



FINAL PHASE 1 REPORT

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Cost Benefit Analysis of Smart Metering and Direct Load Control Stream 2: Network Benefits and Recurring Costs Phase 1 Report

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1. INTRODUCTION

CRA International Pty Ltd (CRA) has been engaged by the Ministerial Council on Energy (MCE) to assist in the development of a cost benefit analysis (CBA) of rollout of smart meters to all small customers in Australia.

The CBA is being undertaken for each of four scenarios:

1. Smart meter roll-out led by distributors (Scenario 1);
2. Smart meter roll-out led by retailers (Scenario 2);
3. Non-smart meter direct load control roll-out led by distributors (Scenario 3); and
4. Smart meter roll-out with centralised communication infrastructure (Scenario 4).

The work involved in the CBA has been split into six streams of work, covering the following areas:

- Stream 1 – overall co-ordination;
- Stream 2 – network (distribution) benefits and recurring costs;
- Stream 3 – customer benefits and recurring costs;
- Stream 4 – retail benefits and recurring costs;
- Stream 5 – electricity market and greenhouse gas effects;
- Stream 6 – transitional costs.

CRA has been appointed to Stream 2 and Stream 5.

The CBA is being conducted in two phases:

- Phase 1 – Assessment of the costs and benefits of additional functionality above a core set of functionality, and thus determining a national minimum functionality specification for smart meters; and
- Phase 2 – Taking the national minimum functionality specification and considering the costs and benefits associated with each of the specified scenarios and assessing the jurisdictional and regional variations in costs and benefits.

This report contains the findings of CRA in Stream 2 in Phase 1. CRA is reporting separately on its findings in Stream 5. At the time of writing this report, Phase 2 has not yet commenced.



CRA's work in Stream 2 has been undertaken in consultation with all the electricity distribution businesses in Australia:

- Ergon Energy;
- Energex;
- Country Energy;
- Integral Energy;
- Energy Australia;
- Powercor and CitiPower;
- SP AusNet;
- Alinta AE;
- United Energy Distribution;
- ETSA Utilities;
- ActewAGL;
- Aurora Energy;
- Western Power;
- Horizon Power; and
- Power and Water Corporation.

CRA would like to thank all those distribution businesses for the information and the support that they have provided for this study.

2. METHODOLOGY

This section contains an overview of our approach to this study. It details both the analytic approach and our approach to data gathering.

2.1. DEVELOPMENT OF REQUEST FOR INFORMATION

In order to collect information on network benefits and recurrent costs in a structured way, a Request for Information (RFI) was developed. The RFI, which is attached as Appendix A, listed and described various, core and additional functionalities and performance levels as specified by the Smart Meters Working Group.

For each of the additional functionalities, the RFI included our initial inputs and requested fuller information from each electricity distribution business on each of the following:

- Recurring network costs;
- Suggested Network Benefits;
- Suggested input metrics and method of quantification of network benefits; and
- Estimate of quantifiable benefits.

The RFI was sent to all electricity distribution businesses on 3 August 2007, with a requested response date of 14 August 2007. This short timeframe was constrained by project schedules that were outside our control.

2.2. RESPONSES TO REQUEST FOR INFORMATION

As at 24 August 2007, RFI responses had been received from seven distribution businesses. Most responses expressed concern at the short timeframe, which made it difficult for the distribution businesses to provide the fullest information, given the short time allowed.

Thus, most of the RFI responses received contained only scant information. Some of the RFI responses, however, did contain a significant amount of relevant information, which was of great assistance to us.

We also contacted several of the distribution businesses directly by phone or through in-person meetings, to seek further information or to understand the basis of information provided in their responses.



2.3. ASSESSMENT OF BENEFITS

Based on the information received from the RFI process together with data from the CRA database on smart metering, a model that calculates the benefits for each additional functionality was developed. As a result of this, quantified benefits have been identified for 16 out of the 21 additional functionalities, and these are detailed in Section 3. Copies of the benefits model have also been supplied to all distribution businesses for comment.

These benefits have been estimated as those accruing to the distribution businesses, at least in the first instance, and are independent of whether provision of the smart meter infrastructure is the responsibility of distributors, retailers or some centralised agency.

2.4. ASSESSMENT OF RECURRING COSTS

This stream of work also included estimation of the recurring costs that would be incurred (at least in the first place) by distribution businesses.

3. ESTIMATION OF THE BENEFITS OF SMART METER INFRASTRUCTURE

3.1. ASSUMPTIONS USED IN BENEFITS MODELLING

Table 1 below details the general assumptions used in the benefits analysis.

Table 1: General Assumptions

Item	Source	Value
Network tariff c/kWh as % of retail tariff	CRA database on retail and network tariffs	40%
Distribution business profit margin	CRA database on distribution business operations	10%
Labour rate for non-specialist field services (\$/hr)	Victorian Electricity Distribution Price Review 2006-2010 and Energy Australia	\$90/hr
Labour rate specialist field services (\$/hr)	Impaq Consulting database on technical services rates	\$120/hr
Call centre – average cost per call (\$)	Victorian Electricity Distribution Price Review 2006-2010	\$10.44

Table 2 below details the assumed number of small customers per distribution business.

Table 2: Numbers of Small Customers by Distribution Business

Distribution Business	Number of Small Customers
Ergon	629,373
Energex	1,211,996
Country Energy	796,094
Integral Energy	827,561
Energy Australia	1,528,340
Powercor	658,986
CitiPower	290,850
SPAN	591,961
Alinta	285,073
UED	606,957
ETSA Utilities	794,192



Distribution Business	Number of Small Customers
ACTEW	146,683
Aurora	260,000
Western Power	933,152
Horizon Power	36,000
NT PAWA	81,841

3.2. BENEFIT ESTIMATES BY FUNCTIONALITY

The following discussions detail how the benefits of each additional functionality (items 9 to 29 inclusive) were estimated¹e.

3.2.1. Item 9: Remote Daily Reading

Daily reading provides benefits to customers, retailers and network businesses. For network businesses there is demand side response benefit when customers have daily feedback on their electricity costs for the previous day. This might be in the situation where customers are experiencing consecutive critical peak price events and on the morning of the second day can view over the internet their electricity consumption and cost for the previous day and therefore take actions to reduce demand in peak periods.

Based on the short run elasticity responses developed by NERA in the Stream 4 work, the benefit of this functionality in terms of reduced capacity requirements in distribution networks was calculated to be \$4.07 per meter per annum

3.2.2. Item 10: Power Factor Measurement (using reactive energy interval data)

This functionality would allow distribution businesses to identify customers or groups of customers with low power factor, and also to measure the kVA demand of customers, which would then allow the use of kVA demand as part of the network tariff. It is noted that for some larger customers with three-phase metering, kVA demand is already part of the network tariff for some distribution businesses. There appears to be no material cost for the continuation of this practice as three-phase metering comes with power factor measurement as standard.

¹ The core functionalities 1 to 8 are not assessed in Phase 1 of the CBA.

The issue then can be narrowed down to the benefits (and related costs) for power factor measurement for single phase customers. Distribution businesses believe there is a benefit in having some measure of power factor for single phase customers, however they have not quantified that benefit. It is noted that reactive energy (and hence power factor) is measured and recorded for medium voltage feeders at most zone substations and this may be adequate for distribution businesses to keep track of power factor in each part of their network. It is arguable whether power factor measurement and recording at single phase meters has more than limited value, since small customers typically do not have the capability of easily changing their power factor (even if it is low) through the use of power factor correction equipment, such as capacitor banks. .

An option for consideration for single phase meters is to record low power factor occurrences as events, along with the other Quality of Supply events covered in item 19. This way the meter would log instances of low power factor which would then be available to DBs in the investigation of low power factor issues on the LV network.

3.2.3. Item 11: Import/Export

Import/export metering enables the recording of active interval energy flows both into and out of a premise. This can be useful where the customer has installed generation capacity. This functionality allows for the accurate metering of energy injected into the distribution network from customers' local generation (e.g. photovoltaic (PV) cells). The ability to measure by half-hourly intervals the energy being provided to the network would support the development of innovative energy purchase tariffs for PV cells and distributed generation, which in turn may be an incentive for customers to install such generation.

One benefit of this functionality is that it allows customers that install local generation to avoid the cost of installation of special metering that records both import and export energy flows independently. On a forward-looking basis it is assumed that there will be an increasing take up of PV cells by customers, particularly given the incentives that some governments are proposing, including feed-in retail energy tariff rates of around \$0.60 per kWh. It has therefore been assumed that after 15 years there would be 5% of customers with local generation and that this results from a steady take-up rate of 0.33% of customers per annum installing local generation. We estimated the avoided cost of supplying and installing a meter suitable for recording interval energy flows out of a customer's premises at \$265. This is based on RFI responses (which estimated the charge as between \$250 and \$300) and also a cost build up using the costs of appropriate interval meters (as derived from the Victorian Electricity Distribution Price Determination 2006-2010) at \$85.26 and an installation charge of \$170. When the avoided cost of \$265 for customers with local generation is averaged over the total customer base it translates to a net benefit of \$0.88 per customer per annum.

3.2.4. Item 12: Connect/Disconnect

Case A

Remote connect/disconnect functionality allows the power to a customer's premise to be connected or disconnected either locally or remotely.

At present, some jurisdictions perform a disconnection when a customer moves out and a subsequent reconnection when a customer moves in. Other jurisdictions only do a final reading on customer move-out, and bill the customer that moves in for whatever power is used in the interim. However, this approach does result in some lost revenue. The benefits of this functionality that have been quantified are:

1. The avoided cost of manual disconnections on move outs and reconnections on move-ins;
2. The avoided cost of disconnections for non-payment and subsequent reconnections; and
3. The avoided loss of revenue between customer move-out and customer move-in if there is not a disconnection on move out.

Victoria and SA Benefits

Benefits 1 and 2 have been combined, as only total disconnect/reconnect figures were available and then only from some of the distribution businesses. The connect/disconnect charges used in the calculation are drawn from the Victorian Electricity Distribution Price Review 2006-2010 and for SA are from the RFI submission from ETSA Utilities.

Because the connect/disconnect charges are excluded service charges, the total value of the charge has been used in the calculation.

The avoided cost of manual connections and disconnections have been amortised across all customers in VIC and SA, resulting in an average per customer avoided cost of \$5.76 per annum.

Benefits in Other Australian States and Territories

The value of benefit 2 above has been calculated based on the figures provided NSW and QLD distribution businesses. The number of disconnections and reconnections has been multiplied by the relevant distribution business' published charge for these services, and then averaged across all their customer bases. This results in an average avoided cost per customer per annum of \$1.00.

The value of benefit 3 has been calculated based on figures provided by NSW distribution businesses. The lost revenue at a retail level has been multiplied by 40% to give the lost revenue at a network tariff level (refer general assumptions).² The net avoided lost revenue per customer has been calculated at \$0.71 per annum.

² The remaining 60% is included in Stream 4: Retail Benefits



Combining the results of the VIC/SA benefits calculations with the benefits calculations in the other states and territories gives an overall national benefit of \$3.06 per customer per annum.

There are other benefits of connect/disconnect which have not been quantified. One such benefit is the ability to better stage the restoration of supply after an outage.

Case B

Case B is the same functionality as Case A above, however the performance level is higher with a response time of 10 minutes compared to 30 minutes. This improved performance level provides the capability for prepayment metering functionality to be part a smart metering system, thereby avoiding the costs for prepayment metering for those customers that take up a prepayment tariff. For the purposes of estimating the value of this benefit we have calculated the avoided cost of prepayment metering based on:

- Assumed take up of prepayment tariffs of 0.2% of customers per annum (CRA estimate)
- Prepayment metering cost of \$200 per meter (CRA estimate from discussions with metering vendors)
- Cost of replacing a credit meter with a prepayment meter (installation cost) of \$176 based on DB charges for installation of a 3 phase meter

This results in an avoided cost of \$376 per meter for any customer taking up a prepayment tariff. Averaging this avoided cost over all Australian customers gives a per customer per annum benefit of \$0.75.

3.2.5. Item 13: Supply Capacity Control

Supply capacity control provides the ability to set a power limit in each individual customer's meter, which, when it is exceeded, trips the connect/disconnect contactor. This functionality is dependant on the existence of functionality 12: connect/disconnect and functionality 25 remote reconfiguration). Supply capacity control can be used in two principal ways:

1. Supply capacity control can be used as a normal supply capacity limit under a contractual agreement with the customer. This could allow:
 - Retailers or distribution businesses to offer demand-based tariffs to customers (as in some overseas jurisdictions – notably in Europe) where customers contract for a certain supply capacity.
 - Distribution businesses to defer some augmentation projects. For example, on long, low-capacity feeders, supply capacity control could be used to ensure equitable sharing of the feeder capacity between customers and so defer a large capital expenditure on line augmentation or replacement that is not financially justified given the small number of customers served.
 - Retailers to offer supply capacity products to assist low income customers manage their expenditure, or as an alternative to disconnection for defaulting customers.

2. Supply capacity control can also be used as an emergency supply capacity limit following a network outage. The ability to restore supply at less than full supply capacity provides potential societal benefits. Instead of having whole geographic areas blacked out, supply to all customers in a geographic area could be restored albeit with restricted capacity. This then allows essential infrastructure – such as traffic lights, hospitals, cellular mobile phone base stations, fire stations, police stations, ambulance depots, street lights and security lighting – to be operational. It also would allow a base level of amenity to be available to all customers - for example, allowing the operation of lights and refrigerators or freezers. By having settable supply capacity limits, some customers – such as those on life support systems – could be exempted from such emergency capacity limits.

Hence, supply capacity control can provide benefits to retailers, distribution businesses, customers and the broader economy. Most of these benefits are difficult to quantify. There are, however, some minor benefits to distribution businesses for which quantification has been attempted.

The Avoided Cost of a Supply Capacity Circuit Breaker

The Victorian Service Installation rules (SIRs) provide that a supply-capacity circuit breaker may be fitted to new customer installations in addition to a service fuse. At least one Victorian distribution business has implemented this on new customer installations. The supply capacity control functionality of smart meters would meet this requirement, thus avoiding the need for a supply-capacity circuit breaker. The value of this benefit has been estimated based on:

- Assumed customer growth rate of 1.6% (as per the Victorian Electricity Distribution Price Review 2006-2010);
- Cost of 63A supply-capacity circuit breaker (installed by customer's REC) – \$16.28 Source: Middendorp Electric Co Pty Ltd (electrical wholesalers);
- Incremental installation time of 8 minutes (CRA estimate); and
- Installation labour rate of \$90/hr (see general assumptions).

The resultant saving averaged across all of one VIC distribution business' customers is \$0.43 per customer or \$0.03 per customer per annum, nationally.

The Avoided Cost of Replacing Service Fuses that have Blown from Overload

Based on information provided by distribution businesses, about 1% of service fuses are replaced per annum. If it is assumed that about 50% of these have failed due to overload rather than fault level currents, then this proportion of fuse replacements could be avoided by supply capacity control which would interrupt supply in an overload situation (but not a fault situation). The avoided labour charge for a fuse replacement is estimated based on connection charges to be \$44. The cost of a 100A HRC service fuse cartridge was assumed to be \$16 based on pricing from Lawson (a manufacturer of fuses). The average cost per customer of avoided fuse replacements was calculated to be \$0.38 per annum.

3.2.6. Item 14: Load Management at Meters through a Dedicated Control Circuit

Load management at meters through a dedicated control circuit relates to the existing arrangement for load control of electric storage water heating and space heating systems. Functionality number 8 deals with most of the requirements for this, and is included in the core functionality specification. Functionality number 14 Case B is the ability to remotely set “turn on” and “turn off” times for time switched controlled loads, or to remotely alter the equivalent of ripple control channel settings for load that has been controlled by ripple control systems. Smart meters can also provide more flexible control of storage heating loads by having the capability to remotely reset turn on and turn off times.

Case B

This functionality about setting times may actually be a subset of functionality 25 – remote reconfiguration.

Benefits from this functionality that can be readily quantified are:

1. The avoided cost of site visits to manually alter turn on and turn off times for time switches; and
2. The avoided cost of site visits to manually alter ripple channel settings (e.g. in NSW for a change from tariff OP1 to OP2 or in QLD from tariff 33 to 31 – or visa versa).

In relation to the former of these benefits, discussion with distribution businesses has yielded an estimate of 2% of time switches being reset each year. The charge for this service is based on the Energex excluded service price of \$48.10. This results in an average avoided per customer cost of \$0.34 per annum for the states that use time switches for off-peak load control.

In relation to the second of these benefits, from discussions with NSW distribution businesses it was estimated that about 1% of customers on off-peak tariffs would have their ripple relay channels changed (mainly due to change in off-peak tariffs). The cost of these changes was taken from the Integral Energy services price list, at \$47. For some of these changes there is no charge at present, however, the quantum of the charge in the price list would provide an indication as to the real costs for the service. The resulting avoided cost per customer is \$0.15.

The weighted average of the benefits 1 and 2 above at a national level is calculated to be \$0.24 per customer per annum.

Case C

Case C appears to provide an enhancement to core functionality 8 in being able to remotely “Turn on” or “turn off” controlled load at 99% of meters within 1 minute. This is mimicking the performance of ripple control systems which are in extensive use in NSW and QLD. In these states ripple control is used at present to manage mainly storage water heating load but can also provide this control for other loads such as air conditioning and pool pumps. At times of system stress it is an important operational tool to be able to shed at some of this controlled load. However it turns out that functionality 14C is not really an enhancement as the smart metering systems capability required for functionality 8 can meet this 1 minute response criterion anyway. Hence there is no incremental benefit for this functionality compared with that for functionality 8.

It is noted that the capability provided by core functionality 8 could avoid the replacement cost of the ripple control systems in most of NSW and those in South East QLD. This is a major benefit that will be quantified in phase 2 of the project.

3.2.7. Item 15: Interface to Load Control Devices

This functionality would allow Utilities (Distribution Businesses & Retail Businesses) to directly control customers’ end-use devices. (i.e. air conditioners cycled; pool pumps, dryers, etc. constrained off). The interface considered in this functionality is an interface directly to the smart metering communications system and is not through a meter. It is noted that the interface does not in itself provide the hardware required to control the end-use devices, but it would provide the ability to communicate with those controls. The Stream 6 report captures the costs for the interface and the end-use devices that are required to allow the control of the above mentioned loads.

An alternative means of achieving the same outcomes is to use the interface to the Home Area Network (HAN) as outlined in functionality 16. The benefits for either of these alternatives are the same and are outlined under item 16 case A & B.

3.2.8. Item 16: Interface to Home Area Network (HAN)

This functionality involves the inclusion of a Zigbee interface in each meter that would allow the meter to communicate through a Zigbee HAN with a range of in-home devices including In-Home Displays (IHD), Smart Thermostats, Home Computers, and Household appliances.

Case A & B -- Interface to HAN, IHDs, and Personal Computers to Control Air Conditioners

This functionality entails a Zigbee interface between the smart metering infrastructure and the customer’s home area network (HAN), which could then control end-use appliances by communications to dedicated switches built into the appliances themselves, or through an IHD, or the customer’s personal computer network.



Although these controls can be used to operate a wide range of end-use appliances, the modelling considered their application only to air-conditioning. Functionalities 15, 16a and 16b were assumed to be applied only in new and replacement applications of larger air conditioners (larger split and all ducted systems)³.

The Stream 6 report contains the costs for the interface and the control devices that would be required to control the customer's end-use equipment. The calculation of the wholesale market and greenhouse gas benefits uses a lower bound assumed take-up rate for this functionality of 7.5% of all eligible air-conditioning load and an upper bound of 25%, as put forward in Stream 4⁴.

Based on the short run elasticity responses developed by NERA in the Stream 4 work, the benefit of this functionality in terms of reduced capacity requirements in distribution networks was calculated to be \$3.80 per meter per annum for the lower bound and \$12.67 per meter per annum for the upper bound.

As for 16C below it is assumed that there would need to be a payment to participating customers of \$75 per annum to secure their participation

Case C – Interface to HAN and Smart Thermostats to Control Air Conditioners

The interface to the HAN allows considerable demand side benefits to be realised through better management of customers' loads. One such benefit is the ability to control customers' air conditioners at peak times to either cycle the compressors or to increase the settings of the thermostat. This picks up a larger segment of air conditioning load than 16 A & B above. In 16 A & B only new and replacement air conditioners can be controlled. In this case (16 C) by using smart thermostats this capability can effectively be retrofitted to almost all existing air conditioners as well (at least those that have remote control units that use infra-red communications).

ETSA Utilities has undertaken a trial in SA of cycling customers' air conditioners and has achieved significant peak reductions for those customers. The California Statewide Pricing Pilot used smart thermostats and achieved reductions for small customers of about 13% of peak energy usage. (http://www.fypower.org/now/demand_resp.html)

³ The switches would either be added on to the appliances or come as OEM equipment with new appliances.

⁴ Modelling of an alternate take-up of 25% is to be conducted prior to finalisation of the Phase 1 report.



The Zigbee interface to a HAN together with a smart thermostat offers the capability of either direct Utility load control or elective customer response to CPP tariffs. The retailer or distribution business can signal through the smart meter communications network, through the meter and HAN to the smart thermostat to alter the temperature settings of the air conditioner. This is effective for central air conditioners and also for packaged / split systems air conditioners that use Infra Red remote controls (both new and existing units). Smart thermostats have been costed at \$50 to \$100 – refer to the Stream 6 Transitional Costs report.

Table 3 below provides a summary of the calculation of the range of annual benefits. As shown, modelling of the benefits of this functionality assumes it is applicable to new, replacement and retrofit applications⁵.

Table 3: Calculation of Benefits of DR Enabled by HAN Interface

	Low range	High Range
Percentage of customers with Air Conditioning	65%	65%
Assumed uptake of load management tariff	7.5%	25%
Total number of customers that accept tariff	471,854	1,572,847
Average load reduction (kW)	1	1
Total load reduction (MW)	472	1573
Marginal Capacity cost (\$/kW/year)	130	130
Total Value of avoided demand (\$m)	61.34	204.47
Total benefit (\$ per customer per annum)	6.34	21.13

The percentage of customers with air conditioning nationally has been obtained from the NERA Stream 4 Customer report page 121. The assumed uptake of customers on such a load control tariff is based on the experience of ETSA's demand management program. ETSA targeted some 12,000 customers for this trial and obtained positive expressions of interest from 4,000 – a potential take-up of 33%. After evaluating the air conditioners of these customers for suitability, ETSA selected 1,700 customers' sites – a net 15% of those originally targeted. (It is noted that use of smart thermostats in this functionality should allow a higher proportion of air conditioners to be suitable for control.) For the purposes of calculating the benefit we have assumed a low range uptake of 7.5% and a high range uptake of 25%.

ETSA offered trial participants \$100 each to allow ETSA to cycle their air conditioner on peak days.

⁵ The retrofit applications were limited to more recent vintage air-conditioners which operate or can operate via remote controls.



NERA in their Stream 4 report identified that the average air conditioner size is 1.9kW. Based on ETSA's trials we believe that those that are most suited to use this functionality are typically 3kW and above. The average load reduction in kW is an estimate based on the VIC Essential Services Commission position paper "Installing Interval Meters for Electricity Customers - Costs and Benefits" November 2002 and on the results of the ETSA trials (http://www.etsa.com.au/content_page_without_modules.jsp?xcid=991). The marginal capacity cost of \$130 per kW per annum is taken from the above mentioned paper from the ESC page 87, and is consistent with CRA's experience of the annualised value of network capacity augmentation deferral in a number of network demand management feasibility studies and projects. The resulting benefit is in the range of \$6.34 to \$21.13 per customer per annum. It is assumed that there would need to be a payment to participating customers of \$75 per annum to secure their participation⁶. In addition, participating customers would receive a smart thermostat.

The ETSA pilot also included participation by small business customers. Other DLC programs have also included the control of customers' pool pumps. Both of these opportunities would provide the potential for additional demand response through DLC. These sources of additional potential demand reduction have not been considered in the modelling.

3.2.9. Item 17: Mandatory Provision of In-Home Displays (IHD)

This functionality would result in an IHD being part of the core functionality. As a practical matter, inclusion of IHDs might be limited to the residential sector.

The incremental benefit of the provision of IHDs has been estimated by NERA in its Stream 4: Consumer Benefits work to be a reduction of 0% to 0.48% of total system peak demand, based on the jurisdiction. Based on this level of demand reduction and the annualised value of demand reduction on distribution systems estimated by the VIC Essential Services Commission position paper "Installing Interval Meters for Electricity Customers - Costs and Benefits" November 2002, mandatory provision of IHDs would provide a benefit (in NPV terms) between \$1.27 and \$2.57 per meter per year.

3.2.10. Item 18: Interface for Gas and Water Metering

The addition of an interface for communications from gas and water meters is a potential additional functionality. Such an interface may allow the smart metering infrastructure operator to offer remote reading of gas and water meters to the respective companies, resulting in a cost saving overall and an additional line of business for the smart metering infrastructure operator. Where a customer has an IHD, an interface with gas and water may also allow usage data from these utilities to be provided to the customer via this display.

⁶ This has been judgementally reduced from the incentive level used in the ETSA pilot program to reflect (a) the high response rate gained by ETSA, and (b) the high levels of satisfaction obtained in the pilot which are likely to allow incentive payments to be reduced, at least over time.

In scenario 1 where the distribution business is the smart metering infrastructure operator there are potential benefits for the distribution businesses to realise. In scenarios 2 & 4 the benefits would accrue to retail businesses.

Case A – Register reads for Gas and Water metering according to the current reading cycle frequency

For the purposes of estimating the benefits it has been assumed that water and gas utilities would be charged the equivalent of 33% of the avoided cost of manual reading. Based on information from contract meter reading businesses the direct cost of manual reading of gas and water meters is \$0.50 per read. It is assumed that gas meters are read 6 times a year and water meters are read 4 times a year. It is further assumed that the proportion of Gas customers to electricity customers is 35% and water customers to electricity customers is 85%. The total per electricity customer average benefit is \$0.91 per annum.

It is considered unlikely that there would be a positive business case based on this level of benefits as the cost for the interface in the electricity meter to connect to gas and water metering is in the range of \$18 to \$22 (without considering the cost of back end systems). This does not necessarily cut off all possibility of leveraging the investment for remotely reading electricity meters to also provide for remotely reading gas and water meters. There are two options:

1. There may be an opportunity to read gas and water meters using the Zigbee HAN which is the subject of functionality 16. The technical specification of the Zigbee smart meter application profile would appear to allow this.
2. If Mesh Radio is used for the smart meter communications network then gas and water meters can be connected to that network directly as other nodes on the mesh. There are smart meter installations in the USA where this has been done.

Even when these two options are considered, there may not be a positive business case for rolling out remote reading of all gas and all water meters. The cost of replacing gas and water meters with those that have remote communications capability is estimated to be of the order of \$120-180 each. However there could well be a business case for new and replacement gas and water meters to be read this way as it is estimated that the incremental cost of adding remote communications to a new gas or water meter is much less – about \$20-\$50 each.

Case B - Register reads for Gas metering but reading of hourly interval data for Water metering according to the current reading cycle frequency

This case is different from Case A in that the water the metering is assumed to provide hourly interval data. The calculation of the benefit for case B is as per Case A except that for the water meters there is the avoided cost of reading hourly interval data instead of just register data. The cost of reading interval data from water meters has estimated based on the cost of manual reading of interval data from electricity meters. The Victorian Electricity Distribution Price Review 2006 to 2010 set a price of \$1.50 per read. Based on this the total per annum benefit per electricity customer is \$2.03.

Despite the increased benefits of Case B it is still considered unlikely that there would be a business case for remote reading of gas and water. However as for Case A there may be case for new and replacement gas and water meters to be remotely read.

3.2.11. Item 19: Quality of Supply and Other Event Recording

Smart metering infrastructure can incorporate functionality to record data in relation to defined quality of supply (QoS) events (such as outages or under-voltage) and other events. The meter or the system can record the nature of the event, the date and time at the beginning of the event and the date and time at the end of the event.

Although it is considered that QoS event recording will assist distribution businesses in the planning and operation of their networks, it has been difficult to quantify these benefits. Two ranges of avoided costs have been calculated.

Lower range

The lower range benefit has been quantified based on the avoided cost of investigation of QoS issues raised by customers. There are circumstances at present where, upon receipt of a QoS complaint, monitoring equipment is placed at the customer's premises to record data on QoS. This cost can potentially be avoided with the use of smart meters.

The avoided cost of investigating QoS events has been estimated from the following data:

- Assumed % of customers that initiate QoS complaints = 0.07% (based on discussions with distribution businesses);
- Annualised cost of QoS monitoring equipment (capital & maintenance) = \$4,000 each;
- Number of QoS monitoring sets per 100,000 customers = 3;
- Labour hours in setting up and taking down QoS equipment (including travel time) = 3 hours (CRA estimate);
- Labour hours in analysis of results = 2 hours (CRA estimate); and
- Hourly rate for specialist field services = \$120 (see general assumptions).

Based on the above, the average cost across all customers is \$0.54 per annum.

In addition to the QoS investigation, it was estimated that there would be two call centre calls related to each QoS incident. The average cost across all customers is \$0.015. The total then is \$0.56 per customer per annum.

Upper range

The upper range estimate is based on data provided to CRA by one of the smaller distribution businesses as the cost of manually investigating QoS events. This cost has been scaled up to a national average across all customers of \$5.56 per customer per annum.

3.2.12. Item 20: Meter Loss of Supply and Outage Detection

Under this functionality, loss of supply to a customer's meter is detected by regular communications with the meter. Overseas jurisdictions that have implemented smart metering consider this functionality to be one of the most beneficial. Three benefits have been quantified:

1. Reduction in calls to fault and emergencies lines;
2. Avoided cost of distribution business staff visiting customers premises to check supply; and
3. Avoided cost of rectifying nested outages.

Each of these is considered in turn.

Reduction in Calls to Fault and Emergency Lines

The ESC Victoria published a report on 31 August 2006 on the "Performance of electricity distribution business' call centres during wide-scale emergency situations". This report was in response to the significant outages that occurred after major storms in January 2006. The report provides a range of information and analysis on calls to the faults and emergencies lines of the Victorian distribution businesses. The report indicated that there are a total of 980,000 calls to these lines per annum and 29% of these end up being answered by an operator. The average Victorian distribution businesses' total call centre cost per call is calculated as \$10.44 per call based on information provided by distribution businesses in the 2006-2010 Victorian Electricity Distribution Price Review processes. Thus, the total cost for all calls answered by an operator is \$2,967,416. Based on personal discussions with Pennsylvania Power and Light, it is estimated that the volume of calls to fault and emergency lines will decrease by about 60% once customers know that the distribution business can tell when they are off supply. This would translate to a reduction of about \$1.8 million per annum across all distribution businesses in Victoria, or \$0.73 per customer per annum. It would seem reasonable that this level of saving would apply nationally.

Avoided Cost of Distribution Business Staff Visiting Customers' Premises to Check Supply

In discussions with a NSW Distribution Business, it was determined that there was a significant number of wasted calls by Emergency Services Offices (EMSOs) to respond to customer complaints of having no power. In many instances, safety switches or circuit breakers had tripped or fuses had blown. The annual cost of these wasted EMSO visits was estimated to be \$600,000 per annum. This would translate to an average cost per customer of \$0.73 per annum.

Avoided Cost of Rectifying Nested Outages

One of the significant benefits identified by overseas jurisdictions for smart meters is the ability to detect nested outages. When there are major outages (often due to storms), field crews go to an outage area, fix the major cause of the outage and then return to the depot. However, although most customers have supply returned some have nested outages – for example a service cable may be down. Some time later, the customers in nested outage call to advise that they are still off supply. This results in another call out of a field crew to fix the nested outage. With smart meters, distribution businesses can check that all customers in an area are back on supply before letting field crews return, thereby avoiding subsequent call outs.

The avoided cost of additional call outs from nested outages has been estimated from the following data:

- The number of severe storms per annum = average of 100 (Bureau of Meteorology);
- Average number of major storm outages per distribution business per annum = 6 (CRA estimate);
- Average number of nested outages per storm per distribution businesses = 40 (CRA estimate); and
- Cost for crew call out to fix nested outage = \$1600 (including labour, materials and truck costs – CRA estimate).

Based on this, the calculated average avoided cost per customer for nested outages is \$0.60 per annum.

Total Benefits Identified

The total avoided cost from the three benefits categories above is \$2.05 per customer per annum.

3.2.13. Item 21: Customer Supply Monitoring

Customer supply monitoring is a conceptual functionality in which the meter would send an alarm if it detected (i) reverse polarity at a customer's connection; (ii) degradation of the customer's neutral; or (iii) degradation of the customer's earth connection (from switchboard to earth). Such monitoring could provide improved electrical safety in customers' homes (through faster and more accurate fault detection), reduction in electrical fatalities, and cost savings for the distributors from reduced unnecessary testing of the integrity of neutral and earth connections.

The following information has been provided by a Victorian distribution business:

- Cost of network service testing (NST) per customer = \$25;
- Frequency of NST testing = once every 10 years;
- Reduction in NST testing possible = 60%;
- Reduction in fatalities = 0.2 per annum; and
- Cost of fatalities = \$5m each.

Based on the above, a total avoided cost per customer per annum is \$1.91.

It is noted, however, that this functionality is not yet proven and may require considerable field testing before there could be confidence in recommending its inclusion in the smart metering functionality specification.

3.2.14. Item 22: Real Time Service Checking

This functionality is similar to outage detection but enables a customer's meter to be accessed remotely in real time in order to immediately check the presence of supply. This would enable customers to ring the call centre if they experienced an outage and to find out while they were on-line whether the problem was a loss of supply to their premise or a circuit interruption within their premise (e.g. blown fuse or safety switch trip).

Although this is similar to outage detection only one of the three benefits from item 20 is achieved – that is the avoided cost of distribution business staff visiting customers' premises to check supply. Hence the value of the benefit of this item is \$0.73 per customer per annum.

3.2.15. Item 23: Interoperability for Meters / Devices at the Application Layer

This provides interoperability of devices by using a known or standardised application layer. This may have benefits to the smart meter system operator, and may also allow parties other than the meter owner or smart meter operator to access data from the smart meter. This is achieved through having known application layer protocols.

Distribution businesses have indicated that they are in favour of interoperability as it should provide them greater choice of meters (in Scenario 1) and may allow them to have one Network Management System (NMS) that can support different smart metering infrastructure. They have not been able to quantify any of these benefits. Retailers and MDAs have also indicated they are in favour of interoperability to provide greater choice of smart metering infrastructure devices (for Scenarios 2 & 4). There is a more detailed discussion of the issues and merits of interoperability in the Stream 6 report.

3.2.16. Item 24: Hardware Component Interoperability

Hardware component interoperability allows the different hardware components of the smart metering infrastructure to be sourced from different vendors and still work together. This functionality potentially allows for greater competition for the supply of hardware components, resulting in a lower cost for that hardware.

Distribution businesses Retailers and MDAs have indicated that they are in favour of hardware interoperability as it should provide them greater choice of meters and other components of smart metering infrastructure. They have not been able to quantify any of these benefits.

There is a more detailed discussion of the issues and merits of hardware component interoperability in the Stream 6 report.

3.2.17. Item 25: Remote Reconfiguration

Remote reconfiguration allows the meter settings to be changed remotely. It is noted that this functionality impinges on other functionalities – particularly load management (functionality 14), supply capacity control (functionality 13), quality of supply recording (functionality 19) and Customer supply monitoring (functionality 21). Each of these other functionalities requires adjustable settings as part of its configuration. If all configuration settings are included under item 25, then all the other functionalities listed above depend on this one.

The benefit of this functionality is the avoidance of costs for field visits to manually change settings in meters in the alternative case (the base case for this incremental assessment) where this functionality is not incorporated. Thus this is not the avoidance of costs currently incurred by distribution businesses.

Based on the experience of trials in NSW and Victoria, a great deal of setting changes may be required with smart metering infrastructure, and it is expected that this would be particularly true in the early years of roll-out. If it is assumed that over the life of the smart metering infrastructure there is a need to change settings on average once every five years (or 0.2 times per annum) and the time to change settings in a meter is 10 minutes each, then based on an hourly rate of \$90/hr the annual cost per meter is \$3.

This functionality also provides the capability to meet the requirements of functionality 14B. Hence the benefits of 14B can also be added; that is \$0.24 per customer per annum. The total net benefit is therefore \$3.24 per customer per annum.

3.2.18. Item 26: Remote Software Upgrade

This functionality is the ability to remotely upgrade the software (really firmware) in smart meters, and their associated data concentrators. Based on the experience of smart meter system trials in NSW and Victoria, the remote firmware upgrade functionality is a very useful one. There have been multiple instances of the need to change firmware for devices in the field. It is expected that firmware upgrades would be needed in the early days of a smart meter rollout to fix various bugs or fine tune the operation of functionalities.

The benefit of this functionality is quite similar to item 25 above, and it is also a benefit of the avoidance of a cost in the alternative base case rather than a current cost.

The benefit has been calculated as for item 25 above, except that the frequency of field visits has been assumed to be once every 3 years (0.33 times per annum). The resulting avoided future cost of remote software upgrade is \$4.50 per customer per annum.

3.2.19. Item 27: Standard Base Plate

This functionality relates to using a separate standard base plate (meter socket) into which meters could be plugged. This would enable future replacement of the smart meter by unplugging one meter and plugging a new meter, rather than disconnecting wiring from meters as is currently the case. This would result in labour cost savings at the time a meter is replaced.

An analysis of the potential benefits of this has been undertaken by a NSW distribution business. The benefits in this report and the costs in the Stream 6 report have been derived from the financial modelling done by that NSW distribution business, with input from the experience of Victorian distribution businesses.

As noted above, the majority of the benefits accrue when there is a replacement of smart meters at the end of their life cycle, assuming a 15-year meter life. There is also some benefit realised on replacement of failed meters during the 15-year period. It is assumed that:

- When there is a replacement of all smart meters at the end of their life that a plug-in meter will require 20 minutes less time to replace than a bottom connected meter. Using a \$90 per hour labour rate (see general assumptions) this equates to a \$30 saving per meter;
- There is a 1% failure rate of meters per year;
- For meters that fail during their useful lives there is a labour saving of 30 minutes as a result of using plug-in meters and the applicable labour rate is \$120/hr (see general assumptions) due to the need for specialist skills not required for a rollout, but that are required on meter failure to be able to assess the cause of meter failure and any related damage that may have occurred to the metering installation.
- Labour costs grow at 3% in real terms per annum; and
- The discount rate is 8%.

The resulting present value of the benefit is \$20.66 per customer.

3.2.20. Item 28: Non-Meter Board Installation

This functionality is intended to avoid replacing meters on meter boards particularly where there are issues such as the presence of asbestos or where the insulation of wiring is degraded. Hence, it has some appeal to consider putting new smart meters on poles at the front of customers' premises. By metering the customer's consumption at the beginning of the service connection (i.e. at the pole) there is also the benefit that it is harder for customers to by-pass the meter.

The benefit to the network business (for Scenario 1 where the network business is the responsible party (RP)) is the avoided cost of replacing meters on meter boards. The benefit has been calculated as shown in Table 4 below:

Table 4: Calculation of Benefit of Non-Meter Board Installation

Meter Type	Proportion	Installation Cost (\$)	Cost (\$)
Single Phase - non off peak	53%	80	42.4
Single Phase - Off peak	35%	141	49.35
Three phase direct connect	10%	176	17.6
Three phase CT connect	2%	504	10.08
Average per meter avoided cost			\$119.43

The proportions of meters by meter type are a CRA estimate based on data from previous studies on metering. The installation cost by meter type is sourced from the Victorian Electricity Distribution Price Review 2006-2010.

Although there is a significant per customer benefit resulting, the costs for non-meter board installations are between 4 times and 30 times the value of the benefit. Additionally customers would suffer from not being able to monitor their usage by reading the meter themselves.

3.2.21. Item 29: Plug and Play Device Commissioning

Plug and play device commissioning of meters allows the meters to be activated and registered on the system remotely once they are installed, avoiding the costs of manual registration.

The benefit of this functionality is the avoidance of a future cost rather than a current cost.

It is estimated that the avoided manual commissioning time per meter would be 6 minutes. At a labour rate of \$90/hr this provides a once off \$9 per customer benefit.

4. RECURRING COSTS

The categories of recurring costs for incremental functionalities for network businesses that have been considered are:

- IT systems;
- Telecommunications;
- Smart metering data concentrators and LAN;
- Smart meters; and
- DR capabilities.

4.1. IT SYSTEMS

4.1.1. Scenario 1

Table 5 below shows the IT Capital and Operating Costs for Scenario 1. The capital cost numbers are from EMCa who have assessed this as part of the assessment of transitional costs. The costs are on a per customer basis. Given the lack of detail available for these systems, the annual operating cost has been obtained by taking the industry norm of 15% of the capital costs. Given that the timeframe over which the smart metering benefits and costs are being calculated is 15 years, it seems reasonable to allow for a system refresh mid way through at about year 7. The systems refresh is costed at 40% of the original capital cost. Systems refreshes are normally significantly less costly than original installation as generally business processes do not need major change, and there is no major change to the systems architecture.



Table 5: IT Systems Operating Expenditure – Scenario 1

Functionality	Capital		Opex			
	Total		Annual		Year 7 replacement	
	Lower	Upper			Lower	Upper
Energy Measurement						
9. Remote reading (daily)	1.25	1.87	0.19	0.28	0.50	0.75
10. Power factor measurement	0.79	1.19	0.12	0.18	0.32	0.47
11. Export/import metering	-	-	-	-	-	-
Switching & Load Management						
12. Remote connect/disconnect - Case A	0.39	0.62	0.06	0.09	0.16	0.25
12. Remote connect/disconnect - Case B	3.42	5.13	0.51	0.77	1.37	2.05
13. Supply Capacity Control	2.19	3.29	0.33	0.49	0.88	1.31
14. Load management at meters through a dedicated control circuit - Case B	2.19	3.29	0.33	0.49	0.88	1.32
14. Load management at meters through a dedicated control circuit - Case C	2.19	3.29	0.33	0.49	0.88	1.32
15. Interface for Other Load Control Devices - Case A	0.40	0.61	0.06	0.09	0.16	0.24
15. Interface for Other Load Control Devices - Case B	0.40	0.61	0.06	0.09	0.16	0.24
Facilitation of Customer Interaction						
16. Interface to Home Area Network using Open Standard - Case A	0.95	1.42	0.14	0.21	0.38	0.57
16. Interface to Home Area Network using Open Standard - Case B	0.95	1.42	0.14	0.21	0.38	0.57
17. Provision of an in-home display - Case A	-	-	-	-	-	-
17. Provision of an in-home display - Case B	-	-	-	-	-	-
17. Provision of an in-home display - Case C	-	-	-	-	-	-
18. Interface for Communications from gas and water meters - Case A	4.68	7.02	0.70	1.05	1.87	2.81
18. Interface for Communications from gas and water meters - Case B	4.68	7.02	0.70	1.05	1.87	2.81
Supply and Service Monitoring						
19. Quality of supply and other event recording	4.06	6.09	0.61	0.91	1.62	2.44
20. Meter Loss of Supply Detection and Outage Detection	3.13	4.69	0.47	0.70	1.25	1.88
21. Customer Supply Monitoring	0.33	0.49	0.05	0.07	0.13	0.20
22. Real time service checking	1.96	2.94	0.29	0.44	0.78	1.18
Standards and Interoperability						
23. Interoperability for meters/devices at application layer	-	-	-	-	-	-
24. Hardware component interoperability	-	-	-	-	-	-
Upgradeability and configurability						
25. Remote reconfiguration	1.17	1.76	0.18	0.26	0.47	0.70
26. Remote software upgrade	0.01	0.01	0.00	0.00	0.00	0.00
27. Separate standard base plate	0.01	0.01	0.00	0.00	0.00	0.00
28. Non meter board installation	0.01	0.01	0.00	0.00	0.00	0.00
29. Plug and Play Device commissioning	-	-	-	-	-	-

4.1.2. Scenarios 2

Table 6 below shows the capital cost and annual operating cost for network businesses in Scenarios 2. The same comments as made for Scenario 1 apply here as well.



Table 6: IT Systems Operating Expenditure – Scenarios 2

Functionality	Capital		Opex			
	Total		Annual		Year 7 replacement	
	Lower	Upper			Lower	Upper
Energy Measurement						
9. Remote reading (daily)	0.62	0.93	0.09	0.14	0.25	0.37
10. Power factor measurement	0.70	0.89	0.10	0.13	0.28	0.36
11. Export/import metering	-	-	-	-	-	-
Switching & Load Management						
12. Remote connect/disconnect - Case A	0.70	0.93	0.10	0.14	0.28	0.37
12. Remote connect/disconnect - Case B	3.73	5.44	0.56	0.82	1.49	2.18
13. Supply Capacity Control	2.18	3.27	0.33	0.49	0.87	1.31
14. Load management at meters through a dedicated control circuit - Case B	2.49	3.58	0.37	0.54	1.00	1.43
14. Load management at meters through a dedicated control circuit - Case C	2.49	3.58	0.37	0.54	1.00	1.43
15. Interface for Other Load Control Devices - Case A	0.70	0.89	0.10	0.13	0.28	0.36
15. Interface for Other Load Control Devices - Case B	0.70	0.89	0.10	0.13	0.28	0.36
Facilitation of Customer Interaction						
16. Interface to Home Area Network using Open Standard - Case A	0.93	1.40	0.14	0.21	0.37	0.56
16. Interface to Home Area Network using Open Standard - Case B	0.93	1.40	0.14	0.21	0.37	0.56
17. Provision of an in-home display - Case A	-	-	-	-	-	-
17. Provision of an in-home display - Case B	-	-	-	-	-	-
17. Provision of an in-home display - Case C	-	-	-	-	-	-
18. Interface for Communications from gas and water meters - Case A	-	-	-	-	-	-
18. Interface for Communications from gas and water meters - Case B	-	-	-	-	-	-
Supply and Service Monitoring						
19. Quality of supply and other event recording	4.36	6.38	0.65	0.96	1.74	2.55
20. Meter Loss of Supply Detection and Outage Detection	3.42	4.98	0.51	0.75	1.37	1.99
21. Customer Supply Monitoring	0.62	0.78	0.09	0.12	0.25	0.31
22. Real time service checking	1.94	2.92	0.29	0.44	0.78	1.17
Standards and Interoperability						
23. Interoperability for meters/devices at application layer	-	-	-	-	-	-
24. Hardware component interoperability	-	-	-	-	-	-
Upgradeability and configurability						
25. Remote reconfiguration	1.48	2.06	0.22	0.31	0.59	0.82
26. Remote software upgrade	-	-	-	-	-	-
27. Separate standard base plate	-	-	-	-	-	-
28. Non meter board installation	-	-	-	-	-	-
29. Plug and Play Device commissioning	-	-	-	-	-	-

4.1.3. Scenarios 4

Table 7 below shows the capital cost and annual operating cost for network businesses in Scenarios 4. The same comments as made for Scenario 1 apply here as well.

Table 7: IT Systems Operating Expenditure – Scenarios 4

Functionality	Capital		Opex			
	Total		Annual		Year 7 replacement	
	Lower	Upper			Lower	Upper
Energy Measurement						
9. Remote reading (daily)	0.62	0.93	0.09	0.14	0.25	0.37
10. Power factor measurement	0.70	0.89	0.10	0.13	0.28	0.36
11. Export/import metering	-	-	-	-	-	-
Switching & Load Management						
12. Remote connect/disconnect - Case A	0.70	0.93	0.10	0.14	0.28	0.37
12. Remote connect/disconnect - Case B	3.73	5.44	0.56	0.82	1.49	2.18
13. Supply Capacity Control	2.49	3.58	0.37	0.54	1.00	1.43
14. Load management at meters through a dedicated control circuit - Case B	2.49	3.58	0.37	0.54	1.00	1.43
14. Load management at meters through a dedicated control circuit - Case C	2.49	3.58	0.37	0.54	1.00	1.43
15. Interface for Other Load Control Devices - Case A	0.70	0.89	0.10	0.13	0.28	0.36
15. Interface for Other Load Control Devices - Case B	0.70	0.89	0.10	0.13	0.28	0.36
Facilitation of Customer Interaction						
16. Interface to Home Area Network using Open Standard - Case A	0.93	1.40	0.14	0.21	0.37	0.56
16. Interface to Home Area Network using Open Standard - Case B	0.93	1.40	0.14	0.21	0.37	0.56
17. Provision of an in-home display - Case A	-	-	-	-	-	-
17. Provision of an in-home display - Case B	-	-	-	-	-	-
17. Provision of an in-home display - Case C	-	-	-	-	-	-
18. Interface for Communications from gas and water meters - Case A	-	-	-	-	-	-
18. Interface for Communications from gas and water meters - Case B	-	-	-	-	-	-
Supply and Service Monitoring						
19. Quality of supply and other event recording	4.36	6.38	0.65	0.96	1.74	2.55
20. Meter Loss of Supply Detection and Outage Detection	3.42	4.98	0.51	0.75	1.37	1.99
21. Customer Supply Monitoring	0.62	0.78	0.09	0.12	0.25	0.31
22. Real time service checking	2.26	3.23	0.34	0.48	0.90	1.29
Standards and Interoperability						
23. Interoperability for meters/devices at application layer	-	-	-	-	-	-
24. Hardware component interoperability	-	-	-	-	-	-
Upgradeability and configurability						
25. Remote reconfiguration	1.48	2.06	0.22	0.31	0.59	0.82
26. Remote software upgrade	-	-	-	-	-	-
27. Separate standard base plate	-	-	-	-	-	-
28. Non meter board installation	-	-	-	-	-	-
29. Plug and Play Device commissioning	-	-	-	-	-	-

4.2. TELECOMMUNICATIONS

For the purposes of calculating the incremental telecommunications costs it has been assumed that all technologies use a public wireless communications link at some point in the smart metering infrastructure. Point-to-point smart metering technologies use a public wireless link all the way from the back office to the meter. For Mesh Radio, DLC and PLC it is assumed that public wireless is used from data concentrators back to the back office systems.

The recurrent cost of incremental functionalities is determined from the data required by those functionalities. Fixed or standing charges for public wireless connections do not vary with functionalities; it is only the charges for data that will vary with volume of data involved in each functionality. Appendix B contains an analysis of the data volumes for each functionality. The data volume analysis considers separately what volume of data is involved upstream and downstream. Furthermore, the peak day volumes and average daily volumes are identified. It is the average daily volumes that will be used as the driver for data charges.

The data volumes for smart metering are quite small. The total average upstream daily volume is 1623 bytes and the downstream volume is 2015 bytes. These figures include a factor of three allowance for the overhead associated with possible common application layer protocols. If the overhead for those is not included and only 10% of customers have an IHD then the average daily upstream volume is just 541 bytes and the downstream volume is just 400 bytes.

The incremental cost for such volumes of data is quite small. Telecommunications carriers have quoted incremental data costs ranging from \$0.10 to \$0.30 per megabyte. Indeed, retail wireless internet access plans typically have data costs (above the volume included in the monthly contract) between \$0.25 and \$0.30 per megabyte. Hence, the range of annual cost for all functionalities is from \$0.036 per annum (based on minimum data volume and \$0.10 per megabyte rate) to \$0.40 per annum (based on maximum data volume and \$0.30 per megabyte rate).

4.3. DATA CONCENTRATORS AND LAN

The major recurrent costs associated with data concentrators is maintenance. The level of maintenance for data concentrators is not be affected by the functionalities with which it is dealing.

The recurrent cost of a LAN is not affected by the number or nature of functionalities. In Mesh Radio, DLC and PLC systems, the LAN between the data concentrator and the meter is a private network and there are no costs for varying volumes of data.

4.4. SMART METERS

The major recurrent cost associated with smart meters is maintenance. The level of maintenance for meters is not likely to be affected in any material way by the functionalities included.

4.5. DEMAND RESPONSE CAPABILITIES

The main source of recurring cost in the incremental functionalities that provide demand response is the cost of participation incentives in the DLC programs described in Functionalities 15 and 16. These recurring costs have been assumed to be \$75 per participating customer per year.

Other recurring costs of the functionalities that provide demand response related benefits are assumed to be very low. This is based on the following assumptions:

- Once the smart meters are installed, upfront costs would be incurred for:
 - Developing a CPP tariff, which would be done once and then become part of the tariff re-balancing that the networks routinely undertake with regard to all their tariffs; and



- Developing and implementing a messaging capability to inform customers of the fact that a CPP event was being called.
- CPP tariffs will be implemented at the distribution business level (rather than on an area-specific basis). Recurring costs will be incurred in the areas of:
 - Messaging; that is, the actual variable costs for sending messages to customers on critical peak days; and
 - Program impact monitoring to determine whether the demand response received in areas where network augmentation deferrals are possible are achieving the reductions required to effect the deferrals.

These recurring costs have been estimated at \$200,000 per distribution business per year.

APPENDIX A – REQUEST FOR INFORMATION SENT TO DISTRIBUTION BUSINESSES

Core Functionality

No	Requirement	Performance Levels for Assessment
1.	Half-hourly⁷ consumption measurement and recording Meters should record active energy in 30 minute intervals	Assumed storage: minimum storage of 200 days for 1 channel of 30 minute interval energy data or 50 days per channel for 4 channels of 30 minute interval energy data.
2.	Remote reading (Weekly) Routine and special reading of interval energy data	Case A: To match data collection from current market critical customers i.e. those with current type 4 meters: All data from 80% of meters by 8am the day after reading All data from percentage of meters to achieve market data long term performance by 5:00 pm the second day after the read date
3.	Local reading – hand-held device Special reading of interval energy data at the meter – hand-held device used by DB/RB/MDA etc	
4.	Local reading – visual display on meter	
5.	Communications and data security The smart meter system would ensure the security of:	

⁷ A reference to 'Half-hourly' should be read as "in line with the settlement interval in the relevant wholesale market". In actual practice this may be half-hourly or every fifteen minutes.

No	Requirement	Performance Levels for Assessment
	The data in the end point devices (including meters and data concentrators, where used); The communications system; and Collected data.	
6.	Tamper Detection The smart meter system would support detection of attempts to tamper with the meter and remote communication of tampering detected to the NMS.	
7.	Remote Time Clock Synchronisation Remote setting of the clock and maintenance of clock accuracy	Date and time within meters maintained within 20 seconds of EST time. <i>General comment: To achieve time accuracy, need time setting within maybe 10 seconds; if delay in getting synch signal to meter is not predictable within seconds then less accurate time synch may have to be accepted to keep costs down. What are the real costs of inaccurate time?</i>

No	Requirement	Performance Levels for Assessment
8.	<p>Load management at meters through a dedicated controlled circuit – Case A</p> <p>The following are the features required of single phase or three phase meters with an internal controlled load contactor and three phase meters equipped to operate an external controlled load contactor:</p> <p>Storage in the meter of automatic “turn on” & “turn off” times.</p> <p>Ability to remotely override “turn on” & “turn off” commands, both for individual meters and in broadcast groups.</p> <p>“Boost” facility for single phase controlled load meters. When a customer presses the meter’s “boost” button, the meter would energise the controlled load for a preset time.</p> <p>Meters with integrated single phase load control would have a controlled load contactor with a minimum current rating of 31.5 A resistive (AC1 rating) and a nominal voltage rating of 230 Vac⁸.</p> <p>Meters for three phase load control, would have an integral relay with a minimum rating of 1.0A, and a nominal voltage rating of 230 V AC for operation of an external three phase load control contactor.</p>	<p>Case A: For broadcast “turn on” or “turn off” commands to any broadcast group of meters the performance level required is:</p> <p>Action performed at 90% of meters within 20 minutes</p> <p>Action performed at 99% of meters within 1 hour</p>

⁸ The tolerance on the rated voltage is as per the Electricity Distribution Code

Additional Functionality

No	Requirement	Performance Levels	Recurring Network Costs	Suggested Network Benefits	Suggested Input Metrics & Method of Quantification of Network Benefits	Estimate of Quantifiable Benefits (Annual Value \$)
	Energy Measurement					
9.	Remote reading (daily) Routine and special reading of interval energy data	<p>Case B: Daily collection of the previous trading day's 30 minute interval energy data according to the following schedule:</p> <p>All data from 99% of meters within 4 hours after midnight</p> <p>All data from 99.9% of meters within 24 hours after midnight</p>		No benefits to DBs.		
10.	Power factor measurement Half-hourly reactive energy measurement sampled by DBs.	Remotely activated functionality. Assume all meters measure and store reactive interval energy data but that this data is only retrieved for 5% of meters.		<p>1. Ability to monitor power factor down to an individual customer. Enabling identifying customers with poor power factor and then subsequently working with those customers to improve power factor to within code requirements. Thereby enabling deferment of augmentation capex on the network.</p> <p>2. More options for network tariffs – able to charge by KVA supplied.</p>	<p>Value of augmentations to MV/LV network required because of poor power factor</p> <p>\$.....pa</p> <p>Proportion of these augmentations that can be deferred if power factor problems could be tracked and fixed</p> <p>.....%</p> <p>Benefits from network</p>	

No	Requirement	Performance Levels	Recurring Network Costs	Suggested Network Benefits	Suggested Input Metrics & Method of Quantification of Network Benefits	Estimate of Quantifiable Benefits (Annual Value \$)
					tariff using kVA?	
11.	<p>Import/export metering</p> <p>Record active energy flows in both directions</p>	<p>Remotely activated functionality. It is assumed that import active energy interval data is only retrieved on 10% of meters.</p>		<p>Avoided cost of changes to metering when a customer installs local generation such as PV cells</p>	<p>Forward looking projection of number of customers likely to install local generation per annum</p> <p>.....% of customers</p> <p>Cost of changing metering for customers installing local generation</p> <p>\$.....</p>	
	<p>Switching & Load Management</p>					
12.	<p>Remote connect/disconnect</p> <p>Connect/disconnect contactor on all direct-connect meters, able to be controlled both locally and remotely, and with ability to check the status remotely.</p> <p>Note: This item of functionality is a prerequisite for functionality 13 & 21</p>	<p>Case A: The following performance level for up to 2% of all meters in any day.</p> <ul style="list-style-type: none"> (1) Action performed at 90% of meters within 30 minutes (2) Action performed at 99% of meters within 1 hour (3) Action performed at 99.9% of meters within 6 		<p>Case A:</p> <p>1. Avoided cost of manual disconnections and reconnections:</p> <ul style="list-style-type: none"> - For move outs/ move ins - Disconnections for non-payment - Reconnections for payment - Disconnections due to extended vacancy of 	<p>Case A:</p> <ul style="list-style-type: none"> 1. Number of manual connections pa Number of manual disconnections pa Charge for disconnections 	

No	Requirement	Performance Levels	Recurring Network Costs	Suggested Network Benefits	Suggested Input Metrics & Method of Quantification of Network Benefits	Estimate of Quantifiable Benefits (Annual Value \$)
		<p>hours</p> <p>(4) Action performed at "last" 0.1% of meters before COB next business day after request made.</p> <p>Case B: For up to 2% of all meters, in any day action is performed at 90% of those meters within 10 minutes</p>		<p>premises (but not supply abolishment)</p> <ul style="list-style-type: none"> - Reconnections after extended vacancy of premises - Disconnections for safety issues <p>2. Quicker connections resulting in reduction in unserved energy</p> <p>Case B:</p> <ul style="list-style-type: none"> - Benefit of higher speed connections and disconnections 	<p>and reconnections</p> <p>\$..... each</p> <p>2. Average improvement in connection timehours</p> <p>Average number of reconnections per day</p> <p>Average customers hourly electricity cost (network tariff only)</p> <p>\$..... per hour</p> <p>Case B:</p> <p>Incremental value if remote connections/disconnections could be performed in 10 minutes rather than 30 minutes?</p> <p>\$.....each</p>	

No	Requirement	Performance Levels	Recurring Network Costs	Suggested Network Benefits	Suggested Input Metrics & Method of Quantification of Network Benefits	Estimate of Quantifiable Benefits (Annual Value \$)
13.	<p>Supply Capacity Control (functionalities 12 & 25 - connect/disconnect & remote configuration are prerequisites for this functionality)</p> <p>Smart meters (except CT connected meters) shall have two supply capacity limit settings – a normal limit and an emergency limit. This functionality applies only to direct connected meters (i.e. does not apply to CT connected meters):</p> <p>Normal supply capacity limit:</p> <p>Emulation of the operation of a supply capacity control circuit breaker currently installed at a range of new customer installations; and</p> <p>Providing the capability to limit supply capacity for short periods of time in accordance with customer contractual agreements, (subject to the development of appropriate regulatory</p>	<p>Case A: The performance level required for individual meters, up to a total of 2% of all meters installed, in any day.</p> <ul style="list-style-type: none"> (1) Action performed at 90% of meters within 30 minutes (2) Action performed at 99% of meters within 1 hour (3) Action performed at 99.9% of meters within 6 hours <p>Case B: For broadcast commands to any group or meters:</p> <ul style="list-style-type: none"> (1) Action performed at 90% of meters within 10 minutes (2) Action performed at 99% of meters within 1 hour 		<p>Normal supply capacity limit:</p> <ul style="list-style-type: none"> 1. Ability to offer demand based network tariffs (which more accurately reflect the cost drivers of the network business) 2. Ability to limit customers supply to a lower value than the service fuse rating 3. Ability to remotely restore customers supply after they have exceeded their supply capacity limit – i.e. avoided cost of replacing blown service fuse or resetting tripped service circuit breaker. <p>Emergency supply capacity limit:</p> <ul style="list-style-type: none"> 1. Ability to restore more customers to supply more quickly after system trips (blackouts due to supply shortages) 2. Avoided cost of proportion 	<p>Normal supply capacity limit:</p> <ul style="list-style-type: none"> 2. Avoided augmentation capex by being able to limit customers supply to a rating lower than service fuse rating <p>\$..... pa</p> <ul style="list-style-type: none"> 3. Avoided cost of service fuse replacement. <ul style="list-style-type: none"> - Number of customer service fuses replaced pa. - Average Charge for each service fuse replacement <p>\$.....</p> <p>Total annual avoided charges</p> <p>\$.....</p> <p>Normal supply capacity</p>	

No	Requirement	Performance Levels	Recurring Network Costs	Suggested Network Benefits	Suggested Input Metrics & Method of Quantification of Network Benefits	Estimate of Quantifiable Benefits (Annual Value \$)
	<p>arrangements).</p> <p>Emergency supply capacity limit:</p> <p>Activated by a broadcast to groups of meters, or by commands sent to individual meters.</p> <p>When the emergency supply capacity limit is activated this will take precedence over the normal supply capacity setting.</p> <p>The emergency supply capacity limit functionality must be capable of being disabled for selected meters (e.g. for life support customers)</p>			<p>of calls to call centre regarding being off supply</p> <p>3. Public safety – e.g. less car accidents due to quicker restoration of power to traffic lights</p> <p>4. Improved SAIDI, CAIDI</p>	<p>limit:</p> <p>Avoided cost of proportion of calls to call centre regarding being off supply</p> <p>Number of callspa</p> <p>Average cost per call \$.....</p>	
14.	<p>Load management at meters through a dedicated controlled circuit – Cases B & C (Case A is in the Core). Note this assumes functionality No 25</p> <p>The following are the features required of single phase or three phase meters with an internal controlled load</p>	<p>Case B: For “turn on” and “turn off” commands sent to individual meters, up to a total of 2% of all meters in any day:</p> <p>Action performed at 90% of meters within 1 hour</p> <p>Action performed at 95% of meters within 2 hours</p> <p>Action performed at 99% of meters</p>		<p>Case B:</p> <p>Demand response benefit in being able to shift network load away from peak periods</p> <p>Case C:</p> <p>Ability to shed load quicker (<1 min) results in what value of benefit to DBs?</p>		

No	Requirement	Performance Levels	Recurring Network Costs	Suggested Network Benefits	Suggested Input Metrics & Method of Quantification of Network Benefits	Estimate of Quantifiable Benefits (Annual Value \$)
	contactor and three phase meters equipped to operate an external controlled load contactor in addition to functionality 8: "Turn on" and "turn off" times are remotely settable for each meter separately and in groups, through the smart meter communications system. – This is however included in functionality 25	within 3 hours - Action performed at 99.9% of meters within 6 hours Case C: Remote "Turn on" or "turn off" action performed at 99% of meters within 1 minute				
15.	Interface for Other Load Control Devices smart meter systems shall have the capability to communicate to other load control devices via the smart meter communications network (a) Load control devices shall have integral time clocks and separate sets of "turn on" & "turn off" times per week day and per weekend day (b) At "turn on" times meters would react by turning on the controlled load after a	As for controlled load management at meters Case A: - Action performed at 90% of meters within 20 minutes. - Action performed at 99% of meters within 1 hour. Case B: - Action performed at 99% of meters within 1 minute		Case A: 1. Ability to remotely and directly control loads such as pool pumps, air conditioners, dishwashers etc. This may allow DBs to better manage their networks and defer augmentation capex. 2. Ability to offer interruptible network tariff and thereby defer network investment Case B: As for case A but able to interrupt load quicker – within a minute.	a) For each 1% of reduction of peak demand through use of this functionality what would be the consequent value of augmentation capex that can be deferred \$.....pa b) What % peak demand reduction could realistically be achieved using this functionality %	

No	Requirement	Performance Levels	Recurring Network Costs	Suggested Network Benefits	Suggested Input Metrics & Method of Quantification of Network Benefits	Estimate of Quantifiable Benefits (Annual Value \$)
	<p>randomised time delay remotely settable from 0 minute to 60 minutes in 1 minute increments (Often referred to as "spread on").</p> <p>(c) "Turn on" and "turn off" times are remotely settable for each device individually and in groups by broadcast, through the smart meter communications system.</p> <p>(d) Ability to respond to broadcast primary (Master) group commands, secondary groups group commands and individual load control commands.</p> <p>(e) The meter shall be remotely programmable to respond to one primary (master) group and one secondary group.</p>					

No	Requirement	Performance Levels	Recurring Network Costs	Suggested Network Benefits	Suggested Input Metrics & Method of Quantification of Network Benefits	Estimate of Quantifiable Benefits (Annual Value \$)
	Facilitation of Customer interaction					
16.	<p>Interface to Home Area Network (HAN) using Open Standard</p> <p>(a) All smart meters shall have the capability to communicate with devices (such as In Home Displays – IHDs) connected to a HAN using open standard. E.g. Zigbee protocol. The meter will be an end device (not a co-ordinator) on the HAN network.</p> <p>(b) All communications to a customer’s HAN shall be uniquely bound to the customer’s meter. (This is to ensure that a customer’s HAN receives information pertaining to their premises and not a neighbour’s premises.)</p> <p>(c) The HAN co-ordinator shall be able to read from the meter:</p> <p>(1) The meter’s current demand (kW) with</p>	<p>The smart metering infrastructure shall be able to send messages through meters to HAN devices (and receipt shall be confirmed back from IHD to NMS).</p> <p>Tariff Update Messaging Requirements: Tariff update messages (up to 12 times a year) to allow updating of rates (c/kWh) and times for the tariffs stored in the IHD.</p> <p>Case A: The performance level required for sending tariff update messages to all meters with IHDs connected.</p> <p>Message received by 99.5% of meters to which an IHD is connected, in 7 days</p> <p>Message received by 99.9% of meters to which an IHD is connected, in 14 days</p> <p>Case B: The performance level required for sending tariff update messages to 2% of meters with IHDs connected.</p> <p>Message received by 99.5% of</p>				

No	Requirement	Performance Levels	Recurring Network Costs	Suggested Network Benefits	Suggested Input Metrics & Method of Quantification of Network Benefits	Estimate of Quantifiable Benefits (Annual Value \$)
	<p>sign to indicate export or import (unvalidated data).</p> <p>(2) The last 30 minute interval energy data (unvalidated data) for real energy export and real energy import together with the date and time.</p> <p>(3) The applicable supply capacity limit (kW).</p> <p>(d) The HAN co-ordinator or any other device on the HAN shall not be able to write information to the meter.</p> <p>(e) Should there be insufficient bandwidth to send freeform messages to each customer individually there shall be allowance to broadcast these to customer groups according to which retailer and tariff they use. (e.g. allowing for 20 retailers and 30 message types per retailer this would equate to 600 broadcast</p>	<p>meters to which an IHD is connected, in 12 hours</p> <p>Message received by 99.9% of meters to which an IHD is connected, in 24 hours</p> <p>Critical Peak Pricing Requirements: Advice of a critical peak price event (maximum of 10 times a year) The performance levels required to send CPP notification messages to IHDs</p> <p>Message received by 99.5% of meters to which an IHD is connected, in 6 hours</p> <p>Message received by 99.9% of meters to which an IHD is connected, in 12 hours</p> <p>Freeform message requirements: Freeform text messages up to 255 characters long (maximum of once per day). The performance levels required to send 10 freeform messages to IHDs (either individual messages or broadcast messages to each tariff/retailer group) per day per retailer:</p> <p>Message received by 99.5% of meters to which an IHD is</p>				

No	Requirement	Performance Levels	Recurring Network Costs	Suggested Network Benefits	Suggested Input Metrics & Method of Quantification of Network Benefits	Estimate of Quantifiable Benefits (Annual Value \$)
	messages instead of unique messages to each customer).	connected, in 24 hours Message received by 99.9% of meters to which an IHD is connected, in 48 hours Receipt flags to be sent.				
17.	Provision of an in-home display An in-home display is provided as part of the meter package.	<i>Performance Levels</i> Case A: 3 Lights – Southern California Edison version Case B: Free form messaging Case C: Capable of providing customer initiated response		With rollout of IHDs obtain a higher demand response		
18.	Interface for Communications from gas and water meters Communications interface to allow communications from gas meters and water meters, allowing them to send information upstream.	Case A: 3-monthly meter readings Case B: hourly interval readings (water)		Business opportunity to read gas and water meters. Assumed revenue from this would be up to 50% of avoided cost of manual reading as done currently	Assume direct gas/water meter reading cost is \$0.50 per read. Gas yearly read cost is \$3, Water is \$2. Assumed remote reading charge of 50% of current charges - \$2.50 p.a?	
	Supply and service monitoring					
19.	Quality of Supply & other event recording All smart metering infrastructure is to have the	To read the full event log for any single meter, for up to 2% of all meters in any day The data from 90% of meters in 1		Ability to remotely monitor Quality of Supply at every customer premises. Benefits: 1. Able to identify areas with		

No	Requirement	Performance Levels	Recurring Network Costs	Suggested Network Benefits	Suggested Input Metrics & Method of Quantification of Network Benefits	Estimate of Quantifiable Benefits (Annual Value \$)
	<p>capability to record Quality of Supply (QoS) events and other events, which can be remotely retrieved. The smart meter would record the nature of the event (e.g. outage, under-voltage, disconnect, meter loss of supply, change of settings etc), the date and time of the beginning of the event, and the date and time of the end of the event.</p>	<p>hour</p> <p>The data from 95% of meters in 2 hours</p> <p>The data from 99% of meters in 3 hours</p> <p>The data from 99.9% of meters in 6 hours</p> <p>To read the event logs remotely for all meters:</p> <p>The data from 99.5% of meters in 1 week</p> <p>The data from 99.9% of meters in 2 weeks</p>		<p>volt drop problems and target network reconfiguration or augmentation to those areas where there is likely to volt drops in excess of the distribution code.</p> <p>- saving of avoided cost of manual methods of tracking voltage performance at customers premises</p> <p>- Deferment of MV and LV augmentation in areas where there are not capacity or volt drop issues.</p> <p>2. Ability to identify areas with higher minutes off supply and higher contributions to CAIDI, CAIFI SAIFI and SAIDI) and then through targeted actions to improve performance.</p> <p>- saving of avoided cost of manual methods of tracking outage duration and frequency performance measures</p> <p>- improvement in effectiveness of targeting network augmentation to improve outage duration and</p>		

No	Requirement	Performance Levels	Recurring Network Costs	Suggested Network Benefits	Suggested Input Metrics & Method of Quantification of Network Benefits	Estimate of Quantifiable Benefits (Annual Value \$)
				frequency results		
20.	<p>Meter Loss of Supply detection and Outage Detection</p> <p>All smart metering infrastructure would include a means of detecting loss of supply to meters including those at individual customer's premises (e.g. using a routine service ping). Smart metering infrastructure would also include means for outage detection, either at meters or at distribution transformers. When a meter loss of supply or outage is detected it would be alarmed.</p>	Alarms to be received within one hour for 90% of meters		<p>1. Faster detection of customer outages – does not rely on customers calling in, and includes more accurate plotting of extent of outages and hence better fault identification:</p> <ul style="list-style-type: none"> - saving of avoided cost of call centre operators dealing with outage notification calls (reduction of X%) - quicker diagnosis resulting in reduced outage durations resulting in lower CAIDI - quicker restoration resulting in reduction in unserved energy <p>2. Faster detection of brown outs:</p> <ul style="list-style-type: none"> - saving is avoided cost of customers claims for damage to appliances (e.g. fridge motors burnt out due to low voltage) <p>3. Improved efficiency in mopping up after storms. Supply to all customers in an</p>		

No	Requirement	Performance Levels	Recurring Network Costs	Suggested Network Benefits	Suggested Input Metrics & Method of Quantification of Network Benefits	Estimate of Quantifiable Benefits (Annual Value \$)
				area can be checked before crews leave a storm affected area. Benefit – avoided cost of subsequent crew callouts.		
21.	<p>Customer Supply Monitoring</p> <p>All single phase meters would have means for detecting:</p> <p>Reverse polarity on customer's connection</p> <p>Degradation of the customer's neutral</p> <p>Degradation of the customer's earth connection (from switchboard to earth)</p> <p>Alarms sent upstream when the above conditions are detected</p>	Alarms to be received within one day for 90% of meters		<p>Note: This functionality assumes functionality No 12</p> <p>Benefits:</p> <p>1. Increased Safety:</p> <ul style="list-style-type: none"> - Avoid fatalities and electric shocks caused by reverse polarity - Avoid fatalities and electric shocks caused by deteriorated neutral connections - Avoid fatalities and electric shocks caused by deteriorated customer earths <p>2. Reduced costs:</p> <ul style="list-style-type: none"> - Avoid NST testing the entire population of LV services every 10 years - Schedule replacement of LV services prior to failure, 		

No	Requirement	Performance Levels	Recurring Network Costs	Suggested Network Benefits	Suggested Input Metrics & Method of Quantification of Network Benefits	Estimate of Quantifiable Benefits (Annual Value \$)
				therefore reducing the replacement costs. 3. Improve reliability: - Schedule replacement of LV services prior to failure, therefore avoiding customer outages in fault conditions.		
22.	<p>Real-time service checking</p> <p>The meter accessed remotely in real time to check the presence of supply to the meter</p>	<p>Latency of 1 minute or less to 90% of meters</p>		<p>What is the incremental benefit of this functionality above the benefits in item 20 above? Ability to check supply at customer's meter while the customer is on the phone.</p> <p>Benefits: Avoided cost of return call to the customer when service is checked using functionality 20 above</p>		
	Standards and interoperability					
23.	<p>Interoperability for meters / devices at application layer</p> <p>Interoperability (i.e. known device driver protocols) for</p>	<p>N/A</p>		<p>Ability to use an NMS system other than that provided by the smart metering infrastructure vendor. Also the ability to use one NMS to manage more than one smart</p>		

No	Requirement	Performance Levels	Recurring Network Costs	Suggested Network Benefits	Suggested Input Metrics & Method of Quantification of Network Benefits	Estimate of Quantifiable Benefits (Annual Value \$)
	communications with meters or devices at the application layer, rather than the underlying hardware and network layers of the system. This would allow requests and messages to be sent to the system by parties other than the party primarily responsible through a standard interface (e.g. MV90-type solution).			metering infrastructure (e.g. metro system and rural system). Hence more competition in supply of NMS systems resulting in reduction in costs.		
24.	<p>Hardware component interoperability</p> <p>Hardware components which can operate with components from different manufacturers – for example communications modules and meters</p>	N/A		<p>Benefits:</p> <p>Ability to source compliant meters, data concentrators and other smart metering infrastructure devices from several vendors thereby gaining price reductions through competitive supply. (This assumes that such standards compliant smart metering infrastructure is available)</p>	<p>Assumed price reduction achievable</p> <p>.....</p> <p>....%</p>	
	Upgradeability and configurability					
25.	<p>Remote reconfiguration</p> <p>Meter settings would be remotely reconfigurable.</p>	For changing one setting, or for reading all the settings, in up to 2% of all meters in any day		<p>Benefits:</p> <p>Avoided cost of visiting customers' sites to alter</p>	Assumed forward looking number of visits to customers premises to	

No	Requirement	Performance Levels	Recurring Network Costs	Suggested Network Benefits	Suggested Input Metrics & Method of Quantification of Network Benefits	Estimate of Quantifiable Benefits (Annual Value \$)
	Settings would include, for example: es for controlled load switching eshoulds for quality of supply events ply capacity control settings Note: This functionality is a prerequisite for number 14.	on performed at 90% of meters within 1 hour on performed at 95% of meters within 2 hours on performed at 99% of meters within 3 hours on performed at 99.9% of meters within 6 hours		controlled switching times, thresholds for quality of supply events or supply capacity settings. Assume 1 visit every 5 years (0.2 visits pa).	alter settings pa Cost of customer premises visit to change meter settings \$ per visit	
26.	Remote software upgrades The software in the meter can be upgraded remotely by the responsible person over the communications link. The software shall be installed in the meter without the need for a site visit or action from the customer.	N/A		Benefits: Avoided cost of visiting customers' sites to upgrade smart metering infrastructure firmware. Assume 1 visit every 5 years (0.2 visits pa).	Assumed forward looking number of visits to upgrade metering firmware pa Cost of customer premises visit to upgrade metering firmware \$ per visit	
27.	Separate standard base plate A base plate into which the meter can be plugged. It may be possible for the	N/A		Benefits: 1. Reduced meter replacement time when replacing smart meters that fail during the infrastructure	Reduction in maintenance replacement time ofminutes at labour rate of \$.....per hour.	

No	Requirement	Performance Levels	Recurring Network Costs	Suggested Network Benefits	Suggested Input Metrics & Method of Quantification of Network Benefits	Estimate of Quantifiable Benefits (Annual Value \$)
	communications unit to be plugged into the base plate as well.			lifecycle time. 2. Reduced meter replacement time at end of smart meter infrastructure lifecycle when all meters are replaced with the next technology	Assumed failure rate of meters% Reduction in end of lifecycle replacement time of smart metersminutes at labour rate of \$.....per hour.	
28.	Non meter board installation Instead of the meter mounted on the wall of the premises, it is mounted elsewhere (e.g. on the power pole supplying the premises).	N/A		Avoids replacing meters on customer meter boards and then dealing with bad wiring or asbestos Reduction in electricity fraud using meter by passing	Avoided cost of replacing meters for smart metering infrastructure rollout \$..... Reduction in fraud (non technical losses) from% of revenue to% of revenue	
29.	Plug and Play Device commissioning			Reduction in smart meter commissioning time and reduction in re-visiting meters to complete commissioning or fix commissioning errors	Reduced commissioning time per meter ofminutes at labour rate of \$...../hr	

APPENDIX B -- RECURRENT COMMUNICATIONS COSTS

	Daily Data Volume Metrics					
	Upstream - Peak daily volume (bytes)	Upstream Average daily Volume (bytes)	Upstream - assumptions	Downstream Peak Daily volume (bytes)	Downstream average daily volume (bytes)	Downstream - assumptions
CORE FUNCTIONALITY						
1. Half hourly consumption measurement and recording	0	0				
2. Remote reading (weekly)	200	200	4 bytes for each half hour of data	10	10	Read request
3. Local reading - hand-held device	0	0				
4. Local reading - visual display on meter	0	0				
5. Communications and data security	0	0				
6. Tamper Detection	30	1				
7. Remote time clock synchronisation	0	0		30	30	Daily time synch
8. Load management at meters through a dedicated controlled circuit	0	0		40	40	Daily load control on and off commands
ADDITIONAL FUNCTIONALITY						

	Daily Data Volume Metrics					
	Upstream - Peak daily volume (bytes)	Upstream Average daily Volume (bytes)	Upstream - assumptions	Downstream Peak Daily volume (bytes)	Downstream average daily volume (bytes)	Downstream - assumptions
Energy Measurement						
9. Remote reading (daily)	0	0	Same average daily volume as for Functionality No 2	0	0	
10. Power factor measurement	200	10	for 5% of customers - 5% of 200 bytes	10	1	Depending on how frequently read per day
11. Import/export metering	200	10	for 5% of customers - 5% of 200 bytes	10	1	
Switching and Load Management						
12. Remote connect/disconnect	5	1	Sending Ack response	30	1	It is not anticipated that Connect/disconnect is used frequently - perhaps 30% of customers once per annum. The commands are relatively small

Daily Data Volume Metrics					
Upstream - Peak daily volume (bytes)	Upstream Average daily Volume (bytes)	Upstream - assumptions	Downstream Peak Daily volume (bytes)	Downstream average daily volume (bytes)	Downstream - assumptions
5	1	Sending Ack response	30	1	<p>data volumes and hence the average daily volume would be negligible</p> <p>It is not anticipated that changes to supply capacity control would occur frequently - perhaps 30% of customers once per annum. The commands are relatively small data volumes and hence the average daily volume would be negligible</p>

13. Supply Capacity Control

Daily Data Volume Metrics					
Upstream - Peak daily volume (bytes)	Upstream Average daily Volume (bytes)	Upstream - assumptions	Downstream Peak Daily volume (bytes)	Downstream average daily volume (bytes)	Downstream - assumptions
5	1	Sending Ack response	100	1	It is not anticipated that changes to load control switching times would occur frequently - perhaps 30% of customers once per annum. The commands are relatively small data volumes and hence the average daily volume would be negligible Assumes that there are about 5% of customers that take up this functionality and that it is used
5	1	Sending Ack response	100	1	

14. Load mgt at meters through a dedicated control circuit

15. Interface for Other Load Control Devices

Daily Data Volume Metrics						
Upstream - Peak daily volume (bytes)	Upstream Average daily Volume (bytes)	Upstream - assumptions	Downstream Peak Daily volume (bytes)	Downstream average daily volume (bytes)	Downstream - assumptions	
					about 10 times a year on peak days. Hence the average data	
Facilitation of Customer Interaction						
16. Interface to Home Area Network using Open Standard	5	1	Sending Ack response	255	25	Assume 10% uptake of IHDs
17. Provision of an in home display	5	5		255	255	Requires 100% uptake
18. Interface for Communications from gas and water meters	50	1	Assumes that gas and water meter readings are register reads and not interval data and reading frequency is every 2 months			
Supply and Service Monitoring						
19. Quality of supply and other event recording	200	5	Average of 10 events per year	5	1	Sending Ack response

Daily Data Volume Metrics					
Upstream - Peak daily volume (bytes)	Upstream Average daily Volume (bytes)	Upstream - assumptions	Downstream Peak Daily volume (bytes)	Downstream average daily volume (bytes)	Downstream - assumptions
20. Meter Loss of Supply detection and Outage Detection	300	300	Assumes pinging the meter every 15 minutes, with total of 3 bytes per ping	300	300
21. Customer Supply Monitoring	30	1	one event every 5 years		
22. Real-time service checking	3	1	Every 2 years - this is a ping	3	1
Standards and Interoperability					
23. Interoperability for meters/devices at application layer 24. Hardware component interoperability	2886	1082	Increased overhead on communications to implement an open standard. Assume this triples the data volumes due to increased protocol overhead	24556	1360
					Increased overhead on communications to implement an open standard. Assume this triples the data volumes due to increased protocol overhead

	Daily Data Volume Metrics					
	Upstream - Peak daily volume (bytes)	Upstream Average daily Volume (bytes)	Upstream - assumptions	Downstream Peak Daily volume (bytes)	Downstream average daily volume (bytes)	Downstream - assumptions
Upgradeability and Configurability						
25. Remote reconfiguration	0	0		1000	1	Once every 3 years Assumes downloading a software patch - once every 3 years
26. Remote software upgrade	100	1		10000	10	
27. Separate standard base plate						
28. Non meter board installation						
29. Plug and Play Device commissioning	100	1		100	1	Once every 5 years
	4329	1623		36834	2015	Total with 100% IHDs
					1760	Total with 10% IHDs
Total without overhead of interoperable protocols (No 23) & only 10% IHDs		541			400	