UTILITIES COMMISSION SUBMISSION

REVIEW OF SYSTEM CONTROL CHARGES AND ASSOCIATED FUNDING ISSUES

March 2019

Date	Version	Comment
01/03/2018	Final	Final issue for Utilities Commission Submission
31/08/2018	Add1	Edits based on UC comments on Submission
29/10/2018	Add2	Edits based on UC Commissioner comments on Submission
12/11/2018	Add2.1	Replace Table A1 to include 2017/18 Budget
28/02/2019	Add3	Edits based on ACIL Allen recommendations to UC
18/03/2019	Add3.1	Edits based on UC comments at decision meeting 14/3/19

Version Control

Version	Date	Details	Authorised Name/Position	Signature(s)
Draft 1	14/02/2018	Draft issued for review	Shannon Morgon Acting Operations Planning Manager	
Draft 2	21/02/2018	Draft accepted and endorsed	Amelia Farmilo Real Time Operations Manager	
Final	01/03/2018	Final issue for Utilities Commission Submission	Malcolm Conway General Manager System Control Power System Controller Power Water Corporation	
Add1	31/08/2018	Edits based on UC comments on Submission	Malcolm Conway General Manager System Control Power System Controller Power Water Corporation	
Add2	29/10/2018	Edits based on UC Commissioner comments on Submission	Malcolm Conway General Manager System Control Power System Controller Power Water Corporation	
Add2.1	12/11/2018	Replace TableA1 to include 2017/18 Budget	Malcolm Conway General Manager System Control Power System Controller Power Water Corporation	
Add3	28/02/2019	Edits based on ACIL Allen recommendations to UC	Peter Billing General Manager Core Operations Power Water Corporation	
Add3.1	18/03/2019	Edits based on UC comments at decision meeting 14/3/19	Peter Billing General Manager Core Operations Power Water Corporation	

This page has been intentionally left blank.

Table of Contents

Table of Contents 4
Glossary 6
Executive Summary 7
1 Introduction 9
1.1 Basis of Submission 9
1.2 Objectives of this Submission 9
1.3 Background 9
1.4 Market Reforms 11
1.5 Power and Water's Submission Approach 12
1.6 Current Financial Issues 12
1.6.1 Financial Sustainability 12
1.6.2 Service Level Agreement System Control – TGen 13
1.6.3 Market Development Costs 14
2 Financial Position 14
2.1 Five Year Projections 14
2.2 Assumptions (Costs Framework) 15
2.3 Components of the Proposed Charges 16
2.3.1 System Control Costs to be recovered 16
2.3.2 Market Operator Costs to be recovered 16
2.4 Funding 17
2.4.1 Market Operator Funding 17
2.4.2 System Control Funding 17
2.5 Additional Foreseeable Costs 18
2.5.1 Relocation of Control Centre and New Administrative Centre 18
2.5.2 External INTEM and NTEM Development Costs 19
2.5.3 Assets 20
2.6 Power and Water Corporate Overheads 21
3 Customer Impacts 21
3.1 Financial Impacts 21
4 Demand 22
5 Price Control Mechanism 22
6 Tariff Structures 23
6.1 Structure 23

6.2 Tariff Benchmarking 24
7 Summary 25
APPENDIX A: Supporting Financial Data and Assumptions 26
1. Proposed Operational Costs: System Control & Market Operator 26
2. System Control Costs 30
3. Benchmarking 31
4. Market Operator Costs 32
5. Review of the Electricity Retail Supply Code 33
6. I-NTEM and NTEM Implementation Costs 34
7. Control Centre and New Administration Centre 35
APPENDIX B: Corporate Overheads 36

Glossary

AEMO	Australian Energy Market Operator
AER	Australian Energy Regulator
CAM	Cost Allocation Methodology
DTF	Department of Treasury and Finance (NT)
GOC	Government Owned Corporation
INTEM	Interim Northern Territory Electricity Market
kWh	kilowatt hour
MWh	megawatt hour
NEM	National Electricity Market
NER	National Electricity Rules
NT	Northern Territory
NTEM	Northern Territory Electricity Market
Power and Water	Power and Water Corporation
SLA	Service Level Agreement
TGen	Territory Generation, a NT GOC
The Commission	Utilities Commission
WEM	Wholesale Electricity Market of Western Australia
WMS	Wholesale Market Service

Executive Summary

Power and Water make this System Control Price Proposal to the Utilities Commission (the Commission) under Section 39 of the *Electricity Reform Act* (ER Act) and seeks the Commission's decision of a revised System Control charge. Section 39 of the ER Act states that a Power System Controller is entitled to impose and recover charges relating to the operations of system control, subject to the approval of the Commission.

Power and Water have been appointed as the:

- Licenced System Controller for the Northern Territory power system under the *Electricity Reform Act;* and
- Licenced Market Operator for the Interim Northern Territory Electricity Market (INTEM), effective from 27 May 2015

The System Controller provides a range of System Control independent regulated functions, including those associated with power system security and reliability, operational and technical regulatory reporting, generation dispatch, and perform technical audits. The Market Operator provides a range of independent regulated functions that support the market operations including registration of all market participants operating in the INTEM, market settlements that involve the calculation and issue of invoices to retailers and credit notes to generators, and the daily publication of market prices and other wholesale trading data.

These activities and functions benefit participants and end use consumers within the Northern Territory power system and the wider Northern Territory economy, with the operation of a safe, reliable, secure, and efficient power system. Power and Water, in this submission is seeking to ensure that the System Control and Market Operator functions are financially sustainable, subject to delivering cost effective services.

The Commission approved the current System Control Charge in 2000. Since then there has been significant change in the number and nature of the functions and the cost of their delivery. The result is that Power and Water have been funding the shortfall which has expanded exponentially since the commencement of the INTEM.

The current System Control Charge of $0.001/kWh has remained constant in nominal terms for 19 years, providing funding of approx. $1.8M per annum. In 2017-2018 the actual operating costs for System Control and Market Operator regulatory functions are $9M, with the $7.2M shortfall funded by Power and Water.

In light of this continued cost shortfall, Power and Water propose the following:

- The System Control Charge be increased from the current $0.001 per kWh (combined charge for System Control and Market Operator functions), to the charges shown in Table E1 (calculations shown in Appendix A1). The proposed charges used a revenue cap mechanism with a materiality band of 5% as recommended by ACIL Allen (refer to sections 5.1 and 5.2 in ACIL Allen report – R*eport to Utilities Commission 15 February 2019* ***2018 System Control Charges Review*** *Review of Power and water's Submission to the Commission FINAL REPORT*).
- Charge for the two functions was separated as recommended by ACIL Allen. This is reasonable as system control function is mature and the costs required to perform this function could be forecast with a reasonable degree of certainty over a 5 year period, but the costs associated with the market operator function are currently highly uncertain with the timing and scope of the transition from the INTEM to the Northern Territory Electricity Market (NTEM) uncertain. This proposal would increase the industry funding from approximately $1.8M to approximately $10.2M.

Table E1 Proposed Charges (Real $2019)

	2019-20	2020-21	2021-22	2022-23	2023-24
System control charge ($/kWh)	0.0048	0.0048	0.0047	0.0047	0.0046
Market operator charge ($/kWh)	0.00052	0.00051	0.00050	0.00049	0.00048
Combined Total ($/kWh)	**0.00532**	**0.00531**	**0.00520**	**0.00519**	**0.00508**

The key messages of the Power and Water's System Control Price Proposal are:

- Enable review and alignment with market developments, enable Power and Water to implement cost efficiencies and to minimise potential for future price shocks;

- The establishment of a sound financial basis for System Control and Market Operator to achieve financial sustainability whilst fulfilling their regulatory obligations;

- System Control and Market Operator to be challenged to improve efficiency and effectiveness (i.e. The proposed funding does not fully recover current operating costs); and

- The Non-Regulated functions provided by System Control and the Market Operator have been fully costed and are ring fenced from this submission.

1 Introduction

1.1 Basis of Submission

Section 39 of the ER Act states that a Power System Controller is entitled to impose and recover charges relating to the operations of system control, subject to the approval of the Commission. Power and Water make this System Control Price Proposal to the Commission under Section 39 of the *Electricity Reform Act* and seeks the Utilities Commission's decision of a revised System Control charge.

1.2 Objectives of this Submission

This submission is designed to ensure the financial sustainability of the regulated functions of the System Controller and the Market Operator commencing 1 July 2019.

In doing so, this submission will also:

- further delineate regulated and non-regulated functions undertaken by System Control and Market Operator Business Units of Power and Water;
- ensure no duplication in the cost allocations between regulated and non-regulated functions;
- demonstrate continued efficient cost regimes within the System Control and Market Operator roles; and
- inform the Commission of other activities being undertaken by Power and Water to unbundle a number of transitional arrangements that mix both regulated and non-regulated functions in different charging regimes

1.3 Background

Power and Water is a wholly owned Northern Territory Government corporation under the Government Owned Corporations Act, with the objectives under Section 4 to:

- operate at least as efficiently as any comparable business, and
- maximise the sustainable return to Northern Territory on its investment in Power and Water[1]

Power and Water is one of the largest businesses in the Northern Territory (NT), employing more than 910 people and is the major provider of electricity networks, water supply sewerage services to more than 85,000 customers across the NT. Power and Water provides services across an area of over more than 1.3 million square kilometres.

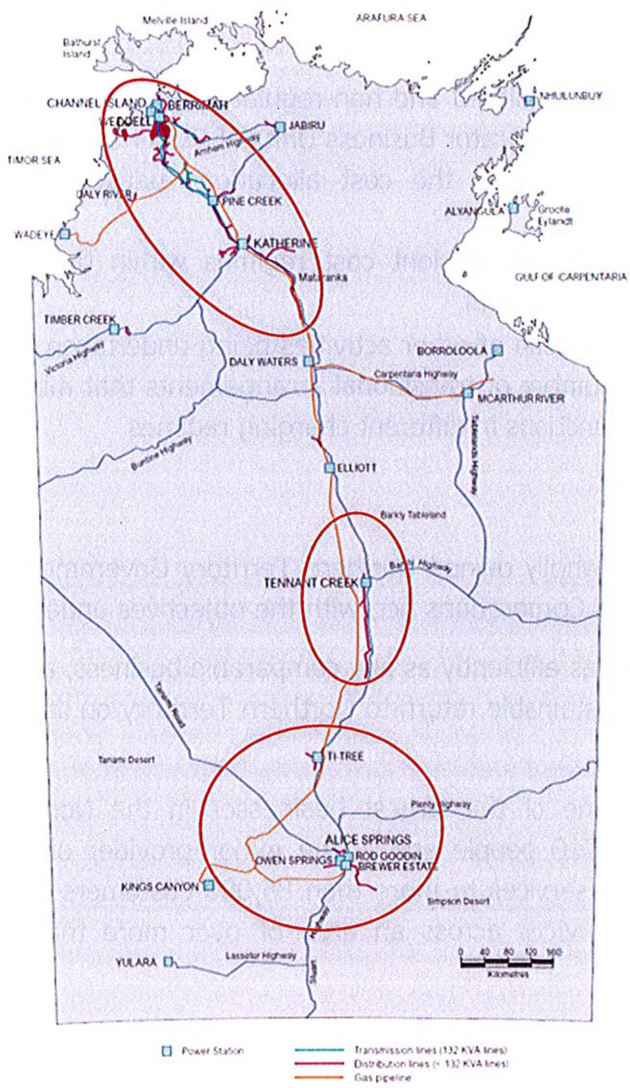
[1]Section 4, *Government Owned Corporations Act (NT)*

Power and Water provides:

- Power Network services
- System Control services
- Market Operator services
- Water and Sewerage services
- Remote Operation services
- Gas services.

These services are delivered across the NT's variety of climates including the tropics of Northern Australia and the deserts of Central Australia. The regulated Northern Territory electricity systems consist of three systems namely Darwin-Katherine Power System, Alice Springs Power System, and Tennant Creek Power System. (Refer Map 1 below.)

Map 1 NT Power System



1.4 Market Reforms

In August 2013, Cabinet approved a major reform program for its energy portfolio, including the establishment of a wholesale electricity market.

A review was undertaken by the Commission on the establishment of a wholesale electricity market, with the subsequent recommendation to establish INTEM approved by Cabinet in July 2014.

The regulatory changes to implement the INTEM now obligate the System Control Licence holder to provide both the System Controller and Market Operator functions. Power and Water is the current Northern Territory System Control Licence holder and as such is obligated to undertake both functions.

On 1 July 2014, structural separation of the Power and Water electricity generation and retail electricity business units, into separate government owned corporations (GOC) occurred as part of the Northern Territory Government reform of the Northern Territory Electricity Market (NTEM).

INTEM commenced operations on 27 May 2015.

These reforms together with the Electricity Reform Act and amendments to the Electricity (Third Party Access) Act, led to the introduction of the Market Operator role and significant change in the System Control functions and responsibilities. As a result Power and Water have undertaken a suite of reforms including improved transparency and efficiency of power system operations, further independence of operations, the development of market prices, and greater clarity in reporting information.
Further development of the Northern Territory electricity market is occurring and is expected to continue, including:

- review of provision and funding of ancillary services;
- market development and design;
- development and implementation new market systems;
- new market participants;
- transition to the NER and jurisdictional derogations;
- expanded levels of market information and transparency;
- expanded levels of scrutiny of system capability

System Control and the Market Operator will play a significant role in the coming period influencing the ongoing evolution, implementation and refinement of the wholesale electricity market and supporting the efficient and effective operation of the Northern Territory power system and electricity market.

1.5 Power and Water's Submission Approach

This submission outlines Power and Water's proposed efficient costs for the provision of System Control and Market Operator services and their translation into the System Control Charge for end use customers. It also includes provision for charging by System Control for Regulated ad hoc services and by the Market Operator for charges under an Amended Electricity Retail Supply Code.

Recognising the current Northern Territory electricity market reforms undertaken to date and the potential for further electricity market evolution decisions, Power and Water are proposing:

- an assessment of this price proposal against Section 21(2) of the *Utilities Commission Act;*
- adoption of the revised Power and Water Cost Allocation Methodology (CAM) cost allocation in line with Australian Energy regulator (AER) approved methodology (updated from the CAM previously approved by the Commission in the 2014 Network price Determination);
- use of real dollars;
- further market participant, customer and stakeholder engagement to inform future price control mechanisms and tariff reform; and

In line with recommendations by ACIL Allen,

- cost base is the 2019/20 budget with CPI escalation in subsequent years;
- that the System Control charge and Market Operator charge be separated; and
- the charges be reviewed on a five year basis hereafter

1.6 Current Financial Issues

1.6.1 Financial Sustainability

The System Control and Market Operations are not financially sustainable based on the current system control charge and Power and Water is funding all deficits. Market Operations **regulated** functions performed by Power and Water are not funded in any form. This includes annual operating costs and the development costs associated with the design and development of the market and the associated systems that give effect to the market.

System Control **regulated** functions are currently partially funded by the System Control Charge. This was set in 2000 at $0.001 per kWh charged to end customers based on electricity consumption. Despite the increase in consumption, the growth in revenue has not offset the increased cost of providing these services, nor addressed the additional costs resulting from the expanded role of System Control under the market reforms.

The above has been recognised by the Utilities Commission in the "2013-14 Power System Review":

'it is becoming more important to separate the System Control function of PWC and put in place fully independent governance structures and funding. The adequacy of funding is particularly relevant in light of the workload System Control is facing in establishing a number of market-related tasks such as economic dispatch arrangements, ancillary services framework, dynamic models for the systems and testing plant to ensure compliance with the technical codes.'[2]

1.6.2 Service Level Agreement System Control – TGen

Currently System Control has a transitional Service Level Agreement (SLA) with Territory Generation (TGen) which has expired on 30th June 2017. This SLA provides approximately $2.5M in revenue per annum for System Control ($2.2M regulated and $0.3M non-regulated).

Negotiations to extend the SLA on current obligations and fees will continue in anticipation of the outcome of this submission.

This SLA predominantly funds regulated functions provided by System Control to TGen but also includes some non-regulated functions. The regulated functions provided under this SLA include:

- Short term load forecasting
- Plant outage approval
- Day-ahead plant schedule
- Daily plant dispatch
- Emergency operation
- Develop Key Performance Indices
- NTEM development
- Generator start and stop
- Post-trip management
- Test-run of power plants
- Liaison between GenCorp and nominated parties
- Reporting

[2] Utilities Commission, *2013-14 Power System Review*, www.utilicom.nt.gov.au, p4

The proposed cost of providing these regulated functions are included in this submission. It is recognised that by including these costs into the proposed System Control Charge there is potential double charging to consumers. This will be a number for TGen to adjust its pricing to reflect the savings derived from this change. This is not directly a matter for System Control and the Market Operator however for full transparency it is appropriate that the issue be identified.

It is proposed that the next SLA will include the following non-regulated responsibilities (assuming that this proposal is accepted and implemented)

- Regional settlements (Territory Generation)
- Engineering Support for Major Projects
- Short Notice (Non-Emergency) Outage Assessment
- Non Market Related Data Requests

1.6.3 Market Development Costs

The implementation of the electricity market has required a substantial investment by Power and Water (actual to 30 June 2017 was $2.35M) to develop systems, tools and procedures to facilitate the management of the market. These costs are currently not funded via any customer charge with Power and Water funding these development costs from existing operational cash flows.

Provisions for continued development of these systems over the next three years are included in this submission. Further details are provided in Section 2.5 – Additional Foreseeable Costs (2.5.2 – External INTEM and NTEM Development Costs).

2 Financial Position

2.1 Five Year Projections

Power and Water are proposing the following Regulated Expenditure be recovered via the revised System Control and Market Operator Charges. (Refer Table 1 below). Costs related to non-regulated functions have been excluded from this submission. These projections are based on an Activity Based Model that analysed the cost per time and activity for every position.

This submission (in line with recommendations from ACIL Allen) proposes that the revised System Control and Market Operator Charges are proposed separately and apply commencing 1 July 2019, using 2019/2020 Budget as the base for the five year projection (2019/20 to 2023/24). Further details and analysis is included in Appendix A.

Table 1 Proposed System Control and Market Operator Costs to be recovered (Real $2019)

	2019-20	2020-21	2021-22	2022-23	2023-24
System control					
Personnel costs	$6,246,938	$6,234,444	$6,253,147	$6,284,413	$6,322,120
Other direct costs	$621,059	$615,667	$465,367	$465,367	$465,367
Corporate overheads	$2,005,861	$1,882,657	$1,805,923	$1,726,639	$1,650,835
Total	**$8,873,858**	**$8,732,767**	**$8,524,438**	**$8,476,419**	**$8,438,322**
Market operator					
Personnel costs	$516,019	$514,987	$516,532	$519,115	$522,230
Other direct costs	$105,420	$104,759	$74,107	$74,107	$74,107
Corporate overheads	$211,001	$198,041	$189,969	$181,629	$173,655
Total	**$832,440**	**$817,787**	**$780,608**	**$774,851**	**$769,992**

2.2 Assumptions (Costs Framework)

The regulated costs outlined above are premised on the factors outlined below:

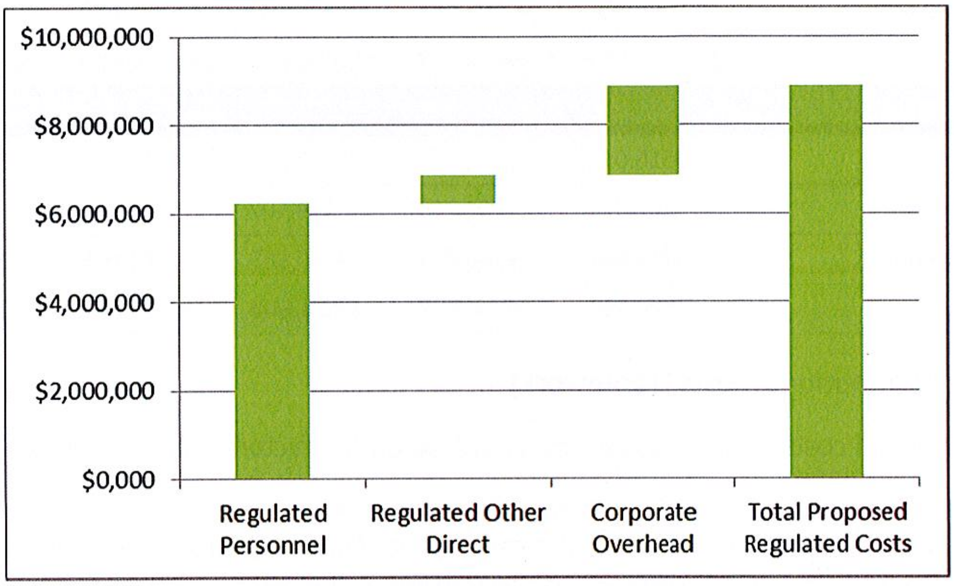
- There has been no review of the charge since 2000;
- The establishment of an electricity market (Market Operator and the expanded System Control role) was not contemplated at that time;
- Significant escalation in salary costs since 2000 i.e. >50%;
- The Market Operator is providing current services in a low cost optimised fashion;
- System Control has increased technical staff numbers to improve compliance and technical effectiveness – market and system requirement;
- System Control's 24 hour rotating shift structure requires a minimum 21 staff which is competitive when benchmarked. This structure has capacity to service greater client numbers and or energy flows (i.e. staff numbers are linked to coverage of positions);
- System Control leverages the control centre to provide non-regulated services which provides synergies and benefits for both regulated and non-regulated functions;
- System Control corporate cost allocation will decrease over the five years in line with Power and Water broader reductions in controllable corporate expenditure; and
- The proposed new administrative centre and control centre are excluded in the proposed System Control charge. Refer section 2.5 – Additional Foreseeable Costs (2.5.1 – Relocation of Control Centre and New Administrative Centre).

2.3 Components of the Proposed Charges

The costs components that comprise the total costs recovered by the proposed System Control Charge and Market Operator Charge are illustrated in Charts 1 and 2 below.

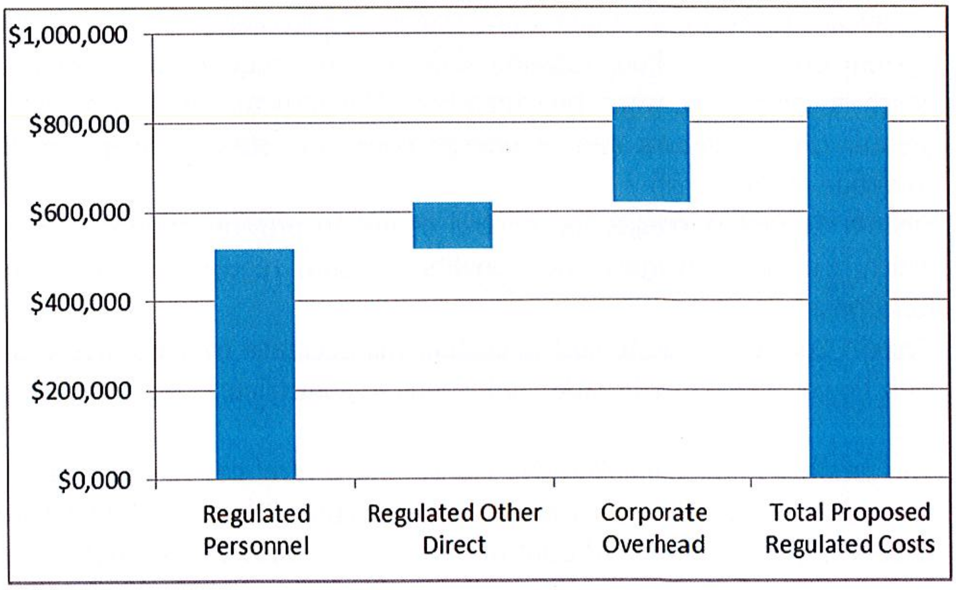
2.3.1 System Control Costs to be recovered

Chart 1: 2019/20 System Control Operational Expenditure by category



2.3.2 Market Operator Costs to be recovered

Chart 2: 2019/20 Market Operator Operational Expenditure by category



2.4 Funding

For System Control and the Market Operator to perform their independent market based roles they need to be fully funded for their regulated functions based on efficient, effective operating procedures and ensure no cross subsidisation occurs between the provision of regulated and non-regulated services.

2.4.1 Market Operator Funding

The Market Operator function is performed by the Wholesale Market Service (WSM) team. WMS is the combined functions of Market Operator, Full Retail Contestability and other non-regulated activities. The Market Operator is in the development phase with three staff members undertaking the operational functions and also supporting the development costs.

Labour is the predominant costs for the Market Operator with additional costs included only to support these personnel. These additional costs have been allocated consistent with the labour allocations, outlined in Appendix A, clause 4.

The non-regulated activities undertaken by the Market Operator (wholesale market service) are limited and will largely be either:

- handed back to Power Services to perform; and or
- subject of separate Electricity Retail Supply Code amendment submission; to
- classify them as regulated functions of the Market Operator; or
- Retained by Market Operator as non-regulated activities albeit on a smaller scale than before.

The projected costs and revenues associated with the remaining non-regulated functions have been ring fenced to ensure they are not being cross subsidised from the regulated functions. These functions relate to supporting TGen in the provision of market data and are expected to progressively decline as the market evolves and or TGen matures.

2.4.2 System Control Funding

System Control has undertaken an analysis of its costs and the roles of each of the positions within its current structure to identify the costs of its regulated and non-regulated functions. In undertaking this analysis, Power and Water identified efficiency improvements within its current operations. These efficiency targets include reduction in the number of shift staff through business improvement initiatives.

A summary of the position analysis is included in Appendix A, Table A2. This submission incorporates the implementation of these initiatives and assumes a consistent allocation between regulated and non-regulated functions.

Power and Water has undertaken benchmarking of the System Control function using the two most logical comparators namely the West Australian electricity networks.

The benchmarking analysis indicates that System Control, with the achievement of the current strategic business plan initiatives, is operating on comparable control room staffing levels as Horizon Energy and Western Power in 2018/19. In respect to staffing levels a direct comparison is more difficult due to the nature of the respective businesses however System Control's regulated staffing levels to support the broader functions of System Control and the operation of the control centre are minimal.

The salaries and respective terms and conditions applicable to the above are mandated by the Office of NT Government Public Sector Commissioner under enterprise bargaining agreements.

For further details regarding the benchmarking analysis, refer to Appendix A, clause 3.

2.5 Additional Foreseeable Costs

The proposed increase in charges captures purely the System Control and Market Operator operational costs. There are a number of foreseeable costs that would not be funded by the proposed System Control and Market Operator Charges.

2.5.1 Relocation of Control Centre and New Administrative Centre

The current System Control centre is located within a Power and Water substation at Hudson Creek. The building is over 30 years old and has been modified and extended numerous times to accommodate the evolution of technology to control networks and generators and the expansion of staff numbers as the functions of System Control increased.

The current PWC Disaster Recovery plan identified a deficiency in providing a secure accommodation to maintain electricity supply to the NT during cyclone season. This was highlighted by Cyclone Marcus in March 2018.

Relocation of the current control centre to a new site would enable the Hudson Creek site to be retained as the back-up facility in a time of emergency. Additional benefit of retaining Hudson Creek is that with the continued use of the existing Hudson Creek system control infrastructure will lower the costs of the new facility.

The establishment of a new Administrative Centre and Control Centre to accommodate System Control and Market Operator staff is proposed. There are a number of existing issues associated with the current location of System Control. These include:

- Lack of a suitable back up facility in the event that the current system control is extensively damaged or destroyed (single point of failure);
- Restricted ability to renovate and or extend the current building;
- System Control regulatory activities should be an independent function free from any interference; if it remains fully reliant on Power and Water for all its accommodation, systems, and procedures, this can create a perception that an independent System Control (regulatory activities) continues to be controlled/ managed by Power and Water;
- Cultural change benefits and cost effectiveness associated with relocation to a suitable new site is expected to outweigh the cost of any renovations or extensions to the existing facility at Hudson Creek; and
- A detailed business case.

Power and Water estimate that the relocation costs would be approximately $2.275 million in capital costs and annual operational costs of $670k pa. This cost recovery is excluded in this submission. This is due to the uncertainty of the timing for the proposed new control and administrative centre. PWC is waiting on a business case to be prepared for this centre. However, ACIL Allen recommended that the costs associated with the new centre be included in the revenue cap system control mechanism in this current period when there is more certainty. More details on the estimated costs and the basis of those costs are included in Appendix A, clause 6.

2.5.2 External INTEM and NTEM Development Costs

Following the government direction to establish INTEM in May 2015, Power and Water were required to develop and implement a number of new processes for the System Controller and the Market Operator to adequately perform their independent regulatory functions.

In order to fulfil these obligations, Power and Water funded approximately $2.35M of external consultant costs between 2014/15 to 2016/17 for the provision of specialist advice and technical skills to establish the tools, processes and procedures necessary to facilitate the I-NTEM. This prior spend for external consultants/ contractor costs, with the exclusion of corporate overheads are presented in Table 2 below.

Table 2: Prior Investment in External NTEM Development Costs

Actual & Forecast to 30 June 2017	14/15 & 15/16	16/17 *	TOTAL
Project Management	$202,700	$200,000	$402,700
Code/Rule Development	$152,300		$152,300
Develop I-NTEM External and Internal Procedure	$65,000		$65,000
Settlements System Development	$345,000	$40,000	$385,000
DPT Development	$544,000	$586,000	$1,130,000
SS Operation	$31,000	$24,000	$55,000
DPT Operation	$160,000		$160,000
Development of New Features			$0
TOTAL	**$1,500,000**	**$850,000**	**$2,350,000**

NOTE: 2016/17 includes YTD + forecast*

To enable the transition from the I-NTEM to NTEM, further investment is required for external consultancy costs over three years as the systems evolve. Power and Water expect the external consultancy costs to be in the order of $3.755M over the three years 2018/19 to 2020/21. (Refer Table 3 below).

Table 3: Projected Investment in External NTEM Development Costs

	2018-19	2019-20	2020-21
Design	**1,000,000**	**400,000**	**400,000**
High Level Design Work	200,000	100,000	100,000
Detailed Design Work	300,000	200,000	200,000
Rule Drafting	100,000	50,000	50,000
Legal Review	50,000	50,000	50,000
Independent Rule Review	50,000		
Project Management Support	200,000		
EMS Expert	100,000		
Implementation	**755,000**	**700,000**	**500,000**
Settlement System Upgrade	100,000	50,000	
EMS Upgrade	300,000	350,000	350,000
DPT Upgrade	150,000	250,000	100,000
Procedural Documentation	150,000	50,000	50,000
Stakeholder Consultation	20,000		
Training Documentation	20,000		
Training Coordination	15,000		
Total	**1,755,000**	**1,100,000**	**900,000**

While $6.1M in total investment is a significant investment, it is relatively small amount in the context of developing suitable suite of tools and equipment that are appropriate for implementation in the Northern Territory; recognising size and scale of the market does not warrant adoption of the full suite of AEMO style systems. Power and Water do not have in house capability to develop such tools and systems and hence external consultants have been utilised to build these tools and systems.

The future development costs for NTEM could be considered as "provisional" item and be approved and included in the System Control Charge only once it occurs. It is excluded from this submission.

The provision relates only to external consultant costs with no corporate overheads or additional internal supervision costs being applied. This provision is based on a set of assumptions detailed in APPENDIX A: Supporting Financial Data and Assumptions, clause 6.

2.5.3 Assets

System Control does not own any assets.

2.6 Power and Water Corporate Overheads

Power and Water have implemented a CAM to ensure it is utilising best practice in allocating corporate overheads to its respective business units and between its regulated and non-regulated functions. This process is AER approved and is described in Appendix B.

Corporate Overheads for Power and Water are allocated across its operational Business Units based on key drivers including headcount, time, cost, and square metres. This allocation method is used to ensure equitable allocation across the operational Business Units.

Corporate Overheads allocated to System Control Business Unit are then allocated between the Regulated and Non-Regulated functions of System Control and Market Operator.

3 Customer Impacts

3.1 Financial Impacts

The proposed System Control Charge has been modelled against customer groups, based on usage levels, to assess the impact on customers' annual bills if the proposed increase was implemented. This analysis was undertaken to assist Power and Water, the Utility Commission and the Government of the potential impact on customers, if the full increase was approved and passed onto the customers. The results of this analysis are included in Table 4 below.

Table 4: Impact of proposed System Control Charge on Customers annual electricity bills

IMPACT ON CUSTOMER'S BILLS TO PROPOSED SYSTEM CONTROL CHARGE							
kWh	Customer Type	Current System Control Bill Component p.a.	2017/18 Bill p.a.	Proposed System Control Bill Component p.a.	$ increase per customer group p.a.	Proposed 2019/20 Bill p.a.	% bill change
4,532	Couple	$4.53	$1,448	$24.11	$19.58	$1,468	1.4%
6,943	Small Family	$6.94	$2,115	$36.94	$29.99	$2,145	1.4%
10,653	Medium Family	$10.65	$3,143	$56.67	$46.02	$3,189	1.5%
15,316	Large Family	$15.32	$4,434	$81.48	$66.17	$4,500	1.5%
50,000	Small Business	$50.00	$16,346	$266.00	$216.00	$16,562	1.3%
750,000	Large Business	$750.00	$131,898	$3,990.00	$3,240.00	$135,138	2.5%

Power and Water acknowledge that the increase sought in System Control Charge is significant in absolute terms. However, in the context of the overall annual electricity bill the proposed increase is less than 2% across all groups with exception of the large business group with an increase of 2.5%.

The above analysis assumes all other elements of the customers' electricity bills remains constant. The proposed increased System Control and Market Operator Charges constitute approx. 1.5% of any customer's annual electricity bill. Some of these costs would be currently recovered by TGen (refer Section 1.6.2).

4 Demand

Power and Water propose to adopt the forecast energy consumption figures provided by Australian Energy Market Operator (AEMO). AEMO has developed the demand forecasts for the Power and Water distribution determination by AER for the 2019 to 2024 regulatory period. (Refer Table 5).

Table 5: Energy Consumption Forecast by Region in MWh

Year	Darwin-Katherine	Alice Springs	Tennant Creek	Total (MWh)	% Increase	Comment
2016-17	1,639,800	217,000	29,100	1,885,900		Actual
2017-18	1,626,300	216,800	29,400	1,872,500	-0.7%	AEMO Forecast
2018-19	1,591,100	214,300	37,300	1,842,700	-1.6%	AEMO Forecast
2019-20	1,579,500	211,900	37,400	1,828,800	-0.8%	AEMO Forecast
2020-21	1,581,600	209,700	37,500	1,828,800	0.0%	AEMO Forecast
2021-22	1,584,300	207,800	37,600	1,829,700	0.0%	AEMO Forecast
2022-23	1,587,600	206,000	37,700	1,831,300	0.1%	AEMO Forecast
2023-24	1,592,600	204,600	37,800	1,835,000	0.2%	AEMO Forecast
2024-25	1,598,100	203,200	37,900	1,839,200	0.2%	AEMO Forecast
2025-26	1,604,000	202,000	38,100	1,844,100	0.3%	AEMO Forecast
2026-27	1,610,800	200,900	38,200	1,849,900	0.3%	AEMO Forecast

The above reflects the relatively stable nature of the energy consumption profile within the NT networks and therefore the risk of over and under recoveries are mitigated.

5 Price Control Mechanism

Power and Water proposed the adoption of a maximum price cap for the System Control Charge in its prior submission. This is because as indicated above, electricity consumption forecast in the Northern Territory regulated power system is relatively static. Hence, there is limited risk of systematic over or under collection of revenues from the System Control and Market Operator Charges as the charges are only calculated from electricity consumption. Hence, it is not necessary to adopt more complex forms of price control mechanisms for this period.

However, ACIL Allen recommended that a revenue cap mechanism be adopted to control both the system control and market operator charges over the five year period. The revenue cap for the charges will operate with an overs and unders account which is only applied when the balance in the overs and unders account exceeds a materiality band.

Their concern is that due to the Territory Government's Roadmap to Renewables policy, there is a possibility of a material variation between forecast and actual demand. Hence the use of a revenue cap mechanism with a materiality band will address this uncertainty.

If no material demand variance exists between forecast and actual, the revenue cap mechanism should be fairly simple to administer as stated by ACIL Allen in their recommendation. Therefore, in this submission, the proposed charges by Power and Water utilised a revenue cap mechanism as recommended by ACIL Allen.

If this charge increase is to be funded via a Community Service Obligation (CSO) mechanism, then a True Up/Down position could be adopted with an adjustment mechanism established to balance any over/under recovery in the following years CSO payment.

6 Tariff Structures

6.1 Structure

In the prior submission, Power and Water proposed continuation of the current flat tariff charge on energy consumed tariff (dollars per kWh charge), recovered from all electricity sales within the NT regulated power systems. The flat rate tariff approach has the benefit of being administratively simple and provided equitable recovery of costs across all electricity consumers within the NT regulated power systems, based on their total consumption. While the INTEM currently only applies to the Darwin-Katherine regulated power system the benefits of a simple easily applied flat tariff charge outweigh the more complex task of segmenting the Market Operator role solely for the Darwin-Katherine power network and then overlaying the System Controller role across the three regulated networks.

However, ACIL Allen has recommended that the system control charge be separated into system control and market operator charges; with system control charge to cover the three power systems and the market operator charge to only apply to the Darwin – Katherine power system (this is where INTEM exists). This is because System Control function is mature and future costs can be forecast more accurately. INTEM to NTEM transition, the future costs remains uncertain. Hence it is prudent to split the cost recovery into the two distinct functions.

In this submission, Power and Water has used this recommendation to recover the annual operational costs of the Market Operator and System Controller separately.

6.2 Tariff Benchmarking

The most appropriate and easily understood method of benchmarking in this context is on the key cost inputs which in this case are labour and related organisation structure including corporate overheads. That is the labour inputs for the control centre can be benchmarked on the basis of the number of operators per operational desk and then secondly the level of corporate overheads applied to System Control and Market Operator regulated business.

System Control has addressed the staffing levels in this submission and included a specific reduction in the number of staff required. This is reflected in the Efficiency Challenge in Appendix A, Table A2.

This efficiency challenge is allocated to both the regulated and non-regulated components of System Control costs.

Our benchmarking against the Staffing Structures of Western Power and Horizon Energy indicate that System Control will (on achievement of the Efficiency Challenge) be directly comparable to both these organisations staffing levels for operational personnel.

Power and Water have recently completed a review of corporate overheads and have implemented a revised CAM in line with AER approved allocation methods. (Please refer to Appendix B).

The benchmarking of AEMO System Control Charges compared to those proposed by Power and Water are substantially distorted by the size and scale efficiencies of providing those services across the number of customers, energy consumed and their complex tariff structures.

7 Summary

Power and Water has submitted this revised proposed review of the System Control Charge to establish a financial sustainable basis for System Control and Market Operator to undertake their regulated roles with the appropriate resources.

In the submission, Power and Water has acknowledged that improved efficiency and cost reductions are required and that improvement plans are either in place or being put in place to achieve these efficiencies over the next two years.

These targets have been included in the financial estimates of future costs and any failure to achieve these savings will require Power and Water to continue to subsidise any operating deficit incurred by System Control and the Market Operator.

Power and Water have also demonstrated that these functions are being performed by a relatively small number of people and that this can only be achieved by sharing the synergies derived from also providing non-regulated services. The end customer is receiving the benefits of this by a lower than would otherwise exist Network Pricing regime (i.e. would increase if they were required to own and operate their own 24 hour control centres) and via lower than otherwise System Control Charge if they also required a 24 hours staffed control centre.

APPENDIX A: Supporting Financial Data and Assumptions

1. Proposed Operational Costs: System Control & Market Operator

Table 1 Proposed System Control and Market Operator Costs to be recovered (Real $2019)

	2019-20	2020-21	2021-22	2022-23	2023-24
System control					
Personnel costs	$6,246,938	$6,234,444	$6,253,147	$6,284,413	$6,322,120
Other direct costs	$621,059	$615,667	$465,367	$465,367	$465,367
Corporate overheads	$2,005,861	$1,882,657	$1,805,923	$1,726,639	$1,650,835
Total	**$8,873,858**	**$8,732,767**	**$8,524,438**	**$8,476,419**	**$8,438,322**
Market operator					
Personnel costs	$516,019	$514,987	$516,532	$519,115	$522,230
Other direct costs	$105,420	$104,759	$74,107	$74,107	$74,107
Corporate overheads	$211,001	$198,041	$189,969	$181,629	$173,655
Total	**$832,440**	**$817,787**	**$780,608**	**$774,851**	**$769,992**

The basis for all of the calculation and values used in the prior submission's analysis were based on System Control 2017/18 actual and System Control 2017/18 SCI for the following 3 years (2018/19 to 2020/21).

This submission used the revised costs as recommended by ACIL Allen. The labour costs used 2019/20 budget cost as base and adjusted using Deloitte Access Economics real labour price growth forecasts as used in AER's draft determination for PWC 2019-24 for labour costs in subsequent years (2020/21 to 2023/24). Additional cost for the proposed market operator (NTEM) is not in these calculations. Other direct costs (non-labour costs) are presented in 2019 real dollars and escalated by CPI in each subsequent year. Corporate Overhead costs are those approved by AER and are presented in 2019 real dollars and escalated by CPI in each subsequent year.

Methodology used

- An Activity Based Costing Model (ABC) was used.
- All personnel completed time allocations according to weekly usage of their time on the following basis:
  - ➢ **Regulated**
    - ✓ System Control Technical Code & Licence Activities (70 activities listed in Table A1a separated into System Control and/ or Market Operator function)
  - ➢ **Non-regulated**
    - ✓ Territory Generation SLA (5 activities)
    - ✓ Power Networks SLA (29 activities)
    - ✓ Remote Operations SLA (6 activities)
    - ✓ Water Services SLA (6 activities)

Table A1a Regulated Activities

Activity No.	System Control Technical Code & Licence Activities	Code References	Nature of Function
1	Near real time power system monitoring and control	1.7.4 (b); 3.3.1 (a), (b); 6.18	System Control
2	Develop and enhance operational tools e.g. SCADA interfaces, contingency analysis module	3.3.1 (f), (h), (i), (j)	System Control
3	Half yearly reports to UC	8.4.1	System Control
4	Short term advices & directions	1.7.4 (a)(1); 3.3.1 (s); ERA S 38	System Control
5	Development of Operational Procedures / SCOD	1.7.4 (d)	System Control
6	Review of Operational Procedures / SCOD	1.7.4 (d)	System Control
7	AGC and Real Time Generation Monitoring	3.3.1 (h), (i), (j)	System Control
8	UFLS scheme	3.10.1(b)	System Control
9	RFA process	3.3.1 (c), (d), 6.5, 6.6	System Control
10	GOTR process	3.3.1 (k); 6.5, 6.6	System Control
11	System risk process	3.3.1 (a), (g) (f), (i), (j), (k)	System Control
12	Load flow studies for contingency analysis	3.3.1 (a), (f)	System Control
13	System Participants technical compliance auditing	6.22	System Control
14	Customers Complaints monitoring and tracking/investigation	License 12.1 (a) (iv)	System Control
15	Scada alarm limits	3.3.1 (f)	System Control
16	Liaison with Asset Managers	6.1 - 6.14	System Control
17	Issuing non reliable notices	3.7	System Control
18	Outage Coordination Meetings with Power Networks and TGEN	6.5-6.10	System Control
19	Monitoring and coordinating wall boards	3.3.1 (b), (c)	System Control
20	Approval of generation black start procedures	3.3.1 (p); 5.7.2	System Control
21	System restart procedures	1.7.4(e)(1); 3.2.1(c)(4); 3.3.1(o), (q); 5.7.3; ERA S 38	System Control
22	Witnessing black start testing and assessing black start capability	6.22; 6.23; 6.24	System Control
23	Witnessing code compliance testing and assessing evaluation	6.24	System Control
24	Scoping code compliance testing	6.24	System Control
25	Developing operational test plans	3.3.1 (c)	System Control
26	Develop and maintain system models	3.3.1 (j)	System Control
27	Review incidents for reporting requirements	3.3.1(v); 7	System Control
28	Preliminary fault reports	7.4.3	System Control
29	Final incident reports	7.4.4	System Control
30	Track FIR recommendations	3.3.1 (a), (e), (f), (m), (v)	System Control

Activity No.	System Control Technical Code & Licence Activities	Code References	Nature of Function
31	Follow up FIR recommendations with participants	3.3.1 (a), (e), (f), (m), (v)	System Control
32	UFLS strategy	3.3.1 (j); 3.10.1	System Control
33	Generation dispatch	4.4B, 4.4C	System Control
34	Ancillary services dispatch	3.3.1 (h), (i), (j); 5.3	System Control
35	Voltage control dispatch	3.3.1 (h), (i), (j); 5.2	System Control
36	Develop and review SSG	3.5	System Control
37	Consult and publish SSG	3.5.2; 3.5.3; 3.5.4	System Control
38	Monitor and report on compliance SSG	3.3.1 (e); 3.5.5; 8.4	System Control
39	Outage restoration	1.7.4 (e); 3.3.1 (c), (r), (t)	System Control
40	Monitor System Participant advice	1.7.4 (b); 8.2.4	System Control
41	Evaluate risk based on participant advice	3.2.10	System Control
42	Pre-dispatch	A6.1 (c)	Market Operator
43	Market Price	A6.1 (c)	Market Operator
44	Participant registration	A6.2	Market Operator
45	Market consultations	A6.1 (f)	Market Operator
46	Annual load forecasting	3.11.2	System Control
47	Market settlements	A6.1 (b)	Market Operator
48	Short term load forecasting	3.11.2	System Control
49	Market, industry and regulatory reform	A6.1 (d), (e); SC License: 18; ERA: 30(1)(d), 45(2)	50% System Control 50% Market Operator
50	Code review	1.8.2 (d)	System Control
51	Plant outage approval	1.7.4 (a) (3), (4)	System Control
52	Day ahead plant schedule	A6.1 (c)	Market Operator
53	Daily Plan dispatch	A6.1 (c)	Market Operator
54	Generator start and Stop	1.7.4 (a) (3), (4); 3.3.1 (h)	System Control
55	Post trip Management	1.7.4 (a) (7)	System Control
56	Test run of power plants	3.3.1 (g), (j); 6.2.4	System Control
57	Reporting	7	System Control
58	Emergency Operation	3.3.1 (r), (t)	System Control
59	Develop KPIs	1.7.4 (c); 8.4.1	System Control
60	NTEM Development	License 15.4	Market Operator
61	Voltage management plan	2.2 (d)	System Control
62	Historical Data Requests	8.5	Market Operator
63	Standard Data Requests	8.5	Market Operator
64	Customer Transfers	A6.1 (a), (b)	Market Operator
65	Darwin - Katherine settlements	A6.1 (b)	Market Operator
66	Ancillary Services Calculations	A6.11	Market Operator
67	Maintain participant register	A6.2	Market Operator
68	IES deemed profile allocations	A6.4 (c) (2), (d)	Market Operator
69	Perform ad hoc revisions	A6.5 (b)	Market Operator
70	Publication of market data	A6.1 (c); A6.12	Market Operator

All operational costs has been allocated based on the percentage of time spent on each of these activities – regulated (System Control and/or Market Operator) and non-regulated. Operational costs were separated into personnel, direct costs and corporate overhead – regulated and non-regulated. As recommended by ACIL Allen, personnel costs associated with Senior Real Time Operations Manager and the Control Room Coordinators, which have been allocated to Business Management, were only allocated to personnel with system control functions and not to personnel with market operator functions only. Refer to Table A1b below.

Table A1b: SUMMARY (REAL $2019)

	System control	Market operator	Regulated	Non regulated	Total
2019-20					
Personnel costs	$ 6,246,938	$ 516,019	$ 6,762,957	$ 1,262,970	$ 8,025,927
Direct costs	$ 621,059	$ 105,420	$ 726,479	$ 98,828	$ 825,307
Corporate overheads	$ 2,005,861	$ 211,001	$ 2,216,862	$ 416,326	$ 2,633,189
Total	**$ 8,873,858**	**$ 832,440**	**$ 9,706,299**	**$ 1,778,124**	**$ 11,484,423**
2020-21					
Personnel costs	$ 6,234,444	$ 514,987	$ 6,749,431	$ 1,260,444	$ 8,009,875
Direct costs	$ 615,667	$ 104,759	$ 720,426	$ 97,658	$ 818,084
Corporate overheads	$ 1,882,657	$ 198,041	$ 2,080,697	$ 390,755	$ 2,471,452
Total	**$ 8,732,767**	**$ 817,787**	**$ 9,550,554**	**$ 1,748,857**	**$ 11,299,411**
2021-22					
Personnel costs	$ 6,253,147	$ 516,532	$ 6,769,680	$ 1,264,225	$ 8,033,905
Direct costs	$ 465,367	$ 74,107	$ 539,474	$ 78,610	$ 618,084
Corporate overheads	$ 1,805,923	$ 189,969	$ 1,995,892	$ 374,828	$ 2,370,721
Total	**$ 8,524,438**	**$ 780,608**	**$ 9,305,046**	**$ 1,717,663**	**$ 11,022,710**
2022-23					
Personnel costs	$ 6,284,413	$ 519,115	$ 6,803,528	$ 1,270,546	$ 8,074,074
Direct costs	$ 465,367	$ 74,107	$ 539,474	$ 78,610	$ 618,084
Corporate overheads	$ 1,726,639	$ 181,629	$ 1,908,268	$ 358,373	$ 2,266,640
Total	**$ 8,476,419**	**$ 774,851**	**$ 9,251,270**	**$ 1,707,529**	**$ 10,958,799**
2023-24					
Personnel costs	$ 6,322,120	$ 522,230	$ 6,844,349	$ 1,278,170	$ 8,122,519
Direct costs	$ 465,367	$ 74,107	$ 539,474	$ 78,610	$ 618,084
Corporate overheads	$ 1,650,835	$ 173,655	$ 1,824,490	$ 342,639	$ 2,167,129
Total	**$ 8,438,322**	**$ 769,992**	**$ 9,208,314**	**$ 1,699,418**	**$ 10,907,732**

Table A1c shows the proposed charges based on the proposed system control and market operator costs to be recovered and using the AEMO demand forecast for the 3 power systems for system control charge and the AEMO demand forecast for Darwin – Katherine only, for market operator charge.

Table A1c Proposed Charge Calculation (Real $2019)

	2019-20	2020-21	2021-22	2022-23	2023-24
System Control Costs Recovered ($)	8,787,141	8,698,607	8,610,965	8,524,207	8,438,322
Energy Consumption - 3 power systems (MWh)	1,828,800	1,828,800	1,829,700	1,831,300	1,835,000
System control charge ($/kWh)	**0.0048**	**0.0048**	**0.0047**	**0.0047**	**0.0046**
Market Operator Costs Recovered ($)	821,515	808,320	795,336	782,561	769,992
Energy Consumption - Darwin-Katherine (MWh)	1,579,500	1,581,600	1,584,300	1,587,600	1,592,600
Market operator charge ($/kWh)	**0.00052**	**0.00051**	**0.00050**	**0.00049**	**0.00048**

2. System Control Costs

System Control have undertaken a strategic review of its operations and developed:

- a series of business improvement initiatives designed to consolidate the recent improvements in effectiveness and general compliance culture while incorporating planned efficiency improvements to reduce costs of both regulated and non-regulated functions;
- SLA with Power and Water's Power Networks for the provision of non-regulated services, leveraging the 24 hour manned control centre required for the system controller functions;
- An activity based costing model that ring fences both the regulated and non-regulated activity drivers performed and the costs and revenues associated with each activity.

Personnel expenditure was based on the staffing numbers assumed in Table A2 below. Included is a reduction in controller staffing through operational efficiency improvements and additional staff estimates to support System Control & Market Operator functions.

Table A2: FTE PLAN 2017-2021 BENCHMARKING

System Control FTE Plan 2017 - 2021					
Key Drivers	**Jun-17**	**Jun-18**	**Jun-19**	**Jun-20**	**Jun-21**
Existing Business	**50**	**45**	**44**	**42**	**41**
General Manager	1	1	1	1	1
Executive Assistant	1	1	1	1	1
Business and Strategy	2	2	2	2	2
Operation Planning	6	5	5	5	5
Operation System	3	3	3	3	3
Real Time Operations	28	25	24	23	22
Project Manager	1	1	1	0	0
Operations Support	3	3	3	3	3
Market Operations	5	4	4	4	4
New Business	0	7	7	4	4
Roadmap to renewables		1	1	1	1
I-NTEM to NTEM transition		4	4	3	3
Regulated Power System Dynamic Modelling		1	1		
Ancillary Services Reliability Project Alice Springs Design Specification		1	1		
Revised FTE	**50**	**52**	**51**	**46**	**45**

3. Benchmarking

The key driver of costs of providing the system control functions is the personnel numbers and their associated costs with staffing a 24h /365 day control centre. For benchmarking the most appropriate measure is the staff numbers per desk. The PWC numbers includes all staffing associated with the PWC shift rosters at the Hudson Creek control centre which now controls Darwin, Katherine, Alice Springs and Tenant Creek. This is the same basis as the control centre numbers for Western Power and Horizon Energy.

Table A3: BENCHMARK DATA CONTROL ROOM DESKS

Feature/Function	Benchmarking data Western Power (1)	Horizon Energy (2)	PWC 2018/19	PWC 2020/21
Staff Numbers (Control Numbers)	42	8	24	22
Controllers	7			
Shift Supervisors	**49**	**8**	**24**	**22**
Functions				
Transmission desks	2	1	1	1
Distribution Desks	6	0.3	1	1
Generation Dispatch Desks	0		1	1
	8	**1.3**	**3**	**3**
Ratio				
Controller number per Desk	6.13	6.15	8.00	7.33
Rosters (24 Hours 7 days pw)	2x12	2x12	3x8	3x8
Rosters (8 Hours 7 days pw)		1x8		

Note the above numbers for Power and Water include both regulated and non-regulated functions provided from the 3 operational desks with only 74% of the costs being allocated to the regulated functions.

The above illustrates that System Control is targeting a reduction to an appropriate benchmark being in the range of 6-7 staff per desk. It is understood that Western Power can and does reduce the number of distribution desks rostered on night shift to accommodate management of the overall roster. This demonstrates the scale benefits of a larger group. Note also that Western Power no longer undertakes generation dispatch with this function being transferred to AEMO. Horizon Energy operates the second desk on a day shift only.

For System Control to achieve savings over and above the current targets would require a combination of:

- A reduction in the number of desks from 3 to 2.5 (i.e. eliminate night shift on one desk); or

- The introduction of 12 hour shifts.

Potential additional savings would range from an additional 2-4 personnel with notional annual savings of $0.25M to $0.6M

In the current environment and given the evolution of the market, management considers it inappropriate to consider the implementation of these options at this time. The current focus is to ensure staff are multi-skilled to work across a number of desks in order that the shift staff can work effectively as a team without the need for additional shift supervision or additional back up during periods of peak activity.

System Control's staffing levels outside the control centre itself are relatively low with a small engineering group, business support and general management totalling some 19 personnel. The Hudson Creek control centre now controls the Darwin/ Katherine, Alice Springs and Tenant Creek regulated networks. This is a lean operation which has only recently been bolstered to accommodate the technical requirements of managing the system security and market operations.

The engineering group has been progressively developed and scaled to match market developments and the reliability of the network. This has substantially increased the effectiveness of this group and facilitated enhanced interrelationship between System Control and System Participants in driving an enhanced governance focus.

4. Market Operator Costs

The Wholesale Market Services (WMS) Team within the Strategy and Transformation Business Unit undertakes a number of functions both regulated and non-regulated. The regulated functions include:

- Implementation and operation of the wholesale electricity market, including all market settlements, comparisons and daily market data publishing as outlined in the System Control Technical Code.

- Operation of the full retail contestability function (FRC), including standing data, historical data and customer transfer requests as outlined in the Electricity Retail Supply Code. The revenue associated with the provision of historical data is directed through to Power Networks.

The non-regulated functions undertaken by the WMS team relate to the production of settlement statements for the regional electricity systems across the Northern Territory on behalf of the local generator. Currently the production of the settlement statements service is classified as an alternative control service with all revenue and costs being allocated to Power Networks.

The WMS team consists of currently of 3, but anticipated that it will require 5, staff members which undertake both regulated and non-regulated functions.

This submission addresses only those charges eligible under the System Control Technical Code.

5. Review of the Electricity Retail Supply Code

Power and Water provided a submission to the Utilities Commission requesting a review of the Electricity Retail Supply Code. The submission incorporated a request to transfer the responsibility for certain functions from the Network Provider to the Market Operator. If this were to occur the Market Operator would require access to a revenue source to provide these services. The services in question are:

1. Standing Data requests;
2. Customer transfer requests; and
3. Business to Business processes, such as service order requests.

Within the National Electricity Market these services are provided by the AEMO. AEMO recovers the costs associated with these services via two sources: a fee for service; and a c/kWh charge applied to all market customer wholesale purchases. At this stage in the NT the provision of these services is a manual task, however a system is being investigated to automate the process and provide real time access to market information.

The costs associated with these services have not been incorporated into the System Control Charge submission and a fee for service arrangement will be introduced should the Code amendments be approved.

6. I-NTEM and NTEM Implementation Costs

The projected cost only covers external costs incurred with Power and Water proposing to fund the internal staff costs within its budgets. These external costs are further explained in Appendix A but are principally consultant costs to assist in the design and development of software tools and systems appropriate for use in a market the size of the I-NTEM. i.e. simple adoption of AEMO style systems and tools was not appropriate.

Power and Water consider this investment was prudent and efficient given that Power and Water was responding to challenges and timeframes not of their making. By their nature these development costs are of a one off nature and Power and Water does not possess nor should they possess the internal capacity to develop these tools and systems. They were charged with developing systems suitable for the I-NTEM with the inherent recognition that these interim market design would evolve and thus require some ongoing development.

Power and Water consider the development costs of $2.35M over three years to be relatively efficient on this basis.

It is estimated that further expenditure of $3.755M on external consultants will be required over the next three financial years (2018-19 to 2020-21) to assist the NT's transition to a full NTEM from the current interim arrangement. This work requires dedicated specialist skills not otherwise available within Power and Water. External specialist skills were an essential component to the successful implementation and ongoing operations of the I-NTEM. Work identified for the external consultant for both the Market Operator and System Controller is consistent with the NTEM Roadmap that was released by the DTF in July 2016.

It is expected that the majority of the budgeted $3.755M will be required for projects in 2018-19 and 2019-20 years to mainly support ancillary service unbundling and financial settlement in line with DTF's revised preliminary plan that financial separation and related market functions be implemented in 2019. This works builds on what has been done to date and may change if DTF amend their implementation plan.

It should also be noted that the staged transition to full NTEM may require additional resources during both the development and ongoing operational stages once full market design is completed and all system management functions identified.

The external costs of the above program of works are shown in the Table 3 below.

Table 3: Projected future External NTEM Development Costs

	2018-19	2019-20	2020-21
Design	**1,000,000**	**400,000**	**400,000**
High Level Design Work	200,000	100,000	100,000
Detailed Design Work	300,000	200,000	200,000
Rule Drafting	100,000	50,000	50,000
Legal Review	50,000	50,000	50,000
Independent Rule Review	50,000		
Project Management Support	200,000		
EMS Expert	100,000		
Implementation	**755,000**	**700,000**	**500,000**
Settlement System Upgrade	100,000	50,000	
EMS Upgrade	300,000	350,000	350,000
DPT Upgrade	150,000	250,000	100,000
Procedural Documentation	150,000	50,000	50,000
Stakeholder Consultation	20,000		
Training Documentation	20,000		
Training Coordination	15,000		
Total	**1,755,000**	**1,100,000**	**900,000**

7. Control Centre and New Administration Centre

The current System Control centre is located within a Power Networks substation at Hudson Creek which is currently provided rent free by Power Networks. The building is relatively old and has been modified and extended various times to accommodate the evolution of technology to control networks and generators and the expansion of staff numbers as the functions of System Control have developed.

There are deficiencies in the current back up arrangements in the event of the loss of the Hudson Creek facility due to natural or system disaster. The Hudson Creek site has some historical weaknesses as the primary site for a control centre due to the age of the building and its existing SCADA infrastructure. There are a number of single points of failure at the current site where a failure within the SCADA master station at Hudson Creek would result in the loss of remote control of a number of the older zone substations at both Hudson Creek and at Ben Hammond back up facility.

The current Disaster Recovery Plan identifies a limited temporary arrangement at Power Network's Ben Hammond complex as the only available option. This requires Power Network to temporarily relocate some staff to accommodate the Control Centre and will provide only limited capacity to control the network and generators for a limited time. An alternative site with more secure back-up arrangements has been identified as a priority.

Relocation of the current control centre to a new site would enable the current site to be retained as the back-up facility, providing a more secure arrangement to maintain electricity supply to the Northern Territory.

The retention of Hudson Creek as the back-up facility and the continued use of the existing control system infrastructure will assist in lowering the costs of the new facility as some of these can be relocated to the new facility.

The Table A4 are the costs estimated for the new facility.

Table A4: Estimated Control Room / Admin Centre Costs

Element	Cost/m2	Size (m2)	
Rent	455	850	
Fitout	1500	850	1,275,000.00
Control Room equipment			500,000.00
Communications			500,000.00

The above calculations are in 2017/18 dollars and represent 100% of the costs. The costs included in the submission are escalated to 2017/18 dollars and include only 90% of the costs. Power Networks will fund the remaining 10% and also continue to provide the Hudson Creek facility as a back-up facility on a rent free basis.

The costs have been based on a 10 year amortisation period which acknowledges that while the physical building may be operational for a number of years (ie 30 + years) the fit out and the respective equipment will likely continue to be developed and replaced within a 10 year period. It is proposed that the building be leased rather than purchased so hence an estimated rental has been included based on discussions with TGen relative to the cost of their new centre, adjusted for size and accommodation requirements.

APPENDIX B: Corporate Overheads

In 2017-18 PWC revised its Corporate Overheads allocations based on causal cost drivers at a more granular level to PWC's current corporate structure. Corporate Overheads are allocated based on underlying drivers including headcount, time, cost, and square metres to ensure equitable allocation across the operational Business Units of PWC. The cost allocation methodology is AER-approved. Refer: https://www.aer.gov.au/system/files/Power%20and%20Water%20Corporation%20-%20Cost%20Allocation%20%20Methodology%20-%2024%20November%202017.pdf pages 33 and 34. Table A5 shows the corporate overhead activities and causal allocators.

TABLE A5: CORPORATE OVERHEAD AND CAUSAL ALLOCATORS

Cost category	Cost sub-category	Stated Allocator
Customer and billing		FTE and Contractors
Finance	General	FTE
	Overdraft	Debt Level
	Accounts payable	Invoice numbers
IT	FMS GIS Maximo RMS	Licence numbers
	Business Intelligence system Datamart system EDMS Internet administration Intranet administration Service Desk Small systems administration	Hardware
	BSIM administrations	FTE and Contractors
HR	Training	FTE and Contractors
	HR Operations and Employee Relations	FTE
Insurance	Workcover Insurance	FTE
	General Insurance	Assets
	Vehicle Insurance	Vehicle numbers
Other Corporate	Facilities Work, Health and Safety Risk, Audit & Compliance Sustainable Energy Managing Director	FTE and Contractors
	Procurement Communicatons and Marketing Board Executive Records Management	Revenue
	General Counsel	Legal Instructions
	Design & Diagnostic Ministerial and Client Relations Wholesale Markets	Forecast share
	Environmental Services	Emvironmental
	Project Management Office	PMO
	Regions (Southern Administration) Strategy & Planning	Even
	Economics & Regulation	Time