Jemena Electricity Networks (Vic) Ltd

2016-20 Electricity Distribution Price Review Regulatory Proposal

Revocation and substitution submission

Attachment 7-17 Power of Choice business case

Public

6 January 2016

Jemena Electricity Networks (Vic) Ltd

Power of Choice Business Case - Phase 1

Program Establishment

Program of Work

Public

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Name	Job Title	Date	Signature
Reviewed by:			
Matthew Serpell	Asset Regulation & Strategy Manager		

Approvers:

See Section 2

History

Rev No	Date	Description of changes	Author
0.1	5 Nov 2015	Initial Draft	Michael Macfarlane
1.0	7 Dec 2015	Final – revised and include internal feedback and external review	Michael Macfarlane
1.1	9 Dec 2015	Final document mark-ups and revisions	Michael Macfarlane et al
1.2	17 Dec 2015	Revised Approvers to include IT PMO and Finance, plus minor editorial changes	Michael Macfarlane
1.3	21 Dec 2015	FINAL - Added Investment Management breakdown of establishment phase costs, clarification of funding source, clarification of no requirement for retirement of IT systems plus minor editorial changes	Michael Macfarlane

Owning Functional Area

Business Function Owner:	Cameron Dorse Chief Information Officer

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1. EXECUTIVE SUMMARY

1.1 BUSINESS CASE DEVELOPMENT APPROACH

This business case has been produced by the Power of Choice project team in consultation with subject matter experts representing IT Strategy & Architecture, IT Portfolio Management & Delivery, Service Delivery, and Asset Strategy. The financial viability has been reviewed with Finance and delivery feasibility reviewed within IT and the impacted functional groups being Service Delivery, Information Technology, Asset Management, Strategy Regulation and Markets.

1.2 EXECUTIVE SUMMARY

Executive Summary	**Background and Context**	Substantial reforms to the National Electricity Market (NEM) are underway following recommendations to the state and federal governments by the AEMC's "Power of Choice review – giving consumers options in the way they use electricity". The scale and breadth of projects under the banner of the Power of Choice (PoC) reform are extensive, complex and frequently inter related; however the delivery is staggered with both parallel and sequentially programmed deliverables. As such a single JEN program governance framework is proposed to be overlaid across the breadth of PoC to ensure the coordination and collaboration of the program along with its internal and external interactions. This business case includes implementation works for the following PoC impacts • PoC - Metering Competition (MC) • PoC - Customer Access to Data (CAD) • PoC - Shared Market Protocol (SMP) • PoC - Distribution Network Pricing (DNP) • PoC - Program Governance
	Scope and Objectives	Maintaining compliance through change of the regulatory, technical and operational environments, Maintain business continuity and availability of market systems, Adopt and leverage market change befitting a rational and efficient environment, Enhance consumer energy engagement and demand side participation, Engage with industry and advocate for the future market environment and commercial realities of the Power of Choice reform
	Rationale for the project: *demonstrate the need or driver for the project/program to be approved*	Compliance to NER rule changes associated with the Power of Choice market reforms
	Costs	Phase 1 Establishment and Governance 1.32M Capex, $0.08M Opex, Total $1.40M (Forecast Program Capex $24.98M, Opex $0.88M, ACS Metering $0.35M Total $26.2M)

Benefits	Regulatory compliance Adopt the rule power of choice changes for a more complex market environment without a negative impact to customer and market service operations Heightened consumer energy engagement Enable the consumer benefits identified in the power of choice reform program
Timeframe	April 2016 to March 2018
Financial assessment and funding source	JEN budget for Metering Contestability ($10M) a deliverable of Power of Choice market reforms is the initial funding source for the program establishment phase.. The establishment phase of the program is accountable for attaining Band A approval for the entire Power of Choice program Lowest cost to meet compliance without a negative impact on operational costs
Highlight any key risks, issues or other factors that may affect approving this project	Regulatory Risk – Non-compliance if works not undertaken. Financial Risk – Project cost overrun compared with forward estimates due to incorrect assumptions or reform program scope creep. Operational Risk – Cost overrun of customer and market services operations that cannot be maintained within the regulatory allowance. Reputational Risk – Consumer adverse reaction to market change and benefits not being realised. Safety Risk – Electrical safety of contestable metering installations put the customer or public at risk of electric shock, fire or unexpected outages.
RECOMMENDATION	This business cases recommends to establish the initial funding for phase 1 of the program to the order of $1.40M for the Power of Choice Program Management project, with the charter for development and delivery of the budgeted PoC work stream projects including the complete sufficient planning, design and business requirements analysis works and development of efficient business cases for a response to each Power of Choice rule change and or its associated instrument or events including: - Reconfigure existing customer & market system for the commencement of Metering Competition with conversion of type 5 AMI to type 4 AMI (AMI-SAP centric) - Establishing an interim workaround ahead of a reconfigured self-service customer portal that supports all JEN customers to meet the obligations of the Customer Access to Data rule change, - Implement the Shared Market Protocol business to business market interfaces as at the commencement of Metering Competition, - Establishing a centralised power of choice Program Governance to ensure coordination, and efficiency of the PoC change events.

1.3 INTENDED AUDIENCE

The intended audience for this document are:

1. Cameron Dorse, Chief Information Officer
2. Sonia Greguol, GM Portfolio Management & Delivery
3. Alan Hume, GM IT Strategy & Architecture
4. Erin Chain, GM Customer Service
5. IT Portfolio Management & Delivery
6. JEN strategy Committee

2. APPROVERS

Decision: Approval of business case against Power of Choice Program - phase one for budget funding $1.38m to establish the program of works				
	Name	**Title** *(For Agree, specify the scope of agreement)*	**Signature**	**Date**
RECOMMEND[1] *<One Recommend>*	Michael Macfarlane	Commercial Manager Metering	[signature]	15/12/2015
AGREE[2] *<Can have multiple Agree>*	Sonia Greguol	GM Portfolio Management & Delivery	SEE REVISED SIGN	SHEET
	Alan Hume	GM IT Strategy & Architecture	[signature]	15/12/2015
	Erin Chain	GM Customer Service	[signature]	17/12/2015
PERFORM[3] *<Can have Multiple Perform>*	PM&D	Portfolio Management & Delivery - Team	n/a	n/a
INPUT[4] *<Can have multiple Input>*	Steve Burge	Project Manager	NO LONGER AVAILABLE	N/A
	Nilesh Kevat	Enterprise Applications Architect	[signature]	16/12/15
	Nick Koulbanis	Business Partner	[signature]	18/12/15
	Mohan Kuppusamy	Revenue Operations Manager VIC	[signature]	17/12/15
DECIDE[5] *<One Decide>*	Cameron Dorse	Chief Information Officer	SEE REVISED SIGN	SHEET

Note two approvers pages are included in this PDF

1 **Recommend** a proposal on a key decision, gathering appropriate input/data (from Input role) and actively seeks agreement from impacted stakeholders and relevant functional experts (Agree role). R takes recommendation to Decider and must note if A agrees or disagrees.

2 **Agree** – person(s) who agrees (or disagrees) to the recommendation, as it relates to their scope of expertise and provides reason why agrees or disagrees. Has the right to escalate non-agreement directly to the Decider.

3 **Perform** – responsible for implementation of the decision. During decision process, might also be an ***Agree*** or an ***Input*** to how the decision should be implemented.

4 **Input** – the person(s) who provides specific functional expertise or other input to the recommendation – data, key analysis, advice.

5 **Decide** – person who has final decision rights and commits the organisation to action. With Recommender (at beginning of decision process) agrees what scope of recommendation will be and who should be involved (e.g. A's and I's).

2. APPROVERS

Decision: Approval of business case against Power of Choice Program - phase one for budget funding $1.40m to establish the program of works				
	Name	**Title** *(For Agree, specify the scope of agreement)*	**Signature**	**Date**
RECOMMEND[1] *<One Recommend>*	Michael Macfarlane	Commercial Manager Metering		22/12/2015
AGREE[2] *<Can have multiple Agree>*	Sanjay Patel	GM Business Finance Partner	([illegible] on behalf of Sanjay)	23/12/2015
	Sonia Greguol	GM Portfolio Management & Delivery		23/12/2015
	Alan Hume	GM IT Strategy & Architecture		23/12/2015
	Erin Chain	GM Customer Service		
PERFORM[3] *<Can have Multiple Perform>*	PM&D	Portfolio Management & Delivery - Team	n/a	n/a
INPUT[4] *<Can have multiple Input>*	Manisha Sethi	IT PMO Manager		
	Nilesh Kevat	Enterprise Applications Architect		
	Nick Koulbanis	Business Partner		
	Mohan Kuppusamy	Revenue Operations Manager VIC		23/12/2015
DECIDE[5] *<One Decide>*	Cameron Dorse	Chief Information Officer		23/12/2015

1 **Recommend** a proposal on a key decision, gathering appropriate input/data (from Input role) and actively seeks agreement from impacted stakeholders and relevant functional experts (Agree role). R takes recommendation to Decider and must note if A agrees or disagrees.

2 **Agree** – person(s) who agrees (or disagrees) to the recommendation, as it relates to their scope of expertise and provides reason why agrees or disagrees. Has the right to escalate non-agreement directly to the Decider.

3 **Perform** – responsible for implementation of the decision. During decision process, might also be an ***Agree*** or an ***Input*** to how the decision should be implemented.

4 **Input** – the person(s) who provides specific functional expertise or other input to the recommendation – data, key analysis, advice.

5 **Decide** – person who has final decision rights and commits the organisation to action. With Recommender (at beginning of decision process) agrees what scope of recommendation will be and who should be involved (e.g. A's and I's).

2.1 FOR CAPEX PROJECTS

Refer to the attached delegation of financial approval: http://jemena-intranet.alinta.net.int/resources/delegation-of-financial-Authority/

Approval is sought under Annexure 3 for Capital Expenditure projects.

This business case seeks budget provision for Power of Choice program and does not release the complete funds for all work streams. The business case however does establish the Power of Choice program governance framework for coordination of the work streams and development of the identified projects as the rule PoC final decisions are released or equivalent crystallising milestone. In each case the PoC work stream projects governed under the program requires a business case development and separable DFA approval as the rule changes and industry impact is known;

PoC program establishment funding requires an initial approval from Band C (up to $2M) for the first three months of the program establishment phase to the value of $1.40M. The program being the sum of the projects including the program management oversight value of $26.2M over the life of the program requires Band A approval. During the establishment phase the program is required to attain Band A Program approval.

3. PROJECT INFORMATION

3.1 BUSINESS CONTEXT AND REQUIREMENTS

3.1.1 BUSINESS CONTEXT

Substantial reforms to the National Electricity Market (**NEM**) are underway following recommendations to the state and federal governments by the AEMC's "Power of Choice review – giving consumers options in the way they use electricity" (AEMC 2012[6]).

The final report for the Power of choice review sets out recommendations for supporting market conditions that facilitate efficient demand side participation (**DSP**).

- Objective of the review is to provide that the community's demand for energy services is met by the lowest cost combination of demand and supply side options.
- PoC Objective is best met when consumers are using electricity at the times when the value to them is greater than the cost of supplying that electricity.

The AEMC report identified several areas of reform, recommended actions and outlined an implementation plan[7]. The AEMC are processing a number of rule change requests from the COAG Energy Council and other parties in response to these recommendations.

The scale and breadth of projects under the banner of the Power of Choice (**PoC**) are extensive, complex and frequently inter related; however the delivery is staggered with some activities in parallel and synchronised while others are non-concurrent . As such a single JEN program governance framework is proposed across the breadth of PoC initiatives to ensure the coordination and collaboration of the program, along with its internal and external industry engagement (eg process working groups).

3.1.2 POWER OF CHOICE SCOPE

The scope of the power of choice work program is well established but still subject to some variability until industry consultations conclude. The following work streams are active under the Power of Choice review. It is expected that several industry sub committees will form and finalise the details of many of the work streams which are described here.

3.1.2.1 Metering Competition (MC)

A new framework for extending metering competition and services to small customers in the NEM[8].

The Metering Competition rule changes lay the foundation for a market-led and consumer driven approach to the deployment of smart meters. Other than where a new or replacement meter needs to be installed, advanced meters would only be deployed where energy businesses and consumers want access to the services enabled by advanced meters at a price they are willing to pay for those services. A Metering Coordinator (MC) role replaces the Responsible Person (RP) metering role. A Distribution Network Service

[6] http://www.aemc.gov.au/Markets-Reviews-Advice/Power-of-Choice-Stage-3-DSP-Review

[7] http://www.aemc.gov.au/getattachment/16851b15-935c-42c2-b8db-5bc392f6e456/Final-report-Implementation-plan.aspx

[8] The final determination for Metering Competition was released on the 26th November 2015 with a proposed 'Go live' of 1st December 2017.

Providers (DNSP) metering coordinator business is likely to be ring fenced based on guideline requirements to be determined by the AER. Provisions in the new rule allow for interoperability between Metering Coordinators at least at the shared market protocol level so that commercial service provision of metering can be made by any existing MC (MDP & MP) without requiring a change of meter (meter churn) ie Churn of a retailer will not require churn of the MC as each MC must implement minimum services to the market via a Shared Market Protocol.

3.1.2.2 Customer Access to Data (**CAD**)

Customers will be able to access electricity consumption data from Retailers and DNSP's in an understandable format and timely manner so that they can make more informed choices about energy products and services.

CAD AEMO procedures establish minimum requirements for the manner and form in which retailer or DNSP must provide metering data to a retail customer or their authorised representative in response to a request for metering data from either party.

3.1.2.3 Embedded Networks (**EN**)

Brings increased retail competition into embedded networks by establishing a regulatory framework for embedded networks in the Rules. A New Embedded Network Manager role is responsible for managing service provision within an embedded network. The Embedded Network Manager must fulfil MSATS/B2B obligations in regard to setting up and maintaining embedded network child connection points, in a similar manner to what an LNSP would normally perform for distribution network connection points.

3.1.2.4 Shared Market Protocol (**SMP**)

A set of services, service level requirements, transport and formatting rules primarily intended to facilitate service requests and responses in regard to advanced metering services. While the SMP facilitates the making of requests for services to service providers, the commercial arrangements for those services will be between requestor and service provider. A new SMP platform is to replace/augment the Business to Business (B2B) Hub which supports B2B functionality, transaction delivery, including Peer to Peer (P2P) transactions.

3.1.2.5 Multiple Trading relationships (**MTR**)

Note the AEMC has determined that the MTR rule change will not proceed and is no longer in scope of this PoC program. MTR had proposed that multiple retailers at a premises for a single customer. A customer could have multiple FRMPs (Retailers) and multiple NMIs at a single site supporting parallel, subtractive and net metering arrangements. The project would have logically separated the connection point from the settlement point and there could have been more than one metering installation at a site. The LNSP would have been responsible for the creation of the NMI, even for a downstream NMI where the meter is not directly connected to their network assets.

3.1.2.6 Distribution Network Pricing (**DNP**)

The Distribution Network Pricing Arrangements rule change establishes four new pricing principles for distribution businesses so the prices reflect the efficient costs of providing network services to each consumer. This will allow consumers to compare the value they place on using the network with the costs of using it.

1. Each network tariff must be based on the long run marginal cost of providing the service.

2. The revenue to be recovered from each network tariff must recover the networks efficient and non-distorted costs of providing the service.
3. Tariffs are to be developed with the consumer impact principles in mind, so they can be understood, accepted and gradually phased-in.
4. Network tariffs must comply with any jurisdictional pricing obligations

The new rule retains the existing pricing principle that is designed to minimise cross-subsidies between different classes of consumers.

In response to the new rule and pricing principles JEN has developed new tariff structures which include a maximum demand charge from 2018 onwards.

3.1.2.7 Demand response Mechanism (**DRM**)

DRM market mechanism to promote demand response from large customers. A new role of Demand Response Aggregator (DRA) can contract large customers (>100 MWh per year, though varies by jurisdiction) for demand response. A DRA would be paid by the market for reduction in demand, and the host retailer charged based on an AEMO estimate of what demand would have been incurred had the demand response not occurred.

- COAG has proposed that retailer participation should be voluntary. This means a DRA would only have access to customers of retailers who have opted in. Equally a retailer who does not opt in could not offer demand response to their customers.

3.1.2.8 Meter Replacement Process (**MRP**)

The Meter Replacement Processes rule change stemmed from a procedure change by AEMO in response to finding that the current procedures were not consistent with the NER; essentially ensuring that only a party who had a formal relationship with the metering installation could instigate meter churn. The rule change seeks to provide provisions for parties with a prospective, rather than a formal relationship with a metering installation, to initiate meter churn.

Note that the Meter Replacement Process consultation by the AEMO has largely rejected the proposed changes and in its place proposing a minor clarification of the rules (the scope is not identified as a material change and is not included in the capital scope of this program as a project).

3.1.2.9 Cleansing NMI Standing Data / MSATS Effectiveness Review (**CDER**)

COAG has tasked AEMO with cleansing NMI standing data (with priority on address formats) and reviewing effectiveness of MSATS Procedures with respect to objections and other relevant matters. Improved protocols and standards for NMI Standing Data, including a standardised physical address format, obligations on participants to support cleansing of data, and on-going future improvements in data.

3.1.3 BUSINESS REQUIREMENTS

The key business requirement is for JEN to continue to meet its market and customer impacted or enabled by the Power of Choice reforms while;

- maintaining compliance through change of the regulatory, technical and operational environments,
- maintain business continuity and availability of market systems,

- enhance consumer energy engagement and demand side participation,
- engage with industry to facilitate the realisation of benefits identified under the power of choice reform program

3.2 PROGRAM AND SOLUTION OBJECTIVES

The objectives of the JEN power of choice program and solutions are to:

- Maintain comprehensive compliance for JEN through the regulatory, technical and operational environmental changes set in motion by the Power of Choice program and associated works,
- Maintain continuity and availability of Market Systems, so that business continuity is not adversely impacted through the program iterations and continue with ongoing operations,
- Proactively adopt change and ensure the market environment and solutions are befitting a rational and efficient solution by; continuing to support the market development activities of the Power of Choice program through industry engagement,
- Delivery an efficient cost controlled program in response to Power of Choice obligations based on a total cost of ownership perspective,
- Ensure that the market solution remains efficient through appropriate technology selection and application of automation,
- Support and enable the future market environment and commercial realities of the Power of Choice reform.

The Market Systems environment for JEN comprises an integrated architecture of proprietary and custom systems. Table 3–1: Referenced Market Systems identifies a macro level view of the market system environment for the purpose of reference in this document. The table should be read in conjunction with Figure 3–1: Market Systems Logical Architecture being a block visual interpretation of the integrated solution. Functionally the depicted systems represents a baseline starting point in time for Power of Choice as at June 2016 at the completion of enterprise wide IT projects presently in progress and schedule for go-live in May 2016. The market systems environment, when considered holistically, is a combination of people process and technology, where the market procedures, standards and rules dictate the obligations.

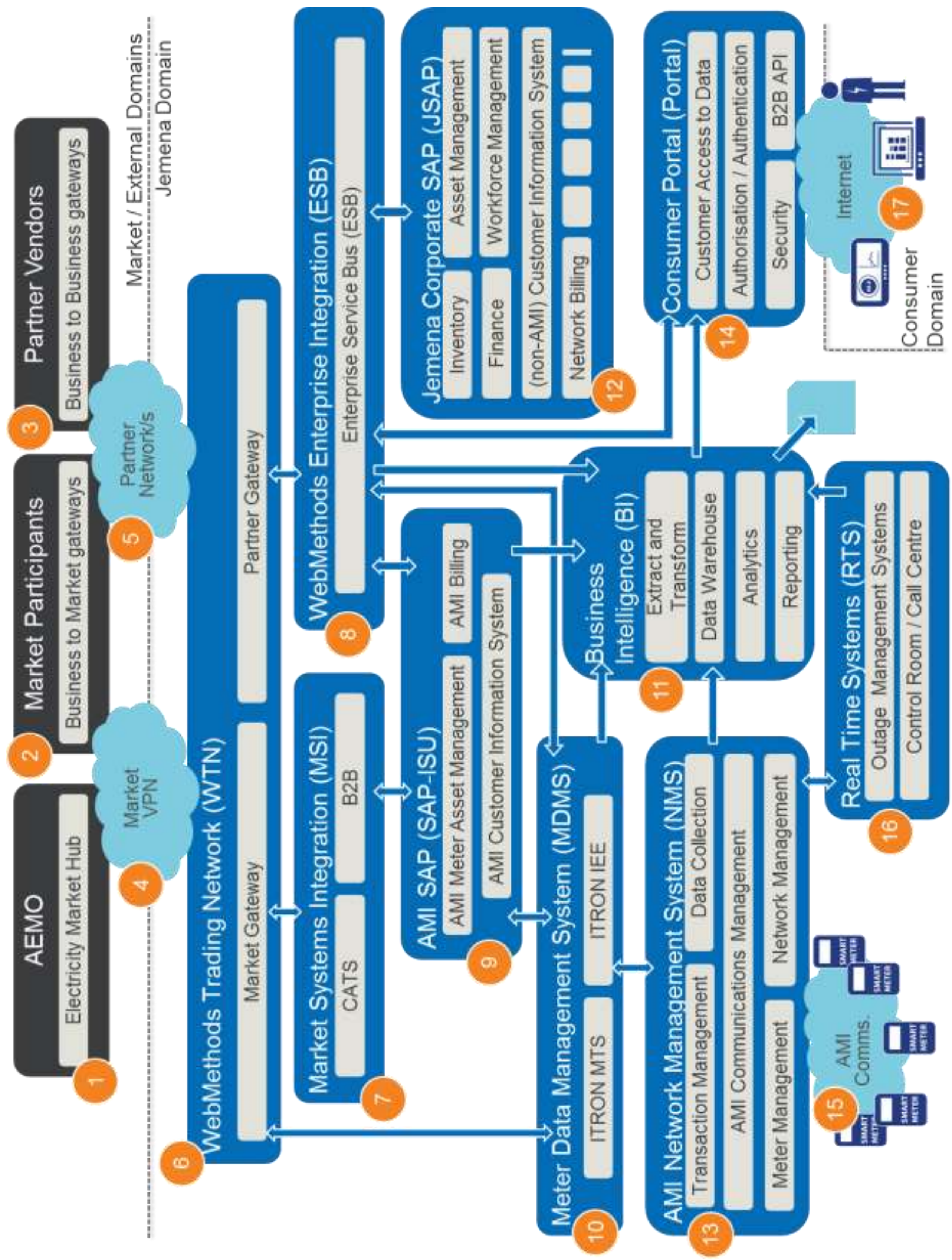
Table 3–1: Referenced Market Systems

Ref No	System	System Functional Purpose
1	AEMO - Market systems	AEMO market systems are hosted by AEMO and all JEN to market transactions are generally carried through the electricity market hub (eg MSATS & CATS).
2	Market Participant - Systems	Market participants registered and accredited by AEMO to transact through the electricity market hub are external (or ring fenced) parties.
3	Partner & Vendor Systems	JEN leveraged external partner business provide goods and services through Business to Business gateways. The type of connectivity to JEN is dependent on the commercial, technical and trust relationship of the partner.

Ref No	System	System Functional Purpose
4	Market VPN Network	A virtual private market trading networks, only registered and accredited market participants are connected to the AEMO hosted market systems cloud.
5	Partner Network/s	Partner networks and systems may be hosted internally, externally or in virtual networks. The security zone and relationship is dependent on the commercial, technical and trust relationship of the partner.
6	WebMethods Trading Network (WTN)	The trading network provides an external facing service bus for market based transactions as a middleware interface. The trading network is a managed environment with all transactions being logged, monitored, transformed (as required), packaged, acknowledged and delivered with quality of service (ie guaranteed delivery). The trading network services the market gateways and partner networks (eg datalink and transport layers).
7	Market Systems Integration (MSI)	MSI supports market integration logic and the JEN implementation of CATS B2B. Market transactions and B2B requests are initially processed by MSI through predefined sequential function automation logic. MSI thus provides an integration function between the market gateway and market systems. Straight through and near real time processing capability is provided by MSI.
8	WebMethods Enterprise Integration (ESB)	The Enterprise Service Bus provides a common platform for internal integration between enterprise (and market) systems so that systems each application can interact with each other using a common managed interface.
9	AMI SAP (SAP-ISU)	AMI SAP is a standalone instance of SAP which is dedicated to AMI metering customers and AMI metering assets. SAP IS-U is the industry specific utilities SAP solution. AMI SAP provides functions of Meter Asset Management, AMI Billing and AMI Customer Information. AMI SAP is the only system that supports AMI meters and solution. AMI SAP is exclusively used for JEN AMI customers (Includes Type 5 AMI, excluded all Type 1-4, Legacy Type 5, 6, 7 and unmetered customers).
10	Meter Data Management System (MDMS)	The Meter data management systems are the authoritative meter data store for all versions of interval data collected and stored. The MDMS is collectively a hybrid solution of Itron IEE and Itron MTS. Note IMS (MV90) is assumed to be retired as of May 2016 and MDMS services all types of interval meters and interval data.
11	Business Intelligence (BI)	The JEN Market Systems Business Intelligence solution is a big data analytics platform for management customer, market and metering systems. Most market systems have exported data transformed, and stored in a central data warehouse, BI systems run scheduled and ad hoc process to analyse and prepare data views for scheduled and ad hoc reporting.

Ref No	System	System Functional Purpose
12	Jemena Corporate SAP (JSAP)	Corporate SAP is the Jemena enterprise wide enterprise resource planning solution. With respect to market systems JSAP provides the following functions; Inventory management, Asset Management, Finance, Workforce Management, (non-AMI) Customer Information System, Network Billing. The May 2016 JSAP system includes an instance of SAP ISU servicing all non-AMI metering and customer information systems.
13	AMI Network Management System (NMS)	AMI NMS also known as UtilityIQ (UIQ) the Network Management System is the head end system managing the AMI mesh radio network. The NMS functions include transaction management, data collection, AMI Communications Management, Meter Management, Network Management for 327,000 AMI meters.
14	Consumer Portal (Portal)	Electricity Outlook is a web base graphical user interface portal for customer access to data and analytics. The portal is integrated into the market systems environment and provides a self-service interactive consumer interface to energy data. A key aspect to the portal is the integration into the market systems environment for authorisation, security, historical meter data, data warehouse and a market facing B2B application programming interface (API).
15	Advanced Metering Infrastructure Communications Network (AMI Comms)	The AMI Mesh radio communication network is a proprietary last mile communications infrastructure to and between AMI integrated AMI meters (Network Interface Cards), pole mounted relays, pole mounted access points using a 3G telco based backhaul to the two data centres (Primary and DR).
16	Real Time Systems (RTS)	Real Time Systems environment include a suite of applications used by network operations to efficiently manage the primary infrastructure assets including but not limited to SCADA (Supervisory Control & Data Acquisition), Outage Management Systems (OMS), Distribution Management Systems (DMS), Graphical Information Systems (GIS), and Outage web.
17	Consumer Domain	The Consumer domain represents the extension and direct interaction of market systems with the consumer from the distribution network service provider.
18	New Connections Portal	The new connection portal provides a web based Service order management tool for raising and managing customer initiated work orders.

Figure 3–1: Market Systems Logical Architecture



3.3 PROGRAM SCOPE

3.3.1 IN PROGRAM SCOPE

Item No.	In Scope	Comments
IS-1	PoC - Metering Competition (MC)	AEMC's final determination for Metering Competition was released on the 26th November 2015 with a 'Go live' on 1st December 2017. Some metering businesses will move early as the present market rules do not preclude it.
IS-2	PoC - Customer Access to Data (CAD)	On 6 Nov 2014, the AEMC made new rules for consumers to obtain information about their electricity consumption from networks and retailers in an easy-to-understand, affordable and timely way. AEMO has published a new procedure for CAD which comes into force as of the 1st March 2016.
IS-3	PoC - Shared Market Protocol (SMP)	The SMP final rule determination is anticipated in May 2016 with an AEMC recommended minimal implementation of new functions for Dec 2017. This may allow for a coincident go live with metering competition however this program does not presently assume a coincident go live due to the extensive consultation and change required to develop and implement the SMP.
IS-4	PoC - Distribution Network Pricing (DNP)	The DNP rule change was complete in November 2014 and prescribed the pricing development in the submitted case for JEN EDPR 2016-2020. The DNP project allows for the technical implementation in the market solution which is not yet supported in the approved form for commencement in Jan 2017 for large customers & Jan 2018 for small to medium customers.
IS-5	PoC - Program Governance	Program Management, Budgeting, Finance, Risk, Scheduling, Legal, Reporting, Contract Management, Consulting, Industry Engagement, Working groups, Business Engagement, Resource Backfill, Change Management, Continuous monitoring of program change variance to Power of Choice scope.

3.3.2 OUT OF PROGRAM SCOPE

Item No.	Out of Scope	Comments
OS-1	PoC - Meter Replacement Process (MRP)	MRP has no identified impact to the regulated JEN market systems environment and is excluded from this program. Note the rule change is now expected to be a minor clarification within the existing rules and processes. The PoC Governance framework will keep a watching brief in case the situation changes.

Item No.	Out of Scope	Comments
OS-2	PoC - Embedded Networks (EN)	EN assumptions have a moderate identified impact to the regulated JEN market systems environment; Based on the present assumptions these changes could be completed by business as usual resources and is therefore presently excluded from this program. The PoC Governance framework will keep a watching brief in case the situation changes.
OS-3	PoC - Demand Response Mechanism (DRM)	DRM has no identified impact to the regulated JEN market systems environment and is excluded from this program. The PoC Governance framework will keep a watching brief in case the situation changes.
OS-4	Cleansing NMI Standing Data / MSATS Effectiveness Review (CDER)	CDER is presently not well defined and the initial assumptions are not adequate to forecast the event. CDER remains out of scope of the program until it is defined and assessed to have an impact beyond Business as usual administrative actions. The PoC Governance framework will keep a watching brief in case the situation changes.
OS-5	Emerging unregulated market opportunities are out of scope	The PoC shall be viewed from the perspective of a JEN regulated asset for the purpose of costing. That is emerging unregulated opportunities are out of scope and would require their own business cases for a new and unregulated activity. An unregulated operating model would need to be consistent with the to be released ring fencing guidelines.
OS-6	Establishing an unregulated contestable metering business or capability is out of scope	If or when Jemena enters the contestable metering market it would be in isolation and ring fenced in accordance with the to be released ring fencing guidelines (ie separation from the JEN regulated metering business) and is therefore outside of scope.
OS-7	PoC - Multiple Trading relationships (MTR)	On 19 November 2015 the AEMC published a draft rule determination to not make a draft rule in relation to the multiple trading relationships (MTR) rule change request.[9]. It is therefore known that MTR in its present form will not proceed and is excluded from scope.

3.3.3 PROGRAM ASSUMPTIONS AND DESIGN PRINCIPLES

Due to the staggered program of works and development of the Power of Choice reforms it is necessary to define the working assumptions and establish design principles at the time of preparing the business case and program budget.

[9] http://www.aemc.gov.au/Rule-Changes/Multiple-Trading-Relationships

Table 3–2: Program Level Assumptions and or Principles

Item No.	PoC Work Stream	Assumption	Comments
AS-1	All	High Levels of Automation and integration are to be maintained	High Levels of Automation are required to be maintained when implementing change to market systems to ensure the existing workforce is not further negatively impacted on an ongoing basis (thus we assume no additional FTEs for service delivery or IT support).
AS-2	All	Project and options analysis need to consider the Total cost of ownership	Projects cost estimates will need to consider the total cost of ownership, and include estimates for variance to ongoing opex or capex where they vary from the escalated baseline year (CY2014).
AS-3	All	System and process change shall be bundled where it is efficient and possible to do so	When implementing change to systems or processes the scope of a project should include a balanced approach to compliance and tactical elements that are advantageous or advance JEN position. Ie concurrent scope should be considered for inclusion to improve efficiency or operating costs of JEN.
AS-4	All	Assumptions and principles shall be used to allow for unknown market environment requirements	Project estimates assume probable (realistic) case scenario for unknown variables to ensure adequate regulatory allowances are determined.
AS-5	All	JEN shall continue to be actively engaged in the industry engagement for PoC through the implementation phases	Each project requires a level of industry engagement for development of operational procedures guidelines, frameworks and program governance. JEN shall assume an active engagement in each PoC work-stream.

Table 3–3: Metering Competition Assumptions and or Principles

Program Assumptions - Metering Competition (MC)			
Item No.	**PoC Work Stream**	**Assumption**	**Comments**
AS-10	MC	JEN will continue to operated regulated meters as the incumbent metering coordinator	JEN Regulated Metering will continue to operate after the commencement of metering competition and be ring fenced from any contestable unregulated metering business (JEN or other).
AS-11	MC	Jemena Contestable metering opportunities remain out of scope	If or when Jemena enters the contestable metering market it would be in isolation and ring fenced from the JEN regulated metering business and is therefore outside of scope.

Program Assumptions - Metering Competition (MC)			
Item No.	**PoC Work Stream**	**Assumption**	**Comments**
AS-12	MC	From the commencement of metering competition at least new connections will be installed and serviced by a contestable metering coordinator	New connections will be made with meters supplied and operated by contestable metering providers on the JEN network and retailer nominated MCs.
AS-13	MC	JEN will become the default MC for existing AMI meters	As the incumbent Responsible Person (RP) JEN will become the default Metering Coordinator (MC) for all small to medium metering customers for Type 5 and 6 class meters
AS-14A	MC	AMI meters will be mass market converted from a type 5 AMI to a type 4 AMI meter at the AMI derogation lapses (NER Clause 9.9C.4).	Existing AMI meters will be compulsorily converted from a type 5 AMI to a type 4 (4, 4A or 4B) in the market at the commencement of competition. This will result in a bulk change data conversion in the market for all 327,000 JEN AMI meters. This will change the logic in automation and impact multiple system, interfaces and processes.
AS-14B	MC	MC/MP/MDP Type 4, 5 and 6 Accreditation / Re-accreditation will be required	An incumbent LNSP RP Default MC will not be gifted an AEMO accreditation under the revised rules. Reclassification of AMI meters to Type 4 AMI will require a new AEMO accreditation. Existing accreditation will need to be renewed for legacy Type 5 and Type 6 Meters.
AS-15	MC	Metering Contestability will only partly share synergies with other projects as the PoC project implementations are staggered	Metering Contestability and Shared Market protocols are share a common commencement date but staggered rule change dates. Therefore the program can gain some further synergies through the later part of the MC and SMP project deliveries by sharing test and implement cycles/releases. ie end to end testing, change and release. The Metering Contestability /Shared Market Protocol project will therefore be have some opportunity synergies or efficiencies.
AS-16	MC	Metering contestability requires new industry process for coordination across a wider group of participants	A new or updated operational process is required to support connection and metering works to accommodate coordination of new parties at the connection point / metering installation. For instance out of sequence meter install by a third party would result in a wasted truck visit.
AS-17	MC	Faulted and end of life meters will be replaced with 3rd party contestable meters (not JEN regulated meters) from the 1st Dec 2017	Any end of life type 5 or 6 meter will be replaced by the FRMPs nominated contestable metering provider.

Program Assumptions - Metering Competition (MC)			
Item No.	**PoC Work Stream**	**Assumption**	**Comments**
AS-18	MC	Every metered connection must have a functional meter or supply outages will not be restored.	Connection points without a functional meter will not remain energized or be energized (unless they are an unmetered supply point). Therefore an all supply fault that is dependent on a meter replacement to reenergize the site will remain off supply until the nominated MC or their delegate installs a functional and compliant meter.
AS-20	MC	Remote disconnections can be performed directly by the Retailer.	The FRMP will have the capability and right to remotely disconnect a customer’s supply without the DNSPs service provision. The FRMP will be required to notify the DNSP of remote service disconnection / reconnection (DNP / Move In / Move out).The DNSP will have the capability to query the status of the remote service contactor position from the market systems and or FRMP using SMP meter ping or an equivalent near real time service order transaction.
AS-21	MC	JEN’s existing market systems are fit for purpose for the new regulatory environment	The existing JEN market systems, technology platforms and licences are fit for purpose to support the anticipated contestable metering environment. The Contestable Metering project should therefore be considered as a reconfiguration of a brown fields JEN IT market ecosystem.
AS-22	MC	Coordination and scheduling is required for PoC against existing IT and Market systems programs of work	Some IT systems and processes are scheduled for migration to updated platform versions or other products and those changes will remain within the scope of other projects; however this project may take advantage of a new environment or process established by another project where that decision to do so will reduce subsequent rework. e.g..The Business Intelligence platform is migrating away from Cognos the incumbent AMI BI solution, new BI reports and analytics developed should therefore be prepared in the new BI environment in favour of the legacy outgoing Cognos BI where it makes sense to do so.
AS-23	MC	Market validation and substitution rules will not the same as those used for Type 5 AMI meters	Presently Type 4 and Type 5 validation, substitution and estimate rules are not consistent event though type 4 and type 5 meters are of the same accuracy. Adopting validation, substitution and estimate rules for the bulk of the JEN meter population result in a substantial step change of systems and process.
AS-24	MC	Bulk type changes and new rule framework will require redevelopment of market systems translation logic	Webmethods (WTN & ESB) and MSI process automation and transaction translation logic changes will be required to accommodate the re-typing of meters and new procedures developed for Metering Contestability

Program Assumptions - Metering Competition (MC)			
Item No.	**PoC Work Stream**	**Assumption**	**Comments**
AS-25	MC	A contestable meter estimation and substitution obligation lies with the external Meter Data Provider (MDP)	JEN cannot substitute or estimate reads for a type 4 smart contestable meter, this will be the Metering Coordinators MDP that provides that service. Given the new market initial complexity and number of new players a significantly higher number of estimates will be required compare to the incumbent MDPs

Table 3–4: Customer Access to Data Assumptions and or Principles

Program Assumptions - Customer Access to Data (CAD)			
Item No.	**PoC Work Stream**	**Assumption**	**Comments**
AS-30	CAD	AEMO Metering data provision procedures is the basis for design of CAD	JEN intends to comply with the AEMO Metering data provision procedures (1 Sep 2015) as of the commencement date 1st March 2016.
AS-31	CAD	Existing IT projects in progress prohibit implementation of CAD by the due date.	JEN is constrained by existing IT commitments and change freezes that will impact its capacity to deliver a fully automated and self-service solution that is compliant to all aspects of the AEMO procedure for all types of JEN customer.
AS-32	CAD	JEN cannot satisfy the whole customer population with the present AMI portal solution.	JEN will require an interim measure to satisfy the obligations of the procedure ahead of the final technical solution which can be delivered in due course. JEN is largely compliant to the service obligation using the Electricity Outlook Portal (AMI Portal) however this does not satisfy the prescribed formatting and is limited to 98% of the customer base.
AS-33	CAD	An interim Opex solution is required prior to the final solution implementation.	JEN proposes an interim manual process to supplement the existing portal solution for the customers that request meter data in the prescribed format which are not satisfied with the existing portal service. This measure will allow for full interim compliance ahead of a comprehensive self-service solution.
AS-34	CAD	JEN is partially compliant to the requirements however the new obligations are highly prescriptive.	To date manual requests for meter data are principally satisfied by directing a customer to register an account on the AMI portal. The customer can then graphically view, or download a CSV file of their own data in a controlled and authorised manner. This approach is limited to AMI (type 5) customers (98% of customer base) and does not satisfy customers with Types 1 – 4 & 6 meters (<2% of customer base). The file formats are equivalent but not compliant to the prescribed formatting in the AEMO procedure.

Program Assumptions - Customer Access to Data (CAD)			
Item No.	**PoC Work Stream**	**Assumption**	**Comments**
AS-35	CAD	Customer authorised agent use of CAD will grow substantially and a manual process will be unsustainable.	The rule introduction promotes authorised agents to access a customer's meter data which in JEN's experience has been used in only a limited way to date. The prescribed format will allow for greater numbers of third party consultants, brokers and retailers to utilise and become an authorised agent for many customers and a substantial increase in single and batch requests for data is assumed. It is not expected that a manual process will be sustainable to satisfy the demand for customer meter data.
AS-36	CAD	A New baseline market systems environment is in place from May 2016 which will be the base environment for CAD development.	The CIS+ replacement project are in progress and will not be completed until May 2016. It is improbable that customer access to data impacts can be included in the existing project as a change request and that Customer Access to Data self service capability will be delivered in succession sometime after the CIS+ replacement project.

Table 3–5: Shared Market Protocol Assumptions and or Principles

Program Assumptions - Shared Market Protocol (SMP)			
Item No.	**PoC Work Stream**	**Assumption**	**Comments**
AS-40	SMP	Shared market protocol is opt-in in for market participants.	Use of the proposed shared market protocol is provided on an opt-in basis as the technical implementation proposed by AEMO is prospectively in parallel to the existing Business to Business (B2B) services.
AS-41	SMP	JEN must opt-in to SMP to satisfy its network and Metering Coordinator obligations	As a new Metering Coordinator JEN must make available minimum advanced services to the market such as remote connect, remote disconnect and meter enquiry. JEN must implement the shared market protocol at the time the SMP goes live as it requires the new meter ping service to satisfy its regulatory obligations for managing network connections and the meter ping function will not be available as an existing B2B service and JEN must be able to discover remotely disconnected JEN customers through the market transactions.
AS-42	SMP	JEN optimum outcome is to implement SMP at the time of initial release	Implementation of a shared market protocol will be most effectively interoperable with the industry working together on a concurrent implementation.

Program Assumptions - Shared Market Protocol (SMP)			
Item No.	**PoC Work Stream**	**Assumption**	**Comments**
AS-43	SMP	JEN can only advocate for advanced features if it is an early adopter driving change	JEN can influence and advocate for greater development of advanced SMP functions like HAN voltage and power quality to enable AMI benefits if it is an active participant in the SMP industry go live. Note JEN already propose network projects AMI network benefit realisation projects, without greater advanced functions for contestable meters such benefits would be reduced as the contestable market grows.
AS-44	SMP	A singular go live is preferred over a staged release of SMP functions.	JEN assumes that two phases of delivery of SMP will be implemented in the regulatory period. Initial minimum services and a subsequent enhancement for advanced features of smart meter functions otherwise smart metering benefits will go unrealised.
AS-45	SMP	JEN will not implement peer to peer advanced comms using SMP with market participants initially.	JEN does not intent to implement peer to peer communications with other market participants using the SMP as a transport in the first instance. JEN has an established and preferred business to business information exchange model in place for collaboration with industry partners.
AS-46	SMP	JEN can leverage existing know how as a base to implement SMP for maximum efficiency	The Gas distribution market interface implementation of B2B services is likely to be used as a template by AEMO for implementation of the SMP. It is therefore assumed that AEMO will use a similar but more current version of webservices in the development of the SMP market gateway. JEN will therefore have a level of reuse of existing knowhow and system from the Jemena Gas Network implementation of B2B and MSI for the JEN implementation of SMP.
AS-47	SMP	Existing environments and service buses are fit for purpose and reuse	JEN can leverage the existing Enterprise Services Bus (web methods) architecture to implement the shared market protocol.
AS-48	SMP	Metering contestability and shared market protocol releases are now coincident.	For the purpose of forecasting JEN accepts that the go live of the shared market protocol is now aligned to the go live of metering contestability and that the project delivery of MC and SMP can and should be combined into a single project for delivery.

Table 3–6: Multiple Trading Relationships Assumptions and or Principles

Program Assumptions - Multiple Trading Relationships (MTR)			
Item No.	**PoC Work Stream**	**Assumption**	**Comments**
AS-50	MTR	MTR will proceed in one form or another.	On 19 November 2015 the Australian Energy Market Commission (AEMC) published a draft rule determination to not make a draft rule in relation to the multiple trading relationships (MTR) rule change request. Note: While the MTR rule change format has ceased, without MTR, further change can or will be included in Embedded Networks and Contestable Metering rule changes to promote MTR like scenarios, ie provision for domestic embedded network in MC change, use of gross or subtractive metering for co-gen / storage installations. The market / industry is committed to a form of multiple trading relationships albeit not the MTR itself that would provide more flexibility for a customer to settle their energy discretely for import and export or at one or more settlement points behind the connection point.
AS-51	MTR	An MTR alternative measure may ensue under the Power of Choice program	JEN shall maintain a watching brief for scope change related to the initial intent of MTR under the Power of Choice program of works.eg program scope change risk.

Table 3–7: Distribution Network Pricing Arrangements Assumptions and or Principles

Program Assumptions - Distribution Network Pricing Arrangements (DNP)			
Item No.	**PoC Work Stream**	**Assumption**	**Comments**
AS-60	DNP	New JEN demand based tariffs are mandated and approved by the AER.	In response to the rule change Distribution Network Pricing Arrangements JEN has developed a new tariff offerings including a Demand tariff component. Demand based tariffs are approved from the regulator as part of the JEN EDPR preliminary determination.
AS-61	DNP	The market systems solution and processes do not yet support the approved tariffs	The structure of the proposed demand based tariffs are not presently supported by the market systems and pursuant to the approval of such a structure needs to be integrated into the market systems capability.
AS-62	DNP	The proposed IT project to implement tariffs is based on outdated assumptions and need to be updated	The proposed EDPR IT Project ID096 ($548k) to implement tariff changes is inadequate to complete the implementation of demand tariffs and shall be replaced. A change in underlying assumptions and extent of the project impact was driven by feedback acquired during the TSS consultation; the regulatory conditions have changed since the development of the initial IT implementation proposal and an updated forecast is required.

Table 3–8: Demand Response Mechanism Assumptions and or Principles

Program Assumptions - Demand Response Mechanism (DRM)			
Item No.	**PoC Work Stream**	**Assumption**	**Comments**
AS-70	DRM	DRM has no identified impact to the regulated JEN market systems environment	There are presently no identified JEN system or process operational impacts associated with the proposed rule change for Demand Response Process.

Table 3–9: Embedded Network Assumptions and or Principles

Program Assumptions - Embedded Network (EN)			
Item No.	**PoC Work Stream**	**Assumption**	**Comments**
AS-80	EN	Existing market systems are fit for purpose for the proposed Embedded Network regulatory environment	The existing JEN market systems, technology platforms and licences are fit for purpose to support the anticipated Embedded network rule change
AS-81	EN	A new market role is established – Embedded Network Operator	The addition of a new role of Embedded Network Operator in the market will required a reconfiguration of market systems to support the rule change.
AS-82	EN	The new rule creates a more formal on market recognition of an ENO	Embedded Networks exist today in an off-market system with wholesale electricity supply connection points. The embedded network rule change formalises the embedded network operator in the market systems as a new type of participant.
AS-83	EN	Embedded networks will become more numerous	The rule change is designed to promote growth in the number of Embedded Networks with competition between Embedded Network Operators. JEN can therefor reasonably assume that the ENO market will be numerous with complex relationships of energy service provision.
AS-84	EN	Change is required to market systems to allow for ENO role and association to boundary and child meters	JEN will require changes to the existing market systems to support the new role and associated operational interactions. These changes will include a moderate reconfiguration of the customer information systems, integration layers, business to business interfaces, associated and impacted procedures.
AS-85	EN	Even minor changes require some level of regression testing	Even moderate changes to the market systems required due diligence to ensure continuity of compliance, billing and operation; therefore appropriate regression testing and governance is required for what might otherwise be considered a minor project.
AS-86	EN	Implementation of ENO role is a relatively small project	The scale of the EN change as proposed is not assessed at this time as requiring a large capital project.

Table 3–10: Cleansing NMI Standing Data / MSATS Effectiveness Review Assumptions and or Principles

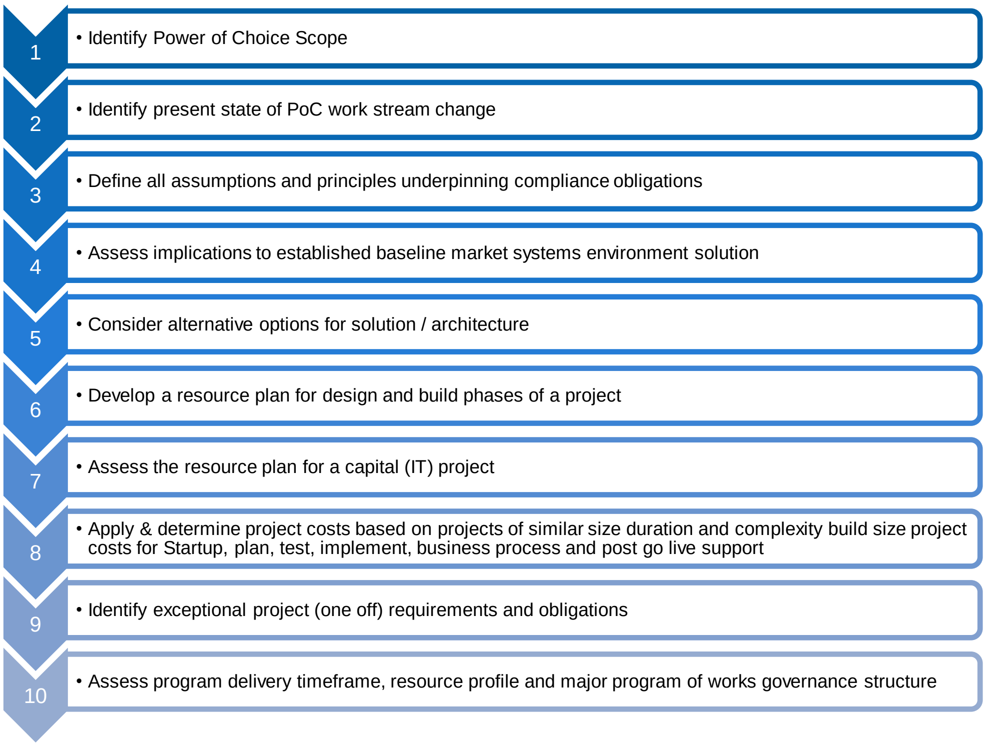
Program Assumptions - Cleansing NMI Standing Data / MSATS Effectiveness Review (CDER)			
Item No.	**PoC Work Stream**	**Assumption**	**Comments**
AS-90	CDER	A review of MSATS will recommend administrative change and some enhancements to available and required data fields	It is assumed that a meaningful industry review of NMI standing data and MSATS will recommend a clean-up of the process and existing standing data to; • Discard the use of unstructured address data in favour of structured address data • Enhance the fields available and obligations to maintain secondary fields of record • Delete or archive redundant records • Reaffirm the validity of the market standing records
AS-91	CDER	Additional market fields would require a schema change	Therefore a schema change will be required for MSATS data and market interfaces
AS-92	CDER	Market participants would be required to wash (clean-up) the data sets that they are the authoritative source for	A form of semi-automated washing of data is required along with a significant volume of manual inspection and processing of or verification of all customer records
AS-93	CDER	Data processing would be continuously incremental as each participant updates their source	The authoritative source for standing data fields is held in each case by one of the LNSP, FRMP or market operator. Each participant will synchronously process updates to their authoritative records over the project period.
AS-94	CDER	JEN will principally be a receiver of change as existing data quality is good	JEN data sources was recently cleaned through the AMI rollout program, are well structured and do not suffer quality issues as may be experience by other market participants
AS-95	CDER	There is Insufficient evidence to indicate a large capital CDER project	The present conditions of JEN market systems and data quality does not yet indicate a major impact of MSATS review.

3.4 MARKET SYSTEM IMPACT ASSESEMENT

The power of choice program comprises multiple deliverables with each work stream at different stages of readiness. The program is presently forecast for delivery over some 30 months of capital program commencing in June 2016 through to November 2018. Each Power of Choice work stream was individually assessed with an initial 5 projects identified (note initial assessment was prior to MC final decision and MTR cessation decision) along with a program management and delivery governance framework.

A 10 step process Figure 3–2: Project Assessment Approach was adopted in developing the impact assessment and funding requirements for Power of Choice and the subsequent tables summarise the findings.

Figure 3–2: Project Assessment Approach



All four of the remaining capital work streams (excludes initial assessments of MTR) as are summarised in Table 3–11: Market System Impact Summary with the underlying commentary in the subsequent tables.

Table 3–11: Market System Impact Summary

System / Domain	MC	CAD	SMP	DNP
(1) AEMO - Market systems	Med	Nil	High	Low
(2) Market Participant - Systems	Med	Med	High	Med
(3) Partner & Vendor Systems	Low	Low	Low	Nil
(4) Market VPN Network	Nil	Nil	Med	Nil
(5) Partner Network/s	Nil	Nil	Nil	Nil
(6) WebMethods Trading Network (WTN)	High	Low	High	Low
(7) Market Systems Integration (MSI)	High	Low	High	Med
(8) WebMethods Enterprise Integration (ESB)	Med	Med	High	Low
(9) AMI SAP (SAP-ISU)	Med	Low	Med	Med
(10) Meter Data Management System (MDMS)	Med	Low	Low	Med
(11) Business Intelligence (BI)	Med	High	Med	High
(12) Jemena Corporate SAP (JSAP)	High	Low	Med	Med
(13) AMI Network Management System (NMS)	Low	Nil	Low	Nil
(14) Consumer Portal (Portal)	Low	High	Low	Med

System / Domain	MC	CAD	SMP	DNP
(15) Advanced Metering Infrastructure Communications Network (AMI Comms)	Low	n/a	Low	n/a
(16) Real Time Systems (RTS)	Low	Nil	Med	Nil
(17) Consumer Domain	Med	Med	Low	Med
(18) New Connections Portal	Med	Nil	Nil	Low

3.4.1 METERING COMPETITION (MC)

Key elements underpinning the commencement of metering competition that have substantive impacts to the project include the:

- The end of AMI derogation[10] triggers a change in the treatment of AMI meters with the expiration of NER clause 9.9C.4 on the 1st December 2017 being the same date as the start of metering competition rule change. The Rule permits the *"Classification of relevant metering installations - A relevant metering installation which, but for it being capable of remote acquisition, would be a type 5 or type 6 metering installation, is taken to be a type 5 or type 6 metering installation respectively."* Therefore all type 5 AMI meters can no longer remain as a type 5 as each AMI meter has by definition remote acquisition,
- the obligation to convert all existing AMI meters from Type 5 (AMI) to a Type 4 (AMI) that at the end of the AMI derogation that all meters will be treated in market in accordance with Chapter 7 of the NER[11],
- the inherent change in validation rules for the majority of incumbent JEN meters associated with the bulk reclassification AMI meters as type 4 AMI,
- the consequent need for reaccreditation as a type 4 meter data provider and meter provider triggered by the change of meter type, Changes to Systems and changes to market obligations,
- AEMO will not gift a type 4 accreditation of the incumbent LNSPs accreditation for a type 5 MDP[12],
- the adoption of new rules and obligations,
- the need to be able to accept new meter types and meter classifications from 3rd party contestable metering coordinators for all JEN network new and replacement meters (Adds, Alts and Faults),
- the gradual reversing of data flows for source billing records from inside-outside to outside-inside, consequent shift in scale of meter hosted CRM systems from Contestable vs JEN,

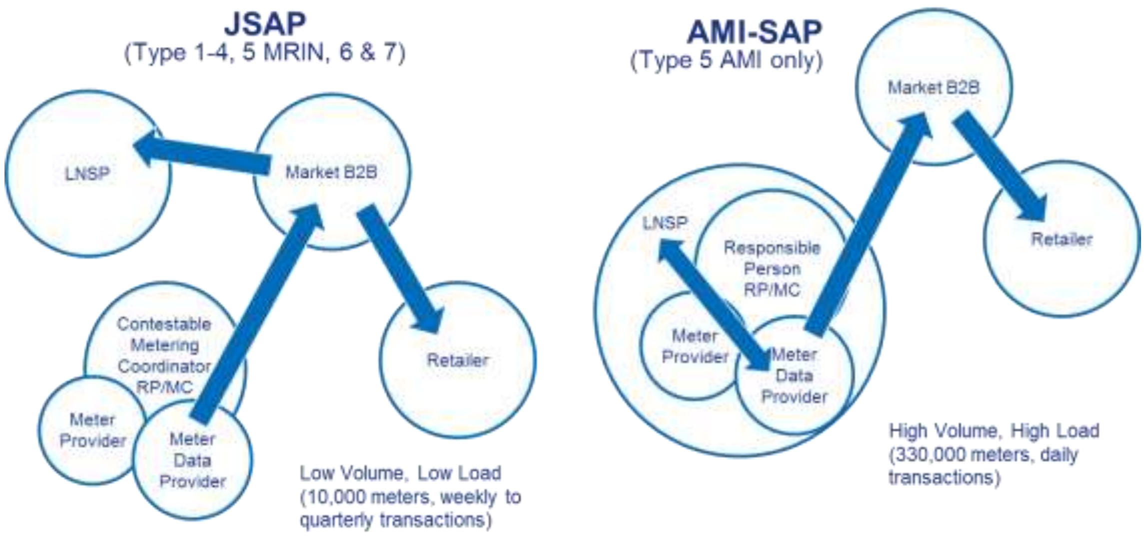
[10] http://www.aemc.gov.au/getattachment/19b656b1-148c-45f8-95b8-2d1cb66948c1/National-Electricity-Rules-Version-76.aspx

[11] AEMC Rule Determination National Electricity Amendment (Expanding competition in metering and related services) Rule 2015, National Energy Retail Amendment (Expanding competition in metering and related services) Rule 2015, Table F.1, page 528, http://www.aemc.gov.au/getattachment/ed88c96e-da1f-42c7-9f2a-51a411e83574/Final-determination.aspx. Obligation to convert from Type 5 AMI to Type 4 AMI is further supported and recorded at the 3rd AEMO Metering Contestability Workshop.

[12] "The final rule adds a new requirement to the capabilities that Metering Providers and Metering Data Providers for small customer metering installations must demonstrate to the reasonable satisfaction of AEMO in order to be accredited. This additional requirement relates to the establishment of an appropriate security control management plan and associated infrastructure and communications systems for the purposes of preventing unauthorised local access or remote access to metering installations, services provided by metering installations and energy data held in metering installations.411 While the Commission considers that the roles and responsibilities of a Metering Provider and Metering Data Provider under the final rule are similar to their existing roles and responsibilities, AEMO will need to determine whether any other changes are required to its accreditation procedures for Metering Providers and Metering Data Providers as a consequence of the new framework"– Final determination, page 165

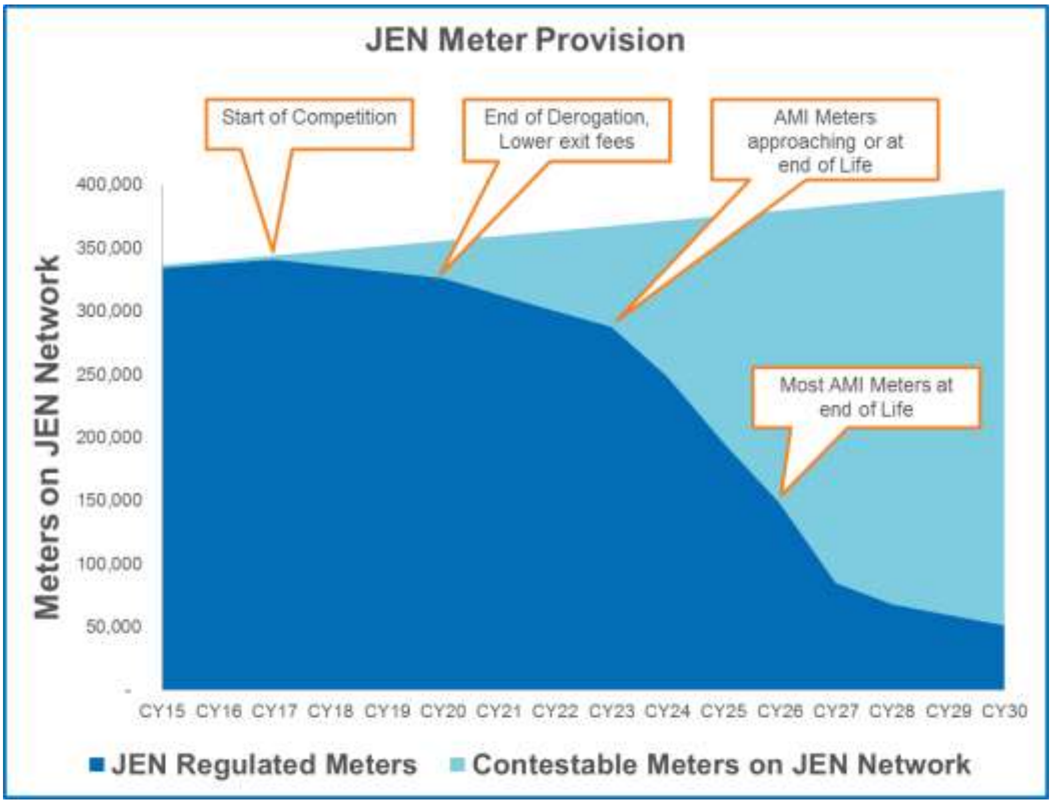
- the existing type 4 meters and customers are managed in J-SAP which does not support smart meters and the existing AMI type 5 meters and customers are managed in AMI-SAP see Figure 3–3: JEN CRM Hosted Systems,
- the AMI-SAP CRM ISU instances (2) are processing a high volume of daily transactional workflows whereas JSAP instance (1) of ISU is lightly loaded by comparison, at least three instances would be required even in a consolidated SAP environment,
- While a consolidated SAP environment may initially appear as an efficient outcome the availability (performance) risk of an integrated CRM including AMI is unreasonable,
- rework of each existing SAP ISU is efficient and program delivery shall select the target environment for each permutation of meter market type in combination,
- this AMI-SAP system will be retired in the future as AMI meter populations fall below a critical threshold that then supports an efficient program of consolidated SAP-IS-U solution in JSAP (or equivalent) see Figure 3–4: JEN Meter Provision,
- only type 5 AMI regulated meters will be supported by AMI-SAP and the platform will be converted to type 4 AMI,
- all other meter types inclusive of contestable meters (Types 1-7) will be hosted by JSAP ISU.

Figure 3–3: JEN CRM Hosted Systems



With metering contestability commencing on 1st Dec 2017 the regulated metering business for JEN will be immediately in a state of decline as all new meter installations will need to be performed by a nominated contestable metering coordinator which by definition cannot be or use JENs present type 5 accreditation for AMI meters. JEN does not presently hold type 1-4 accreditation for MDP and should JEN choose to enter the contestable metering market it would be via an unregulated entity and is therefore out of scope of this business case which is limited to solely regulated activities. Figure 3–4: JEN Meter Provision provides a visualisation of the balance between regulated metering services (Type 5 & 6) provided by JEN and the balance of meters services by the existing and future contestable metering market. This meter market forecast takes into consideration the key impact events including the commencement of competition, competitive market growth from new connections, lost regulated meters to abolishment's, fault replacements by contestable, meter churn with reduced exit fees after 2020, AMI meter replacements at end of life as meters installed between 2009-2017 reach the end of their 15 year useful life.

Figure 3–4: JEN Meter Provision



In the first year of competition contestable growth is principally driven by new connections and abolishment's, consequently system scale will gradually shift from AMI-SAP to JSAP as all externally provided meters are provisioned through the JSAP ISU hosted CRM and associated metring systems. As depicted above all regulated metering systems are in decline and externally hosted meter provision receives positive growth of transfers and new.

Meter type in market and jurisdiction impacts the level of functionality provided or available to the meter and meter service providers. For the purpose of this document a distinction should be made between the meter types and how they relate to system functionality and consequent differentiation of impact of those systems.

Meter Types 1,2,3 & 4 are already contestable predominantly servicing the Commercial & Industrial markets although type 4 can be used for small customers. Type 1, 2 & 3 are all provided for large and very large customers and this regulatory change has minor implications to the existing contestable markets for these meter types (types 1-3). A type 4 meter in today's market ahead of competition commencing is a remotely read interval meter, whereas a type 5 is a by the rules a manually read interval meter. In Victoria by derogation AMI meters are classified as type 5 and the Victorian AMI specification prescribes a high minimum functionality. The Metering Competition rule change establishes a new type 4 minimum service specification for smart meters with subsequent detail yet to be agreed.

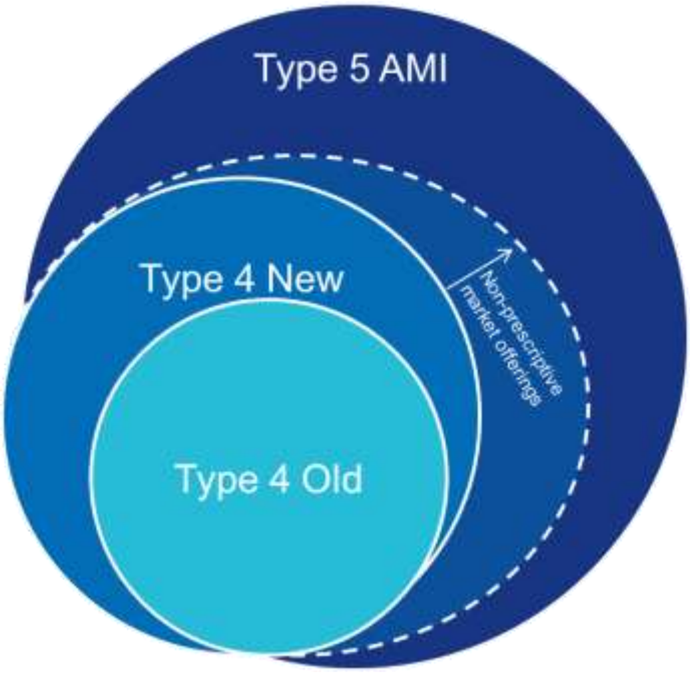
As such there are three distinct version of type 4 functionality in the future market.

Table 3–12: Metering Competition Impact Assessment

Meter Type Group	Functionality (not exhaustive)	Example distinguishing features
Type 4 Old	• Accuracy +/- 1.5% • 30 min interval • import & export • remote reading.	• Baseline functionality of legacy type 4 meter ahead of the commencement of competition. • Remote reading is as per next scheduled read date, typically weekly or monthly. Meter Data flow direction from MC to Market to LNSP.
Type 4 New	• Accuracy +/- 1.5% • 30 min interval • import & export • remote reading • remote connect & disconnect • meter ping	• Minimum service specification increases remote and advanced functional requirements over and above of Type 4 Old to include remote and advanced • Remote connect & disconnect. • Remote meter ping (real time) • Retailer can initiate a remote disconnect and notify the LNSP. MC must provide meter enquiry (ping) capability in near real time Meter Data flow direction from MC to Market to LNSP and bidirectional B2B transactional data flows
Type 5 AMI	• Accuracy +/- 1.5% • 30 min interval • import & export • remote reading • remote connect & disconnect • meter ping • outage detection • auto disconnect • load control • HAN services	– Minimum service specification is highly prescriptive of functional and service level requirements over and above of Type 4 Old and Type 4 New – Remote connect & disconnect with auto disconnect. – Last gasp outage detection (real time) – Remote meter ping (real time) – Load control supply capacity control, emergency supply capacity control – ZigBee HAN binding and messaging services – LNSP actions remote disconnects and notify the market. Meter Data flow direction from LNSP to market, advanced transactions internal application to application and bidirectional to market, customer and 3rd parties.

In each case the meter types are minimum functional or service level specifications and the source of the minimum is a combination of Rules, Procedures and Jurisdictional instruments. Metering Coordinators will offer advanced services that extend beyond the minimum set and where those services are new and not defined in the market or market systems a respective change will be required to uniquely identify and utilise those functional services. Figure 3–5: Meter Functionality depicts overlapping concentric circles of the respective minimum functional obligations and how they relate to each other meter type grouping as per Type 4 Old, Type 4 New and Type 5 AMI (Type 5 AMI is classifiable as Type 4 AMI). Each market systems needs to therefore accommodate identifying the type of meter, type of service provider (including contracts) and available functions/services for the varying data flow directions, process workflows and their directions in an complex integrated technology environment.

Figure 3–5: Meter Functionality



The impact assessment below is based on a reconfigured dual SAP end state solution at the commencement of metering competition. Note options analysis for MC considered but did not recommend a consolidated SAP solution.

Table 3–13: Metering Competition Impact Assessment

Metering Competition	MC	Impact Assessment Notes
(1) AEMO - Market systems	Med	New Metering Coordinator roles and functions are established in the market, data conversion will be required for existing
(2) Market Participant - Systems	Med	All market participants that deliver or receive meter data from contestable meter providers will be impacted

Metering Competition	MC	Impact Assessment Notes
(3) Partner & Vendor Systems	Low	External vendor systems need to be updated / enhanced to accommodate new metering obligations
(4) Market VPN Network	Nil	No identified impact
(5) Partner Network/s	Nil	No identified impact
(6) WebMethods Trading Network (WTN)	High	New market procedures, roles and functions will impact the trading network
(7) Market Systems Integration (MSI)	High	Market systems logic is impacted by the market changes with new procedures, reversing data flows, and changing source systems for the bulk of the JEN meter population.
(8) WebMethods Enterprise Integration (ESB)	Med	Changes in source systems will require the redirecting of interfaces and data flow directions
(9) AMI SAP (SAP-ISU)	Med	SAP-IS-U would be reconfigured to support the new market conditions for AMI type 5 regulated meters as type 4 AMI or equivalent.
(10) Meter Data Management System (MDMS)	Med	Data validation rules will change with the change of meter type, and revised market procedures will impact MDMS process
(11) Business Intelligence (BI)	Med	Comparable extract and reporting requirements remain however source systems are changing
(12) Jemena Corporate SAP (JSAP)	High	Smart meter advanced functions are relocated and modified for inclusion in JSAP to support type 4 AMI meters and customer converted and ported out of SAP-IS-U
(13) AMI Network Management System (NMS)	Low	The NMS remains largely ignorant to the change, destination systems and interfaces will change
(14) Consumer Portal (Portal)	Low	The Customer portal will still need to be able to service data to customers with contestable meters. At this time it will only support internally hosted AMI meters. Some crossover of scope with CAD.
(15) Advanced Metering Infrastructure Communications Network (AMI Comms)	Low	Meters lost to contestable metering providers will impact the integrity of the mesh radio network and network operations. This capital impact for network augmentation is included in the AMI exit fees build up.
(16) Real Time Systems (RTS)	Low	Meter ping function will not be available for contestable meters, this function is available to the control room and call centre today. Equivalent capability would be required for new connections as contestable meters
(17) Consumer Domain	Med	Consumers serviced by contestable providers will a have a differentiated (less or more) service compared to AMI. eg customer HAN devices may not be available from other party, outage functionality may not be available.

Metering Competition	MC	Impact Assessment Notes
(18) New Connections Portal	Med	Change in process for the meter provider and coordination of site work for new connections and alterations will impact the workflows and process for New Connections.

The Metering Contestability impact assessment has not identified any assets that are to be scrapped, become obsolete, redundant, or get redeployed as this project reconfigures the established architecture systems and infrastructure. The project will require transitionary environments for development, test and implementation phases of works.

The end state customer and market systems environment is forecast to retain an equivalent IT licencing profile and no identified uplift in licence maintenance costs are identified or allowed for.

The following Table is a summary of the resource profile for the MC Project

Table 3–14: Metering Competition Project Resource Profile

MC Phase	Activity	Resource	Qty	Term (months)
Analyse & Design	Business requirements / process and analysis	Business Analyst - Senior	8.0	4.00
Analyse & Design	User Interface & report design / mock-up's	Business Analyst - Senior	8.0	4.00
Analyse & Design	Detailed solution design	Solution Designer	8.0	4.00
Analyse & Design	BAU Resource Backfill	General Staff	8.0	6.00
Analyse & Design	Produce test strategy	Testing & Performance Manager	2.0	4.00
Build	SAP	Developer	4.0	6.0
Build	Meter Data Management System (MDMS)	Developer	2.0	6.0
Build	WebMethods Enterprise Integration (ESB)	Analyst Programmer - Senior	2.0	6.0
Build	Market Systems Integration (MSI)	Analyst Programmer - Senior	1.0	6.0
Build	New Connections	Analyst Programmer - Senior	1.0	6.0
Build	Business Intelligence (BI)	Analyst Programmer - Senior	2.0	6.0
Build	Consumer Portal (Portal)	Analyst Programmer - Senior	1.0	6.0
Build	BAU Resource Backfill	General Staff	8.0	2.0
Test	Produce test plans, scenarios and cases	Business Analyst - Senior	8.0	3.00
Test	Develop unit test automation	Test Automation Engineer	4.0	4.00
Test	Execute tests & document results	Tester General	16.0	5.00
Test	Test remediation	Analyst Programmer - Senior	12.0	3.00

MC Phase	Activity	Resource	Qty	Term (months)
	BAU Resource Backfill (UAT)	General Staff	8.0	2.00
Test	Document Test Summary Report	Test Manager	2.0	9.00
Test	Testing oversight	Testing & Performance Manager	1.0	9.00
Implement	Transition to production and project close	Project Manager - Senior	1.0	1.00
Implement	BAU Resource Backfill (Business process redesign and documentation / user guides / training)	General Staff	8.0	3.00
Implement	Implementation activities / trial runs	DBA	2.0	1.00
Implement	Implementation activities / trial runs	Wintel Engineer	3.0	1.00
Implement	Post go live support	Analyst Programmer - Senior	4.0	1.00
Project Management	Metering Competition (MC)	Project Manager - Senior	1.0	13.0
Project Management	Team Leads BA - Planning & Design	Project Manager	2.0	4.0
Accreditation	AEMO accreditation	AEMO	1.0	n/a

Resource cost unit rates are reflective of market daily rates for contract resources, this rate is sufficient to cover the direct and indirect costs of a forecast skilled resource required. For example direct property cost per FTE desk is to be changed directly to each project within the program in accordance with the FTE resource profile.

3.4.2 CUSTOMER ACCESS TO DATA (CAD)

Key elements underpinning the introduction of Customer access to data obligations that have substantive impacts to the project include the:

- The existing Electricity Outlook portal is not compliant to the Customer Access to Data obligations as the portal is only integrated into the AMI solution while the CAD obligation does not distinguish between customers of different meter types or origin of the Metering Coordinator. That is the obligation is for all LNSP connected physically metered customers.
- The portal does not support the new CAD prescriptive report formats for either CSV data or analytical graphical formats
- Customers records are split between two CRM solutions and the new solution needs to support both
- Market participants and 3rd party energy service providers will act as agents for customers and a high demand of energy requests are forecast so a manual solution would be unsustainable.
- Existing JEN IT projects are prohibiting an immediate start on development of the end state solution
- Security and privacy of customer data is paramount and the LNSP has a duty of care to protect and authenticate all access in accordance with Australian Privacy Principles. Energy consumption data is regarded as Personal Information.

Figure 3–6: AMI Portal Customer Access to Data depicts the flow of data and high level interconnected systems to provide self-service customer access to energy consumption data and associated analytical services.

Figure 3–6: AMI Portal Customer Access to Data

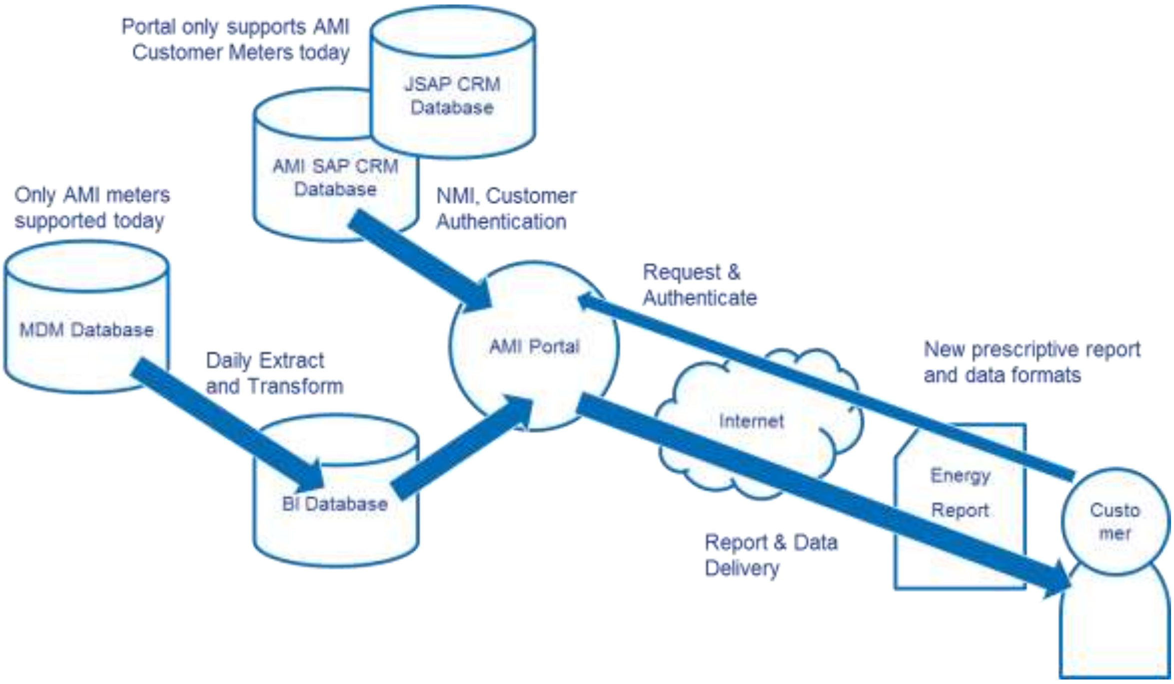


Table 3–15: Customer Access to Data Impact Assessment

Customer Access to Data	CAD	Impact Assessment Notes
(1) AEMO - Market systems	Low	AEMO have prepared data provision procedures and should provide oversight of delivery of CAD
(2) Market Participant - Systems	Med	Retailers and LNSPs are required to provide Customer Access to Data. Metering Coordinators and Mater Data Providers are not obliged to service the customer directly for CAD.
(3) Partner & Vendor Systems	Low	The Customer portal leverages some external services and application for data analytics and CAD provision. Eg provision of data to external switch on plan comparator is a value add Vic government service that uses CSV data.
(4) Market VPN Network	Nil	No identified impact
(5) Partner Network/s	Nil	No identified impact
(6) WebMethods Trading Network (WTN)	Low	CAD requests require authentication of the authorised parties and logical interaction with market systems through the webmethods platform. Ie external requests for CAD will use WTN to validate the authenticity of the request
(7) Market Systems Integration (MSI)	Low	As above (ATN). MSI logic will direct information and authentication requests.

Customer Access to Data	CAD	Impact Assessment Notes
(8) WebMethods Enterprise Integration (ESB)	Med	The Portal enterprise integration is to be expanded to include all meter types, presently limited to AMI type 5.
(9) AMI SAP (SAP-ISU)	Low	Change relates to mostly data enquiries of SAP – ISU, existing function of AMI type 5 should be largely unchanged
(10) Meter Data Management System (MDMS)	Low	Extract and transform of other meter type data into BI is required, MDMS is the source system.
(11) Business Intelligence (BI)	High	Business Intelligence and the Data Warehouse are central repositories for meter data being severed to CAD. Expansion of the existing platform is required to accommodate other meter types. BI is the tools that will be used to develop new exportable report formats.
(12) Jemena Corporate SAP (JSAP)	Low	Change relates to mostly data enquiries of SAP, existing function of AMI type 5 should be reusable from AMI-SAP to JSAP
(13) AMI Network Management System (NMS)	Nil	No identified impact
(14) Consumer Portal (Portal)	High	The self-service consumer portal is directly affected and needs to be upgraded to accommodate all customer meter types, all prescribed reports, all available tariffs
(15) Advanced Metering Infrastructure Communications Network (AMI Comms)	n/a	No identified impact
(16) Real Time Systems (RTS)	Nil	No identified impact
(17) Consumer Domain	Med	CAD provides direct connectivity to the consumer via Portal, Phone and Post. An increase in activity and customer agents is anticipated and business process needs to be established to reflect the change in environment.
(18) New Connections Portal	Nil	No identified impact

The Customer Access to Data impact assessment has not identified any assets that are to be scrapped, become obsolete, redundant, or get redeployed as this project reconfigures the established architecture systems and infrastructure. The project will require transitionary environments for development, test and implementation phases of works.

The end state customer and market systems environment is forecast to retain an equivalent IT licencing profile and no identified uplift in licence maintenance costs are identified or allowed for.

The following Table is a summary of the resource profile for the CAD Project

Table 3–16: Customer Access to Data Project Resource Profile

CAD Phase	Activity	Resource	Qty	Term (months)
Analyse & Design	Business requirements / process and analysis	Business Analyst - Senior	1.0	2.00
Analyse & Design	User Interface, Application Interface, & report design / mock-ups	Business Analyst - Senior	2.0	2.00
Analyse & Design	Detailed solution design	Solution Designer	1.0	2.00
Analyse & Design	BAU Resource Backfill	General Staff	1.0	3.00
Analyse & Design	Produce test strategy	Testing & Performance Manager	1.0	1.00
Build	Business Intelligence (BI)	Analyst Programmer - Senior	1.0	3.0
Build	Consumer Portal (Portal)	Analyst Programmer - Senior	2.0	2.0
Build	BAU Resource Backfill	General Staff	1.0	2.0
Build	Extract Transform Load (ETL)	Analyst Programmer - Senior	1.0	2.0
Test	Produce test plans, scenarios and cases	Business Analyst - Senior	1.0	2.00
Test	Develop unit test automation	Test Automation Engineer	1.0	2.00
Test	Execute tests & document results	Tester General	1.0	2.00
Test	Test remediation	Analyst Programmer - Senior	2.0	2.00
Test	BAU Resource Backfill (UAT)	General Staff	1.0	2.00
Test	Document Test Summary Report	Test Manager	1.0	2.00
Test	Testing oversight	Testing & Performance Manager	-	-
Implement	Transition to production and project close	Project Manager - Senior	1.0	1.00
Implement	BAU Resource Backfill (Business process redesign and documentation / user guides / training)	General Staff	1.0	1.00
Implement	Implementation activities / trial runs	DBA	1.0	1.00
Implement	Implementation activities / trial runs	Wintel Engineer	1.0	1.00
Implement	Post go live support	Analyst Programmer - Senior	1.0	1.00
Implement	Transition to production and project close	Project Manager - Senior	1.0	1.00
Implement	BAU Resource Backfill (Business process redesign and documentation / user guides / training)	General Staff	1.0	1.00

CAD Phase	Activity	Resource	Qty	Term (months)
Implement	Implementation activities / trial runs	DBA	1.0	1.00
Project Management	Customer Access to Data (CAD)	Project Manager - Senior	1.0	6.00
Work Around	Interim work around (manual)	General Staff	1.0	6.00

Resource cost unit rates are reflective of market daily rates for contract resources, this rate is sufficient to cover the direct and indirect costs of a forecast skilled resource required. For example direct property cost per FTE desk is to be changed directly to each project within the program in accordance with the FTE resource profile.

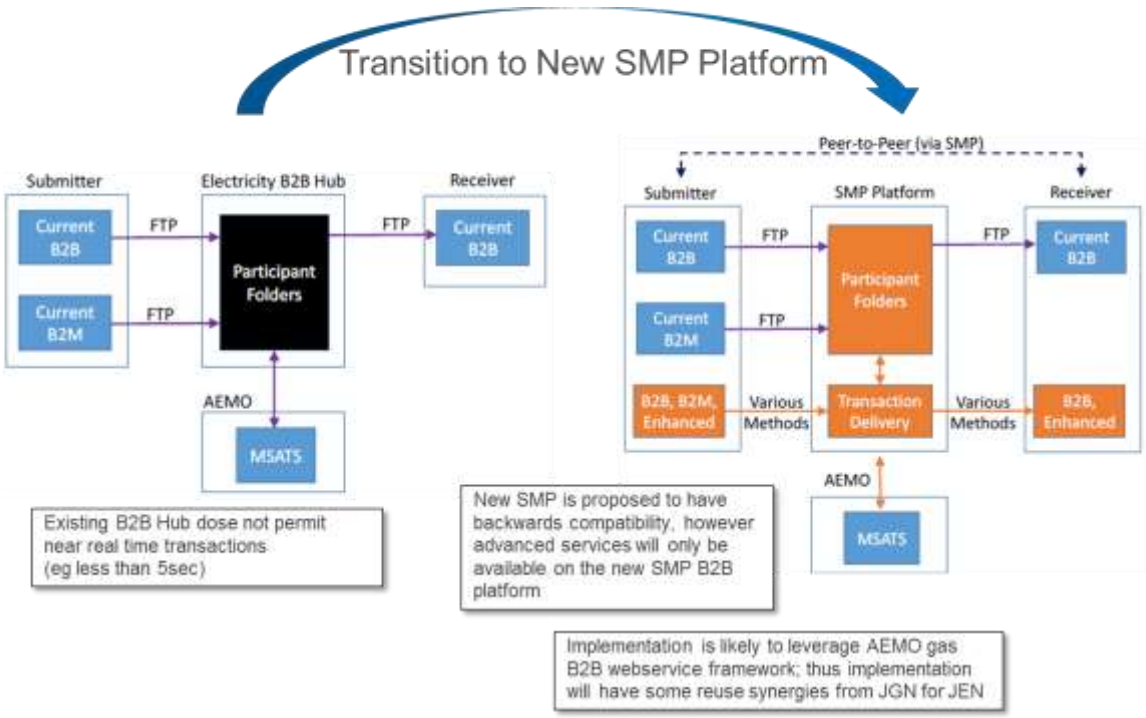
3.4.3 SHARED MARKET PROTOCOL (SMP)

Key elements underpinning the introduction of Shared Market Protocol that have substantive impacts to the project include the:

- Shared market protocol is a replacement platform for business to market (B2B/B2M) interaction and does not utilise the same communications technology for transport and data layers, but may reuse some application layer functionality
- Advanced features of new smart meters provided by other parties can only be used or made available if JEN as a LNSP implements the SMP
- A Victorian LNSP must implement the SMP at the time of market commencement so that it can meet its network obligations for managing customers and network connections using AMI functional and AMI service levels
- JEN as the incumbent AMI Metering Coordinator must implement the SMP at the time of market commencement so that it can provide the mandatory minimum metering services to the market
- JEN must implement a replacement market interaction client side platform so that it can meet its market obligations.

Figure 3–7: Shared Market Protocol Transition to new market side platform depicts the proposed AEMO market gateway logical architecture and parallel operation of the existing B2B services and the new Shared Market Protocol. While the SMP is regarded as an opt in platform all Metering Coordinators servicing smart meters will be obliged to implement the new platform as well as those participants that use smart services. Figure 3–8: Shared Market Protocol Services is an AEMO summary of the minimum services to be implemented or supported through the market interfaces, it should be noted that these services extend beyond metering services and include infrastructure services.

Figure 3–7: Shared Market Protocol Transition to new market side platform[13]



13 Excerpt adapted from AEMO Minimum Functionality & Shared Protocol Reference Group working documents

Figure 3–8: Shared Market Protocol Services[14]

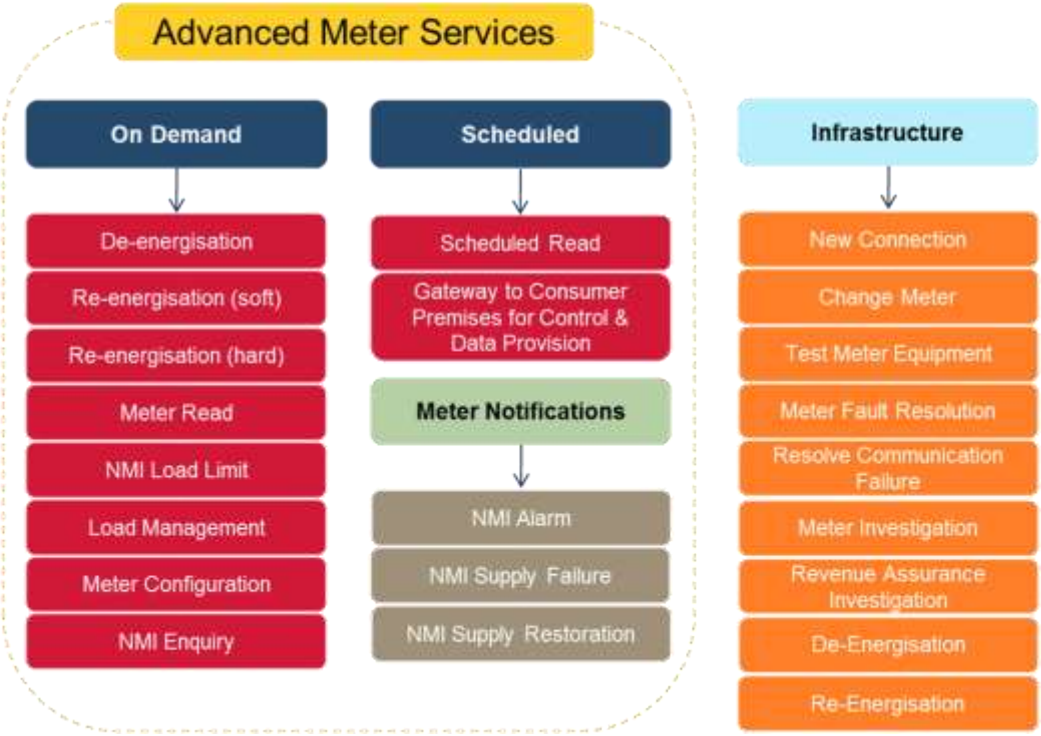


Table 3–17: Shared Market Protocol Impact Assessment

Shared market Protocol	SMP	Impact Assessment Notes
(1) AEMO - Market systems	High	A replacement or duplicated AEMO IT market gateway system is to be implemented with new transport layer, datalink layer and at least some new application layer functions.
(2) Market Participant - Systems	High	All progressive market participants will opt into the new SMP and implement a companion system to the AEMO SMP changes.
(3) Partner & Vendor Systems	Low	Some JEN partner market interaction is required due to multi sourcing arrangements
(4) Market VPN Network	Med	New security measures are presumed to be included in the SMP implementation, eg participant certificates
(5) Partner Network/s	Nil	No identified impact
(6) WebMethods Trading Network (WTN)	High	All existing B2B and new SMP advanced functions are to be integrated into the trading network interfaces

[14] Excerpt from AEMO Minimum Functionality & Shared Protocol Reference Group working documents

Shared market Protocol	SMP	Impact Assessment Notes
(7) Market Systems Integration (MSI)	High	All existing B2B and new SMP advanced functions are to be integrated into the MSI logic and automation
(8) WebMethods Enterprise Integration (ESB)	High	All existing B2B and new SMP advanced functions are to be integrated into the Enterprise Service Bus
(9) AMI SAP (SAP-ISU)	Med	Remote AMI services and B2B functions are to be integrated and made available to the SMP advanced market participant's ie inbound AMI transactions.
(10) Meter Data Management System (MDMS)	Low	Central meter data store will be impacted by some inbound SMP B2B enquiries
(11) Business Intelligence (BI)	Med	SMP transactional data and new transactional types are managed and overseen utilising BI reporting and logging capability. New transactions and interfaces need to be monitored in the integrated environment
(12) Jemena Corporate SAP (JSAP)	Med	All new SMP functions and services need to be integrated for new and old contestable meters with SMP integration. JSAP integration will be largely outbound such as meter ping (NMI enquiry)
(13) AMI Network Management System (NMS)	Low	Inbound SMP enquiries use the NMS platform for transaction delivery to JEN hosted AMI meters via facilitated access to advanced functions. NMS impact will be largely transparent as a transport application.
(14) Consumer Portal (Portal)	Low	Some advanced functions like binding and outage management are integrated into the portal. New market interfaces will have a minor impact to the portal and presented services.
(15) Advanced Metering Infrastructure Communications Network (AMI Comms)	Low	Increased transactional traffic and service level obligations may require some returning to support market obligations.
(16) Real Time Systems (RTS)	Med	Outage management systems rely on (Ping) NMI enquiry and last gasp outage detection to assess the status of customer supply, load contactors, volts and instantaneous load. Advanced SMP functions need to be integrated into RTS to meet network obligations
(17) Consumer Domain	Low	Call centre (Faults Desk) services rely in near real time communications to smart meters for outage and trouble management. Largely addressed by RTS impacts on Outage Management Systems
(18) New Connections Portal	Nil	No identified impact

The Shared Market Protocol impact assessment has not identified any assets that are to be scrapped, become obsolete, redundant, or get redeployed as this project reconfigures the established architecture systems and infrastructure. The project will require transitionary environments for development, test and implementation phases of works.

The end state customer and market systems environment is forecast to retain an equivalent IT licencing profile and no identified uplift in licence maintenance costs are identified or allowed for.

The following Table is a summary of the resource profile for the SMP Project

Table 3–18: Shared market Protocol Project Resource Profile

SMP Phase	Activity	Resource	Qty	Term (months)
Analyse & Design	Business requirements / process and analysis	Business Analyst - Senior	3.0	3.00
Analyse & Design	User Interface & report design / mock-up's	Business Analyst - Senior	-	-
Analyse & Design	Detailed solution design	Solution Designer	1.0	3.00
Analyse & Design	BAU Resource Backfill	General Staff	1.0	3.00
Analyse & Design	Produce test strategy	Testing & Performance Manager	1.0	1.00
Build	WebMethods Enterprise Integration (ESB)	Analyst Programmer - Senior	2.0	4.0
Build	Market Systems Integration (MSI)	Analyst Programmer - Senior	1.0	4.0
Build	BAU Resource Backfill	General Staff	6.0	1.5
Test	Produce test plans, scenarios and cases	Business Analyst - Senior	3.0	3.00
Test	Develop unit test automation	Test Automation Engineer	2.0	3.00
Test	Execute tests & document results	Tester General	4.0	2.00
Test	Test remediation	Analyst Programmer - Senior	2.0	3.00
	BAU Resource Backfill (UAT)	General Staff	2.0	3.00
Test	Document Test Summary Report	Test Manager	1.0	3.00
Test	Testing oversight	Testing & Performance Manager	-	-
Implement	Transition to production and project close	Project Manager - Senior	1.0	1.00
Implement	BAU Resource Backfill (Business process redesign and documentation / user guides / training)	General Staff	2.0	1.00
Implement	Implementation activities / trial runs	DBA	-	-
Implement	Implementation activities / trial runs	Wintel Engineer	1.0	0.50
Implement	Post go live support	Analyst Programmer - Senior	1.0	1.00
Project Management	Team Lead	Project Manager	1.0	6.0

SMP Phase	Activity	Resource	Qty	Term (months)
Project Management	Project Manager	Project Manager - Senior	-	6.0

Resource cost unit rates are reflective of market daily rates for contract resources, this rate is sufficient to cover the direct and indirect costs of a forecast skilled resource required. For example direct property cost per FTE desk is to be changed directly to each project within the program in accordance with the FTE resource profile.

3.4.4 DISTRIBUTION NETWORK PRICING (DNP)

Table 3–19: Distribution Network Pricing Impact Assessment

Distribution Network Pricing	DNP	Impact Assessment Notes
(1) AEMO - Market systems	Low	New time of day based demand tariffs and the consequences are not yet considered in the market systems.
(2) Market Participant - Systems	Med	Retailers should reflect the new network demand based tariffs through their systems and offer similar structured tariffs to the consumer. It is likely that some will collapse the tariffs into simpler supported structures while others will fully implement
(3) Partner & Vendor Systems	Nil	No Identified Impact
(4) Market VPN Network	Nil	No Identified Impact
(5) Partner Network/s	Nil	No Identified Impact
(6) WebMethods Trading Network (WTN)	Low	Some new B2B transactions and transaction derivatives are required to be implemented in the market facing interfaces
(7) Market Systems Integration (MSI)	Med	Some new B2B transactions and transaction derivatives are required to be implemented in the enterprise integration logic
(8) WebMethods Enterprise Integration (ESB)	Low	Some new B2B transactions and transaction derivatives are required to be implemented in the market facing interfaces
(9) AMI SAP (SAP-ISU)	Med	Aggregation of network billing data for demand based tariffs needs to be implemented in the AMI SAP–ISU CRM system to support the new tariff structures for AMI JEN hosted meters
(10) Meter Data Management System (MDMS)	Med	Meter Data systems are the central repository for all versions of meter data including demand tariff components
(11) Business Intelligence (BI)	High	New and more complex tariff structures increase the complexity of network billing, revenue management and revenue reconciliation. New data fields, ETLs and reporting capability is required to operationally support DNP

Distribution Network Pricing	DNP	Impact Assessment Notes
(12) Jemena Corporate SAP (JSAP)	Med	Aggregation of network billing data for demand based tariffs needs to be implemented in all contestable interval meters in the JSAP–ISU CRM system to support the new tariff structures for non-AMI meters externally hosted
(13) AMI Network Management System (NMS)	Nil	No identified impact
(14) Consumer Portal (Portal)	Med	The consumer portal only supports up to 3 part ToU tariffs. Demand based tariffs need to be implemented in the portal price comparator. Note customer engagement and demystification of demand tariffs is dependent on the consumer being able to compare old and new tariffs against real energy consumption data records.
(15) Advanced Metering Infrastructure Communications Network (AMI Comms)	n/a	No identified impact
(16) Real Time Systems (RTS)	Nil	No identified impact
(17) Consumer Domain	Med	Consumers are directly impacted with new tariffs and pricing structures. Extensive customer engagement is required to allow for acceptance of new tariff regimes
(18) New Connections Portal	Low	New tariff structures new to be integrated into the New connections portal.

The Distribution Network Pricing impact assessment has not identified any assets that are to be scrapped, become obsolete, redundant, or get redeployed as this project reconfigures the established architecture systems and infrastructure. The project will require transitionary environments for development, test and implementation phases of works.

The end state customer and market systems environment is forecast to retain an equivalent IT licencing profile and no identified uplift in licence maintenance costs are identified or allowed for.

The following Table is a summary of the resource profile for the DNP Project

Table 3–20: Distribution Network Pricing Project Resource Profile

DMP Phase	Activity	Resource	Days Effort[15]
Planning & Design	Project Management	Project Manager	156
Planning & Design	Business Analysis	Business Analyst - Senior	20

15 Note DNP costs estimate was developed in total days effort in lieu of months by resource type, the baseline DNP project estimate was initial developed in isolation and in advance of all other PoC work streams.

DMP Phase	Activity	Resource	Days Effort[15]
Planning & Design	Solutions Design	Solution Designer	20
Test and Implement	Change Management	Wintel Engineer	5
Test and Implement	Test Management	Testing & Performance Manager	5
Test and Implement	Cutover & Transition	Wintel Engineer	10
Test and Implement	Allowed nominal days for flip switch & support activities	Wintel Engineer	10
Build	SAP-ISU - Residential	Developer	205
Build	SAP-ISU – Small Business	Developer	65
Build	SAP-ISU – Large Business	Developer	40
Build	iTron IEE/MTS - Create/modify new billing determinant	Analyst Programmer - Senior	25
Build	iTron IEE/MTS - Create/modify rates	Analyst Programmer - Senior	47
Build	iTron IEE/MTS - Create/modify TOW schedule	Analyst Programmer - Senior	25
Build	iTron IEE/MTS - Create new rolling demand component (based on peak rather than all time).	Analyst Programmer - Senior	40
Test and Implement	Business Intelligence (BI)	Analyst Programmer - Senior	20
Test and Implement	Customer Energy Portal	Analyst Programmer - Senior	60
Test and Implement	MVRS/MV90	Analyst Programmer - Senior	88
Test and Implement	Test Manager	Testing Manager	5
Test and Implement	E2E Technical Test	Testing Manager	50
Test and Implement	UAT Test andTest Cases	General Staff	95

Resource cost unit rates are reflective of market daily rates for contract resources, this rate is sufficient to cover the direct and indirect costs of a forecast skilled resource required. For example direct property cost per FTE desk is to be changed directly to each project within the program in accordance with the FTE resource profile.

3.4.5 POC PROGRAM MANAGEMENT AND DELIVERY

The PoC program management and delivery project provides coordination of the rule, market system and process changes for the JEN assets and services as they are impacted by one or more of the multiple concurrent work streams of Power of Choice. The PoC program of market changes requires a diverse pool of internal and external resources to adequately engage, assess and respond. Functionally program management includes standing resources that oversees and coordinates the staggered market change delivery across the duration of the market changes. Program management is required for the forecast 30 month duration of the PoC capital works program and adopts PoC projects as they transition from rule change into tangible capital projects. Functionally the program management provides resources for:

- Program management
- Program governance
- Stakeholder management
- Business (impact) analysis
- Industry engagement (and or backfill to support industry engagement)
- Reporting and scheduling
- Contract management
- Business change management (Communications internal / external)
- Financial management
- Risk and issue management
- Independent external auditing
- An allowance for external legal council

The following Table is a summary of the resource profile for the centralised and shared Program Management functions

Table 3–21: Common Program Resource Profile

PGM Phase	Activity	Resource	Qty	Term (months)
All	Business Analysis	Business Analyst	1.00	24.0
All	Program Management and Oversight	Program Director	1.00	24.0
All	Industry Engagement (Backfill)	General Staff	2.00	24.0
All	Reporting and Scheduling	Project Manager	1.00	24.0
All	Contract Management	Commercial Manager	0.50	24.0
All	Change Management (Communications internal / external)	Business Project Manager	1.00	22.0
All	Financial Management	Program Accountant	1.00	24.0
All	Business Analysis	Business Analyst	1.00	24.0

PGM Phase	Activity	Resource	Qty	Term (months)
All	Program Management and Oversight	Program Director	1.00	24.0
All	Industry Engagement (Backfill)	General Staff	2.00	24.0

Resource cost unit rates are reflective of market daily rates for contract resources, this rate is sufficient to cover the direct and indirect costs of a forecast skilled resource required. For example direct property cost per FTE desk is to be changed directly to each project within the program in accordance with the FTE resource profile.

This business cases establishes the funding for the first year of Power of Choice Program Management project to the value of $2M, with the charter to develop and delivery PoC work stream projects budgeted including the development of efficient business case for a response to each Power of Choice rule change and or its associated instrument or event.

3.5 REGULATORY ALIGNMENT

3.5.1 REGULATORY ALIGNMENT

Justification	Explanation
Safety	Ensure continuity of safety of network assets including metering installations is maintained through the business impact, market change and introduction of new roles and functions into the market. ie Metering installation safety, life support (sensitive load notifications and management), remote disconnection and restoration of supply by other parties.
Maintaining supply to existing customers	Ensure market change and market process does not negatively impact security of supply through the introduction of roles, functions and new processes for demand management or equivalent advanced functions. Ensure that networks can leverage emergency supply capacity control capability for network events and supply capacity control for hardship cases. Mitigate the risk of demand management impacting security of supply; ie risk of loading or unloading giving rise to network power quality events. Ensure ongoing availability of advanced outage management capability for outage management, faults desk and resource scheduling (meter ping).
Managing integrity of service risk	As Above
Regulatory obligation	All Power of Choice projects are regulatory events and in each case triggered by rule changes or equivalent instrument under the "Power of choice review - giving consumers options in the way they use electricity"[16] Metering Competition Final Determination Rule change was issued by the AEMC 26 Nov 2015[17].

[16] http://www.aemc.gov.au/Markets-Reviews-Advice/Power-of-Choice-Stage-3-DSP-Review

[17] http://www.aemc.gov.au/Rule-Changes/Expanding-competition-in-metering-and-related-serv#

Justification	Explanation
	Distribution Network Pricing event trigger is the AEMC "National Electricity Amendment (Distribution Network Pricing Arrangements) Rule 2014"[18] Customer Access to Data market change is prescribed in the AEMO "Final report and determination on Metering Data Provision Procedures"[19] Shared Market Protocol is a proposed rule change with implementation advice provided by AEMC to COAG. This rule change may be incorporated in the Metering Competition Rule Change due on the 26 Nov 2015[20] Multiple Trading Relationships is a proposed rule change under AEMC consultation. AEMO lodged this rule change request with the AEMC following the completion of a preliminary design for a multiple trading relationships framework[21]. Note this list is not exhaustive
Net present value benefit	The Power of Choice program introduces operational complexity through market change by introducing new roles, new functions, revised procedures and encourages adoption of new demand side technologies amongst other things. PoC change will not improve efficiency of networks operations and will instead provide greater levels of choice and established new competitive and unregulated secondary energy markets. Consequently the introduction of PoC reforms is not forecast to generate efficiency improvements. Instead inefficiencies are likely through heightened interaction with a multitude of participants and 3rd parties. JEN implementation approach and capital works programs objective is to have no negative operational efficiency impact as a result of PoC reform within a more complex and interactive market environment that creates and efficiency competitive tension. The program is to maintain efficiency equilibrium through the implementation of the Power of Choice market change program by adopting technology solutions (eg thorough automation and high levels of operational technology integration).

3.5.2 EFFICIENCY CHECK

Efficiency measure	Explanation
Project costs	The power of Choice program of works leverages all existing market systems and does not establish any new functional applications. Therefore the program will not seek for external vendors for the replacement or addition of any components. The Program can in essence be considered a reconfiguration of existing systems to accommodate the iterative market change consequent to PoC rule changes.

18 http://www.aemc.gov.au/Rule-Changes/Distribution-Network-Pricing-Arrangements/Final/AEMC-Documents/Final-determination

19 http://www.aemo.com.au/Consultations/National-Electricity-Market/Metering-Data-Provision-Procedures

20 http://www.aemc.gov.au/Markets-Reviews-Advice/Implementation-advice-on-the-Shared-Market-Protoco#

21 http://www.aemc.gov.au/Rule-Changes/Multiple-Trading-Relationships#

Efficiency measure	Explanation
	The Power of Choice program will establish internal turnkey project delivery teams using a multi sourced team. External works are to be competitively tendered in accordance with the established DFA procedures and IT project management methodology
Cost allocation	Power of Choice capital projects are all attributed to JEN Non-Network IT Capex. Note while metering components are included in the program these projects principally relate to the network preparing for market change as opposed to JEN establishing in itself as a competitive meter provider
Finance approval of estimation of any indirect costs or sharing of multi-asset projects	SGSPIAA initial budget for Power of Choice and Metering Contestability is provisionally set for $10M equally split across CY16 and CY17. This project proposes to establish the PoC program and revise the budget in accordance with the restated forecast in section 0 of this document
Shared Program Costs	The staggered delivery of the PoC program of works and evolving detailed design inputs is addressed by JEN through a shared PoC program governance and delivery model. The Program oversight provides a coordinated response to the Power of Choice reform as a whole using a federated organisational model with centralised oversight and management of the greater PoC program while allowing for PoC projects to autonomously deliver and resolve their specific obligations. The model allows for shared specialised resources, financial controls, RAPID decision making, reporting and monitoring of the program. Centralised PoC Program oversight reduces resource duplication, inefficiencies of resource start-ups & shutdowns cross project coordination, risk, issue, and opportunity management.
Project Deliverable Alignment	Shared Market Protocol and Metering Contestability rule changes are related but not aligned with separate rule changes delivered in Q1 2016 and November 2015 respectively. The government and industry are however indicating a strong bias towards a simultaneous go live of SMP and MC on the 1st Dec 2017. JEN have therefore elected to merge two PoC project streams into a single project deliverable with a single go live date of the 1st Dec 2017. Merging the two PoC projects results in incremental savings of management and tighter controls for IT change with coincident go live dates. This approach reduces risk of Coincident IT change, however locks in the two activities together to be released simultaneously as they are then bound together into a single and dependent IT transition and go live.

3.5.3 OTHER REGULATORY RISKS AND OPTIONS

Risk/option	Explanation
Is the project and project cost within the AER allowance?	AER allowance proposed is in alignment with the financials in this business case; the AER final determination will be complete after the initiation of the proposed program
Variance to regulatory assumptions	Note PoC rule changes are not yet complete and scope is at risk of change. Changes may not trigger a cost pass through change event.
Regulatory incentive schemes	n/a

Risk/option	Explanation
Alternative funding options	n/a
Deferred status	n/a

4. SUMMARY OF OPTIONS

OPTION ASSESSMENT PROCESS

SUMMARY OF OPTIONS

The options considered for Power of Choice are in combination of those identified as recommended in the following table:

Option	Prime reason for recommendation / rejection
Do Nothing	JEN has an obligation to comply with the rule changes and the systems will not accommodate the future regulatory, technical and operational Environment. Declining to adopt market change would result in major non-conformance and the inability to collect revenue for new tariffs
Metering Competition – Reconfigure Existing System (new type 4 in JSAP)	**Recommended** Incumbent market systems are fit for purpose and scalable to accommodate the future market state, reconfiguring existing systems to accommodate new meter classifications, reclassifications of existing AMI meters and re-accreditation is the lowest total cost option for compliance to the Metering Competition rule change. (Refer to summary costing in A1. Project Identified Costs)
Metering Competition – Reconfigure Existing Systems and consolidate JEN metering to one instance of SAP	Reconfiguration of the incumbent market systems and consolidation of the two metering SAP instances is based on the assumption that a single enterprise SAP system has a lower ongoing operating cost. However technical performance limitations make such a consolidation unviable in the time frame of the metering contestability rule change. AMI-SAP is a standalone instance of SAP with the high volumes of daily workflows, introducing this intensity of processing into JSAP would require a threefold scaling of the JSAP environment and result in no material infrastructure or licence savings. Metering Competition Consolidation is not recommended due to the technical risk, highest cost option and lack of identified ongoing operational savings.
Metering Competition – Reconfigure Existing Systems (new type 4 in AMI-SAP)	Incumbent market systems are fit for purpose and scalable to accommodate the future market state, reconfiguring existing systems to accommodate new meter classifications, reclassifications of existing AMI meters and re-accreditation is the a comparable total cost option for compliance to the Metering Competition rule change as per the recommended option. This option considers if a new connection contestable meter (New type 4) should be implemented functionally in AMI-SAP or JSAP. Technical complexity and level of effort was assessed to be comparable although AMI-SAP implementation has lesser long term continuity prospects compared to JSAP
Customer Access to Data – Minimal Solution for only AMI Meters	Customer access to data is principally served from the Electricity Outlook (AMI Portal) portal today but limited to AMI only customers. This option considers a minor upgrade of the AMI portal to provide data in new prescribed formats but only for AMI customers. This option would result in partial compliance with less than 2% of the

Option	Prime reason for recommendation / rejection
	population yet 50% of the network load unserved. Further this would be exasperated with every new connection s contestable meter also being unserved. This option was discarded as it does not adequately comply with the AEMO CAD procedures.
Customer Access to Data – Minimal Solution manual workaround process	This option considers the potential to support CAD request through manual interaction with systems by building reports that can be run by a meter data management analyst and exported to the customer. Such a process would serve exception customers that are not satisfied with the AMI portal outputs. Such a solution would only accommodate a small number of requests and not readily scale up to the future CAD forecasts. As customer agents and brokers are known to be preparing for leveraging CAD high volumes of transactions are anticipated and a manual workaround process would be unsustainable.
Customer Access to Data – Automated Process for all customers before March 2016	Redevelop the AMI portal to support all customer meter and billing types for a full self-service interface ahead of the go live date 1 March 2016. Due to the dependencies of the present market system changes in progress a stable baseline environment will not be available to develop CAD until June 2016. This option cannot be technically delivered before the compliance date.
Customer Access to Data – Automated Process for all customers after March 2016 with interim work around	**Recommended** Redevelop the AMI portal to support all customer meter and billing types for a full self-service interface after the go live date 1 March 2016 and implement an interim workaround for exception management. This option provides full interim compliance with an interim operational impact. The scale of initial requests will determine the level of interim impact. This option is recommended as it meets the compliance, efficiency and customer engagement objectives for JEN. (Refer to summary costing in A1. Project Identified Costs)
Shared Market Protocol – Full Implementation	**Recommended** A shared market protocol capability is develop and implemented with all initial functionally for day 1 and any subsequent release in the program period. Baseline market systems including the webservices based Jemena Gas Network Market gateway will be leveraged to establish a replacement of the existing JEN Business to market gateway and associated interfaces, logic and process. This option provides a near real time baseline communication capability for all new market meters and service required to efficiently operate the network. (Refer to summary costing in A1. Project Identified Costs)
Shared Market Protocol – Opt out	Shared Market Protocol is proposed as an opt in interface with the existing B2B hub function retained for an unspecified amount of time including translation. Only new functionality will be made available via the SMP. This option was discarded as any new contestable smart meter and its advanced functions like ping (Meter inquiry) will not be network accessible without an SMP. As volumes of constable meters grow JEN will lose its network management capability presently in service and providing network benefits.
Shared Market Protocol – Defer	Implementation of an SMP instance for JEN at a later date would result

Option	Prime reason for recommendation / rejection
Implementation	in an initial shortfall in capability and opportunity to participate in industry wide testing. No cost savings is identified nor advantage in taking a later release date.
Shared Market Protocol – Minimum Implementation	Shared Market protocol could be implemented with a minimal set of functions and only those used at the time of its release. JEN is an advocate for greater SMP functionality and adopting a minimum entry position will not permit JEN to leverage services like HAN binding for Vic AMI via the SMP. This option is discarded as it leaves JEN functionally incomplete and unable to access or offer advanced services.
Distribution Network Pricing – Reconfigure Existing Systems	**Recommended** The existing market systems are fit for purpose and require reconfiguration to support the new classes of tariffs and combinations of tariffs. This option is recommended as it leverages existing systems and allows for the implementation of the approved tariffs. No other alternative was identified. (Refer to summary costing in A1. Project Identified Costs)
PoC Program Governance	**Recommended** JEN proposes a single programme governance framework for oversight of all Power of Choice scope to ensure coordination, continuity and complete implementation. This was favoured over higher levels of project governance in the individual work streams. That is combining and centralising the programing functions and resources into a single working group over the entire PoC project implementation time frame. (Refer to summary costing in A1. Project Identified Costs)
PoC Project Governance	Project level governance only will not satisfy the complexity of delivery of a multi-faceted program across the same systems. Increased cost to serve the program as high level project functions are duplicated across multiple project work streams. Parallel work streams prohibit coincident implementation at go live as they share a common code base.

5. RECOMMENDED OPTION

5.1.1 DESCRIPTION

The Business case proposes the establishment of the first phase of the JEN Power of Choice program of works being the first three months of funding of the forecast 2 year Power of Choice program of works. The establishment phase is required to complete sufficient planning, design and business requirements analysis works so that subsequent phases of the PoC program delivery (or total program) can be approved in accordance with the relevant DFA.

The PoC program obligations are now sufficiently certain that the initial phase of planning design and business requirements analysis are required to meet the obligations of the PoC rules changes that are already complete.

This business cases recommends delaying the commencement of the main program of works until the completion of the existing IT customer and market systems projects which are scheduled to go live in June 2016.

This business case recommends the establishment of a single centralised Power of Choice programme governance framework for oversight of all Power of Choice scope to ensure coordination, continuity and complete implementation of compliant market systems change. The PoC program management and delivery project provides coordination of the rule, market system and process changes for the JEN assets and services as they are impacted by one or more of the multiple concurrent work streams of Power of Choice. The PoC program of market changes requires a diverse pool of internal and external resources to adequately engage, assess and respond. Functionally program management includes standing resources that oversees and coordinates the staggered market change delivery across the duration of the market changes. Program management is required for the forecast 30 month duration of the PoC capital works program and adopts PoC projects as they transition from rule change into tangible capital projects. Functionally the program management provides resources for:

Program management, program governance, stakeholder management, business (impact) analysis, industry engagement (and or backfill to support industry engagement), reporting and scheduling, contract management, business change management, internal communications internal, external communications, financial management, risk and issue management, independent external auditing, and legal council as required.

It is then recommended that the Power of Choice Program management framework would be chartered to deliver an efficient and compliant solution based on the incumbent market system solution in accordance with the scope and regulatory change and market environment for:

1. Metering Competition - by reconfiguring the incumbent market systems to accommodate new meter classifications, reclassifications of existing AMI meters and seek re-accreditation for compliance to the Metering Competition rule change. Existing AMI meters would be reclassified as type 4 but retained in the existing AMI-SAP system, new contestable type 4 meter capability would be established in the existing JSAP system, all impacted market systems would be redeveloped to accommodate the new process workflows, logic and business change.
2. Customer Access to Data - by redeveloping the AMI portal to support all customer meter and billing types for a full self-service interface after the go live date 1 March 2016 and further implement an interim operational workaround for exception management and interim compliance to the AEMO procedures. Monitor the scale of initial requests and consider the operational impact of the intermediate workaround.

3. Shared Market Protocol - by developing a fully functional JEN instance of the shared market protocol with all initial functionally for day 1 and any subsequent release in the program period. Fully integrate the SMP into the market system environment, engage with industry wide testing and advocate for greater functionality to be initially or subsequently released. Establish a baseline market systems including the webservices based Jemena Gas Network Market gateway will be leveraged to establish a replacement of the existing JEN Business to market gateway and associated interfaces, logic and process. This option provides a near real time baseline communication capability for all new market meters and service required to efficiently operate the network.

4. Distribution Network Pricing - by reconfiguring existing market systems to support the new classes of tariffs and combinations of tariffs. This option is recommended as it leverages existing systems and allows for the implementation of the approved tariffs.

This business cases establishes the initial funding for the Power of Choice Program Management project, with the charter to develop and delivery PoC work stream projects budgeted including the development of efficient business cases for a response to each Power of Choice rule change and or its associated instrument or event.

5.1.2 TOTAL COST

The power of choice market reforms establish a more complex market environment with greater separation of roles, more participant role types, greater number of market participants and considerably more diversity in functionality and service offerings. Therefore this program of work seeks to adopt the market change without a net negative operational impact.

JEN's implementation approach and capital works programs objective is to therefore to have no negative operational efficiency impact as a result of PoC within a more complex and interactive market environment that creates and efficiency competitive tension.

The program is to maintain efficiency equilibrium through the implementation of the Power of Choice market change program by adopting technology solutions thorough automation and high levels of operational technology integration.

The program proposes to utilise all incumbent market systems without any appreciable changes to applications therefore operational IT costs should remain level

The program has not explicitly identified or costed any ongoing positive or negative step changes in operational efficiency at this time. Detailed design of project deliverables may consequently identify a corresponding step change and result in a revised forecast to that of the forward estimate proposed by this business case.

5.1.3 BENEFITS

Market system change projects under the Power of Choice are all driven by a Regulatory Electricity Industry change with an objective of meeting the regulatory requirements, therefore business benefits have not been extensively defined but include outcomes of:

No	Benefit	Outcome	Benefit Owner	How it will be measured
B-01	Regulatory compliance	• Comply with regulatory obligations • Comply	• Retain Licence and Accreditation • Avoid non-	• Audit reports • Non-conformance notices • Brand Recognition,

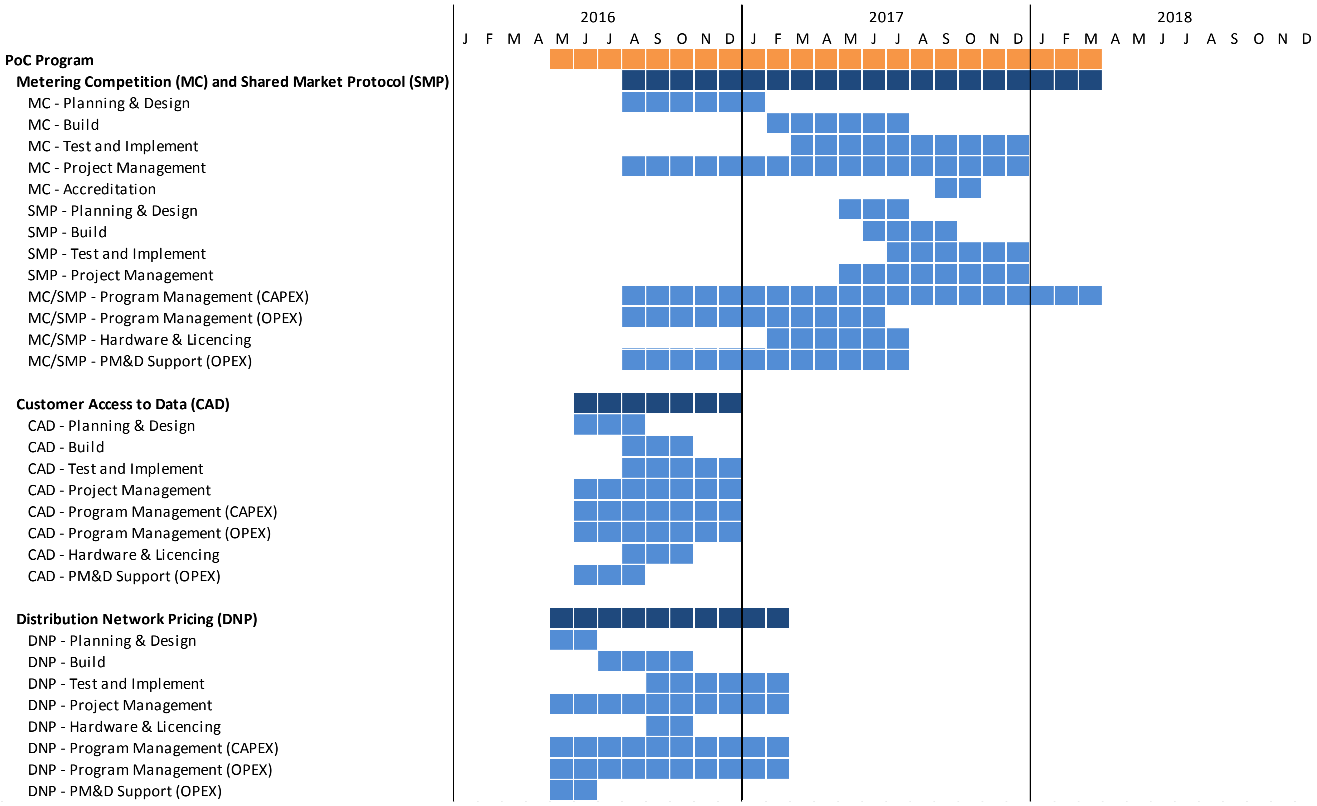
No	Benefit	Outcome	Benefit Owner	How it will be measured
		participant with role specific conditions	compliance penalties • Maintain reputation and brand	
B-02	Non Net negative impact to operations	• Maintain customer and market services opex at base step trend budgeted rate	• Efficient operations maintained	• Financial management reporting against budget year on year prior to and after change
B-03	Heightened consumer energy engagement	Realise benefits of PoC including: • Heightened Consumer energy engagement • Load shifting out of peak periods • Higher utilisation of infrastructure assets	• Heightened Energy Efficiency Awareness • Demand Tariff acceptance	• Net Promoter Score performance, and customer surveys results • Statistical shift in loading outside of peak
B-04	Facilitate future alternatives for demand management	• Availability of further enabling technology / regulatory options for load growth	• Alternative demand programs	• Alternative demand project planning initiation & delivery

5.1.4 STAKEHOLDER / CUSTOMER IMPACT

Impacted Party	Nature of Impact
Revenue Operations	New billing and tariff structures, revenue management and reconciliation of revenue forecasts
Metering Operations	Change in service provider for new connections
Metering Asset Services	Change in meter volumes and forecast methodologies, lifecycle management, sourcing arrangements for meters, refurbishments and family management
AMI Network Operations	Increased diversity of transactional sources for advanced metering operations, competition will make holes in the mesh networks requiring remediation
Information Technology	Change and release management of projects and programs, architectural assessment and alignment of design and system change, oversight of program and schedule, IT governance, business owner of systems impacted, performance management of

	scaling environments, technical risk management
Meter Data Management	Reaccreditation of reconfigured systems, reversing data flows and scales of systems, secondary systems gradually become the primary systems, obligations and compliance to Customer Access to Data obligations, change to embedded networks obligations,
Service Desk / Faults Desk	Consumer engagement and management of new process for CAD, Meter Ping, outage management, assets management, CRM across multiple systems, network performance monitoring
Control Room	Impacted Real Time Systems by market change, meter ping, outage management, customer trouble order management
New Connections	Change in meter service provider for new connections, change in procedures and appointment scheduling, change in default CRM systems, change in operational procedures, reporting and performance management
Industry Development	Heightened industry engagement through PoC reforms

5.1.5 PROGRAM SCHEDULE



Project Baseline Start Date	**1/04/2016**	**Project Baseline Finish Date**	**31/03/2018**

Project	**Planned Start Date**	**Planned Completion Date**
Metering Competition (MC)	1/05/2016	31/12/2017
Customer Access to Data (CAD)	1/06/2016	31/12/2016

Shared Market Protocol (SMP)	1/05/2016	31/12/2017
Distribution Network Pricing (DNP)	1/05/2016	28/02/2017
PoC Program Management	1/04/2016	31/03/2018

5.1.6 RISKS & ISSUES

Risk Description	Mitigation Action	Assigned to
Regulatory Risk - A PoC rule change does not proceed in the proposed form, with the stated assumptions or expected time frame	Maintain a proactive coordinated engagement with industry and working groups	Strategy Regulation and Markets
Financial Risk – Project cost overrun compare with forward estimates due to incorrect assumptions or reform program scope creep	Establish program management and governance methodology early in CY2016 to provide a coordinated and monitored program of works, establish efficiency controls and practices to ensure reporting transparency and cost controls are effective	IT Portfolio Management & Delivery
Operational Risk – Cost overrun of customer and market services operations that cannot be maintained at the same or lower levels than base step trend	Embed principles of automation and integration into the program delivery requirements to ensure the more complex environment can be maintained with equivalent staffing levels	Service Delivery
Reputational Risk – Consumer adverse reaction to market change and lack of true value benefits passed to consumers through a costly power of choice program	Continue the active and direct JEN engagement with consumers, consumer representative, advocates, consumer councils and consumer centric organisations	Stakeholder Relations
Safety Risk – Electrical safety of contestable metering installations put the customer or public at risk of electric shock, fire or unexpected outages	Work with jurisdictional safety regulators and standards organisations to ensure ongoing consistency and best practice in line with or better than the established Electricity Safety Management Systems and associated procedures	Metering Operations & Asset Services

5.1.7 ASSUMPTIONS & FORECASTING METHODS

Power of Choice IT System Estimation Methodology; the Power of Choice IT System Project forecast estimates are based on a 10 step assessment process as depicted in Figure 3–2: Project Assessment Approach above to determine the scope, present environmental state, incoming assumptions, design principles, obligations, business requirements, process impacts, IT environment impacts, fitness of established solution, viable options available.

Project resource forecasts were then developed by capturing effort estimates; the effort estimates for the initiatives known as Customer Access to Data, Metering Competition, Multiple Trading Relationships and Shared Market Protocol were each subject to the following process:

1. The key business process owners and subject matter experts were taken through an explanation of each initiative. This was a two way process whereby any potential issues were raised and discussed in order to define an appropriate business treatment.

2. At the end of the discussions there was a shared understanding of the business changes and how they would best be addressed.
3. The potentially impacted IT Systems were identified
4. System specialists associated with each affected IT Systems were then engaged in a similar discussion resulting in high level effort and duration estimates. These estimates were founded on experience working on similar project / system changes.

Translation to Project cost estimates; each initiative was then costed using an estimation model in use by the IT Portfolio Management & Delivery team with the design and build phase work estimates being calculated as either man days on man months. Each project delivery was top and tailed with project resources based on projects of similar size duration and complexity build size project costs for establishment, plan, test, implement, business process and post go live support along with identified exceptional line items as is required to meet the obligations.

Program phasing was informed based on timing of the known dates for rule change final determinations. Known rule commencement dates and best available program of works information available from AEMC and AEMO were used as program inputs. Identified resource constraints were further introduced to be factored into the program phasing. Phasing of the works allowed for assessment of program synergies and identifying coincident resource requirements along with the expected high demand for utility IT contracting resources through the program delivery.

Note: Two PoC work streams were combined (MC+SMP) due to their interdependencies and common commencement date. A common program management function was established across the whole PoC program of works to allow for coordination, and project synergy realisation

The outputs of the forecast estimates were subsequently validated using relativity test as well as “rule of thumb” estimation theory.

5.1.8 RELATIVITY AND BENCHMARK PROJECTS

JEN sought to validate the project change and budget forecast against comparable projects of scale and scope which have either completed in the preceding period or are proposed and approved in the subsequent period. For this purpose only Non-Network IT projects are considered as relative benchmark-able projects.

Project	Capital Cost	Relativity Notes
NMS Upgrade Project	$2.1M	Dot point version upgrade of the AMI head end systems
Itron Upgrade Project	$0.5M	Meter Data management Systems minor upgrade and release
Legacy Replacement Project	$6.3M	In progress project that retires functionality for customer and legacy market systems associated with type 1-4, 7 and unmetered supplies into JSAP centric hosted CRM environment.
CIS+ Replacement Project	$4.9M	In progress project that retires functionality for customer and legacy market systems associated with basic type 5 & 6 (excludes AMI) into JSAP centric hosted CRM environment.
SAP Lifecycle Management - Technical Improvements Provision	$1.9M	Continuous improvement project for JSAP (small changes), indicative of resource costs complexity of

Project	Capital Cost	Relativity Notes
		the SAP integrated environment
Business Intelligence Project - Stage 2	$1.5M	Reporting engine
Data Warehouse - Replacement	$2.7M	Business intelligence project enterprise data warehouse consolidation, replaces and consolidates BI environment components

The “rule of thumb” estimation theory first advocated in “The Mythical Man-Month” (Brooks 1975). The principles behind this theory are commonly used in the IT industry as a foundation for developing time constrained order of magnitude cost estimates.

In “The Mythical Man-Month” Brooks states that as a fraction of the total time of the project, planning consumes about 1/3, coding consumes 1/6, component test consumes 1/4, and system test consumes1/4. Thus, if a project estimate is made based on the expected coding time (the main element for which we can derive an estimate), this in reality will usually represent only about 17 percent of the entire project time.

On this basis the coding estimate can be used as a base to derive the other components as ratios. i.e. coding= 1, planning = 2 X, testing = 3 X (component test: 1.5 X, system test 1.5 X).

1. the planning and design phase estimate is 2 X the build estimate (as per the Rule of thumb estimation theory)
2. the test and implement phase is 3 X the build estimate (as per the Rule of thumb estimation theory and an assumption that implementation costs will not make a material difference).
3. the start-up phase being 1 month of mandate development and 1 month of business case development
4. the cost a senior project manager for the duration of the project

Based on rule of thumb theory the project estimation methodology was consequently validated with estimates consistently achieving comparable results to the bottom up build forecast

Based on the relativity review a one to one benchmark tests the forecasting has not identified that there are any other projects that directly match in terms of complexity across the broad scope of systems that has recently undergone substantial architectural change. Nor has the relativity review has not identified any outliers that stand out as being substantively under or over evaluated against the PoC program of works.

JEN sought to further test the estimation methodology and validity of the PoC forecast using an independent external industry consultant (Deloitte Access Economics). The associated independent report is provided for reference[22].

5.1.9 CONSTRAINTS & DEPENDENCIES

Existing projects are in progress impacting customer and market systems at the time of preparing this business case, three key projects need to complete prior to commencement of the PoC program of works to ensure that a solid base architecture is in place prior to design and development phases of the PoC Program implementation including;

22 Deloitte Access Economics Pty Ltd, Jemena, Review of Power of Choice Business Case, Dec 2015

- Itron Upgrade Project – Meter Data Management System minor version upgrade
- Legacy Replacement Project – Consolidation of type 1-4, 7 and unmetered supply customers into Jemena corporate SAP centric CRM
- CIS+ Replacement Project – Consolidation of legacy type 5 & 6 (non AMI) customers into Jemena corporate SAP centric CRM
- JGN GAS++ go live data conversion consolidates JGN GAS customers CRM into Jemena Corporate SAP

Notably the above systems changes are collectively major changes to the JEN market systems environment and due for release in June 2016. System performance of the solution is potentially unstable post go live with some post go live support bedding in to stabilise the IT environment. As such the baseline system environment for development is based on and dependent on the end state system market solution at the completion of the above projects.

6. COSTS

6.1 PROJECT FUNDING SOURCE

The establishment phase of the Power of Choice program, covering the first three months of the program forecasts $1,402,916 of costs being $1,323,607 Capex and $79,309 Opex and proposes to draw down on the approved Capital budget that was originally setup for Contestable Metering. An allowance in the CY2016 budget of $5,045,941 was approved by the Jemena Funding Committee, the CY2017 budget for the remainder of the PoC program is not yet approved. “Contestable Metering”, Non-Network IT, CY2016 budget of $5,045,941 was approved by the Jemena Funding Committee. CY2017 budget of $5,045,941 is proposed to the Jemena funding committee but is not yet approved.

1. The April 2015 EDPR submission proposal for 2016-2020 and AER preliminary decision did not include a Contestable Metering forecast and instead included a proposal to treat Metering Contestability and the Power of Choice rule changes as cost pass through events. This approach was rejected by the AER.

2. The approved JEN IT Capex program and budget does not include a specific allowance for Distribution Network Pricing or Customer Access to Data

3. The April 2015 EDPR submission proposal for 2016-2020 and AER preliminary decision includes a capital allowance for implementation of “New Pricing Structures, Methods & Reporting” of $547,802 and a consequent ongoing opex step change event “New Tariff Implementation” $2.46m over the 2016 regulatory period (5 years).

4. The Jan 2016 Revised EDPR submission for 2016-2020 includes Capital expenditure proposal for $24.98M for the Power of Choice program and a further $1.23M one off Power of Choice Opex step change proposal.

The AER final determination is due to be complete on the 30th April 2016 prior to the commencement of the main body of work for the Power of Choice.

Budget Source	Details
☐ Cost Centre	N/A
☒ Asset Owner	Jemena Electricity Network
☐ WBS	N/A
☐ External Funding	N/A

6.2 PROGRAM COST FORECAST SUMMARY

The following tables show the project cost amounts against funding allocation in the approved budget for both Capex and Opex.

Table 6–1: PoC Program Cost Forecast Summary

Real $2015, un-escalated	CY16	CY17	CY18	CY19	CY20	TOTAL
CAPEX ($M)						
PoC Program Cost	9.173	15.808	-	**-**	**-**	**24.980**
Metering Competition (MC) and Shared Market Protocol (SMP) - Including Program Management	4.796	15.432	-	-	-	20.228
Customer Access to Data - Including Program Management	1.863	-	-	-	-	1.863
Distribution Network Pricing - Including Program Management	2.514	0.375	-	-	-	2.889
Funding allocation in approved budget	5.045					
OPEX ($M)						
PoC Program Cost	**0.389**	**0.838**	**-**	**-**	**-**	**1.228**
Metering Competition (MC) and Shared Market Protocol (SMP) - Including Program Management and Accreditation Costs	0.238	0.825	-	-	-	1.063
Customer Access to Data - Including Program Management	0.065	-	-	-	-	0.065
Distribution Network Pricing - Including Program Management	0.087	0.014	-	-	-	0.100
Funding allocation in approved budget	-					
TOTAL $M (Capex & Opex)						
PoC Program Cost	9.562	16.446	-	-	-	26.208
Funding allocation in approved budget	5.045					

7. FINANCIAL EVALUATION

7.1 FINANCIAL ASSUMPTIONS

The following financial assumptions have been taken into account for this business case

- The Power of Choice program will take a phased approach with incremental project approvals to ensure a prudent and efficient outcome with appropriate detailed financial options analysis. The program of works is certain and this business case approves phase one establishment of PoC program management and coordination.
- A program allowance hardware (2.9%) and licence / software cost (2%) is included in the project to support duplicate environments for the project phase of development and test and or staged transitions through implementation.
- The projects are largely reconfiguration works of existing architecture environments and project build costs are 100% resource based (intangible) being principally capital in nature.
- Some allowance is made for Operational expenditure of PoC project start up, auditing, legal counsel and external accreditation costs.
- Jemena shared services allocations (5%) of project costs have been included in the program management project forecast only.
- No allowances have been made for project contingency.
- Project costs will be funded through Electricity EDPR submissions.
- An increase in ongoing opex is not presently forecast despite the expected more complex operating environment for market systems. The projects are required to address all complexities through capital investment such as automated workflows so that the established base year resource levels are capable of servicing ongoing customer and market system operations without a step change. Note the program / project delivery will include and forecast for one off data conversions during the program timeline.

7.2 PROGRAM FINANCIAL SUMMARY

Financial summary of PoC expenditure by project, year and expenditure type (Real $2015 un-escalated)

PoC Program Summary - Project		CY16-20 Total	CY16	CY17
Metering Competition (MC)/ Shared Market Protocol (SMP)		21,291,359	5,034,086	16,257,273
Customer Access to Data (CAD)		1,927,420	1,927,420	-
Distribution Network Pricing (DNP)		2,989,451	2,600,659	388,792
		26,208,229	9,562,164	16,646,065
PoC Program Summary - by Cost Type				
Network Capex	SCS CAPEX	24,980,429	9,172,793	15,807,637
Network Opex	SCS OPEX	877,800	389,371	488,429
ACS Metering Opex	ACS Metering OPEX	350,000	-	350,000
ACS Metering Capex	ACS Metering CAPEX	-	-	-
		26,208,229	9,562,164	16,646,065

PoC Program Summary - Outputs		CY16-20 Total	CY16	CY17
Metering Competition (MC) and Shared Market Protocol (SMP)	SCS CAPEX	20,228,241	4,795,891	15,432,350
Metering Competition (MC) and Shared Market Protocol (SMP)	SCS OPEX	713,118	238,194	474,924
Metering Competition (MC) and Shared Market Protocol (SMP)	ACS Metering OPEX	350,000	-	350,000
Metering Competition (MC) and Shared Market Protocol (SMP)	ACS Metering CAPEX	-	-	-
Customer Access to Data (CAD)	SCS CAPEX	1,862,864	1,862,864	-
Customer Access to Data (CAD)	SCS OPEX	64,556	64,556	-
Customer Access to Data (CAD)	ACS Metering OPEX	-	-	-
Customer Access to Data (CAD)	ACS Metering CAPEX	-	-	-
Distribution Network Pricing (DNP)	SCS CAPEX	2,889,324	2,514,037	375,287
Distribution Network Pricing (DNP)	SCS OPEX	100,127	86,621	13,505
Distribution Network Pricing (DNP)	ACS Metering OPEX	-	-	-
Distribution Network Pricing (DNP)	ACS Metering CAPEX	-	-	-
		26,208,229	9,562,164	16,646,065

Appendix 1 Project Identified Costs

Appendix 2 Cost Allocation to Asset Owners

Appendix 3 Attachments

Appendix 4 References

Appendix 5 Jemena Risk Management Manual

Appendix 6 Jemena Business Plan

A1. PROJECT IDENTIFIED COSTS

Project Capex Costs

CAPEX Description	Tangible/Intangible	Quantity	Unit Rate		Total (May-Jul 2016)
Labour					
PoC - Planning & Design	Intangible			$	659,667
PoC - Build	Intangible			$	217,913
PoC - Test and Implement	Intangible			$	-
PoC - Project Management	Intangible			$	128,110
			Sub-Total	*$*	*1,005,689*
External Vendors					
External Labour				$	-
			Sub-Total	*$*	-
Hardware					
PoC Hardware Allowance	Tangible			$	20,661
			Sub-Total	*$*	*20,661*
Software					
PoC Licencing Allowance	Intangible			$	14,249
			Sub-Total	*$*	*14,249*
			Sub-Total	**$**	**1,040,600**
Program Management (CAPEX)				**$**	**283,008**
Contingency (0%)				$	-
			Total CAPEX Costs	**$**	**1,323,607**

Project Opex Costs

OPEX Description	Tangible/Intangible	Quantity	Unit Rate	Total (May-Jul 2016)
Labour				
PoC Program Management	Intangible			$ 12,814
PoC - PM&D Support	Intangible			$ 46,612
			Sub-Total	*$ 59,426*
External Vendors				
PoC Program Management	Intangible			$ 19,883
			Sub-Total	*$ 19,883*
Other				
			$ -	$ -
			Sub-Total	*$ -*
			Sub-Total	**$ 79,309**
Contingency (0%)				$ -
Project Startup (already approved)				$ -
			Total OPEX Costs	**$ 79,309**

Ongoing Costs (Opex)

COST ITEM Description	Tangible/Intangible	Quantity	Unit Rate	Total
Labour				
				$ -
			Sub-Total	*$ -*
External Vendors				
				$ -
			Sub-Total	*$ -*
Other				
				$ -
			Sub-Total	*$ -*
			Sub-Total	**$ -**
				$ -
Contingency (0%)				$ -
			Total OPEX Costs	**$ -**

Note: this business case does not identify incremental operational costs not already covered by approved budgets

Program Cost Forecasts

Metering Competition (MC) - Recommended Dual SAP System Option

Analysis Category	Est Cost	Int Lab	Ext Lab	Non Lab	%	Class	Asset Type
Planning & Design	4,048,000	4,048,000	-	-	30.5%	CAPEX	INTANGIBLE
Build	2,408,000	2,408,000	-	-	18.1%	CAPEX	INTANGIBLE
Test and Implement	5,790,000	5,790,000	-	-	43.6%	CAPEX	INTANGIBLE
Project Management	674,000	674,000	-	-	5.1%	CAPEX	INTANGIBLE
Accreditation	350,000	-	-	350,000	2.6%	**OPEX**	INTANGIBLE
Sub-total	**13,270,000**	**12,920,000**	**-**	**350,000**	**100%**		
PM&D Support (CAPEX)	-				0%	CAPEX	INTANGIBLE
PM&D Support (OPEX)	-				0%	**OPEX**	INTANGIBLE
Sub-total	**-**						
Contingency (CAPEX)	-				0%	CAPEX	INTANGIBLE
Contingency (OPEX)	-				0%	**OPEX**	INTANGIBLE
Sub-total	-						
TOTAL	**13,270,000**						

Metering Competition (MC) – Alternative Consolidated SAP System Option

Analysis Category	Est Cost	Int Lab	Ext Lab	Non Lab	%	Class	Asset Type
Start Up	68,000	68,000	-	-	0.3%	OPEX	INTANGIBLE
Planning & Design	7,152,000	7,152,000	-	-	30.6%	CAPEX	INTANGIBLE
Build	3,576,000	3,576,000	-	-	15.3%	CAPEX	INTANGIBLE
Test and Implement	10,728,000	10,728,000	-	-	46.0%	CAPEX	INTANGIBLE
Hardware & Licencing	1,132,919	-	-	1,132,919	4.9%	CAPEX	TANGIBLE/INTANGIBLE
Project Management	690,000	690,000	-	-	3.0%	CAPEX	INTANGIBLE
Sub-total	**23,346,919**	**22,214,000**	**-**	**1,132,919**	**100%**		
PM&D Support (CAPEX)	-				0%	CAPEX	INTANGIBLE
PM&D Support (OPEX)	-				0%	OPEX	INTANGIBLE
Sub-total	**-**						
Contingency (CAPEX)	-				0%	CAPEX	INTANGIBLE
Contingency (OPEX)	-				0%	OPEX	INTANGIBLE
Sub-total	-						
TOTAL	**23,346,919**						

Customer Access to Data (CAD) – Recommended Option

Analysis Category	Est Cost	Int Lab	Ext Lab	Non Lab	%	Class	Asset Type
Planning & Design	328,000	328,000	-	-	23.5%	CAPEX	INTANGIBLE
Build	256,000	256,000	-	-	18.3%	CAPEX	INTANGIBLE
Test and Implement	488,000	488,000	-	-	35.0%	CAPEX	INTANGIBLE
Project Management	324,000	324,000	-	-	23.2%	CAPEX	INTANGIBLE
Sub-total	**1,396,000**	**1,396,000**	**-**	**-**	**100%**		
PM&D Support (CAPEX)	-				0%	CAPEX	INTANGIBLE
PM&D Support (OPEX)	-				0%	CAPEX	INTANGIBLE
Sub-total	**-**						
Contingency (CAPEX)	-				0%	CAPEX	INTANGIBLE
Contingency (OPEX)	-				0%	**OPEX**	INTANGIBLE
Sub-total	-						
TOTAL	**1,396,000**						

Distribution Network Pricing (DNP) – Recommended Option

Analysis Category	Est Cost	Int Lab	Ext Lab	Non Lab	%	Class	Asset Type
Start Up	-	-	-	-	0%	OPEX	INTANGIBLE
Planning & Design	90,000	90,000	-	-	4.4%	CAPEX	INTANGIBLE
Build	1,199,250	1,199,250	-	-	58.6%	CAPEX	INTANGIBLE
Test and Implement	376,500	376,500	-	-	18.4%	CAPEX	INTANGIBLE
Hardware & Licencing	30,000	-	-	30,000	1.5%	CAPEX	TANGIBLE
Project Management	351,000	351,000	-	-	17.1%	CAPEX	INTANGIBLE
Sub-total	**2,046,750**	**2,016,750**	**-**	**30,000**	**100%**		
PM&D Support (CAPEX)	-				0%	CAPEX	INTANGIBLE
PM&D Support (OPEX)	-				0%	OPEX	INTANGIBLE
Sub-total	**-**						
Contingency (CAPEX)	-				0%	CAPEX	INTANGIBLE
Contingency (OPEX)	-				0%	OPEX	INTANGIBLE
Sub-total	-						
TOTAL	**2,046,750**						

Power of Choice Program Management

Analysis Category	Est Cost	Int Lab	Ext Lab	Non Lab	%	Class	Asset Type
Program Management (Capex)	5,124,000	5,124,000	-	-	73.8%	CAPEX	INTANGIBLE
Program Management (Opex)	592,000	232,000	360,000	-	8.5%	**OPEX**	INTANGIBLE
Hardware & Licencing	1,224,217	-	-	1,224,217	17.6%	CAPEX	**TANGIBLE**
Sub-total	**6,940,217**	**5,124,000**	**-**	**-**	**100%**		
PM&D Support (CAPEX)	-				5%	CAPEX	INTANGIBLE
PM&D Support (OPEX)	285,800				5%	**OPEX**	INTANGIBLE
Sub-total	**285,800**						
Contingency (CAPEX)	-				0%	CAPEX	INTANGIBLE
Contingency (OPEX)	-				0%	**OPEX**	INTANGIBLE
Sub-total	-						

TOTAL	**7,226,017**

A2. COST ALLOCATION TO ASSET OWNERS

#	Asset Owner	Description	Amount (AUD $)	Allocation (%)
1	JEN CAPEX (SCS)	PoC regulatory change is limited to the Jemena Electricity Network.	24,980,429	95.3%
2	JEN OPEX (SCS)	PoC regulatory change is limited to the Jemena Electricity Network.	877,800	3.3%
3	JEN (ACS Metering)	Note all impacts related to the JEN network business being able to operate in a Power of Choice enabled Market. Nor is any allowance is made for a Jemena constable metering market entry	350,000	1.3%
	TOTAL (EXC GST)		26,208,229	**100.00**

A3. ATTACHMENTS

Document Title	Attachment (Embedded document OR Live Link Reference)
Deloitte Access Economics Pty Ltd, Jemena, Review of Power of Choice Business Case, Dec 2015	

A4. REFERENCES

Document	ECMS/shared drive location
None	

A5. JEMENA RISK MANAGEMENT MANUAL

The risk management process is managed as per the guidelines and processes outlined in the Jemena Risk Management Manual

A6. JEMENA BUSINESS PLAN

Click here to access Jemena business plan on the Intranet