Final

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Comparable Costs of Operating Electricity Markets in Different Jurisdictions

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ACKNOWLEDGEMENTS

Part of our approach has been to directly approach benchmark jurisdictions to supplement publicly available data with more tailored information and insights. We have reached out to our contacts to better understanding the drivers and rationale behind publicly available data, obtain non-public or less transparent information, and to gain insights related to ERA's queries.

We would like to thank:

- John Clarke, General Manger Operations, Transpower NZ Ltd (New Zealand System Operator);
- Shane Dinnan, Head of Energy Markets, NZX Limited (New Zealand Market Operator);
- Toh Seong Wah, Chief Executive Officer, Energy Market Company (Singapore Market Operator); and
- Andy Ott, President & CEO, PJM Interconnection (US RTO - Market and System Operator).
- Adam Keech, Executive Director Market Operations, PJM Interconnection (US RTO - Market and System Operator)

Each responded positively to our approaches and made themselves and/or their teams available for detailed teleconference calls. Section 8 draws particularly from insights shared with us.

Much of the other detail we have garnered throughout the report has been supplemented, clarified, confirmed or characterised with greater nuance (or caution) as a result of these conversations. Where necessary to protect the commerciality of any sensitive information made available to us, we have employed ranges, trends, and aggregates, or otherwise made generalised but accurate comments.

1. EXECUTIVE SUMMARY

1.1. Overview

The Wholesale Electricity Market (WEM) rules set out the allowable revenue process for Australian Energy Market Operator (AEMO) WA. Every three years AEMO is required to make a submission to the Economic Regulation Authority (ERA) with a forecast of expenditures. AEMO WA is currently in the process of their fifth allowable revenue process.

In January 2019, AEMO provided market participants with an indicative view of its forecast expenditure and the resulting market fees. The final AEMO expenditure requirement and market fees are to be published and communicated to market participants after the ERA publishes an issues paper and formally commences public consultation.

1.2. Overall Results

We collected data and information for this study from the following markets, as set out in Table 3.

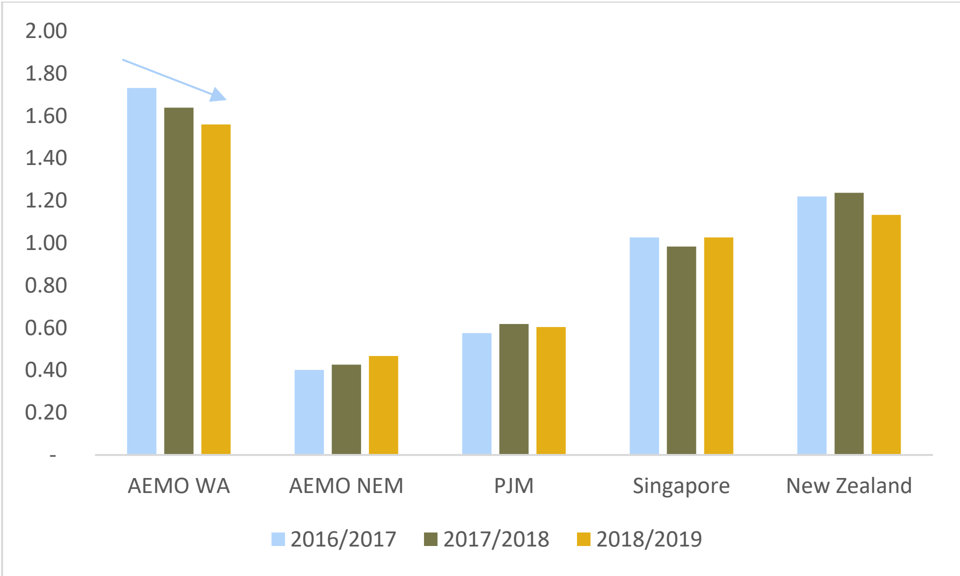
Table 1: Markets Studied

Market	Market Operator	System Operator
Australia, WEM	AEMO WA	AEMO WA
Australia, NEM	AEMO NEM	AEMO NEM
Singapore	EMC (Energy Market Company)	EMA PSO (Energy Market Authority, Power System Operator Division)
New Zealand	NZX	Transpower
USA, PJM Interconnection (PJM)[1]	PJM	PJM
UK	Exelon	Not included in study
Ireland	SEMO and SEMOpx	Not included in study
South Korea	KPX (Korea Power Exchange)	KPX

1 The initial "PJM" originally stood for Pennsylvania, New Jersey, and Maryland, the three original state participants in a near century old power pool. Many more US states now participate in PJM, and the old power pool has evolved into a competitive wholesale electricity market. The PJM Interconnection is the largest electricity wholesale market in the United States, and one of the largest in the world.

At the highest overall level, the costs of AEMO's WA market operations and system management functions are higher than those of other market and system operators that we observed when scaled to be on a per MWh basis. However, it is also the case that the relevant unit costs have decreased across the last three years.

Figure 1: Total Cost per MWh of Combined Market and System Operations



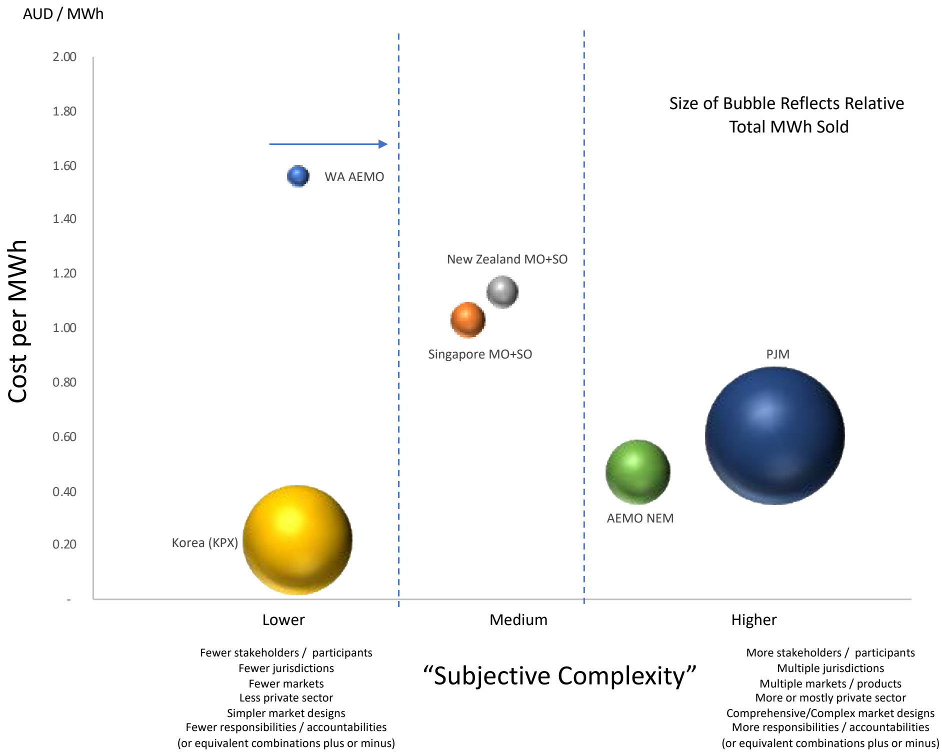
Note: The values demonstrated above are calculated by dividing the total market and system operator cost by the total system demand. These values differ from the market fees, which also include the costs for ERA.

Importantly, both AEMO and PJM are combined system and market operators. Singapore and New Zealand have these two functions performed by two separate entities. The larger markets appear to have a cost advantage often despite also being more complex markets or having additional functional obligations, more participants/stakeholders, and complex multi-jurisdictional regulatory processes.

1.2.1. Complexity

In Figure 2, using a general and partly subjective ranking incorporating number of stakeholders, market design and functionality, level of commercial participation and trading, compactness, and number of regulatory or planning jurisdictions, we have sorted key markets into "lower", "medium" and "higher" levels of complexity that plausibly influence costs (beyond pure scale effects).

Figure 2: Cost vs Complexity



The benchmarking results highlight a significant gap between market and system operations cost in WA and similar costs incurred elsewhere.

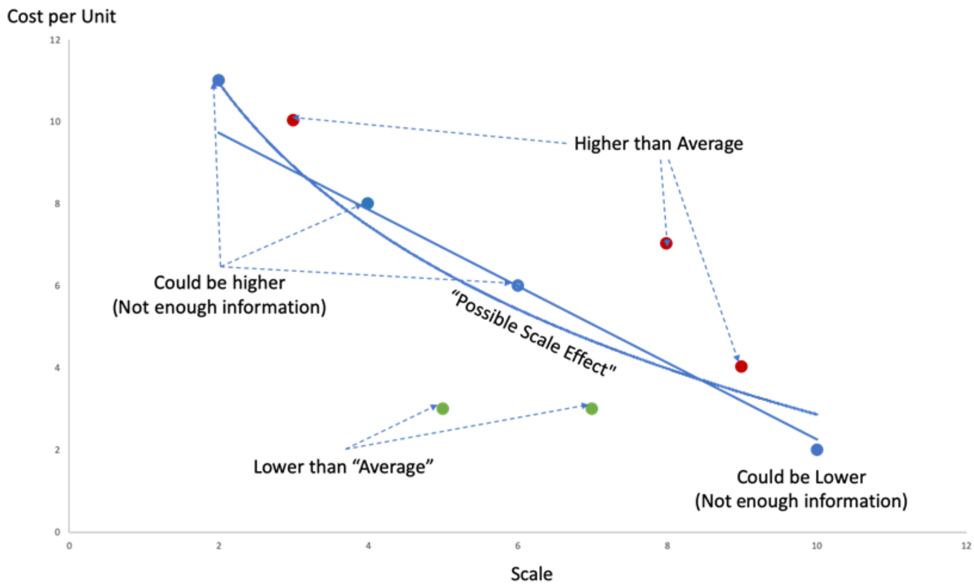
It is reasonable to conclude that scale is a key factor when considering the lower costs (compared to WA, Singapore, and New Zealand) of AEMO NEM and PJM and Korea's KPX market. Scale is not the only factor. The additional complexity of PJM as compared to the NEM appears to offset any additional scale effects arising from PJM's much larger size as compared to the NEM.

In contrast, the comparative simplicity of the Korean market combined with its comparatively large size provides one measure of the pure benefits of scale compared to WA. Notably, the South Korean government controls KEPCO through minimum 51% ownership. South Korea's overall industry structure is simplified by the fact that KEPCO currently supplies over 70 percent of South Korea's generation.[2] KPX has fewer stakeholders and a less complex market development processes to deal with than, say, the NEM or PJM, which have comparable scale and much greater complexity.

2 "KEPCO Investor Presentation," June 2019, available at: https://home.kepco.co.kr/kepco/EN/ntcob/list.do?boardCd=BRD_000242&menuCd=EN030405

Even if scale is considered a significant and material differentiating factor, it is not possible to attribute confidently the entirety of an observed difference to scale when a comparator is an outlier (WA is smaller relative to other markets). Accordingly, the uncertainty implicit in benchmark comparisons (including the choice of "best" functional form relationship) increases, as illustrated by the example shown in Figure 3.

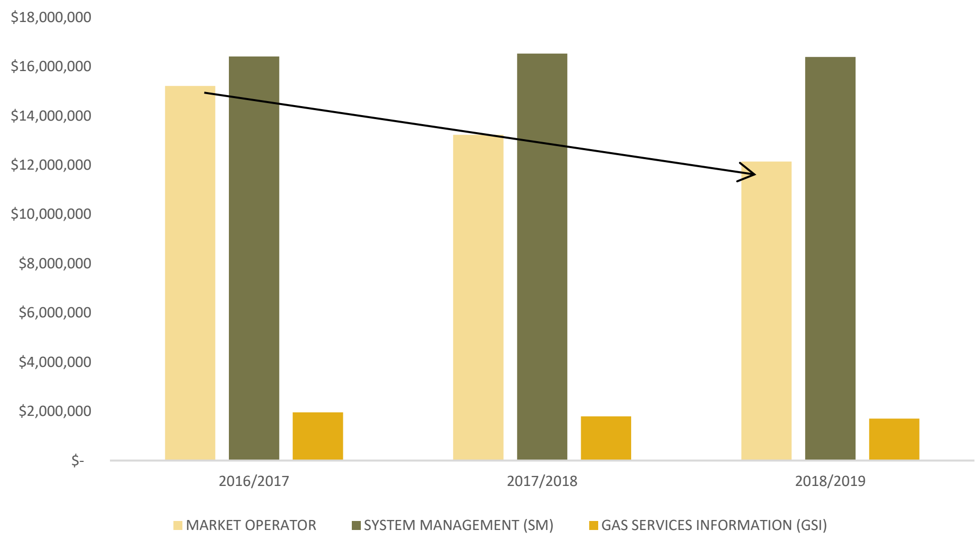
Figure 3: Challenges When Benchmarking Scale



1.2.2. Trends

AEMO assumed the role of the WA's energy market operator from 30 November 2015 and the role of WA's system operator from 1 July 2016. Breaking the data down to distinguish between AEMO's WA market and system operations costs, it is clear that market operations costs have come down the most over the past three years, whereas system operations costs have remained constant, as shown in Figure 4.

Figure 4: Trend in AEMO Market and System Operations Costs



Source: AEMO.

1.3. Deeper Dive Results

We looked at more detailed cost information and relied on discussions with other market and system operators. WA's costs per full time equivalent (FTE) employee have been higher than the others for which similar data is available, but have come down since joining AEMO.

Figure 5: Employment Related Costs per FTE for the Market Operator Function

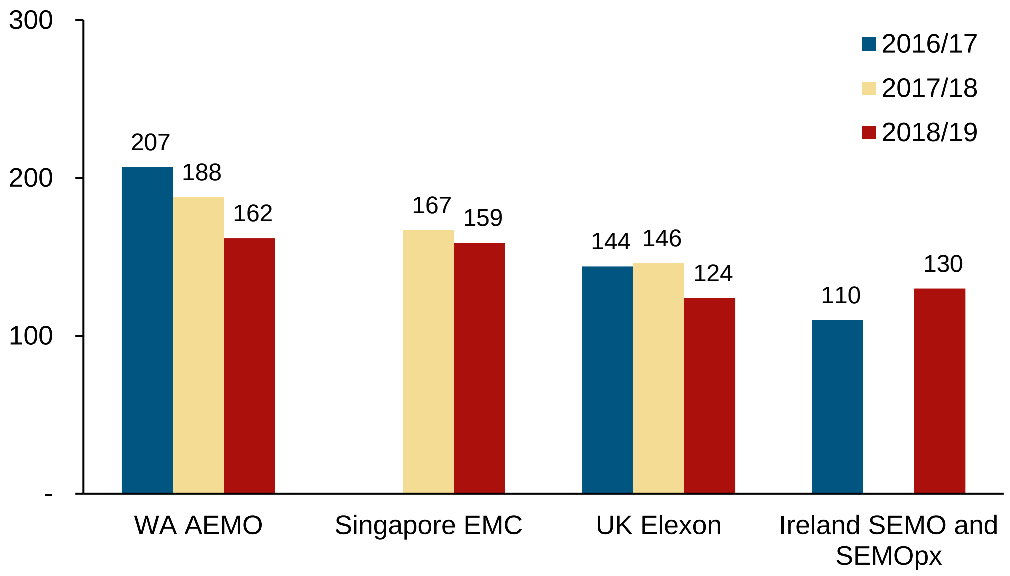


Table 2: Comparison of Employee Costs, FTE and Employee Cost per FTE

	2016/17	2017/18	2018/19
WA AEMO			
Full Time Equivalent (FTE) Employee	25.82	28.85	32.87
Employees Benefit Expense ('000 AUD)	5,344	5,420	5,317
Employee cost per head ('000 AUD)	206.97	187.86	161.78
Singapore EMC			
Full Time Equivalent (FTE)		64	60
Employees Benefit Expense ('000 AUD)		10,698	9,558
Employee cost per head ('000 AUD)		**167**	159
UK Elexon			
Full Time Equivalent (FTE)	166.9	174.5	189.6
Employees Benefit Expense ('000 AUD)	24,000	25,468	23,472
Employee cost per head ('-000 AUD)	**144**	**146**	124
Ireland SEM and I-SEM			
Full Time Equivalent (FTE)	42		69.9
Employees Benefit Expense ('000 AUD)	4,625		9,096
Employee cost per head ('000 AUD)	***110***		*130*

1.4. BUDGETING

We also note differences in budgeting and governance models as these influence types and levels of costs incurred and, particularly, the underlying level of understanding and acceptance of the purpose of those costs. PJM uses a transparent budgeting and fee-setting process relying heavily on stakeholder participation to guide priorities, with final recommendations approved by independent directors, a process that has worked well.

Where differences in costs can arise for many reasons that are not easily reconciled – and perhaps especially given how WA's small size limits access to significant economies of scale or scope – a transparent budgeting and stakeholder engagement process is crucial.

2. INTRODUCTION

2.1. Overview

The Wholesale Electricity Market (WEM) rules set out the allowable revenue process for Australian Energy Market Operator (AEMO) WA. Every three years AEMO is required to make a submission to the Economic Regulation Authority (ERA) with a forecast of expenditures. AEMO WA is currently in the process of their fifth allowable revenue process.

The WEM rules set out that AEMO is able to recover the costs of providing the following services in WA:

- Providing the WEM with market and system management services, as set out in clause 2.22.A.1 of the WEM Rules.
- Providing the Gas Services Information (GSI) services, as set out in rule 107 of the GSI Rules, which includes the Gas Bulletin Board and other information services provided by AEMO to gas market participants.
- Facilitating implementation of WA Government's WEM reforms including constrained network access reforms, and undertaking any activities in support of reforms as outlined in clauses 1.20.1 and 1.20.2 of the WEM Rules.

For the Market Operations, System Management and Gas Services Information, allowable revenue typically includes the following cost categories:

- Employee benefits and expenses;
- Accommodation;
- Supplies and services;
- Borrowing costs; and
- Depreciation and amortisation.

The requirement on AEMO to facilitate implementation of WEM reforms is a recent addition to AEMO allowable revenue services.

2.2. Scope

The ERA engaged The Lantau Group (TLG) to undertake research and provide advice on the costs of operating electricity markets in different jurisdictions and to compare these costs to those proposed by AEMO for the Western Australian Market.

In particular, the ERA requested information concerning:

- The high-level range of costs of operating electricity markets in different jurisdictions, including system management;
- Understanding why the costs to perform similar functions differ between different jurisdictions and what are the main drivers of costs in different jurisdictions; and
- Comparisons of the costs of common market operation activities in different jurisdictions.

We gathered information about a number of different market and supplemented this information with deeper discussions with market and system operators to develop a clearer understanding of costs and how to compare and contrast them given the significant differences that exist in market design and market evolution.

2.3. Markets Compared

We considered the following markets in particular as set out in Table 3.

Table 3: Markets Studied

Market	Market Operator	System Operator
Australia, WEM	AEMO WA	AEMO WA
Australia, NEM	AEMO NEM	AEMO NEM
Singapore	EMC (Energy Market Company)	EMA PSO (Energy Market Authority Power System Operator
New Zealand	NZX	Transpower
USA, PJM Interconnection (PJM)[3]	PJM	PJM
UK	Exelon	Not included in study
Ireland	SEMO and SEMOpx	Not included in study
South Korea	KPX (Korea Power Exchange	KPX

3 The initial "PJM" originally stood for Pennsylvania, New Jersey, and Maryland, the three original state participants in a near century old power pool. Participants from many more US states are now part of PJM, and the original power pool has evolved into the PJM Interconnection (PJM). PJM operates the largest electricity wholesale market in the United States, and one of the largest in the world.

We also considered smaller isolated systems such as Hawaii, but with no equivalent market operator and less transparency on system operations costs, we determined to instead focus on the traditional competitive wholesale and retail markets with an emphasis on smaller markets such as Singapore, New Zealand, and Ireland, as well as well-established larger markets such as the NEM and PJM for effective contrast.

2.4. Approach

Benchmarking aims to inform views on the credibility of costs and the potential for realising cost savings based on comparisons with others who perform similar functions. The essence of benchmarking is to develop comparisons that are as close to "apples-to-apples" as possible either through judicious screening and curation or through quantitative or qualitative adjustments for differences in key situational factors and underlying cost drivers. In the case of comparing the cost of market and system operations across countries or markets, a fully quantitative adjustment focussing on underlying differences in cost drivers is not possible given information available.

Accordingly, we have undertaken this research in three ways:

- Compare at a high level the AEMO's operations in Western Australian (WA) against eligible markets utilising publicly available information;
- Drill down where possible on markets (and functions within markets) that appear most relevant in comparison with WA with the intent to refine high-level comparisons and increase available insight; and
- Conduct interviews with contacts in key markets to further refine / validate our understanding of key cost drivers, situational context, and benchmarking approach.

Published information varies widely across other jurisdictions, with some, like New Zealand, being highly transparent, and others, like Singapore's system operator, being much less so. Additionally, the differences in market design, market complexity, grid complexity, scale of operations and the institutional structuring of the organisations, makes direct comparisons with WA challenging. We have thus drawn on experience and discussions with contacts in these different markets to draw out relevant comparisons and lessons.

3. AEMO WA OVERVIEW

To assist TLG benchmarking of WA AEMO's cost against other jurisdictions, data was provided to TLG by AEMO and ERA. TLG focused on benchmarking the most recent historical data using actual costs for 2016/17 and 2017/18 and forecast spend for 2018/19.

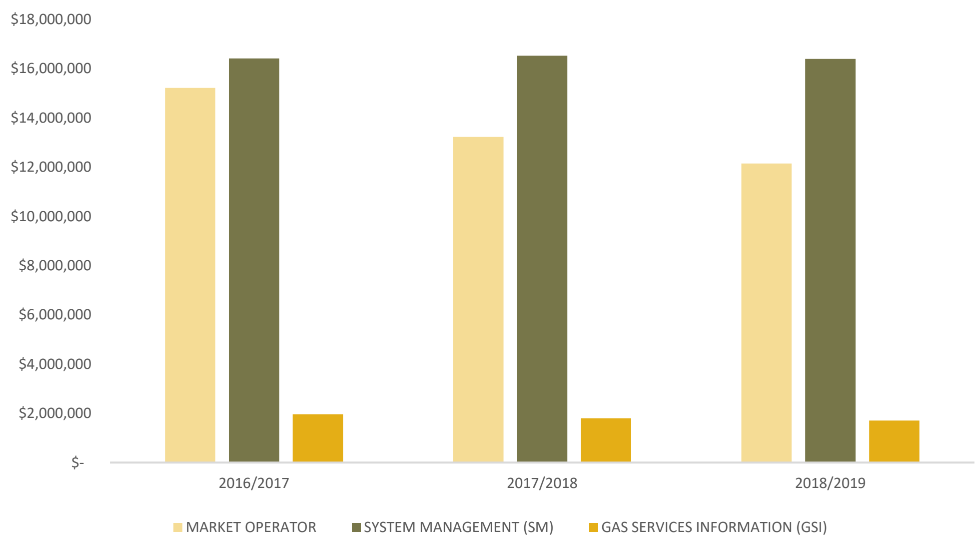
3.1. BACKGROUND

As shown in Figure 6, the data are sorted into WA AEMO's three major operational roles:

- Market Operations;
- System Management; and
- Gas Services Information.

The most noticeable trend is the decline over the three-year period in costs attributable to WA AEMO's Market Operations role. Costs for the other two main roles, System Management and Gas Services Information, remained flat.

Figure 6: WA AEMO Historical Cost by Operational Role



Source: AEMO

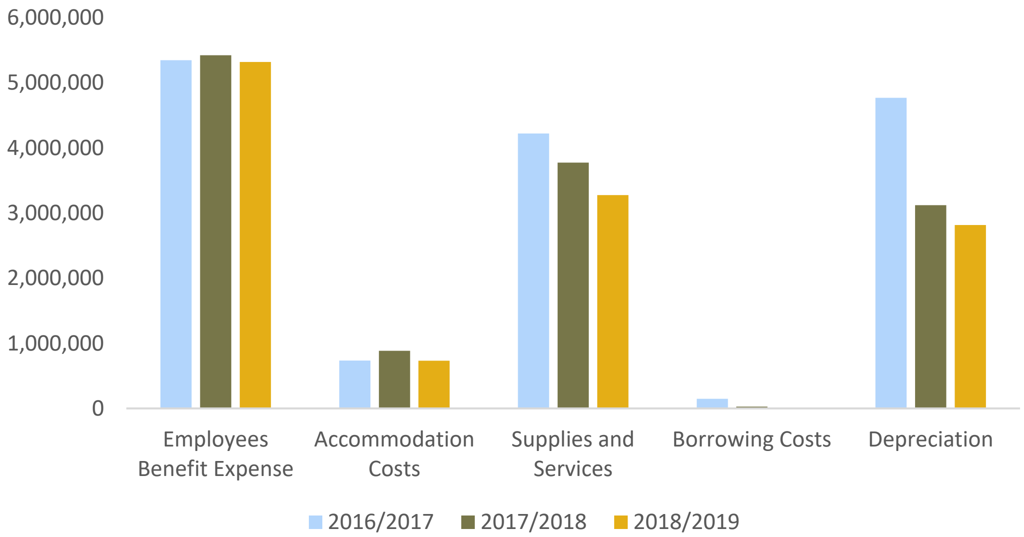
Within each functional role, costs can be sorted into more specific categories:

- Employee benefits expense – salaries, superannuation, payroll tax and fringe benefits tax;

- Supplies and services – outsourced expenditure including IT, auditing, labour hire, insurance, travel and training. In addition, consultant expenditure in support of service delivery;
- Accommodation – office rental, cleaning, electricity, maintenance and car parking;
- Depreciation – depreciation and amortisation of assets; and
- Borrowing – interest expense.

WA AEMO's cost for each operational role per cost category are shown in Figure 7, Figure 8, and Figure 9.

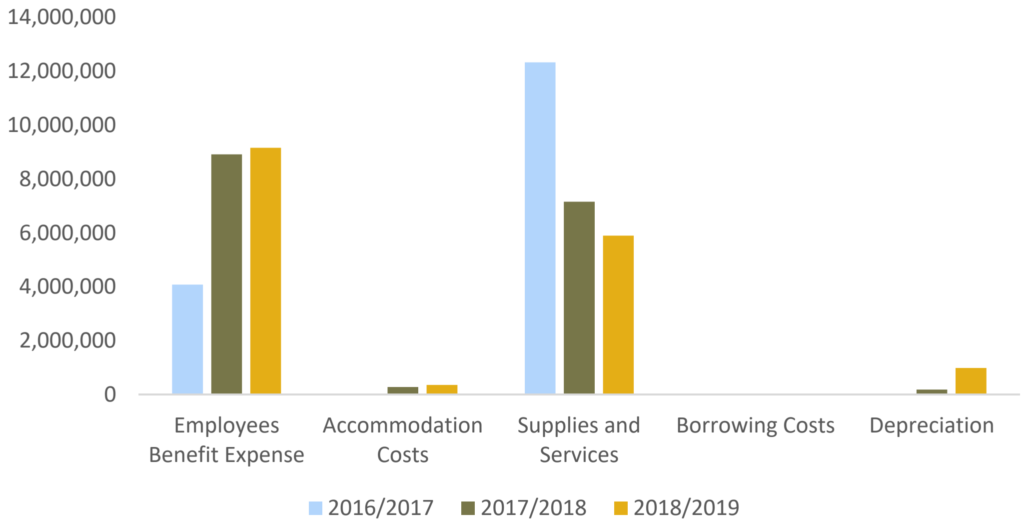
Figure 7: Cost Breakdown by Category AEMO WA (Market Operations)



Source: AEMO

The differences in System Management cost by year are small (within one percent). However, the composition of costs has changed much more, as highlighted in Figure 8, with employee benefit costs increasing (in proportion to the total); whereas supplies and services costs reduced. This shift aligns with the tail-end of AEMO bringing System Management functions in-house and ending the service level agreement with Western Power.

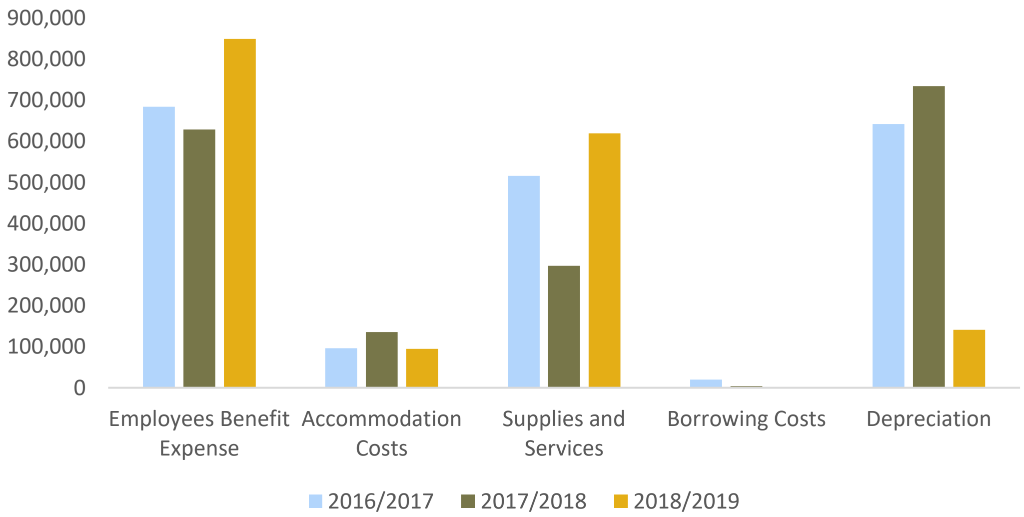
Figure 8: Cost Breakdown by Category AEMO WA (System Management)



Source: AEMO

With respect to the Gas Services Information function, costs have trended down very slightly in percentage terms, but the underlying composition of costs has changed much more, apparently driven in part by offsetting shifts in employee costs (up) and supplies and services (up) versus depreciation (down) suggesting a shift in the approach to delivering the underlying services.

Figure 9: Cost Breakdown by Category AEMO WA (Gas Services Information)

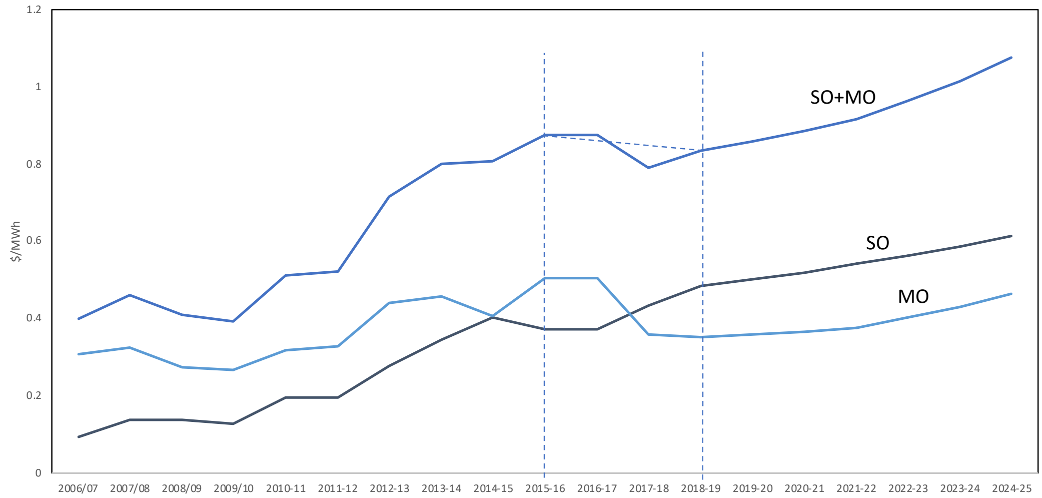


Source: AEMO

3.2. Market Fees

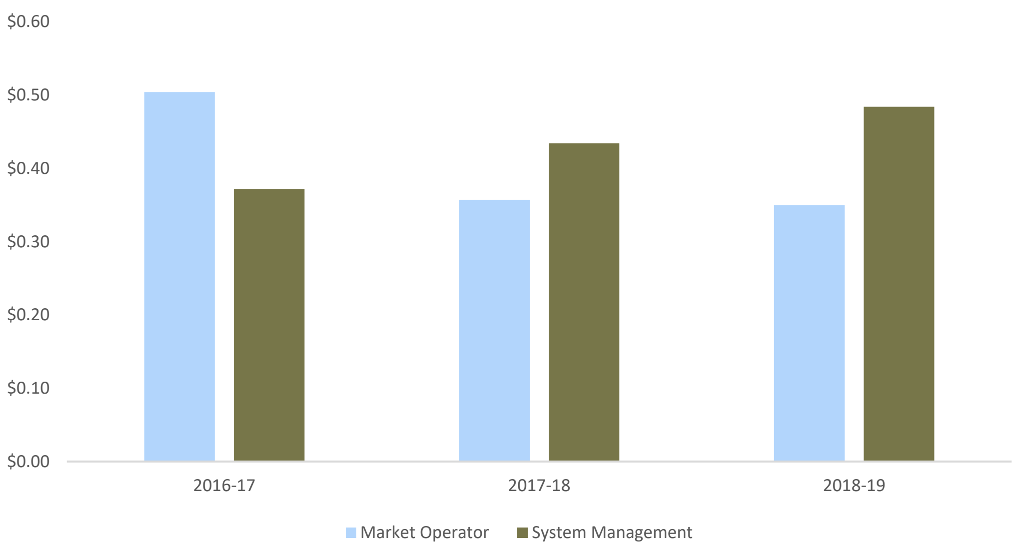
In addition to total cost, AEMO provided the market fee component for each market fee recipient in dollars per MWh from market start and projected to 2024/25, shown in Figure 10. Despite an overall reduction in (mainly market operations) costs over the past three years as shown in Figure 11, WEM fees are projected to have an increasing trend going forward. The increased market fee is mostly attributed to increased capital costs separately attributable to the continuing integration of System Management and additional reforms to the WEM.

Figure 10: Historical and Future WEM Market Fees for MO and SO Functions ($/MWh)



Source: AEMO

Figure 11: WA Market Fees ($/MWh) 2016 to 2019



Source: AEMO

3.3. Underlying Factors

From the data AEMO provided the ERA, we were able to summarise the full-time employee count allocated to each operational role, detailed in Table 4. Headcount increased significantly in percentage terms for the Gas Services Information function, however the absolute numbers are probably too small to infer meaningful trends from the resulting percentage changes alone. It may be useful to map the increased headcount to new roles, services, or performance requirements.

Table 4: WA AEMO Operational Head Count

Opex	2016/17	2017/18	2018/19	Percent Increase since 2016/17	Increase in FTE since 2016/17
Market operations	25.82	28.85	32.87	27%	7.0
Gas services information	3.03	4.18	6.47	113%	3.4
System management	30.65	36.47	41.81	36%	11.2
Total	59.50	69.50	81.15	36%	21.7

Source: ERA Data

4. BENCHMARKING AGAINST COMBINED MARKET AND SYSTEM OPERATORS MORE GENERALLY

4.1. Overview

AEMO in WA includes both market operations and system management, just as does AEMO in the NEM. In this section, we expand the comparisons to include several other markets, including:

- AEMO WA and AEMO NEM;
- PJM – one the largest and most sophisticated markets;
- New Zealand – for comparison we combine the costs of NZX' market operations and Transpower's system operations;
- Singapore – for comparison, we combine the costs of EMC's market operations and the EMA's PSO division's system operations; and
- South Korea – the Korea Power Exchange (KPX) is similarly structured to AEMO WA, AEMO NEM and PJM.

In subsequent sections, we benchmark AEMO's WA market operations and system operations costs separately.

4.2. Market Summaries

No other market is structured or has equal roles and responsibilities as the AEMO WA. Table 5is an overview of the different jurisdictions and their particular structure.

Table 5: Summary of Jurisdictional Structures

Jurisdiction	Separate or Combined MO and SO	Single or Multi-Jurisdictional
Australia WEM	Combined	Single
Australia NEM	Combined	Multi
USA PJM interconnect	Combined	Multi
New Zealand	Separate	Single
Singapore	Separate	Single
South Korea	Combined	Single

Note: Table 8: Operational Parameters of Benchmarked Market Operators provides a further summary of market operation features and relative complexity

4.2.1. National Energy Market (NEM)

The Australian National Electricity Market (NEM) serves the eastern and south-eastern sections of Australia from the state of Queensland in the north through New South Wales (NSW), Victoria and South Australia and the island state of Tasmania via HVDC cable. The Australian Capital Territory sits within NSW.

Ownership of the industry is a mix of private and public entities with some states fully privatised and others retaining significant public ownership.

The NEM was introduced in 1998, initially involving New South Wales, Victoria and South Australia. Queensland joined in 1999 and Tasmania in 2005. The NEM is a zonal or regional energy-only market (no separate payment for capacity as it exists in many international markets). Extensive external financial risk management instruments and significant vertical integration of generation and retailing hedge the inherent risks of the spot market. The boundaries of the spot market regions align closely with the jurisdictional boundaries of the participating states.

4.2.2. PJM Interconnection

The PJM Interconnection (PJM) in the United States started over 90 years ago as one of the first formal power pools supporting electricity trading across multiple independent regulated monopoly utilities. Just over twenty years ago, PJM evolved to become a regional transmission system operator and bid-based wholesale electricity market. PJM operates one of the most complex electricity markets in the world, with nodal energy pricing, ancillary services regional capacity markets and financial transmission rights. Enhancing coordination between electricity and US gas markets has also become an increasing point of complexity and focus.

PJM is the largest electricity market in the United States. PJM has roughly over four times higher electricity consumption than the NEM and has annual operational costs of around $AUD 500 million.

PJM has complex jurisdictional accountabilities. PJM covers all or parts of the states of Delaware, Illinois, Indiana, Kentucky, Maryland, Michigan, New Jersey, North Carolina, Ohio, Pennsylvania, Tennessee, Virginia, and West Virginia, as well as the federal region of Washington DC. Each state has its own regulatory commission. PJM also is accountable to the US Federal Energy Regulatory Commission (FERC) which oversees interchanged power flows across state boundaries.

PJM employs about 55 people (as compared to AEMO's approximately 26 in WA) in market operations associated roles despite being approximately 46 times bigger (MWh basis), thus providing a useful indication of potential scale economies. PJM operates on a profit neutral basis; thus, total revenues and expenses must equal each other over the long term.[4] PJM is permitted to retain up to six percent of PJM's stated rate (fee) revenue as a financial reserve.

4.2.3. New Zealand

Market Operations

The New Zealand Electricity Authority (regulator) contracts out the various services required in running an electricity market. This contracting process is competitive with contracts awarded for approximately five to eight-year terms, but these can be extended. New Zealand Exchange is contracted to provide majority of the services required in running an electricity market. New Zealand Exchange (NZX) has been the market operator since 2009 through the acquisition of The Marketplace Company (M-co) the market operator since the market commenced in 1996.

System Operations

New Zealand's Electricity Authority, the industry regulator, assigns the role of system operator through a competitive tendering process. Transpower is the system operator as well as the network owner. The system operation role is funded through an incremental and unavoidable cost approach. This means Transpower can only seek funding for the system operations role for costs that *uniquely* relate to that function. As an example, Transpower normally must deploy SCADA across its network in its role as network owner. It is therefore only the *incremental cost of SCADA used for system operations* that is charged to the system operator function.

4 https://learn.pjm.com/who-is-pjm/how-does-pjm-make-money.aspx.

4.2.4. Singapore

Market Operations

EMC is a privately owned, for-profit company that operates Singapore's energy market called the National Electricity Market of Singapore (NEMS). EMC's budget and fees are annually determined through a transparent process involving publishing a draft budget, inviting public and stakeholder feedback, providing project level budgets to the industry Rules Change Committee for comment, and formal budget submissions to the regulator the Energy Market Authority (EMA) for approval. Importantly, the EMA determines an overall price cap for a 5-year period and EMC's annual budget is effectively an advice to the market on how this fee cap is being spent. The market operator's costs are recovered through nominal fixed fees and through a market fee levy.

System Operations

In Singapore the system operator is part of EMA, the regulatory body. This unusual arrangement was put in place at the time of industry restructuring as part of what was otherwise a comprehensive plan to open ownership of the sector to the private sector – including a contracted for-profit private sector market operator -- without international ownership restrictions. The budget and fees of the system operator are governed by the market rules.

4.2.5. South Korea

The Korea Power Exchange (KPX) is similarly structured to AEMO WEM, NEM and PJM in the sense that KPX is both the market and system operator. KPX was established in 2001 following reforms to move from a vertically integrated state-owned Korean Electric Power Corporation (KEPCO) into a privatized industry operating in a competitive power market. South Korea generates around 553 terawatt hours (TWh) electricity annually, making it just over three times larger than the NEM.

Like the WEM, the South Korean electricity market is cost-based and has a capacity payment arrangement. However, Korea's originally planned market reforms (including substantial industry privatisation) largely stalled in 2001. Whereas, there have been ongoing enhancements to systems and the market, the Korean market is not nearly as developed as the NEM or PJM. Inclusion in the benchmarking is a reflection of seeking additional insight into the contribution of market design sophistication, number of stakeholders, and overall market structure, amongst other similar differentiating factors.

4.3. Scale and Scope Synergies

AEMO only assumed the role of the WA's energy market operator from 30 November 2015 and the role of WA's system operator from 1 July 2016. AEMO's total costs of market and system operations are bundled in the NEM but are separated in the WEM.

WA may gain benefits of scale and cost synergies from joining AEMO, but almost certainly in the near term there will be adjustment costs as existing and new systems are enhanced or expanded. Evidence of these benefits is confounded by the fact that the WEM is expected to adopt and thus implement through new systems and processes a number of significant wholesale market changes.

It is useful to bear in mind that mergers are often premised on synergies that are both difficult to estimate ex ante and usually require some combination of time, effort, and investment to realise ex post. McKinsey notes that “managers in about 60 percent of mergers deliver the planned cost synergies almost totally, in about a quarter of all cases they are overestimated by at least 25 percent.”[5] The difficulties in realising expected synergies do not lie merely in managers’ efforts post-merger but also in the challenges associated with estimating prospective synergies in the first instance.

Therefore benchmarks, more than anything else, are best suited in this case to identify focus areas for further review; to highlight unexpected trends; or even to highlight where different approaches to governance or regulation may be necessary given the multi-factored nature of cost drivers and the likelihood of different benefit and cost outcomes associated with market design details.

4.4. Benchmarking Results

4.4.1. Perspective

The markets compared vary widely from the largest (PJM) with over 800 terawatt hours of electricity sold each year. WA is the smallest (by far) and is less than half the size of New Zealand’s market.

Table 6: Relative Size of Each Market (Annual GWhs)

	2016/2017	2017/2018	2018/2019	Relative to WA (2018/2019)[6]
AEMO WA	18,262	18,153	18,296	--
AEMO NEM	180,311	181,009	178,650	9x
PJM	830,000	807,000	836,000	45x
Singapore	48,627	49,644	50,400	2x
New Zealand	40,747	41,176	41,173	1x

5 https://www.mckinsey.com/business-functions/strategy-and-corporate-finance/our-insights/where-mergers-go-wrong

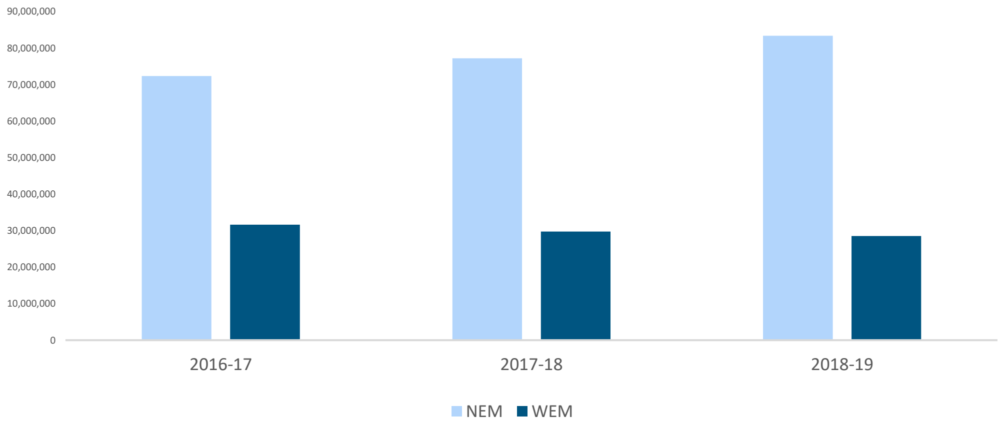
6 Rounded.

	2016/2017	2017/2018	2018/2019	Relative to WA (2018/2019)[6]
South Korea	497,039	507,746	526,150	28x

4.4.2. Overall Benchmark Results

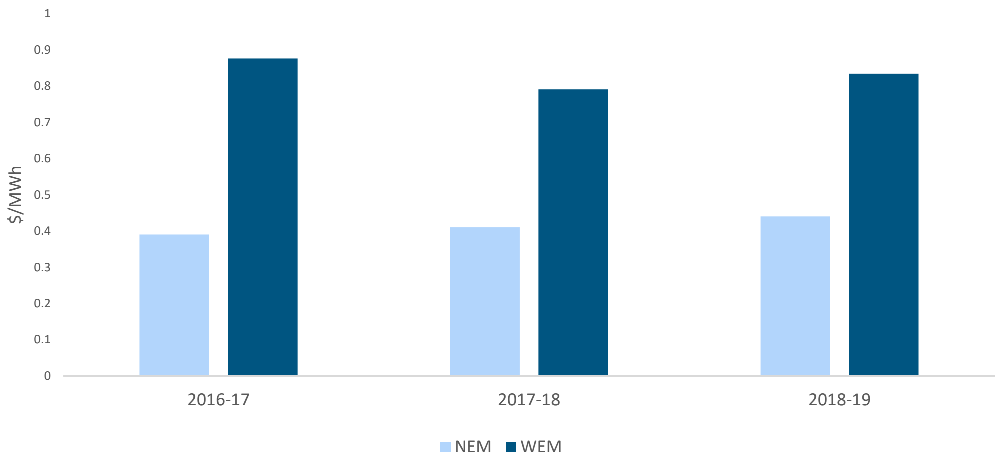
AEMO's total costs for the NEM are more than 1.5 times greater than those for the WEM. On a cost-per-MWh basis, AEMO's NEM costs are about half those for the WEM, as shown in Figure 12 and Figure 13.

Figure 12: Total Cost NEM vs. WEM



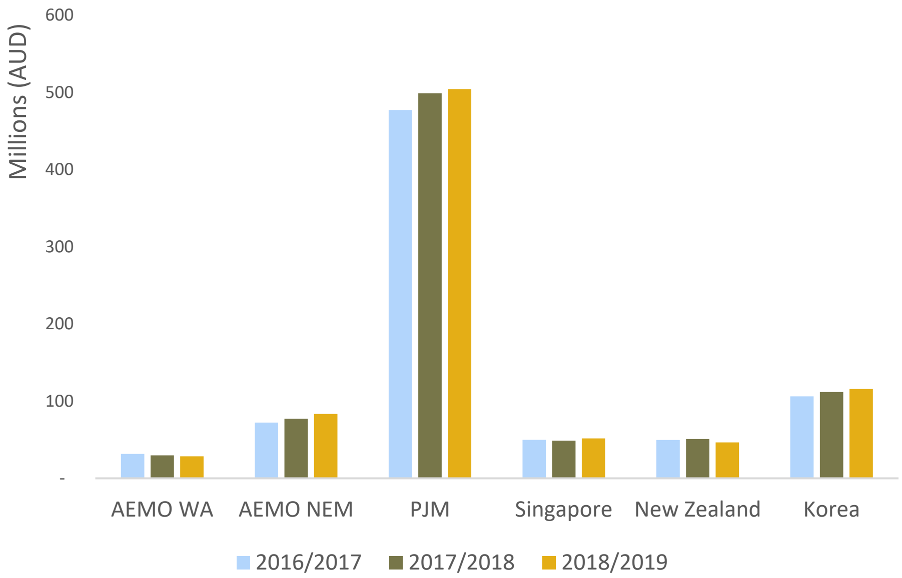
Source: AEMO Data, TLG analysis

Figure 13: Market Fees NEM vs. WEM (Excluding WA ERA)



We see similar outcomes when we expand the analysis to the broader benchmark sample as shown in Figure 14 and Figure 15.

Figure 14: Comparison of Total Costs of Combined Market and System Operations



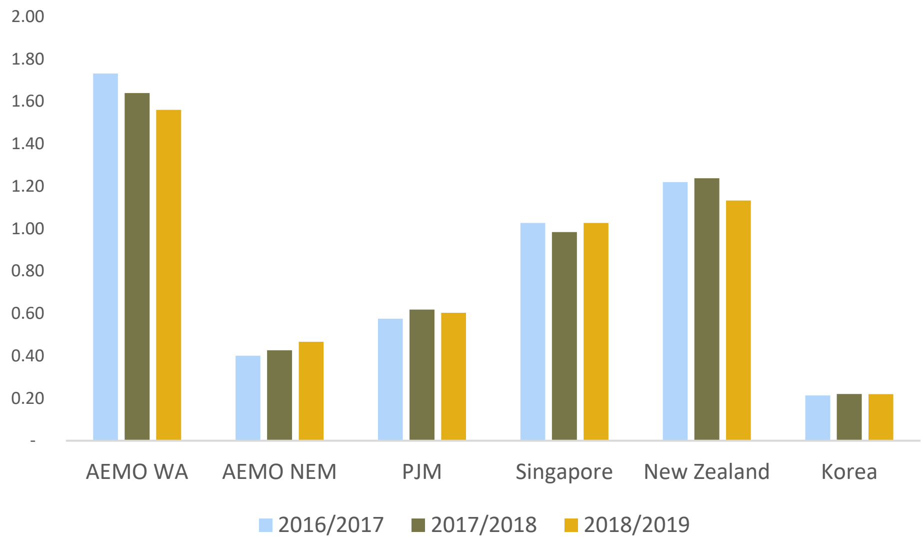
Source: Public Data, TLG analysis

The overall results in Figure 14 are striking in three simple respects. PJM is the largest and has higher overall costs. In MWh terms, South Korea is about 60 percent the size of PJM (and about twice the size of the NEM) and has costs that are clearly much lower in proportion to size. Singapore and New Zealand – two markets that are about the same overall size (within 20 percent of each other in terms of total MWhs) have similar overall costs. WA has lower total costs than all others.

Figure 15 provides a scaled perspective that highlights the fact that WA's costs are much higher than those of any other market and system operator when considered on a cost per MWh basis. That said, the trend for these costs in WA has been downward over the past three years. Singapore and New Zealand have similar overall levels of cost (per MWh), whereas the larger markets of the NEM and PJM have much lower costs per MWh.

South Korea's cost per MWh are by far the lowest. Based on our understanding and discussions, we believe that PJM is considered a cost-effective market and system operator in the US.[7] The differences in cost between South Korea and PJM more likely a result from fundamental market design and industry ownership and governance structure differences. It can further be reasonably inferred that these market design and other differences are likely to be amongst the most material cost drivers, with scale affording an opportunity to spread costs over a larger number of MWh.

Figure 15: Comparison of Costs per MWh (in AUD) of Combined Market and System Operations



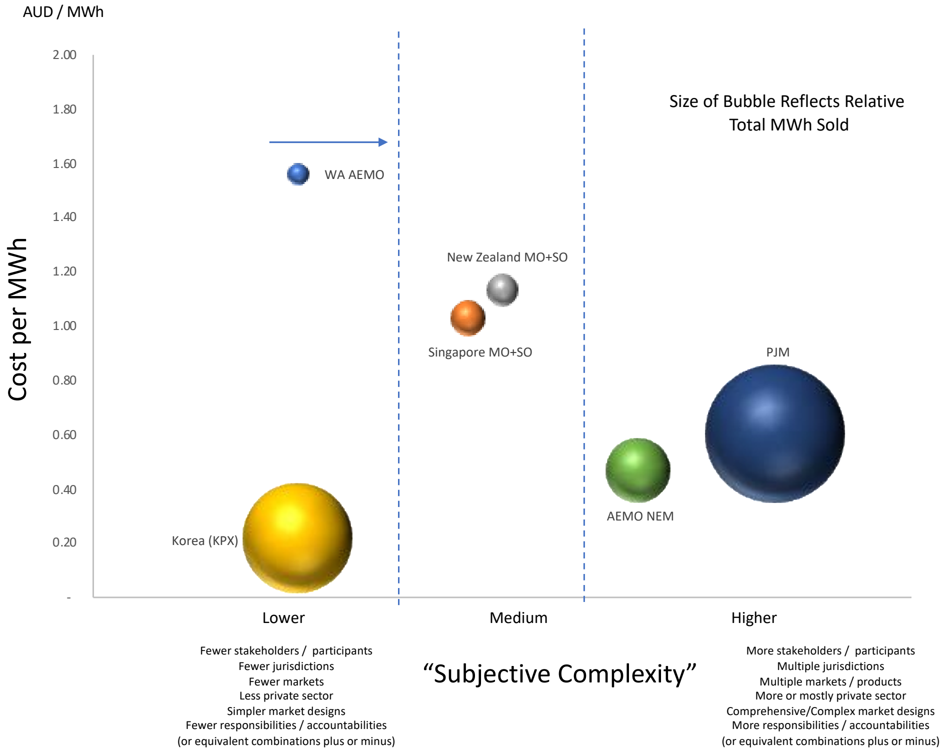
Source: Public Data, TLG analysis

Based on our discussions with the market operators and our understanding of each market, we then broadly categorised the underlying markets based on their level of fundamental complexity (low, medium and high). Larger numbers of stakeholders, more regulatory jurisdictions, complex and more sophisticated market design features, greater responsibilities for planning (and not just information provision), all suggest greater complexity. On that basis, being a single jurisdiction in a smaller market (and thus with fewer stakeholders), we assigned the WA market to be the least complex but note that complexity is very much increasing through the many recent and on-going market evolution initiatives. However, it remains the case that, at least in our view, WA has been simpler market than Singapore and New Zealand over the benchmarking period.

7 Membership in PJM is voluntary, and PJM has grown by attracting new members (often adjoining, but not always) through the combination of lower fees and greater realized efficiency of market coordination. Given the existence of other market operators in the USA, evidence of growth is a reasonable indication of perceived value for money.

Singapore's market includes additional market design features, is more substantially privatised, and has an especially high sensitivity to security of supply. New Zealand has a more complex multi-island system with many more stakeholders than Singapore. The AEMO NEM joins PJM in the higher complexity region, as both are more complex, commercially focussed markets with significant multi-jurisdictional interactions and detailed and granular price formation requirements.

Figure 16: Cost per MWh vs "Complexity"



Source: Public Data, TLG analysis

As noted, we expect WA to move further to the right as a result of the many market evolution and system enhancements that are on-going. Direction and speed of change as well as what is specifically expected or required to fulfil the functions assigned are likely to be material cost drivers, though they can be more difficult to put into context.

4.5. Governance and Budgeting

4.5.1. AEMO WA and NEM

The budgeting process between AEMO WA and AEMO NEM is different. In the NEM, AMEO sets their budget yearly on a cost recovery basis. The budget is approved by AEMO's board following consultation with the industry. Where fees change specific reasons are provided, with many detailed fees being set and assigned to specific functions and services

Figure 17: AEMO Fee Changes Example

Final 2018-19 fees

Table 1 — Fees

Function	Budget 2018-19	Current 2017-18	Change		Key drivers of fee changes
Electricity					
NEM ($/MWh)	0.44	0.41	↑	8%	Increased grid operation costs, managing changing nature of generation and modernising our markets.
FRC - Electricity ($/MWh)	0.077	0.075	↑	3%	To recover costs associated with the Power of Choice program.
National Transmission Planner ($/MWh)	0.02339	0.02126	↑	10%	Uplift in forecasting and planning and preparation of the Integrated System Plan (which incorporates the National Transmission Development Plan).
VIC TNSP - TUOS Fees ($'000)	462,312	474,580	↓	-3%	Higher settlement residue revenue due to higher spot prices.
WA WEM Fee ($/MWh)	0.833	0.791	↑	5%	Increased fee due to lower energy consumption in 2017-18. Expenditure is in-line with WA Economic Regulatory Authority Allowable Revenue.
Gas					
DWGM - Energy Tariff ($/GJ withdrawn)	0.08459	0.08544	↓	-1%	
STTM - Activity Fee ($/GJ withdrawn)	0.05192	0.06884	↓	-25%	Reduced costs due to market establishment assets being fully depreciated and funding being repaid.
VIC FRC Gas ($ per customer supply point per month)	0.06893	0.08305	↓	-17%	Reduced fees due to higher than budget prior year revenues and stable operating costs.
QLD FRC Gas ($ per customer supply point per month)	0.22256	0.22256	↔	0%	
SA FRC Gas ($ per customer supply point per month)	0.21484	0.22615	↓	-5%	
NSW & ACT FRC Gas ($ per customer supply point per month)	0.16410	0.16918	↓	-3%	
WA FRC Gas ($ per customer supply point per month)	0.13485	0.13485	↔	0%	
Gas Statement of Opportunities ($ per customer supply point per month)	0.03799	0.03518	↑	8%	Uplift in gas forecasting focus and additional insights reports.
Gas Supply Hub - daily ($/GJ)	0.03	0.03	↔	0%	
Gas Supply Hub - weekly ($/GJ)	0.02	0.02	↔	0%	
Gas Supply Hub - monthly ($/GJ)	0.01	0.01	↔	0%	
Gas Bulletin Board ($'000)	1,997	1,429	↑	40%	Increased due to improvements in the GBB to enhance breadth and accuracy of information.
WA Gas Services Information ($'000)	1,520	1,527	↔	0%	
Other					
SA Planning ($'000)	1,000	1,000	↔	0%	
Settlement Residue Auctions ($'000)	295	295	↔	0%	
Fees collected on behalf of Energy Consumers Australia (ECA)					
ECA (Electricity) ($ per connection point for small customer per week)	0.00985	0.00979	↑	1%	
ECA (Gas) ($ per customer supply point per month)	0.03547	0.03199	↑	11%	

In addition to yearly budget process, AEMO NEM consults periodically on the structure of its fees. The most recent consultation occurred from 2015-16. This consultation focused on the fee structure, and not the amounts to be recovered (levels). When determining the fee structure, AEMO NEM must have regard to the National Electricity Objective (NEO), which provides guidance and allow flexibility in determining the fee structure:

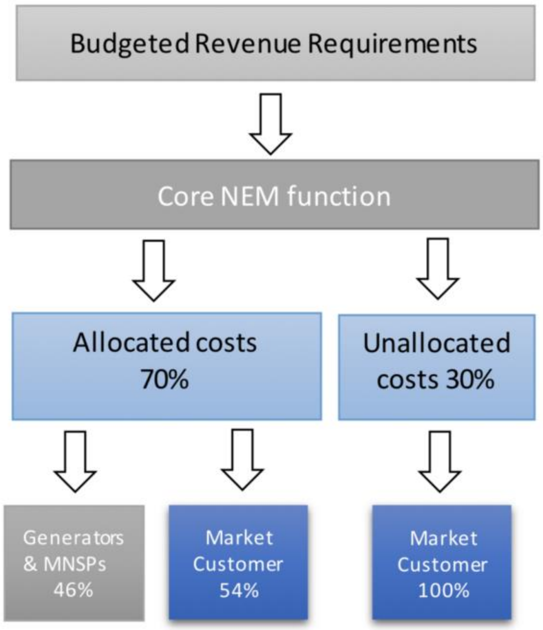
- The structure of Participant fees should be simple.

- The components of Participant fees charged to each registered participant should be reflective of the extent to which AEMO's budgeted revenue requirements involve that registered participant.
- Participant fees should not unreasonably discriminate against a category or categories of registered participants.
- Fees and charges are to be determined on a non-profit basis that provides for full cost recovery.
- The structure of the Participant fees should provide for the recovery of AEMO's budgeted revenue requirements on a specified basis.

Over time most of these principles have remained the same (or with some minor wording changes), while one principle has been added concerning the determination of fees and charges on a non-profit basis that provides for full cost recovery. The interpretation and application of these principles has always involved judgement and, at times, has resulted in formal dispute.

AEMO's latest fee structure review aimed to identify the direct costs attributable to key NEM outputs. AEMO's review concluded 70 percent of its costs can be attributed to a direct function, whereas the remaining 30 percent are indirect. AEMO NEM identified the key broad activities (e.g. power system security, metering and settlements) to which it could directly attribute costs. Following this analysis, it determined to attribute 46 percent of the directly attributable to Generators and Market Network Service Providers (MNSPs) and 54 percent to Market Customers. The resulting overall NEM fee structure is shown in Figure 18:

Figure 18: Overview of NEM Fee Calculation



Source: Final report structure of participant fees in AEMO's electricity markets 2016.

Whereas simplicity is one principle, the AEMO's NEM approach must also try to align cost recovery of performing a specific role to those who utilise the role – effectively reflecting a balancing of simplicity against causer pays approach and efficient cost recovery objectives. In WA, the cost allocation to market participant is not required to achieve multiple objectives in a balanced way (or even necessarily to balance multiple potentially conflicting objectives). Rather, in WA, AEMO's relevant cost are simply recovered via a participant's generation or consumption share.

The overall situation is thus one where (across jurisdictions) there are different models of cost recovery (fee determination and cost allocation) and different drivers of costs (stages of market development and differences in design and function and participation). These differences *may* influence the way participants participate in the process. Participants avoiding a cost may not care if the cost is inefficiently incurred. Participants who bear a cost may want that cost reduced with indifference to whether that cost incurrence has benefits for anyone else. We have not considered cost allocation issues or their nexus or implication for governance, but we do observe that the overall process by which costs are budgeted and communicated and approved in WA differs from the NEM and also from what we would consider best practice levels of stakeholder engagement or transparency.

4.5.2. PJM's Governance and Budgeting Model

PJM operates one of the more complex and comprehensive multi-jurisdictional electricity markets in the world and thus it is more difficult to develop benchmark comparisons. As PJM has evolved over time – and particularly given its multi-jurisdictional coverage – budgeting process is strongly linked to governance arrangements. Whereas on one hand a governance model might aim to include proportionate representation from actual stakeholders in an effort to achieve balance of insights and views, the PJM Board follows the full independence model, requiring that the members of the PJM Board "have no personal affiliation or ongoing professional relationship with, or any financial stake in, any PJM market participant."

PJM costs are developed through a multi-layered process involving longer-term roadmaps and shorter-term regulatory budgets (which are translated into approved charges and fees for the various services PJM provides). The Finance Committee regularly reviews PJM's consolidated financial statements, budgeted and actual capital costs as well as operating budgets and expenses. The Finance Committee comprises non-voting PJM employees as chair and secretary, two non-voting members from the PJM Board and *two voting members from each of the five member sectors*.[8]

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8 The five member sectors are: transmission owner, generation owner, electric distributor, end-use customer and other supplier. For more detail see: https://www.pjm.com/about-pjm/member-services/membership-and-sector-selection.aspx

In 2006 the Finance Committee and PJM published a Financial Report & Communications Protocol.[9] This protocol requires PJM to publish agendas and minutes for each Finance Committee meeting, and also to provide meeting materials to all Finance Committee members and other PJM members registered to attend Finance Committee meetings.

PJM publishes an annual work plan[10] that outlines how PJM will comply with the protocol as well as the topics discussed at the Finance Committee meetings. PJM presents preliminary budget requirements to the Finance committee and is required to addresses the committee’s questions and revise the budgets as needed before submitting a final proposal. All this is publicly available from the Finance Committee website. For example, the “Finance Committee Letter to the PJM Board” notes that:

> *PJM has proposed an expense budget of $296 million for its Stated Rate expenses in 2019. This value is within the long-term projections discussed in the updated stated rates mechanism implemented on January 1, 2017. The PJM Sector-Elected Finance Committee members appreciate PJM Management’s efforts to control the company’s expenses and provide timely, accurate and highly usable financial analysis for the committee.*
>
> *For 2018, PJM proposed, and the PJM Board of Managers ("Board") approved, an expense budget of $293 million. Current forecasts project PJM’s actual expenses will be approximately $290 million for 2018, which is in line with the original budget. The Sector-Elected representatives of the PJM Finance Committee recommend that the Board accept the proposed 2019 expense budget while encouraging PJM Management to continue to seek and sustain cost-saving initiatives that enhance efficiency, reliability, and effectiveness of PJM markets.*

PJM’s budgeting process is transparent and open to industry participation. PJM is required to provide more information to the industry on the development of its budget than what is required of AMEO in WA. The PJM approach is intended to increase support from industry and achieve greater clarity on budget requirements and priorities.

4.6. SUMMARY

The comparison of combined system and market operators is instructive because it both highlights the challenges of benchmarking different jurisdictions while at the same time providing useful insights to spur relevant questions. For example, the overall “per kWh” cost of AEMO WA is very high compared to other market and system operators, though AEMO has achieved a downward cost trend since the operations were combined.

9 See https://www.pjm.com/-/media/committees-groups/committees/fc/postings/financial-reporting-and-communications-protocol.ashx?la=en

10 For example, the 2019 work plan is available here: https://www.pjm.com/-/media/committees-groups/committees/fc/20181128/20181128-2019-finance-committee-work-plan.ashx?la=en

The impact of scale is apparent in the benchmark results as some of the more complex, multi-jurisdictional and multi stakeholder markets achieve the lowest costs on a per MWh basis, an observation that points clearly towards the existence of economies of scale and scope that would be difficult for WA to achieve.

In the absence of more accessible scale and scope economies, it makes sense to consider other ways to establish and maintain the credibility of cost levels being incurred. Differences in budgeting processes and governance (such as the PJM example) may suggest useful alternatives.

5. BENCHMARKING MARKET OPERATIONS COSTS

AEMO is both the system and market operator in WA. We focus specifically in this section on AEMO's market operations costs by comparing AEMO's market operations function to other market operators. Accordingly, we evaluated the costs and organisation of the following market operators in additional detail:

- Singapore Energy Market Company (EMC);
- New Zealand Exchange (NZX);
- Ireland – Single Energy Market Operator (SEMO); and
- UK – Elexon.

With the exception of the UK, the chosen market operators are in comparatively smaller markets (closer in size to WA). We focused on jurisdictions with an existing and mature energy market that have clearly defined market operation providers. Therefore, other potential smaller isolated but highly developed jurisdictions, such as Hawaii, were not included in the benchmarking.

5.1. Overview of Selected Market Operators

5.1.1. Singapore EMC

EMC is a privately owned, for-profit company that operates Singapore's energy market called the National Electricity Market of Singapore (NEMS). EMC's budget and fees are annually determined through a transparent process involving publishing a draft budget, inviting public and stakeholder feedback, providing project level budgets to the industry Rules Change Committee for comment, and formal budget submissions to the regulator (EMA) for approval. Importantly, the EMA determines an overall price cap for a 5-year period and EMC's annual budget is effectively an advice to the market on how this fee cap is being spent. The market operator's costs are recovered through nominal fixed fees and through a market fee levy.

5.1.2. New Zealand Exchange

The regulator contracts out the various services required in running an electricity market. This contracting process is competitive with contracts awarded for approximately 5-8 year terms but can be extended. New Zealand Exchange is contracted to provide majority of the services required in running an electricity market. New Zealand Exchange has been the market operator since 2009 through the acquisition of M-co, the market operator since the market commenced in 1996.

At present there are three companies that perform market operator functions in New Zealand as identified in Table 7:

Table 7: Market Operation Contracts in New Zealand

Service Contract	Provider
Clearing Manager	NZX
Extended Reserve Manager	NZX
Pricing Manager	NZX
Reconciliation Manager	NZX
Wholesale Information and Trading System Manager (WITS)	NZX
Stress Testing	NZX
Registry Manager (Retail Switching)	JADE
Financial Transmission Rights (FTR) Manager	EMS, a division of Transpower

Source: Service Provider and Electricity Authority websites

5.1.3. Ireland

The Single Energy Market (SEM) is a gross pool wholesale electricity market that covers Ireland and Northern Ireland since 2007. The Single Energy Market Operator (SEMO) is responsible for operating the SEM. SEMO is a joint venture between the two network operators in Ireland (Eirgrid and Soni).

The SEM has currently been under significant change in response to European Union legislation combining energy markets across Europe. The new Integrated – Single Energy Market (I-SEM) commenced operation on 1 October 2018. Under the I-SEM, SEMO is now responsible for the balancing and capacity markets, and a new entity, SEMOpx, is responsible for a day-ahead (DAM) and intraday electricity market (IDM).

The role of market operator has evolved from operating a previously relatively simple gross pool market to one that comprises multiple markets. Accordingly, under I-SEM market operating functions are split between SEMO and SEMOpx, with each responsible for operating different markets and settlement:

- SEMO is a contractual joint venture between EirGrid and SONI through which they implement their functions as the Nominated Electricity Market Operator (NEMO) for Ireland and Northern Ireland respectively.

- SEMOpx operates the DAM and IDM whilst SEMO operates the capacity market, balancing market and Trading and Settlement Code (TSC) settlement.

SEMO is jointly regulated by the Utility Regulator and the Commission for Energy Regulation. The Single Energy Market Committee (SEMC) is the decision-making body. As part of SEMC's decision-making role is the approval of SEMO's revenue allowance, performed via a three-year price control.

5.1.4. Elexon

Great Britain's electricity market is regulated by the Gas and Electricity Market Authority, operating through the Office of Gas and Electricity Markets (Ofgem). Elexon administers the Balancing and Settlement Code, which was launched in March 2001.

Elexon is a not for profit company that operates the balancing energy market in Great Britain while also a provider of metering services. Elexon is funded by participants who have signed up to the balancing and settlement code. Elexon's fees comprise of both fixed and variable charges.

5.2. Relevant Similarities and Differences

In seeking comparables we gave particular consideration to three differentiating factors: the scope or breadth of the market operational role; the overall complexity of the market design; and the overall market size.

Of the above noted markets, we consider Singapore and New Zealand as the most comparable markets due to their size, design, and structure. Despite similarities of size, Singapore and New Zealand are still materially different to WA's WEM. Both Singapore and New Zealand are energy-only markets, and both are approximately three times the size of the WA WEM.

We also included Ireland as it, too, is a comparatively smaller market (a market of similar electricity consumption as New Zealand). Uniquely, however, Ireland is in the midst of transitioning to a very substantially new and different market structure during the benchmarked years. For example, from 2016 work commenced to replace the SEM with the Integrated Single Energy Market (I-SEM). Accordingly, SEMO's budget reduced as the SEM was being wound down. From 2019, following the implementation of I-SEM, SEMO's budget will increase to approximately 10 million Euros. Nonetheless, it is useful to include Ireland because WA's market reforms have included a number of similarly significant changes and evolution-related developments with associated costs.

We summarise these in Table 8 below.

Table 8: Operational Parameters of Benchmarked Market Operators

	WA	Singapore	New Zealand	Ireland*	UK
Breadth of Role					
Operations	✓	✓	✓	✓	✓
Rule Making	✗	✓	✗	✗	✗
Surveillance	✗	✓	✗	✓	✓
Gas monitoring	✓	✗	✗	✗	✗
Market Design Complexity					
Balancing	✗	✗	✗	✓	✓
Energy	✓	✓	✓	some**	✗
Capacity	✓	✗	✗	✓	✓
Co-optimised	✗	✓	✓	✗	✗
Pricing	Postage stamp	Nodal	Nodal	contract based/ balancing	contract based/ balancing
Market Size					
Annual Demand (GWh)	~18,000	~50,000	~41,000	~40,000	~334,000
No. of Participants	86	57	>300[11]	NA	464
Size of transmission network (Km)	~7,800	5,817	~11,300	6,814	8,760
Number of customers	~1.1 million	`1.57 million	~2 million	~2 million	~21.6 million

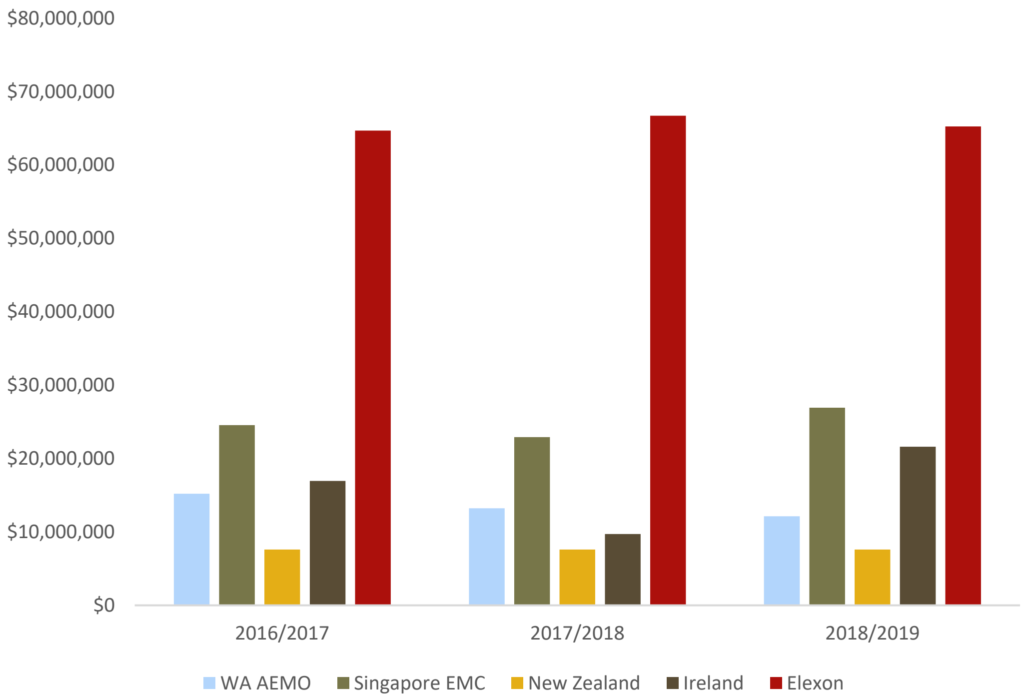
* The Irish market began with a pool-based system but is transitioning to a forward contract-based system with real-time balancing in order to comply with EU regulations. ** SEMOpx provides intra and day-ahead markets but this is based on an EEPEX spot platform and ECC clearing.

Source: Published data, TLG analysis

11 Number of registered participants in New Zealand is high, but many are very small or may not necessarily be active.

On a total cost basis, WA is the fourth most costly of the markets evaluated, behind Singapore and Elexon, shown in Figure 19. Singapore is more similar to WA due to the standalone nature of EMC's role as market operator. EMC is largely independent in its role of being the energy market operator, unlike many of the other market operators. However, we note that EMC has been purchased by SGX (the Singapore national stock and financial exchange operator) and thus will naturally be undergoing changes in internal processes, systems, and operations in order to identify and take advantage of cost sharing opportunities across these organisations. New Zealand's M-co was similarly acquired by NZX (the national stock and financial exchange operator in New Zealand) also with the intent of achieving cost savings.

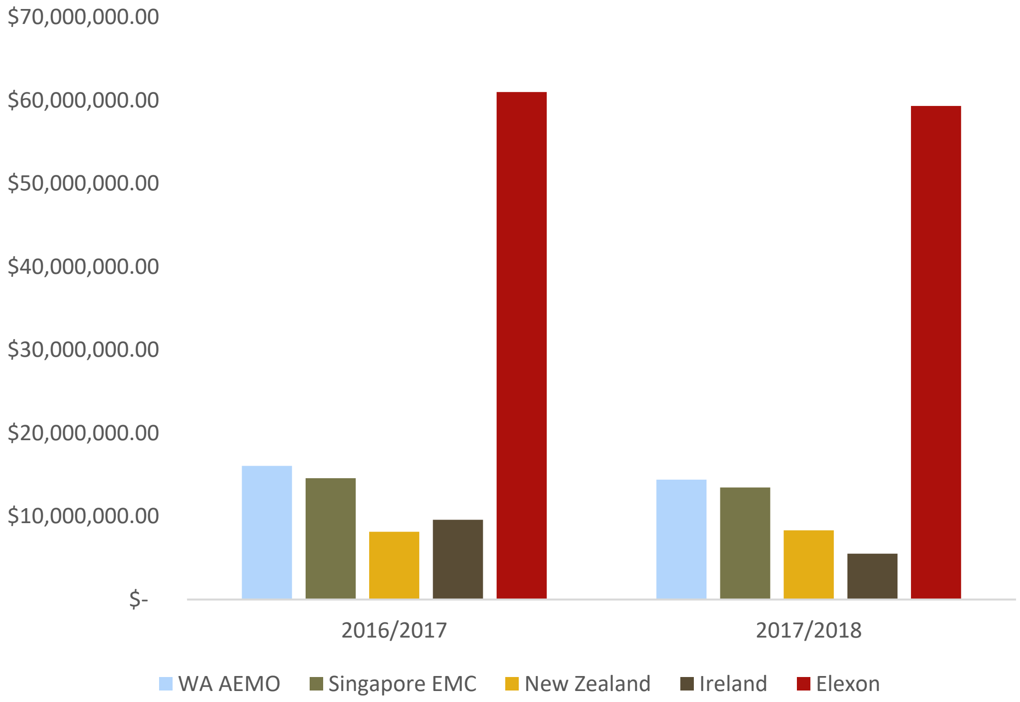
Figure 19: Total Cost for Market Operations in Other Jurisdictions



Source: Publicly available annual report data adjusted to Australian Dollars

Figure 20 compares the total cost of market operations on a PPP basis, which adjusts the comparisons across countries for purchasing power. If two countries appear to have the same costs for a good or service but one country's currency has greater purchasing power even after taking the exchange rate into account, then the corresponding PPP adjustment will show a higher cost on a PPP basis relative to the other country for the particular comparison. On a PPP basis, WA compares less favourably to Singapore and Ireland and about the same to New Zealand and the UK (Elexon).

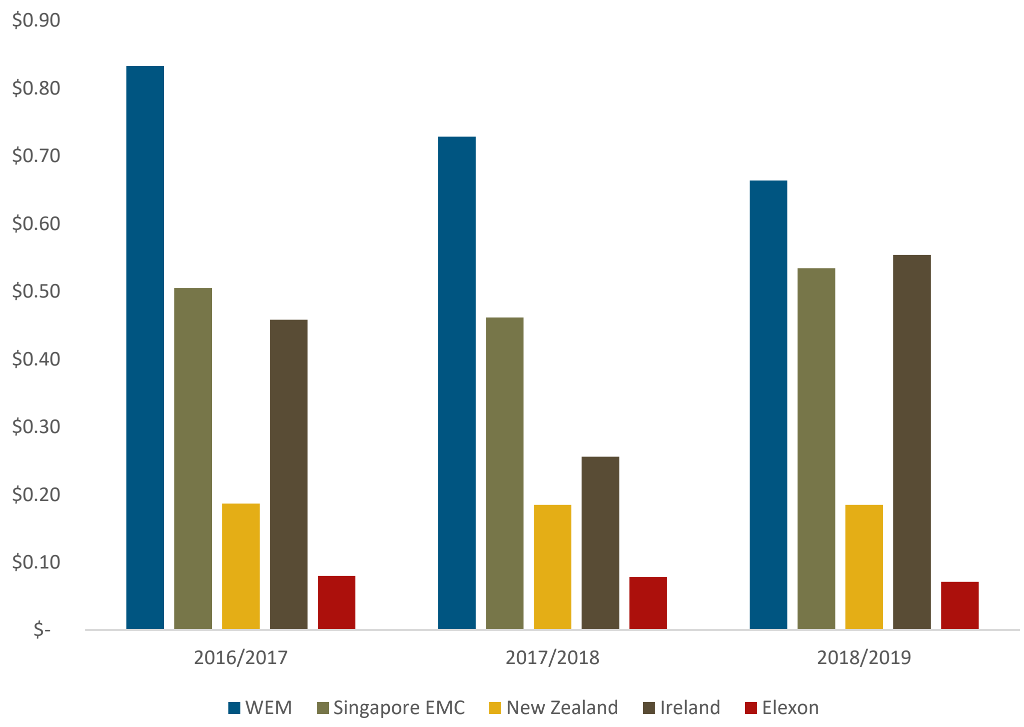
Figure 20: Total Cost for Market Operations in Other Jurisdictions (PPP Basis)



In New Zealand, the role of the market operator is awarded through a competitive process. That said, New Zealand's lower cost cannot be attributed to competition alone. As noted, New Zealand Exchange as well as being the energy market operator is also the exchange for stocks and financial markets in New Zealand. In discussions with Senior NZX staff we understand that the New Zealand Exchange has achieved certain cost efficiencies through sharing common services across its different market groups and is actively seeking to leverage off electricity market platforms and skillsets to expand into other markets. Such scaling of services and leveraging of markets cannot be as easily replicated in Western Australia.

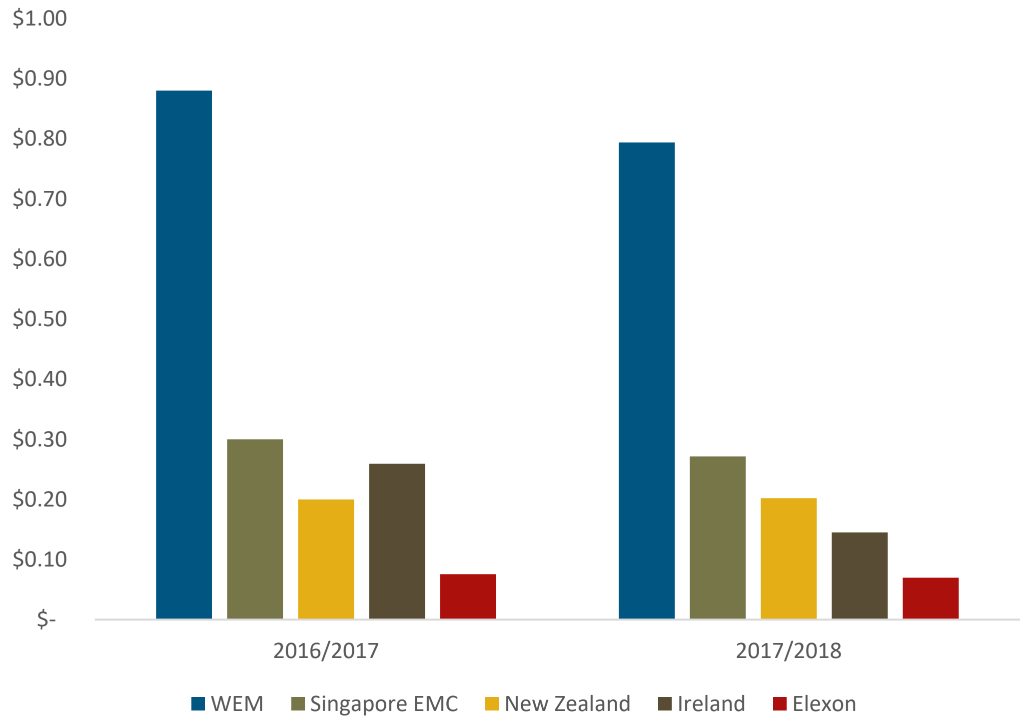
Once the necessary energy market systems are in the place, some costs associated with operations should experience economies of scale. This is an area where WA market participants are arguably at a disadvantage due to the small size and isolated, island nature of the WEM. The small size results in certain cost of operating the market having to be recovered over fewer transactions then would be the case in larger markets. We note that on a per MWh basis, the WA market is the highest, as shown in Figure 21 and also highest on a PPP basis as shown in Figure 1.

Figure 21: Cost of Market Operation Based on MWh Consumption



Source: Publicly available annual report data adjust to Australian Dollars

Figure 22: Cost of Market Operation Based on MWh Consumption (PPP Basis)



5.3. EMPLOYEE COSTS AND BENEFITS

Market operators in Singapore, Ireland and UK typically incurred or budgeted for employee cost per headcount in the range of A$100k to A$200k per FTE, see Figure 23 and Table 9 for more detail. WA started well above these observed averages, but has trended downward significantly suggesting a cost restructure as part of joining the AEMO.

Figure 23: Employee Costs and Benefits per FTE Comparison

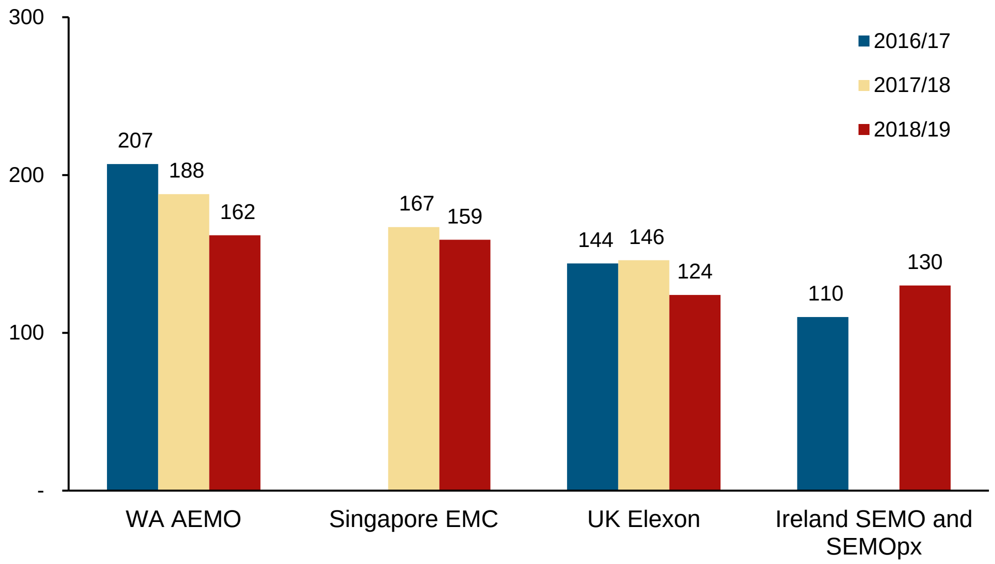


Table 9: Comparison of Employee Costs, FTE and Employee Cost per FTE

	2016/17	2017/18	2018/19
WA AEMO			
Full Time Equivalent (FTE)	25.82	28.85	32.87
Employees Benefit Expense ('000 AUD)	5,344	5,420	5,317
Employee cost per head ('000 AUD)	**207**	**188**	**162**
Singapore EMC			
Full Time Equivalent (FTE)		64	60
Employees Benefit Expense ('000 AUD)		10,698	9,558
Employee cost per head ('000 AUD)		**167**	**159**
UK Elexon			
Full Time Equivalent (FTE)	166.9	174.5	189.6
Employees Benefit Expense ('000 AUD)	24,000	25,468	23,472

	2016/17	2017/18	2018/19
Employee cost per head ('-000 AUD)	**144**	**146**	**124**
Ireland SEM and I-SEM			
Full Time Equivalent (FTE)	42		69.9
Employees Benefit Expense ('000 AUD)	4,625		9,096
Employee cost per head ('000 AUD)	***110***		***130***

Table 10 summarises cost items included in employee costs for other jurisdictions. UK Elexon is not included for comparison as its budgets do not include detailed breakdown of employee costs.

Table 10: Comparison of Employee Costs, FTE and Employee Cost per FTE

Categories	WA AEMO	Singapore EMC	Ireland
Salaries	Salaries Overtime	Salaries 13th Month Pay	Salaries Overtime
Bonus	Performance Pay	Performance Bonus	Bonus
Leave	Annual Leave Provision Long Service Leave Other paid leave	n/a	n/a
Pension Contribution	Superannuation	Central Provident Fund	Employer's pension contribution
Tax	Payroll tax	n/a	n/a
Welfare/Benefits	Allowances	Staff Welfare	Car and other benefits
Insurance	Salary Continuance Insurance		Employer PRSI (Social Insurance)
Others			Contractor/Agency costs

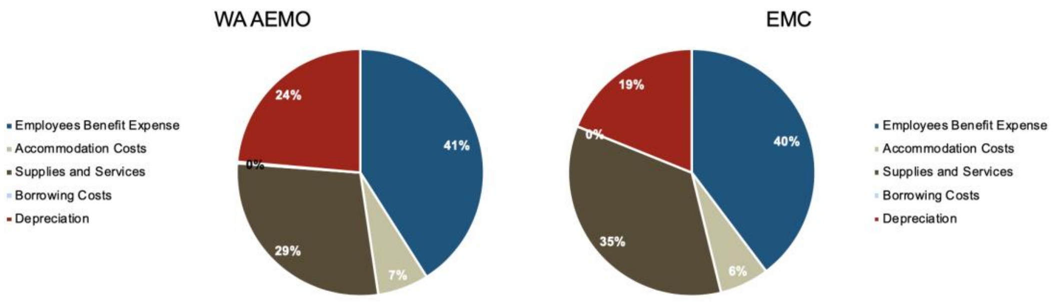
5.4. Additional Cost Breakdowns

To better understand the cost drivers between WA and other markets, we compared various cost composition data.

5.4.1. Comparisons between AEMO WA and Singapore

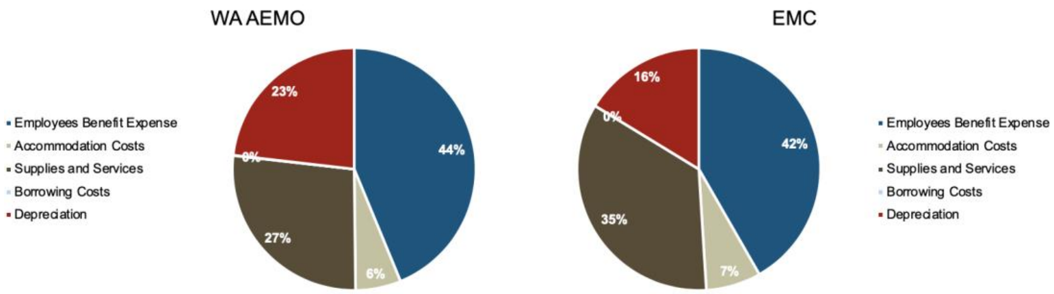
A more detailed comparison between WA and Singapore is shown in Figure 24 and Figure 25.

Figure 24: 2017/18 AEMO & Singapore EMC Market Operator Cost Breakdown (percent)



Source: Publicly available annual report data adjust to Australian Dollars

Figure 25: 2018/19 AEMO & Singapore EMC Market Operator Cost Breakdown (percent)



Source: Publicly available annual report data adjust to Australian Dollars

Singapore's EMC and AEMO WA have a similar breakdown of costs, with employee costs being the largest cost category. This is in line with observations from other jurisdictions. After employee cost the next largest cost is for supplies and services. Again, WA's proportion of total cost attributed to supplies and services is broadly in line with other jurisdictions.

The employee allocations at EMC reflects its role as market operator, with the two largest teams being market operations and information technology, as highlighted in Table 11.

Table 11: EMC Employee Count by Department

Department	FY 2018/19 Forecast	FY 2018/19 Approved	FY 2019/20 Budget
CEO Office	2	1	2
Corporate Services	10	11	10
Market Administration	8	7	8

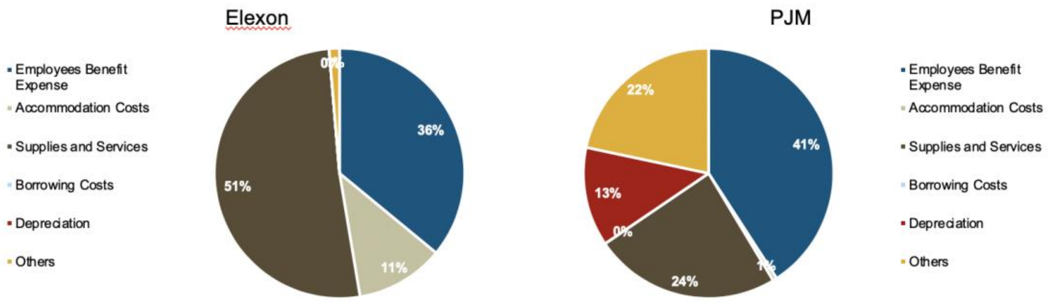
Department	FY 2018/19 Forecast	FY 2018/19 Approved	FY 2019/20 Budget
Information Technology	21	21	21
Information Security	3	1	5
Market Operations	18	18	18
Market Assessment Unit	5	6	5
Communications	2	2	2
Human Resources	2	2	2
Total	**71**	**69**	**73**

Source: EMC's NEMS Budget for the Financial Year Ending 30 June 2020

5.4.2. Comparisons between Elexon (UK) and PJM (USA)

For example, Elexon employee costs comprise 36 percent of their total cost and PJM's employee costs comprise 41 percent of their total costs, as show in Figure 26.

Figure 26: 2018/19 Elexon & PJM Market Operator Cost Breakdown by Per Cent



Source: Publicly available annual report data adjust to Australian Dollars

5.4.3. Comparisons to Ireland

On absolute terms, I-SEM's market operator operating expenses have significantly increased from the previous regulatory period. The increase in costs are primarily driven by I-SEM's expanded markets (relative to the previous SEM) and settlement which require a larger number of staff.

Compared with AEMO WA, as shown in Table 12, market operator costs are higher for both SEM and I-SEM period due to the larger market size.

Table 12: Market Operator Cost Comparison (000 AUD)

'000 AUD	2016/17 SEM	2018/19 I-SEM	2016/17 WA	2018/19 WA
Full Time Equivalent (FTE)	***42***	***70***	***26***	***33***
Employees Benefit Expense	4,625	9,096	5,344	5,317
Accommodation Costs	1,029	1,538	734	733
Supplies and Services	6,177	9,327	4,219	3,275
Total before borrowing and depreciation	**11,831**	**19,961**	**10,296**	**9,325**
Borrowing Costs			148	6
Depreciation	5,125	n/a	4,768	2,814

On a per FTE basis, both SEM and I-SEM have similar costs per head in all comparable cost categories, as shown in Table 13.

Table 13: Market Operator Cost Comparison (000 AUD per FTE)

000 AUD per FTE	2016/17 SEM	2018/19 I-SEM	2016/17 WA	2018/19 WA
Employees Benefit Expense	110	130	206	161
Accommodation Costs	25	22	28	22
Supplies and Services	147	134	162	99
Total	**282**	**286**	**396**	**282**

5.5. Summary Overall Comparisons

We grouped market operator costs into five cost categories: employees benefits; accommodation; supplies and services; borrowing; and depreciation as summarised in Table 14.

Table 14: Market Operations Cost Breakdown by Cost Category for Each Jurisdiction

		2016/2017	2017/2018	2018/2019
WA AEMO	Employees Benefit Expense	$5,343,827	$5,420,437	$5,317,122
	Accommodation Costs	$733,592	$885,471	$733,228
	Supplies and Services	$4,218,896	$3,772,066	$3,274,844

		2016/2017	2017/2018	2018/2019
	Borrowing Costs	$147,957	$28,114	$6,013
	Depreciation	$4,768,275	$3,120,054	$2,813,625
	Others			
	Total	**$15,212,547**	**$13,226,141**	**$12,144,831**
Singapore EMC	Employees Benefit Expense	$-	$10,698,485	$9,557,730
	Accommodation Costs	$-	$1,741,371	$1,671,508
	Supplies and Services	$-	$9,403,405	$7,955,043
	Borrowing Costs	$-	$-	$-
	Depreciation	$-	$5,088,558	$3,723,615
	Others	$-	$-	$-
	Total	**$-**	**$26,931,820**	**$22,907,897**
Ireland (SEM)	Employees Benefit Expense	$4,624,577	$1,884,674	$522,641
	Accommodation Costs	$1,029,444	$411,777	$95,026
	Supplies and Services	$6,176,661	$5,289,756	$205,889
	Borrowing Costs	$-	$-	$-
	Depreciation	$5,125,045	$2,136,491	$823,555
	Others	$-	$-	$-
	Total	**$16,955,726**	**$9,722,698**	**$1,647,110**
Ireland (I-SEM)	Employees Benefit Expense	$-	$-	$9,095,529
	Accommodation Costs	$-	$-	$1,544,947
	Supplies and Services	$-	$-	$9,327,154
	Borrowing Costs	$-	$-	$-
	Depreciation	$-	$-	$-
	Total	**$-**	**$-**	**$19,960,668**
UK Elexon	Employees Benefit Expense	$23,999,857	$25,467,653	$23,471,819
	Accommodation Costs	$7,349,177	$7,756,187	$7,443,417
	Supplies and Services	$32,445,647	$32,616,524	$33,466,563

		2016/2017	2017/2018	2018/2019
	Borrowing Costs	$-	$-	$-
	Depreciation	$-	$-	$-
	Others	$873,293	$873,293	$873,293
	Total	**$64,667,973**	**$66,713,657**	**$65,255,092**

Source: TLG Analysis

5.5.1. Ireland Market Operator Operating Expenses

SEMO's operating expenses prior to the I-SEM market are determined in Price Control 2016-2019, which covers three distinct periods, the SEM trading period (Oct 2016 to Oct 2017), SEM resettlement period (Nov 2017 to Dec 2018) and SEM decommissioning period (Jan-19 to start).

During the 2016-2019 price control period, there is only one year of normal SEM operations. In fact, headcount and operating expenses have reduced to reflect the winding down of SEM, detailed in Table 15.

Table 15: SEMO OPEX Budget Under SEM

Million Euro	FY 2016/17	FY 2017/18	FY 2018/19
Full Time Equivalent (FTE)	***42***	***15***	***7***
Payroll	2.92	1.19	0.33
IT and Communications	2.92	2.72	0.02
Facilities and Insurance	0.65	0.26	0.06
Professional Fees	0.31	0.15	0.05
General and Administrative	0.22	0.08	0.01
Corporate Services	0.45	0.39	0.05
Total OPEX	**7.47**	**4.79**	**0.52**

Allowance for SEMO's operating expenses are determined in Price Control 2018-2021[12] whilst SEMOpx's operating expense budget is determined in Price Control 2018-2019[13] covering period from May 2018 to October 2019.

80 percent of operating costs incurred during pre-go live period are to be capitalised with the remaining 20 percent of costs treated as operating expenses, which explains the low allowance during this period.

Headcount has increased during I-SEM period due to the changing roles and responsibilities. Including headcount from SEMOpx, the total FTEs for market operations in I-SEM increased from 42 in 2016/17 to 69.9 in 2018/19.

Table 16: SEMO OPEX Budgets Under I-SEM

SEMO OPEX (Million Euro)	Pre-Go Live@20%	May-Sep 2018	2018/2019	2019/20	2020/21
Full Time Equivalent (FTE)	***22***	***57.2***	***57.2***	***59.2***	***59.5***
Payroll	0.35	1.48	4.60	4.75	4.77
IT and Communications	0.11	0.92	2.75	2.38	2.30
Overheads	0.14	0.64	1.91	1.97	1.97
Facilities & Property Management	*0.06*	*0.27*	*0.80*	*0.82*	*0.83*
Recruitment, HR and Admin costs	*0.02*	*0.11*	*0.32*	*0.34*	*0.33*
Corporate costs	*0.05*	*0.26*	*0.79*	*0.81*	*0.81*
Finance and Regulation Costs	-	0.20	0.60	0.55	0.45
Total OPEX	**0.60**	**3.23**	**9.86**	**9.65**	**9.48**

Overhead costs include costs for facilities and property management, recruitment, HR and administrative costs and corporate costs. As facilities and property management costs are separately categorised by WA as accommodation costs, we have separated this sub category out for cost categorisation for comparison with WA market operator costs.

12 tSEM-18-003

13 SEM-17-096

Table 17: SEMOpx OPEX Budgets Under I-SEM

SEMOpx OPEX ***Million Euro***	**Pre-Go Live@20%**	**May-Sep 2018**	**2018/2019**
Full Time Equivalent (FTE)		***12.65***	***12.65***
Labour Cost	0.13	0.38	1.15
IT and Telecommunications	-	0.02	0.06
Overheads	**0.05**	**0.12**	**0.36**
Facilities & Insurance	*0.02*	*0.06*	*0.17*
Recruitment, HR and Admin costs	*0.02*	*0.03*	*0.09*
Corporate costs	*0.01*	*0.03*	*0.10*
Finance and Regulation Costs	-	0.07	0.20
Contract Services and Market Coupling	-	0.48	1.43
Total OPEX	**0.18**	**1.06**	**3.19**

6. BENCHMARKING SYSTEMS OPERATIONS COSTS

6.1. OVERVIEW

In some markets, typically due to the way the industry was owned and structured before reforms commenced, the system operator function is with the grid operator. For example, the UK's system operator recently became a separate subsidiary of National Grid Gas (NGG) having previously been a "ring-fenced" division. In New Zealand, system operations are part of Transpower, the national transmission company. In Singapore, the system operation function – quite unusually – is a division of EMA, the industry regulator.

6.2. SYSTEM OPERATORS REVIEWED

In this section, we take a deeper look at two system operators:

- New Zealand Transpower; and
- Singapore Power System Operator (PSO).

We focussed particularly on smaller systems for the comparison of System Operations costs.

6.2.1. New Zealand: Transpower

The regulator, New Zealand's Electricity Authority, assigns the role of system operator through a competitive tendering process. Transpower is the system operator as well as the network operator. The system operation role is funded through an incremental and unavoidable cost approach. This means Transpower can only seek funding for the system operations role for costs that uniquely relate to that function. As an example, Transpower will deploy SCADA across its network in its role as network owner. It is only the *incremental cost of SCADA used for system operations* that is to be charged to the system operator function.

6.2.2. Singapore Power: Power System Operator

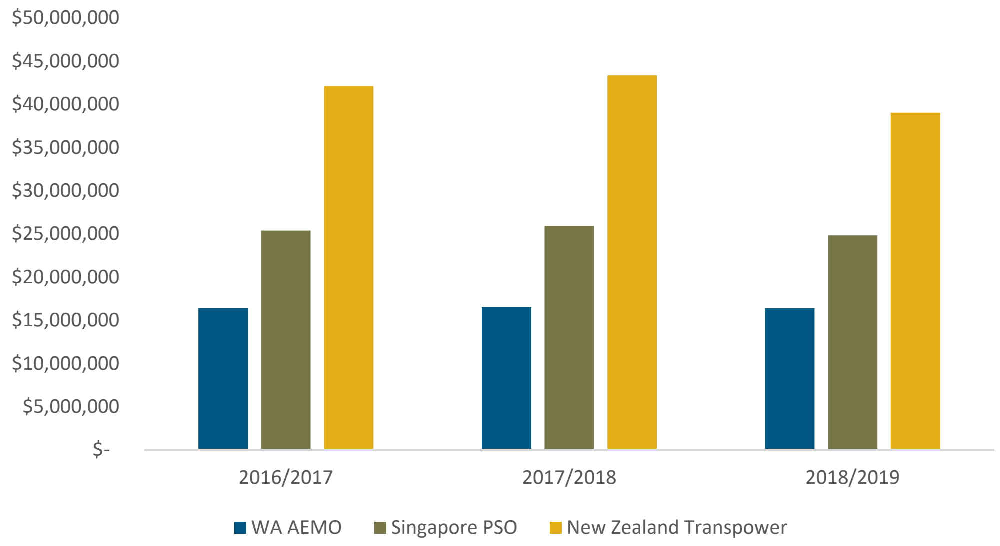
In Singapore the power system operator (PSO) is a subsidiary of the Electricity Market Authority (EMA), the regulatory body. The budget and fees of the system operator are governed by the market rules. Under the Market Rules, it is mandatory in the event of under or over recovery at the end of each fiscal year to publish the revised expenditure and revenue requirements as well as schedule of fees for the remainder of the current five-year fiscal period.

However, because of a rule change in 2010 the requirement for the System Operator to present its budget to the industry Rule Change Panel was removed, thus significantly lessening transparency. Under the Market Rules, PSO is only required to publish its finalised budget and fees for five consecutive fiscal years, see Table 18. However, this arrangement must be interpreted within the context that the EMA already has deeply connected oversight owing to its direct control over the system operator as a subsidiary entity to EMA itself. Consequently, there is much less public information about PSO operations.

6.3. Benchmarking Results

On a total cost basis of the jurisdictions benchmarked WA is the least cost, demonstrated in Figure 27.

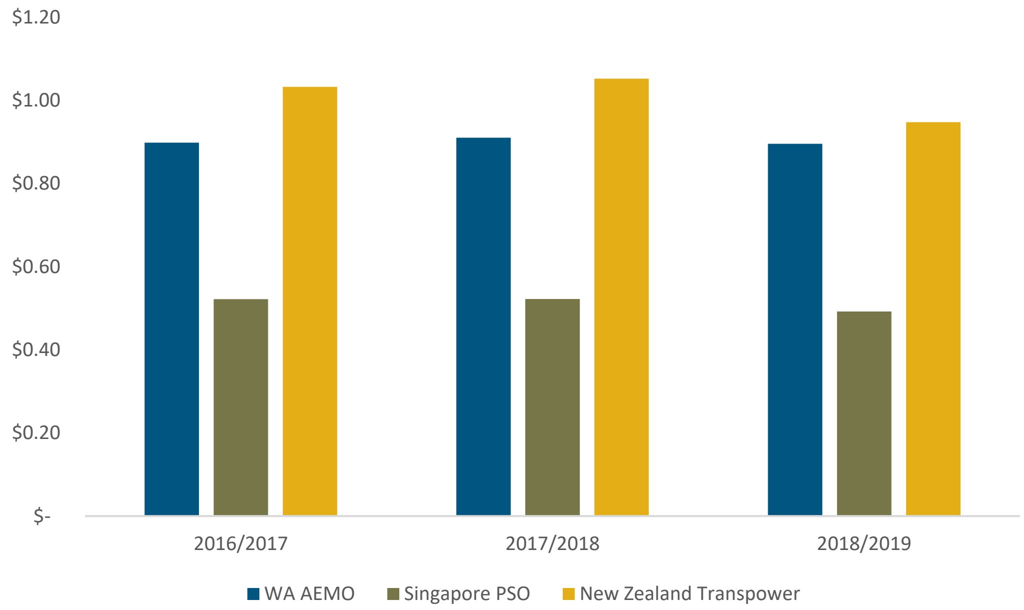
Figure 27: Comparison of System Operations Cost (Total)



Source: Publicly available annual report data adjust to Australian Dollars

When the system operations costs are equalised on demand Singapore resulted with the lowest cost, shown in Figure 28. Singapore's PSO control centres are in two locations outside of Singapore's more expensive central business district. Singapore's PSO is unable to share information beyond the limited information it is compelled to make available under the market rules.

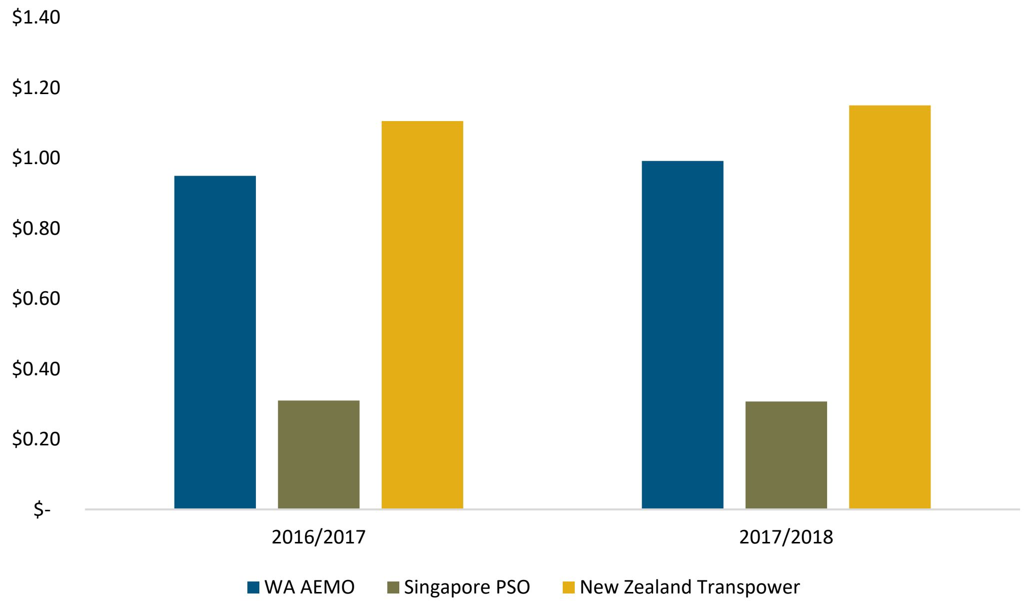
Figure 28: Comparison of System Operations Cost (per MWh)



Source: Publicly available annual report data adjust to Australian Dollars

Figure 29, compares system operations costs per MWh equalised using the World Bank's Purchasing Power Parity (PPP) ratio.

Figure 29: Comparison of System Operations Costs (per MWh) on a PPP Basis

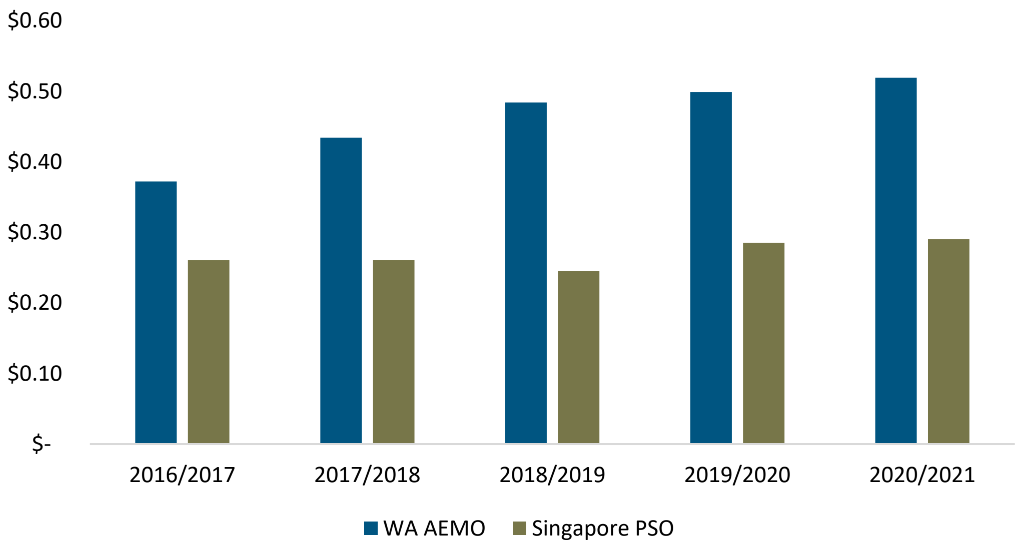


Source: World Bank PPP conversion factor https://data.worldbank.org/indicator/PA.NUS.PPPC.RF

Transpower's system operations costs are predominately operational in nature, constituting approximately 60% of the total costs for Transpower's system operations function. The balance of the costs comprise depreciation for capital expenditure and a budgeted allowance for market development. Transpower has around 100 employees working as part of the system operator function. Roughly 30 are employed in the control room, an additional approximately 15 power system engineers and around 15 other employees support the energy market. Transpower operates two control centres, with one located in the central business district in Wellington and the other located in Hamilton, over 500 kilometres away.

System operator market fees in Singapore are lower than in WA, as shown in Figure 30.

Figure 30: Market Fee for System Operation WA and Singapore ($/MWh)



Source: Energy Market Authority; adjusted to Australian Dollars

Table 18: Singapore's PSO Budget and Fees

	FY 2016/17	FY 2017/18	FY 2018/19	FY 2019/20	FY 2020/21
PSO finalised expenditure and revenue requirement for 5-fiscal year period ($'000)	24,781	26,837	27,483	28,212	29,300
Previous year's audited adjustments	(450)	(1,976)	(3,692)	-	-
PSO finalised expenditure and revenue requirement for each FY	24,331	24,861	23,791	28,212	29,300
Projected Electricity Sales (GWh)	48,664*	49,643*	50,596	51,566	52,563

Estimated PSO Fees ($/MWh)**	$0.2500	$0.2504	$0.2351	$0.2736	$0.2787

Source: Energy Market Authority

As can be seen in Table 18 expenditures increased at an average annual rate of about four percent from the FY 2016/17 year to FY 2020/21. Fees increased at a somewhat lower rate of 2.8 percent due to increased electricity sales growth.

7. GAS SERVICES INFORMATION

The Gas Services Information funding in WA is particularly challenging to benchmark due to the difficulty in finding comparable functions amongst other jurisdictions. The Gas Industry Company (GIC), in New Zealand, has a similar role as WA AEMO in so far as providing information on the state of the gas industry, gas availability and forecasting gas demand/production. However, New Zealand's GIC has additional roles that go beyond the Gas Information Services, such as oversight of a gas spot market.

The GIC's role that's most similar to the WA Gas Services Information is providing efficient, competitive, and confident gas markets (of which information disclosure is a sub-set). This is funded partly through market fees with the remainder through a levy on industry participants.

GIC gas information services are captured under its Strategic Goal 1 (see Table 19) which has a total fee of NZ$758k. This compares to the much narrower role performed in WA which has an annual fee of around AUD$1.9 million.

Table 19: Gas Industry Company (GIC) Work Programme and Levy, FY2020

Description	$
Strategic Goal 1: Provide efficient, competitive, and confident gas markets	
Comprising: Retail Contracts Oversight Scheme, Gas Distribution Contracts Oversight Scheme; Regulation and Rule Changes; Retailer Insolvency: Gas Quality; Gas Measurement; Supply/Demand Model; Wholesale Market; Information disclosure.	758,361
Strategic Goal 2: Facilitate efficient use of, and investment in, gas infrastructure	
Comprising: Transmission Access and Pricing' Transmission Pipeline Balancing: Transmission Code Changes and Appeals;Transmission Pipeline Interconnection; Gas Transmission Security and Reliability.	1,222,002
Strategic Goal 3: Deliver effectively on Gas Industry Co's accountabilities as the gas industry body	
Comprising: Downstream Reconciliation; Switching and Registry; Critical Contingency Management; Compliance and Enforcement; Statement of Intent and Annual Report.	3,092,010
Strategic Goal 4: Develop and communicate the role of gas in meeting New Zealand's energy needs	
Comprising: New Zealand Gas Story; Other Reporting.	159,963
Total Work Programme Costs	**5,232,336**
Less: Approximate Market Fees	**1,458,000**
Levy Funding Requirement	**3,774,336**

Source: Gas Industry Company - Consultation on Gas Industry Co FY2020, Work Programme and Levy

We also note from the proposed 2020 work programme for the GIC that information disclosure concerns have been expressed by some market participants regarding asymmetric access to information, particularly information regarding upstream outages (both planned and unplanned). In parallel, the New Zealand Minister of Energy and Resources has written to GIC expressing concern with the lack of transparency regarding upstream activities and asking whether the Gas Act provides the necessary tools to address this issue.

While the Gas Act would need to be amended to support this matter, the GIC has commenced a work stream to consider options for addressing this issue as well as seeking information as to what the upstream sector, together with large end-users, may be willing to do to remove the information asymmetry. The workstream is expected to require 0.6 FTE (subject to adjustment as the work proceeds). By the end of FY2019, following industry consultation and preparation of an options paper the GIC is to identify whether a non-regulated solution is feasible or if regulation is likely to be required.

Accordingly, the AEMO WA Gas Services Information costs are more than double that of the single comparative benchmark that we have been able to find. We do however caution that this is based on a single observation where additional work is considered necessary to enhance transparency and that we have been unable to explore deeper on the specifics of what this function entails in the benchmark jurisdiction (New Zealand).

8. OTHER ISSUES

Efficiency targets are one way to obtain incremental information not otherwise easily observed about the relationship between budgets, costs, and performance. If appropriately defined and measured, they can secure a stronger nexus between costs incurred and specific performance attributes of particular value to stakeholders.

8.1. EFFICIENCY INCENTIVE EXAMPLES

8.1.1. New Zealand Transpower (System Operator)

Within the agreement with the Electricity Authority, Transpower is subject to a number of performance metrics and incentives that are negotiated and set yearly for the next financial year. Transpower is required to monitor and report on its performance against the performance metrics.

Up until 2016 Transpower has had a fixed allowable budget with which to perform its role, with capital project approvals being treated as additional. From 2016, however, the funding arrangements were changed to allow Transpower to take on some capital budgeting and execution risk. In the past Transpower would need to negotiate with the Authority for each new project it commenced. However, it observed that the level of capital required was approximately the same each year. As a matter of ordinary steady-state operations, this is not particularly surprising given that the number of normal capital projects that can be concurrently deployed is at least partly constrained by the size and skills of the available team; the ability of the industry to absorb change; and the related challenges of managing risks associated with attempting to deliver too much change at one time while maintaining all other objectives.

It was thus agreed between Transpower and the Authority that an annual allowance for capital projects could be agreed (split approximately two-thirds on service maintenance projects and one-third on market development projects). This approach also helped to smooth levies to the industry. This risk arrangement also provides Transpower the ability to benefit from early and successful capital project spending.

Before commencing a high value capex project Transpower is required to negotiate with the Authority. A part of the negotiation is agreeing on project delivery incentives[14]. The delivery incentive is a payment from the authority to Transpower for the successful implementation of a high value project. The two parties agree on the:

- Delivery incentive value;
- Early delivery incentive date;

14 See System operator service provider agreement available at https://www.ea.govt.nz

- No delivery incentive date; and the
- Late delivery incentive date.

If Transpower is able to commission the project on or before the early delivery incentive date, then Transpower receives 100 percent of the delivery incentive. If Transpower commissions the project between the early delivery incentive date and the no delivery incentive date, then Transpower receives a pro rata payment of the delivery incentive. If the commissioning of the project occurs after the no delivery incentive date, then Transpower does not receive the delivery incentive payment. However, if the project is commissioned after the late delivery incentive date, then Transpower is required to pay the Authority the delivery incentive value. If the project is commissioned between the no delivery incentive date and the late delivery incentive date, then Transpower power is required to pay the authority the delivery incentive payment on a pro rata basis.

8.1.2. Singapore Market Operator (EMC)

The Singapore market operator, EMC, operates under a 10-year licence granted by the regulator, EMA. The licence was initially granted on 1 January 2003 and subsequently renewed on 1 January 2013. The licence renewal process provides some competitive tension on EMC to maintain high service levels, compliance, and an efficient cost structure. Additionally, EMC licence provides for the recovery of costs, together with a reasonable return to be determined by the EMA having regard for the capital and operating costs incurred by EMC and any inherent risks associated with providing the applicable services.

Regulatory Regime

Costs and a 'reasonable' return are set using a Revenue Regulatory Regime for each successive five-year period. EMC will be allowed to charge a fixed $/MWh fee for electricity traded in the NEMS for each 12 months period from 1 April to 31 March in each of the five years. Costs are set based on bottom-up zero-based budget projections taking into account forecasted capital projects and depreciation. Returns are set using a WACC return set by the regulator. To the extent that EMC is able to deliver projects and services below the profiles used in the five-year model, it is able to retain these cost-efficiencies as additional profits until the next five-year regulatory reset. Yearly adjustments would be made to EMC's price cap in each year for exogenous costs and savings not arising from efficiency actions by EMC (e.g. depreciation savings due to project delays).

Under the new five-year period from 1 April 2018 this scheme was tightened to introduce some caps and banding around additional profits with a sharing mechanism with industry participants.

Performance Incentive Sceme

EMC's licence provides for a "performance-based regulation regime". Initially EMC was given a balanced scorecard system by the EMA to measure and incentivise its performance based on six measures, of which three were quantitiave and three were qualitative. The quantitative measures were based around its market operations in three key areas: system up-time (essential for a ½ hour, continuously traded market); pricing accuracy; and settlement accuracy (to provide confidence to stakeholders around market outcomes and payment certainty). The qualitative measures were based on annual surveys of market participants and governance committees. These surveys were conducted by EMC's external auditors to measure satisfaction around its customer responsiveness, market assessment and rule change management. This was intended to ensure that EMC maintained an outward customer focus on its services. The targets and associated performane achieved are summarised in Table 20.

Table 20: Performance Incentive Scheme, Singapore Market Operator

Targets and performance	Approved target	Actual Performance	
		FY 2011/2012	FY 2012/13
Quantitative Measures			
System Availability	99.90%	99.99%	99.99%
Pricing Accuracy	99.70%	100.00%	99.99%
Settlement Accuracy	99.90%	100.00%	100.00%
Qualitative Measures (Satisfaction rating)			
Customer Responsiveness	85.00%	78.05%	92.50%
Market Assessment	90.00%	83.33%	83.33%
Rule Changes	85.00%	79.41%	92.47%

Source: EMC Bulletin, issue 74, May-July 2013

The system was intended to incentivise high performance and was called the Performance Incentive Management System (PIMS). Under this system, if EMC exceeded the approved targets it would earn additional revenue (capped at two percent of its approved regulatory revenues). Conversely, if targets were not met the incentive was reduced (with a zero floor).

The EMA removed the system, with effect from 1 April 2013, on the basis that a performance management system that it was not necessary to maintaining the desired level of performance (which was being routinely achieved).

Budget Process

Singapore's EMC provides a useful example of transparency with regard to budget formation. EMC takes the view that, given the industry will ultimately pay for the market operator's cost, the industry should have a say on whether these costs are acceptable and whether the budget is targeted in the right areas to address industry priorities. This philosophy is also evident in the budget approach adopted by PJM, as previously noted.

The process followed is shown in Table 21 below.

Table 21: EMC's Obligations with Respect to Rules and Market Licence in Preparation of Budgets

Requirements	Action to be taken by
Market Rules Chapter 2 sections 10.1.1.1 and 10.1.1.2 No less than 100 days prior to the beginning of each fiscal year EMC is: To submit proposed expenditure and revenue requirements and a schedule of fees for the following fiscal year to the RCP for review; and Publish notice of its proposed expenditure and revenue and schedule of fees	23 March
Market Rules Chapter 2 section 10.1.4 The RCP shall submit a written report to the EMC Board indicating the views of the RCP and a summary of any material submissions from interested persons pursuant to Chapter 2 section 10.1.1.2 Market Rules Chapter 2 Section 10.1.5 The RCP report shall be submitted to the EMC Board no later than 75 days before the beginning of the new fiscal year	17 April
Market Rules Chapter 2 section 11.1.1 EMC shall no less than 60 days prior to the beginning of the fiscal year to submit to the EMA for the approval its proposed expenditure and revenue requirements and either: a schedule of fees or a statement of fee methodology	30 April
Market Licence Condition 18 "The Licensee shall, no less than 60 days before the beginning of the Licensee's fiscal year, submit to the Authority the Licensees proposed expenditure and revenue requirements for the following fiscal year to the Authority for review and approval … in the manner and to the extent … in the manner and to the extent, if any, required by the market rules."	30 April

Source: EMC Budget Publication

8.1.3. Ireland Budgeting Process and Governance

SEMO's operational and capital costs are recovered through Market Operator tariffs and fees, levied on market participants. The budget is set and approved through a *price control*, approved by the SEM Committee (SEMC) that set's out SEMO's allowable revenue for a three-year period.

SEMO provides a submission to the SEMC outlining its revenue requirements. SEMC's principal objective is to protect the interests of electricity consumers. In carrying out that function, SEMC gives particular regard to the following principles when evaluating SEMO's revenue submission:

- Transparent;
- Accountable;
- Proportionate;
- Consistent; and
- Targeted.

OPEX

SEMO's operational expenditure is regulated and incentivised through the application of a revenue cap. Revenue cap regulation incentivises SEMO to reduce costs by increasing efficiency of internal processes and seeking cost savings on purchased products or services. Any efficiency and price savings are retained by SEMO while overspends must be absorbed unless approved by the regulator on the basis that the overspend has been efficiently and prudently incurred.

Since the SEM was being wound down during the 2016-2019 price control period, SEMO was granted the ability to pass on the cost of any overspend related to the resettlement and decommission of SEM. Additionally, any underspend related to the SEM resettlement and decommissioning was to be returned to customers.

CAPEX

SEMO's capital expenditure is regulated via set rate for return. This provides a return to SEMO based on its regulated asset base. SEMO regulated asset base is calculated based on the actual historical costs of their asset base, depreciated on a straight-line basis over five years and increased each year for any additions. The additions are subsequently then subject to the same depreciation policy. SEMO's regulated asset base value is indexed each year, for inflation, and a rate of return (representing compensation for risk and the opportunity cost of the capital) is provided. The rate of return (WACC) is a combination of the WACC applicable to EirGrid and SONI.

Incentivisation

The price control framework for SEMO includes key performance indicators to incentivise performance. The key performance indicators are aimed at improving performance, promoting customer service, increasing efficiencies and delivering value to customers. SEMO's performance against the indicators, see Table 22, is assed quarterly. SEMO can receive up to a maximum of 4% of total OPEX revenue for each year as a result of performance payments.

Table 22: SEMO Key Performance Indicators

	Weightings	Target	Upper Bound
Ex-ante pricing report	0.15	99%	100%
Ex-post initial pricing report	0.10	99%	100%
Invoicing	0.20	97%	100%
Credit Cover Increase Notices	0.10	99%	100%
SEMO related resettlement queries	0.20	<9[1]	<5[2]
General Queries	0.15	97%[3]	99%[4]
System Availability (7am to 5pm Mon-Sun)	0.10	99.5%[5]	99.9%[6]

Source: Decision Paper on SEMO Price Control 2016-19

Note: 1) 9 or less upheld queries incidents per quarter
2) 5 upheld queries incidents per quarter
3) 97% of Queries answered within 20 business days
4) 99% of Queries answered within 20 business days
5) 99.5% System availability between 7am and 5pm Monday to Sunday excluding planned outages
6) 99.9% System availability between 7am and 5pm Monday to Sunday excluding planned outages

8.2. INSIGHTS FROM JURISDICTIONAL INTERVIEWS

Throughout this benchmarking exercise TLG interviewed contacts from other jurisdictions, below is a high level summary of key insights from those discussions.

8.2.1. Partnership Approach

One of our responders highlighted the value of taking a longer term 'partnership' approach between the operator and the regulator. Having a longer contract or license period provided more certainty for the operator to take a longer-term view to innovate and invest, being able to spread capital recovery over the longer period (shorter period contracts limit investment and payback period which is often counter to overall cost efficiency). This allowed the operator to build a track record of delivery to leverage on "not having to always be the cheapest all of the time". The idea being that a single trusted provider could deliver a lower risk solution with reduced co-ordination costs than multiple providers. In return, some of this additional value earned could be offered back to the regulator in the way of fee reductions to industry part way through contract/license periods.

Under this 'partnership' model the license/contract arrangements allowed the regulator to use a number of safety checks that competitive prices were being offered, including using open book pricing, requiring charge out rates consistent with other (non-electricity) customers, and independent audit. Where incremental revenues were earned from electricity customers by the operator they could be shared with the regulator (to recognize the leveraging of operator costs between regulated and non-regulated activities to the same customer).

8.2.2. Risk Sharing

A responder discussed with us that in some circumstance a more cost-effective outcome could arise from the operator taking on additional risk in return for a potential upside gain (or potential downside loss). However, it was stressed that this risk sharing needed to be agreed between the regulator and operator to ensure that the way each priced risk was the same. In most case this risk sharing would have a ceiling and a floor and may also have a number of tranches where additional profit/losses were shared between the operator and the industry.

8.2.3. Contributing to Sector Development

One responder highlighted the importance of the regulator "leaving enough flesh on the bone" so that the operator would have sufficient capability and capacity to support sector development initiatives that may have not been explicitly known at the beginning of the planning/budgeting cycle. This additional capacity also provided some buffer for incremental operator tasks to be required by the regulator before having to require an explicit review for additional revenues to be provided.

Another responder stated that they had explicitly provided (and been approved budget) for one FTE to provide consultancy services to their regulator.

8.2.4. Broader Efficiency Incentives

As well as explaining to us the official efficiency measures used in their jurisdiction one of our responders highlighted that other unintended incentives for efficiency were also in place to drive customer focused service delivery and cost effectiveness. This was, as an entity able to pursue other commercial activities, maintaining positive relationships with their electricity industry customers helped them (or other parts of their holding company) the ability to secure additional commercial business.

8.2.5. Reform Activity Experience

All markets should have in their cost structures the capacity to identify and implement small step improvements on a continuous basis (markets that fail to adapt to keep pace with normal industry evolution and improvements in technology will lose relevance with their stakeholders fairly quickly). However, when it comes to larger reform activity, each jurisdiction will have different ways that they manage the resourcing and funding for this. Even further, based on our own experience, and as confirmed with our recent discussions with senior managers in our benchmarking jurisdictions, the way this is handled can vary from project to project within the same jurisdiction.

The accounting treatment for large capital projects can also vary from jurisdiction to jurisdiction and this can affect the way that costs are carried on balance sheets and ultimately reported through income statements. Key material differences will be in two areas – the treatment of intangible assets (the capitalisation of employee costs spent on project implementation) and the depreciation period used (how to assess the useful asset life of a project's output). Other accounting treatment variations will result from an operators' decisions around ownership of infrastructure (e.g. are large computer systems purchased, leased or tele-housed) – this is unlikely to have a significant net income statement difference but will shift large cost components between depreciation and service costs.

Funding decisions will also vary from jurisdiction to jurisdiction and project to project with decisions not necessarily being solely based on rational cost effectiveness. For example, the level of (or lack of) transparency can also be a driver. In some cases, an operator will fund large capital projects (and recover this cost through an increase in its regulated asset base and consequential increase in WACC return) or an explicit and externalised industry development fund may be utilised with costs therefore sitting outside of the operator's accounts.

Typically, most regulators will be concerned with the cost impact of reforms on market participants (and ultimately consumers). A common theme that we hear is a desire to smooth out the impact of significant sector developments over a longer period of time. What we tend to see is that because of this desire for smoothing, combined with a operators' limited capacity to manage large projects, the associated risk aversion for concurrent projects, and market evolutionary paths being more sequential than parallel, is that most jurisdictions will have a predictable and fairly level cost incidence of reform activity when viewed over a longer period of time.

We thus see that depreciation expensed each year remains fairly even (as older projects become fully depreciated newer ones replace them). Staffing numbers (at a headline level) may be peakier, but because of the way staff costs related to reform projects are capitalised (intangible assets), employee costs at an operational expense level remain fairly even. Over the longer-term staffing levels may increase to cope with the new operational demands of a more complex and evolved market design but this is also offset (at least partially) by automation in other areas as greater use of technological developments are deployed. As greater IT infrastructure is required to cope with increased data volumes, increased market granularity (e.g. moves to 5-minute pricing), and more real -time computation power (e.g. a shift from ex-ante and ex-post to real-time security constrained schedules) this has largely been offset by technological advances and computing costs reducing (thus significant IT assets may be replaced every 5 years but this is often at a similar cost to that originally incurred but with significantly enhanced capacity and power).

8.3. Summary

The use of efficiency incentives and more transparent budget setting involvement more stakeholder input and review are two well-established approaches to increase the credibility and relevance of the fees paid by stakeholders. The extent to which specific incentives are appropriate depends on the nature of the underlying expenditures and their controllability. New Zealand's approach has evolved to provide more flexibility over capital budgeting. Singapore's performance incentive approach was removed after it was found the incentives were easily met. Both Singapore and PJM adopt a more stakeholder-engaged budgeting process. All of these approaches highlight the importance that each market adopt mechanisms and approaches to both incentivise where possible and to enhance credibility where necessary.

APPENDIX A

A.1 New Zealand Energy Market

A.1.1 Service Provider Contracting (Electricity Authority)

The Electricity Authority contracts a range of market operation service providers to operate the electricity markets. They aim to create fit-for-purpose market services that increase market efficiency, ensure effective market operation and facilitate market development.

The service provider roles are summarised below and then covered in more detail in the Market Operator and System operator sections.

Clearing Manager

The clearing manager is responsible for ensuring that industry participants pay or are paid the correct amount for the electricity they generated or consumed and for market-related costs.

NZX manages the clearing and settlement arrangements for the wholesale market. This entails the monthly settlement of all trades on the spot and financial transmission rights markets, and the billing for all transmission ancillary services. In addition, NZX actively monitors the risk exposure of market participants to the spot market and ensures sufficient prudential security is available to meet their market obligations.

Extended Reserve Manager

NZX's role as Extended Reserve Manager (ERM) is to select and monitor blocks of load that can be automatically disconnected during large under-frequency events in the electricity system.

Financial Transmission Rights (FTR) manager

The FTR manager is responsible for the creation and allocation of financial transmission rights (FTRs). The FTR manager:

- creates inter-island and intra-island FTRs;
- allocates FTRs to industry participants via regular auctions;
- manages the FTR register, in which all FTR holdings are publicly listed;
- registers parties who wish to participate in FTR auctions; and
- undertakes other activities associated with operating, promoting and developing the FTR market.

Energy Market Services (EMS), a division of Transpower, is contracted as the FTR manager.

Pricing Manager

The pricing manager is responsible for calculating and publishing the spot prices at which electricity market transactions are settled. Over 12,000 spot prices every day are published by the pricing manager to market participants through WITS (Wholesale Information and Trading System).

On a daily basis, NZX calculates the half-hour energy and reserve market settlement prices at approximately 270 grid locations. These prices are also used by the sector across a range of areas such as derivative contract valuation and price scenario forecasting. NZX uses a suite of established procedures and analytical tools to ensure a robust and accurate price is calculated.

Reconciliation Manager

Ensuring that industry participants (electricity generators or buyers) are allocated their correct share of electricity generation or consumption is a key role in operating an efficient market.

NZX in its reconciliation role is responsible for allocating all quantities of electricity consumed to purchasers and all quantities of electricity supplied to generators. NZX uses the metering information supplied by market participants to scale, calculate and allocate unaccounted for electricity. Quantity information calculated in this process is used for monthly spot market settlement.

Registry Manager

The registry manager oversees the registry to facilitate switching of retail customers.

The main processes that the registry manager oversees are:

- the maintenance and validation of installation control point (ICP) information, both current and historical, via online and batch functions;
- a notification facility that advises all affected participants of changes made to ICP information;
- a delivery mechanism for the switching protocols;
- the provision of ICP look-up facilities to authorised participants, both online and in batch (file) mode; and
- the provision of compliance reporting.

Part 11 of the Code details the management of information held by the registry and outlines the process for switching customers between retailers, metering equipment providers and distributors.

Jade Software Corporation (New Zealand) Limited is contracted as the registry manager.

System Operator

The system operator is responsible for co-ordinating electricity supply and demand in real time in a manner that avoids fluctuations in frequency or disruption of supply.

Wholesale Information and Trading System (WITS) Manager

The wholesale information system manager runs the wholesale information and trading system (WITS) used by industry participants to upload their bids and offers.

NZX operates the trading and information system used to support the 24-hour buying and selling of spot market electricity. The Wholesale Information and Trading System (WITS) processes around 25,000 market orders per day and publishes information such as dispatch schedules, transmission constraints and nodal prices.

Stress Testing

NZX, as an independent registrar, manages the stress test collection and reporting process. Electricity market participants purchasing electricity from the clearing manager, and consumers directly connected to the national grid, are required under the code to produce a spot price risk disclosure statement no later than five working days before the beginning of the quarter. This disclosure statement is used to indicate their risk exposure to the market spot price.

A.1.2 Market Operator (NZX)

The market operator is responsible for the following areas:

Pricing Manager

- The primary role of the pricing manager is to calculate financial binding prices for the wholesale electricity market.
- Prices are calculated using the system operator’s Scheduling, Pricing and Dispatch (SPD) model. This is the same model used by the system operator to forecast prices and dispatch generation.
- Prices are calculated the day after trading for all grid exit points and grid injection points, for every half hour trading period.
- Prices are published on WITS.
- The pricing manager also manages the pricing error claim process.

WITS (Wholesale Information Trading System)

WITS is the wholesale information trading system, it:

- Allows participants to upload offers and bids for the wholesale electricity market;
- Provides access to pricing information published by the system operator and pricing manager. Besides prices, participants can also view their forecast cleared generation, HVDC flows, transmission constraints and SPD infeasibilities; and
- Provides access to the clearing manager portal. Participants use this portal to receive invoices, statements and prudential information.

Reconciliation Manager

The reconciliation manager is responsible for calculating the quantity of electricity purchased and generated by each participant in the wholesale electricity market.

- On a monthly basis, calculate purchase and generation quantities for every trading period and grid location.
- Key inputs to this calculation include:
  - Metered grid quantities; and
  - Participant quantity submissions (referred to as “volume submissions”).
- As part of the calculation process the reconciliation manager will:
  - Adjust volume submissions to account for electrical losses within a network;
  - On a monthly basis, convert non-half hourly volume submissions to a half hourly basis. This is achieved using a ‘profile’ either provided by the participant or as calculated by the reconciliation manager; and
  - Calculate unaccounted for electricity and apportion this to participants. Unaccounted for electricity is where there is a difference between metered grid quantities and total participant quantity submissions.

Clearing Manager

The clearing manager has the following key functions:

- Ensuring participants maintain the minimum amount of prudential security defined in the Code. This includes calculating minimum prudential security amounts on a daily basis and monitoring each participant’s security holdings.

- Preparing invoices and statements for participant purchases and sales of electricity to the wholesale electricity market. Invoices also cover ancillary services (as provided by the system operator), and financial transmission rights (FTRs).

Ensuring the orderly payment of invoices as required to settle the market

A.1.3 System Operator (Transpower)

As the System Operator, Transpower is responsible for managing the real-time power system and operating the wholesale electricity market.

The System operator is regulated by the Electricity Authority in accordance with the Electricity Industry Participation Code (the Code).

The organisation of Transpower's System Operations group is based on the time-focus of the various tasks needed to be undertaken:

- Real Time;
- Short to Medium Term;
- Medium Term; and
- Long Term.

Real Time

The System Operations Manager and the team of system co-ordinators and support staff have the task, in real time, of managing the power system, in accordance with the rules and regulations which define the market structure in New Zealand, and meeting the performance objectives that the system operator is required to achieve.

Short to Medium Term

The Engineering Manager provides support functions for the real time group. This includes all of the necessary investigations and planning to ensure that the ultimate delivery of the system operator function in real time is well planned and understood prior to its real time implementation. A key function is the security planning to ensure the "lights stay on", if at all possible, in real time.

Medium Term

The Business Manager is responsible for the overall risk management within the system operator group. In addition, there is a requirement for monitoring the compliance and performance of the System Operator to ensure it meets its performance objectives as required by the Electricity Authority.

Long Term

The Market Manager is required to plan and develop new systems both in terms of IT&T products, and of market and system operations tools. This will allow Transpower to deliver the system operator function to the Electricity Authority and all industry parties more efficiently.

A.2 Singapore Energy Market

The *Electricity Act* was enacted in 2001 to govern the electricity sector and the electricity market. The act provided for the licensing of generation, transmission, retail, market support services and wholesale market operator licensees. It enabled the establishment of the wholesale electricity market via the market operator and the Market Rules.

The rights and obligations of the participants in the wholesale market are set out principally in the Singapore Electricity Market Rules, and in the electricity licences and codes of practice issued by the EMA. The major themes are transparency, equity and ownership of the Market Rules by the market participants. The Market Rules are, in effect, a contract between each market participant and EMC. The objectives (or guiding principles) of the Market Rules are:

- To establish and govern efficient, competitive and reliable markets for the wholesale selling and buying of electricity and ancillary services in Singapore;
- To provide market participants and the Market Support Services Licensees (MSSLs) with non-discriminatory access to the transmission system;
- To facilitate competition in the generation of electricity; and
- To protect the interests of consumers with respect to price, reliability and quality of electricity service.

The Market Rules govern the following areas:

- Participation;
- Administration, supervision and enforcement;
- System operation;
- Market operation; and
- Settlements.

Governance of the market is achieved through the rule change process, market surveillance and compliance, and dispute resolution and compensation. These processes are discussed in more detail later in this chapter.

The objectives of the governance structure are to fairly and efficiently:

- Evolve the rules;
- Settle market related compensation claims;
- Settle market disputes; and
- Provide incentives to comply with the rules.

On 1 January 2003, the National Electricity Market of Singapore (NEMS) commenced operations. It is a real-time energy-only spot market, trading energy, reserves of three classes and regulation at each half hourly interval.

Key features of NEMS are:

- It produces a real time, physically feasible, security constrained, dispatch;
- Relies on generation self-commitment;
- Uses nodal pricing; and
- Co-optimizes energy, reserves and regulation.

The real-time prices determined by the market reflect the fundamentals of demand and supply taking into consideration the power system and market constraints. Prices determined in NEMS send signals to investors for generation planting and also influence consumer consumption patterns.

A.2.1 Market Operations (EMC)

EMC is the sole market company licensed by EMA to operate and administer Singapore's wholesale electricity market called the National Electricity Market of Singapore (NEMS). Besides operating and administrating the NEMS, EMC also schedules generating units and settles accounts of market participants. Its key activities include calculating prices, scheduling generation, clearing and settling market transactions as well as supporting governance of the market.

The EMC's functions are to:

- Operate and administer the wholesale market;
- Prepare schedules for generating units, loads and the transmission system;
- Settle accounts of market participants;
- Facilitate the planning and augmentation of the transmission system;
- Provide information and other services to facilitate decisions for investment and the use of resources in the electricity industry; and

- Exercise and perform the functions, powers and duties assigned to the EMC under the Electricity Act, its electricity licence, the market rules and applicable codes of practice.

Under the market rules, some of the EMC's functions are required to be carried out by persons, panels or committees appointed by the EMC. These are:

- Energy Market Company Board - The market rules assign certain functions, powers and duties specifically to the EMC Board and prohibit it from assigning or delegating them. These include voting on rule changes.
- Dispute Resolution Counsellor and Dispute Resolution Panels - The dispute resolution counsellor is responsible for managing the dispute resolution process described in the market rules and for facilitating the resolution of individual disputes. The dispute resolution counsellor is also responsible for selecting a group of people onto a roster from which persons may then be selected to form a dispute resolution panel in respect of individual disputes. The dispute resolution counsellor is appointed by the EMC Board and is required to act independently of the marketplace.
- Rules Change Panel - The principal tasks of the rules change panel are:
  - To review any proposed changes to the market rules (including any changes that it may itself have proposed) and to provide recommendations in this regard to the EMC Board;
  - To review proposed market manuals and the system operation manual, and any changes to them;
  - To review the EMC’s and PSO’s budgets and fees (the PSO budget fee review was removed in 2010 through a rule change); and
  - Market Surveillance and Compliance Panel - The market surveillance and compliance panel is an external panel established by the EMC Board to monitor the conduct of market participants and MSSLs in the wholesale market and the structure and performance of the wholesale electricity market itself. It is assisted by the EMC's internal market assessment unit.

Market Operations

EMC’s Market Operations department provides the trading platform for generators and retailers to sell and buy electricity. The market operates continuously and establishes prices and quantities every half-hour for the energy, reserve and regulation products traded.

A key function of the Market Operations department is to determine the real-time dispatch schedule for the Power System Operator to issue the dispatch instructions to the applicable generators. A dispatch schedule is determined based on the offers submitted by generators and the forecast demand for electricity, taking into account the physical configuration of the transmission system.

EMC is the counterparty for all electricity transactions and acts as the central clearinghouse and settlement agent for all market transactions and fees. To ensure that the market remains financially secure, it operates a prudential settlement regime.

The Market Operations department also studies market price trends and market outcomes and provides market data and analyses to market participants and the public via EMC's website.

EMC also acts as the contracting party for the ancillary services necessary to ensure the reliability and security of the physical supply of electricity.

Market Administration

EMC's Market Administration team manages the market rules change process. It conducts analyses of rule change proposals and advises the market Rules Change Panel (RCP), the EMC Board and the EMA.

The team analyses market issues and explores new concepts using economic, legal, engineering and cost-benefit frameworks with the objective of improving the operational and economic efficiency of the market.

The team regularly engages and consults with market participants, the Power System Operator and other stakeholders. It also prepares annual two-year work plans for the RCP based on a formal survey of all market participants.

Proactive management of the evolution of the market framework ensures that the market structures remain relevant and that new sources of efficiency continue to be identified.

The team also registers participants and generation and load facilities for the wholesale market.

Market Assessment

EMC's Market Assessment Unit (MAU) manages the market surveillance, compliance and dispute resolution processes. It advises and supports three external and independent governance bodies, namely the Market Surveillance and Compliance Panel (MSCP), the Dispute Resolution Counsellor (DRC) and the Dispute Resolution and Compensation Panel (DRCP).

The MAU enforces compliance with the market rules through its surveillance activities, investigations of alleged rule breaches and supporting and advising the independent MSCP on enforcement actions. It monitors the outcomes of the wholesale electricity market as well as the behaviours of market participants to check that the market functions efficiently and identifies areas of inefficiency. It provides market training to and advises the MSCP on the state of competition and efficiency of the wholesale market in order for the panel to recommend changes or remedial actions to the Authority to address areas of inefficiency.

The MAU assists the DRC to set up and maintain dispute management systems among market participants. It provides market training and operational support to the DRC and DRCP members on all dispute-related matters.

A.2.2 System Operator (Power System Operator)

In Singapore, the Power System Operator (PSO), is a division of the Regulator, EMA. The PSO is responsible for the reliable supply of electricity to consumers, as well as the operation of the power system in Singapore.

As the natural gas and power systems are closely interlinked, PSO also oversees the operation of the natural gas transmission system.

To ensure future electricity generation and transmission capacities remain adequate and reliable, PSO carries out power system studies. Additionally, it assesses the impact of new generating plants as well as the expansion plans of electricity and gas transmission licensees.

In addition to operating the real time system, the Power System Operator also performs the following additional tasks.

System Planning

Detailed system planning is needed to ensure Singapore's power system remains secure and reliable. This involves looking into large-concentrated and small-distributed generating plants, electricity transmission network, control and communication facilities.

To ensure a secure and reliable power system, system planning is critical. PSO takes measures to ensure that the current and future electricity and natural gas systems are adequate. This includes the:

- Review of Plans for the Development of the Transmission Network;
- Design and Impact Assessment of Proposed Generating Plants;
- Inter-dependency of Gas and Electricity System;
- Interruptible Load Facility; and

- Operating Reserve Policy.

System Operation

Teams of system operators monitor and control the electricity generation and transmission system, as well as the gas transmission system around the clock. Working on eight hour shifts, each team is led by an experienced Control Manager and assisted by four Technical Executives. The Power System Operation Procedures and Singapore's Electricity Emergency Plan outline the standards and procedures that industry players must comply with to maintain a secure and reliable electricity system.

System Operations has teams of operators who monitor and control the electricity generation and transmission system around the clock. Working on eight-hour shifts daily, each team is led by an experienced Control Manager and supported by Technical Executives. They are tasked to:

- Control the generating operators' output and regulate system frequency;
- Regulate system voltages and direct power flows through the Transmission System;
- Liaise with the market operator and market participants on dispatch schedules & compliance to dispatch instructions; and
- Supervise the operation of the natural gas transmission system as there is high interdependency between this and the power system.

When there is a power system disturbance, officers on duty will activate contingency plan to stabilise, before returning the power system to a normal operating state. If there is an electricity supply disruption, crisis management plans will be activated to restore supply.

Supporting the National Electricity Market

PSO works with various market participants to ensure compliance with operational standards and obligations. These include both market administration and market operation activities as described below:

- Agreements with Market Participants: Market Participants in the National Electricity Market of Singapore (NEMS) are required to enter into regulatory agreements with the PSO.
- Facility Registration: Every market participant is required to provide up-to-date data of its facilities to the PSO, including the physical characteristics, ratings and operational limits of all relevant equipment/facilities connected to the PSO-controlled system.
- Market Operations: Details of power system information, such as network status, outage schedules and load forecasts that are sent to the EMC.

- Electricity Market Compliance Monitoring: The PSO ensures all non-compliance notices issued to market participants are shared with the Market Surveillance and Compliance Panel via the Market Assessment Unit of the EMC.
- Ancillary Services: Ancillary services deal mainly with balancing the power supply and demand over short time intervals throughout the power system. These services, regulation and reserves are essential to ensure the reliable operation of the power system.
- Outage Co-ordination: The PSO is responsible for coordinating the outage schedules of registered generation facilities, generating stations and transmission facilities. This also covers new or retrofitted facilities for construction, testing, commissioning/re-commissioning, and maintenance/repair.
- Power System Adequacy & Security Assessment: The PSO assesses the adequacy and security of the PSO-controlled system on a daily and monthly basis.

A.3 Ireland Energy Market

The electricity sector in Ireland originally operated as two separate markets. The northern parts of Ireland operated as part of the United Kingdom and the rest of Ireland operated separately. In 2007 the two markets were combined, establishing the Single Energy Market (SEM).

The SEM Committee (SEMC) established in 2007 is the decision making body that governance the market. The principal objective of the SEMC "*is to protect the interests of consumers of electricity wherever appropriate by promoting effective competition between persons engaged in, or in commercial activities connected with the sale or purchase of electricity through the SEM.*" The SEMC consists of eight members, six from the regulators, one independent member and one deputy independent member.

The Ireland market is regulated by the Utility Regulator and the Commission for Regulation of Utilities. The Utility Regulator is responsible for regulating the electricity, gas, water and sewerage industries in Northern Ireland. The Commission for Regulation was established in 1999 and known at that time as the Commission for Energy Regulation. It was renamed in 2017 to better reflect its expanded powers and functions that extending to included regulation of water.

The regulators issues separate licenses for the functions needed in administering and operating Ireland's energy market. In the event a company holds multiple licenses the regulators seek to ensure that each licensed activity is ring-fenced from the other actives

Transmission licenses are held by System Operator for Northern Ireland Limited (SONI), a subsidiary of EirGrid for Northern Ireland, NIE Networks Limited for the main transmission system and Moyle Interconnector Limited, a subsidiary of Mutual Energy Limited for the interconnector linking Ireland to the Great Britain system in Scotland.

SONI also holds the system operator license and in conjunction with EirGrid holds the market operator license.

The market codes authorise and define the functions of the system operator, market operators, market participants and the manner that the market and interconnectors operate. The market codes fall in to two categories: codes specific to the Ireland energy market and European network codes. When there is conflict between codes or regulation the following order of precedence is applied:

- requirements under European Laws;
- requirements under Irish Laws or Northern Ireland Laws;
- any applicable requirement, direction, determination, decision, instruction or rule of any;
- Competent Authority;
- the applicable Licence;
- the Grid Code;
- the Metering Code;
- the Capacity Market Code; and
- the Trading and Settlement Code.

The SEM that has been in operation since 2007 was a gross pool mandatory wholesale market with a single marginal price. The market was operated under license from the regulators by the Single Energy Market Operator (SEMO). The SEM was a single-side market, meaning only suppliers participated submitting day ahead offers. Energy retailers did not bid into the market. The energy price was calculated ex-post based on actual energy consumption.

Energy markets in Europe were starting to evolve and integrate. The markets were evolving into two-way markets where both buyers and sellers were placing bids. The Norway Nordpool market expanded to cover large parts of Scandinavia and then followed by initiatives to integrate the markets in the Netherlands, Belgium and France. These changes and European Union requirements ultimately led to the re-design the SEM to enable integration with EU markets

The design of the integrated energy market (I-SEM) was to include the following:

- Forwards financial contract markets;
- Forwards financial transmission rights for cross border transactions;
- Firm day-ahead market integrated with EU market coupling;

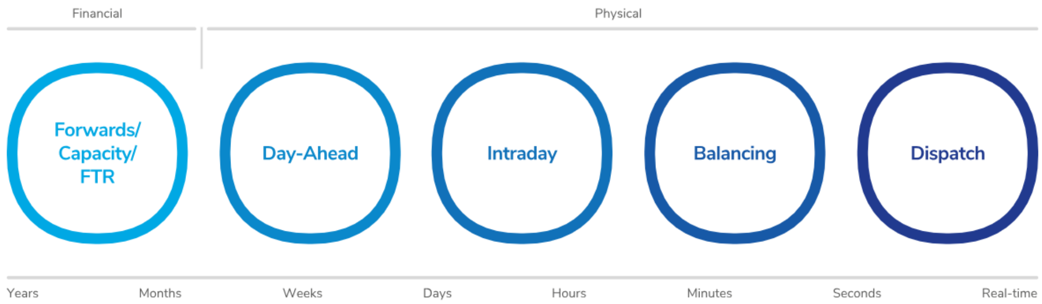
- Firm intraday market integrated with EU cross-border intraday (XBID);
- Balancing market with balancing responsibility; and
- A market based capacity remuneration mechanism.

The new integrated market arrangements came into effect on 1 October 2018 and are designed to deliver increased levels of competition which should help put a downward pressure on prices as well as encouraging greater levels of security of supply, transparency and investment.

A.3.1 Market Operations

As of October 2018, a new wholesale electricity market has replaced its predecessor SEM as the new Integrated Single Electricity Market (I-SEM) for Ireland and Northern Ireland. Under the new market arrangement, I-SEM has introduced multiple markets and auctions that span different trading timeframes with separate clearing and settlement mechanisms, as shown in Figure 31:

Figure 31: I-SEM Markets and Timeline



- Two new ex-ante energy markets, the Day-Ahead Market and the Intraday Market are short term markets that are trading between one day ahead to shortly before real time.
- A balancing market that runs before and into real time is where generators offer balancing services into that helps to balance the transmission system in real time and are paid by generators and consumers whose actual generation or demand differ from traded volumes.
- Two new markets for financial instruments, the Forwards Market where Contract-for-Differences are traded and used to hedge against price fluctuations and the auctioned Financial Transmission Right (FTR) that help to protect price differentials across energy zones due to congestion.
- Capacity is traded in the Capacity Market up to five years in advance of the trading day. The capacity market replaces the Capacity Payment Mechanism from SEM and provides capacity payment only to cost competitive capacities that win the auctions and are required and can generate to meet demand.

Market Operations in the I-SEM are provided by SEMO and SEMOpx. SEMO is managed as a contractual joint venture between EirGrid, the Transmission System Operator for Ireland; and SONI, the Transmission System Operator for Northern Ireland.

The market regulators licensed SONI Ltd and EirGrid plc to provide day-ahead auction and intraday markets. In a separate joint venture, SONI and EirGrid established SEMOpx in June 2015 to provide additional market services.

Market operations in Ireland consist of the following markets:

- Forwards/Financial Transmission Rights (operated by the Joint Allocation Office);
- Capacity (operated by SEMO);
- Day ahead (operated by SEMOpx);
- Intraday (operated by SEMOpx); and
- Balancing (operated by SEMO).

Forwards/Financial Transmission Rights

The interconnector between Ireland to Great Britain currently sells a physical transmission right. The Joint Allocation Office (JAO) facilitates the electricity market by organising auctions for interconnected electricity systems. On 1 October 2018, JAO became the Single Allocation Platform (SAP) for all European Transmission System Operators (TSOs) that operate within the European Union.

The JAO will auction Financial Transmissions Rights (FTRs) on both sides of the Ireland and Great Britain interconnector. These rights enable a participant to buy interconnector capacity in a long- term/forwards auction and to nominate a flow of electricity across the interconnector via SEMO. The holder of the FTRs earns the price difference between the two markets.

Capacity Market

The capacity market is designed to ensure adequate electricity supply to meet the Ireland's electricity demand. Participation is limited to capacity providers in Ireland, and participation is mandatory for all existing providers.

The capacity price is determined by a yearly capacity auction. Capacity providers submit price offers to sell their qualified capacity. The regulator imposes a demand curve, with the capacity auction clearing at the intersection of the capacity price offers and demand curve.

Day ahead

A single Europe wide energy market with a daily auction that takes place at 11:00 each day. Members may trade electricity in 24 one-hour trading periods, starting at 11pm and ending 11pm the following day. The auction results are published as soon as possible from 11:42pm.

The Day-Ahead Market is a dual currency auction. Exchange Members with Units registered in Northern Ireland are required to submit their offer data in GBP, and Exchange Members with Units registered in Ireland are required to submit their offer data in Euro.

The day ahead market consists of simple and complex orders. Simple orders are a price-quantity pair without conditions for one trading period. Complex orders are a price-quantity pair with conditions for one or more trading periods.

Intraday

The intraday Auction Market consists of three daily auctions linked to the European markets. The first two auctions (IDA-1 and IDA-2) are coupled with the Great Brittan bidding area via the interconnector. The third auction (IDA-3) is an Ireland only auction.

The intraday auction timelines are shown in Table 23.

Table 23: SEMOpx Intraday Auction Timelines

Auction	Auction Start Time	Trading Periods	Auction Duration
IDA-1	17:30	23:00 – 23:00	24 hours
IDA-2	08:00	11:00 – 23:00	12 hours
IDA-3	14:00	17:00 – 23:00	6 hours

Source: SEMOpx

The intraday auction is not mandatory but is the only method of engaging with the intraday European market. The products able to be offered in the intraday market are:

- FOK “Fill or Kill” - the order must be executed immediately after entry and with its entire quantity or it is automatically cancelled;
- GTD "Good till Date" - the order is deleted at the specified date/time;
- ICB "Iceberg Order" - iceberg orders are limit orders which are only visible with part of their total quantity in the market, while their full quantity is exposed to the market for matching; and

- IOC "Immediate or Cancel" - the order must be executed immediately after entry or it is automatically cancelled. Partial executions against more than one counterorder are allowed. Market Sweep Orders match orders across multiple offers to satisfy the volume.

Balancing

Real-time energy balancing market for the Ireland electricity market. Balancing services are offered into the market by generators and suppliers. The system operator determines the use of these services. The balancing market operator ensures that providers of the services required by system operator are remunerated.

The trading day is divided into 48 intervals covering 30 minutes. Participation is mandatory for all generators above 10MW and is voluntary for disputable generators below 10MW.

A.3.2 System Operations

System operations in Ireland is split between SONI and EirGrid. Control centres are placed in Belfast and Dublin; used to control Irelands transmission system. The main objective of the system operations is to "*operate the transmission system in the most economical manner, consistent with safety, security, continuity, quality and environmental standards*."

The system operators' obligations are to provide the following:

- Generation Outage Planning;
- Transmission Outage Planning;
- All Island System Planning;
- Applications for Connections;
- Determination of TUOS Tariffs;
- Revenue Transfer between System Operators;
- Calculation of Transmission Loss Adjustment Factors; and
- Grid Code Governance Schedule.

A.4 PJM

PJM Interconnection, L.L.C. (PJM) is a Regional Transmission Organization (RTO) that covers the transmission grid of all or parts of in Delaware, Illinois, Indiana, Kentucky, Maryland, Michigan, New Jersey, North Carolina, Ohio, Pennsylvania, Tennessee, Virginia, West Virginia, and the District of Columbia, forming part of the Eastern Interconnection portion of the overall US power system.

The main roles of PJM are:

- To operate a centrally dispatched and competitive wholesale power market;
- To coordinate and direct the operation of the transmission grid; and
- To plan transmission expansion improvements to maintain grid reliability in this region.

PJM manages all aspects of the grid and the wholesale market, including all services administrating the purchase and sale of energy, transmission services, and ancillary services.

The electricity industry in the PJM Region is subject to a complex series of government policies and legislation at the federal, state, and local levels.

The U.S. Department of Energy (DOE) develops national energy policy, administers federal funding for energy research, and approves construction of international transmission lines thereby advancing the national, economic and energy security of the United States. As a federal agency, DOE is also responsible for establishing and maintaining energy standards and practices across the country.

The Federal Energy Regulatory Commission (FERC) is an independent commission which has regulatory powers in electricity, hydropower, and natural gas and oil markets. It also regulates interstate electricity and gas markets. Under the Energy Policy Act of 2005, FERC is required to adopt and enforce standards that ensure the reliability of the national grid through the North American Electric Reliability Corporation (NERC).

There are two other independent federal agencies that are pertinent to electricity sector: The Environmental Protection Agency (EPA) and the Nuclear Regulatory Commission (NRC). EPA enforces federal environmental protection legislation and works in conjunction with state-level environmental departments. NRC is responsible for regulating the nuclear industry, ensuring safe operation and decommissioning of nuclear power plants.

State governments formulate the overall energy policies for its state based on their generation resources and environmental circumstances which sets fuel mix and environmental targets, such as State Renewable Portfolio Standards (RPS), Emissions Tax, Cap-and-Trade, Feed-in Tariff, Mandated Power Purchase Agreements, Loan Programs, Grant Programs, and Tax Incentives.

All the states in PJM have regulatory commissions in forms of Public Utility Commissions (PUCs) and Public Service Commission (PSC) which have the responsibility to regulate energy and other utilities within the jurisdiction. States regulate all retail electricity rates and services as well as decisions on siting and construction of electricity generation and transmission through these PUCs.

A.4.1 Market Operations

In its role as market operator, PJM balances the needs of suppliers, wholesale customers, and other market participants and monitors market activities. The market operator provides the following services:

- Energy Markets, which include the sale or purchase of energy in PJM's Day-Ahead Market and Real-Time Market;
- Capacity Market, or Reliability Pricing Model (RPM) Auction;
- Ancillary Services: Regulation Market, Synchronized Reserve Market, Black-start Service, Reactive Services; and
- Financial Transmission Rights (FTRs) market.

Energy Markets

The largest of the PJM markets is the Energy Market, comprising around 63% of the wholesale electricity costs. The Energy Market is divided into the Day-Ahead and Real-Time Markets in order to meet consumers' demands both in real time and in the near term.

The Day-Ahead Market is a "forward" market, where prices are set for energy that will be delivered the next day. Hourly prices are calculated based on generator offers, bids from power consumers and market-related financial transactions.

PJM matches offers from the lowest- to highest-priced seller until it meets the bid-in demand for electricity, plus some reserves. All cleared bids and offers establish a financial position in the Day-Ahead Market. Any deviations from cleared quantities in the Day-Ahead Market are settled in the Real-Time Market.

The Real-Time Market serves electricity needs in real time. The Real-Time Market is a spot market. Supply and demand are paired, and prices are calculated every five minutes for more than 10,000 different pricing points based on actual grid operating conditions.

PJM continually follows fluctuations in generation, demand and transmission, sending an electronic signal every five minutes to let suppliers know what their electricity output should be. If a supplier is committed to run by PJM and follows dispatch instructions, it will be compensated. Suppliers are paid the day-ahead price for whatever they were scheduled for, and the real- time price for any generation that exceeds the scheduled amount. If a supplier deviates from PJM's instructions, it may be charged a penalty.

Capacity Market

The capacity market represents about 20% of wholesale electricity costs. The capacity market is also called the Reliability Pricing Model or RPM. PJM's capacity market was implemented to secure enough power supplies three years into the future to ensure sufficient supply will be available to meet peak demand.

Each year, PJM administers a competitive auction to obtain these future power supplies at the lowest price.

Market participants whose future capacity is sold at the auction are said to "clear" the auction. Cleared generation resources are required to offer power into the energy market for the year for which they are committed. Cleared capacity is also required commit to serve PJM's emergency needs whenever called upon.

The capacity market provides the PJM consumers' the assurance of reliable power in the future. In return, power resources receive a dependable flow of income to help maintain their existing capability, attract investment in new resources and to encourage companies to develop new technologies and sources of electric power.

Ancillary Services Markets

Balancing the system means matching supply and demand while maintaining a system frequency of 60 Hertz. PJM market operator provides to types for ancillary services markets:

- **Regulation:** Used to control small mismatches between load and generation.
- **Reserves:** Used to recover system balance by making up for generation deficiencies if there is loss of a large generator.

Financial Transmission Rights

Financial Transmission Rights or FTRs allow market participants to offset potential losses (hedge) related to the price risk of delivering energy to the grid. FTRs are a financial contract entitling the FTR holder to a stream of revenues (or charges) based on the day-ahead hourly congestion price difference across an energy path.

FTRs are a method to bypass congestion charges associated with PJM's Locational Marginal Pricing or LMP. They give market participants the ability to attain a better price certainty when delivering energy across the grid.

FTRs are worth the economic value determined by the day-ahead hourly congestion prices. The FTR serves as a benefit, or credit, to the holder if it represents a flow of energy in the same direction as the congested flow. The FTR serves as a liability, or charge, to the holder if it represents a flow of energy in the opposite direction as the congested flow.

A.4.2 System Operations

In its role as System Operator, PJM is responsible for:

- Managing PJM transmission grid and interregional grid; and
- Planning and directing needed transmission expansions and upgrades to provide efficient, reliable and non-discriminatory transmission service.

PJM does not own any transmission or generation assets. In its role as system operator PJM is responsible for the real-time balancing of electricity supply and demand across its members state boarders. PJM performs *what if* scenario evaluation throughout each day to asses network conditions based on data from hundreds of thousands of points on the grid every four seconds.

PJM tests the transmission system to ensure the network preforms to national and state standards. When transmission improvements are required PJM collaborates with the transmission owners to develop the required changes.

The system operator is responsible for the Regional Transmission Expansion Plan (RTEP). This plan provides a 15-year outlook that identifies transmission system additions and improvements needed to keep supplying electricity in PJM's region. PJM's annual RTEP Report describes transmission study input data, processes and results, as well as PJM Board-approved transmission upgrades and process changes during the previous year.

The PJM systems operations control room is responsible for transmission operations, reliability coordination and balancing authority. These tasks are separated in to the following roles:

- **Balancing authority master coordinator**: Responsible for load forecasting, generation outage processing, next stage generation scheduling and interchange coordination.
- **Balancing authority generation dispatcher**: Responsible for real-time generation and load balancing, reserve monitoring and deployment, and generator dispatch.
- **Master dispatcher**: Responsible for transmission system security, transmission outage coordination and voltage control
- **Reliability engineer**: Responsible for next day outage analysis, interacting with neighbouring areas and providing technical support.

A.5 Korea Power Exchange

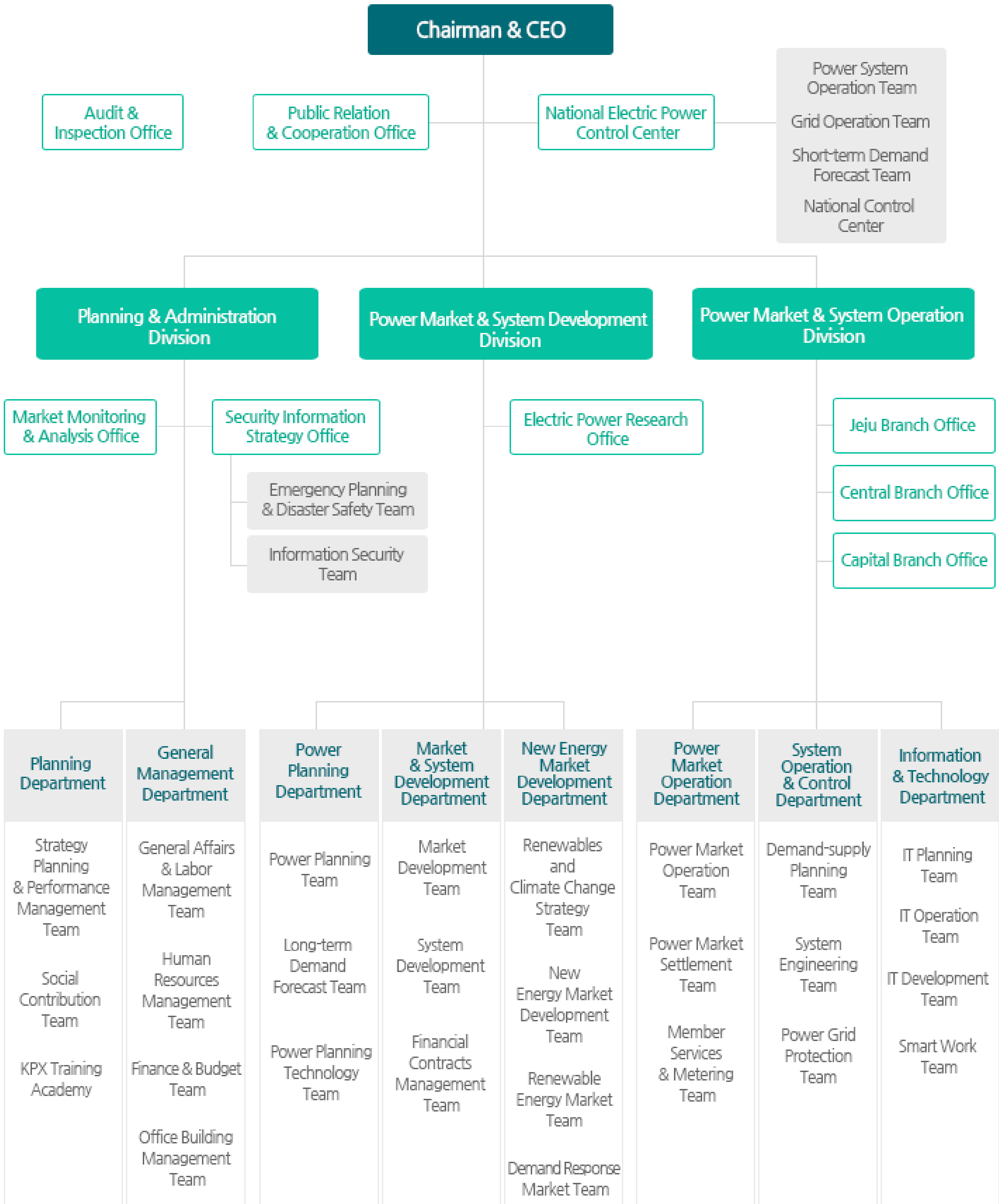
Korea Power Exchange (KPX) was established in 2001 in accordance with the Electricity Utility Act charged with (i) operating a fair and transparent electricity trading market and system; and (ii) establishing a long-term plan for electricity supply and demand.

KPX has three major roles:

- Market Operation: the operation of electricity market, including bidding, metering, settlement, payment, and enact and revise market rules.
- System Operation and Real-time Dispatch: Short- and long-term transmission network stability assessment, power system operation planning, and preparation for contingencies; and balancing the real time supply and demand.
- Short-term and long-term electricity supply and demand planning: KPX assists the government in short- to long-term planning and in developing demand forecast modelling.

KPX operates it under three key departments, each responsible for planning, development and operation. Figure 32 presents the overview of KPX functions in three key system operation roles:

Figure 32: Organisation Chart of KPX



A.5.1 Market Operator

Electricity Market Operation

KPX conducts market operations from cost evaluation, bidding, settlement, metering, market surveillance and information disclosure, dispute resolution in accordance with the Electricity Market Operational Rules.

Renewable Energy Certificate (REC) Market Operation

With the introduction of the Renewable Portfolio Standards (RPS) in 2012, KPX's roles have expanded to cover the operation of Renewable Energy Certificate (REC) market and the management of the RPS compliance costs. In addition, KPX administers the auctions for REC trades, linking REC off-takers (gencos subject to RPS) and REC suppliers (renewable projects).

Electricity Market Operation Council

Electricity Market Operation Council is an organisation established to ensure objective and fair market operation. The members of the council consist of industry experts from various stakeholders from both public and private sectors.

Three major committees operate under the council: Rule Revision Committee, Cost Evaluation Committee and Dispute Mediation Committee.

- Rule Revision Committee: The Electricity Market Operational Rules is the most important set of rules that forms the basis of standards, procedures, and methodologies to implement the objective of market rules. The relevant team of KPX submits the rule draft and the committee reviews and decides. The committee consists of 9 members, chaired by the CEO of KPX.

- Cost Evaluation Committee: Current electricity market is a Cost-Based Pool, and the market price is essentially set at pre-assessed variable costs of a marginal plant on a least cost basis. Thus, it is the important that Cost Evaluation Committee evaluates cost components of the market operation in a fair and transparent manner. Cost evaluation is primarily focusing on variable costs and capacity payment for respective plant, and it has expanded to cover costs, compensation and penalties relevant to the operation of Renewable Portfolio Standard (RPS) in recent years. The committee consists of 8 members, including the chairman.

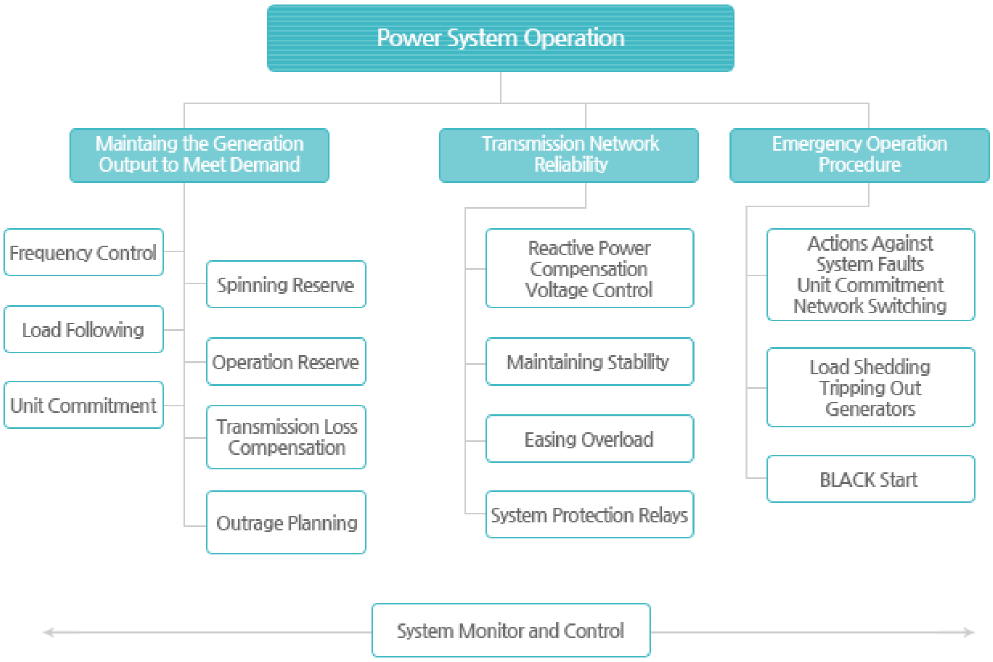
- Dispute Mediation Committee: This committee resolves disputes arising from KPX's market and system operations. KPX manages a pool of experts, comprised of those in the power industry with various background in legal, engineering, accounting and economics. Three members are selected from the pool by the parties involved in the dispute for dispute resolution.

A.5.2 System Operator

Grid Operation and Load Dispatch

KPX operates the power system required to transmit the to load centres. Figure 33 presents the overview of KPX functions in three key system operation roles in maintaining System Adequacy, Transmission Network Reliability and Emergency Operation Procedure

Figure 33: Overview of System Operation Functions of KPX



Source: KPX

In essence, the KPX's functions are to:

- Monitor and control of the power system;
- Maintain the balance of electricity supply and demand;
- Efficient operation of the electricity market;
- Reliable operation of the power system;
- Prevent outage and timely restoration; and
- Control system voltage and frequency.

In order to carry out these functions, KPX sets up dispatch plan to prevent overload, and establishes contingency plan to ensure system reliability based on failure analysis, power flow analysis, optimisation of system stability and scheduled maintenance schedule, and failure preventive system analysis.

KPX is charged with establishing appropriate countermeasures in case of major transmission network failure of a large-scale generation facility, by installing a control circuit that can immediately block out the selective unit from the system and other generating units can back up as normal operation.

One of the important roles is to monitor and identify vulnerable part of the grid and to reinforce in order to ensure supply reliability. In order to carry out this role, KPX prepares power restoration plans and recovery measures in case of power failure, develops in-house capability for continuous monitoring of the grid system and conducts regular trainings of KPX staff and personnel of member companies.

Real Time Balancing of the Supply and Demand

At any time, KPX ensures real-time balancing of supply and demand by controlling the output of all the generators so that the generation cost is minimized throughout the operation following load changes. KPX secures 4 GW of adequate reserve at all times.

Short Term Supply-Demand Operation

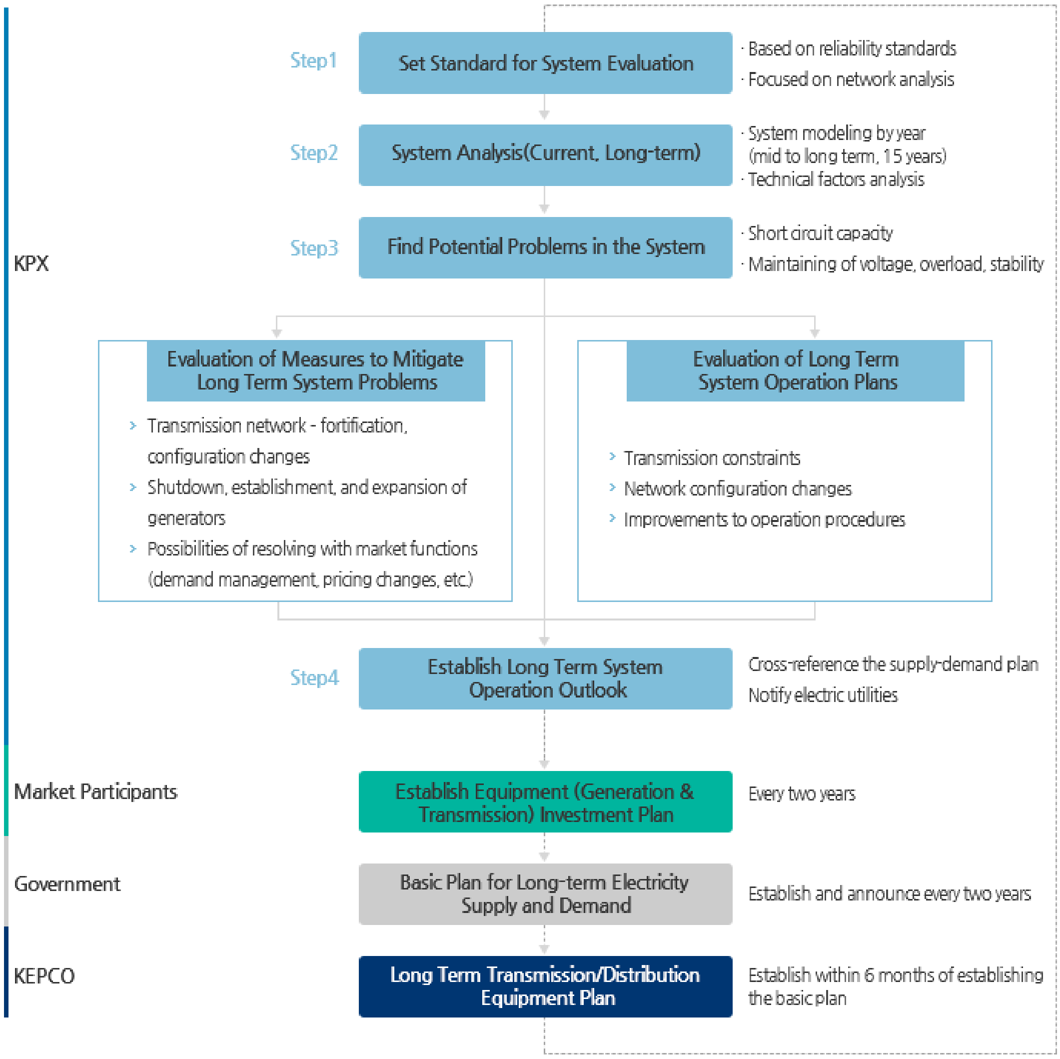
KPX establishes annual, monthly and daily power supply and demand for efficient system operation. Economic trends and demand pattern analysis forms a critical part of demand forecasting, and KPX takes a main role in setting scheduled maintenance plan of generating units.

A.5.3 Long-term Supply and Demand Planning

In support of the government's long-term electricity supply and demand planning, KPX assists the government in short- to long-term planning and in developing demand forecast modeling.

Figure 34 overlays the role of KPX in preparing the Basic Plan of Electricity Supply and Demand.

Figure 34: Process Diagram of Setting Long-term System Planning



Source: KPX