**	**741,097**	**870,797**	**129,701**	
NETWORK CHARGES	-	-	-	583,324	653,394	70,070	583,324	653,394	70,070	
NET REVENUE	**179,301**	**198,357**	**19,056**	**(21,528)**	**19,045**	**40,573**	**157,773**	**217,402**	**59,630**	
OPERATING EXPENDITURE										
Total Labour and Contractors ~	117,118	131,607	14,489	7,265	9,625	2,361	124,383	141,232	16,849	D
Total Labour~	128,025	174,372	46,347	7,376	9,480	2,104	135,400	183,852	48,451	
Capitalised internal labour	(13,089)	(44,273)	(31,184)	(111)	(115)	(4)	(13,200)	(44,388)	(31,188)	
Contractors	2,183	1,508	(674)	-	260	260	2,183	1,768	(414)	
Consulting	18,207	19,846	1,640	5,370	4,578	(792)	23,577	24,424	847	E
Fees-Agency, Licence and Audit	2,357	2,166	(191)	-	-	-	2,357	2,166	(191)	
Information Technology and Telecommunication	24,672	31,333	6,661	0	188	188	24,672	31,522	6,849	F
Occupancy	7,531	7,467	(65)	-	-	-	7,531	7,467	(65)	
Training & Recruitment	3,194	4,019	824	56	64	8	3,250	4,082	832	
Travel & Accommodation	3,298	3,424	126	33	78	46	3,331	3,502	172	
Other Expenses from Ordinary Activities	7,428	8,418	990	3	11	8	7,431	8,429	998	G
Depreciation and Amortisation	22,709	31,017	8,308	9	9	-	22,718	31,026	8,308	H
Financing Costs	609	869	260	0	-	(0)	609	869	260	
OPERATING EXPENDITURE (excluding external recoverable costs)	**207,123**	**240,166**	**33,042**	**12,735**	**14,553**	**1,817**	**219,859**	**254,719**	**34,860**	
External Recoverable Consultancy	500	1,367	867	1,480	1,821	341	1,980	3,188	1,208	
TOTAL OPERATING EXPENDITURE	**207,623**	**241,533**	**33,909**	**14,215**	**16,374**	**2,158**	**221,839**	**257,907**	**36,068**	
ANNUAL SURPLUS / (DEFICIT)	**(28,323)**	**(43,176)**	**(14,852)**	**(35,743)**	**2,672**	**38,414**	**(64,066)**	**(40,504)**	**23,561**	
Transfer to Reserves / Recoveries	4,819	4,500	(319)	(6,188)	(5,887)	301	(1,369)	(1,387)	(18)	
Brought Forward Surplus	6,143	(3,329)	(9,472)	42,145	3,085	(39,060)	48,288	(244)	(48,532)	
ACCUMULATED SURPLUS / (DEFICIT)	**(17,361)**	**(42,005)**	**(24,643)**	**214**	**(130)**	**(344)**	**(17,147)**	**(42,135)**	**(24,988)**	
Contributed capital relating to Vic Wholesale gas market	(8,704)	(8,704)	-	-	-	-	(8,704)	(8,704)	-	
ADJUSTED ACCUMULATED SURPLUS / (DEFICIT)	**(26,064)**	**(50,710)**	**(24,643)**	**214**	**(130)**	**(344)**	**(25,851)**	**(50,839)**	**(24,988)**	

~Total labour includes both opex and capex labour.

Notes to the consolidated profit and loss 2019-20

Revenue

A TUOS income is higher due to a lower brought forward surplus, higher easement tax, network charges and inter-regional TUOS costs.

B Increase in settlement residue reflecting higher auction proceeds.

C Higher other revenue due to an increase in funded network charges, a cost pass-through for AEMO in the Victorian TNSP function and higher connection revenue.

Expenditure

D Labour includes a provision for an Enterprise Agreement increase and an uplift in expertise to manage the growth, pace and complexity of the energy industry. Resource capability on initiatives including the Integrated System Plan (ISP), Regulatory Investment Tests for Transmissions (RIT-T) and Reliability and Emergency Reserve Trading (RERT) are representative of the contemporary challenges requiring additional resources in addition to expertise to support the significant digital rate of change.

E Consulting costs show a slight uplift in the specialist advice and support regarding initiatives such as the digital uplift, increased cyber security requirements and the management of distributed energy resources.

F IT and Telecommunications costs are materially higher reflecting new security analytics and vulnerability management, additional licences for organisational headcount and post project software support (including extrication from Western Power systems). Elevation of cloud computation for modelling and a new strategic agreement with the Bureau of Meteorology for extreme weather forecasts also contribute to the increase.

G Other Expenses from Ordinary Activities are higher due to an annual increment for Insurance and initiatives supporting Workplace Health, Safety & Environment.

H Depreciation and Amortisation are $8.3m higher than 2018-19 due to the increased project program planned for 2019-20 onwards that is detailed further in section 3.

2.2 Balance Sheet 2019-20

	Forecast 2018-19 $'000	Budget 2019-20 $'000	Variance $'000
ASSETS			
Current Assets			
Cash and Short Term Deposits	22,621	7,343	(15,278)
Participant compensation fund	7,414	8,574	1,160
Receivables	82,836	93,512	10,677
Other Current Assets	7,075	5,965	(1,110)
Total Current Assets	**119,945**	**115,394**	**(4,552)**
Non - Current Assets			
Intangible Assets - Software	84,765	208,873	124,107
Property, Plant and Equipment	35,222	61,256	26,034
Trade and Other Receivable	1,058	390	
Total Non Current Assets	**121,045**	**270,519**	**149,474**
TOTAL ASSETS	**240,990**	**385,913**	**144,922**
LIABILITIES			
Current Liabilities			
Payables	76,695	96,506	19,811
Borrowings	15,000	15,000	-
Provisions	26,367	28,568	2,201
Other Current Liabilities	11,471	10,838	(633)
Total Current Liabilities	**129,532**	**150,912**	**21,379**
Non - Current Liabilities			
Borrowings	82,020	246,845	164,825
Provisions	1,855	1,909	54
Lease Liability	6,683	5,886	(797)
Total Non Current Liabilities	**90,558**	**254,640**	**164,082**
TOTAL LIABILITIES	**220,090**	**405,552**	**185,462**
NET ASSETS / (LIABILITIES)	**20,900**	**(19,640)**	**(40,540)**
EQUITY			
Capital contribution	7,093	7,093	-
Participant compensation fund reserve	7,533	8,693	1,160
Land reserve	2,946	3,173	227
Accumulated surplus/(deficit)	3,328	(38,599)	(41,927)
TOTAL EQUITY	**20,900**	**(19,640)**	**(40,540)**

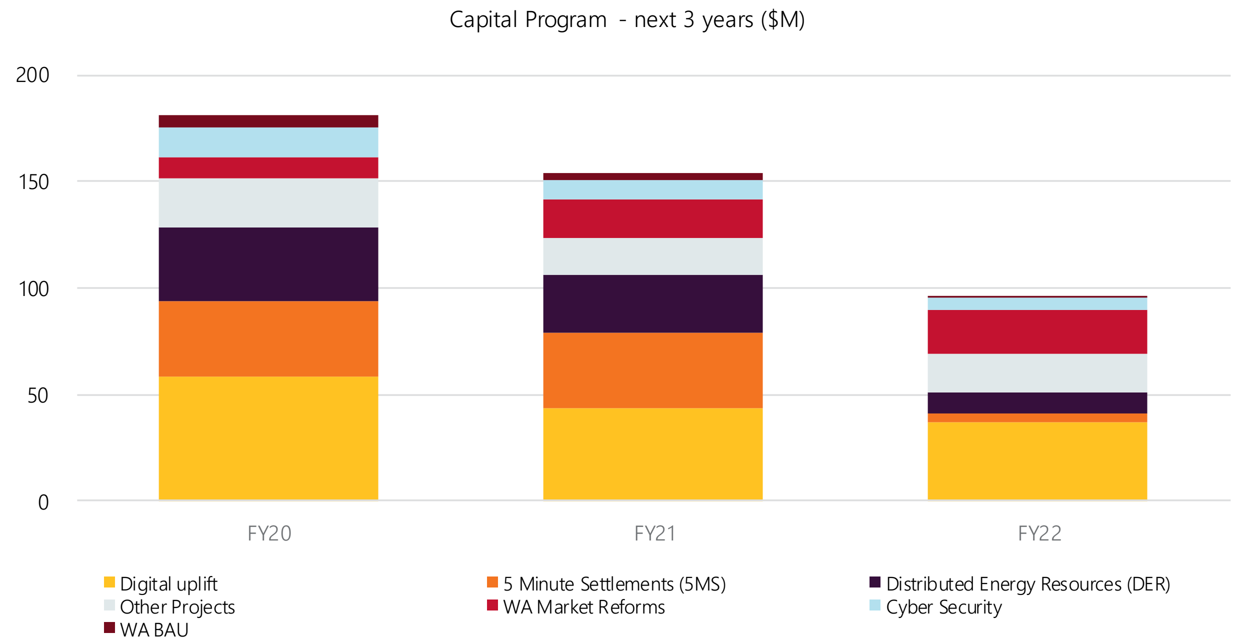
2.3 Cash Flow Statement 2019-20

	Budget 2019-20 ($'000)
Cash at the beginning of the period at 1 July 2019	**22,621**
Receipts from customers	945,146
Payments to suppliers and employees	(944,079)
Net cashflows from operating activities	**1,067**
Payments for property, plant & equipment	(181,170)
Net cashflows from investing activities	**(181,170)**
Proceeds from borrowings	164,825
Repayment of borrowings	-
Net cashflows from financing activities	**164,825**
Cash at the End of Period at 30 June 2020	**7,343**

3. AEMO capital expenditure program

The capital expenditure budget for 2019-20 is $181.2m and the key initiatives are outlined in figure 11 below.

Figure 11 Capital initiatives for 2019-20 and two years after



The key capital initiatives are:

- Digital Replacement – replacing the ageing IT systems and platforms which includes the consolidation of applications and movement to hosting in the cloud.
- 5 Minute Settlements – to reduce the NEM settlement cycle from 30 minutes to 5 minutes.
- DER impacts on Power System Security – includes development and implementation of a national database of distributed energy resources, the launch of Australia's first virtual power plant trial and a program to allow consumer usage data to be made available to customers to enhance competition.
- Cyber Security – security-by-design will underpin cyber security defences which will uplift the ability of AEMO and the industry to identify, protect, detect, respond to, and recover from cyber threats.
- Other programs – funding to implement new WA Market reforms and delivering a range of projects to implement new market rules will ultimately reduce operating costs for both AEMO and the industry. Other projects will improve services whilst reducing duplicated investment and lowering entry barriers to enhance competition.

The digital replacement program is the largest investment over the budget period.

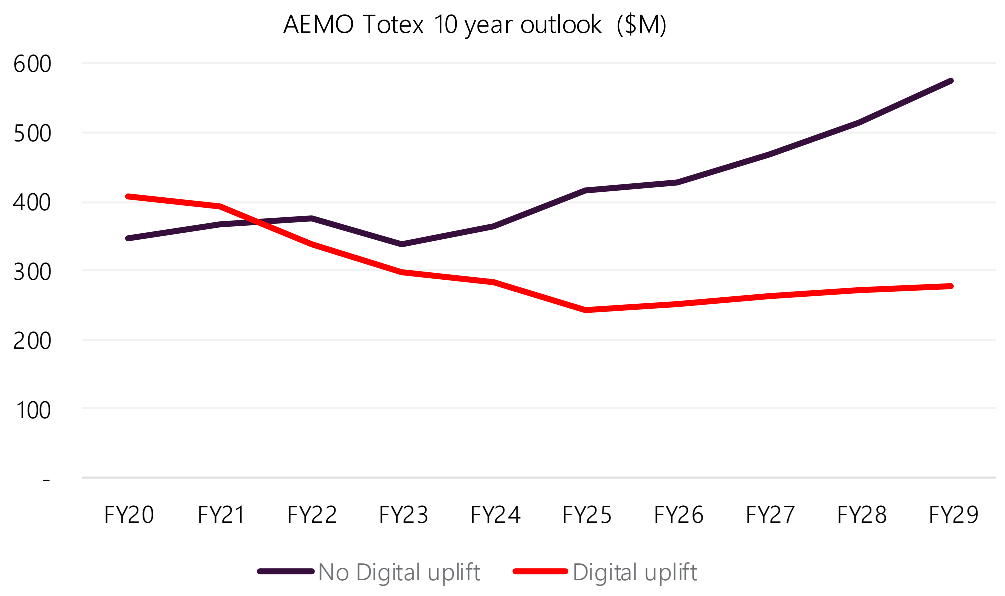
AEMO's current technology infrastructure was developed in an era where energy markets were stable and the use of data was predictable and limited.

Taking into account the exponentially faster rates of digital change and the technology requirements to deliver significant initiatives including the 5 Minute Settlement (5MS) Program and WA Market reform, AEMO conducted an assessment of its technology requirements and concluded that the preferred option is to replace the current ageing infrastructure.

Ultimately, this investment will deliver a new platform and services that will reduce operating costs for both AEMO and the industry and provide services that support the transition to a new energy environment. AEMO's 10-year projections show lower overall Totex (combination of operating and capital costs) if the digital investment is made now, while not investing will incur a significant cost burden over time as AEMO's ageing infrastructure becomes more costly to maintain.

Figure 12 provides a comparison of the estimated costs, over a 10 year period, between investing in the digital uplift compared to retaining our current technology.

Figure 12 **AEMO total operating and capital cost 10-year outlook**



Appendix A. Fee schedules

A1.1 Fee schedule of electricity functions

Table 29 **Budgeted total revenue requirement by function**

Function	Budget 2019-20 $'000	Rate	Paying Participants
NEM			
General Fees (unallocated)	26,801	$0.14940/MWh of customer load	Market Customers
Allocated Fees			
Market Customers	33,769	$0.18825/MWh of customer load	Market Customers
Generators * and Market Network Service Providers	28,766	Daily rate calculated on 2018 capacity/energy basis	Generators and Market Network Service Providers
NEM Revenue Requirement	**89,336**		
Participant Compensation Fund	1,000	Daily rate calculated on capacity/ energy basis	Scheduled Generators, Semi-Scheduled Generators and Scheduled Network Service Providers
Registration fees	3,500		
Other	7,322		Dependent on service provided
TOTAL NEM	**101,158**		
FRC ELECTRICITY			
FRC Operations	13,558	$0.02550 per connection point per week	Market Customers with a Retail Licence
TOTAL FRC ELECTRICITY	**13,558**		
National Transmission Planner	5,454	$0.03040/MWh of customer load	Market Customers
Energy Consumers Australia	5,707	$0.01082/connection point for small customers/week	Market Customers
Additional Participant ID		$5,000 per additional participant ID	Existing Participants
Incremental charge		$250 per hour	Dependent on service provided
WA WHOLESALE ELECTRICITY MARKET			
WEM Market Operator fee	13,277	$0.362/MWh	Market Customers and Generators
WEM System Management fee	18,302	$0.499/MWh	Market Customers and Generators
WA WEM Revenue Requirement	**31,579**		

* Excluding non-market non-scheduled generators.

Table 30 **Fee schedule of new NEM registrations**

Application type	2019-20 $
Registration as Scheduled Market Generator [A]	23,000
Registration as Semi-Scheduled Market Generators	31,000
Registration as Scheduled Non-Market Generator	17,000
Registration as Semi-Scheduled Non-Market Generators	26,000
Registration as Non-Scheduled Market Generator	20,000
Registration as Market Customer	11,000
Registration as Market Small Generation Aggregator	11,000
Transfer of Registration	11,000
Registration as Metering Co-ordinator (MC)	11,000
Registration as Market Ancillary Service Provider	16,000
Registration as Non-Scheduled Non-Market Generator	14,000
Registration as Network Service Provider	10,000
Registration as Trader	14,000
Registration as Reallocator	13,000
Classification of generating units as frequency control ancillary services generating units [B]	10,000
Classification of load as frequency control ancillary services load - new ancillary services or classify load in a new region [C]	10,000
Classification of a Dedicated Connection Asset	5,000
Amendment of the relevant plant associated with its existing load classification, and/or aggregating further load to its existing load classification for frequency control ancillary services purposes.	2,000
Registration as Intending Participants	6,000
Exemption from registration	6,000
Disbursements Charge - Additional Energy Conversion Model – Semi Scheduled Market Generator	5,000
Disbursements Charge - Additional Energy Conversion Model – Non Scheduled Market Generator	2,500

A. Each category of Generator in this table includes applications made by persons intending to act as intermediaries.
B. This fee is additional to the fee required to register as a Generator
C. This fee is additional to the fee required to register as a Market Customer or Market Ancillary Service Provider.

Table 31 **Fee schedule of new WA WEM registrations**

Application type	2019-20 $
Rule Participant Registration Application Fee	1,130
Facility Registration Application Fee	570
Facility Transfer Application Fee	650
Conditional Certification of Reserved Capacity	1,130
Resubmission - Application for Early Certified Reserved Capacity	10,360
Consumption Deviation Application reassessment Application Fee for Non-Temperature Dependent Loads and for Relevant Demand (clauses 4.26.2CC and 4.28.9B of the WEM Rules)	500

Note: Consumption Deviation Application reassessment Application Fee is effective from 1 October 2019.

Table 32 **Fee schedule of new Power of Choice accreditations**

Application type	2019-20 $
Initial Deposit - Embedded Network Manager	2,000
Initial Deposit - Metering Data Providers	5,000
Initial Deposit - Metering Providers	5,000
Incremental charge rate per hour	250

A1.2 Fee schedule of gas functions

Table 33 **Gas fee by function**

Function	Rate 2019-20	Basis
Vic Declared Wholesale Gas Market		
Energy Tariff	0.08713	$/GJ withdrawn
Distribution Meter	1.36970	$/day per meter
PCF	Nil	$/GJ withdrawn
VIC Gas FRC	0.06548	$ per customer supply point/ mth
QLD Gas FRC	0.24482	$ per customer supply point/ mth
SA Gas FRC	0.20839	$ per customer supply point/ mth
NSW/ ACT Gas FRC	0.15097	$ per customer supply point/ mth
WA Gas FRC	0.12811	$ per customer supply point/ mth
Annual fee - members	20,231	per annum
Annual fee - associate members*	3,945	per annum
STTM		

Function	Rate 2019-20	Basis
Activity Fee	0.04258	$/GJ withdrawn
PCF Fee - Syd	Nil	$/GJ withdrawn per hub per ABN
PCF Fee - Adel	Nil	$/GJ withdrawn per hub per ABN
PCF Fee - Bris	Nil	$/GJ withdrawn per hub per ABN
Energy Consumers Australia	0.03556	$ per customer supply point/ mth
Gas Statement of Opportunities	0.03989	$ per customer supply point/ mth
Gas Supply Hub		
Fixed Fee – Trading Participants	12,000	$ per licence per annum
Fixed Fee - Trading Participants	12,000	$ per additional licence per annum
Fixed Fee - Reallocation participants	9,000	$ per licence per annum
Fixed Fee - Viewing participants	3,600	$ per licence per annum
Variable Fee - Daily product fee	0.03	$/GJ
Variable Fee - Weekly product fee	0.02	$/GJ
Variable Fee - Monthly product fee	0.01	$/GJ
Gas Trading Platform		
Fixed Fee - commodity & capacity	12,000	$ per licence per annum
Fixed Fee - capacity only	7,000	$ per licence per annum
Variable Fee - Daily product fee	0.044	$/GJ
Variable Fee - Weekly product fee	0.034	$/GJ
Variable Fee - Monthly product fee	0.024	$/GJ
Day Ahead Auction	0.034	$/GJ
Gas Bulletin Board		
Producers	0.00054	$/GJ withdrawn
Wholesale market participants	0.00268	$/GJ withdrawn
WA Gas Services Information	1,708	$'000
Additional Participant ID	5,000	$ per additional participant ID
Incremental charge	250	$ per hour

* Associate members are self-contracting users that are party to the WA Gas Retail Market Agreement.

Table 34 **Fee schedule of new gas registrations**

Market	Budget 2019-20	Basis
Victoria FRC Gas	19,000	$ per participant

Market	Budget 2019-20	Basis
QLD FRC Gas	17,000	$ per participant
SA FRC Gas	16,000	$ per participant
NSW FRC Gas	N/A	N/A
WA FRC Gas	13,163	$ per member
WA FRC Gas	2,632	$ per associate member
Victoria Wholesale Gas	N/A	N/A
STTM	N/A	N/A
Capacity Trading Reform/ Day ahead auction – part 24 Facility Operator	15,000	$ per facility operator
Day ahead auction – Auction Participant	15,000	$ per participant
BB allocation agents	15,000	$ per participant
BB transportation facility user	11,000	$ per participant
BB capacity transaction reporting agents	11,000	$ per participant

Symbols and abbreviations

Term	Definition
5MS	5 Minutes Settlement
B2B	Business-to-Business
CTP	Capacity Trading Platform
DAA	Day Ahead Auction
DER	Distributed Energy Resource
DWGM	Declared Wholesale Gas Market
ERA	Economic Regulation Authority
FRC	Full Retail Contestability
GBB	Gas Bulletin Board
GJ	Gigajoule
GSOO	Gas Statement of Opportunities
ESOO	Electricity Statement of Opportunities